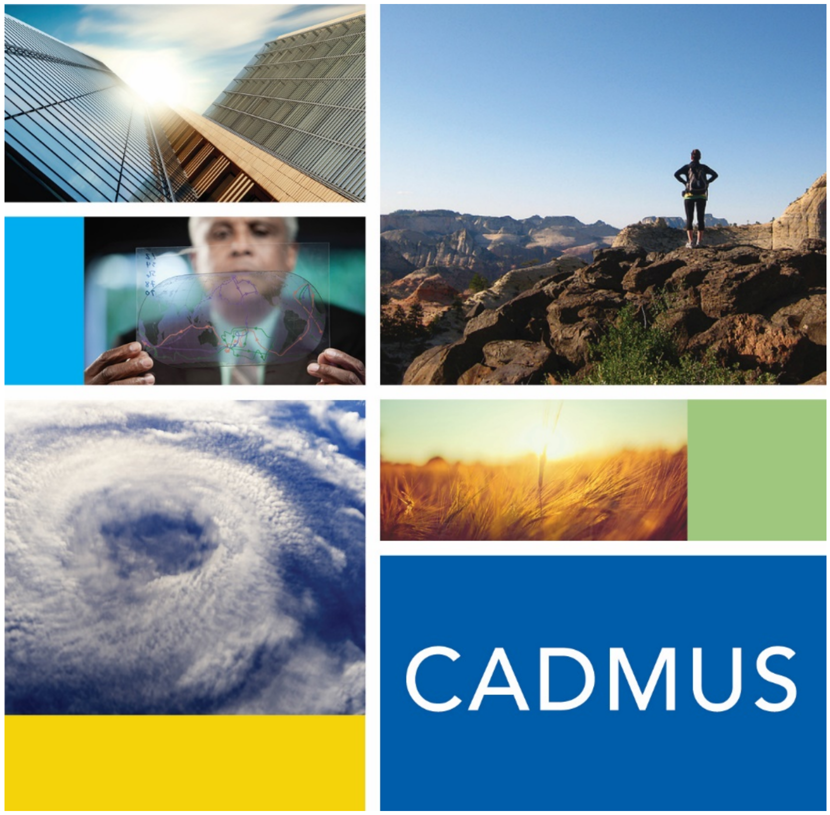

Demand Response Potential in Bonneville Power Administration's Public Utility Service Area

Final Report

March 19, 2018

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Acknowledgements

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Acronyms and Abbreviations

Acronym or Abbreviation	Definition
AGS	Average Generator Size
AMI	Advanced Metering Infrastructure
aMW	Average Annual Megawatts
BPA	Bonneville Power Administration
BTM	Behind the Meter
BYOT	Bring-Your-Own Thermostat
C&I	Commercial and Industrial
CAC	Central Air Conditioner
CBSA	Commercial Building Stock Assessment
CHP	Combined Heat and Power
CPP	Critical Peak Pricing
DER	Distributed Energy Resources
DG	Distributed Generation
DLC	Direct Load Control
DOE	U.S. Department of Energy
DR	Demand Response
DSM	Demand Side Management
DVR	Demand Voltage Reduction
EIA	U.S. Energy Information Administration
EMS	Energy Management System
EPA	U.S. Environmental Protection Agency
ESS	Energy Storage Systems
ETS	Electric Thermal Storage
FERC	Federal Energy Regulatory Commission
FTM	Front of the Meter
GW	Gigawatt
IOU	Investor-Owned Utility
ISO	Independent System Operator
kV	Kilovolt
kW	Kilowatt
LCOE	Levelized Cost of Electricity
MW	Megawatt
NEEA	Northwest Energy Efficiency Alliance
O&M	Operations and Maintenance
PCT	Programmable Controllable Thermostat

Acronym or Abbreviation	Definition
PV	Photovoltaic
R&D	Research and Development
RAC	Room Air Conditioner
RBSA	Residential Building Stock Assessment
RTF	Regional Technical Forum
RTO	Regional Transmission Organization
RTP	Real-Time Pricing
SCADA	Supervisory Control and Data Acquisition
TOU	Time of Use
TRC	Total Resource Cost

1. Executive Summary

1.1. Background

To facilitate the consideration of potential capacity delivered by energy efficiency measures and demand response resources in regional resource planning processes, the Northwest Power and Conservation Council, in its Action Plan for the Seventh Power Plan, recommended several actions including these:

- First, it directed the Regional Technical Forum (RTF) to develop quality guidelines to validate the reliability of capacity savings achieved through energy efficiency.
- Second, it recommended that the Bonneville Power Administration (BPA) assess the achievable DR potential within its service area and include that assessment's results in the its 2017–2018 Resource Program.

To fulfill the Action Plan's second recommendation and to meet its internal planning needs, BPA engaged Cadmus to conduct a comprehensive assessment of opportunities, costs, and barriers to deployment and adoption of distributed energy resources (DER) in BPA's firm energy service area and within the Pacific Northwest Region (for the purposes of these studies, herein referred to as the Region). The study covers three DER options: demand response (DR); customer-sited distributed generation (DG); and storage.

The study primarily focuses on DR, and it is split into two parts:

- Assessment 1 (covered in this document) evaluated commercially viable DR products and estimated the technical and achievable DR potential in the BPA service area
- Assessment 2, a complementary volume to Assessment 1, investigated the barriers and challenges to deployment and adoption of DR from the perspectives of various regional DR market stakeholders

Assessment 1 provides BPA and the Region with an understanding of the magnitude and costs of the realistically achievable DER potential within the BPA's service area. Assessment 2 explores and discusses the potential barriers that may hamper the Region's ability to deploy DER resources in a timely and cost-effective manner.

This report presents the Assessment 1 results, aimed at evaluating technically feasible and reasonably achievable DR amounts in the Pacific Northwest's public power sector. Importantly, the assessment results will generate the information necessary to develop DR supply curves, which will provide the inputs necessary for BPA's resource planning process.

1.2. Assessment's Scope

The BPA's experience with DR dates to the late 1970s and early 1980s, with early load control pilot projects in Port Angeles (Washington) in 1977–1978 and the City of Milton-Freewater (Oregon), starting in 1984. During the 1990s, BPA Power Services explored "non-wires" opportunities for BPA Transmission

Services, implementing more than 15 Transmission-funded DR pilot projects through partnerships with BPA public power customers.

Most of these projects focused on winter peak reductions using water heating loads, residential space heating, and voltage reduction, in addition to several time-of-use (TOU) rate experiments. For example, BPA used DR and DG for six winter seasons as a non-wires program in Washington's San Juan Islands (Orcas Power & Light Coop's Energy Partners program, from 1994–2002). In its Demand Exchange program (2000–2006), BPA built a 900 megawatt (MW) DR portfolio of controllable loads for power supply reliability and marketing purposes. BPA also implemented several DR projects through the 2000s on Washington's Olympic Peninsula, in Seattle, and across BPA's service area from 2010–2015. More recently, BPA implemented three large (30 MW–60 MW) DR demonstration projects from 2014–2017.

As the first comprehensive examination of DR potential within BPA's public power service area, this study encompasses 162 BPA Power customers within BPA's approximately 300,000-square-mile service area in Washington, Oregon, Idaho, and western Montana, and adjoining small portions of California, Nevada, Wyoming, and Utah. About 38% of these utilities and industries fall within BPA's western area (west of the Cascade Mountains) and 62% fall within its eastern area (east of the Cascade Mountains). In 2016, BPA delivered over 74,000 GWh of power to meet the energy demand of customers in these two areas, peaking at slightly over 8,626 MW in the western area and 4,224 MW in the eastern area on December 17, 2016, respectively.

1.2.1. Demand Response Products

Utilities can use DR as a mechanism to manage system loads, ensuring reliability or mitigating price spikes by encouraging customers to curtail demand during peak periods (peak shaving) or shift loads from peak to off-peak hours (load shifting). DR products analyzed in this study included 14 common programmatic options and products currently offered by utilities across the United States. These DR products fall into four broad categories: direct load control (DLC), time-varying prices, demand curtailment, and utility distribution automation or demand voltage reduction (DVR). These jointly account for the large majority of load reduction capability achieved by U.S. utilities active in DR.

1.3. Key Findings

This report assessed both technical and achievable demand response potential, including base and high cases for achievable potential. This assessment's results indicate a maximum BPA service area technical potential of 6.9 GW (winter) and 7.4 GW (summer) of demand reduction potential from all products included in the assessment. This represents, respectively, 44% and 55% of the forecasted 2036 peak load basis[1] within BPA's public power service area, as shown in Table 1.

Table 1. DR Technical Potential by Area, MW in 2036

Area	Winter Technical Potential (MW)	Percent of Area System Peak—Winter	Summer Technical Potential (MW)	Percent of Area System Peak—Summer
West	4,729	44%	4,393	59%
East	2,135	42%	2,980	50%
Total	**6,863**	**44%**	**7,374**	**55%**

Cadmus assessed achievable DR potential under base-case and high-case scenarios, reflecting projected market responses to DR product offerings. The expected base-case market response was determined primarily by benchmarking against an average of achievements made by other public and investor-owned utilities in the United States; therefore, it can be considered an average in a range of typical DR penetration rates. Given that many DR programs operate under predetermined targets or budget limits, the base-case scenario might represent a *constrained* potential. For most DR products, the high-case scenario represents approximately one-half standard deviation above the average. For DR products such as thermal storage and real-time pricing, there is a paucity of information from benchmarking, so the high-case scenario assumed a doubling of their current saturations.

Under the base-case scenario, approximately 1,551 MW (9.8%) of estimated winter technical potential and 1,602 MW (12.0%) of summer technical potential are expected to be achievable over the course of a 20-year planning horizon. As expected, the larger share of summer DR capabilities falls within the eastern part of BPA's service area, and a larger share of winter DR potential falls within the western part of BPA's service area, as shown in Table 2.

Table 2. DR Base Achievable Potential by Area, MW in 2036

Area	Winter Achievable Potential (MW)	Percent of Area System Peak—Winter	Summer Achievable Potential (MW)	Percent of Area System Peak—Summer
West	1,061	9.9%	807	10.8%
East	490	9.6%	795	13.5%
Total	**1,551**	**9.8%**	**1,602**	**12.0%**

Under the high-case scenario—which differs from the base case scenario achievable—DR potential increases to 2,790 MW in winter and 2,796 MW in summer. The total BPA service area achievable potential under the high-case scenario is expected to reach 18% and 21% of the BPA service area winter and summer peak loads, as shown in Table 3.

[1] For each season and area, the forecasted peak load basis is calculated as the sum of all end-use loads that are coincident with BPA's total system seasonal peak, based on BPA Power planning's 18-hour capacity event peak definition. They are not the same as each area's absolute single-hour peak load. More information is supplied in the Scope and Method section.

Table 3. DR High Achievable Potential by Area, MW in 2036

Area	Winter Achievable Potential (MW)	Percent of Area System Peak—Winter	Summer Achievable Potential (MW)	Percent of Area System Peak—Summer
West	1,876	17.6%	1,528	20.5%
East	914	18.0%	1,268	21.5%
Total	**2,790**	**17.7%**	**2,796**	**21.0%**

These base-case results remain consistent—though somewhat higher—than those experienced in other parts of the country, particularly by regional transmission organizations (RTOs), where DR capabilities have averaged about 2.5% to 10% of annual peaks. As described earlier, this range is highly dependent on the needs and market in the specific independent system operator (ISO)/RTO. These needs are not necessarily representative of potential; A transmission organization may need only 1,000 MW of demand reduction potential but have 3,000 MW of achievable DR potential. Analysis of data from the U.S. Energy Information Administration (EIA) indicates a wide range of DR use among public utilities, averaging approximately 10% of peak load. EIA data also show that a small number of public utilities have achieved DR potentials as high as 50% of their peak loads. These, however, tend to be very small utilities, representing exceptions in the data.

In both the base-case and the high-participation rate scenarios, differences in achievable potential between western and eastern parts of BPA's service are explained by differences in the areas' peak loads.

1.3.1. DR Product and Supply Curves

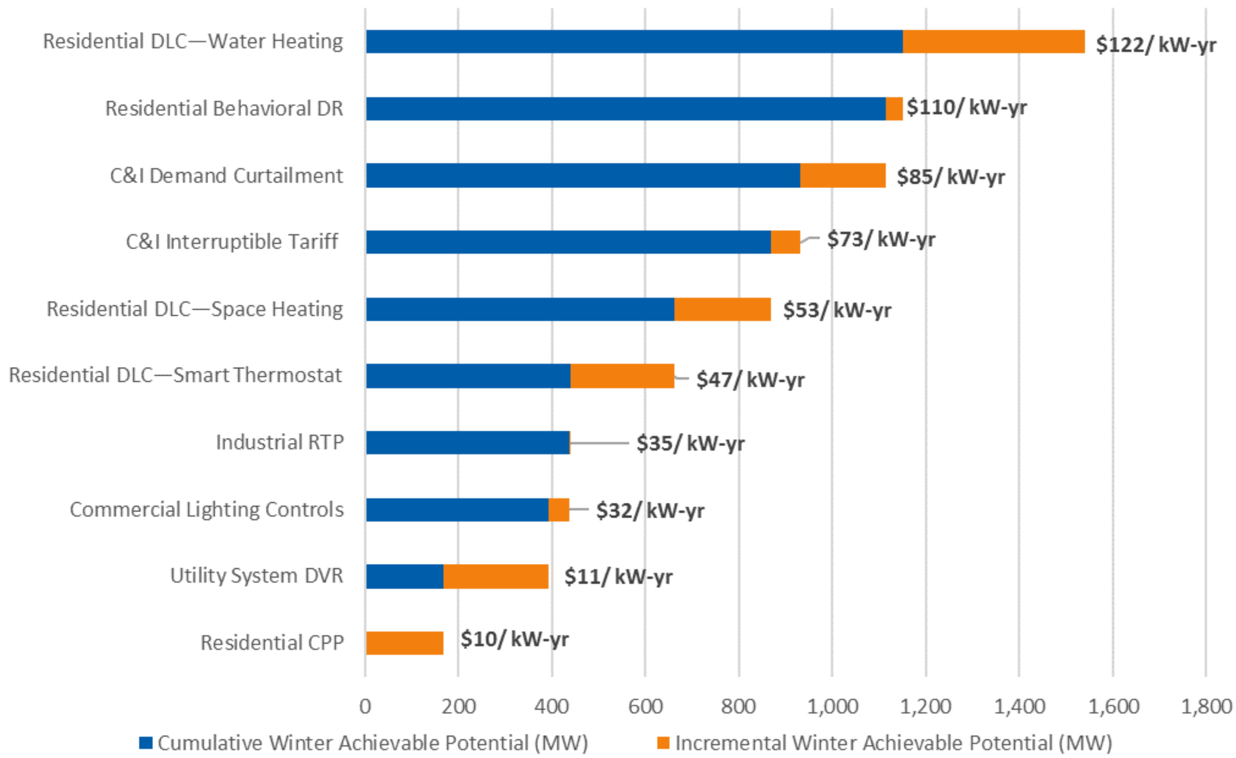
DR products considered in this assessment offer varying amounts of load reduction capability. They also vary with respect to development and deployment costs.

Figure 1 and Figure 2 illustrate base-case supply curves for DR products evaluated in this study during, respectively, winter and summer seasons. Each supply curve shows the incremental contribution to total DR capability and its associated price. All DR product prices are calculated as the DR product's annualized, per-unit, lifecycle cost ($/kW-year), from the total (generation capacity) resource cost (TRC) perspective for developing and deploying the DR product. The cost estimates account for avoided line losses but do not factor in benefits from deferred transmission or distribution investments. Because the fixed DR program development and deployment costs are a small fraction of total DR product costs, per-unit costs under the high-case scenario are assumed to be the same as in the base-case scenario. Cadmus made no judgments about how DR acquisition costs might be shared between BPA, local utilities, or consumers. Cadmus only notes that such cost sharing could occur, potentially reducing costs allocable to BPA.

As shown in Figure 1, most of the estimated DR capability under the base-case scenario is expected to be available for deployment at a levelized lifecycle cost of $100/kW-year or less. Direct control of residential water- and space-heating loads, commercial and industrial (C&I) demand curtailment, and smart thermostats offer the highest incremental achievable potential.

Despite its high potential, residential water heating DLC tends to be expensive, though the cost of deploying this product can be expected to drop if low-cost technologies (such as timeclocks or factory-installed communication ports) are used or if the product is deployed jointly with other products (such as space heating DLC). Residential Critical Peak Pricing (CPP) offers modest DR capabilities at the lowest cost.

Figure 1. 20-Year Base Achievable Potential Supply Curve for DR, Winter Peak, with Levelized Costs



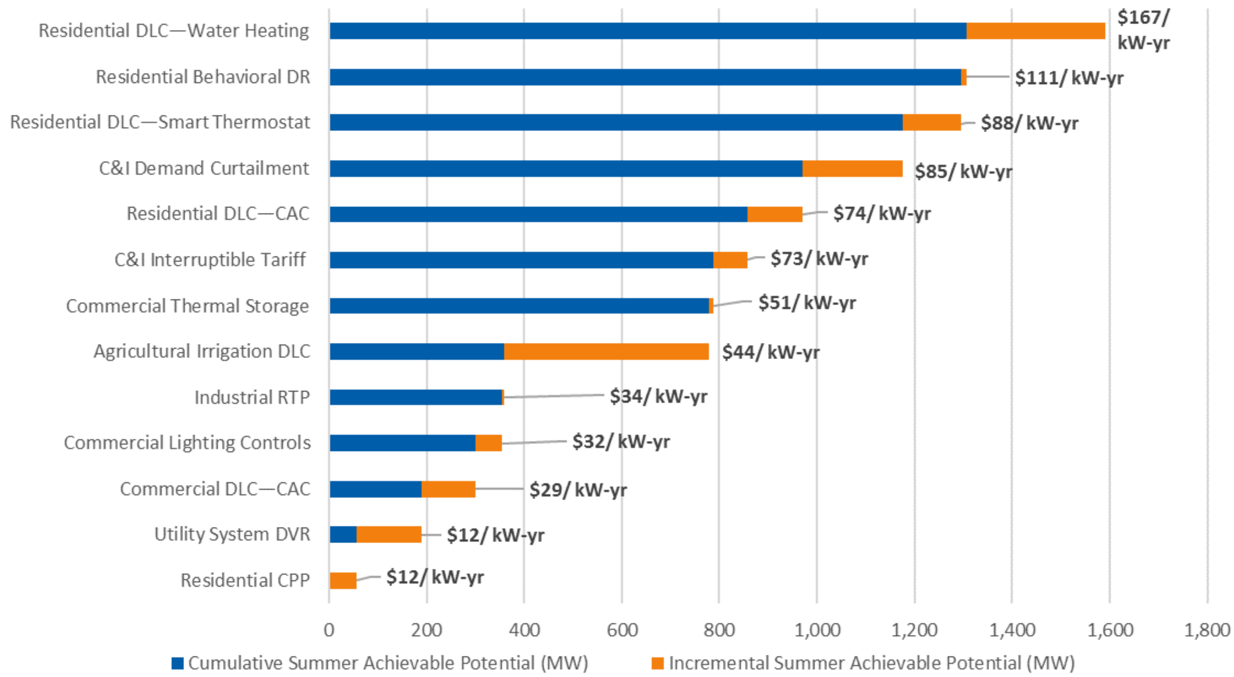
As can be seen in Figure 2, this assessment's results show that more than 1,175 MW of estimated achievable potential in summer may be deployed at a levelized cost of $100/kW-year or less. By far, agricultural irrigation load control offers the largest amount of achievable DR potential at a relatively low cost ($44/kW-year, levelized). Direct control of residential water heaters and C&I demand curtailment show the next highest achievable potential, albeit at the significantly higher levelized costs of $167/kW-year and $85/kW year, respectively.

It is important to note that projected achievable potential amounts represent potential under typical conditions along with assumptions about DR product design and, importantly, incentive structures. As these assumptions change, so does the potential. Achievable potential, therefore, is understood better as a range than as a point estimate. To gain additional perspective, an accompanying assessment—the *Demand Response Elasticities Analysis*—investigated the elasticity of achievable potential with respect to incentives. The results of this analysis show that the elasticity estimate of the supply of demand response capacity equals 0.23 for all customers, 0.30 for residential customers, 0.43 for commercial customers, and 0.54 for industrial (and probably also agricultural) customers. For residential and commercial customers, for example, the results implied that a 1% increase in utility incentive payments results in approximately a 0.3% to 0.4% increase in demand response capacity. The supply of demand response capacity, derived from industrial customers, proved to be most responsive to increased incentives.

Overall, the findings of the *Demand Response Elasticities Analysis* are consistent with the results from the survey of end-use customers in the accompanying *Demand Response Barriers Assessment*—the survey found that when asked whether they would be willing to participate in a DR program without a financial incentive, 21% of residential customer respondents said yes and 44% said no, a ratio greater than two to one. It is also important to note, however, that—as BPA's experience with certain DR pilot projects have shown—customers of public utilities and electric cooperatives may be willing to participate in certain DR programs that offer lower or no incentives, because of the appeal to their sense of ownership and social responsibility. BPA has implemented more than a dozen small-scale residential DR pilot and research and development (R&D) projects in past years without consumer incentives, achieving fast ramp rates and high penetration rates.

DR potential amounts in the supply curves resulting from this assessment are merely indicative of the amounts of achievable technical DR potential likely available at particular price points. They do not represent economically viable potential. Rather, these supply curves were developed to inform BPA's resource planning process. The economic subset of achievable potential will be determined based on the optimal amount of resources "selected" through BPA's resource planning process.

Figure 2. 20-Year Base Achievable Potential Supply Curve for DR, Summer Peak, with Levelized Costs



The per-unit lifecycle costs are based on the discounted stream of the DR product's deployment costs, including fixed product development costs, ongoing operation expenses, and incentives. The incentive amounts were determined based on those typically offered by other U.S. public and private (investor-owned) utilities, with an emphasis on those provided by Northwest utilities.

Study Limitations

Estimating long-term demand response potential is complex and requires large amounts of data from multiple, varied sources over a long period. It also involves making assumptions about the future market conditions and consumers' behavior. Inherent in these studies are uncertainties about the magnitude of the potential for each DR product, the cost of deploying them, and transformations in technologies that support these products. The results of this study are also based on assumptions about how DR products are designed and deployed and the expectations about how consumers might respond to the product offerings. Achieving the potential for the DR products analyzed in this study also depends on the existence of economic and institutional frameworks that enable and facilitate deployment of DR.

Moreover, because this study did not apply an economic screen to estimate economic potential, the final quantities of economically viable DR will depend on the outcomes of BPA's resource planning process. The results of this study should be viewed in the light of these caveats and be considered as indicative of long-term market opportunities for DR, rather than definitive targets. Actual BPA delivery of DR programs and quantities will not necessarily depend on a theoretical study of this type, or on planning studies, but rather on the needs of internal BPA Power and Transmission clients and close coordination with the retail load-serving utilities.

Organization of this Assessment

This report focuses on quantifying the amounts and costs of various DR options. The report begins with a description of the national and regional DR experience and DR accomplishments. It then describes the methods, data, and assumptions used to estimate DR potential and costs. Later sections of the report present the annual, detailed analyses of individual DR products. Separate appendices are provided to present supplemental analyses, including an assessment of DR potential in six specific geographic areas within BPA's public power utility customer service territory, a DR potential assessment under an extreme 1-in-10 weather scenario, and analyses of supplemental DER options such as distributed generation and storage.

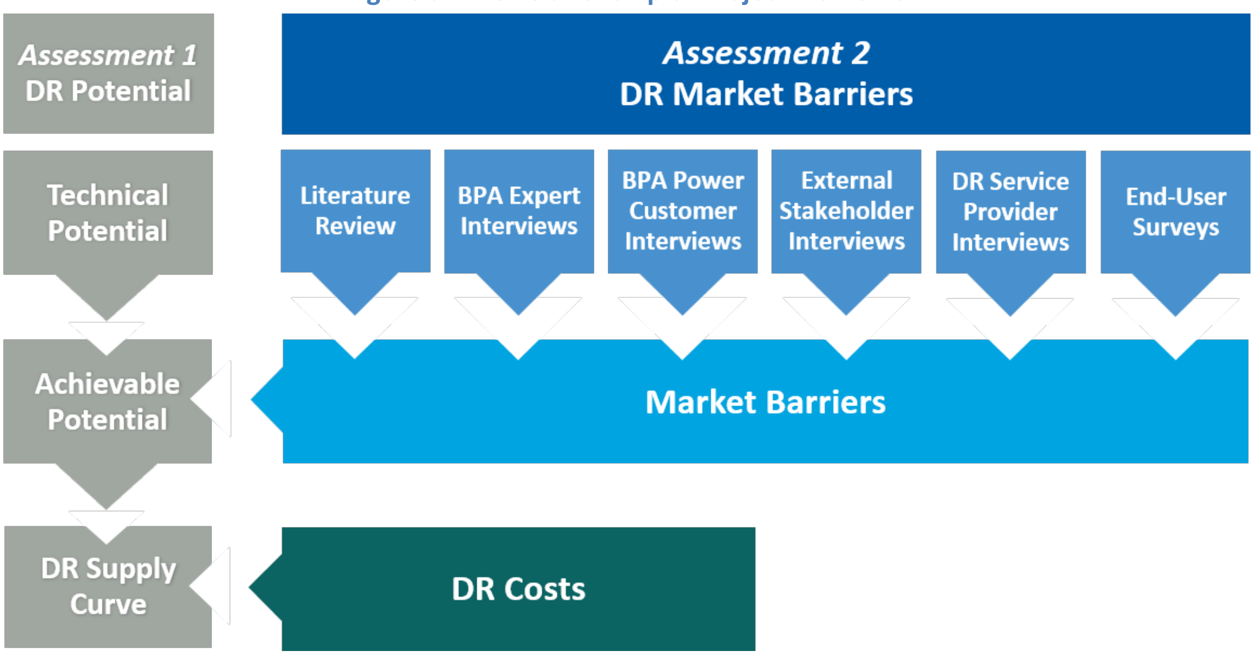
2. Introduction

The Bonneville Power Administration (BPA) has sponsored a comprehensive assessment of the opportunities, costs, and barriers to regional deployment and adoption of distributed energy resources (DER) within BPA's firm energy service area in the Pacific Northwest. The study covers three DER options: demand response (DR), customer-sited distributed generation (DG), and storage. The study, however, primarily focused on DR and is presented in two parts:

- Assessment 1 (covered in this document) evaluates commercially viable DER products and estimates the technical and achievable DR potential of products in BPA's service area.
- Assessment 2, a complementary volume to Assessment 1, informs the evaluation of achievable DR potential by describing DR market barriers and strategies to overcome those barriers.

Figure 3 illustrates the study's elements and their relationships.

Figure 3. Interrelationship of Project Elements



2.1. Assessment Objectives

To facilitate the consideration of potential capacity delivered by energy efficiency measures and DR resources in the BPA and regional resource planning processes, the Northwest Power and Conservation Council's Seventh Power Plan's Action Plan (Council 2016) recommended several actions, including these:

- It directed the Regional Technical Forum (RTF) to develop quality guidelines to validate the reliability of capacity savings achieved through energy efficiency.

- It recommended that BPA assess the achievable DR potential within its service area and to include that assessment's information in BPA's 2017-2018 Resource Program planning process.

Designed to fulfill the Action Plan's second recommendation, this assessment's results will serve to inform BPA's resource planning process. The two assessments provide BPA with an understanding of the magnitude and costs for procuring realistically achievable DER potential within its service area. They also provide information on the potential barriers that may hamper BPA's ability, and the ability of its Power customer utilities, to deploy the resources in a timely and cost-effective manner.

2.2. Scope of the Assessment

This study encompasses 162 wholesale BPA Power customers within BPA's approximately 300,000 square mile service area in Washington, Oregon, Idaho, western Montana, and adjoining small portions of California, Nevada, Wyoming, and Utah.[2] About 38% of these customers fall within BPA's western area (west of the Cascade Mountains) and 62% fall within its eastern area (east of the Cascade Mountains). In 2016, BPA delivered over 74,000 GWh of power to meet the energy demand of customers in those two area, peaking at 8,626 MW in the western area and 4,224 in the eastern area on December 17, 2016, as shown in Table 4.

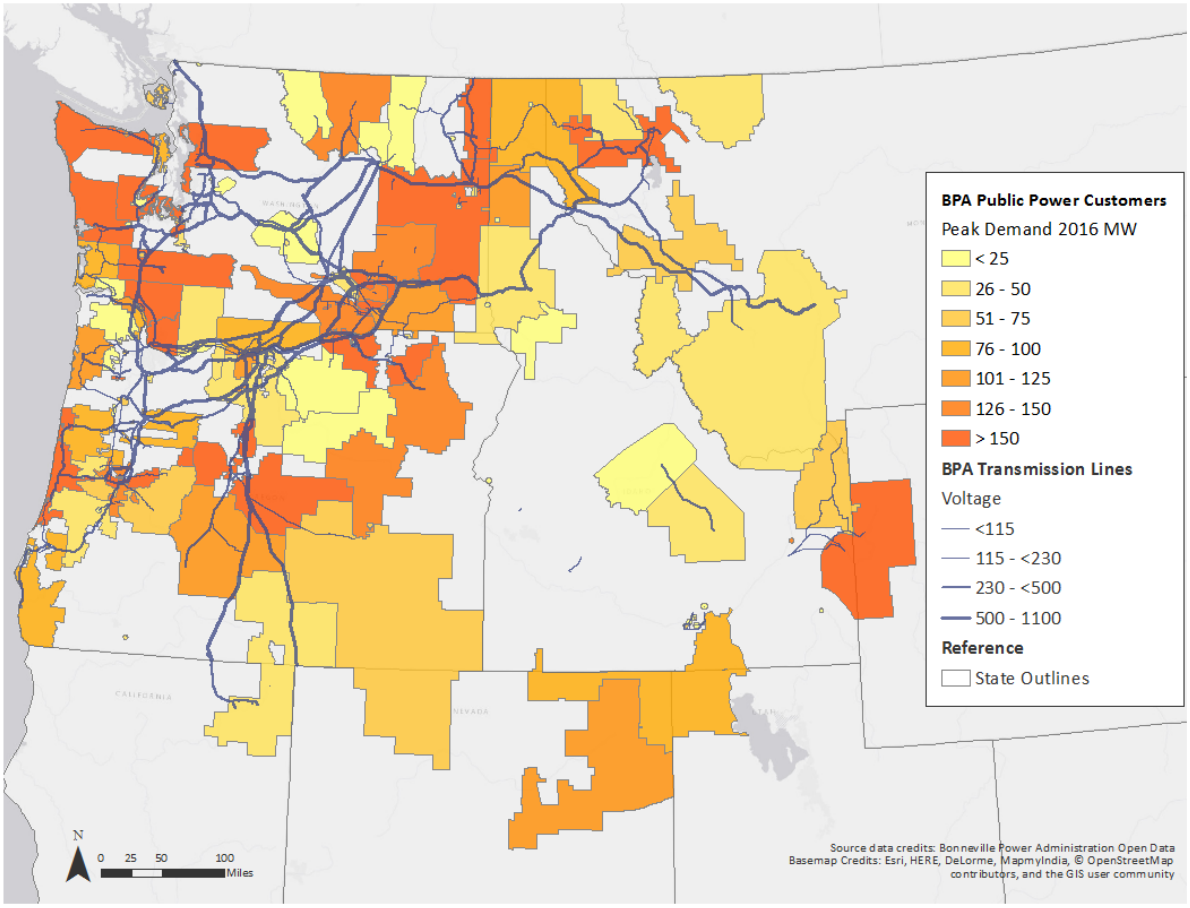
Table 4. BPA's Sales and Peak Demand by Area in 2016

Area	West	East	Total
Number of BPA Power customers	61	101	162
Delivered Power (MWh)	51,525,595	22,702,669	74,228,264
Peak Demand	8,626	4,224	12,849

Figure 4 and Figure 5 show concentrations of peak demand (Figure 4) and power sales (Figure 5) in BPA's service area. As shown in Figure 6, although both areas (west and east) peaked during winter, most of the peak-load hours in BPA's western service area occurred during winter and in BPA's eastern area during both summer and winter.

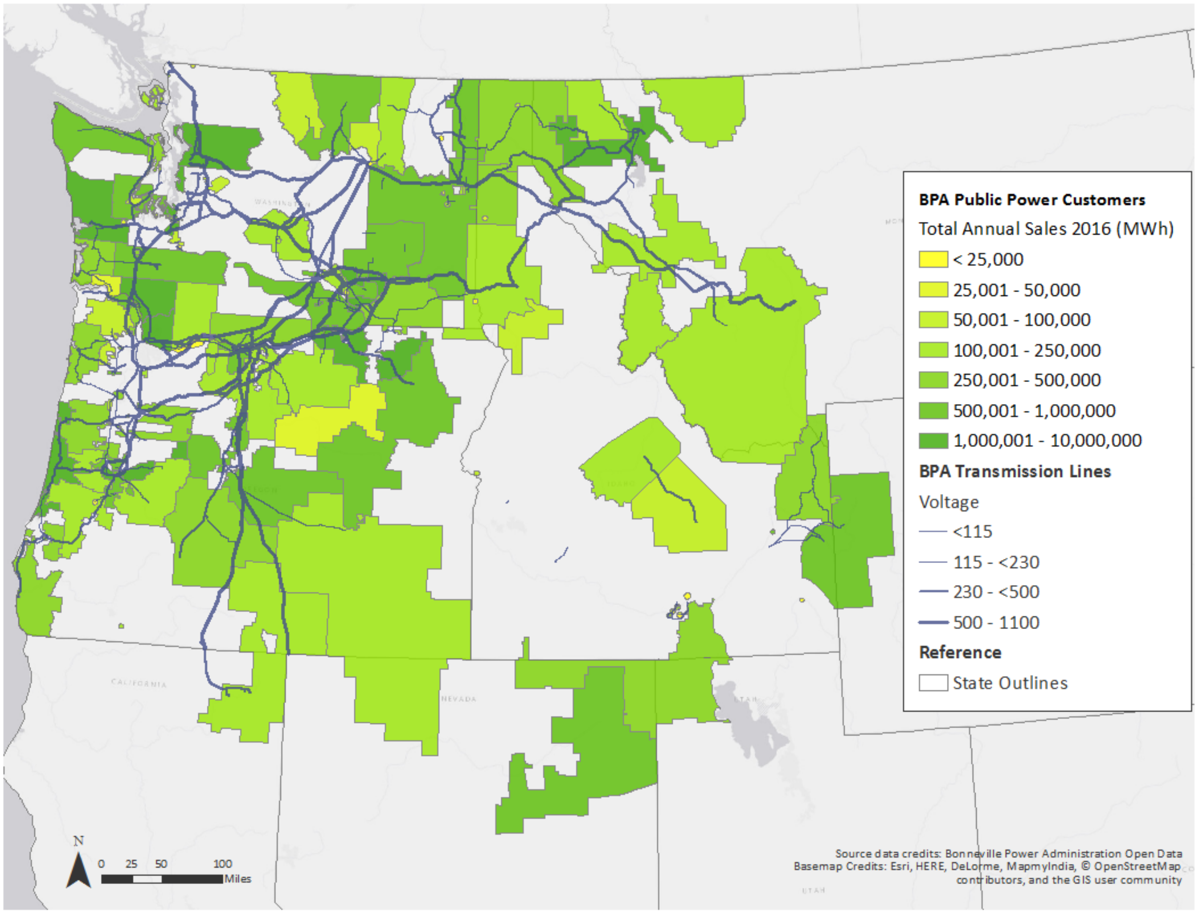
[2] The analysis included the loads of all firm energy customers, including federal agencies, direct-service industrial customers, tribal utilities, federal irrigation districts, and one port district. Please see the full list in Appendix H. Figure 4 and Figure 5 did not display 38 customers – including 27 federal irrigation districts - because their map boundaries were not available in BPA-sourced maps.

Figure 4. BPA Public Power Customer Peak Demand in 2016



Note: This map excludes 38 of the 162 customers in the analysis scope as their map boundaries were unavailable in the BPA-sourced map, publicly available here: https://hub.arcgis.com/datasets/BPAGIS::bpa-customerpublics.

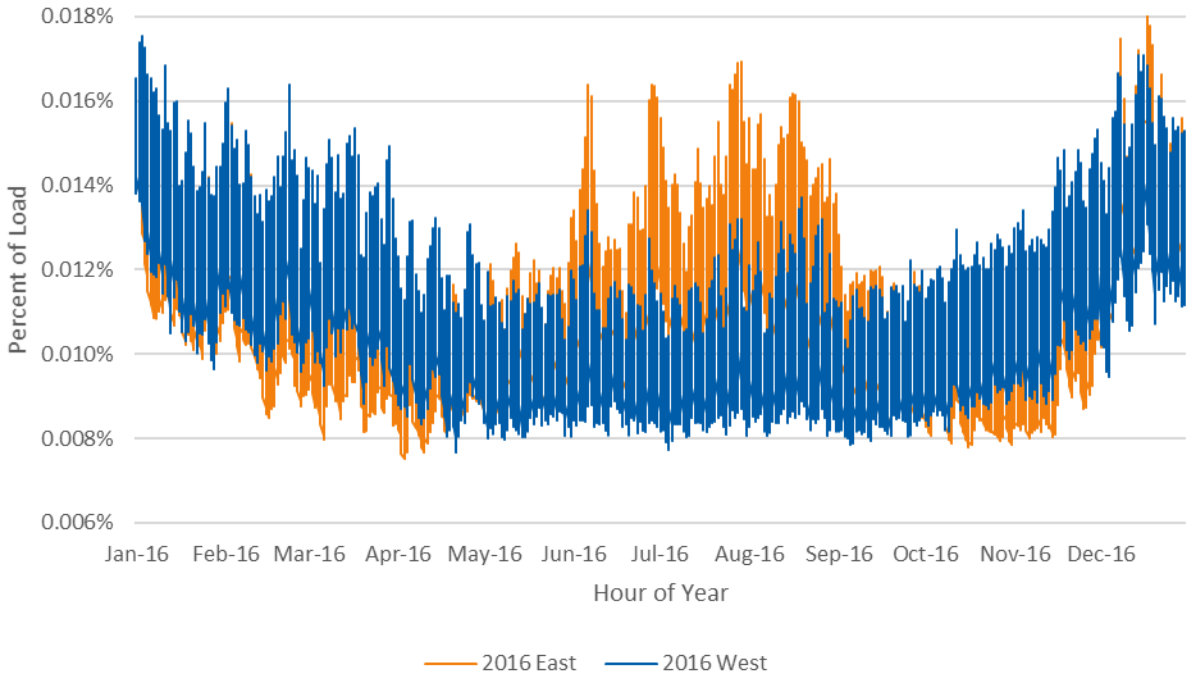
Figure 5. BPA Public Power Customer Annual Sales in 2016



Note: This map excludes 38 of the 162 customers in the analysis scope as their map boundaries were unavailable in the BPA-sourced map, publicly available here: https://hub.arcgis.com/datasets/BPAGIS::bpa-customerpublics.

While system load profiles and load duration curves serve as the main determinants of DR opportunities, they also inform program design and determine programmatic intervention types that can help address load management objectives. The Pacific Northwest's public power system—and of the Region as a whole—historically peaks in winter. As shown in Figure 6, although the system still peaks in winter, summer's peak demand frequency has increased markedly, largely due to increasing saturations of space cooling loads, especially on the east side.

Figure 6. 2016 Hourly Load Duration, BPA East vs. West



Demand Response Options Covered

This study defines DR as a mechanism utilities can use to manage system loads that ensure reliability or mitigate price spikes by encouraging customers to curtail demand during peak periods (peak shaving) or shift loads from peak to off-peak hours (load shifting). This definition is consistent with DER definitions used by the Federal Energy Regulatory Commission (FERC) and the Council.

FERC defines DR as (FERC 2018):

> "Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."

Similarly, the Council defines DR as "a voluntary and temporary change in consumers' use of electricity when the power system is stressed...."[3]

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3 The Council adds that, although changes in consumers' use are usually reductions, "There are situations in which an increase in use would relieve stress on the power system and would qualify as DR." See Chapter 14: Demand Response in the *Seventh Northwest Conservation and Electric Power Plan* (Council 2016).

DR products analyzed in this study include 14 common programmatic options and products currently offered by utilities across the United States and accounting for the large majority of load reduction achieved. These DR products fall into three broad categories:

- **Direct load control (DLC)**. One of the oldest DR products available, utilities across the United States have used DLC since the 1960s. Under a DLC program, the utility typically controls a customer's electric space heating, water heating, central air-conditioning, lights, irrigation pumps, or industrial processes. DLC products have a distinguishing feature: they are dispatched directly by the utility—or its agent, in the case of DLC programs operated by a third-party aggregator or DR service provider.
- **Time-varying prices.** Rate-based DR options cover a broad range of price-based programmatic approaches used by utilities to encourage customers to lower demand during system peak periods. Time-of-use (TOU) rates, offered by many utilities outside of the Pacific Northwest region, are the most common time-varying DR product. This assessment considered two tariff-based DR products: critical peak pricing (CPP) and real-time pricing (RTP). Both CPP and RTP can yield a higher DR potential due to the concentration of events over fewer high-load hours. From a policy standpoint, this assessment assumes that CPP and RTP would be deployed as a rider to an existing TOU tariff available from the utility, as commonly observed in other utilities. From an implementation standpoint, this assessment assumes that during system peak periods (for which potential estimates are calculated), CPP and RTP prices are in effect (as opposed to TOU prices), so potential estimates represent the load impacts of CPP and RTP, not of TOU.
- **Demand curtailment.** Demand or load curtailment programs consist of contractual arrangements between a utility (or with a contractor working on its behalf) and its customers (typically large C&I end users), which agree to curtail or interrupt customers' operations, in whole or in part, for a predetermined period when requested by the utility. Unlike DLC, where DR events are called and executed by the utility, the participating customer executes the curtailment in demand curtailment programs.

Table 5 lists DR products covered in this assessment. These products correspond to products serving as the basis for the DR portion of the Council's Seventh Power Plan. In addition to being commonly available, proven, and viable offerings, several of these products are dispatchable. The Detailed Resource Potentials by Product section of this document provides detailed descriptions of each product.

Table 5. DR Products

Sector	DR Product	Deployment Mechanism	Seasonality
Residential	DLC—Water Heating	DLC	Summer and winter
	DLC—Space Heating	DLC	Winter only
	DLC—Central Air Conditioning (CAC)	DLC	Summer only
	DLC—Smart Thermostats	DLC	Summer and winter
	Critical Peak Pricing (CPP)*	Tariff-Based	Summer and winter
	Behavioral DR	Direct Communication (e.g., event notifications)	Summer and winter
Commercial**	DLC—CAC	DLC	Summer only
	Lighting Controls	Automated Response	Summer and winter
	Thermal Storage	Cooling Storage	Summer only
Industrial***	Real Time Pricing (RTP)*	Tariff-Based	Summer and winter
Commercial and Industrial	Demand Curtailment and DLC	Contract (Automated or Manual Response)	Summer and winter
	Interruptible Tariff	Tariff-Based	Summer and winter
Agricultural	Irrigation DLC	DLC	Summer
Utility System	Demand Voltage Reduction	SCADA	Summer and winter

*Cadmus assumed that TOU rates were already in place.

**In this assessment, Cadmus included public buildings in the commercial sector.

***In this assessment, Cadmus included public process loads such as municipal water treatment plants in the industrial sector.

2.2.1. Types of Potential Covered

This study determined two types of potential, technical and achievable:

- **Technical potential** represents technically feasible DR opportunities, constrained only by physical factors such as fuel and technology saturations and expected peak load impacts, derived from engineering calculations or from metering data provided by national secondary utility sources. Technical potential is not constrained by economic considerations of cost-effectiveness, budgets, or any applicable targets.
- **Achievable (or market) potential** reflects a subset of technically feasible DR opportunities which are assumed to be reasonably obtainable, based on market conditions and the end-use customers' ability and willingness to participate in the DR market. Estimating achievable potential has two components: market acceptance (or the participation rate) and the ramp rate. Market acceptance is the amount of DR potential that end-users will likely deliver, given internal constraints and available incentives to help offset real or perceived costs of DR participation. Market acceptance is often thought of as the penetration rate—that is, how many participants will sign up for a DR program over several years of marketing and recruitment activity. The ramp rate is the speed at which DR could be implemented and how quickly the market acceptance potential can be achieved.

In this study, Cadmus used benchmarking—against current DR activity levels in the United States, particularly in the Northwest—as the approach for determining achievable DR potential. We recognize that DR amounts achieved by utilities today may reflect constrained potentials, defined by existing targets or budget limitations; hence, these may not necessarily reflect what *can* be achieved.

In general, current DR activity levels may more accurately reflect achievable potential in more conventional DR options (e.g., time-varying prices, curtailable tariffs), where such offerings have been available for many years. They may not, however, accurately represent achievable potential for DLC products or demand curtailment contracts, especially when these products are delivered by DR service providers and aggregators. In these cases, what is achieved may be based on bilateral agreements between the utility and the DR service provider, with predetermined targets or budgets.

Ramp rates, the second component of achievable potential, reflect the timing of DR deployment. Ramp rates show the amount of time required to design, develop, and launch DR products. As a simplification, for nearly all DR products evaluated in this assessment, maximum market saturations are assumed reachable within seven to nine years after launching the product. The maximum market penetration, however, can be reached more quickly if a utility or utility organization (e.g., a Regional Transmission Operator [RTO] or an Independent System Operator [ISO]) make budget and programmatic commitments to do so. A program's pace can be accelerated, maintained, or slowed, depending on the utility's DR needs.

BPA has implemented successful pilot and R&D DR projects that have achieved high penetrations in the targeted sectors very quickly (e.g., >30% of all residences signed up for space and water heating DLC after one season or year of marketing). BPA has also implemented DR demonstration projects in which recruitment of loads was slow and load reduction delivery was not successful.

Program design, the role of the local utility, marketing plans and approaches, and program goals have seemed to influence ramp and penetration rate results much more so than has the provision of incentives or the amount of incentives. Seasoned DR staff will often say that marketing DR opportunities to consumers is as much an art as it is a science. Each combination of markets and programs is unique, and it is genuinely difficult to predict recruitment and marketing outcomes in advance.

3. Assessment Background

The Pacific Northwest enjoys an abundance of unique hydroelectric resources on rivers with large quantities of runoff and steep drops in elevation. This has allowed the construction of dams with large storage capacity and the built-in capability to respond quickly to peak power demand. Historically, this has provided the Region with more-than-adequate resources to meet electricity peak demand. Thus, the Region 's utilities traditionally have planned for new resources based on the need for energy (kWh) rather than capacity (kW). However, because of increased constraints in operating the hydroelectric system, resulting primarily from measures designed to protect endangered fish, and as intermittent resources claim a growing share of the Region 's power supply, the Region's focus of long-term resource adequacy planning has shifted increasingly to addressing capacity needs.

As the Council notes in its Seventh Northwest Conservation and Electric Power Plan, "The Northwest power system has gradually become less energy constrained and more capacity constrained" (Council 2016). At the same time, as the Region's number of summer days with extreme heat continues to climb and air conditioning loads increase, the Region's historically winter-peaking system has experienced a sharp rise in summer demand, transforming the Region as well as the BPA service area to a dual-peak system.

In its Seventh Power Plan, the Council estimated that the Northwest can achieve 5,100 average megawatts (aMW) of electricity savings over the plan's 20-year horizon (Council 2016).[4] The Council further estimated that, if implemented, estimated energy efficiency savings will translate into as much as 9,700 MW of capacity benefits during the Northwest's regional winter peak and 6,600 MW of capacity benefits during the summer peak in the Plan's final year (2035).[5] The Council further determined that additional capacity savings of approximately 3,500 MW during winter and nearly 3,300 MW during summer can be achieved by implementing standard DR technologies. According to the Seventh Plan, the cumulative load impacts of technically achievable potential could offset over 8% of projected winter and summer peak demand, respectively, by 2035.

The Council's Action Plan recommended that—including savings achieved in 2016—the Region should achieve a minimum conservation goal of 1,400 aMW by 2021, 3,000 aMW by 2026, and 4,300 aMW of cost-effective conservation by 2035. The Action Plan further recommends building 600 MW to 2,000 MW of new DR capacity by winter 2021–2022. The Action Plan concludes that the Region could have sufficient generation and demand-side capability using its existing system to meet balanced and

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4 One megawatt of capacity produced continuously over a period of one year. 1 aMW = 1 MW x 8760 hours/year = 8,760 MWh = 8,760,000 kWh.

5 The Council defines winter peak as occurring at 6:00 p.m. on weekdays during December, January, and February and summer peak as occurring at 6:00 p.m. on weekdays during July and August.

flexible reserve requirements, provided that the Region achieves the energy efficiency and DR development goals in the six-year Action Plan and the 20-year overall Plan.

3.1. National Demand Response Experience

Using DR to manage peak load and lower operating costs dates back to the early 1960s (and even earlier in the late 1950s by several Midwest utilities). DR's importance has, however, grown markedly in managing the reliability, adequacy, and cost of electric power generation, transmission, and distribution during the last decade. In no small measure, this growth resulted from recognizing DR as a policy tool at the national level, subsequent to the Energy Policy Act of 2005 (EPAct 2005) and the Energy Independence and Security Act (EISA) of 2007.

Section 529 (a) of the EISA directed the FERC to conduct a National Assessment of Demand Response Potential and to report the following to Congress:

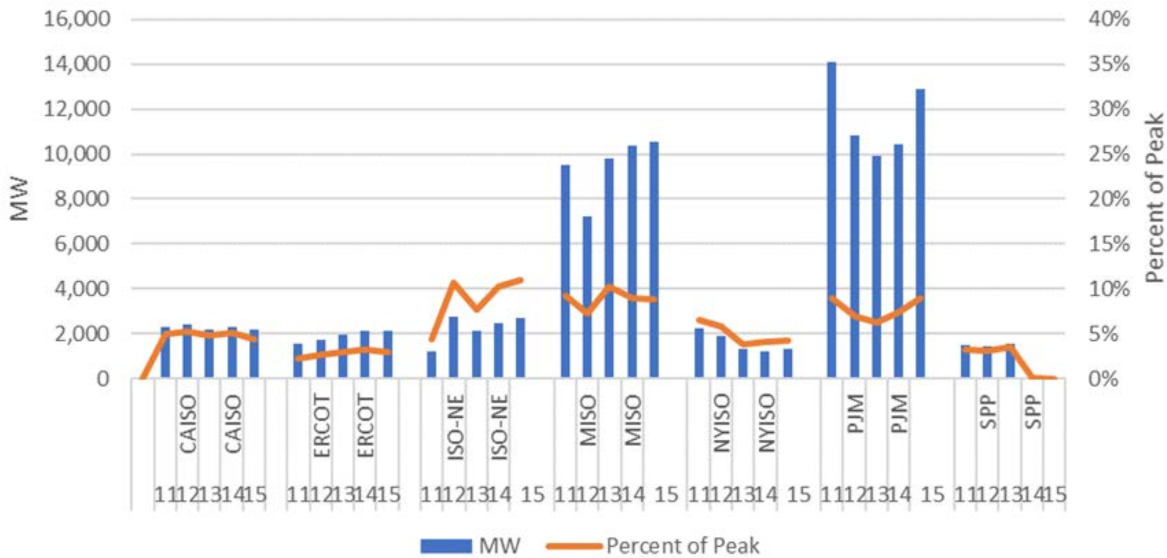
- Estimates of nationwide DR potential in 5- and 10-year horizons on a state-by-state basis, including a methodology for annual updates
- Estimates of how much potential can be achieved within those time horizons
- Identification of DR program barriers and recommendations for overcoming any barriers

In compliance with Section 529, FERC issued the National Assessment of Demand Response Potential in 2009. This report concluded that, under the most optimistic scenario, 188,000 MW of peak demand reduction could be achievable by 2019 in the United States, representing a 20% reduction in projected 2019 national summer peak demand (FERC 2009).

In 2006, FERC began conducting biennial national surveys of DR progress in the United States. The largest DR increase occurred in RTOs wholesale markets. FERC's reports indicated the potential peak demand reduction increased from 12,656 MW in 2008 to 22,884 MW in 2010. Much of the DR increase resulted from DR growth in RTOs, from a reported 9,060 MW in 2008 to 20,533 MW in 2010. Per FERC reports, DR activity in wholesale markets has remained stable, changing little from 32,488 MW in 2011 to 32,754 MW in 2015—the last year for which data were available and reflecting potential peak load reductions of just under 6%, on average, in the nation's RTO markets, as shown in Figure 7.

In 2015, the Midcontinent Independent System Operator, with 10,563 MW, and PJM Interconnection, with 12,910 MW, attained the highest DR peak load reduction percentages, achieving nearly a 10% reduction in their peaks through DR. The DR quantities reported by RTOs do not represent the technical or available potential of DR in these wholesale markets; rather, they reflect the amounts of load reduction achieved through existing contracts and forward auctions, quantities of DR the RTOs have decided are necessary and cost-effective to acquire. These MW quantities are lower than the actual market potential.

Figure 7. DR Resources in Wholesale Markets of RTOs/Independent System Operators and Associated Peak Load Reduction



Similar DR load reduction levels have been achieved by provincial utilities in Canada. For example, Hydro Quebec's existing industrial program achieved an estimated 850 MW of DR capability in the winter of 2016–2017, rising to 1,000 MW by the winter of 2018–2019; this represents approximately 2.5% of the utility's winter peak of 37,630 MW. Ontario's Independent Electricity System Operator (IESO) has had about 1 GW of industrial DR available. Additionally, DR resources totaling 455 MW in the summer of 2017 and 478 MW in the winter of 2017–2018 cleared IESO's most recent auction. Together, these DR resources are equivalent to about 6% of EISO's projected summer peak and nearly 7% of the projected winter peak.

Canadian RTOs are a useful model for BPA because they are hydro-based utilities with winter peaks. Almost all large U.S. utilities and RTOs are summer peaking and use thermal generation power supply systems. DR activity levels vary widely across individual utilities. Since 2010, the EIA has collected information on DR from energy organizations, including investor-owned utilities, municipal utilities, cooperatives, public power marketing authorities, and retail power marketers. In 2015, EIA reported information on 484 utilities, including 222 municipal utilities and cooperatives with complete data.

The data from the 222 municipal utilities and cooperatives indicate a DR capability of nearly 3,700 MW. These utilities exercised roughly 66% of their available DR capability, on average, in 2015. The reported DR capability on average represents the equivalent of approximately 10% of peak load, ranging from less than 1% to nearly 55% of annual peak, as shown in Figure 8.[6] The data further show that the average peak load reduction for these utilities has remained relatively stable, at around 10% from 2011 to 2015.

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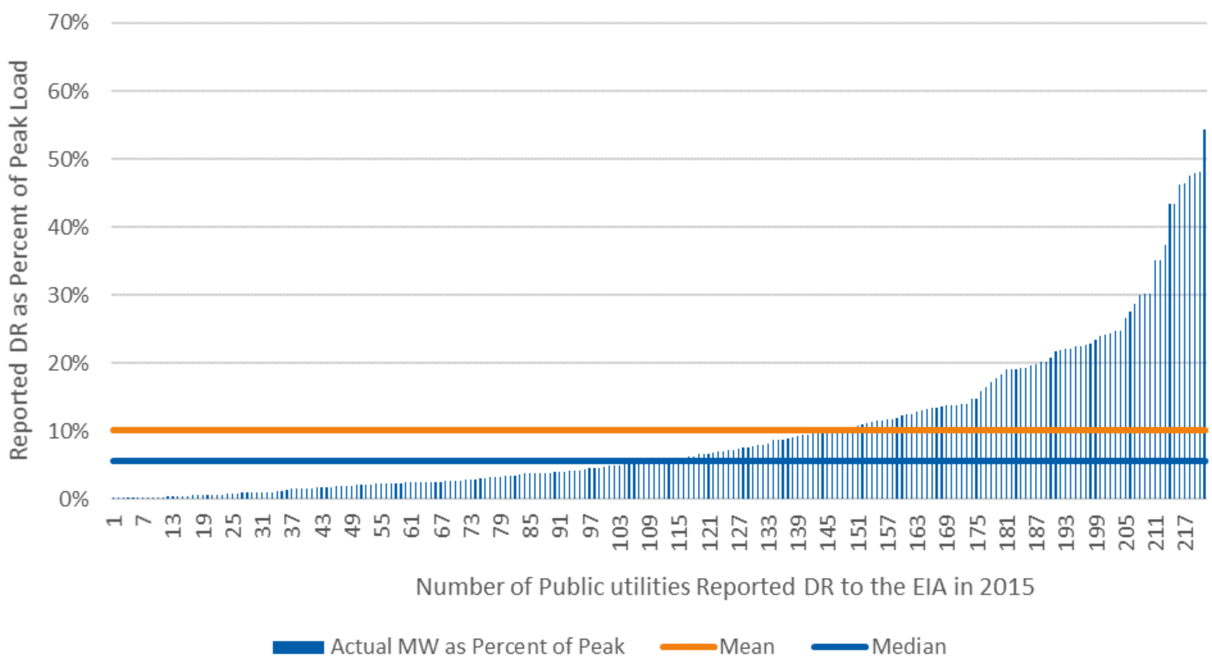
[6] Cadmus removed one outlier because the utility reported inconsistent data between 2011 and 2015.

Further analysis of 20 utilities with the highest peak load reduction percentages shows stable DR capabilities of about 37% peak load reductions over the same five-year period.

Given the skewed distribution of DR potential across these utilities caused by a small number of public utilities with high DR penetration, the 5.6% median value is more representative of DR capability for these utilities. Of course, utilities report to the EIA the amount of DR they use, not their DR potential. Because utilities use only the DR they need, or what laws and policies require, the DR potential across these 222 public utilities is, without question, higher than what they choose to use.

Figure 8. Utility DR Capability as Percent of Peak—Public Utilities (2015)



3.2. Demand Response at BPA

The BPA's DR experience dates to the late 1970s and early 1980s, with early load control pilot projects in Port Angeles (Washington) in 1977–1978 and the City of Milton-Freewater (Oregon) starting in 1984. During the 1990s, BPA Power explored "non-wires" opportunities for BPA Transmission, implementing more than 15 BPA Transmission-funded DR pilot projects in partnerships with BPA Power customer public utilities. Most of these projects focused on winter peak reductions using water heating loads, residential space heating, and voltage reduction, though they included a handful of TOU rate load-shifting tests and pilot projects, marketing experiments, and projects using DG, typically using existing emergency or backup generators.

One non-wires project with Orcas Power & Light Cooperative, which serves the San Juan Islands of Washington State, used DR from 1995–2002 to maintain compliance with contractual and North American Electric Reliability Corporation (NERC) reliability standards and to lower BPA's Transmission capital investment costs. In an evaluation of the project, BPA Transmission estimated that DR use produced cash savings of $8 million to $25 million, at a cost of approximately $1.6 million over six winter seasons. This was a successful, award-winning collaborative project between BPA and Orcas Power & Light.

During the California energy crises of the early 2000s, BPA launched a Demand Exchange Program, which succeeded in developing approximately 850 MW of curtailable load through bilateral contracts with its then-large industrial direct-service customers and 15 BPA Power customer utilities. BPA Power operated the Demand Exchange for 28 months, from June 2000 to September 2002, during which time it produced estimated net savings for BPA of over $2.5 million in reduced power purchase costs (savings in excess of the Demand Exchange operating costs). BPA Transmission then utilized the program for four additional years (October 2002 through September 2006), using the portfolio of DR assets to manage localized transmission constraints.

In the past, BPA has demonstrated its ability to successfully and quickly recruit loads for DR programs, pilots, tests, and projects when the need and desire for such DR load aggregations arise. Notably, BPA took less than four months to sign up, enable, and meter 750 MW of the Demand Exchange portfolio and three additional months to add the final 100 MW to that portfolio.

From 2004 through 2013, BPA also implemented more than two dozen, mostly small-scale pilot projects in partnership with its public power customers. These projects tested a variety of DR products using different control and communication technologies, including DLC of water heaters, irrigation pumps, commercial and public building loads, and residential appliances; programmable thermostats; voltage reduction; timeclock control of water heaters; and thermal storage. Project locations ranged from rural farming and logging communities to urban suburbs and downtown Seattle skyscrapers.

In 2009, BPA initiated a study—the Smart Grid Regional Business Case—to analyze the costs and benefits of smart-grid technologies and to identify smart grid investments with the highest potential value for BPA, electric utilities, and the Northwest. A 2015 report on the project results highlighted opportunities and risks of regional smart grid investments and suggested that benefits to the region and BPA would likely significantly exceed costs.

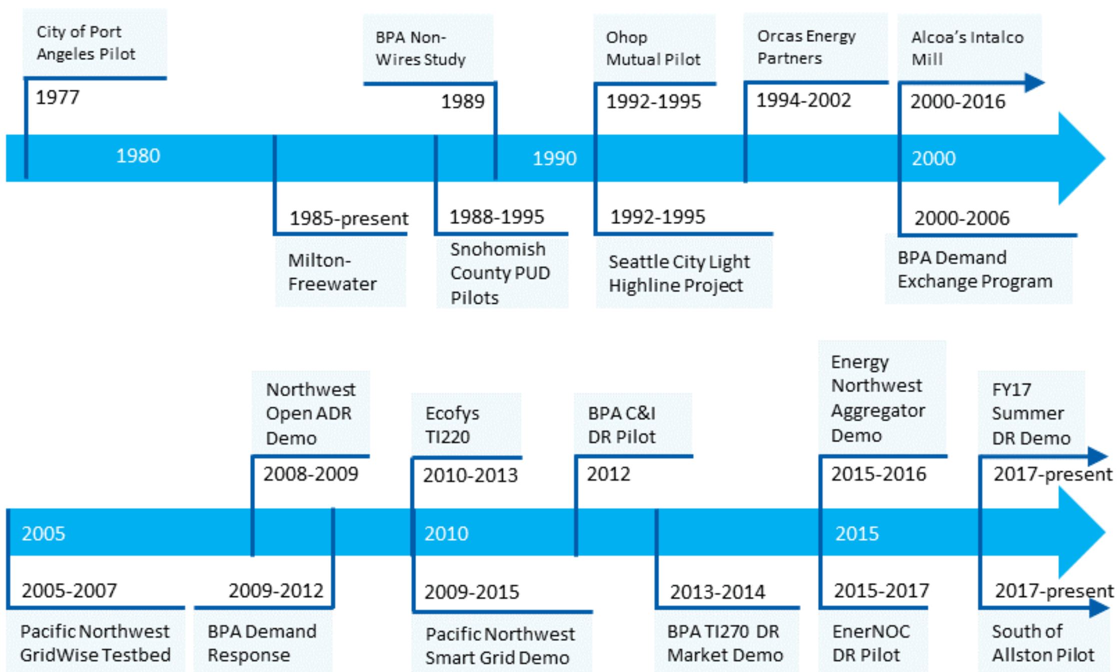
BPA also was a major participant in and contributor to the $180 million, 50% U.S. Department of Energy-funded Pacific Northwest Smart Grid Demonstration Project, led by Battelle Memorial Institute, Pacific Northwest Division, from 2009 to 2015. The project included 11 utilities and five infrastructure partners and involved 112 MW of power flows from a wide range of responsive resources, featuring both load management and generation. Developing a business case served as the centerpiece of BPA's participation in this project. The business case sought to show whether benefits outweighed the costs, so the Region could know which technologies would be sustainable and best for long-term capital investments. A BPA-commissioned report found that smart DR investments and practices had positive benefits to both the region and to BPA (Navigant 2013).

In 2013, BPA began testing DR on a demonstration project scale, with attributes that simulated commercial usage in contracting, incentive structures, operations, measurement and verification, and acquisition models. In total, BPA conducted four demonstrations from 2013 to 2017, using approximately 130 MW of controllable DR loads.

Additionally, in 2016, BPA released an "all-sources" request for offers to demonstrate a non-wires deferral of a transmission investment south of the Allston Substation near Longview, Washington. This demonstration subsequently included one DR load. In May 2017, BPA decided to not build the proposed 500 kilovolt (kV) transmission line, instead relying on several other actions, including use of a non-wires portfolio of DR and generation to maintain reliability south of Allston.

Figure 9 shows the timeline of BPA's DR experiences and a partial list of pilot and demonstration projects and selected studies.

Figure 9. A Partial History of DR at BPA



3.3. Document Organization

In following sections of this document, Cadmus describes the scope of analysis, methods, data sources and assumptions, and DR results included in Assessment 1.

4. Demand Response

4.1. Scope and Method

Cadmus estimated DR potential for two BPA areas (east and west) for two seasons (winter and summer). For each area-season combination, Cadmus estimated the 20-year technical and achievable potential and levelized costs for DR products included in the assessment's scope (shown in Table 5). Cadmus then developed supply curves that ranked DR products by levelized costs, from low to high, and displayed cumulative achievable DR potential for BPA's service area in 2036.

For planning purposes, Cadmus modeled the BPA Power system peak for summer (August 16–31) and winter (February 1–28).[7] The system peak used for BPA Power planning (Capacity Resource Adequacy) purposes is defined as the highest 18-hours of loads occurring in two three-hour peak periods per day for three consecutive days. This planning metric mimics a summer heat wave or winter cold snap.[8]

BPA requires adequate capacity resources to meet such conditions. The 18-hour planning peak was not intended to represent the actual BPA hourly peak demand. BPA hydroelectric resources still have a strong capability to meet individual hourly peaks. From a system planning perspective, the more challenging peak to satisfy is a continuing period of hotter- or colder-than-average days, none of which may be days with individual extreme peak hours. Such conditions challenge hydroelectric resources more than individual, short-term, peak demand spikes.

The winter and summer load basis for DR potential for each area (west and east) was calculated as the BPA service area's maximum winter and summer demands (hereafter called the winter and summer "area system peak"). These winter and summer area system peaks were modeled under average (1-in-2) weather conditions. A supplemental analysis of DR potential under an extreme (1-in-10) weather scenario is provided in Appendix C. 1-in-10 Weather Scenario.

The overall method for estimating DR technical and achievable potential involves five steps:

1. Define DR products
2. Estimate technical and achievable potential
3. Estimate levelized costs
4. Develop supply curves
5. Assess the elasticity of DR supply

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[7] The BPA Power system peak (based on the BPA Power 18-hour capacity peak definition) is lower than BPA Transmission system peak.

[8] For each season, the system peak is calculated as the sum of all end-use loads that are coincident with BPA's total system seasonal peak, based on BPA Power planning's 18-hour capacity event peak definition. They are not the same as each area's absolute single-hour peak load.

More detailed descriptions follow of each of these steps and of the tasks involved in implementing them.

4.1.1. Define Demand Response Products

As the first step in estimating DR potential, Cadmus worked closely with BPA to create a DR product list for evaluation (shown in Table 5). Each DR product included in the assessment was defined according to typical program offerings, such those available within BPA's public power service area. Therefore, each product represented a bundle of particular specifications, including program implementation methods, applicable market segments, affected end uses, load reduction strategies, and incentives. This document's Detailed Resource Potentials by Product section fully describes the DR products.

Cadmus conducted an extensive review of secondary sources addressing existing and planned programs offered for delivering DR products. The secondary sources included (but were not limited to) DR potential assessments, program descriptions, evaluation reports, and pilot and demonstration projects from other utilities, with an emphasis on Northwest utilities and on BPA's public power customers.[9]

DR Product Definition

After reviewing secondary data sources, Cadmus defined the typical program for each DR product using three main parameters: the load reduction strategy, eligibility criteria, and incentive. Given the large number of possible program design permutations, Cadmus defined each program parameter based on data availability and expected applicability to BPA's service area. This was a subjective process, relying on professional experience, judgment, and best available information.

Load reduction strategy. DR products fall into two broad categories—event-based and price-based—depending on what triggers the load reduction and who executes the event. Event-based or "dispatchable" DR (e.g., DLC, Demand Curtailment) can respond to specific events, such as system emergencies. Price-based or "non-dispatchable" DR (e.g., Critical Peak Pricing [CPP]) can reshape how and when electricity is used on a regular, daily basis, according to customers' voluntary actions. This distinction is important because of its implications in terms of DR's benefits, costs, and consumers' willingness to participate. In addition, DLC products may use different cycling strategies for various end-use loads to achieve the desired load reduction. For example, residential DLC programs for central air-conditioning (CAC) may employ a 50% cycling strategy, meaning the participating customer's CAC unit would run for only one-half of the interruption period. With non-event-based products (such as pricing products), end users may adopt a variety of strategies to lower demand during system peak periods to respond to higher power or energy prices. Behavioral DR does not necessarily fit easily into either of these two broad categories. Although the programs can be considered "event-based," they also are non-dispatchable as the utility ultimately does not control the loads that its customers may or may not opt to curtail, depending on the customers' decisions and actions.

[9] See this document's References section for a complete list.

Eligibility. For each DR product, Cadmus determined eligible sectors, segments, and end uses. In addition, other eligibility requirements may exist. For example, some commercial sector programs may require participants to maintain a certain minimum monthly average demand level. For this assessment, Cadmus defined sectors as residential, commercial, industrial, and agricultural. Furthermore, each sector was broken into its own market segments. For example, the residential sector included single-family, multifamily, and manufactured home segments. Cadmus divided the commercial sector into 18 segments and the industrial sector into 14 segments. The commercial sector included public buildings, while the industrial sector included public industries (such as municipal water treatment plants). End uses in each segment included cooling, heating, heat pumps, water heating, lighting, and—for the industrial segments—process loads.

Incentive. Depending on the DR product, incentive structures could vary considerably. For example, utilities could offer an incentive for upfront equipment installation of DR technology, a variable incentive based on the amount of expected or achieved load reduction, and/or a fixed incentive upon joining the program. Incentive structures may also include a penalty for nonperformance. This assessment assumed penalties would influence whether end users participated in the program or responded to an event. Cadmus, however, did not model the impact of penalties on a program's levelized cost.

Small- and medium-scale DR programs have been conducted in the Region and across the nation without (or with negligible) incentives offered to consumers. Cadmus considered such programs, pilots, and demonstrations as exceptions and not representative of typical DR programs operated today. This assumption also was consistent with the Assessment 2 findings (the DR Barriers Assessment), which shows that, in the survey of end users, nearly 80% of respondents across all sectors considered incentives important in their decisions to participate in DR.

DR product interactions. Several DR products (e.g., DLC—Smart Thermostats and Behavioral DR in the residential sector and Demand Curtailment and Interruptible Tariffs in the C&I sectors) may compete for the same end uses, and thus may not produce mutually exclusive load impacts. As the DR products assessed in this study were assumed to be independent, the cumulative potential for all assessed DR products overstates total achievable potential. It should be noted that other factors embedded in the analytical methods of this assessment may have caused the DR potential to be understated. Also, recall that the base case DR potential values are not a point estimate but rather are the mean value within a range. In other words, the estimated DR potentials could be higher, or they could be lower. This is the best that can be delivered when forecasting the potential and costs of the diverse and uncertain DR products used in this assessment.

Also note that interactions occur between DR and energy efficiency. In general, energy efficiency measures shift end-use load profiles downward, lowering the amount of load available for curtailment. For example, the Council estimated that implementing the energy efficiency measures identified in the Seventh Plan would likely produce 9,700 MW of capacity savings over the Plan's 20-year horizon. Peak load reductions of such magnitude could significantly lower the regional DR potential.

4.1.2. Estimate Technical and Achievable Potential

After designing the DR program for each product, Cadmus had sufficient information to estimate technical and achievable potential for each product:

- **Technical potential** assumes 100% participation of eligible customers in all programs included in the assessment. Technical potential represents a theoretical limit, presented in Detailed Resource Potentials by Product section for informational purposes.
- **Achievable potential** assumes achievable market participation rates for eligible customers in all programs included in the assessment. DR potential included in the assessment's main body focuses on achievable potential.

In estimating technical and achievable DR potential, Cadmus' methodology used two methods: bottom-up and top-down. This section describes each estimation method in detail and lists products for which the estimation method was applied.

The Bottom-Up Method

Cadmus used a bottom-up method to estimate potential for most end-use and technology-specific programs, particularly DLC products. From the technical potential point of view, these products are unique in that, unlike other DR options, they affect specific end uses and equipment (e.g., air conditioners and water heaters). The assessment applied the bottom-up method in estimating potential for the following programs:

- Residential DLC—Water Heating
- Residential DLC—Space Heating
- Residential DLC—CAC
- Residential DLC—Smart Thermostats
- Small Commercial DLC—CAC

Technical Potential

The bottom-up method determined technical potential as the product of three variables:

- Number of eligible customers
- Equipment saturation rate
- Expected per-unit (kW) impacts

Cadmus used the following method and data sources for estimating each of these variables:

- **Number of eligible customers.** The number of program-eligible, residential, end-use utility customers derived from a combination of EIA Form 861 data, American Community Survey (ACS) census data, and an expected customer forecast growth rate from the Council's Seventh Plan (Council 2016). For nonresidential sectors, eligible customers were derived from EIA (2016) Form 861 data and other secondary data sources, including the BPA-Northwest Energy Efficiency

Alliance (NEEA) Commercial Building Stock Assessment (CBSA), the NEEA's Industrial Facilities Site Assessment, and other regional data sources.

- **Equipment saturation rates.** Equipment saturation represents the percentage of customers eligible for program participation (i.e., to participate in the Residential DLC—CAC program, a customer must have a CAC or air-source heat pump). The BPA-NEEA Residential Building Stock Assessment (RBSA) and CBSA served as the primary sources for these data (NEEA 2012 and 2016).
- **Expected per-unit impacts.** Cadmus determined per-unit, peak-load reduction impacts from equipment affected by the DR product using benchmarked secondary sources and, as needed, making necessary adjustments to adapt to local conditions.

Achievable Potential

To estimate achievable potential, Cadmus multiplied the expected program participation rate and event participation rate by the technical potential. Moreover, Cadmus assumed that the program would require several years of start up before reaching its steady-state participation level. Therefore, the first few years of achievable potential accounted for the program ramp rate.

Program participation. For each program, Cadmus developed two program participation rates: base and high. These rates are derived from benchmarking against experiences or plans of regional and national utilities with similar DR products. The base participation rate represented a conservative estimate, based on benchmarked values, whereas the high participation rate represented an unconstrained scenario, where program participation would only be limited by end users' willingness to participate and not by utility-related factors (e.g., budget or other planning constraints). These high participation rates exceeded market averages for public utilities and approached the upper bounds of participation, as demonstrated in EIA Form 861 reports (EIA 2016).

For example, eligible customer participation values in benchmarking data collected for this study for residential CAC DLC programs range from 10% to 55%. Cadmus chose 25% as the base case rate because this participation level has been achieved by utilities of various sizes that operate mature programs. Conversely, the high case rate assumed 55% participation, even though this rate has been achieved with insufficient frequency (and primarily by smaller utilities) to represent an unconstrained achievable potential scenario.

Event participation. Once customers joined the program, Cadmus assumed participation in DLC events would become mandatory (i.e., 100% event participation). The study, however, explicitly accounted for attrition (e.g., drop-out rates, switch or communications failures) in determining achievable potential.

Ramp rate. Cadmus developed a series of ramp rates to account for the time needed for product design, planning, and deployment. These ramp rates were developed based on benchmarking and the lessons from several of BPA's DR pilots. They vary depending on the DR product. Ramp rates indicate when the maximum achievable potential may be reached, but they do not affect the amount of maximum achievable potential.

From benchmarking (mostly based on regulated, investor-owned utility DR programs), Cadmus found that DR programs generally achieved their expected achievable potential between three and seven years after deployment was initiated. Given BPA's unique position in the Northwest, however, along with the vast differences in its public power customers and the challenges posed by coordination with these BPA Power customers, assuming a similar trajectory of DR product deployment for its service area might overstate the pace at which DR programs could progress in BPA's service area.

On the other hand, several public utility pilot, research, and demonstration projects in the BPA service area have attracted high percentages of targeted consumer populations in relatively short periods. Anecdotal evidence exists that public utility consumers can respond more quickly than investor-owned utility consumers to DR program opportunities. Messaging often used in public utility service areas (e.g., doing something good for your own utility, doing something good for ratepayers of your utility, doing something good for the environment) may play an important role in utility customers' willingness to participate in DR, particularly for rural cooperative members.

BPA has implemented numerous DR pilots over the decades, achieving 20%–35% penetration rates in the residential sector after just one season or year of marketing within public utility service areas—also usually without any incentives needed to attract residential end-use consumer participation.

Through various DR pilots and programs, BPA and its Power customers have successfully achieved rapid and substantial DR penetration. Notably, the water heating and space heating portions of the BPA and Orcas Power & Light Cooperative's "Energy Partners" peak reduction program from 1996 to 2002 recruited 4,150 homes out of 6,900 non-seasonal homes in the San Juan Islands of Washington over three years of publicity and program marketing. That can be considered equivalent to 60% of eligible homes. Not all were needed to achieve the required load reduction quantity, so not all were put under load control. Note that no incentives were offered for this program (Brown 2012).

Of equal note, while typical achievable potential may be reached between three and seven years after implementation begins, many successful DR programs have continued for decades, adding new participants every year (such as some of the nation's largest residential water heating DLC programs, with participants numbering in the millions of homes). Some of these programs began in the late 1970s and continue to add meaningful numbers of new households and water heaters today, 40 years later.

For this study, after considering national and regional experiences of private and public utilities, Cadmus assumed a seven-year ramp rate period for all residential and commercial DLC products, C&I demand curtailment, agricultural irrigation DLC, and utility system demand voltage reduction (DVR), given that BPA has significant experience in implementing and deploying such commonly used DR resources. For commercial lighting controls and thermal storage, Cadmus assumed a nine-year ramp rate period. The study also assumed a deployment period of nine years for each non-firm resource, including behavioral DR, and for each pricing program requiring BPA to almost entirely rely on its public power customers for implementation. Note that these are conservative ramp rates. BPA has implemented small and short-term DR projects of the types listed above with much faster ramp rates. Note also that the ramp rate assumptions do not affect the total potential, though they do have a small impact on the levelized costs.

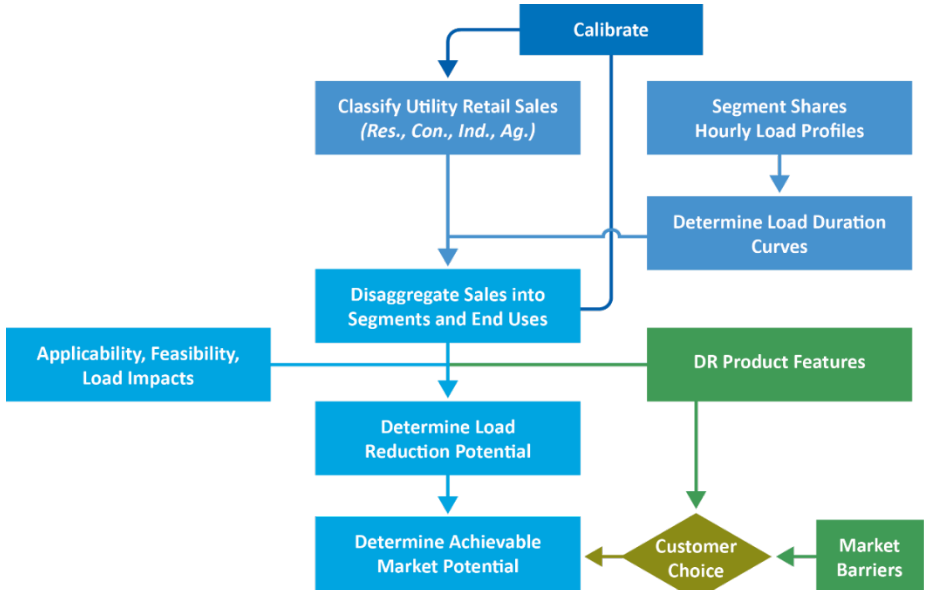
The Top-Down Method

Cadmus used the top-down method to determine potential for non-DLC DR products, including most nonresidential DR products and pricing programs. This top-down estimation method applied for the following DR products:

- Commercial Lighting Controls
- Commercial Thermal Storage
- C&I Demand Curtailment
- C&I Interruptible Tariff
- Residential CPP
- Industrial Real Time Pricing (RTP)
- Agricultural Irrigation DLC
- Residential Behavioral DR
- Utility System DVR

Cadmus began the top-down method by compiling BPA system sales by east and west, disaggregated into sectors, segments, and applicable end uses. For each DR product, Cadmus assessed technical potential at the end-use level by multiplying the percentage of load reduction by the eligible end-use load coincident with the total BPA system peak (i.e., the “load basis”), followed by aggregating end-use load impacts to obtain technical potential estimates for each product. Finally, the study applied program and event participation rates to technical potential, deriving estimates of achievable potential for each product. Figure 10 illustrates the general analytic steps involved in estimating technical and achievable potential.

Figure 10. Illustration of Top-Down Method



Technical Potential

The bottom-up method expresses the load reduction variable in kilowatts per unit. In contrast, the top-down method expresses load reduction as a percentage of the load basis. Cadmus estimated each DR product's technical potential by aggregating end-use load reduction impacts across all end uses, market segments, and sectors where the DR product was applicable.

For each area-season combination, Cadmus estimated the technical potential for each DR product. The following equations show that technical potential (*TP*) for each DR product *(p)* is the sum of impacts at the end-use level (*e*), generated in market segment (*s*) and sector (*c*):

$$TP_p = \sum_{esc} TP_{pesc}$$

$$TP_{pesc} = LB_{esc} \times E_{psc} \times LI_{pesc}$$

In the above equations, LB_{esc} (load basis) is the area's amount of megawatt load in each end use (*e*), segment (*s*), and sector (*c*) coincident with the BPA system's total seasonal peak. To derive the load basis, Cadmus disaggregated the area's total annual sales (MWh) into end-use sales in each segment and sector. Cadmus then multiplied the end-use sales by a peak coincidence factor to derive the end-use load coincident with the total BPA system seasonal peak.

BPA supplied the hourly load forecast and the east-west area designation for each BPA Power customer, from 2017 to 2036. For each area, Cadmus combined the individual Power customer hourly loads into area hourly loads. Then, for each year, Cadmus aggregated each area's hourly load to derive each area's annual energy sales. Then, Cadmus segmented each area's annual energy sales into end-use sales using sector, segment, and end-use shares. Cadmus produced sector, segment, and end-use shares using EIA data for BPA Power customers who reported to the EIA, BPA-supplied data for BPA Power customers who did not report to the EIA,[10] and regional conservation potential studies such as those from Seattle City Light, Snohomish County PUD No. 1, and Avista Utilities.

After the annual energy sales were distributed to end-use sales, Cadmus multiplied the end-use sales by its corresponding peak coincidence factor to derive the segment loads that is coincident with BPA's system peak. The peak coincidence factor is a ratio showing how much of an end-use are coincident with BPA's system peak. Cadmus calculated peak coincidence factors based on BPA's peak definition for each season, BPA's total system load, and end-use load shapes from the End-Use Load and Consumer Assessment Program, the NEEA RBSA metering studies (NEEA 2014), and various other sources of end-use load shape data used by the Council to develop the Seventh Power Plan (Council 2016) and currently employed by the RTF. BPA's total system peak load is modeled separately for summer (August 16–31) and winter (February 1–28) periods and is defined as the average peak hourly load occurring under an 18-hour capacity event across six peak hours per day over a three-day period. BPA's 18-hour capacity definition, established in its capacity needs assessments, defined summer and winter system peaks used for BPA Power supply planning and resource adequacy purposes.[11] The most recent capacity needs assessment, completed in 2015, was detailed in the BPA's White Book of the same year.

E_{psc} (eligibility percentage) equals the fraction of the market segment (*s*) in sector (*c*) eligible for the DR product (*p*) and depends on program eligibility requirements for each DR product. For example, if a commercial program requires customers to have monthly average demand above a minimum threshold, the eligibility percentage for each commercial segment would be the fraction of the commercial segment's load from end users meeting the minimum demand.

LI_{pesc} (load impact percentage) equals the percentage of load reduction in the load for each end-use (*e*) market segment (*s*) in sector (*c*) that results from DR product (*p*). This percentage, based on each DR product's load reduction strategy, was benchmarked against secondary sources.

Achievable Potential

As with the bottom-up method, the top-down method calculates achievable potential as the product of technical potential, program participation, and event participation. Contrary to the bottom-up method products (i.e., DLC products), some top-down products do not require customers to participate in every dispatched event. Therefore, while bottom-up products experience 100% event participation, top-down products' event participation may fall below 100%. Both bottom-up and top-down methods apply ramp rates in the same manner to account for program start-up periods.

[10] The BPA Power customers who did not report to EIA included federal irrigation districts and ports, tribal utilities, DSIs, and other, smaller utilities. The BPA-supplied data allowed Cadmus to separate agricultural sales from industrial sales.

[11] Note that it is not the same peak definition used by BPA Transmission.

4.1.3. Estimate Levelized Cost

This assessment based the valuation of DR products on the levelized costs of electricity (LCOE), the most common metric for comparing the cost of generating electricity from various sources. LCOE—also called the "bus-bar" cost—is the "per-kilowatt-hour cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle" (BPA 2010).[12] LCOE also serves as a common metric for the economic valuation of energy efficiency ($/kWh) and DR ($/kW-year) and for developing energy efficiency and DR supply curves in long-term resource planning. In the context of DR, LCOE represents the constant per kW-year cost of deploying and operating a DR product, calculated as:

LCOE = (The Annualized Cost of DR Product) / (Achievable Annual kW Load Reduction)

This assessment calculated levelized costs based on the total resource cost (TRC) perspective which includes all known and quantifiable costs and benefits related with DR products and programs. Unlike the Council's Seventh Plan demand response potential assessment, this assessment did not use a transmission deferral credit or any other credits to calculate *net* levelized costs by adjusting downward total levelized costs.

The calculation of each DR product's LCOE and the associated sources of information used the following various inputs:

- **Upfront setup cost.** This cost item includes both BPA and local utility program development and setup costs for delivery of the subject DR products, prior to program and DR implementation. This study assumes that this cost occurs in the program's first year and includes program development, marketing initiatives and materials design, program participant recruitment planning, measurement and valuation planning, implementation contractor and DR aggregator hiring, and other common startup costs. Because upfront costs tend to be small relative to total program expenditures, they can be expected to have a small effect on levelized costs.
- **Program operations and maintenance (O&M) cost.** This cost item includes all expenses that both BPA and local utilities incur annually to operate and maintain the program. Expenses may cover administration, event dispatching, customer engagement, infrastructure maintenance, managing opt-outs and new recruiting of loads, and evaluation. For programs run by third-party aggregators, Cadmus assumed participating BPA Power customer utilities would pay the aggregators and thus included aggregator costs in in this cost item.
- **Equipment cost (labor, material, and communication costs).** This cost item includes all expenses necessary to enable DR technology for each participating end user (including obtaining necessary permits). The cost item applies only to each year's new participants. For some programs that assume or require end users to already have DR technology in place, this cost item would be zero.

12 Pp. 9-10 in Bonneville Power Administration's *Guidebook for Potential Studies in the Northwest*.

- **Marketing cost.** This cost item includes all expenses for recruiting end users' participation in the program and applies only to new participants each year. For some programs (typically those run by third-party aggregators), the Utility Program O&M Cost already includes this cost item.
- **Incentive.** This cost item covers all incentives offered to end users per year. Incentives may take the form of fixed monthly or seasonal bill credits or may be variable, tied to actual kW load reduction. This assessment included 100% of the assumed incentive payment to eligible participants in the TRC levelized cost calculation. Although this study assumes incentives are paid to customers participating in DLC and load curtailment programs, previous BPA pilots and demonstration projects have successfully recruited participants without providing financial incentives.
- **Signup bonus.** Where applicable, this cost item covers any program incentives offered to end users upon joining the program.
- **Discount rate.** A 4.2% discount rate, consistent with BPA's resource planning assumptions, was used for all DR products.
- **Product Life cycle.** All DR products were assessed with an assumed 20-year life cycle.

While levelized costs are convenient, useful, and requisite for comparing and modeling DR products and programs against traditional, supply-side capacity generating resources, some program managers and decision-makers more frequently rely on average or first-year costs of DR acquisition. In reality, total average costs over a 20-year lifecycle barely diverge from the total, levelized costs. For example, this assessment estimated 206 MW of achievable potential in the winter for residential space heating DLC at a levelized cost of $53.08 per-kW-year. These MW reductions equated to an average cost of $50.12 per-kW-year. An aggregator-delivered DR program might have a payment stream that looks like the average cost stream. Aggregators usually fold all upfront financing, recruitment, enablement, and annual costs and a small profit into average annual payments for each year of their contract with a utility or RTO/ISO.

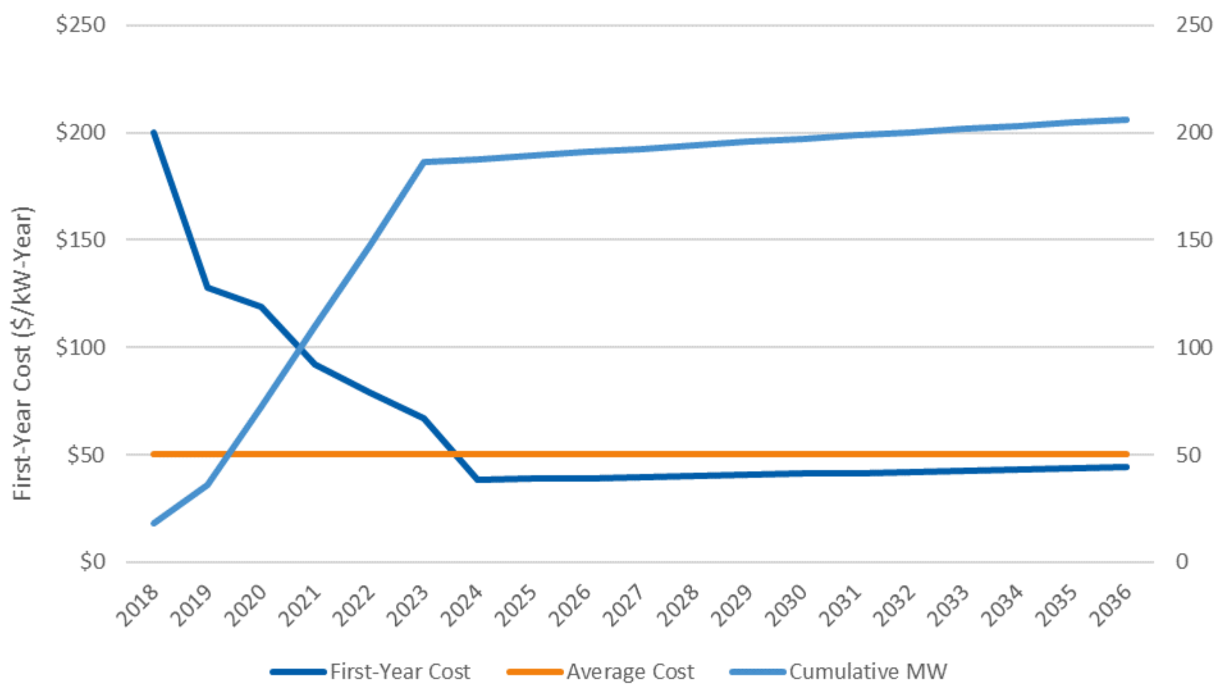
On the other hand, first-year and ongoing cash-basis, or actual annual costs, can vary greatly from year to year, depending on the length of time it takes for a DR program to reach maturity. Figure 11 shows the relationship of declining first-year costs to cumulative MW reductions for the residential space heating DLC example above. As the program ramps to its steady state maturity, first-year (cash-based) actual annual costs steadily decline below the 20-year average cost of $50.12 per kW-year. Cash-based or actual cost streams are common in utility-delivered DR programs, where utilities pay the actual costs incurred in the year in which the costs occur.

BPA energy efficiency programs look a lot like first-year or actual-cost DR programs because BPA provides a high upfront payment for the installation of desired energy efficiency measures, and the savings are produced steadily over many years. In contrast, in the energy efficiency industry, energy savings performance contractors can look like DR aggregators, because they receive steady equal annual payments to offset the financing and upfront costs that they incurred in the first year.

DR is increasingly delivered by performance contractors and aggregators. That is one reason why Cadmus modeled DR cost streams as average annual costs and levelized costs over the 20-year planning period for this assessment. Nevertheless, these are not the only way to pay for DR programs. Past commercial-scale BPA DR programs were all paid for as actual cost (first-cost) programs, similar to how BPA has historically paid for most of its energy efficiency programs and how it pays for energy efficiency measures today.

This assessment made no explicit assumptions about who—aggregators, local utilities, or BPA—ultimately deploys, implements, and manages DR programs. The assessment also did not attempt to estimate differences in aggregator versus utility implementation and administration costs; rather, its primary purpose was to estimate overall MW of DR potential and its associated costs at a more generalized level, not to determine who should deploy the resources and the specific costs related to the choice of implementation strategy. The implementation strategy choice likely would not markedly affect the overall levelized TRC cost of the DR resource potentials identified in this assessment.

Figure 11. First-Year Cost Example: Residential Space Heating DLC



4.1.4. Develop Supply Curves

As the final step in estimating potential of each DR product, Cadmus developed a supply curve showing the amount of achievable DR potential available at the product's levelized cost ($/kW-year). The supply curve ranked DR products by levelized costs, from low to high, and showed the cumulative achievable DR potential at each product's levelized cost price point.

4.1.5. Elasticity of DR Supply

Cadmus performed an elasticity study to estimate the amount of DR capacity achievable through changes in customer incentive payments. The accompanying *Demand Response Elasticities Analysis* report presents the methodology, data sources, results, and an example application. This study was performed to estimate how changes in incentive amounts might affect the amount of DR capacity that customers supply to utilities. The elasticity estimates indicate *incremental* changes in utility DR capacity from an incremental change in incentives, that is the percent increase in DR supply that can be expected from a one percent increase in incentives. This information will be useful to DR product developers and planners.

4.2. Assessment Results

4.2.1. Technical Potential Results

Technical potential represents DR's theoretical limit if all eligible customers participate in DR programs. Technical potential equals the product of all eligible customers in relevant segments and the assumed unit load impacts for applicable products and programs. Barriers to DR adoption are ignored when calculating technical potential.

Table 6 presents estimated technical potentials for all DR products in the BPA's public power utility customer areas—east and west of the Cascade mountain range—and the total BPA Power customer service area for all DR products considered in this study through 2036. MW reductions presented are at the generator and, therefore, include a line loss of 9.056% for both areas and all sectors.[13] Overall, technical potential across BPA's entire service area represents 44% of the system winter peak and 55% of the system summer peak.[14]

Table 6. DR Technical Potential by Area, MW in 2036

Area	Winter Technical Potential (MW)	Percent of Area System Peak—Winter	Summer Technical Potential (MW)	Percent of Area System Peak—Summer
West	4,729	44%	4,393	59%
East	2,135	42%	2,980	50%
Total	**6,863**	**44%**	**7,374**	**55%**

Despite the assumption that all eligible consumers adopt the DR products and participate in the DR programs considered in this study, the technical potential estimates do not equal 100% of peak load. Numerous end-use loads exist that are not typically controlled by products in DR programs. Examples in

13 Provided by BPA.

14 For each season, the system peak is calculated as the sum of all end-use loads that are coincident with BPA's total system seasonal peak, based on BPA Power planning's 18-hour capacity event peak definition. They are not the same as each area's absolute single-hour peak load. More information is supplied in the Scope and Method section.

the residential sector include interior and exterior lighting, baseboard heating, cooking, refrigerators and freezers, dryers, and plug loads (including televisions and other consumer electronics). It is important to note that, at some level, several of these loads are controllable, especially with the advent of smart appliances. Over time, it is possible that the DR technical potential will increase as new and lower-cost technologies become available in the demand side market.

As shown in Table 7, the greatest winter and summer technical potential occurs in the residential sector, followed by the commercial sector in summer. The agricultural sector exhibits technical potential only during the summer season, because the sole agricultural DR product considered by this study is DLC of summer irrigation loads.

Table 7. DR Technical Potential by Sector, MW in 2036

Sector	Winter Technical Potential (MW)	Percent of Total System Peak—Winter	Percent of Total Technical Potential—Winter	Summer Technical Potential (MW)	Percent of Total System Peak—Summer	Percent of Total Technical Potential—Summer
Agricultural	0	0%	0%	894	7%	12%
Commercial	552	3%	8%	2,464	18%	33%
Industrial	1,159	7%	17%	1,175	9%	16%
Residential	4,796	30%	70%	2,629	20%	36%
Utility System	357	2%	5%	211	2%	3%
Total	**6,863**	**44%**	**100%**	**7,374**	**55%**	**100%**

For determining the amount of DR resource availability that BPA and its Power customers can reasonably rely upon, market barriers and constraints must be considered. The next section presents achievable potential results from accounting for such barriers and constraints.

4.2.2. Achievable Potential Results

The achievable potential results assume achievable market participation rates for eligible customers. These participation rates vary by product and, in some cases, by area. The Detailed Resource Potentials by Product section presents product- and area-specific participation rates in greater detail. Most results presented in this section represent base-case achievable potential. For each product, Cadmus estimated a high-case potential scenario if customer participation rates exceeded market averages for public utilities and approached the participation upper bounds, as demonstrated in EIA Form 861 reports.

Table 8 provides the 2036 cumulative base achievable potential for winter and summer seasons, in the east and west areas, and for BPA's total public power utility customer service area. Overall, the base achievable DR potential represents 9.8% of the total system peak in winter and 12.0% of the total system peak in summer.

Table 8. DR Base Achievable Potential by Area, MW in 2036

Area	Winter Achievable Potential (MW)	Percent of Area System Peak—Winter	Summer Achievable Potential (MW)	Percent of Area System Peak—Summer
West	1,061	9.9%	807	10.8%
East	490	9.6%	795	13.5%
Total	**1,551**	**9.8%**	**1,602**	**12.0%**

For comparison purposes to the base achievable potential, Table 9 presents the high achievable potential by area. In this scenario, achievable DR potential accounts for 17.7% of the 2036 forecasted winter season peak. The high-participation, achievable, DR potential in the summer season represents 21.0% of the 2036 forecasted summer season peak.

Table 9. DR High Achievable Potential by Area, MW in 2036

Area	Winter Achievable Potential (MW)	Percent of Area System Peak—Winter	Summer Achievable Potential (MW)	Percent of Area System Peak—Summer
West	1,876	17.6%	1,528	20.5%
East	914	18.0%	1,268	21.5%
Total	**2,790**	**17.7%**	**2,796**	**21.0%**

In both the base-case and the high-case, differences in participation rates, achievability, potential estimates, and variations in the percent of system peak savings can be explained largely by load variations at the sector and end-use levels. For example, the east area has a higher saturation of residential air conditioning loads than does the west.

Table 10 shows each sector's DR base, achievable, potential contribution to the total BPA service area in winter, with the residential sector accounting for approximately 66% of the total BPA service area's base-case achievable potential, followed by the utility system sector (15%). In summer, the residential sector represents nearly 37% of the total base-case achievable potential, followed by the agricultural sector (26%).

Table 10. DR Base Achievable Potential by Sector, MW in 2036

Sector	Winter Achievable Potential (MW)	Percent of Total System Peak—Winter	Percent of Total Achievable Potential—Winter	Summer Achievable Potential (MW)	Percent of Total System Peak—Summer	Percent of Total Achievable Potential—Summer
Agricultural	0	0.0%	0.0%	420	3.1%	26.2%
Commercial	107	0.7%	6.9%	263	2.0%	16.4%
Industrial	197	1.2%	12.7%	200	1.5%	12.5%
Residential	1,022	6.5%	65.9%	586	4.4%	36.6%
Utility System	225	1.4%	14.5%	133	1.0%	8.3%
Total	**1,551**	**9.8%**	**100.0%**	**1,602**	**12.0%**	**100.0%**

For comparison purposes, Table 11 provides the high, achievable, DR potential by sector for the total BPA service area. In this scenario, the residential sector accounts for the majority of peak load reduction in winter (76%) and summer (45%).

Table 11. DR High Achievable Potential by Sector, MW in 2036

Sector	Winter Achievable Potential (MW)	Percent of Total System Peak—Winter	Percent of Total Achievable Potential—Winter	Summer Achievable Potential (MW)	Percent of Total System Peak—Summer	Percent of Total Achievable Potential—Summer
Agricultural	0	0.0%	0.0%	504	3.8%	18.0%
Commercial	123	0.8%	4.4%	623	4.7%	22.3%
Industrial	240	1.5%	8.6%	244	1.8%	8.7%
Residential	2,133	13.5%	76.4%	1,251	9.4%	44.8%
Utility System	294	1.9%	10.5%	174	1.3%	6.2%
Total	**2,790**	**17.7%**	**100.0%**	**2,796**	**21.0%**	**100.0%**

DR Product and Supply Curves

DR resource acquisition costs fall into several categories (e.g., program setup costs, program O&M costs, equipment costs, marketing costs, incentives). Cadmus developed estimates for each cost category for each product using a combination of BPA's pilot history and experience, along with secondary sources such as other utilities' reports on similar programs. In developing levelized cost estimates, Cadmus aggregated annual program expenses over the program's expected life cycle and discounted these expenses using BPA's 4.2% discount rate. This discounted, aggregated program cost and discounted kilowatt reduction produced the levelized per-kilowatt-year cost for each program.

Cadmus constructed supply curves from quantities of estimated achievable potential and per-unit levelized costs for each program. Figure 12 shows the quantity of achievable DR potential (available during the system winter peak hours in 2036) as a function of levelized costs. The supply curve starts with the cheapest winter DR product—residential Critical Peak Pricing (CPP), providing 168 MW of winter achievable potential at $10 per kilowatt-year, levelized. The next cheapest product in the supply curve is utility system DVR, adding 225 MW of winter achievable potential at $11 per kilowatt-year, levelized. Thus, BPA could acquire a total of 393 MW of winter DR at a cost of $11/kw-year or less, levelized. Because residential DLC water heating is the most expensive winter DR product, BPA could acquire as much winter potential as achievable if it paid $122 per kilowatt-year (i.e., the levelized cost for residential DLC water heating).

Figure 13 provides achievable DR potential available during summer peak hours in 2036 as a function of levelized costs. In Figure 12 and Figure 13, orange bars represent the incremental, achievable DR potential available for that product at its associated levelized cost. The blue bars represent the cumulative achievable potential for the products with lower levelized costs.

Figure 12. 20-Year Base Achievable Potential Supply Curve for DR, Winter Peak, with Levelized Costs

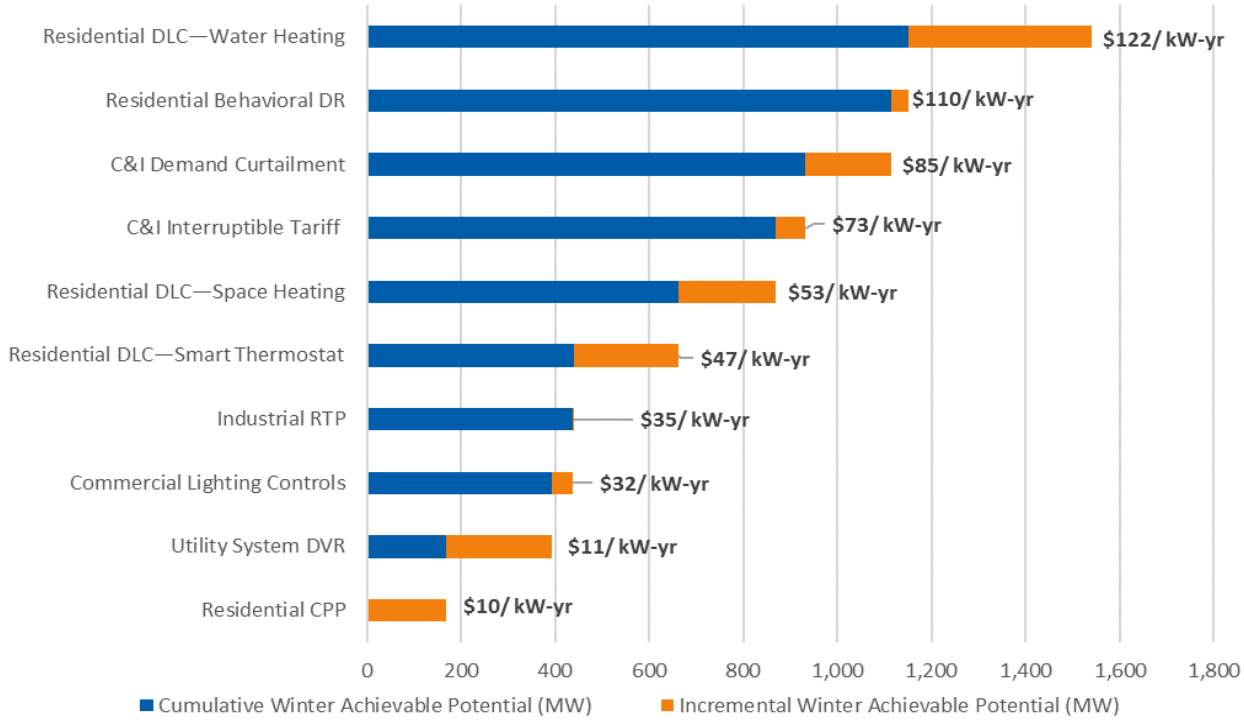
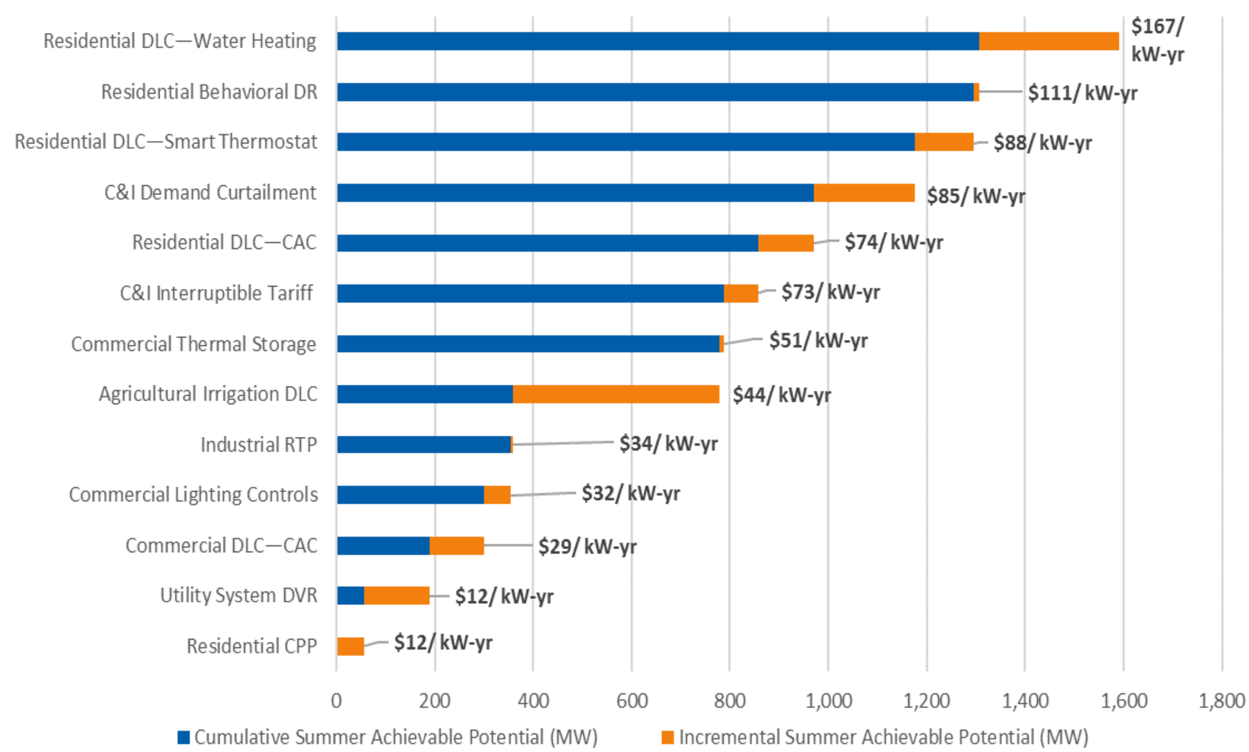


Figure 13. 20-Year Base Achievable Potential Supply Curve for DR, Summer Peak, with Levelized Costs



4.3. Detailed Resource Potentials by Product

This section provides detailed DR technical and achievable potential by product for the participation base case. Appendix A. Scenario Analysis presents the high participation case's product-level results. For each product, Cadmus provided the product description, cost, and impact inputs along with their assumptions and sources, followed by presenting each product's technical and achievable potential and levelized costs by season and area.

Table 12 summarizes the product-level results, showing that Residential DLC—Water Heating had the highest MW achievable potential in winter and Agricultural Irrigation DLC had the highest in summer. The table also shows that levelized costs vary by product, with Residential CPP as the least-expensive product in both winter and summer.

Table 12. Detailed Base Achievable Potential by Product, in 2036 MW

Product	Winter			Summer		
	Achievable Potential (MW)	Percentage of System Peak	Levelized Cost ($/kW-year)	Achievable Potential (MW)	Percentage of System Peak	Levelized Cost ($/kW-year)
Residential DLC—Space Heating	206	1.3%	$53	0	0.0%	N/A
Residential DLC—Water Heating	389	2.5%	$122	285	2.1%	$167
Residential DLC—CAC	0	0.0%	N/A	113	0.8%	$74
Residential DLC—Smart Thermostat	222	1.4%	$47	120	0.9%	$88
Residential CPP	168	1.1%	$10	57	0.4%	$12
Residential Behavioral DR	37	0.2%	$110	13	0.1%	$111
Commercial DLC—CAC	0	0.0%	N/A	110	0.8%	$29
Commercial Lighting Controls	44	0.3%	$32	55	0.4%	$32
Commercial Thermal Storage	0	0.0%	N/A	9	0.1%	$51
C&I Demand Curtailment	184	1.2%	$85	205	1.5%	$85
C&I Interruptible Tariff	62	0.4%	$73	69	0.5%	$73
Industrial RTP	5	0.0%	$35	5	0.0%	$34
Agricultural Irrigation DLC	0	0.0%	N/A	420	3.1%	$44
Utility System DVR	225	1.4%	$11	133	1.0%	$12
Total*	**1541**	**9.8%**		**1592**	**11.9%**	

*The total achievable potential values in this detailed potential by product table do not match those in Table 8 or Table 10. Each of those tables include an estimated achievable potential for direct-service industry customers whose potential was estimated independent of a DR product.

4.3.1. Residential

This assessment includes four different residential DLC products: Water Heating, Space Heating, CAC, and Smart Thermostats. Given the load profiles of their applicable end uses, Water Heating and Smart Thermostats offer load reduction potential in summer and winter, while Space Heating and CAC are limited to one season. Non-DLC products assessed included CPP and Behavioral DR, which can cause end users to reduce demand during peak periods without direct-event dispatches or incentives.

In the summer, the total residential load that is coincident with BPA Power's 18-hour system peak (i.e. the total residential *load basis*) is approximately 3,150 MW (2,080 MW in the west and 1,070 in the east). In the winter, the total residential load basis is approximately 9,340 MW (6,150 MW in the west and 3,190 MW in the east). For each residential DR product, the achievable potential is a subset of the residential load basis that meets the product's participation and impact assumptions.

BPA-Orcas Power & Light Cooperative (OPALCO) Energy Partners Program

OPALCO [partnered] with its members to reduce winter peak loads.

Installation and testing began in summer 1997.

Measures implemented from summer 1997 through winter 2000-2001 included … [residential] space heat cycling (40% of the homes installing water heater controls also installed space heating system controls; 1,050 homes; 0.7MW available) [and water] heater control (2,650 homes; 2.6MW available)

Controllable load (excluding potential use of diesel generators) totaled about 5.8 MW. This proved adequate to keep loads below 49 MW on BPA Submarine Cable 3 from winter 1997-1998 through winter 2000-2001. The program objectives were achieved without ever using the diesel generators, or installing water heater and space heating controls in the homes of all members who volunteered to participate in the program.

Sufficient load was under control by winter 1999-2000, allowing program marketing to end. About 2,650 homes participated in the program. An additional 1,500 homes were on the waiting list but not needed when marketing ended. Out of 6,900 non-seasonal homes in the service area, about 4,150 volunteered for water heater and/or space heat control. No incentives were provided to OPALCO members in the program.

Excerpts from BPA-Orcas Power & Light Cooperative (OPALCO) Energy Partners Program History (Brown 2012)

Residential DLC

Water Heating

Product Description

Water heating DLC programs manage residential loads by directly controlling water heater end uses in customers' homes via load control switches. Communication between the utility and these switches can occur through advanced metering infrastructure (AMI) infrastructure, radio, consumer Wi-Fi connections to the internet, power line carrier, or paging infrastructure as well as through other web-based communications.

For peak event hours in summer and winter, this study assumed water heaters cycled off for

50% of the event's duration. As most electric water heaters use tank storage systems, which allow customers to draw on stored hot water during event times, the water heater load shifts on and off every 20 or 30 minutes for an event's duration. The assessment assumes the Residential Water Heating DLC product will be available for four-hour duration events with up to 10 events per year.

Although this assessment considered only DLC for residential water heating applications, several other technologies exist for curtailing water heating energy usage during peak hours, including the following:

Water Heater Timers. These devices provide automatic control of electric resistance storage water heaters and can be programmed to turn a water heater on or off at times coincident to a utility's normal peak hours. Energy savings and peak demand reductions occur from reducing normal on/off cycling required to maintain water temperature setpoints and by reducing atmospheric heat loss. These devices are simple, relatively cheap (about $50) compared with DLC products, and generally require installation by a licensed electrician. Unlike DLC products, these devices are not dispatchable and cannot be directly controlled by the utility. Examples of modern DR program offerings in public utility service areas include Austin Energy's "Cycle Saver" Water Heater Timer program, eligible to multifamily properties with individual water heaters. BPA partnered with Central Electric Cooperative (Redmond, Oregon) in 2011–2012 to demonstrate and test a very successful, low cost, and simple water heater timeclock-controlled DR program to reduce loads on a Central Electric substation.

Water Heaters as Energy Storage. Much has been written recently in both the Pacific Northwest (Dragoon 2017) and at the national level (Hledik, et. al. 2016) about the possibilities of employing electric storage water heaters—either resistance or heat pump models—as energy storage devices. Multiple strategies exist for controlling these water heaters loads, which provide a range of treatments including traditional peak shaving, load shifting, balancing reserves, and ancillary services. Financial benefits can accrue from avoiding or deferring the need for generation capacity expansion, transmission and distribution investments, and frequency regulation.

BPA conducted its own Technology and Innovation grant program for demonstrating the ability of water heaters to provide power system balancing services and reserves and energy storage to shift water heater load in time. This program, managed by Ecofys, successfully demonstrated how water heaters could provide reliable balancing reserves for renewable energy generation sources tied to the BPA grid. BPA also tested water heater energy storage in several public utility service areas from 1990 through the mid-2000s. Often water heaters could be turned off for 12 to 16 hours during the day time (heavy load hours), using storage control technology, without producing any consumer complaints during several years of tests. These types of water heater control and DR were not considered in this assessment. Further analyses of these DR products (thermal storage water heating and time clocks/timers for water heaters) could by justified to contrast the different costs and load impacts these types of water heating DR technologies can provide.

Eligibility: All residential customers with electric storage water heaters are eligible to participate in water heating DLC programs. Customers, however, with electric instantaneous/tankless water heaters are ineligible. Although such water heaters have significant loads when activated, the lack of stored energy means that customers would be without access to hot water for the duration of an event. Furthermore, the actual load reduction capacity for these water heaters remains poorly understood in the context of DR.

Customers also may opt to purchase new grid-enabled water heaters. This emerging technology allows the installation of water heaters with a preexisting, two-way connection to the utilities' grid infrastructure. The primary advantages of this built-in communication capability include substantially reduced equipment and communication costs and the opportunity for higher participation in water heater DLC programs. In this study's context, however, grid-enabled water heaters are not considered distinct components of the water heater DLC program.

Similarly, Cadmus did not model programmable thermostat-controlled water heaters, which also can result in much lower water heater DR costs. In such systems, programmable space heating thermostats are enabled to also control water heaters in the home, so that DR events called to the thermostat may reduce both space and water heating loads.

As these technologies (grid-enabled and thermostat-enabled water heater controls) increase in their market penetration, justification could be made to analyze their costs and load impacts and contrast them to the type of water heating DR assumed in this assessment.

Incentives: Cadmus assumed that participants in water-heating DLC programs would receive incentives at a yearly rate, independent of the number and duration of events called, as events could be called during any season, depending on demand. Such incentives can be delivered through multiple applicable channels (e.g., bill credits, check lump sums) and can include incentives to cover costs of enabling a DLC device and/or a one-time sign-up bonus to boost enrollment. Fixed, annual, or monthly bill credits are common, simple, and easy to understand, and incentives for residential DLC programs also can be structured to pay per event or per enrolled kW.

Assessment Assumptions

Table 13 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for Residential DLC—Water Heating.

Table 13. Residential DLC—Water Heating: Assessment Assumptions

Residential DLC—Water Heating Assumptions	Base	High	Notes and Discussion
Cost Assumptions			
Upfront Setup Cost (One-time Cost)	$150,000	$150,000	Equal to 1 FTE at $150K/yr.
Program Admin Cost (Annual % of Total Cost)	7.4%	7.4%	The annual program administrative cost assumes 1 FTE at $150,000 per year per 20,000 residential participants. This equates to 9.6% of total cost for Water Heating DLC, or $12/kW and $9/kW in the summer and winter, respectively.
Equipment Cost (Labor, Material, Communication Costs)	$315	$315	Using PacifiCorp's potential study (Applied 2017) estimate: $315 (includes switch and installation and permits, where required). Other sources: Lawrence Berkeley National Laboratory's (LBNL 2017) estimate = $350, which includes costs for control technology, installation, and the communication platform. Range: Arkansas' potential study (Navigant 2015a) = $106 ($60 switch, $46 install); Tennessee Valley Authority's potential study (Global 2011) = $170 (space heat [SH] and water heat [WH] combined, likely does not include labor); Navigant (2012) = $280 (WH and SH combined, additional $275 for gateway).
Marketing Cost ($ per new participant)	$25	$25	DLC range: Navigant (2012) $25; Brattle (2014) $80, Applied (2017) $50.
Incentive (Annual $ per participant)	$24	$24	Assuming $2/mo. for 12 months. Applied (2017) = $24 - $25. Duke Energy (2015) WH DLC = $25. Navigant (2011) WH DLC = $8. BPA (2014) $4/mo.
Sign-up Bonus	$0	$0	N/A
Participation Assumptions			
Per-Participant Tank Impacts—Summer (kW/tank)	0.55	0.55	Season-specific values from recent BPA end-use sub-metering studies. Other values: season non-specific of 0.58, the most frequently used value from Cadmus (2011), Council (2016), Navigant (2011), Applied (2017), Navigant (2015a), and BPA (2014). Global (2011) = 0.5; Duke Energy (2015) = 0.4; Navigant (2011) = 0.49 - 0.77; Cadmus (2011) = 0.54 - 1.65 (SH and WH combined).
Per-Participant Impacts—Winter (kW/tank)	0.75	0.75	
Program Participation (of Eligible Participants)	25%	55%	Applied (2017) = 15% - 23%, Global (2011) = 15% - 25% (low-high), Navigant (2012) = 20%, Navigant (2015a) = 20% - 30% (realistic - max achievable). Highest participation rate for non-IOU, res DLC programs in EIA (2017) data = 55%.
Event Participation	95%	95%	Assuming same as SH DLC, Navigant (2012) had low event participation at 57%, but the following potential assessment estimate was 94%.
Attrition (Percent of Participant Program Drop Outs, per Year)	5%	5%	Cadmus (2011) Kootenai DR pilot.

*Data from DSM Insights, used with permission from E Source.

Results

Table 14 presents assessment results for Residential DLC—Water Heating, which, at a levelized cost of $123/kW-year, could provide 389 MW of winter load reduction by 2036. In the summer, Residential DLC—Water Heating could provide 285 MW of load reduction at $167/kW-year, levelized. Compared to other products, Residential DLC—Water Heating provides the highest MW potential in winter and the second-highest potential in summer (after Agricultural Irrigation DLC).

Table 14. Residential DLC—Water Heating: Assessment Results

Area	Technical Potential—Winter (MW)	Base Achievable Potential—Winter (MW)	High Achievable Potential—Winter (MW)	Base Achievable Levelized Cost—Winter ($/kW-yr)	Technical Potential—Summer (MW)	Base Achievable Potential—Summer (MW)	High Achievable Potential—Summer (MW)	Base Achievable Levelized Cost—Summer ($/kW-yr)
East	455	114	250	$122.35	334	83	184	$166.85
West	1,099	275	605	$122.36	806	202	443	$166.86
Total	**1,554**	**389**	**855**	**$122.36**	**1140**	**285**	**627**	**$166.86**

It should be noted that Table 14 and the remaining product-specific results tables in section 4.3.8 of this report present only the base-case levelized cost results; the high case achievable potential scenarios' levelized costs do not materially differ from the low case scenarios. The reason is that, while achieving the higher participation rates in the high case scenarios requires additional technology, incentives, and marketing expenditures, these costs are offset by the additional MWs from the higher penetration rates, hence the effect on average costs will be small. It is important to note that for certain DR products, larger incentives may be required to achieve higher penetration rates.[15]

Space Heating

Product Description

Residential space-heating DLC programs operate similarly to most DLC product types—the load directly shifts during event hours from space heating end uses via load control switches. Space-heating DLC programs shift loads only during winter peak seasons. The assessment assumes the Residential Space Heating DLC product will be available for four-hour duration events with up to 10 events per winter heating season.

Numerous cycling strategies currently exist for space-heating DLC programs, from conservative 25% cycling to aggressive 100% cycling. This study sets the cycling strategy at 50%, meaning space heating equipment cycles off for 50% of an event's duration.

[15] See the *Demand Response Elasticities Analysis*, which investigated the elasticity of achievable potential with respect to incentives.

Eligibility. All residential customers with centralized electric heating are eligible for the space-heating DLC program, including customers with heat pumps and electric forced-air furnaces. Baseboard heaters remain ineligible as they are not centrally controlled and would require numerous control switches per customer. Ductless heat pumps are excluded for a similar reason, although they are sometimes successfully controlled by utilities in their DR programs.

Incentives. Cadmus assumed, for study purposes, that participants in space-heating DLC programs are paid incentives at a fixed, monthly rate, independent of the number and duration of events called. Cadmus chose this incentive structure due to its simplicity. Furthermore, the incentive structure provides customers with a higher certainty level regarding their bill credit amounts than would happen if the incentive was paid per event or per kW, and no events were called—as could happen in a year with particularly mild winter temperatures. These incentives can be delivered through several applicable channels (e.g., bill credits, check incentives) and can include a one-time sign-up bonus to boost enrollment.

Note that in this analysis, Cadmus assumed that space heating DLC is deployed as a standalone product. If space heating DLC is deployed in conjunction with other DLC products such as water heating DLC, there will be costs efficiencies in labor and material, and (possibly) incentive amount.

Assessment Assumptions

Table 15 lists cost and impact assumptions that Cadmus used to estimate potential and levelized cost for Residential DLC—Space Heating.

Table 15. Residential DLC—Space Heating: Assessment Assumptions

Residential DLC—Space Heating Assumptions	Base	High	Notes and Discussion
Cost Assumptions			
Upfront Setup Cost	$150,000	$150,000	Equal to 1 FTE at $150K/yr.
Program Admin Cost (Percent of Total Cost)	9.6%	9.6%	The annual program administrative cost assumes 1 FTE at $150,000 per year per 20,000 residential participants. This equates to 9.6% of total cost for Space Heating DLC, or $5 per/kW.
Equipment Cost (Labor, Material, Communication Costs)	$215	$215	Using Applied (2017) = $215 ($115 switch + $100 installation); other sources: (LBNL (2017) = $166, which includes the costs for the control technology, installation, and communication platform, Global (2011) = $170/participant; Applied (2017) = $215 Navigant (2015a) CAC DLC = $125 -$189 ($60 switch, rest is installation); Navigant (2012) SH DLC = $370; Xcel (2016) CAC DLC = $150 - $200 equipment cost.
Marketing Cost	$25	$25	DLC range: Navigant (2012) $25; Brattle (2014) $80; Applied (2017) $50. Using low end of range.
Incentive	$30	$30	Assume $10/mo. for Dec., Jan., Feb. Applied (2017) SH DLC = $20; Navigant (2012) SH DLC = $32; Global (2011) SH DLC = $50.
Signup Bonus	$0	$0	N/A

Residential DLC—Space Heating Assumptions	Base	High	Notes and Discussion
Participation Assumptions			
Per Participant Impacts—Winter (kW)—East	1.61	1.61	Using Applied (2017) OR for West, average of ID & WA for East. Research Range: 1.0 - 2.88. Brattle (2016) = 1; Global (2011) = 1; Applied (2017) = 1 - 1.78; Cadmus (2011) = 1.65 (SH and WH combined); Navigant (2012) = 1.21 - 2.88 (morning - afternoon, different values for furnace and heat pumps).
Per Participant Impacts—Winter (kW)—West	1.20	1.20	
Program Participation (of Eligible Participants)	25%	55%	Navigant (2012), Applied (2017), and Brattle (2016) use 20%. Global (2011) gives low- and high-range of 15% - 25%. Highest participation rate for residential DLC programs in EIA (2017) data = 55%.
Event Participation	95%	95%	SH and CAC DLC and PCT programs range from 0.64 - 0.96. Navigant (2012) had 0.94, matching participation for ConEd (2012) and NIPSCO (2012) CAC programs.
Attrition (Percent of Participant Program Drop Outs, per Year)	5%	5%	Assumed to be same as WH DLC.

Results

Table 16 shows that Residential DLC—Space Heating could, by 2036, provide 206 MW of achievable potential in winter. Although it cannot provide load reductions in summer, its levelized cost of $53/kW-year is much lower than that for Residential DLC—Water Heating, a dual-season product.

Table 16. Residential DLC—Space Heating: Assessment Results

Area	Technical Potential—Winter (MW)	Base Achievable Potential—Winter (MW)	High Achievable Potential—Winter (MW)	Base Achievable Levelized Cost—Winter ($/kW-yr)
East	320	80	176	$43.93
West	505	126	278	$58.83
Total	**825**	**206**	**454**	**$53.03**

Central Air Conditioning

Product Description

Residential CAC DLC programs operate similarly to most DLC product types. Load directly shifts during event hours from space cooling end uses via load-control switches. CAC DLC programs allow load shifting only during summer peak seasons. The assessment assumes the Residential CAC DLC product will be available for four-hour duration events with up to 10 events per summer cooling season.

Numerous cycling strategies currently exist for CAC DLC programs, ranging from conservative 25% cycling to aggressive 100% cycling. This study set the cycling strategy at 50%, meaning air conditioning equipment cycles off for 50% of the event's duration.

Eligibility. All residential customers with CAC are eligible for the CAC DLC program. This category includes customers with heat pumps and standard CACs. Packaged terminal air conditioners, ductless heat pumps, and window-mounted air conditioners remain ineligible as customers typically use them for zonal (rather than whole-home) applications, and they require numerous control switches per customer. In addition, portable air conditioning devices (e.g., fans, cooling towers, plug load air conditioner appliances) provide a significant portion (perhaps more than 50%) of the air-conditioning load in the Northwest's residential sector. This report excludes such air conditioning devices.

Incentives. CAC DLC program participants typically receive incentives at a yearly rate, independent of the number and duration of events called. These incentives can be delivered through multiple, applicable channels (e.g., bill credits, check incentives) and can include a one-time sign-up bonus to boost enrollment. Although this report identifies multiple approaches to customer compensation for DLC participation, Cadmus chose this incentive structure for its simplicity and ease of understanding.

Assessment Assumptions

Table 17 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for Residential DLC—CAC.

The Peak Project at Kootenai Electric Cooperative:

The Bonneville Power Administration (BPA) sponsored a residential direct load control (DLC) pilot program, the Peak Project, at Kootenai Electric Cooperative (KEC) in Hayden, Idaho. KEC installed DLC equipment at participants' homes, including programmable thermostats for their heating systems and controls on their water heaters.

Pilot installations began in February 2010, with DLC equipment installed in 92 homes by January 2011. Seventy-eight of these homes received a programmable thermostat to receive heating event signals. Twenty-four homes had heat pumps, which allowed KEC to call cooling events during the summer.

The program exceeded its expected demand savings during winter. The average demand per home was reduced by 1.65 kW over all event hours, exceeding the expected demand reduction of 1.3 kW.

There was significant rebound in demand after the events. Rebound increased with colder event hour temperatures.

Excerpt from Kootenai DR Pilot Evaluation (Cadmus 2011)

Table 17. Residential DLC—CAC: Assessment Assumptions

Residential DLC—CAC Assumptions	Base	High	Notes and Discussion
Cost Assumptions			
Upfront Setup Cost	$150,000	$150,000	Equal to 1 FTE at $150K/yr.
Program Admin Cost (Percent of Total Cost)	12.6%	12.6%	The annual program administrative cost assumes 1 FTE at $150,000 per year per 20,000 residential participants. This equates to 12.6% of total cost for Res CAC DLC, or $9/kW.
Equipment Cost (Labor, Material, Communication Costs, per New Participant)	$215	$215	Using Applied (2017) estimate = $215, which includes costs for the control technology, installation, and communication platform. Other sources: single-family cost value from Brattle (2015). Cost ranges from $125 (Navigant 2015a) - $166 LBNL (2017).
Marketing Cost (per New Participant)	$25	$25	DLC range: Navigant (2012) $25; Brattle (2015) $80, Applied (2017) $50. Using low end of range.
Incentive	$15	$15	Assuming $5/mo. for three months. Sources: Lower range of Brattle (2015) $30–$150. Range: Idaho (2017a) $15; Applied (2017) $20; Duke Energy (2016) $25; Rocky Mountain Power (2017) $25–$40; Xcel (2016) $40; NIPSCO (2016) $40; Global (2011) $50.
Signup Bonus	$0	$0	N/A
Participation Assumptions			
Per Participant Impacts—Summer (kW)—East	0.98	0.98	East (0.98) uses Idaho Power (2016) evaluation results. West uses average of Brattle 2016 (0.80), Applied 2017 Oregon (0.43), and Applied 2017 Washington (0.53).
Per Participant Impacts—Summer (kW)—West	0.59	0.59	
Program Participation (of Eligible Participants)	25%	55%	Low—using Global (2011) estimate. High—assuming higher participation rates. Range is higher than for any other product type: 10%–20% Navigant (2015a); 15%–23% Applied (2017); 15%–25% Global (2011); 50%–52% Brattle (2015). Highest participation rate for res DLC programs in EIA (2017) data = 55%.
Event Participation	95%	95%	Aligning with other DLC products.
Attrition (Percent of Participant Program Drop Outs, per Year)	5%	5%	Navigant (2012); Cadmus (2011) WH DLC. Applied (2017) CAC DLC = 5%; IPL (2014) CAC DLC = 3%; Navigant (2015a) = 1%

Results

As a summer DR product, Residential DLC—CAC can provide 113 MW of achievable potential to the entire BPA service area by 2036, as shown in Table 18. This potential level is significantly lower than for Residential DLC—Space Heating, even though that has a higher levelized cost. This comparison dovetails with BPA’s winter-peaking and having greater load reduction potential in winter than in summer.

Table 18. Residential DLC—CAC: Assessment Results

Area	Technical Potential—Summer (MW)	Base Achievable Potential—Summer (MW)	High Achievable Potential—Summer (MW)	Base Achievable Levelized Cost—Summer ($/kW-yr)
East	219	55	120	$54.98
West	232	58	127	$92.03
Total	**450**	**113**	**248**	**$74.10**

It should be noted that—despite the warmer summer temperatures of the eastern area of BPA's service area, greater per event kW impacts, and higher saturations of central air conditioning—this assessment determined a slightly higher amount of achievable potential for Residential DLC–CAC in the western area compared with the eastern. This difference is easily explained by the much higher number of residential housing units in the western area compared with the eastern. In the first year of the study, there were nearly three times the number of housing units in the western (over 1.7 million) than in the eastern (about 600,000). In addition, this assessment did not attempt to forecast increasing saturations of central air conditioning over time. Rather, it relied upon saturation estimates from the RBSA (2011) and held those values constant.

Smart Thermostats

Product Description

Thermostat technology offers an alternative communication pathway to other DLC product types. Smart Thermostats can be dispatched by the utility, by calling only specific customers for load reduction during an event. Smart thermostats also allow the utility to temporarily adjust internally programmed thermostat schedules around event times, without directly controlling space heating and cooling units themselves. Furthermore, participants in thermostat DLC programs can opt out of the event (by overriding the utility's signal to the thermostat), either entirely or by prematurely resuming typical loads before finishing an event. To account for thermostat DLC programs' voluntary nature, this study utilized an assumed customer opt-out rate.

Certain types of smart thermostats (e.g., those offered by Nest and a few Honeywell models) have been web-enabled through thermostat manufacturers. For these select thermostats, the thermostat manufacturer delivers the event signal at the utility's request via the thermostat web connection or through a thermostat aggregator. Note that some smart thermostats have communication links to water heaters, clothes dryers, and sometimes other appliances and residential loads, allowing the thermostat to be a DR gateway for utilities to several loads in the home. These communications links and controls often have sophisticated cycling or other capabilities.

It is likely that, in the future, these thermostat features will provide several types of DR opportunities to utilities and consumers. At this time, these applications are uncommon, and the load impacts are somewhat speculative. Therefore, Cadmus considered only the space heating impacts of controllable smart thermostats.

Numerous, viable smart thermostat program design options include the following:

- Utility-initiated and managed programs
- Aggregator-contracted programs
- Bring-your-own thermostat (BYOT) programs

Each program option presents varying cost implications for the acquisition of eligible participants and, to a greater degree, smart thermostat purchases and installations. For this study, Cadmus assumed an aggregator-contracted program via one of several vendors that operate and manage smart thermostat DR programs. The immediate implications for this approach are that the study assumes a higher installed cost for smart thermostats, particularly compared with BYOT program designs, which would not experience incremental equipment costs because the study assumes that participating homeowners would have a smart thermostat already installed.

As thermostats can control heating and cooling equipment, thermostat DLC programs can shift loads during summer and winter. As with space heating and CAC DLC programs, it was assumed that thermostats for this study utilized a 50% cycling strategy. The assessment assumes the Residential Smart Thermostat DLC product will be available for four-hour duration events with up to 10 events per year.

Eligibility. All customers with central electric heating, central cooling, or air-source heat pumps become eligible for the thermostat DLC program. Eligibility guidelines for specific equipment in thermostat DLC programs are the same as those for space heating and CAC DLC programs. Customers with central cooling and central heating can shift loads during summer and winter events. This study considered DLC thermostats independently of the summer and winter scenarios; in other words, the study allowed for participants to be included for only a single season if, for example, the participant's home heating fuel source is natural gas but a central air conditioner is used to cool the home.

Incentives. The study assumed participants in thermostat DLC programs receive incentives at a monthly rate of $2 or $24 over an entire year, independent of the number and duration of events called. These incentives can be delivered through multiple, applicable channels (e.g., bill credits, check incentives), and can include a one-time sign-up bonus to boost enrollment. Smart Thermostats offer utilities several unique options for providing incentives; these include per event, per kW reduction, and flat monthly or annual incentives.

Assessment Assumptions

Table 19 provides Cadmus' cost and impact assumptions used to estimate potential and levelized costs for Residential DLC Smart Thermostats.

Table 19. Residential DLC—Smart Thermostats: Assessment Assumptions

Residential Smart Thermostat Assumptions	Base	High	Notes and Discussion
Cost Assumptions			
Upfront Setup Cost	$150,000	$150,000	Equal to 1 FTE at $150K/yr.
Program Admin Cost (Percent of Total Cost)	16.9%	16.9%	The annual program administrative cost assumes 1 FTE at $150,000 per year per 20,000 residential participants. This equates to 16.9% of total cost for Smart T-stats, or $15/kW and $8/kW in the summer and winter, respectively.
Equipment Cost (Labor, Material, Communication Costs)	$279	$279	Using LBNL (2017) estimate = $279, which includes the costs for the control technology, installation, and communication platform.
Marketing Cost	$25	$25	DLC range: Navigant (2012) $25; Brattle (2015) $80; Applied (2017) $50. Using low end of range.
Incentive	$24	$24	Assuming $2/mo. for 12 months. Range: Applied (2017) = $20; ConEd (2016) = $25; Frontier (2016) = $30; Duke Energy (2016) = $50.
Signup Bonus	$0	$0	N/A
Participation Assumptions			
Per Participant Impacts—Winter (kW)—East	1.61	1.61	Aligning with space heating DLC.
Per Participant Impacts—Summer (kW)— East	0.98	0.98	Setting equal to AC DLC. East based on Idaho Power (2016); west average of Applied's (2017) OR/WA impacts.
Per Participant Impacts—Winter (kW)—West	1.20	1.20	Aligning with space heating DLC.
Per Participant Impacts—Summer (kW)—West	0.59	0.59	Setting equal to AC DLC. East based on IPC 2016 Evaluation; west average of Applied's (2017) OR/WA impacts.
Program Participation (of Eligible Participants)	25%	55%	Aligning with space heating DLC.
Event Participation	80%	80%	Rounding IPL's (2014) 21% opt out rate to 20%.
Attrition (Percent of Participant Program Drop Outs, per Year)	5%	5%	Aligning with space heating DLC.

Results

Table 20 shows that Residential Smart Thermostats could provide 120 MW of achievable potential in summer and almost double that amount in winter. Due to the higher winter potential, the levelized cost of deploying Residential Smart Thermostats is lower in winter than in summer.

Table 20. Residential DLC—Smart Thermostats: Assessment Results

Area	Technical Potential—Winter (MW)	Base Achievable Potential—Winter (MW)	High Achievable Potential—Winter (MW)	Base Achievable Levelized Cost—Winter ($/kW-yr)	Technical Potential—Summer (MW)	Base Achievable Potential—Summer (MW)	High Achievable Potential—Summer (MW)	Base Achievable Levelized Cost—Summer ($/kW-yr)
East	460	92	202	$40.04	281	56	124	$65.56
West	648	130	285	$52.68	317	63	139	$107.76
Total	**1,108**	**222**	**488**	**$47.46**	**598**	**120**	**263**	**$88.02**

Residential Non-DLC Programs

Residential Critical Peak Pricing

Product Description

Residential CPP is a time-of-day pricing program that expands on an existing TOU rate program by increasing the price ratio of on-peak to off-peak hours. For example, a TOU program may have a 2:1 (on-peak: off-peak) price ratio, while the CPP program may have a 6:1 ratio. Additionally, CPP pricing typically affects significantly fewer hours during the year (i.e., the critical peak periods) than TOU rates and comes with a higher incentive.

A residential CPP program has never been implemented in the Northwest due to several factors, including an abundance of capacity, lack of an organized commercial DR market, and a weak differential between production costs of capacity in peak and off-peak hours. PGE currently conducts a residential DR pricing pilot (from 2016 through 2018).[16] Even though residential CPP and TOU programs remain uncommon in the Northwest, Cadmus included residential CPP in this study as the programs are common in other parts of the U.S. and could be considered in the Northwest if the current conditions change. For this study, Cadmus assumed the program is voluntary. If a mandatory program can be instituted, program participation may be significantly higher.

From a policy standpoint, this assessment assumes that CPP would be deployed as a rider to an existing TOU tariff available from the utility, as commonly observed in other utilities. From an implementation standpoint, this assessment assumes that during system peak periods (for which potential estimates are calculated), CPP events are called and CPP prices are in effect (as opposed to TOU prices), so potential estimates represent the load impacts of CPP, not of TOU. CPP prices and TOU prices cannot both exist at a given time.

Load Reduction Strategy. Participants are induced to reduce or shift their demand from critical peak periods to low-demand time periods through the CPP price signal. For example, customers may turn off lights more diligently or wait to do laundry until after peak period pricing ends. Utilities will notify

[16] For more information, see http://edocs.puc.state.or.us/efdocs/HAQ/um1708haq163627.pdf.

participants via email or text a day prior to the CPP event and the day of the event. Events may occur on any day of the season for up to six hours; up to 10 events per season (Christensen 2017).

Eligibility: This program uses AMI to monitor and calculate customers' consumption during critical peak periods. In the PGE pilot, depending on the consumption level, PGE will charge customers the appropriate pricing rates. Because AMI is necessary for billing purposes, all residential customers with AMI and already participating in an existing TOU program are eligible. Cadmus assumes that all residential customers will have AMI by 2036.

Incentives: The program does not offer direct incentives, though customers can shift their demand from more expensive critical peak periods to less expensive ones, which cost less than standard residential rates.

Assessment Assumptions

Table 21 provides the cost and impact assumptions that Cadmus used in estimating potential and levelized costs for Residential CPP.

Table 21. Residential Critical Peak Pricing: Assessment Assumptions

Residential Critical Peak Pricing	Base	High	Notes and Discussion
Cost Assumptions			
Upfront Setup Cost	$150,000	$150,000	Cadmus assumes 1 FTE shared between BPA and participating Power customers. This cost is for setting up a program for the entire BPA service area (east and west combined).
Program O&M Cost ($/year)	$75,000	$75,000	Applied (2017): $75,000. Cadmus is assuming 0.5 FTE, which is the O&M cost for all participating utilities combined, for a single program in the BPA service area. The majority of this cost is for event notification and EM&V purposes to verify savings and evaluate program performance.
Equipment Cost (Labor, Material, Communication Costs)	$0	$0	Assumes that AMI is fully deployed for pricing programs.
Marketing Cost ($/New kW)	$93	$93	Cadmus (2013b): $25/new participant; Cadmus (2017): $25/new participant; PacifiCorp (2017) = $50/new participant. Cadmus assumes $25/new participant, converting to $/kW using estimated per participant savings.
Incentive	$0	$0	N/A per program definition.
Signup Bonus	$0	$0	N/A per program definition.

Residential Critical Peak Pricing	Base	High	Notes and Discussion
Participation Assumptions			
Technical Potential (of Applicable Load)	12%	12%	The following sources reported the average event-hour load impact during a CPP event: Cadmus (2013b) for Washington: 15%; Cadmus (2017): 12%; Applied (2017): 12.5%; Christensen (2017): 13%; Brattle (2014): 14.8%. This assessment assumes technical potential is 12% of applicable load.
Eligible Sectors	Residential		
Eligible Segments	All residential segments		
Eligible End Uses	All residential end uses		
Load Class Eligibility	100%	100%	See Eligibility in Product Description.
Program Participation (of Eligible Load)	15%	25%	Cadmus (2013b) for Washington: 5%; Cadmus (2017): 10%; Applied (2017): 17%; Brattle (2015): 29% (opt-in) or 90% (opt-out).
Event Participation	100%	100%	The technical potential percentage accounts for event participation.

Results

Residential CPP is the least expensive DR product in winter and summer; as a tariff-based product, it does not offer incentives for load reductions. As a result, Residential CPP could provide 168 MW of winter achievable potential by 2036 at only $10/kW-year. In summer, smaller available residential loads produce 57 MW of achievable potential at $12/kW-year, as shown in Table 22. Note that the potential results represent the load impact of a CPP event, during which only CPP prices are in effect (CPP prices and TOU prices cannot both exist at a given time).

Table 22. Residential Critical Peak Pricing: Assessment Results

Area	Technical Potential—Winter (MW)	Base Achievable Potential—Winter (MW)	High Achievable Potential—Winter (MW)	Base Achievable Levelized Cost—Winter ($/kW-yr)	Technical Potential—Summer (MW)	Base Achievable Potential—Summer (MW)	High Achievable Potential—Summer (MW)	Levelized Cost—Summer ($/kW-yr)
East	383	57	96	$9.94	129	19	32	$11.70
West	738	111	184	$9.72	249	37	62	$11.43
Total	**1,121**	**168**	**280**	**$9.80**	**378**	**57**	**95**	**$11.52**

Residential Behavioral DR

Product Description

Behavioral DR encourages customers to save energy during peak day events through behavioral changes. As an opt-out program, participants receive notice before the seasons start (via an email or automated phone message). Participants receive this message, which includes ways to save energy and reduce peak consumption, 24 hours before an event. A follow-up message may be sent during the day after an event to reinforce the behavior changes. These programs do not offer incentives. This assessment assumes that desired event duration—during which participants are asked to reduce consumption—is three hours. Events may be called for up to 10 times per season.

The Behavioral DR program is similar to other conventional energy efficiency behavioral programs in that the implementer gives participants information about saving energy or reducing consumption, hoping that participants will carry out the suggested actions without any monetary incentives. On the other hand, the Behavioral DR program differs from energy efficiency behavioral programs in several fundamental ways. Whereas an energy efficiency behavioral program typically sends about four to six home energy reports to participants per year, the Behavioral DR program allows more frequent, larger, and more variable events. This assessment, for example, assumes a maximum of 20 events per year could be called (i.e., 10 per season). In practice, the number of events called per season could vary widely up to the maximum limit.

Load Reduction Strategy. The messages customers receive typically explain how lowering peak demand can reduce overall utility costs, which lowers every customer's bill. Additionally, the demand-reduction tips reduce a customer's bill by lowering their overall energy consumption. These tips include turning off lights, shifting the time of day that a customer uses hot water, and other similar actions.

Eligibility. To conduct adequate evaluation, measurement, and verification of this program, AMI must measure and calculate customers' consumption during events. Therefore, all customers become eligible if they have AMI. Cadmus assumes that all residential customers will have AMI by 2036. In addition, Cadmus assumes that all residential customers have a valid phone and/or an email address.

There are also behavioral DR programs for commercial and industrial customers. Nevertheless, Cadmus targeted residential customers for this Behavioral DR program because, in general, residential behavioral programs are more common.

Incentives. Typically, Behavioral DR programs do not offer incentives (though some do). This assessment assumes the program does not include incentives.

Assessment Assumptions:

Table 23 lists cost and impact assumptions that Cadmus used to estimate potential and levelized costs for Residential Behavioral DR.

Table 23. Residential Behavioral DR: Assessment Assumptions

Residential Behavioral DR	Base	High	Notes and Discussion
Cost Assumptions			
Upfront Setup Cost	$150,000	$150,000	Cadmus assumes 1 FTE shared between BPA and participating Power customers.
Program O&M Cost ($/kW)	$89	$89	For PPL's traditional behavioral program, Opower (the vendor) spends about $4/participant per year (PPL 2011; PPL 2016). Cadmus believes traditional behavioral programs and behavioral DR programs incur similar vendor costs, and used the $4/participant per year for Program O&M Cost. Cadmus' potential results roughly corresponded with 0.05 kW of load impact per participant. Applying this to the $4/participant program O&M cost, Cadmus assumed about $89 per kW of load impact for the Program O&M Cost for this product.
Equipment Cost (Labor, Material, Communication Costs)	$0	$0	Participants must have a device to receive messages.
Marketing Cost ($/New kW)	$0	$0	Included in utility program O&M costs.
Incentive	$0	$0	N/A per program definition.
Signup Bonus	$0	$0	N/A per program definition.
Participation Assumptions			
Technical Potential (% of Peak Period Load)	2%	2%	This assumption is based on the benchmarked sources on the percentage of peak load reduction: Nexant (2016): 1.2%–2.2%; DTE Energy (2017): 2%–4%; Opower (2014): 1.3–3.6%; Thayer (2016): 2.4%
Eligible Sectors	Residential.		
Eligible Segments	All residential segments.		
Eligible End Uses	All residential end uses.		
Load Class Eligibility	100%	100%	See Eligibility in Product Description.
Program Participation (of Eligible Load)	20%	30%	Nexant (2016), DTE Energy (2017), and Opower (2014) reported the total number of participants and the total number of eligible residential end users. Cadmus calculated the program participation rates as participants divided by eligible customers, and found that participation rates varied widely, from 0.9% to 53.6%. Participation rates largely depend on how many residential end users BPA Power customers wish to contact. For this study, Cadmus assumes a participation rate of 20% to 30%.
Event Participation	100%	100%	Technical potential percentage accounts for event participation.

Results

Residential Behavioral DR's winter and summer achievable savings (37 MW and 13 MW, respectively) offer the lowest values among residential programs. Levelized costs in summer and winter equal the second-highest residential seasonal costs. Residential DLC—Water Heating is the only other residential program with a higher seasonal cost than Behavioral DR (shown in Table 24).

Table 24. Residential Behavioral DR: Assessment Results

Area	Technical Potential—Winter (MW)	Base Achievable Potential—Winter (MW)	High Achievable Potential—Winter (MW)	Base Achievable Levelized Cost—Winter ($/kW-yr)	Technical Potential—Summer (MW)	Base Achievable Potential—Summer (MW)	High Achievable Potential—Summer (MW)	Base Achievable Levelized Cost—Summer ($/kW-yr)
East	64	12.8	19.2	$110.19	21.5	4.3	6.4	$111.06
West	123	24.6	36.9	$109.85	41.6	8.3	12.5	$110.69
Total	**187**	**37.4**	**56.1**	**$109.96**	**63.1**	**12.6**	**18.9**	**$110.81**

4.3.2. Nonresidential

Nonresidential DR products included in this assessment spanned the commercial, industrial, and agricultural sectors. Cadmus categorized public buildings in the commercial sector and public industries (such as utility water treatment plants) in the industrial sector.

In the summer, the total nonresidential load that is coincident with BPA Power’s 18-hour system peak (i.e. the total nonresidential load basis) is approximately 10,190 MW (5,360 MW in the west and 4,830 in the east). In the winter, the total nonresidential load basis is approximately 6,420 MW (4,525 MW in the west and 1,895 MW in the east). For each nonresidential DR product, the achievable potential is a subset of the nonresidential load basis that meets the product’s participation and impact assumptions.

Programs offered to commercial end users include Commercial DLC—CAC, Commercial Lighting Controls, and Commercial Thermal Storage. Demand Curtailment and Interruptible Tariff, which are event-based products without specific end uses, are available to C&I end users. The remaining nonresidential products include Industrial RTP and Agricultural Irrigation DLC.

Commercial Small and Medium DLC—CAC

Product Description

CAC DLC programs for small and medium commercial customers operate similarly to most DLC products, directly shifting the load during event hours from space cooling end uses via load control switches. CAC DLC programs offer the ability to shift loads only during the summer peak season. The assessment assumes the Commercial Small and Medium CAC DLC product will be available for four-hour duration events with up to 10 events per summer cooling season.

Numerous cycling strategies exist for CAC DLC programs, ranging from a conservative 25% cycling to an aggressive 100% cycling. This study used a cycling strategy of 50%, meaning air conditioning equipment cycles off for 50% of an hour and remains on for 50% of an hour (i.e., 30 minutes off and 30 minutes on).

Eligibility: Small and medium commercial customers with electric CACs are eligible for the CAC DLC program. This analysis included commercial customers in the following building types:

- Assembly

- Lodging
- Other/miscellaneous
- Restaurants
- Small and medium offices
- Small and medium retail

Excluded building types included hospitals, large offices, large retail, residential care, schools, grocery stores, universities, prisons, and warehouses.

Incentives: CAC DLC program participants receive incentives at a yearly rate (though all payments may occur in the summer season), independent of the number and duration of events called. These incentives can be delivered through several applicable channels (e.g., bill credits, check incentives) and can include a one-time sign-up bonus to boost enrollment.

Assessment Assumptions

Table 25 lists the cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the Commercial Small and Medium DLC—CAC.

Table 25. Commercial Small and Medium DLC—CAC: Assessment Assumptions

Commercial Small and Medium DLC—CAC	Base	High	Notes and Discussion
Cost Assumptions			
Upfront Setup Cost	$150,000	$150,000	Cadmus assumes 1 FTE shared between BPA and participating Power customers.
Program Admin Cost (Percent of Total Cost)	6.6%	6.6%	The annual program administrative cost assumes 1 FTE at $150,000 per year per 10,000 small/medium commercial participants. This equates to 6.6% of total cost for small/medium com customers, or $2/kW.
Equipment Cost (Labor, Material, Communication Costs, per New Participant)	$754	$754	Using PacifiCorp average small ($387) & medium ($1128).
Marketing Cost ($ per new participant)	$75	$75	Range: TVA = $50, PacifiCorp = $63-75, Xcel = $80
Incentive (Annual $ per participant)	$83	$83	Using PacifiCorp average small ($38) & large ($128). Range: Duke = $85 (50% cycling); TVA = $62.
Participation Assumptions			
Per Participant Impacts (kW) – East	7.85	7.85	Using PacifiCorp ID & WA average of small (1.7 and 13.2) & medium (1.3 and 15.2), respectively.
Per Participant Impacts (kW) - West	6.70	6.70	Using PacifiCorp OR average of small (1.1 and 12.3) & medium
Eligible Sectors	Commercial		Product definition is for small and medium commercial
Eligible Segments	Assembly, Lodging, Other/Miscellaneous, Restaurants, Small and Medium Offices, and Small and Medium Retail		
Program Participation (of Eligible Participants)	10%	40%	PacifiCorp = 2.3% - 3.4%, TVA = 10%, PGE = 14%, Arkansas = 1-5%, and Xcel = 15-42%
Event Participation	95%	95%	
Attrition (Percent of Participant Program Drop Outs, per Year) Attrition (Participants, per year)	5%	5%	Consistent with Residential CAC DLC

Results

As a summer-only product, Commercial Small and Medium DLC—CAC could provide 110 MW of achievable potential in 2036 at $29/kW-year, as shown in Table 26.

Table 26. Commercial Small and Medium DLC—CAC: Assessment Results

Area	Technical Potential—Summer (MW)	Base Achievable Potential—Summer (MW)	High Achievable Potential—Summer (MW)	Base Achievable Levelized Cost—Summer ($/kW-yr)
East	743	36	143	$26.39
West	132	74	296	$30.91
Total	**265**	**110**	**439**	**$29.44**

Commercial and Industrial Demand Curtailment

Product Description

In C&I Demand Curtailment, C&I customers agree, when requested by the utility, to curtail their loads at a predetermined level for a predetermined period (i.e., event duration). Event durations observed in similar programs across the country range from one hour to five hours. For this program, Cadmus assumes the event duration is four hours, and up to ten events (for a total of 40 hours) per season may be called. This product represents a firm resource because it assumes that customers would be penalized for noncompliance. Cadmus assumes that a third-party aggregator will implement the program, receiving a fixed $/kW-year payment from the utility. Unlike a C&I DLC program (which is not in the scope of this assessment), where DR events are called and executed by the utility, the C&I Demand Curtailment has the participating customer execute the curtailment after the utility calls the event. Historically, entities in the Northwest have conducted pilots that tested both C&I DLC and C&I demand curtailment products.

As the BPA Demand Exchange program and other recent BPA DR demonstration projects tested C&I demand curtailment more so than C&I DLC, this assessment estimated potential for a C&I demand curtailment program. In addition to C&I Demand Curtailment, this assessment included another program for large C&I customers—C&I Interruptible Tariff—which is explored in the subsequent section.

Load Reduction Strategy. Customers may curtail any of their end-use loads to meet the curtailment agreement, including switching to backup generators. Customers receive payments to remain ready for curtailment, even though actual curtailment requests may not occur. As penalties exist, Cadmus assumes that customers will curtail their loads when requested (i.e., event participation would be close to 100%).

Eligibility. Cadmus assumes eligible participants include large customers (with at least 150 kW of monthly average demand) in all C&I segments. These may include hospitals, large offices, large retail, residential care, schools, supermarkets, universities and colleges, warehouses, government buildings, and similar large industrial and commercial loads.

Incentive. In some cases, customers do not receive payments for individual events, but they do receive compensation through a fixed, monthly amount, per kW of pledged curtailable load (a set percentage drawn from the set of a customer's monthly average load). Though a commonly adopted incentive structure, other demand curtailment programs use different incentive

Balancing Demonstration with Energy Northwest

BPA began this project in 2013 with Energy Northwest, which is serving as an aggregator for public power loads. Through this demonstration project, up to 35 megawatts of reliable demand response capacity from industrial loads can be fully deployed in just 10 minutes, with the objective of testing an additional tool to support the federal hydro system's energy balancing needs.

Excerpt from Fact Sheet: Demand response offers benefits to utilities and consumers (BPA 2015) structures (e.g., pay-for-performance incentives). Cadmus did not include incentive payments for energy reduction during events.

Assessment Assumptions

Table 27 provides the cost and impact assumptions that Cadmus used in estimating potential and levelized costs for C&I Demand Curtailment.

Table 27. C&I Demand Curtailment: Assessment Assumptions

C&I Demand Curtailment	Base	High	Notes and Discussion
Cost Assumptions			
Upfront Setup Cost	$150,000	$150,000	Cadmus assumes 1 FTE shared between BPA and participating Power customers.
Program O&M Cost ($/kW)	$60	$60	Cadmus' current study for Snohomish County PUD No. 1 estimated $20/kW (utility) and $40/kW (vendor); Applied (2017) estimated $71/kW (utility + vendor); and Cadmus (2013) estimated $80/kW (utility + vendor + incentive). Other benchmarked values included $27/kW (Frontier's 2016 emergency option) and $3/kW (Idaho Power 2015), which Cadmus assumes only included utility administrative costs. For this study, the Program O&M Cost includes the utility O&M cost and the vendor O&M cost.
Equipment Cost (Labor, Material, Communication Costs)	$0	$0	Participants must have a device to receive messages.
Marketing Cost ($/New kW)	$0	$0	Included in vendor management costs.
Incentive ($/kW)	$10	$10	California utilities complying state-required programs offer incentives that range from $4 (SMUD) to $12 (SDG&E). For this product, the assumed $10/kW is also consistent with BPA's experience with similar curtailment contracts with large customers. Incentives from non-California utilities ranged from $20/kW (e.g. Idaho Power 2015) to $35/kW (e.g. Cadmus' current study for Snohomish County PUD No. 1). Incentives may be higher for customers who can commit for a longer contract, larger reduction, or guaranteed reductions during peak seasons.
Signup Bonus	$0	$0	N/A per program definition.

C&I Demand Curtailment	Base	High	Notes and Discussion
Participation Assumptions			
Technical Potential (of Applicable Load)	25%	25%	In the Northwest, load reduction estimates range from 20% (Idaho Power 2015) to 30% (Cadmus 2013). The BPA C&I Pilot (2012) demonstrated average reduction of 23%. In the 2015 statewide evaluation (Christensen 2016), California utilities reported higher load reduction: PG&E = 84%; SCE = 80%; SDG&E = 54%.
Eligible Sectors	C&I		
Eligible Segments	All C&I market segments, including municipal water and wastewater treatment facilities		
Eligible End Uses	All C&I end uses.		
Customer Size Requirements	150 kW or greater		The eligible customer size ranges from 100 kW (SDG&E 2017, PG&E 2017) to 200 kW (Cadmus' current study for Snohomish County PUD No. 1, Freeman 2013). Cadmus used the average—150 MW—as the eligible customer size, in line with PacifiCorp's potential study (Cadmus 2013).
Load Class Eligibility	Differs by segment and Area		See Customer Size Requirements.
Program Participation (of Eligible Load)	25%	30%	PG&E's (2016) annual report showed 2.1% of program participation. However, Northwest potential assessments results generally average 20% (county p 2017; Applied 2017).
Event Participation	95%	95%	Benchmarked event participation rates range from 52% (average rate from the BPA 2012) to 95% (BPA and Energy Northwest 2016Cadmus' current study for Snohomish County PUD No. 1).

Results

As shown in Table 28, C&I Demand Curtailment can provide around 184 MW and 205 MW of winter and summer achievable potential at $85/kW-year, providing the most winter achievable potential in the nonresidential sector. In the summer, its achievable potential is topped only by Agricultural Irrigation DLC, a summer-only product. Of the 184 MW of winter, base achievable potential, the industrial sector accounts for approximately 137 MW, the commercial sector 47 MW. In the summer, the industrial sector accounts for 138 MW, compared with 67 MW for the commercial sector.

Table 28. C&I Demand Curtailment: Assessment Results

Area	Technical Potential—Winter (MW)	Base Achievable Potential—Winter (MW)	High Achievable Potential—Winter (MW)	Base Achievable Levelized Cost—Winter ($/kW-yr)	Technical Potential—Summer (MW)	Base Achievable Potential—Summer (MW)	High Achievable Potential—Summer (MW)	Levelized Cost—Summer ($/kW-yr)
East	144	34	41	$84.89	181	43	52	$84.88
West	629	149	179	$84.60	683	162	195	$84.59
Total	**774**	**184**	**220**	**$84.65**	**864**	**205**	**246**	**$84.65**

Commercial and Industrial Interruptible Tariff

Product Description

C&I Interruptible Tariff is nearly identical as the C&I Demand Curtailment, whereby large C&I customers agree to curtail their loads when the utility dispatches load reduction events during a predetermined season. Identical to C&I Demand Curtailment's event parameters, C&I Interruptible Tariff's event duration is three hours, with up to seven events per season. The two programs largely differ through their incentive structures. While C&I Demand Curtailment pays a fixed incentive per kW of contracted curtailment, C&I Interruptible Tariff incentivizes customers by providing them with a reduced demand charge. For the C&I Interruptible Tariff, incentives are typically paid in two parts:

- Discounts on monthly demand charges during the summer and winter seasons
- Event-based performance rewards

In some cases, utilities also offer one-time sign-up rewards, based on reduction nominations. Cadmus assesses the C&I Interruptible Tariff program based on Xcel Energy MN (2016) Electric Rate Savings program, which only offers discounts on monthly demand charges. No penalty occurs for noncompliance during events for the Interruptible Tariff. As a result, Cadmus assumed *event* participation would be much less than for C&I Demand Curtailment.

Assessment Assumptions

Table 29 presents cost and impact assumptions that Cadmus used to estimate potential and levelized costs for the C&I Interruptible Tariff.

Table 29. C&I Interruptible Tariff: Assessment Assumptions

C&I Interruptible Tariff	Base	High	Notes and Discussion
Cost Assumptions			
Upfront Setup Cost	$150,000	$150,000	Cadmus assumes 1F TE shared between BPA and participating Power customers.
Program O&M Cost ($/kW)	$50	$50	The Xcel (2017) potential study estimated $51/kW, accounting for all costs (including marketing) other than incentives.
Equipment Cost (Labor, Material, Communication Costs)	$0	$0	Cadmus assumes that end-use customers have the necessary equipment to participate.
Marketing Cost ($/New kW)	$0	$0	Included in the utility program O&M costs.
Incentive ($/kW)	$10	$10	Xcel (2017). For this product, the assumed $10/kW is consistent with BPA's experience with DR programs targeting large customers.
Signup Bonus	$0	$0	N/A per program definition.

C&I Interruptible Tariff	Base	High	Notes and Discussion
Participation Assumptions			
Technical Potential (of Applicable Load)	20%	20%	Drawing from various Northwest DR studies, Brattle (2016) assumed a peak load impact of 20%.
Eligible Sectors	C&I		
Eligible Segments	All C&I market segments, including municipal water and wastewater treatment facilities.		
Eligible End Uses	All C&I end uses.		
Customer Size Requirements	150 kW or greater		See Customer Size Requirements for Demand Curtailment in Table 27.
Load Class Eligibility	Differs by segment and area		See Customer Size Requirements.
Program Participation (of Eligible Load)	20%	25%	Brattle (2016): Medium = 20%; Average = 30%; Large = 40%. Brattle (2015): Medium = 27%; Large = 54%.
Event Participation	50%	50%	Cadmus assumed, as the Interruptible Tariff is voluntary, that it will experience lower event participation than Curtailment.

Results

Table 30 shows that, by 2036, C&I Interruptible Tariff could provide 62 MW and 69 MW of achievable potential in winter and summer, respectively. It is assumed this product does not involve a penalty if participants fail to reduce loads during events. Consequently, Cadmus assumed it would attain lower event participation, leading to lower levels of achievable potential compared to C&I Demand Curtailment. Nevertheless, it offers a less-expensive program than C&I Demand Curtailment ($73/kW-year versus $85/kW-year).

Table 30. C&I Interruptible Tariff: Assessment Results

Area	Technical Potential—Winter (MW)	Base Achievable Potential—Winter (MW)	High Achievable Potential—Winter (MW)	Base Achievable Levelized Cost—Winter ($/kW-yr)	Technical Potential—Summer (MW)	Base Achievable Potential—Summer (MW)	High Achievable Potential—Summer (MW)	Base Achievable Levelized Cost—Summer ($/kW-yr)
East	115	12	14	$73.31	145	14	18	$73.28
West	503	50	63	$73.08	547	55	68	$73.05
Total	**619**	**62**	**77**	**$73.12**	**692**	**69**	**86**	**$73.10**

Commercial Lighting Controls

Product Description

Cadmus assessed a Commercial lighting controls DR program (referred to in this assessment as "Commercial Lighting Controls"), basing it on the lighting option included in the Automated DR program offered by Pacific Gas and Electric (2015; 2017a). In that program, a participating commercial customer installs an automated lighting controls system to manage a facility's lighting loads, allowing the utility to utilize the controls system's automated DR capability. Some modern lighting systems, especially LED lighting systems, may have factory-installed DR functionality. This assessment assumes that installation of lighting controls systems takes place after customers sign up to participate in this program, which allows program implementers "the opportunity to inspect and approve the project" (PG&E 2015).

Load reduction strategy. With the automated lighting controls system in place, the utility sends automated event signals to the system during peak periods, requesting that the facility reduce its lighting loads. Upon receiving an event signal, the controls system automatically determines whether to reduce loads based on pre-programmed strategies and how to do so with greatest efficiency and least impact on occupants. This assessment assumes that events last four hours, for up to seven events per season.[17]

Eligibility. All commercial customers with lighting loads are eligible for this program.

Incentive. As the program relies on the installation of a sophisticated controls system, the utility offers a large upfront incentive to help pay for the installation costs. During the first year of participation, the local utility customers receive the upfront incentive as dollars per kW of DR load reduction. After the first year, Cadmus assumes customers will continue to allow utilities to dispatch automated DR without additional incentives over the program's entire 20-year lifetime.

Note that these controls systems may be installed for energy efficiency purposes, in which case much of the installation cost may be paid for by utility energy efficiency incentives. In Pacific Gas and Electric's program, if a customer installs a lighting control system to generate energy efficiency savings as well as DR load shed, then Pacific Gas and Electric (2015) would apply the energy efficiency rebate first and then apply the DR incentive to cover the rest of the installation cost. To maintain a consistent methodology in estimating potential and levelized cost, this assessment assumes that there are no energy efficiency incentives to cover the cost of installing the controls system for the Commercial Lighting Controls DR program.

Assessment Assumptions

Table 31 displays cost and impact assumptions that Cadmus used to estimate potential and levelized costs for Commercial Lighting Controls.

[17] In the PG&E (2015) program, participants under the Peak Day Pricing option reduce or shift load for six hours in the afternoon, during nine to fifteen events per year.

Table 31. Commercial Lighting Controls: Assessment Assumptions

Commercial Lighting Controls	Base	High	Notes and Discussion
Cost Assumptions			
Upfront Setup Cost	$150,000	$150,000	Cadmus assumes 1 FTE shared between BPA and participating Power customers.
Program O&M Cost ($/kW)	$10	$10	Navigant (2015a). Cadmus assumes that this program O&M cost would account for program team's verification of load reduction, troubleshooting DRAS connectivity, technical and programmatic facilitation and monitoring, ongoing participant support to ensure DR performance, etc.
Equipment Cost (Labor, Material, Communication Costs) ($/New kW)	$200	$200	PG&E (2016): $400/kW; LBNL (2017) estimated $381–$787/kW, depending on the segment; Navigant (2015a): $235/kW. In 2017 program year, PG&E (2017d) revised the automated DR program incentive for all end uses to $200/kW, which Cadmus used for the equipment cost assumption.
Marketing Cost ($/New kW)	$2	$2	In line with assumptions for Thermal Storage, Cadmus assumes a marketing cost per participant of $80, and translates this to $/kW based on estimated savings per participant.
Incentive	$0	$0	The program incentivizes customers by paying high $/kW during the first year of enrollment. Included in Equipment Costs, this incentive helps pay for installing the auto DR equipment.
Signup Bonus	$0	$0	N/A per program definition.
Participation Assumptions			
Technical Potential (of Applicable Load)	20%	20%	CA (2016) code change for buildings larger than 10,000 square feet. Alternatively, for lighting load > 15 kW, code required 30% reduction.
Eligible Sectors	Commercial		
Eligible Segments	All commercial market segments.		
Eligible End Uses	Interior and exterior lighting (CA 2011).		
Customer Size Requirements	None		
Load Class Eligibility	100%	100%	See Customer Size Requirements.
Program Participation (of Eligible Load)	25%	30%	CA (2011): 70%; Arkansas (2015): 10%. This range of program participation rates corresponds with the assumption that participants are installing automated lighting controls systems *specifically* to participate in the program. There may be other commercial customers installing automated lighting controls systems for energy efficiency purposes who may also be able to offer demand response; however, the demand response potential that these customers may provide is *not* included in the scope of this assessment.
Event Participation	90%	90%	CA (2011).

Results

At about $32/kW-year, Commercial Lighting Controls offer 44 MW and 55 MW of achievable potential in winter and summer, respectively, as shown in Table 32. The Commercial Lighting Controls program costs less than Commercial Thermal Storage, another end-use-specific product that only offers incentives during the first year that participants join the program.

Table 32. Commercial Lighting Controls: Assessment Results

Area	Technical Potential—Winter (MW)	Base Achievable Potential—Winter (MW)	High Achievable Potential—Winter (MW)	Base Achievable Levelized Cost—Winter ($/kW-yr)	Technical Potential—Summer (MW)	Base Achievable Potential—Summer (MW)	High Achievable Potential—Summer (MW)	Levelized Cost—Summer ($/kW-yr)
East	55	12	15	$32.48	67	15	18	$32.40
West	139	31	31	$31.98	178	40	40	$31.90
Total	**193**	**44**	**46**	**$32.12**	**246**	**55**	**58**	**$32.04**

Commercial Thermal Storage

Product Description

The Commercial Thermal Storage program provides incentives to commercial customers that install ice thermal storage technology to shift cooling loads to off-peak hours. Such technology shifts part or all a commercial building's cooling load to off-peak hours (i.e., at night), and stores energy in a cold water or ice tank for usage during peak hours (i.e., by day).

While this Commercial Thermal Storage considers only one type of thermal storage, there are other types of thermal storage including thermal heat storage using electrical thermal storage (ETS) furnaces. Between 2010 and 2013, BPA sponsored a pilot project that involved using ETS furnaces to help reduce Lower Valley Energy's peak demand, which included two commercial participants (Ecofys 2013).

Load reduction strategy. Not an event-based program, demand savings occur during peak hours due to energy stored by installed technology during peak hours, naturally reducing demand during peak hours. Given that most commercial buildings operate

BPA TI 220: Smart End-Use Energy Storage and Integration of Renewable Energy

The Project operated a 1.2 MW portfolio of assets composed of a combination of refrigerated storage warehouses, Steffes electric furnaces with thermal storage, Cypress wireless pneumatic thermostats, Steffes electric water heater controls and Carina electric water heater [controls].

These are small-scale pilots, with total number of residential and C&I sites at around 130, spread across six utilities. These loads responded to the real-time needs of the BPA transmission system.

The Project demonstrated that smart DR represents a nimble, cost-effective resource for renewable integration with a host of other benefits to the users of the Northwest electric system. Another important product of the work was a tool for retail utilities to perform an economic analysis of potential DR opportunities to establish a business case for their management.

Excerpt from TI 220 Project Evaluation Report: Smart End-Use Energy Storage and Integration of Renewable Energy (Ecofys 2013) during weekdays, this load shifting would occur during the modeled BPA system peak period,[18] if not during every weekday in summer and winter.

Eligibility. All commercial customers with cooling loads are eligible to participate in the program.

Incentive. Like the Commercial Lighting Controls program, the Commercial Thermal Storage program offers a high upfront incentive for installing thermal storage equipment and assumes customers will operate the equipment during its entire lifetime. Cadmus assumes the equipment's lifetime will last 20 years (typically, between 10 to 30 years),[19] meaning that peak demand savings will recur annually over the entire program's lifetime. During the first participation year, the upfront incentive provides is a high dollar-per-kW of verified cooling load shift. If implemented as part of a multi-year aggregator DR program, the costs might be more evenly distributed across each year of the aggregator's contract.

Assessment Assumptions

Table 33 presents cost and impact assumptions that Cadmus used to estimate potential and levelized costs for Commercial Thermal Storage.

Table 33. Commercial Thermal Storage: Assessment Assumptions

Commercial Thermal Storage	Base	High	Notes and Discussion
Cost Assumptions			
Upfront Setup Cost	$150,000	$150,000	Cadmus assumes 1 FTE shared between BPA and participating Power customers.
Program O&M Cost ($/year)	$75,000	$75,000	Applied (2017). This program O&M cost would account for program team's verification of load reduction, troubleshooting issues, technical and programmatic facilitation and monitoring, ongoing participant support to ensure DR performance, etc.
Equipment Cost (Labor, Material, Communication Costs) ($/New kW)	$350	$350	California programs (SCE, SDG&E, PG&E): $875/kW; Austin Energy: $350/kW; Duke Energy Progress: $300/kW. PacifiCorp pays one-time equipment and installation costs at $10,000.
Marketing Cost ($/New kW)	$1	$1	Applied (2017): $80/new participant; SDG&E (2017): $25,000 total. Cadmus assumes marketing costs per new participant of $80, and translates this to $/kW based on estimated savings per participant.
Incentive	$0	$0	The program incentivizes customers by paying a high $/kW during the first enrollment year, including this incentive in the Equipment Cost as it helps pay for installing auto DR equipment.
Signup Bonus	$0	$0	N/A per program definition.

18 This assessment uses BPA Power planning's 18-hour capacity event to define the system peak period, which is comprised across six peak hours per day over a three-day period in summer or winter.

19 For more information, see Applied Energy Group (2017).

Commercial Thermal Storage	Base	High	Notes and Discussion
Participation Assumptions			
Technical Potential (of Applicable Load)	50%	50%	Technical potential ranges from 5% (Burbank 2009) to 96% (CA 2016 *ex ante*), but more commonly averages 50% (CA 2011; Austin Power; Duke Progress Energy). Applied (2017): 5kW/meter.
Eligible Sectors	Commercial.		
Eligible Segments	All commercial market segments.		
Eligible End Uses	Space cooling.		
Customer Size Requirements	None.		
Load Class Eligibility	100%	100%	See Customer Size Requirements.
Program Participation (of Eligible Load)	1.5%	3%	Applied (2017). This program participation rate is based on another potential assessment in the Northwest. In general, consumer interest in thermal energy storage in the Northwest is relatively low. In addition, the California statewide program has existed since 2013, but there were only three operational installations statewide as of January 2017 (Nexant 2017a).
Event Participation	95%	95%	Thermal storage has a permanent load reduction strategy; thus, event participation is expected to be high.

Results

Table 34 shows that, in 2036, Commercial Thermal Storage could provide 9 MW of summer-achievable potential to BPA’s service area. At $51/kW-year, Commercial Thermal Storage provides much less achievable potential at a higher levelized cost than Commercial Small and Medium DLC—CAC, another commercial DR product for the cooling end use.

Table 34. Commercial Thermal Storage: Assessment Results

Area	Technical Potential—Summer (MW)	Base Achievable Potential—Summer (MW)	High Achievable Potential—Summer (MW)	Levelized Cost—Summer ($/kW-yr)
East	264	4	8	$51.46
West	350	5	10	$50.21
Total	**614**	**9**	**18**	**$50.74**

Industrial Real-Time Pricing

Product Description

The Industrial RTP program charges customers different hour-to-hour rates for electricity, based on wholesale electricity market prices. Typically established the day before, the utility communicates these rates to participants via the internet or communication-enabled devices. This program does not have load reduction events.

Load reduction strategy. Participants shift their demand from higher-demand time periods to lower-demand time periods through the real-time price signal. Typically, customers receive costs estimates via email for the following day and then follow real-time costs online.

Eligibility. All industrial customers with maximum peak demand greater than 150 kW and with AMI installed are eligible to participate in the program. This eligibility draws from PacifiCorp's 2017 potential assessment, which assumed that only large and extra-large C&I customers are eligible for RTP (Applied 2017). In California, most customers facing CPP rates in 2014 "were large commercial and industrial … customers" (Nexant 2015). California investor-owned utilities only began to offer CPP rates to small and medium businesses in the past couple of years (Nexant 2017b). While the majority of today's RTP programs target large C&I customers, this product could potentially be offered to smaller C&I customers. This assessment assumes that only large industrial customers would be eligible for RTP; however, it is important to note that about 65% of the region's industrial customers—on average across all segments—fall in the "large" category.

Incentive. Though the program does not offer a direct incentive, participants can save money by shifting loads from time periods with higher electricity prices to those with lower electricity prices.

Assessment Assumptions

Table 35 provides cost and impact assumptions that Cadmus used to estimate potential and levelized costs for Industrial RTP.

Table 35. Industrial RTP: Assessment Assumptions

Industrial RTP	Base	High	Notes and Discussion
Cost Assumptions			
Upfront Setup Cost	$150,000	$150,000	Cadmus assumes 1 FTE shared between BPA and participating Power customers.
Program O&M Cost ($/Year)	$75,000	$75,000	CPP costs for SDG&E (2017): $280,000; Applied (2017): $75,000 (i.e., 0.5 FTE). Cadmus assumes 0.5 FTE for program O&M cost of a single program for the entire BPA service area, and covers costs for event notification and EM&V to verify savings and evaluate program performance, etc.
Equipment Cost (Labor, Material, Communication Costs) ($/New kW)	$0	$0	Assuming AMI full deployment.
Marketing Cost ($/New kW)	$30	$30	Applied (2017) = $200/large C&I, $400/extra-large C&I. Cadmus assumes marketing costs per participant of $300, and translates this to $/kW based on estimated savings per participant.
Incentive	$0	$0	N/A per program definition.
Signup Bonus	$0	$0	N/A per program definition.

Industrial RTP	Base	High	Notes and Discussion
Participation Assumptions			
Technical Potential (of Applicable Load)	5%	5%	Applied (2017), Large and Extra-Large C&I: 8%.
Eligible Sectors	Industrial.		
Eligible Segments	All industrial market segments.		
Eligible End Uses	All industrial end uses.		
Customer Size Requirements	150 kW or greater		Applied (2017) assumed only large and extra-large C&I customers are eligible.
Load Class Eligibility	Differs by segment and Area		See Customer Size Requirements.
Program Participation (of Eligible Load)	4%	8%	Applied (2017) Large C&I 3%; Applied (2017) Extra-Large C&I 5%.
Event Participation	100%	100%	Technical potential already considers event participation.

Results

Table 36 shows that, at about $35/kW-year, Industrial RTP can produce 5 MW of achievable potential in winter and summer. Compared to the pricing product for residential end users (Residential CPP), Industrial RTP offers a much smaller and more expensive product.

Table 36. Industrial RTP: Assessment Results

Area	Technical Potential—Winter (MW)	Base Achievable Potential—Winter (MW)	High Achievable Potential—Winter (MW)	Base Achievable Levelized Cost—Winter ($/kW-yr)	Technical Potential—Summer (MW)	High Achievable Potential—Summer (MW)	Base Achievable Potential—Summer (MW)	Base Achievable Levelized Cost—Summer ($/kW-yr)
East	19	1	1	$35.73	19	1	2	$35.28
West	96	4	8	$34.70	98	4	8	$34.26
Total	**115**	**5**	**9**	**$34.87**	**117**	**5**	**9**	**$34.43**

Agricultural Irrigation DLC

Product Description

Cadmus designed the Agricultural Irrigation DLC program based on the Automatic Dispatch Option of Idaho Power's Irrigation Peak Rewards program (2017b). Participating irrigation customers received a financial incentive for providing the utility with control of its irrigation pumps and river pumps during summer peak periods. Cadmus assumed that enrolled pumps would be shut down for a maximum of four hours during each event, for up to 15 hours per week.

Currently, PacifiCorp and Idaho Power offer the largest and most mature irrigation DR programs in the Northwest, though BPA has conducted pilots with Power customers such as United Electric Cooperative (Navigant 2015b), Fall River Electric Cooperative, and other utilities with significant irrigation loads.

There are other types of agricultural irrigation DR programs that this assessment did not analyze, including programs that operate similarly to the C&I Demand Curtailment program where some pumps are manually turned on and off by the participating customer, not directly controlled by the utility.

Load reduction strategy. The program will pay for participating customers to install DLC devices on enrolled pumps, allowing the utility to directly turn off pumps during an event.

Eligibility. Irrigation customers can enroll if their irrigation pumps and/or river pumps have a minimum of 100 cumulative horsepower. The irrigation customers of all BPA Power customers, including federal agencies, are eligible if they pass the eligibility requirement.

Incentive. Cadmus assumed a fixed demand credit per kW of load reduction would be paid to participating customers. In addition, unlike Idaho Power's very mature program, Cadmus assumed that the program would pay for DLC device installation on enrolled pumps. Other kinds of irrigation DR programs, including ones that use a voluntary event opt-in approach and/or pay-for-performance structure, may administer different incentive levels.

Assessment Assumptions

Table 37 presents cost and impact assumptions that Cadmus used in estimating potential and levelized costs for Agricultural Irrigation DLC.

Table 37. Agricultural Irrigation DLC: Assessment Assumptions

Agricultural Irrigation DLC	Base	High	Notes and Discussion
Cost Assumptions			
Upfront Setup Cost	$150,000	$150,000	Cadmus assumes 1 FTE shared between BPA and participating Power customers.
Program O&M Cost ($/kW)	$19	$19	Cadmus (2013): ID—$10/kW; OR—$16; WA—$18; Navigant (2015a): $10/kW. Applied (2017) = $68/kW for new program (third party, includes all cost items). Idaho Power's (2016) total cost is $24/kW, with $5/kW of incentive, leaving $19/kW of utility program O&M. Cadmus used this value for both east and west.
Equipment Cost (Labor, Material, Communication Costs) ($/New kW)	$41	$41	LBNL (2017) estimated an enabling cost for Agricultural DLC at $41/kW. It is important to note that these enabling costs assume typical conditions for the average farm in the region. As two previous BPA pilot initiatives[20] in 2011 and 2016 showed, these enabling costs can be significantly lower for industrial-scale irrigated farms with an existing automated irrigation scheduling, control and monitoring system.
Marketing Cost ($/New kW)	$0	$0	Included in utility O&M costs.
Incentive ($/kW)	East - $15; West - $20		Idaho Power (2016) = $5/kW for three months' bills; Cadmus (2013) = $23/kW.
Signup Bonus	$0	$0	None in most benchmarked reports.
Participation Assumptions			
Technical Potential (of Applicable Load)	75%	75%	Cadmus (2013) Applied (2017) = 100%; Freeman (2012) = 76%. However, Cadmus chose a more conservative estimate of 75%, given some pump stations cannot shut off all pumps as they take a long time to prime (e.g., wineries or cash crops).
Eligible Sectors	Agricultural.		
Eligible Segments	Irrigation.		
Eligible End Uses	Irrigation pumps and river pumps.		
Load Class Eligibility	East - 50%; West - 25%		See Customer Size Requirements.
Program Participation (of Eligible Load)	East—50%; West—25%	East—60%; West—50%	Ranges from 15% (Applied 2017) to 50% (Navigant 2015a). Applied (2017): WA/OR 15%; ID 50%. Cadmus (2013): WA 25%; ID 78%.
Event Participation	94%	94%	Cadmus (2013): 94% (based on 2010 ID program data).

Results

As shown in Table 38, Cadmus estimated that the Agricultural Irrigation DLC could provide 420 MW of summer achievable DR by 2036, almost all of which occurs in the east area. With this potential level, Agricultural Irrigation DLC exceeds all other DR products by at least 100 MW in the summer season.

[20] See, for example, Bonneville Power Administration, Distributed Energy Resources Project Brief, Joint Energy Management of Large-Scale Irrigation Systems: Columbia Rural Electric Association, August 2016.

Table 38. Agricultural Irrigation DLC: Assessment Results

Area	Technical Potential—Summer (MW)	Base Achievable Potential—Summer (MW)	High Achievable Potential—Summer (MW)	Levelized Cost—Summer ($/kW-yr)
East	891	419	503	$43.91
West	3	1	1	$49.25
Total	**894**	**420**	**504**	**$43.92**

4.3.3. Utility System

Utility System Demand Voltage Reduction (DVR)

Product Description

In the DVR program, a utility can reduce its system-wide load by lowering its transformers' distribution voltage. A DVR program is typically implemented by the utility through optimizing its voltage/VAR throughout the year. Generally, it is assumed that a drop in peak load would be proportional—but slightly higher—to a drop in voltage. Based on available data, Cadmus assumed a voltage drop of 2% to 2.5% would correspond with a 3% utility-system load reduction. The assumed voltage reduction is conservative and represents a voltage drop that poses minimal risk to customer power quality. This product is assumed to be available throughout the year.

Milton-Freewater Conservation Voltage Regulation

Conservation voltage reduction is Milton-Freewater's first step to address a peak on the system. Substation voltage regulators lower the system voltage by 1.5 volts on four feeder lines out of the Milton Substation. This reduces the megawatts used on the entire system while still maintaining adequate distribution voltage.

Excerpts from Pacific Northwest Smart Grid Demonstration Project: A Compilation of Success Stories (BPA 2014)

Several northwest utilities have implemented or experimented with voltage regulation programs. Milton-Freewater, for example, has engaged in voltage regulation since the mid-80's. As part of the Pacific Northwest Smart Grid Demonstration Project in 2014, Milton-Freewater tested the application of voltage reduction for peak shaving.

Snohomish County PUD implemented Conservation Voltage Reduction (CVR) to improve system throughput and improve power quality. Although Snohomish County PUD does not deploy the program strictly for demand reduction, their investment of under $5 million has resulted in energy savings of 53,856 MWh/yr, with the associated peak load reduction.

Load reduction strategy. To lower the distribution voltage of its transformers, utilities must have a supervisory control and data acquisition (SCADA) or similar distribution control system in place, so tap changers can automatically respond to a dispatched event.

Eligibility. Some industrial and agricultural loads may prove more sensitive to voltage fluctuations. To avoid risking power quality for these loads, Cadmus excluded transformers serving industrial and agricultural loads from the program. As a result, the program's eligible loads consist of residential and commercial loads. In addition, only substations with existing AMI and SCADA may participate in the program. Thus, Cadmus excluded the costs of AMI and SCADA in the levelized cost calculation.

Incentive. As the program does not directly impact end users, Cadmus assumed that end users do not receive an incentive. Participating utilities may desire incentives from BPA, but this assessment did not consider such incentives.

Assessment Assumptions

Table 39 presents cost and impact assumptions that Cadmus used to estimate potential and levelized costs for Utility System DVR.

Table 39. Utility System DVR: Assessment Assumptions

Demand Voltage Reduction	Base	High	Notes and Discussion
Cost Assumptions			
Upfront Setup Cost	$150,000	$150,000	Cadmus assumes 1 FTE shared between BPA and participating Power customers.
Program O&M Cost ($/year)	$225,000	$225,000	Cadmus assumes each of the 85 participating utilities will spend an average of 40 hours per year, amounting to approximately 1.5 FTE (i.e., $225,000).
Equipment Cost (Labor, Material, Communication Costs) ($/New kW)	$100	$100	Cadmus assumes that utilities will only participate in DVR using substations already with SCADA and AMI. Cadmus estimated upfront enabling costs as the Pacific Northwest's (2015) Milton-Freewater's DVR costs (all costs except AMI), plus the Pacific Northwest's (2015) Lower Valley's estimated load tap changer costs, adjusted to $/kW.
Marketing Cost ($/New kW)	$0	$0	None by program definition.
Incentive ($/kW)		$0	None by program definition.
Signup Bonus	$0	$0	None by program definition.
Participation Assumptions			
Technical Potential	3%	3%	According to BPA Energy Northwest (2016), the City of Richland used 2.5% change in voltage. Cadmus used a conservative assumption that a 2.5% voltage reduction would result in a 3% load reduction. Clinton Utilities Board also reported a 3% load reduction, with a 4% reduction in voltage (Loggins n.d.).
Eligible Sectors	Utility System. The Utility System load encompasses all sector loads. However, because industrial loads are less resistive and agricultural loads may incur greater voltage swings with DVR, Cadmus excludes them from DVR. Thus, the Utility System load used to estimate potential is the sum of residential and commercial sector loads.		
Eligible Segments	All residential and commercial segments.		
Eligible End Uses	All residential and commercial end uses.		
Load Class Eligibility	100%	100%	There are no other eligibility requirements.
Program Participation (of Eligible Participants)	65%	85%	Cadmus assumes utilities will only participate in DVR using substations with SCADA and will be DVR-capable within seven years from 2017. Cadmus also assumes, on average, that utilities have SCADA on about 65%–85% of their substations.
Event Participation	97%	97%	BPA Energy Northwest (2016) City of Richland successful event

Demand Voltage Reduction	Base	High	Notes and Discussion
			rate.

Results

Table 40 shows that Utility System DVR could provide 225 MW of winter achievable potential at $11/kW-year and 133 MW of summer achievable potential at $12/kW-year. As the only DR product in this assessment that does not directly involve end users, Utility System DVR's low levelized costs reflect only the utility's cost of enabling the product. As the second lowest-cost winter and summer product (after Residential CPP), Utility System DVR could provide a midsize, dispatchable resource without disrupting end-user activities.

Table 40. Utility System DVR: Assessment Results

Area	Technical Potential—Winter (MW)	Base Achievable Potential—Winter (MW)	High Achievable Potential—Winter (MW)	Base Achievable Levelized Cost—Winter ($/kW-yr)	Technical Potential—Summer (MW)	Base Achievable Potential—Summer (MW)	High Achievable Potential—Summer (MW)	Levelized Cost—Summer ($/kW-yr)
East	119	75	98	$11.06	72	45	59	$12.27
West	238	150	196	$10.78	139	88	115	$11.94
Total	**357**	**225**	**294**	**$10.87**	**211**	**133**	**174**	**$12.05**

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Appendices

Appendix A: Demand Response Scenario Analysis

Appendix B: Locational DR Assessment

Appendix C: 1-in-10 Weather Scenario

Appendix D: Distributed Generation Assessment

Appendix E: Energy Storage Assessment

Appendix F: BPA's Public Power Customers in the Assessment Scope

6. Appendix A. Scenario Analysis

This appendix provides the results of the high achievable potential scenario results. For each table and figure in Appendix A. Scenario Analysis, all the MW are presented at generator, through 2036.

Figure A-1. 20-Year High Achievable Potential Supply Curve for DR, Winter, with Levelized Costs

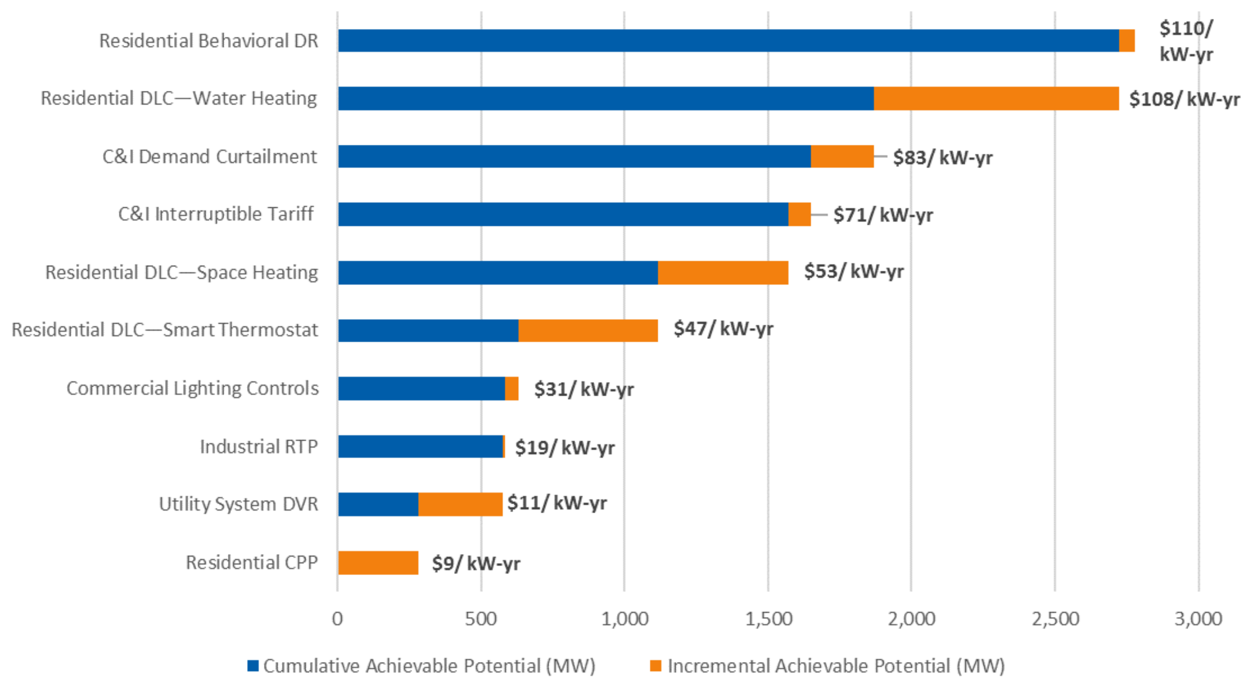


Figure A-2. 20-Year High Achievable Potential Supply Curve for DR, Summer, with Levelized Costs

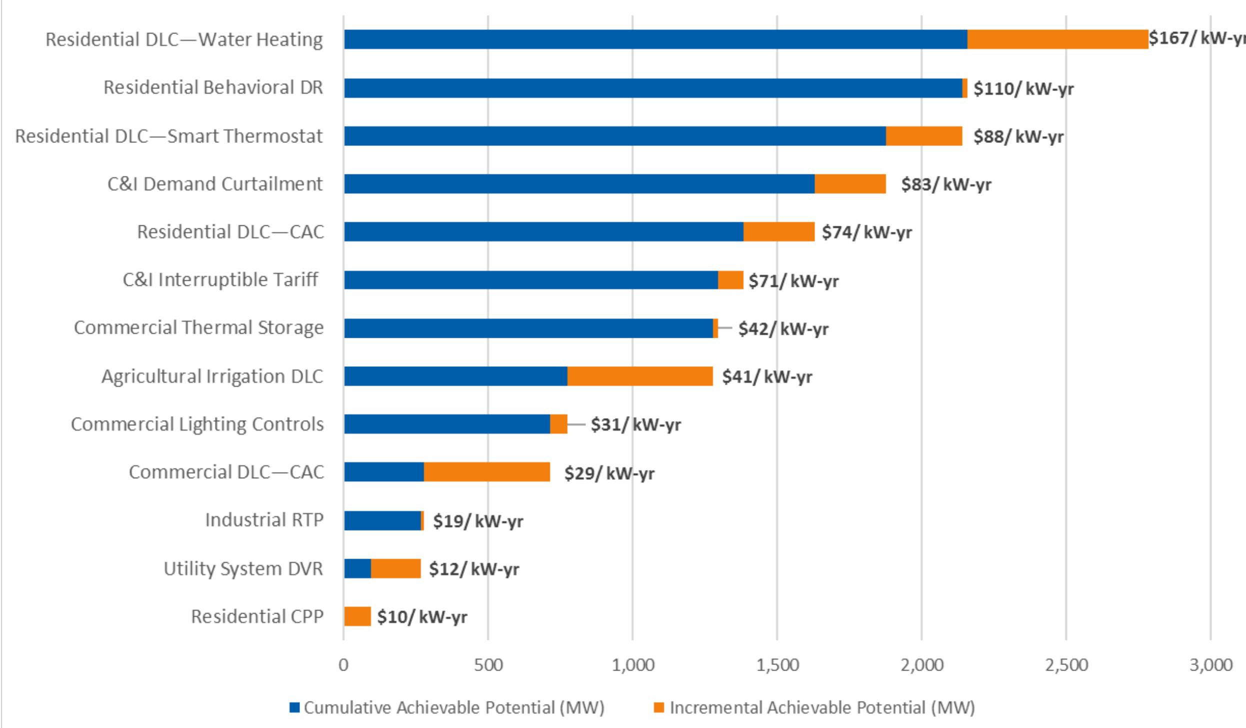


Table A-1. Detailed High Achievable Potential by Product, in 2036 MW

Product	Winter Achievable Potential (MW)	Percent of Area System Peak—Winter	Levelized Cost—Winter ($/kW-year)	Summer Achievable Potential (MW)	Percent of Area System Peak—Summer	Levelized Cost—Summer ($/kW-year)
Residential DLC—Space Heating	454	2.9%	$53	0	0.0%	N/A
Residential DLC—Water Heating	855	5.4%	$108	627	4.7%	$167
Residential DLC—CAC	0	0.0%	N/A	248	1.9%	$74
Residential DLC—Smart Thermostat	488	3.1%	$47	263	2.0%	$88
Residential CPP	280	1.8%	$9	95	0.7%	$10
Residential Behavioral DR	56	0.4%	$110	19	0.1%	$110
Commercial DLC—CAC	0	0.0%	N/A	439	3.3%	$29
Commercial Lighting Controls	46	0.3%	$31	58	0.4%	$31
Commercial Thermal Storage	0	0.0%	N/A	18	0.1%	$42
C&I Demand Curtailment	220	1.4%	$83	246	1.8%	$83
C&I Interruptible Tariff	77	0.5%	$71	86	0.6%	$71
Industrial RTP	9	0.1%	$19	9	0.1%	$19
Agricultural Irrigation DLC	0	0.0%	N/A	504	3.8%	$41
Utility System DVR	294	1.9%	$11	174	1.3%	$12
Total	**2,780**	**17.6%**		**2,786**	**20.9%**	

Table A-2. Residential DLC—Water Heating: High Achievable Potential Assessment Results

Area	Technical Potential—Winter (MW)	Technical Potential—Summer (MW)	High Achievable Potential—Winter (MW)	High Achievable Potential—Summer (MW)	Levelized Cost—Winter ($/kW-yr)	Levelized Cost—Summer ($/kW-yr)
East	455	334	250	184	$166.83	$122.35
West	1,099	806	605	443	$166.82	$122.34
Total	**1,554**	**1,140**	**855**	**627**	**$166.86**	**$107.98**

Table A-3. Residential DLC—Space Heating: High Achievable Potential Assessment Results

Area	Technical Potential—Winter (MW)	High Achievable Potential—(MW)	High Achievable Levelized Cost ($/kW-yr)
East	320	176	$43.89
West	505	278	$58.78
Total	**825**	**454**	**$53.03**

Table A-4. Residential DLC—Smart Thermostat: High Achievable Potential Assessment Results

Area	Technical Potential—Winter (MW)	Technical Potential—Summer (MW)	High Achievable Potential—Winter (MW)	High Achievable Potential—Summer (MW)	Levelized Cost—Winter ($/kW-yr)	Levelized Cost—Summer ($/kW-yr)
East	460	281	202	124	$40.00	$65.50
West	648	317	285	139	$52.64	$107.68
Total	**1,108**	**598**	**488**	**263**	**$47.43**	**$87.95**

Table A-5. Residential DLC—CAC: High Achievable Potential Assessment Results

Area	Technical Potential—Summer (MW)	High Achievable Potential—Summer (MW)	Levelized Cost ($/kW-yr)
East	219	120	$54.93
West	232	127	$91.94
Total	**450**	**248**	**$74.03**

Table A-6. Commercial Small and Medium DLC—CAC: High Achievable Potential Assessment Results

Area	Technical Potential—Summer (MW)	High Achievable Potential—Summer (MW)	Levelized Cost ($/kW-yr)
East	743	36	$26.30
West	740	74	$30.80
Total	**1,482**	**110**	**$29.34**

Table A-7. Residential TOU and CPP: High Achievable Potential Assessment Results

Area	Technical Potential—Winter (MW)	Technical Potential—Summer (MW)	High Achievable Potential—Winter (MW)	High Achievable Potential—Summer (MW)	Levelized Cost—Winter ($/kW-yr)	Levelized Cost—Summer ($/kW-yr)
East	383	129	96	32	$9.58	$10.64
West	738	249	184	62	$9.37	$10.40
Total	**1,121**	**378**	**280**	**95**	**$9.80**	**$10.48**

Table A-8. Residential Behavioral Demand Response: High Achievable Potential Assessment Results

Area	Technical Potential—Winter (MW)	Technical Potential—Summer (MW)	High Achievable Potential—Winter (MW)	High Achievable Potential—Summer (MW)	Levelized Cost—Winter ($/kW-yr)	Levelized Cost—Summer ($/kW-yr)
East	64	21	19	6	$110.04	$110.62
West	123	42	37	12	$109.71	$110.27
Total	**187**	**63**	**56**	**19**	**$109.96**	**$110.81**

Table A-9. C&I Demand Curtailment: High Achievable Potential Assessment Results

Area	Technical Potential—Winter (MW)	Technical Potential—Summer (MW)	High Achievable Potential—Winter (MW)	High Achievable Potential—Summer (MW)	Levelized Cost—Winter ($/kW-yr)	Levelized Cost—Summer ($/kW-yr)
East	144	181	41	52	$83.01	$84.88
West	629	683	179	195	$82.73	$82.73
Total	**774**	**864**	**220**	**246**	**$82.79**	**$82.78**

Table A-10. C&I Interruptible Tariff: High Achievement Potential Assessment Results

Area	Technical Potential—Winter (MW)	Technical Potential—Summer (MW)	High Achievable Potential—Winter (MW)	High Achievable Potential—Summer (MW)	Levelized Cost—Winter ($/kW-yr)	Levelized Cost—Summer ($/kW-yr)
East	115	145	14	18	$71.01	$70.98
West	503	547	63	68	$70.79	$70.77
Total	**619**	**692**	**77**	**86**	**$70.83**	**$70.81**

Table A-11. Commercial Lighting Controls: High Achievable Potential Assessment Results

Area	Technical Potential—Winter (MW)	Technical Potential—Summer (MW)	High Achievable Potential—	High Achievable Potential—	Levelized Cost—Winter ($/kW-yr)	Levelized Cost—Summer

			Winter (MW)	Summer (MW)		($/kW-yr)
East	55	67	15	18	$31.43	$31.36
West	139	178	31	40	$30.89	$30.82
Total	**193**	**246**	**46**	**58**	**$31.06**	**$30.98**

Table A-12. Commercial Thermal Storage: High Achievable Potential Assessment Results

Area	Technical Potential—Summer (MW)	High Achievable Potential—Winter (MW)	High Achievable Potential—Summer (MW)
East	264	8	$42.85
West	350	10	$41.86
Total	**614**	**18**	**$42.28**

Table A-13. Industrial TOU and Real Time Pricing: High Achievable Potential Assessment Results

Area	Technical Potential—Winter (MW)	Technical Potential—Summer (MW)	High Achievable Potential—Winter (MW)	High Achievable Potential—Summer (MW)	Levelized Cost—Winter ($/kW-yr)	Levelized Cost—Summer ($/kW-yr)
East	19	19	1	2	$19.33	$19.10
West	96	98	8	8	$18.78	$18.56
Total	**115**	**117**	**9**	**9**	**$18.87**	**$18.65**

Table A-14. Irrigation DLC: High Achievable Potential Assessment Results

Area	Technical Potential—Summer (MW)	High Achievable Potential—Winter (MW)	High Achievable Potential—Summer (MW)
East	891	503	$41.11
West	3	1	$38.12
Total	**894**	**504**	**$41.11**

Table A- 15. DVR: High Achievable Potential Assessment Results

Area	Technical Potential—Winter (MW)	Technical Potential—Summer (MW)	High Achievable Potential—Winter (MW)	High Achievable Potential—Summer (MW)	Levelized Cost—Winter ($/kW-yr)	Levelized Cost—Summer ($/kW-yr)
East	119	72	98	59	$11.20	$12.18
West	238	139	196	115	$10.95	$11.90
Total	**357**	**211**	**294**	**174**	**$11.03**	**$12.00**

7. Appendix B. Locational DR Assessment

This study provides estimates of the potential for demand response (DR) resources for six geographic areas within Bonneville Power Administration's (BPA) public power utility customer service territory. The DR potentials estimated for each geographic area will provide BPA's transmission planning team with an understanding of the available megawatt (MW) reductions achievable for the 10-year period from 2017 to 2026. These geographic areas were identified as priorities for inclusion for a variety of reasons, including reducing transmission congestion, improving transmission system reliability, and potentially deferring transmission system investments.

These six geographic areas are these:

1. Portland-Vancouver-Columbia Gorge-Willamette Valley-Central Oregon-Oregon Coast (South of Allston Substation geographic area)
2. Tacoma North through Snohomish County Area (Puget Sound geographic area)
3. Central Oregon geographic area
4. Tri-Cities geographic area
5. North of Olympia Substation, including Kitsap County (Olympic Peninsula geographic area)
6. South/Southeast Idaho and Northwest Wyoming (S&SE Idaho and NW Wyoming geographic area)

The geographic parameters for each load area are based upon individual utility service territories and were provided to Cadmus by BPA. Table B-10 though Table B-15 contain the lists of utilities for each geographic area. In some instances, individual utilities may belong to more than one geographic area. For this reason, MW reductions presented in the results tables in this report are not summed across geographic areas as the total would double count some utilities' resource potential.

To assess the levels of various DR resource potential available in these geographic areas within BPA's service territory, Cadmus has investigated the following:

- **Technical potential** assumes 100% participation of eligible customers in all relevant programs within this study. The technical potential represents a theoretical limit.
- **Achievable potential** assumes achievable market participation rates for eligible customers in all relevant programs within this study. In this study, these rates represented a conservative estimate, derived from benchmarking against experiences or plans of regional and national utilities with similar DR products.[21] The achievable potential based on these rates is the average

[21] For the main assessment, Cadmus developed two program participation rates: base and high. The base participation rate represented a conservative estimate based on benchmarked values, whereas the high participation rate represented an unconstrained scenario, where program participation would only be limited by end users' willingness to participate, and not by utility-related factors (e.g., budget or other planning constraints). For the locational DR assessment, achievable potential is based on the base participation rates.

of the range of DR results that typically occur, or are expected to occur, at public and private utilities in the region and BPA service area and elsewhere in the United States. The DR potential in the main body of this report focuses on achievable potential.

For the analysis presented in this report, the total BPA system peak is modeled separately for summer (August 16–31) and winter (February 1–28) periods and is defined as the average peak hourly load occurring under an 18-hour capacity event across six peak hours per day over a three-day period. This is the peak used for Power supply planning and operations at BPA.

Each geographic area's winter and summer load basis for DR potential is calculated as the area's public power utilities' winter and summer demand that is coincident with the total BPA system peak (hereafter referred to as the winter and summer "area demand"). This report presents the MW load reduction results as a percentage of each area's winter and summer area demand.

Cadmus acknowledges that Transmission flows and loads associated with the six geographic areas in this study may be driven mostly by private utility loads and the flows produced by generation suppliers, marketers, exporters, and other sources beyond the public utility loads studied. In some of the geographic areas, most of the loads of concern to Transmission may be caused by loads and resources other than those in public utility service areas.

Studying such loads and flows was outside the scope of this study—Cadmus was under contract to assess only the DR potential of BPA public power customer utility service areas. It is hoped that even though this work may be incomplete for Transmission planning purposes in the six load areas, it may still provide value and insights to Transmission and suggest how more complete load area DR assessments might be completed.

The study estimated DR potential during a 10-year period, from 2017 to 2026. This report presents results for the end year, 2026. Figure B-1 and Figure B-2 present each geographic area's winter and summer area demand in 2026, respectively.

Note that the area demand must not be confused with flows at historic BPA flow gates. For example, peak north to south flows at South of Allston rarely exceed 3,000 MW, including export flows (perhaps 1,500 MW) and loop flows from the south. The area demand, however, is almost 4,500 MW in the service areas of BPA public power customer utilities in areas where DR could help reduce north to south congestion at South of Allston. The private utility peaks in areas where DR could help South of Allston congestion has an area demand approaching 10,000 MW.

Figure B-1. Geographic Area Demand in Winter, MW in 2026

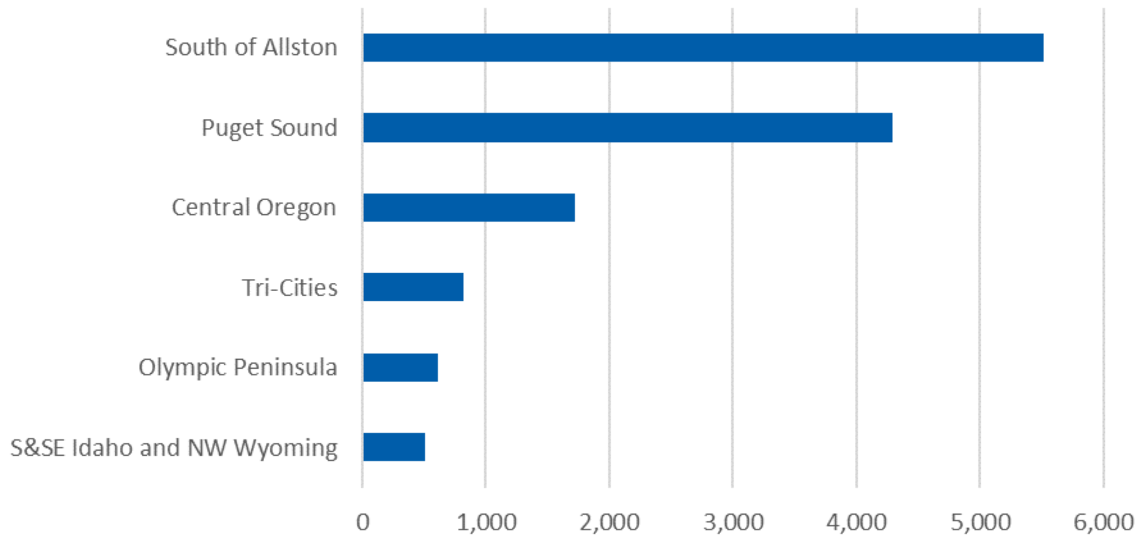
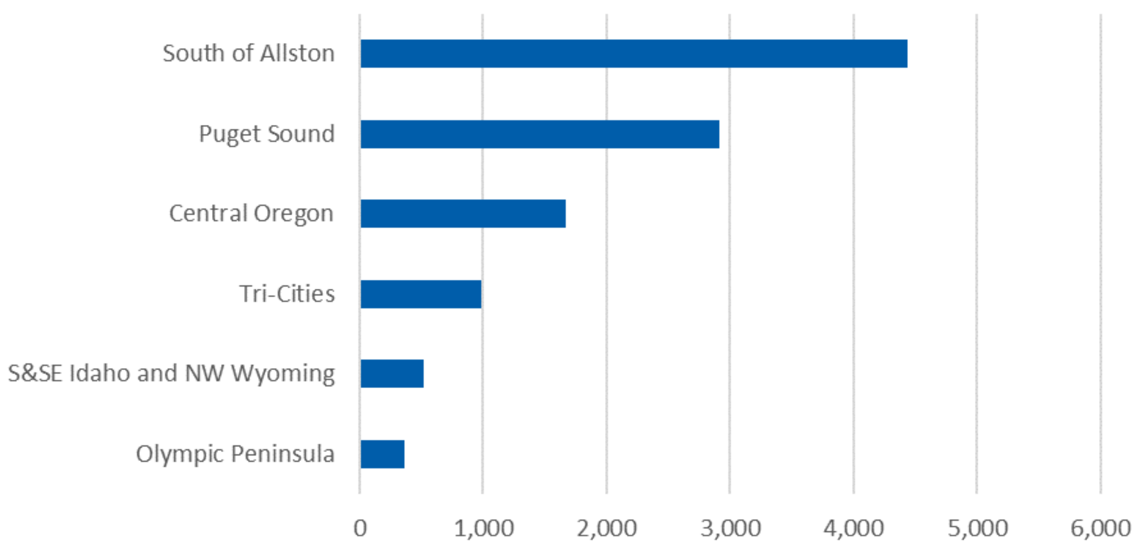


Figure B-2. Geographic Area Demand in Summer, MW in 2026



Obviously, that total public and private utility demand in the South of Allston area is served with several transmission lines beyond just the South of Allston flow gate. The total area demand is also served with thousands of MWs of local generation that do not need to flow through South of Allston.

Cadmus' analysis focused on DR products such as residential direct load control (DLC) for space heat, water heat, central air-conditioning (CAC), and residential smart thermostats. Additional residential products included non-firm options such as behavioral DR and critical-peak-pricing (CPP). Nonresidential products included irrigation DLC, commercial CAC DLC, commercial lighting controls, commercial thermal storage, commercial and industrial (C&I) load curtailment, C&I interruptible tariffs, and industrial real-time-pricing (RTP). In addition to these DR products, demand voltage reduction (DVR) is also included in the scope of this analysis. Distributed generation (DG) and energy storage systems (ESS) are not included in the locational assessment.

7.1. Summary of Results

Table B-1 presents estimated achievable DR potentials for the six geographic areas during both winter and summer in 2026. The greatest winter achievable potential in magnitude is South of Allston, but Tri-Cities is largest in terms of its winter achievable potential as a percentage of its total winter area demand. In the summer, South of Allston represents the greatest achievable potential in magnitude but S&SE Idaho and NW Wyoming's achievable potential is greatest in terms of the percentage of their area demand. This result is because of the higher saturation of residential space cooling and irrigation load in the agricultural sector in S&SE Idaho and NW Wyoming.

Table B-1. Demand Response Achievable Potential, MW in 2026

Area	Winter Achievable Potential (MW)	Achievable Potential as Percent of Area Demand—Winter	Summer Achievable Potential (MW)	Achievable Potential as Percent of Area Demand—Summer
South of Allston	562	9.3%	456	9.3%
Puget Sound	476	10.1%	390	12.2%
Central Oregon	153	8.1%	147	8.0%
Tri-Cities	112	12.5%	109	10.0%
Olympic Peninsula	57	8.5%	40	10.2%
S&SE Idaho and NW Wyoming	45	8.1%	68	12.0%

Table B-2 and Table B-3 show the achievable DR potentials for each area and sector in winter and summer, respectively. Agricultural potential is omitted from Table B-2 due to the lack of irrigation load in winter. The residential sector accounts for the majority of achievable DR potential in winter for every area except for Central Oregon, where most of winter potential occurs in the industrial sector.

Table B-2. Demand Response Achievable Potential by Area and Sector, Winter MW in 2026

Area	Residential Winter Achievable Potential (MW)	Residential Achievable Potential as Percent of Area Demand—Winter	Commercial Winter Achievable Potential (MW)	Commercial Achievable Potential as Percent of Area Demand—Winter	Industrial Winter Achievable Potential (MW)	Industrial Achievable Potential as Percent of Area Demand—Winter
South of Allston	397	6.5%	60	1.1%	106	1.9%
Puget Sound	344	7.3%	94	2.2%	38	0.9%
Tri-Cities	87	9.7%	10	1.3%	15	1.8%
Central Oregon	96	5.1%	12	0.7%	44	2.6%
Olympic Peninsula	45	6.6%	6	0.9%	7	1.1%
S&SE Idaho and NW Wyoming	37	6.6%	8	1.5%	1	0.2%

Table B-3. Demand Response Achievable Potential by Area and Sector, Summer MW in 2026

Area	Residential Summer Achievable Potential (MW)	Residential Achievable Potential as Percent of Area Demand—Summer	Commercial Summer Achievable Potential (MW)	Commercial Achievable Potential as Percent of Area Demand—Summer	Industrial Summer Achievable Potential (MW)	Industrial Achievable Potential as Percent of System Area Peak—Summer	Agricultural Percent of Area Demand—Summer	Agricultural Achievable Potential as Percent of Area Demand—Summer
South of Allston	191	3.9%	120	2.5%	107	2.2%	37	0.8%
Puget Sound	178	5.6%	174	5.4%	38	1.2%	0	0.0%
Tri-Cities	53	4.9%	22	2.0%	15	1.4%	19	1.8%
Central Oregon	53	2.9%	26	1.4%	45	2.4%	23	1.3%
Olympic Peninsula	22	5.6%	11	2.8%	7	1.7%	0	0.0%
S&SE Idaho and NW Wyoming	20	3.5%	17	3.1%	1	0.1%	30	5.3%

7.2. *Geographic Demand Response Assessment Results*

This section details each geographic area's load reduction potentials in 2026.

7.2.1. South of Allston

South of Allston is a large geographic area that encompasses the Greater Portland metropolitan area in northwestern Oregon, most of the rest of the state of Oregon, Vancouver in southwestern Washington, both the Washington and Oregon sides of the Columbia River gorge, and the Tri-Cities in Washington. It has the largest winter and summer area demand out of the six geographic areas. Its total winter and summer achievable DR potentials are 562 MW and 456 MW, representing 9.3% and 9.3% of its winter and summer area demand, respectively. Note that the investor-owned utility loads are not included in this analysis.

Figure B-3 and Figure B-4 show the achievable potential for the top six DR products in South of Allston in winter and summer, respectively. The product with the greatest winter achievable potential for South of Allston is C&I Demand Curtailment (97 MW). This result is due to the relatively high C&I loads in a winter-peaking geographic area. For the top six products, the achievable DR potential is relatively evenly distributed across South of Allston loads. In the summer, C&I Curtailment (106 MW) presents the greatest achievable potential for South of Allston, followed by Residential DLC–Water Heating (56 MW).

Figure B-3. South of Allston 2026 Achievable DR Potential (MW), Winter, Top Six Products

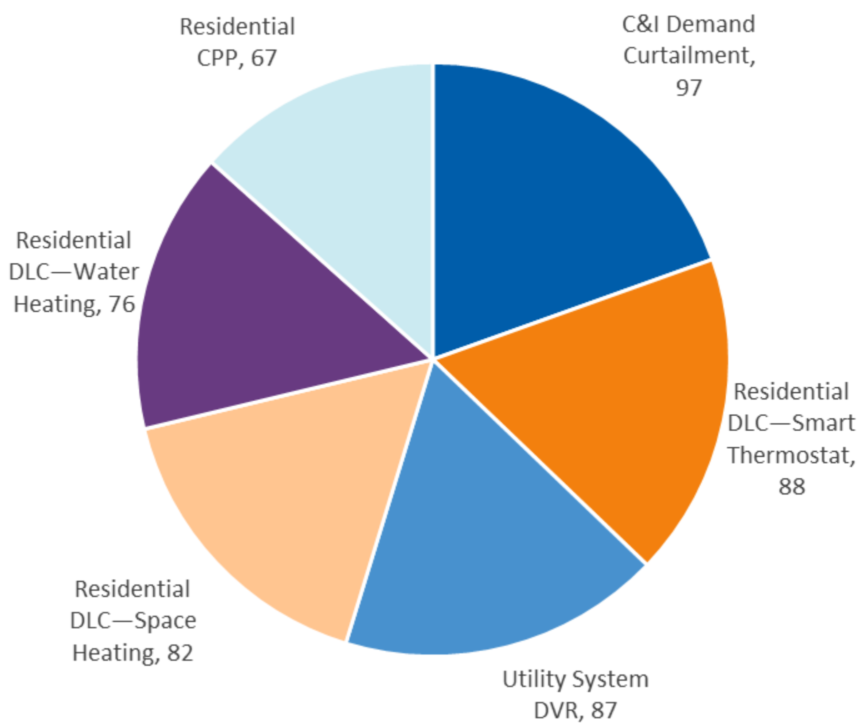


Figure B-4. South of Allston 2026 Achievable DR Potential (MW), Summer, Top Six Products

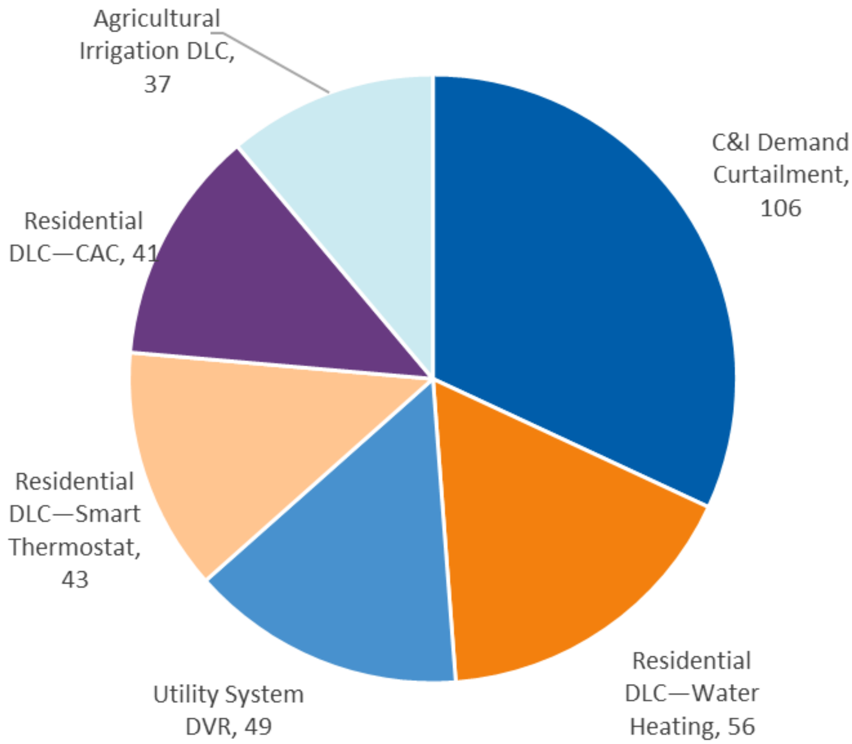


Table B-4 presents the achievable DR potential by product for South of Allston during winter and summer. C&I Demand Curtailment—the product with the greatest winter achievable potential—represents 1.6% of South of Allston's winter demand and 2.2% of South of Allston's summer demand.

Table B-4. South of Allston 2026 Achievable Potential Summary

Product	Winter Achievable Potential (MW)	Percent of Area Demand—Winter	Summer Achievable Potential (MW)	Percent of Area Demand—Summer
Residential Space Heating	82	1.4%	0	0.0%
Residential Water Heating	76	1.3%	56	1.1%
Residential Space Cooling CAC	0	0.0%	41	0.8%
Residential Smart Thermostat	88	1.4%	43	0.9%
Residential CPP	67	1.1%	22	0.5%
Residential Behavioral DR	15	0.2%	5	0.1%
Commercial Space Cooling CAC	0	0.0%	36	0.7%
Commercial Lighting Controls	16	0.3%	21	0.4%
Commercial Thermal Storage	0	0.0%	3	0.1%
C&I Curtailment	97	1.6%	106	2.2%
C&I Interruptible Tariff	33	0.5%	36	0.7%
Industrial Real Time Pricing	3	0.0%	3	0.1%
Agricultural Irrigation DLC	0	0.0%	37	0.8%
Utility System DVR	87	1.4%	49	1.0%
Total	**562**	**9.3%**	**456**	**9.3%**

7.2.2. Puget Sound

Puget Sound is a geographic area that spans the western part of Washington from Seattle to Olympia, including Tacoma and Snohomish County. It has the second largest winter and summer area demand of the six geographic areas, after South of Allston. Its total winter and summer achievable DR potentials are 476 MW and 390 MW, representing 10.1% and 12.2% of its winter and summer area demand, respectively. Note that this analysis covers public utility service areas using BPA firm energy and excludes Puget Sound Energy's service area.

Figure B-5 and Figure B-6 show the achievable potential for the top six DR products in Puget Sound in winter and summer, respectively. Residential water heating (143 MW) is the product with the greatest winter achievable potential for Puget Sound. This result is due to the relatively high saturation of electric water heating for residential customers in a winter-peaking geographic area. In the summer, Residential DLC–Water Heating (105 MW) provides the greatest achievable potential followed by C&I Curtailment (89 MW) for Puget Sound.

Figure B-5. Puget Sound 2026 Achievable DR Potential (MW), Winter, Top Six Products

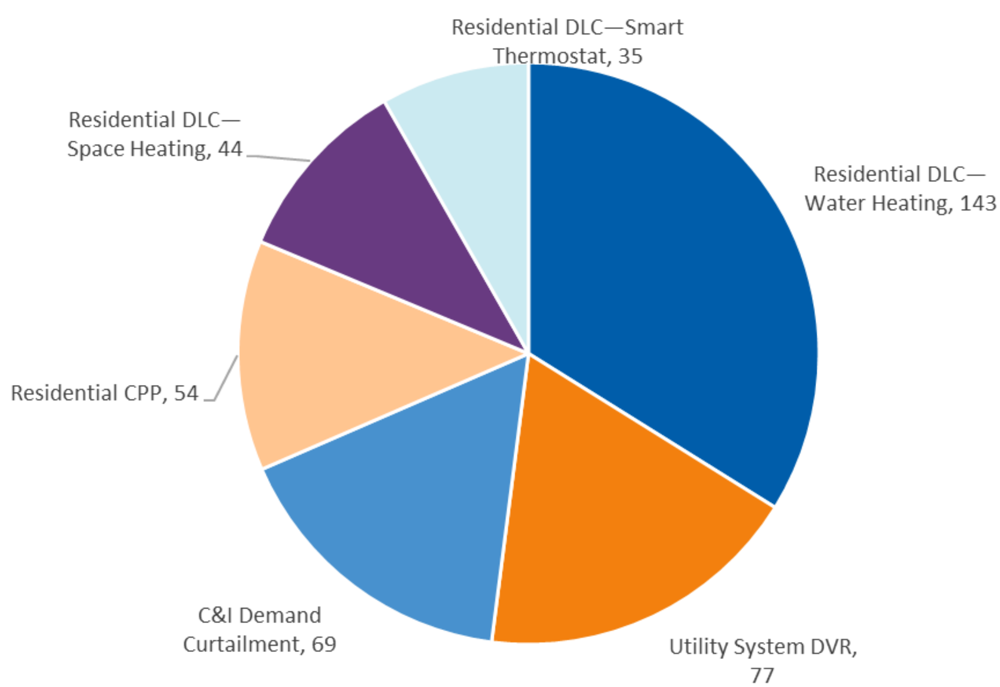


Figure B-6. Puget Sound 2026 Achievable DR Potential (MW), Summer, Top Six Products

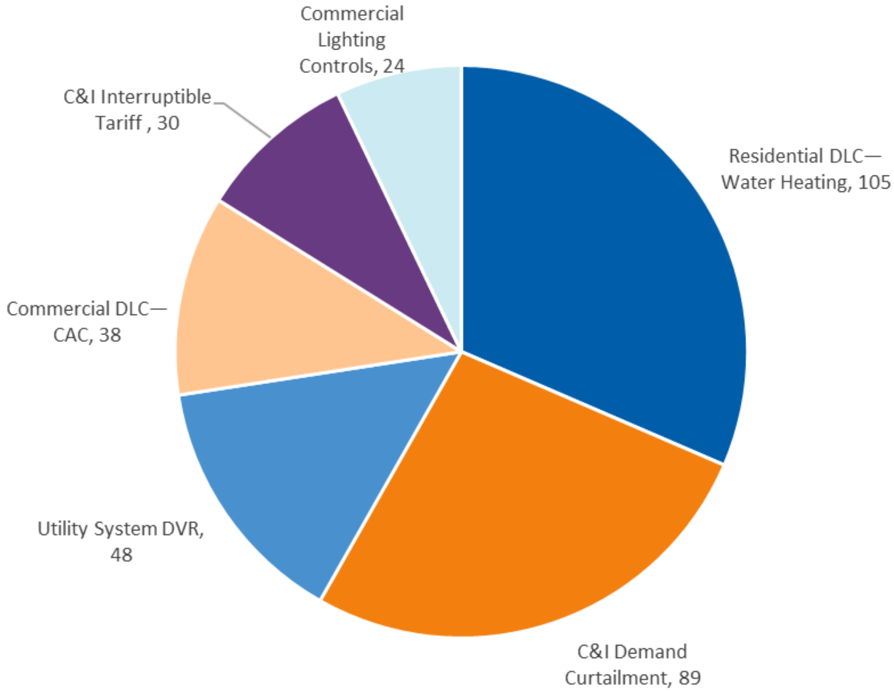


Table B-5 presents the achievable DR potential by product in Puget Sound during winter and summer. Residential Water Heating—the product with the greatest winter achievable potential—represents 3.0% of Puget Sound's winter demand. C&I Curtailment—the product with the second-greatest summer achievable potential—represents 2.8% of Puget Sound's summer demand.

Table B-5. Puget Sound 2026 Achievable Potential Summary

Product	Winter Achievable Potential (MW)	Percent of Area Demand—Winter	Summer Achievable Potential (MW)	Percent of Area Demand—Summer
Residential Space Heating	44	0.9%	0	0.0%
Residential Water Heating	143	3.0%	105	3.3%
Residential Space Cooling CAC	0	0.0%	15	0.5%
Residential Smart Thermostat	35	0.7%	17	0.5%
Residential CPP	54	1.1%	18	0.6%
Residential Behavioral DR	12	0.3%	4	0.1%
Commercial Space Cooling CAC	0	0.0%	38	1.2%
Commercial Lighting Controls	18	0.4%	24	0.7%
Commercial Thermal Storage	0	0.0%	3	0.1%
C&I Curtailment	69	1.5%	89	2.8%
C&I Interruptible Tariff	23	0.5%	30	0.9%
Industrial Real Time Pricing	1	0.0%	1	0.0%
Agricultural Irrigation DLC	0	0.0%	0	0.0%
Utility System DVR	77	1.6%	48	1.5%
Total	**476**	**10.1%**	**390**	**12.2%**

7.2.3. Central Oregon

Central Oregon is a geographic area inside the South of Allston geographic area and includes Madras, Redmond, Bend, Prineville, La Pine, and Sunriver in Oregon. Its winter and summer area demand comprise 32% and 38% of South of Allston's winter and summer area demand. Its total winter and summer achievable DR potentials are 153 MW and 147 MW, representing 8.1% and 8.0% of its winter and summer area demand, respectively.

Figure B-7 and Figure B-8 show the achievable potential for the top six DR products in Central Oregon in winter and summer, respectively. The product with the greatest winter achievable potential (36 MW) for the Central Oregon is C&I Curtailment. In the summer, C&I Curtailment also presents the greatest achievable potential (39 MW) for Central Oregon.

Figure B-7. Central Oregon 2026 Achievable DR Potential, Winter, Top Six Products

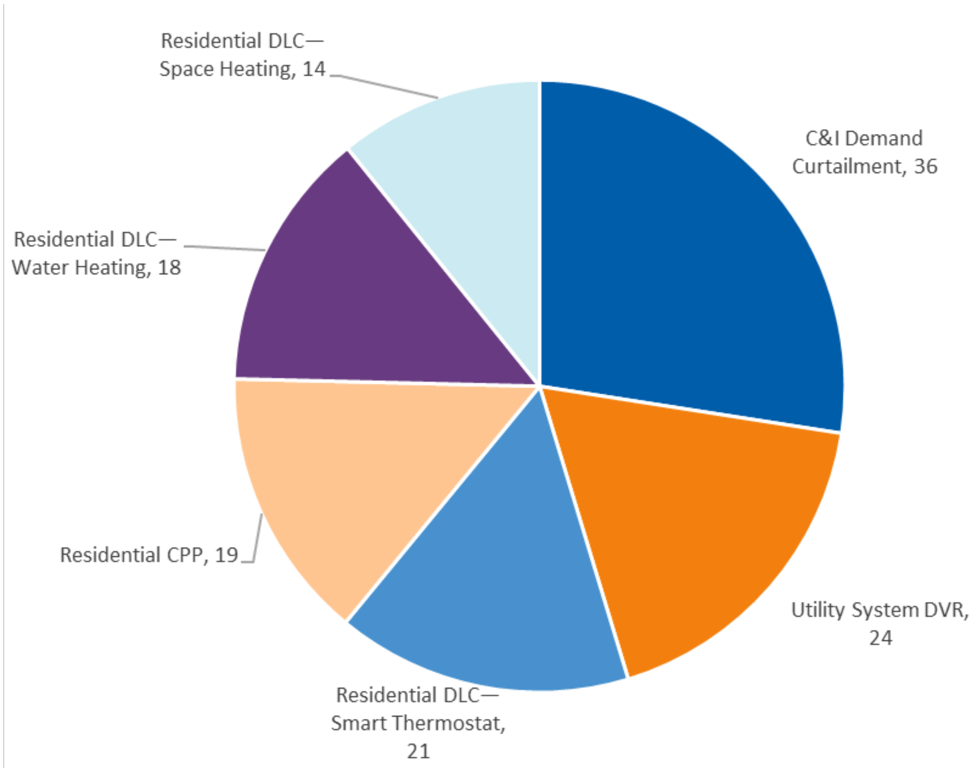


Figure B-8. Central Oregon 2026 Achievable DR Potential, Summer, Top Six Products

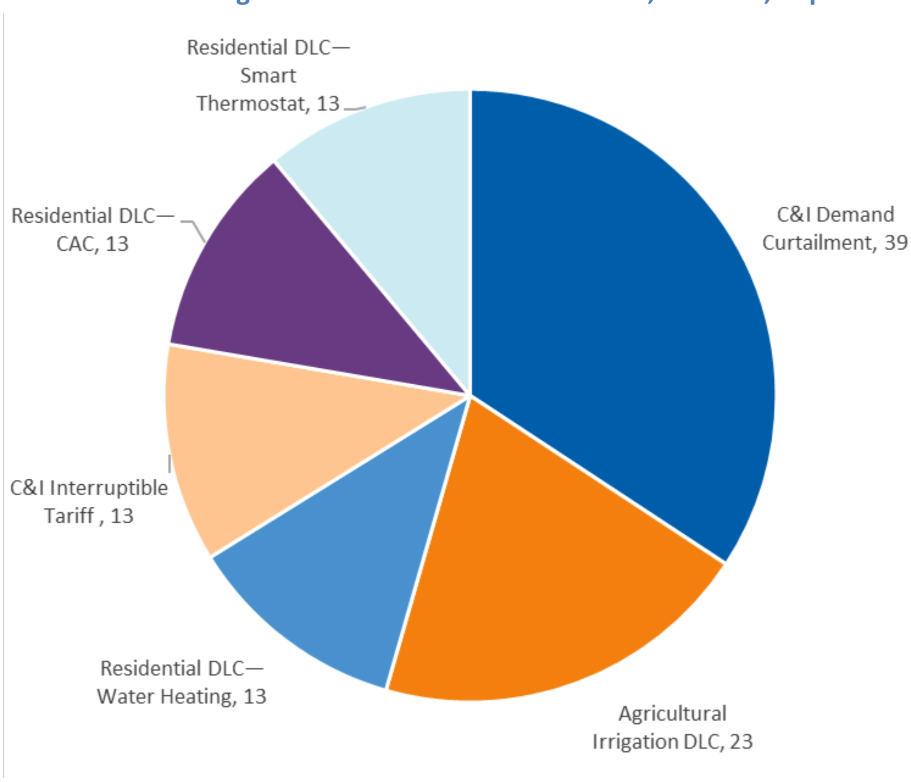


Table B-6 presents the achievable DR potential by product in Central Oregon during winter and summer. C&I Curtailment—the product with the greatest winter (and summer) achievable potential—represents 2.1 % of Central Oregon's winter demand. Irrigation DLC—the product with the second-greatest summer achievable potential—represents 1.4% of Central Oregon's summer demand.

Table B-6. Central Oregon 2026 Achievable Potential Summary

Product	Winter Achievable Potential (MW)	Percent of Area Demand—Winter	Summer Achievable Potential (MW)	Percent of Area Demand—Summer
Residential DLC—Space Heating	14	0.8%	0	0.0%
Residential DLC—Water Heating	18	1.0%	13	0.8%
Residential DLC—CAC	0	0.0%	13	0.8%
Residential DLC—Smart Thermostat	21	1.1%	13	0.5%
Residential CPP	19	1.0%	6	0.4%
Residential Behavioral DR	4	0.2%	1	0.1%
Commercial DLC—CAC	0	0.0%	7	0.1%
Commercial Lighting Controls	3	0.2%	3	0.2%
Commercial Thermal Storage	0	0.0%	1	0.1%
C&I Demand Curtailment	36	1.9%	39	2.3%
C&I Interruptible Tariff	12	0.6%	13	0.8%
Industrial RTP	1	0.1%	1	0.1%
Agricultural Irrigation DLC	0	0.0%	23	1.4%
Utility System DVR	24	1.2%	12	0.7%
Total	**153**	**8.1%**	**147**	**8.1%**

7.2.4. Tri-Cities

Tri-Cities is a geographic area inside the South of Allston geographic area and includes three major cities in south central Washington: Pasco, Kennewick, and Richland. Its winter and summer area demand comprise 15% and 22% of South of Allston's winter and summer area demand. Its total winter and summer achievable DR potentials are 112 MW and 109 MW, representing 12.5% and 10.0% of its winter and summer area demand, respectively.

Figure B-9 and Figure B-10 show the achievable potential for the top six DR products in Tri-Cities in winter and summer, respectively. The product with the greatest winter achievable potential (24 MW) for Tri-Cities is Residential DLC—Smart Thermostats. In the summer, Irrigation DLC presents the greatest achievable potential (19 MW) for Tri-Cities. The top six DR products in Tri-Cities in the winter and summer seasons demonstrated relatively even distributions of achievable potential.

Figure B-9. Tri-Cities 2026 Achievable DR Potential, Winter, Top Six Products

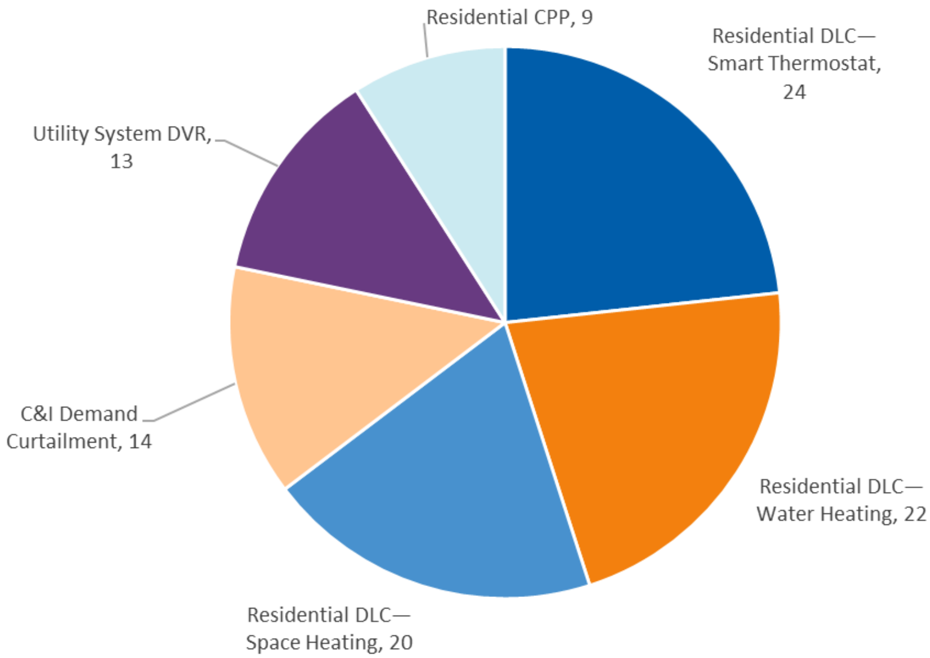


Figure B-10. Tri-Cities 2026 Achievable DR Potential, Summer Top Six Products

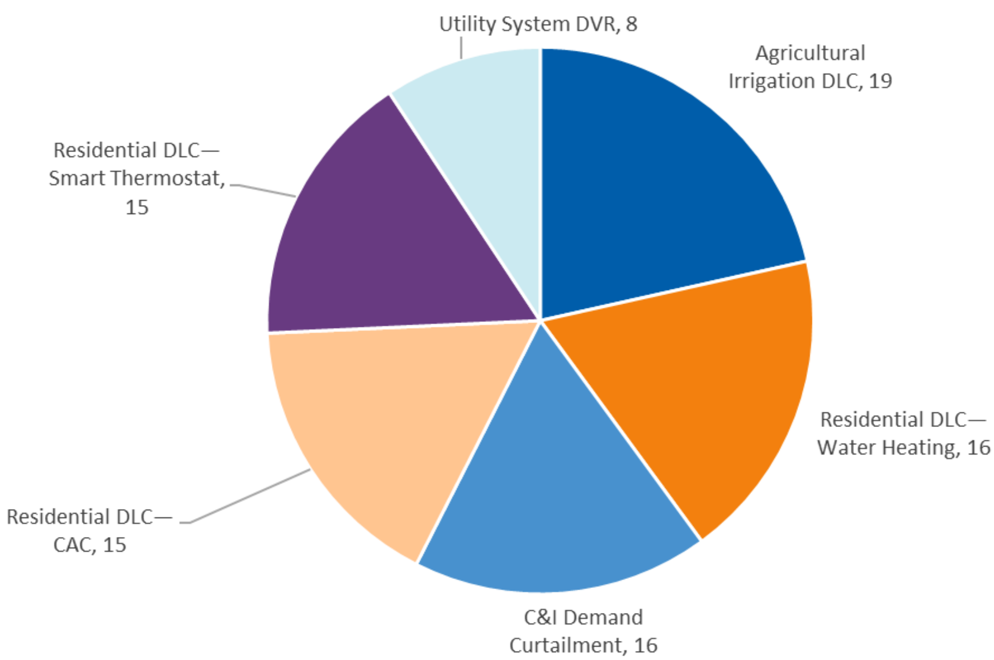


Table B-7 presents the achievable DR potential by product in Tri-Cities during winter and summer. Residential Water Heating—the product with the greatest winter achievable potential—represents 2.9%

of Tri-Cities' winter demand. Irrigation DLC—the product with the greatest summer achievable potential—represents 1.9% of Tri-Cities' summer demand.

Table B-7. Tri-Cities 2026 Achievable Potential Summary

Product	Winter Achievable Potential (MW)	Percent of Area Demand—Winter	Summer Achievable Potential (MW)	Percent of Area Demand—Summer
Residential DLC—Space Heating	20	2.2%	0	0.0%
Residential DLC—Water Heating	22	2.5%	16	1.5%
Residential DLC—CAC	0	0.0%	15	1.4%
Residential DLC—Smart Thermostat	24	2.6%	15	1.3%
Residential CPP	9	1.0%	3	0.3%
Residential Behavioral DR	2	0.2%	1	0.1%
Commercial DLC—CAC	0	0.0%	6	0.6%
Commercial Lighting Controls	3	0.3%	4	0.4%
Commercial Thermal Storage	0	0.0%	1	0.1%
C&I Demand Curtailment	14	1.5%	16	1.4%
C&I Interruptible Tariff	5	0.5%	5	0.5%
Industrial RTP	< 1	<0.1%	< 1	<0.1%
Agricultural Irrigation DLC	0	0.0%	19	1.8%
Utility System DVR	13	1.4%	8	0.8%
Total	**112**	**12.5%**	**109**	**10.0%**

7.2.5. Olympic Peninsula

The Olympic Peninsula is a geographic area west of Puget Sound in northwestern Washington. It includes Clallam, Jefferson, Mason, and Kitsap counties. It has 598 MW of winter demand and 346 MW of summer demand. The difference in winter and summer demand is due to the mildness of summers on the peninsula, the relatively high saturation of residential electric space heating equipment, and the higher share of residential load as a percentage of total area demand. Its total winter and summer achievable DR potentials are 57 MW and 40 MW, representing 8.6% and 10.3% of its area's winter and summer total demand, respectively. As is the case with the Puget Sound Area, Puget Sound Energy loads are excluded. Navy loads served by BPA are included.

Figure B-11 and Figure B-12 show the achievable potential for the top six DR products in the Olympic Peninsula in winter and summer, respectively. Utility System DVR is the product with the greatest winter achievable potential (11 MW) for the Olympic Peninsula. In the summer, Residential DLC—Water Heating presents the greatest achievable potential (8 MW) for the Olympic Peninsula. The top six DR products in the Olympic Peninsula in the winter and summer seasons demonstrated relatively even distributions of achievable potential.

Figure B-11. Olympic Peninsula 2026 Achievable DR Potential, Winter, Top Six Products

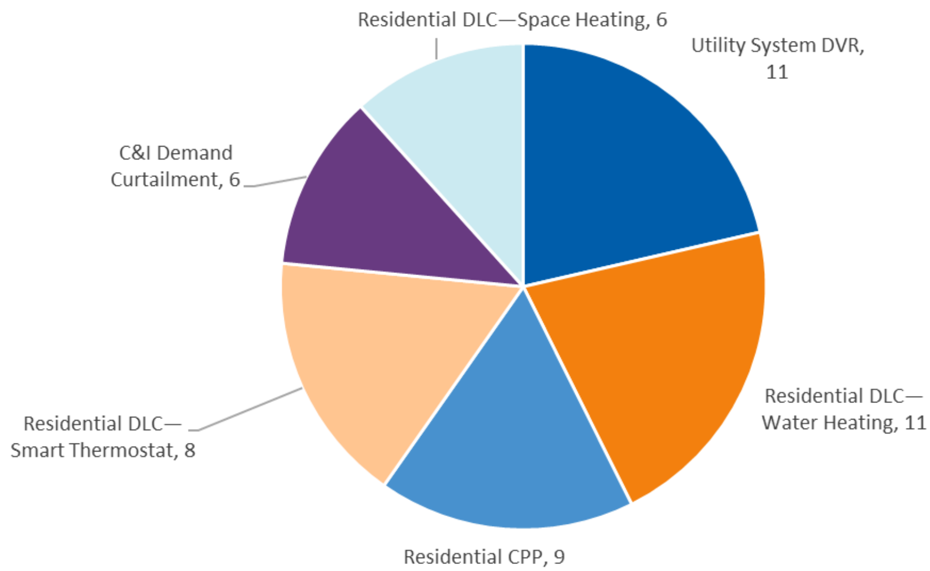


Figure B-12. Olympic Peninsula 2026 Achievable DR Potential, Summer, Top Six Products

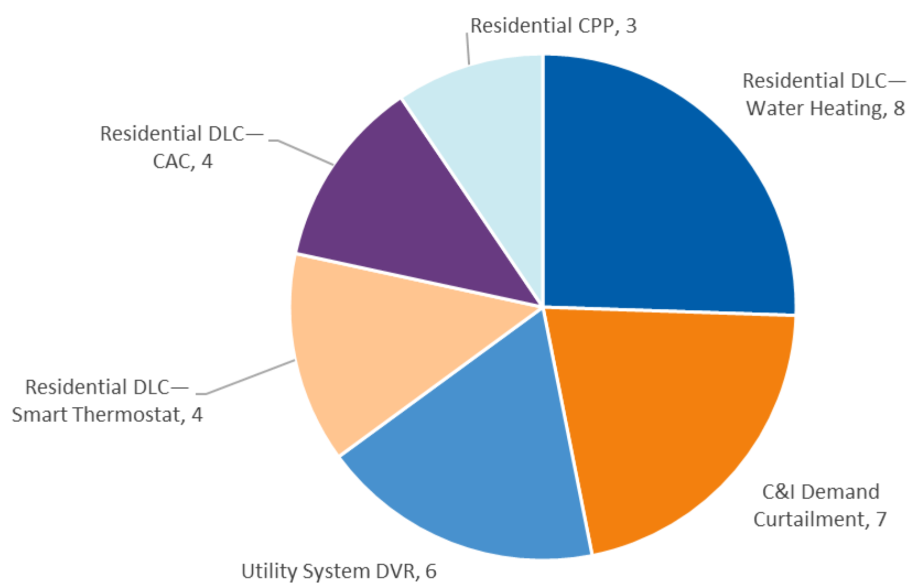


Table B-8 presents the achievable DR potential by product in Olympic Peninsula during winter and summer. Utility System DVR—the product with the greatest winter achievable potential—represents 1.8% of Olympic Peninsula winter demand. Residential DLC—Water Heating—the product with the greatest summer achievable potential—represents 2.3% of Olympic Peninsula summer demand.

Table B-8. Olympic Peninsula 2026 Achievable Potential Summary

Product	Winter Achievable Potential (MW)	Percent of Area Demand – Winter	Summer Achievable Potential (MW)	Percent of Area Demand – Summer
Residential DLC—Space Heating	6	0.9%	0	0.0%
Residential DLC—Water Heating	11	1.6%	8	2.1%
Residential DLC—CAC	0	0.0%	4	1.0%
Residential DLC—Smart Thermostat	8	1.3%	4	1.1%
Residential CPP	9	1.3%	3	0.8%
Residential Behavioral DR	2	0.3%	1	0.2%
Commercial DLC—CAC	0	0.0%	3	0.8%
Commercial Lighting Controls	2	0.2%	2	0.5%
Commercial Thermal Storage	0	0.0%	< 1	0.1%
C&I Demand Curtailment	6	0.9%	7	1.7%
C&I Interruptible Tariff	2	0.3%	2	0.6%
Industrial RTP	< 1	<0.1%	< 1	<0.1%
Agricultural Irrigation DLC	0	0.0%	0	0.0%
Utility System DVR	11	1.6%	6	1.5%
Total	**57**	**8.6%**	**40**	**10.3%**

7.2.6. S&SE Idaho and NW Wyoming

S&SE Idaho & NW Wyoming is a geographic area that encompasses BPA public power utilities and federal irrigation districts in south and southeast Idaho and northwest Wyoming. It has the smallest winter peak and second-smallest summer peak out of the six geographic areas. Its total winter and summer achievable DR potentials are 45 MW and 68 MW, representing 8.1% and 12.0% of its winter and summer area demand, respectively.

Figure B-13 and Figure B-14 show the achievable potential for the top six DR products in the S&SE Idaho & NW Wyoming in winter and summer, respectively. The product with the greatest winter achievable potential (11 MW) for the S&SE Idaho & NW Wyoming area is Residential Water Heating. Compared with the other geographical areas, the saturation of electric residential space heating is much lower. In the summer, Irrigation DLC presents the greatest achievable potential (30 MW) for the S&SE Idaho & NW Wyoming.

Figure B-13. S&SE Idaho & NW Wyoming 2026 Achievable DR Potential, Winter, Top Six Products

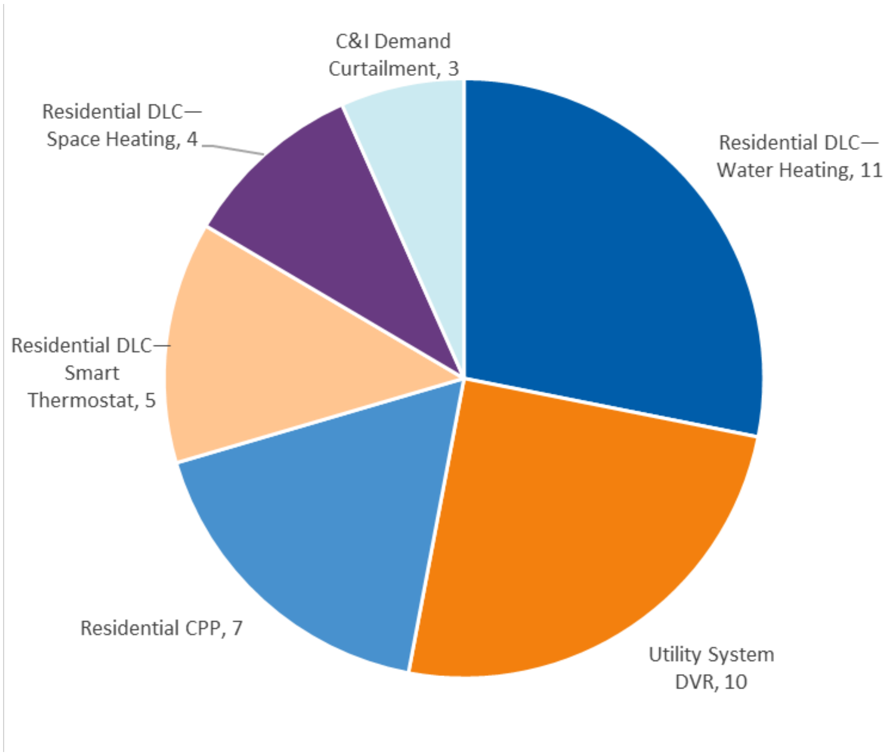


Figure B-14. S&SE Idaho & NW Wyoming 2026 Achievable Demand Response Potential, Summer Top 6

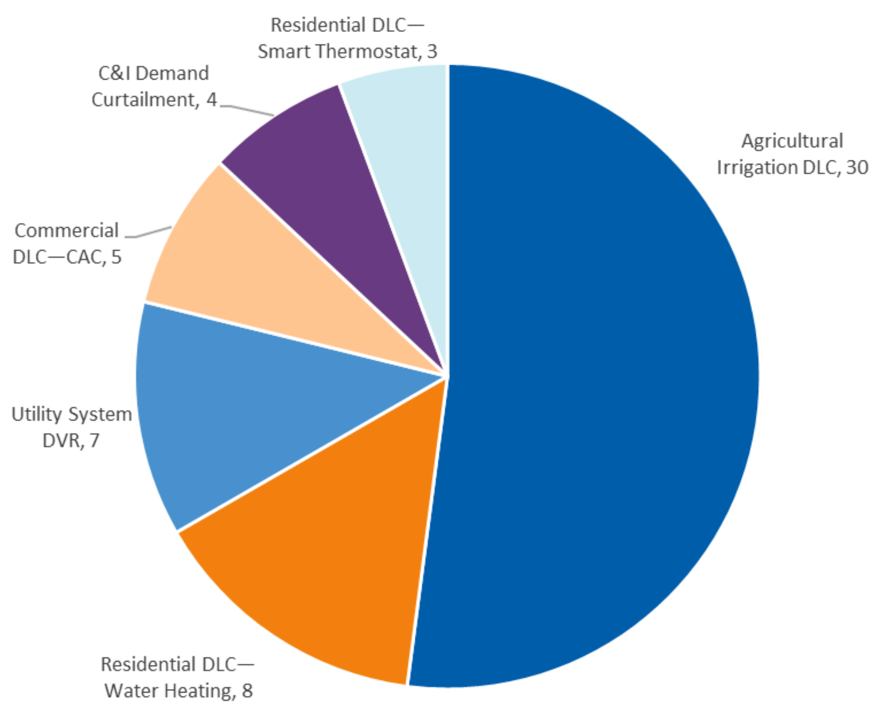


Table B-9 presents the achievable DR potential by product in S&SE Idaho & NW Wyoming during winter and summer. Residential Water Heating—the product with the greatest winter achievable potential—represents 2.0% of S&SE Idaho & NW Wyoming area demand. Irrigation DLC—the product with the greatest summer achievable potential—represents 5.3% of S&SE Idaho & NW Wyoming area demand.

Table B-9. S&SE Idaho & NW Wyoming 2026 Achievable Potential Summary

Product	Winter Achievable Potential (MW)	Percent of Area Demand—Winter	Summer Achievable Potential (MW)	Percent of Area Demand—Summer
Residential DLC—Space Heating	4	0.7%	0	0.0%
Residential DLC—Water Heating	11	2.0%	8	1.5%
Residential DLC—CAC	0	0.0%	3	0.5%
Residential DLC—Smart Thermostat	5	0.9%	3	0.6%
Residential CPP	7	1.3%	2	0.4%
Residential Behavioral DR	2	0.3%	1	0.1%
Commercial DLC—CAC	0	0.0%	5	0.8%
Commercial Lighting Controls	2	0.4%	3	0.5%
Commercial Thermal Storage	0	0.0%	1	0.1%
C&I Demand Curtailment	3	0.5%	4	0.7%
C&I Interruptible Tariff	1	0.2%	1	0.3%
Industrial RTP	0	0.0%	0	0.0%
Agricultural Irrigation DLC	0	0.0%	30	5.3%
Utility System DVR	10	1.8%	7	1.2%
Total	**45**	**8.1%**	**68**	**12.0%**

7.2.7. Utilities by Geographic Area

The following tables provide the list of BPA Power public power utilities and customers and the federal irrigation districts served with federal power by geographic area. In some instances, only a portion of the listed utility's load might be in the geographic area; these small exceptions were ignored in the generalized analysis.

Table B-10. BPA Public Power Utilities and Federal Irrigation Districts, South of Allston

South of Allston—Utility Names
City of Ashland
City of Bandon
Blachly-Lane Electric Cooperative
Canby Utility Board
City of Cascade Locks
Central Electric Cooperative
Central Lincoln People's Utility District
Clark Public Utilities
Clatskanie People's Utility District
Columbia Basin Electric Cooperative
Columbia Power Cooperative Association

South of Allston—Utility Names
Columbia River People's Utility District
Consumers Power Inc.
Coos-Curry Electric Cooperative
The Dalles Irrigation District
Douglas Electric Cooperative
City of Drain
Emerald People's Utility District
Eugene Water & Electric Board
City of Forest Grove
City of Hermiston (Hermiston Energy Services)
Hood River Electric Cooperative
PUD No. 1 of Klickitat County
Lane Electric Cooperative
City of McMinnville
Midstate Electric Cooperative
City of Monmouth
US DOE National Energy Technology Laboratory
Northern Wasco County People's Utility District
Ochoco (Crooked River) Irrigation District
Oregon Trail Electric Consumers Cooperative
Springfield Utility Board
Salem Electric
PUD No. 1 of Skamania County
Tualatin Valley Irrigation District
Tillamook People's Utility District
Umatilla Electric Cooperative
Umpqua Indian Utility Cooperative
Wasco Electric Cooperative
West Oregon Electric Cooperative
PUD No. 1 of Benton County
Benton Rural Electric Association
Columbia Rural Electric Association
East Columbia Basin Irrigation District
Energy Northwest
PUD No. 1 of Franklin County
City of Milton-Freewater
Quincy Columbia Basin Irrigation District
City of Richland
Roza Irrigation District
South Columbia Basin Irrigation District
US DOE Richland Operations Office (Hanford Site)

Table B-11. BPA Public Power Utilities, Puget Sound

Puget Sound—Utility Names

Puget Sound—Utility Names
Alder Mutual Light Company
Town of Eatonville
Elmhurst Mutual Power & Light Co.
Lakeview Light & Power Company
City of Milton
Ohop Mutual Light Company
Parkland Light & Water Company
Peninsula Light Company
Port of Seattle, Seattle-Tacoma Int'l Airport
Town of Steilacoom
City of Seattle (Seattle City Light)
PUD No. 1 of Snohomish County
Tacoma Power
Tanner Electric Cooperative
US Navy, Naval Station Everett, Radio Station Jim Creek

Table B-12. BPA Public Power Utilities and Federal Irrigation Districts, Central Oregon

Central Oregon—Utility Names
Central Electric Cooperative
Columbia Basin Electric Cooperative
Columbia Power Cooperative Association
The Dalles Irrigation District
City of Hermiston (Hermiston Energy Services)
Hood River Electric Cooperative
Midstate Electric Cooperative
Northern Wasco County People's Utility District
Ochoco (Crooked River) Irrigation District
Oregon Trail Electric Consumers Cooperative
Umatilla Electric Cooperative
Wasco Electric Cooperative

Table B-13. BPA Public Power Utilities and Federal Irrigation Districts, Tri-Cities

Tri-Cities Area—Utility Names
PUD No. 1 of Benton County
Benton Rural Electric Association
Columbia Rural Electric Association
East Columbia Basin Irrigation District
Energy Northwest
PUD No. 1 of Franklin County
City of Milton-Freewater
Quincy Columbia Basin Irrigation District
City of Richland
Roza Irrigation District

Tri-Cities Area—Utility Names
South Columbia Basin Irrigation District
US DOE Richland Operations Office (Hanford Site)

Table B-14. BPA Public Power Utilities, Olympic Peninsula

Olympic Peninsula—Utility Names
PUD No. 1 of Clallam County
PUD No. 1 of Jefferson County
PUD No. 1 of Mason County
PUD No. 3 of Mason County
City of Port Angeles
Port Townsend Paper Co.
US Navy, Naval Base Kitsap, Sub Base Bangor
US Navy, Naval Base Kitsap, Bremerton

Table B-15. BPA Public Power Utilities and Federal Irrigation Districts, S&SE Idaho and NW Wyoming

S&SE Idaho and NW Wyoming—Utility Names
A&B Irrigation District
City of Albion
Black Canyon Irrigation District
Burley Irrigation District
City of Burley
City of Declo
East End Mutual Electric Company
Emmett Irrigation District
Fall River Rural Electric Cooperative
Falls Irrigation District
Farmers Electric Company
Fort Hall BIA Irrigation District
City of Heyburn
City of Idaho Falls (Idaho Falls Power)
Lost River Electric Cooperative
Lower Valley Energy Inc.
Milner Irrigation District
City of Minidoka
Minidoka Irrigation District
Owyhee Ditch Irrigation District
Owyhee Irrigation District
Raft River Rural Electric Cooperative
Riverside Electric Company
City of Rupert
City of Soda Springs
South Board of Control Irrigation District
South Side Electric Lines Inc.

S&SE Idaho and NW Wyoming—Utility Names
Salmon River Electric Cooperative
United Electric Cooperative

8. Appendix C. 1-in-10 Weather Scenario

This scenario provides estimates of the potential for demand response (DR) resources within Bonneville Power Administration's (BPA) public power utility customer service territory under an extreme 1-in-10 weather scenario. Whereas the previous analyses completed in this study correspond to average (1-in-2) weather conditions, the analysis in this section assumes a weather forecast that is colder in winter months and warmer in summer months, and which in turn leads to increased weather-sensitive loads. BPA provided Cadmus systemwide load forecast adders for each hour in the 20-year forecast.

With this information, Cadmus summarized the weather adders for the same BPA system peak metrics for summer (August 16–31) and winter (February 1–28) used in the primary analysis. The system peak used for BPA Power planning (Capacity Resource Adequacy) purposes was defined as the highest 18-hours of loads occurring in two three-hour peak periods per day for three consecutive days. This planning metric mimicked a summer heat wave or winter cold snap. Note that this analysis uses BPA Power planning's system peak metric and weather adders; therefore, the results may not be directly applicable to BPA Transmission planning purposes.[22]

Cadmus did not model all products in the 1-in-10 weather scenario because not all products apply specifically to single end uses or to single end uses that are weather-sensitive. For this scenario, Cadmus chose to include direct load control (DLC) products in the residential and small and medium commercial sectors because each product corresponds to a discrete, weather-sensitive end use, as well as C&I Demand Curtailment and Utility System DVR.

The DR products considered in this analysis are these:

1. Residential DLC – Space Heating (winter)
2. Residential DLC – Water Heating (winter and summer)
3. Residential DLC – Smart Thermostats (winter and summer)
4. Residential DLC – Central Air Conditioning (CAC) (summer)
5. Commercial Small and Medium DLC – CAC (summer)
6. C&I Demand Curtailment (winter and summer)
7. Utility System DVR (winter and summer)

For each of these products, Cadmus developed a simplified scalar to be used as a proxy for the increase in diversified load corresponding to either extreme winter or summer temperatures. Scalars were developed for each season's (winter and summer) modeled peak for each year of the study. Base-case per-unit impacts were multiplied by the scalar to develop the 1-in-10 weather impacts for each of the five weather-sensitive products listed above.

[22] The BPA Power system peak (based on the 18-hour capacity peak definition) is lower than BPA Transmission system peak.

The ratio of extreme (1-in-10) to normal (1-in-2) weather determined each season/year combination's unique scalar that was applied to each product's per unit impact. In the winter, the scalar ranged from 1.0157 to 1.0288. The summer scalar ranged from 1.0102 to 1.0178, which is smaller in both relative magnitude and as a range than for winter.

Figure C-1 provides a comparison of the normal weather forecast with the extreme weather forecast from 2017 to 2036. In percentage terms, the annual energy forecast for the extreme weather forecast is higher than the normal weather forecast by a range of 0.79% to 0.91%.

Figure C-1. 1-in 10 Weather Scenario Forecast

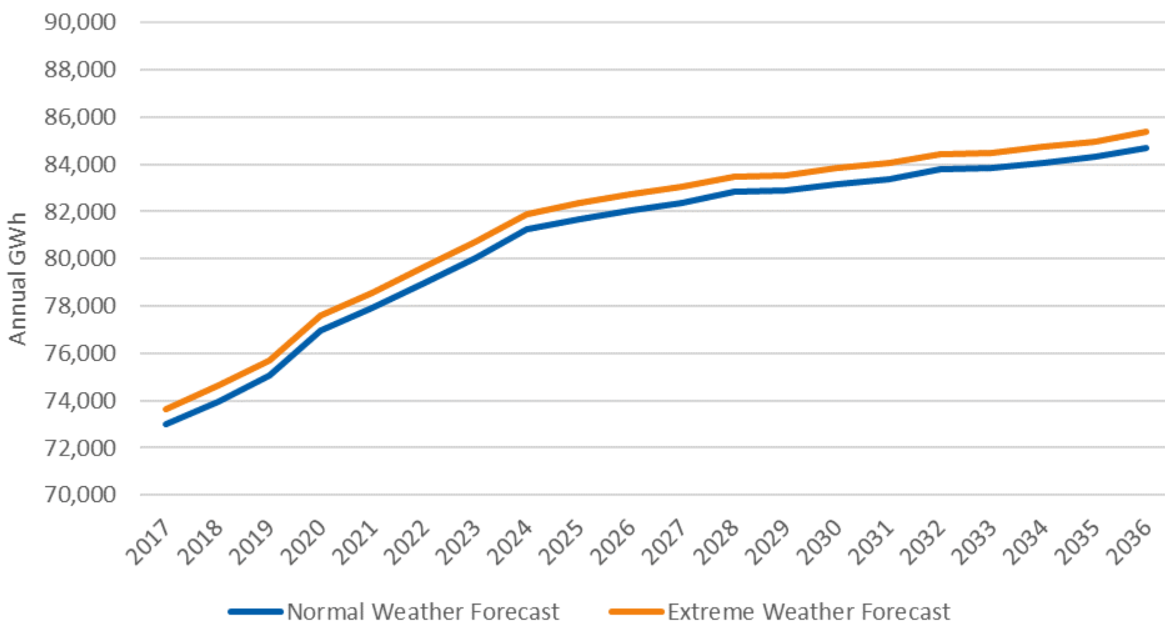


Table C-1 displays the overall results for each product in the 1-in-10 weather scenario. This scenario included only the residential and small and medium commercial DLC products for which the overall potential increased modestly by 10 MW compared with the base case normal weather scenario. Each of these five products incurred modest decreases in levelized cost compared with the normal weather scenario.

Table C-1. 1-in-10 Weather Scenario Results Summary

Product	Winter Achievable Potential (MW)	Percent of Area System Peak - Winter	Levelized Cost ($/kW-year) - Winter	Summer Achievable Potential (MW)	Percent of Area System Peak - Summer	Levelized Cost ($/kW-year) - Summer
Residential DLC—Space Heating	211	1.3%	$52	0	0.0%	N/A
Residential DLC—Water Heating	398	2.5%	$119	289	2.2%	$164
Residential DLC—CAC	0	0.0%	N/A	114	0.9%	$73
Residential DLC—Smart Thermostat	227	1.4%	$46	121	0.9%	$87
Residential CPP	168	1.1%	$10	57	0.4%	$12
Residential Behavioral DR	37	0.2%	$110	13	0.1%	$111
Commercial DLC—CAC	0	0.0%	N/A	111	0.8%	$29
Commercial Lighting Controls	44	0.3%	$32	55	0.4%	$32
Commercial Thermal Storage	0	0.0%	N/A	9	0.1%	$51
C&I Demand Curtailment	188	1.2%	$85	208	1.6%	$85
C&I Interruptible Tariff	62	0.4%	$73	69	0.5%	$73
Industrial RTP	5	0.0%	$35	5	0.0%	$34
Agricultural Irrigation DLC	0	0.0%	N/A	420	3.1%	$44
Utility System DVR	231	1.5%	$11	133	1.0%	$12
Total	**1,571**	**10.0%**		**1,607**	**12.0%**	

Figure C-2 shows the achievable DR potential supply curve for the winter season, with levelized costs, for the extreme (1-in-10) weather scenario.

Figure C-2. 1-in-10 Weather Scenario, Achievable DR Supply Curve, Winter, with Levelized Costs

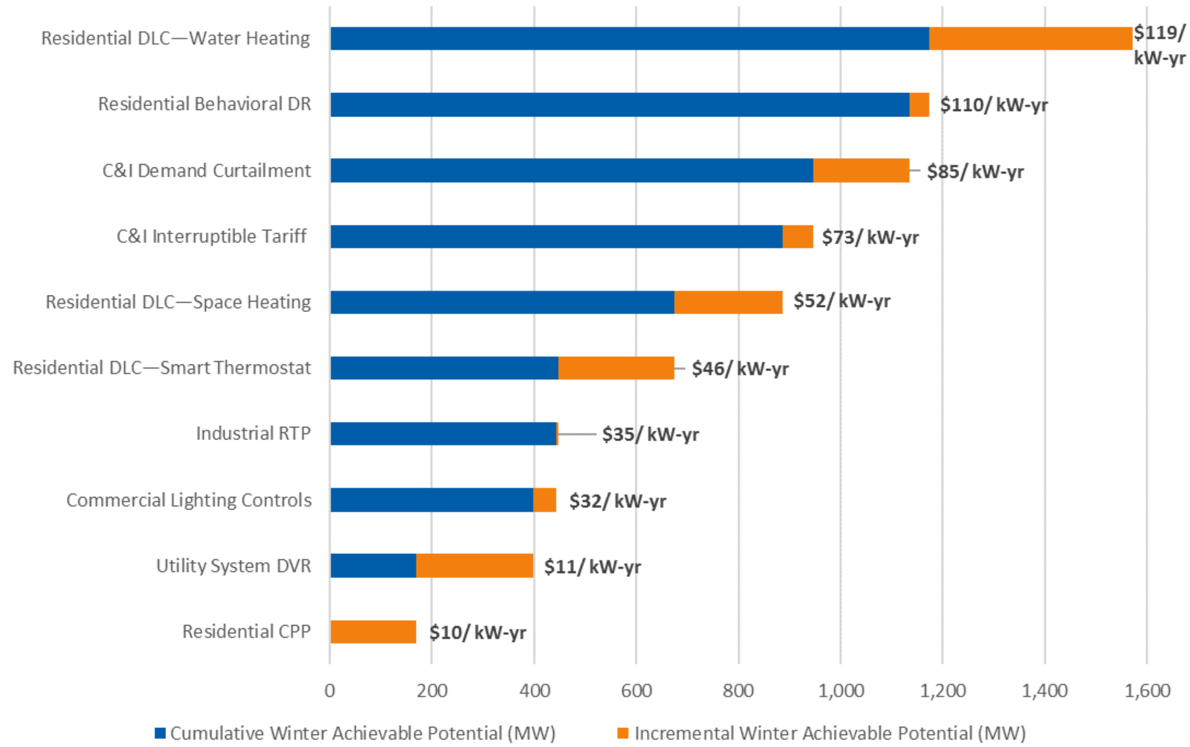
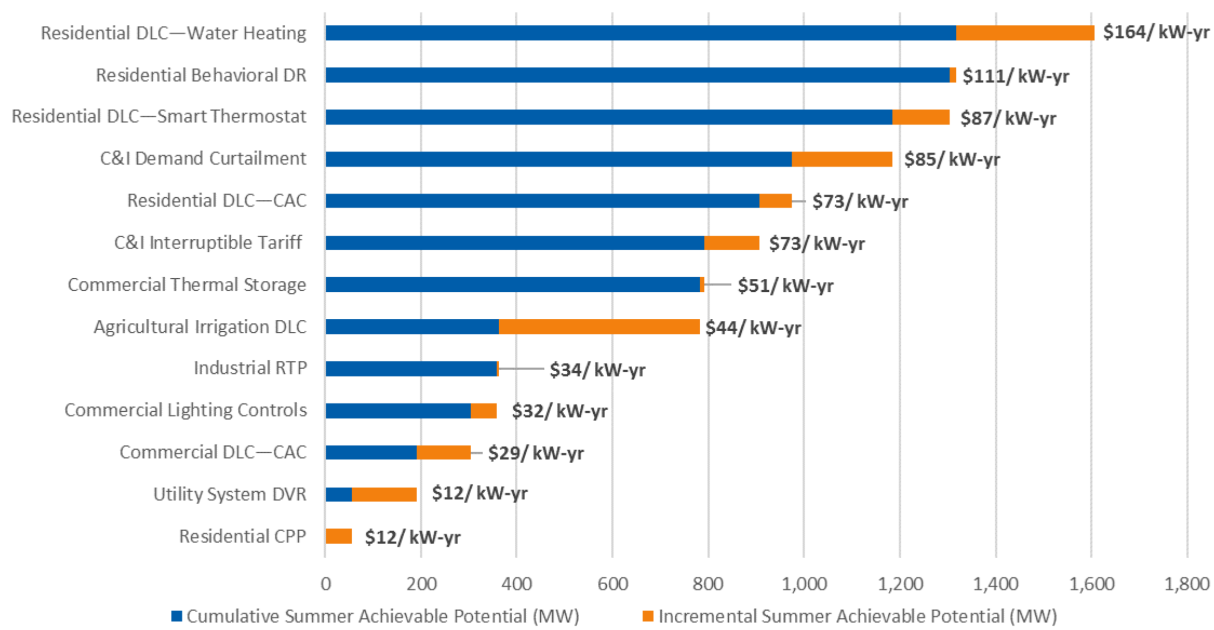


Figure C-3 shows the achievable DR potential supply curve for the summer season, with levelized costs, for the extreme (1-in-10) weather scenario.

Figure C-3. 1-in-10 Weather Scenario, Achievable DR Supply Curve, Summer, with Levelized Costs



These results contrast the Power planning 18-hour peak periods during 1:2 and 1:10 conditions, which do not vary as greatly over 18-hour peak periods as they do for individual monthly hourly peaks. These results would likely be different if analyzed against single hour monthly average and extreme peaks, which is the planning framework used by BPA Transmission. Therefore, these results should not be assumed to represent how different DR Products might perform under Transmission planning 1:2 and 1:10 peaks. It is likely that, for Transmission planning, the additional megawatts produced by the DR products would be much greater under 1:10 weather conditions than these results which are based on BPA Power planning criteria.

9. Appendix D. Distributed Generation

9.1. Scope and Methods

As part of Assessment 1, Cadmus evaluated the technical and achievable potential and estimated costs for solar photovoltaics (PV), combined heat and power (CHP), and standby generation technologies for DG potential within BPA's customer utility service area.

At BPA's request, Cadmus estimated the potential of the following renewable and non-renewable CHP DG technologies:

- **Solar PV:** community- and customer-sited solar PV and any utility-planned PV projects.
- **Non-renewable, natural gas CHPs**: reciprocating engines, micro-turbines, and small gas turbines.
- **Renewable CHPs**: anaerobic digester gas generators and industrial biomass.
- **Standby generation:** synchronous generators, diesel and natural gas.

9.1.1. Distributed Generation

Distributed generation (DG) refers to a broad set of small-scale technologies that produce electricity close to the power system's end users. These technologies often consist of modular, small-scale generators that yield capacities ranging from a fraction of a kilowatt to several megawatts and may include site-specific renewable energy technologies (e.g., wind turbines, geothermal energy production, solar systems, some hydrothermal plants). This assessment includes CHP, standby generation, and solar PV applications.

Though the assessment includes an estimate of technical potential for large-scale solar PV within BPA's Power customer service territory, the data necessary to estimate achievable potential for BPA's many small customer utilities (e.g., hosting capacity) remains unavailable.

Nevertheless, the assessment found that substantial achievable potential exists for solar PV and CHP applications. For behind-the-meter (BTM) solar PV, connected at residences and businesses within BPA's territory, Cadmus anticipates total potential of 486 MW over the study period. Though most of this potential will likely be roof-mounted, the assessment includes some BTM, ground-mounted PV systems. In addition to the business-as-usual market scenario, Cadmus analyzed scenarios involving extensions of known incentive programs, noting that changes in local incentives could have nearly a fivefold impact on the PV potential in BPA's service area.

Dispatchable standby generation (DSG) also appears to offer significant opportunities, with an achievable potential of 520 MW across approximately 290 of BPA's service area's most significant facilities (e.g., hospitals, schools). Though contributing at a modest magnitude, DSG technology offers utilities a high degree of control and dispatchability, which may help balance more intermittent loads and resources.

Finally, CHP offers the greatest DG potential: 3,437 MW in achievable potential by 2036 across BPA's service area. At present, the majority of that potential appears to fall within the 1 MW to 5 MW natural gas-fueled category, though renewable fuels may offer a notable contribution to this total.

9.1.2. Identify Secondary Data, Sectors, and Market Segments

As a first step, Cadmus assessed DG potential by identifying appropriate secondary data sources and applicable sectors and market segments. For each DG technology, Cadmus established a hierarchy of data types, applying these to sources used for estimating technical and achievable potential, installation and levelized costs, and applicable sectors and market segments.

Cadmus used the following secondary data sources to estimate DG's potentials and costs:

- BPA-DG pilot program evaluations and reports
- DG pilot and program evaluations from Northwest utilities (prioritizing public power utilities)
- Reputable industry and public agency publications
- Pilot and program evaluations conducted in climates akin to BPA's service area (e.g., Canada, the Midwest, California)
- Other pilot and program evaluations from North American utilities

Ultimately, Cadmus considered each specific data source in the context of data quality, local applicability, vintage, and freedom from bias. Table D-1 lists DG technologies, their groups, and applicable sectors and segments.

Table D-1. Applicable Distributed Generation Sectors and Segments

Technology	Technology Group	Sectors	Segments
Solar PV	Roof Mounted	Residential, Commercial, Institutional	Seventh Power Plan segments for each sector (e.g., single-family; high-, mid-, and low-rise multifamily for residential; all commercial building types).
	Ground Mounted	Residential, Commercial, Institutional, Community Solar, Utility	Based on land use.
CHP	Non-Renewable, Natural Gas	Commercial, Industrial, Utility	All commercial and industrial building types, utility.
	Renewable CHP	Industrial, Agricultural	Wastewater treatment plants, landfills, large dairy farms.
Distributed Standby Generation	Backup Diesel and Natural Gas Generation	Commercial, Industrial, Utility	Those with customers > 500 kW.

Cadmus worked with the DER team to determine the final list of applicable sectors and segments for estimating distributed energy potential.

9.2. Solar PV Methodology

9.2.1. Solar PV Technical Potential

Solar PV's technical potential depends on available areas suitable for PV installation and the power density of increasingly efficient PV arrays. Cadmus assessed these factors using the methods that follow.

Available Area for Roof-Mounted Solar. To estimate available roof areas for solar PV within BPA's public power utility customer service area, Cadmus reviewed the availability of Light Distance and Ranging (LIDAR) data to profile roof areas for solar applications. LIDAR provides a cost-effective summary of available roof areas within defined categories for slope, orientation, and the solar resource. For this study, Cadmus found extremely limited LIDAR data available, primarily for more populous cities. Rural areas offered little or no available LIDAR data.

To address this data shortage, Cadmus conducted a literature review, identifying recent research from the National Renewable Energy Laboratory (NREL) that combines LIDAR and building stock data to provide a statistical breakdown of roof types and key characteristics. Working with available data and research from this previous NREL study, and incorporating these with updates based on BPA-specific building stock data, Cadmus could determine the available roof area for each segment.

Available Area for Ground-Mounted Solar. To estimate technical potential for community solar and utility-owned solar, Cadmus focused on ground-mounted installations, employing an approach based on geospatial analysis.

Considering data from solar resources, environmental constraints, soil types, and other factors, Cadmus found an initial indication of how favorable site characteristics for renewable energy systems might coincide with identified locations. As Cadmus has used similar analyses to identify promising sites for renewable energy projects at a variety of locations, the team was familiar with the available data and relevant analysis methods. Cadmus narrowed land areas suited to solar development by identifying areas of low, south-facing slopes with minimal land cover. Applying exclusionary criteria removed land areas with environmental precautions, safety concerns, or potentially high-cost barriers (e.g., wetlands requiring special construction permits).

In addition, Cadmus applied regional community solar regulations to targeted areas of interest to identify spatial considerations (e.g., minimum parcel size, interconnection requirements). For this study's purposes, community solar refers to large solar projects that can allocate electricity generation to multiple customer accounts. Sometimes called "solar gardens," this means residential, commercial, and industrial customers can purchase a share of the generation and credit that generation to their accounts, even though the actual PV installation may be miles from their home or facility. The primary requirement for such projects, in addition to the usual infrastructure and hosting capacity considerations, is virtual or remote net metering regulation. This net metering rule serves as the mechanism that allows customers to claim bill credits for electricity generated remotely from their load and utility meters. Cadmus then developed a map of high-potential land areas, incorporating differing criteria concentrations to identify a usable range of land characteristics for solar PV development.

Table D-2 shows some relevant datasets and screening criteria employed in the analysis. For the residential sector, Cadmus drew upon the percentage of installed ground-mounted residential systems, as shown in Lawrence Berkeley National Laboratory data. The residential ground-mounted potential, plus the rooftop potential, determined the total residential technical potential.

Table D-2. Relevant Data Sets for Determining Available Area for Community Solar

Criteria	Suggested Threshold (If Known and Applicable)	Example Data Sources
Availability of solar resource	N/A	National Solar Radiation Database from NREL
Availability of vacant land	Clear of vegetation (trees, shrubbery, grasses)	Global Land Cover 2000
Land cover	Low brush or grasslands (if no clear land available)	Landsat Imagery
Soil type	Avoid cobble, gravel, and silt	U.S. Department of Agriculture Soil Survey
Proximity to watersheds	Varies based on protected status	U.S. Fish & Wildlife Service National Wetlands Inventory
Elevation—aspect	Within 60 degrees of due south	U.S. Geographical Survey (USGS) Digital Elevation Model
Elevation—slope	< 35 degrees	USGS Digital Elevation Model
Proximity to airports (exclusionary)	Varies based on airport approach vectors	Open Flights Database
Environmentally Protected Lands (exclusionary)	IUCN protected areas in undefined or VI categories	Protected Areas Database—United States (PAD-US) from USGS

Utility Planned PV Projects. Cadmus conducted interviews with utility personnel to determine planned development of utility-owned PV facilities. In addition, Cadmus determined key criteria for utility consideration of future projects (e.g., minimum capacity, willingness to consider PV as a means of addressing capacity constraints). Where applicable, Cadmus applied these factors to the above-described geospatial analysis to identify relevant parcels likely to meet utility requirements. (For example, utility-owned systems tended to be larger than other system types considered in this study, so the upper end of the parcel size range may be devoted to utility-owned rather than community solar.)

Power Density. After determining the available area for PV installation, Cadmus determined how much power could be generated on a per-unit area basis. With constant improvements in PV cell and module efficiency, power densities will likely increase by at least 20% or more over the assessment period.

Electricity Generation. PV direct current capacity is a product of available roof area and power density. Cadmus converted PV capacity (kW) into annualized electricity (kWh) generation using industry-standard modeling software (e.g., NREL's System Advisor Model), providing an hourly generation profile that Cadmus could use for annual and peak generation calculations. Though this method poorly reflected a single PV project's expected annual generation, it provided a reasonable approximation of PV system design mixes currently operating within BPA customer utilities' service territories.

9.2.2. Solar PV Achievable Potential

After calculating the technical potential (i.e., providing a likely upper bound on PV capacity growth), Cadmus considered relevant market factors (e.g., current costs, projected future cost trends, past adoption) to determine likely PV growth for customer utilities' service territories. Cadmus used the utilities' interviews to gather information on the likelihood of program changes. Data provided on 20-year infrastructure plans indicated the potential and scope of utility-scale projects over the study period.

To assess achievable potential, Cadmus first examined sector, end-use load, and customer economics for PV within BPA's service area in terms of simple paybacks. Residential and commercial customer surveys provided data on payback requirements for solar PV projects. Cadmus applied these metrics to calculate achievable potential for multiple policy-based scenarios, considering the impacts of federal tax credits, incentives, and policies. For example, the examination included the following scenarios:

- **Business as Usual (BAU) Scenario:** This scenario reflects "business as usual," with all current policies and incentives locked in place as written, including incentive amounts, expiration dates, and similar characteristics. Though typically not the most realistic scenario, this can provide a strong baseline for considering policy alternatives and planning scenarios.
- **Extended Investment Tax Credit (ITC) Scenario:** This scenario shows the effects of extending just the ITC while other incentives (if any) remain the same as the BAU scenario.
- **Extended De-Escalating Incentive Scenario:** This scenario incorporates inputs from local stakeholders, gathered during the survey and interview processes, to identify the most likely policy changes occurring during the study period. Note: this scenario applies only to Washington and Oregon, which have (or are likely to have, based on stakeholder input) relevant incentives.
- **Best Case Scenario:** This scenario includes a likely but favorable mix of policies and models achievable potential based on assumed extensions, incentive levels, and favorable regulations.

Each scenario is described in greater detail in Section 9.3.7 below. In all cases, Cadmus worked closely with BPA and other relevant stakeholders to ensure each scenario was properly documented and aligned with expected policy and regulatory conditions during the study period.

Customer Payback. A metric commonly used in selling energy efficiency and renewable energy technologies, annualized simple payback (ASP) is a simplistic calculation that customers can easily and intuitively understand and provides a key factor in their financial decision-making processes. For this analysis, Cadmus calculated simple payback using the following equation:

$$ASP = \frac{Net\ Costs\ (after\ incentives)}{Annual\ Energy\ Cost\ Savings + Incentive\ program\ payments}$$

Though a conceptually simple equation, the mix of incentives and cost projections add complexity to the calculations:

- **Installed Costs.** Cadmus based these assumptions of installed PV system costs on a variety of public data sources, including a dataset from the Energy Trust of Oregon, tempered by Cadmus' extensive experience in working with distributed and community-based solar PV projects. In previous, similar analyses, Cadmus has drawn cost information from local incentive programs, online customer survey data, and from Lawrence Berkley National Laboratory's *Tracking the Sun* report. The report used a large dataset and robust analytical methods to estimate current (or very recent) installed costs by system capacity and general configuration. It also provided useful inputs for projecting future cost reductions. Cadmus cross-checked this report against projections published by Green Tech Media and the Solar Energy Industries Association.
- **Market Penetration Rates.** Predicting which portion of technically feasible sites will install PV systems during the assessment period is a complex process, driven by many policy, economic, and technical factors beyond the direct control of BPA's customer utilities. These factors can be effectively modeled using their impacts on a quantitative metric (such as customer simple paybacks) and run for a variety of prototypical scenarios.

This model estimates (a percentage of) market penetration as a function of customer payback. Prior to solar PV applications, many energy efficiency studies applied this approach, as it provided a convenient method for modeling a variety of policy and market scenarios (most of which influenced simple payback and the market penetration calculations). The following equation provided the curve used in analysis:

$$MP = A * e^{-B*ASP}$$

Where MP equals the percentage of market adoption, and ASP equals the annual simple payback in years.

For this analysis, Cadmus calculated ASP from the end-use customers' perspectives, including all relevant incentives and fitting the curve to historical adoption rates. For example, on previous projects, Cadmus has estimated (or reviewed documentation of) a previous year's installed system costs, comparing those costs to market penetration achieved during the same years. This curve-fitting process allowed Cadmus to account for, broadly speaking, regional attitudes and bias that might lead end-use customers to adopt solar at a given ASP level (the above equation shows these empirical factors as A and *B).*

For this assessment, Cadmus did not have the necessary information to estimate achievable potential for community solar or utility-owned solar projects. In many cases, the scale of these projects is comparable to the total load served by BPA's partner utilities, meaning that their development is not driven by the same customer-facing economics as BTM systems. Instead, their primary deployment constraints relate to the local utility's interconnection requirements, available hosting capacity, virtual net metering regulations (or lack thereof), and distribution infrastructure. As Cadmus did not receive these data, assessing achievable potential for such large projects falls beyond the current study's scope.

9.3. Solar PV Results

9.3.1. Solar PV Technical Potential

Based on the analysis described in the previous sections, Cadmus estimated 23,971 MW as the total new technical potential for PV installed as BTM on rooftop or ground-mounted systems in the BPA service area over 20 years. Seventy-four percent of this technical potential arose in the commercial sector, and 26% arose from the residential sector. Each sector's technical potential is a function of the fraction of total roof area available and the total roof area. In this case, the residential sector accounted for a smaller percentage of the technical potential because only a modest proportion of total available area for this sector is likely to be suitable for PV installations. If the full technical potential were installed, it would generate approximately 24,842,546 MWh annually. This estimate derives from a series of state-specific capacity factors, calculated using PVWatts, a solar PV yield estimation tool from NREL. Typical capacity factors across BPA's territory range from 0.12 to 0.20.

The full study period resulted in behind-the meter PV technical potential of 22,156 MW, with growth due to expected increases in building stock from 2017 to 2035. Table D-3 shows the solar PV rooftop technical potential for each state within BPA's service area.

Table D-3. New Behind-the-Meter Rooftop PV Technical Potential

	Total	Washington	Oregon	Idaho	Montana
Rooftop Technical Potential MW					
Residential	6,137	4,057	1,274	463	343
Commercial	16,019	10,503	3,509	819	1,188
Total	**22,156**	**14,560**	**4,783**	**1,282**	**1,531**

Based on the Energy Trust's dataset percentage of ground-mounted systems found in each sector, Cadmus estimated the BTM, ground-mounted potential portion of the overall technical potential, with 3.15% of residential sector and 10.12% of commercial installations ground-mounted. Table D-4 shows BTM ground-mounted solar PV technical potential.

Table D-4. New Behind-the-Meter Ground-Mounted Potential

	Total	Washington	Oregon	Idaho	Montana
Behind-the-Meter Ground-Mounted Technical Potential MW					
Residential	194	128	40	15	11
Commercial	1,621	1,063	355	83	120
Total	**1,815**	**1,191**	**395**	**97**	**131**

Note that this analysis treats ground-mounted arrays located at homes and businesses as a percentage of rooftop capacity, based on historical data from Oregon's solar electric program. Though states such as Idaho have ample open space, Cadmus assumed behind-the-meter, ground-mounted PV potential still relates to the number of homes and businesses; thus it is driven more heavily by population than by the raw land area available. Also, because BTM PV systems tend to be small, they can generally fit in a residential yard, over a commercial parking lot, or in similar locations, so available area does not limit deployment.

In addition to the potential for BTM roof-mounted and ground-mounted PV, Cadmus used geospatial analysis to estimate potential for utility-scale and community solar ground-mounted PV systems. This analysis assessed BPA's service area for land areas with low, south-facing slopes, high solar resources, environmental risks, and sparse vegetation or open land cover. Cadmus selected parcel sizes sufficient for 5 MW to 10 MW as a reasonable (though large) system capacity for most smaller BPA utilities. Such PV systems would be deployed to address specific load constraints or to take advantage of well-sited open spaces. Based on site constraints suitable for development (totaling approximately 14,000 square miles of suitable land), Cadmus estimates technical potential of 2,263 GW for community solar (1 MW to 5 MW installations) and 2,257 GW for utility-scale solar PV (5 MW to 10 MW installations).

For the purposes of calculating potential, Cadmus assumed a minimum parcel size of eight acres for community solar and a minimum parcel size of 40 acres for utility scale solar. Table D-5 displays technical potential and suitable land area, by state. Appendix B includes maps detailing suitable land areas by state and total solar resource for BPA's service area.

Table D-5. Technical Potential of Community and Utility Scale Solar PV per State

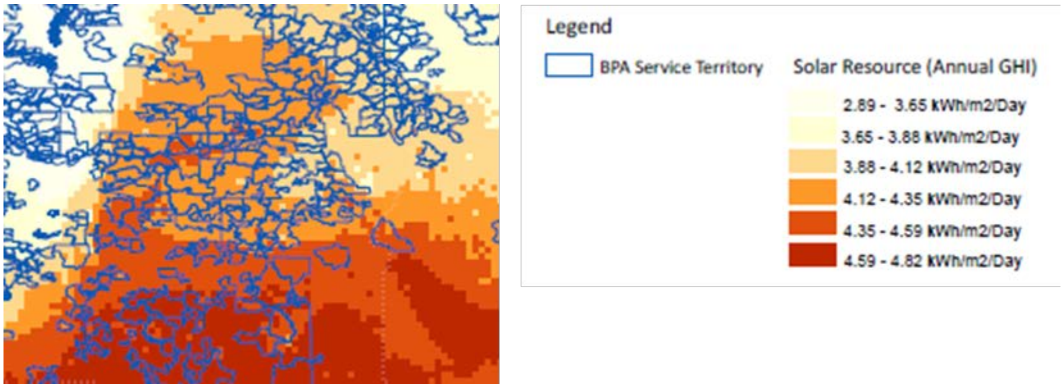
	Total[23]	Washington	Oregon	Idaho	Montana
Community Solar					
Suitable Area (mi^2)	14,146	3,758	5,801	1,731	2,856
Technical Potential (GW)	2,263	601	928	277	457
Utility Scale					
Suitable Area (mi^2)	14,104	3,746	5,790	1,723	2,845
Technical Potential (GW)	2,257	599	926	276	455

NREL solar resource data revealed high annual global horizontal irradiance (GHI) in the southern and central region of BPA's service area, largely concentrated in southern Oregon and Idaho. Cadmus determined suitable land as a region with an annual GHI of 3.65 kWh/square meter per day or higher.

Figure D-1 displays a selection of land in southwest Oregon and southeast Idaho where BPA's service area intersects with areas with high annual GHI. Cadmus used these regions as a platform for additional analysis of land characteristics aiding in optimal development of large solar PV installations.

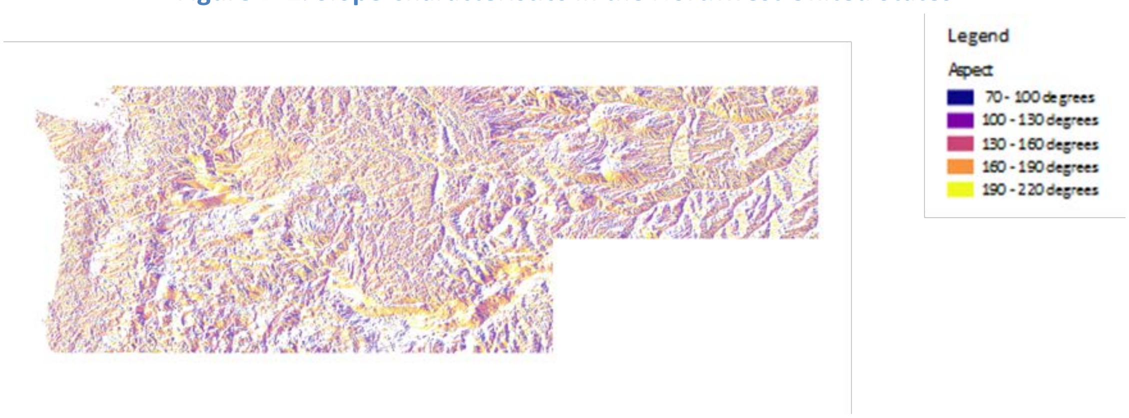
[23] Note that totals are not additive, separate totals are presented for community and utility scale projects but they are not additive.

Figure D-1. Select Regions of Solar Resource Analysis



High annual GHI regions could then be analyzed for large land areas with low, south-facing slopes. Areas with an aspect value between 70 and 220 degrees were considered south-facing; areas with a slope value of less than 20 degrees were considered low-slope. Figure D-2 shows Washington, Oregon, Idaho, and Montana lands with these slope and aspect characteristics.

Figure D-2. Slope Characteristics in the Northwest United States



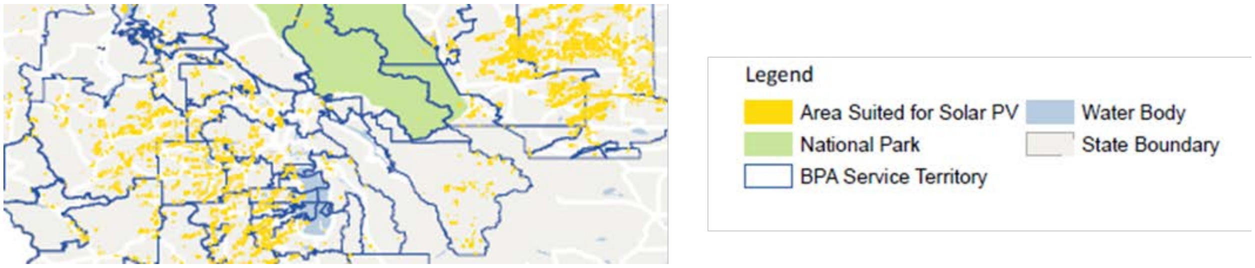
Cadmus pared down land regions with optimal slope and high solar resources by identifying select characteristics from the Global Land Cover 2000 Project (GLC2000)—a worldwide land cover database implemented the Global Vegetation Monitoring Unit, in collaboration with a network of partners across the globe. The database identified several land cover categories indicating clear or available land, optimal for large-scale development of solar PV, as shown in Table D-6.

Table D-6. Identified GLC2000 Categories

Global Land Cover 2000 Project Category	Definition
10	Tree cover, burnt
11	Shrub cover, closed-open, evergreen
12	Shrub cover, closed-open, deciduous
14	Sparse herbaceous or sparse shrub cover
19	Bare areas

Finally, Cadmus used a database of National Park and State Park boundaries to carve out regions with higher environmental regulations and protections than for lands not under the parks' database. Figure D-3 shows a select region of northwest Montana, where the intersection of high solar resources, low- and south-facing slopes, identified GLC2000 categories, and avoided environmentally regulated areas resulted in the total area identified as suitable for solar PV.

Figure D-3. Section of Montana Overlay Example



9.3.2. Solar PV Achievable Potential

Unsurprisingly, chosen policy and incentive scenarios heavily influence PV's achievable potential, a determination further complicated by differing markets, policies, and incentives found for each state within BPA's service area. In this section, Cadmus summarizes the chosen scenarios, with each case reviewed for the proposed scenarios against existing and known legislation, and vetting the resulting scenarios through a series of stakeholder interviews.

Note that this report does not include community- or utility-scale solar PV in estimations of overall achievable potential because the same economic metrics (e.g., simple payback) that drive adoption of BTM systems do not drive these larger project, which may be driven by locational pricing, load relief, public demonstrations, grid support, or other motivating factors not addressed by an economics-based adoption model. Notably, with many smaller customer utilities, Cadmus anticipates that interconnecting larger PV systems in quantity would require substantial infrastructure upgrades to increase the local hosting capacities in areas where suitable land is readily available. Cadmus included hosting capacity and existing and planned large projects in a data request, but those data proved unavailable for this assessment.

Given the very substantial technical potential available for such systems, conversion of even a small percentage of this technical potential would substantially increase the overall BPA service area's achievable potential. Given the case-by-case nature of developing projects at this scale, the lack of available data on utility-planned projects and the impact even a small adoption rate would have on overall potential, this study does not include any further estimates of the market potential for community and utility potential.

PV Policy and Incentive Scenarios

Historically, the PV market has been heavily influenced by policy and incentive decisions, but, over time, future incentives may play a lesser role. For example, projects continue to be completed in California, even though major incentives have ended, and more projects continue to be completed under the Federal Public Utility Regulatory Policies Act. To model the influence of these policy changes on the PV market potential within BPA's territory, Cadmus developed a series of scenarios reflecting the impact of policy changes on customer paybacks and, by extension, market potentials. As summarized below, Cadmus applied individually designed scenarios for each of the four states within BPA's territory.

Business-as-Usual Scenario (Washington)

Under the BAU scenario in Washington, Cadmus assumed that all existing policies and incentives would remain in effect, as currently written, without changes. This includes several key policies:

- Federal Investment Tax Credit: The ITC provides a 30% PV tax credit through 2019, with 26% in 2020, 22% in 2021, and expiring on January 31, 2021, for residential PV but reduced to 10% for commercial building PV.
- Washington State Sales Tax Exemption: Solar PV equipment was exempt from a 6.5% Washington State Sales Tax. This benefit expired on September 30, 2017.
- Washington State Renewable Energy System Cost Recovery Program (Production Incentive): The Production Incentive provides a variable, production-based incentive up to $5,000 per year for PV systems. The incentive level ranges from $0.15/kWh to $0.54/kWh, depending on the customer's eligibility for a variety of incentive adders (e.g., using equipment manufactured in Washington). This incentive is set to expire on June 30, 2020.
- A new Washington State incentive, starting on October 1, 2017, provides lower incentive levels, from $0.05/kWh to $0.21/kWh. The rates de-escalate each year until 2021, when new participation ends, with incentives covering a period of eight years. The incentive includes an adder for equipment manufactured in Washington and a limit of $5,000 per year for PV systems, but the commercial limit has been raised to $25,000. Commercial-size systems are limited to 25% of total funds available, ensuring that all sizes have a chance to benefit. A total program cap exists of $110 million over the course of the entire program. High uptake rates already realized through the program mean entry into the program in later years may be limited.
- Washington State Net Metering: Utilities in the state must offer net metering to systems with nameplate capacities up to 100 kW, subject to a systemwide cap set at 0.5% of peak 1996 loads. For modeling purposes, net metering is assumed to not constrain market potential.

Washington presents a unique case within BPA's service area because of its Cost Recovery Program (CRP) Incentive—a lucrative incentive not available in the other states within the region.

Business-as-Usual Scenario (Oregon)

In the BAU scenario in Oregon, Cadmus assumed all existing policies and incentives remain in effect, as currently written, without changes. This includes several key policies:

- Federal ITC: The ITC provides a 30% PV tax credit through 2019, 26% in 2020, 22% in 2021, and expiring on December 31, 2021, for residential but reduced to 10% for commercial.

- Oregon Residential Energy Tax Credits (RETC): The maximum RETC of $6,000 per site cannot exceed 50% of the project cost after the utility incentive. Generally, any system above 3.5 kW will max out the RETC and receive the full $6,000. The RETC can only be claimed at a maximum of $1,500 per year; the full amount can take up to four years to recover. To qualify for the RETC, a system must produce 75% or greater of the Total Solar Resource Fraction. Though homeowner installations can qualify, they must be verified by a tax credit-certified technician. Both grid-tied and off-grid solar systems are eligible to receive the RETC. This benefit expired on December 31, 2017.
- Oregon Utility Cash Incentives: These utility cash incentives vary from utility to utility and cannot be used in a scenario.
- Net Metering: For modeling purposes, net metering is assumed to not serve as a constraint on market potential.

Business-as-Usual Scenario (Idaho)

In the BAU scenario in Idaho, Cadmus assumes all existing policies and incentives remain in effect, as currently written, without changes. This includes several key policies:

- Federal ITC: The ITC provides a 30% PV tax credit through 2019, 26% in 2020, 22% in 2021; it expires on December 31, 2021, for residential, but reduces to 10% for commercial.
- Idaho law allows (residential) taxpayers an income tax deduction of 40% for the costs of solar energy devices used for heating or electricity generation. Taxpayers can apply this 40% deduction in the year that their system has been installed, and can deduct 20% of the cost each year for three years thereafter. The maximum deduction in any one year is $5,000, with a total maximum deduction of $20,000. This was not included in the scenario as it did not provide a significant incentive.
- Net Metering: No statewide net metering legislation has passed, but voluntary utility policies for net metering are assumed to not constrain market potential.

Business-as-Usual Scenario (Montana)

In the BAU Scenario in Montana, Cadmus assumed all existing policies and incentives remain in effect, as currently written, without changes. This includes several key policies:

- Federal ITC: The ITC provides a 30% PV tax credit for PV through 2019, 26% in 2020, 22% in 2021, and expires on December 31, 2021, for residential but reduces to 10% for commercial.
- Montana Renewable Alternative Energy System Tax Credit: Montana offers individuals investing in solar power an incentive to receive a $500 tax incentive ($1,000 for joint filings) for installation of a renewable energy system.
- Net Metering: For modeling purposes, net metering is assumed not to constrain market potential.

Extended ITC Scenario (All Markets)

In this scenario, Cadmus assumed all incentives and policies remain the same as the base scenario, except that the ITC extends through the study period at its current 30% rate. This is considered, however, quite unlikely.

Best Case Scenario (All Markets)

The best-case scenario reflects the most favorable policy options drawn from the other scenarios. It includes continuation of the ITC (at 30%) as well as the State Sales Tax Exemption through the end of the study period. The CRP incentive level ($/kwh), however, will continue to decline as outlined in the scenarios above (Washington only).

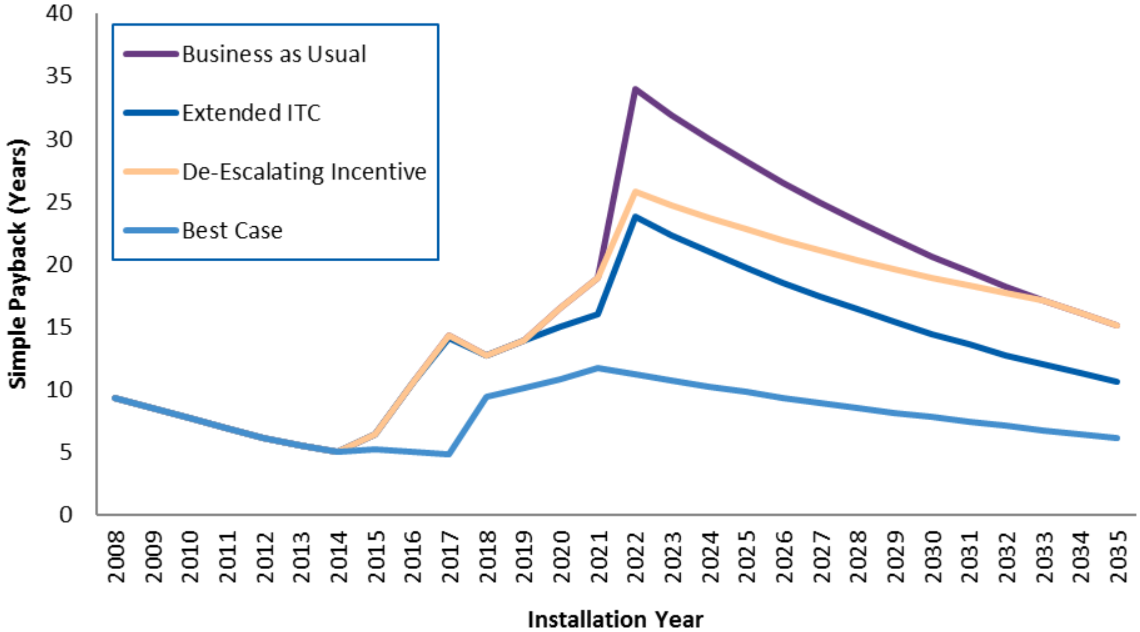
Results

Achievable potential for solar PV varies considerably by state and is heavily influenced by several key factors that drive customer economics:

- **Electricity Rates:** With the declining role of incentives, electricity bill savings are responsible for a growing share of the solar PV value proposition. With relatively low electricity rates for customers across BPA's service area, overall economics are not as attractive as in regions with higher rates. Moreover, variability occurs within BPA's service area, and states with higher rates tend to see more solar development during the study period.
- **Incentives:** Though Oregon and Washington historically have had generous incentives, the nearly simultaneous sunsetting of incentives in the next five years will have a dampening effect on market growth. Though overall solar PV costs continue to decline, much of that decline will be driven by demand in more lucrative markets, and the price decreases likely will not fully offset the relatively rapid decline of incentives. Several states, in fact, will see customer economics worsen by 30% to 50% across the years simply because incentives are expiring.
- **Productivity:** The Pacific Northwest does not rank among the most solar resource-rich regions of the United States, and this relatively low productivity for PV systems, combined with low electric rates and diminishing incentives, provides a third driver adversely affecting future PV adoption.

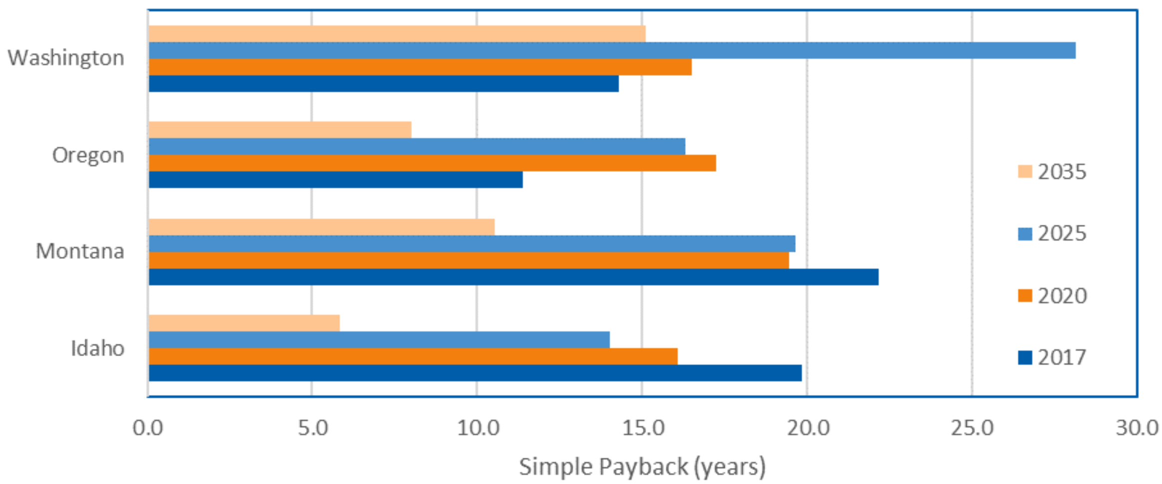
Figure D-4 shows the impact of these scenario choices on expected Washington customer paybacks (residential). The 2017 end of the former production incentive and the new incentive's impact in 2018 can be seen in the rise and fall of expected simple paybacks. The newer incentive is less generous than the previous incentive, and its payback period quickly rises. With ITC's rapid ramping down in the next few years, the payback period will exceed 30 years, despite falling PV costs over the study period. Under the best-case scenario, customers would likely achieve payback periods of less than five years by the end of the study period, but this would require several unlikely policy changes compared to the baseline scenario.

Figure D-4. Washington Residential PV Simple Payback Projections Under Four Policy Scenarios



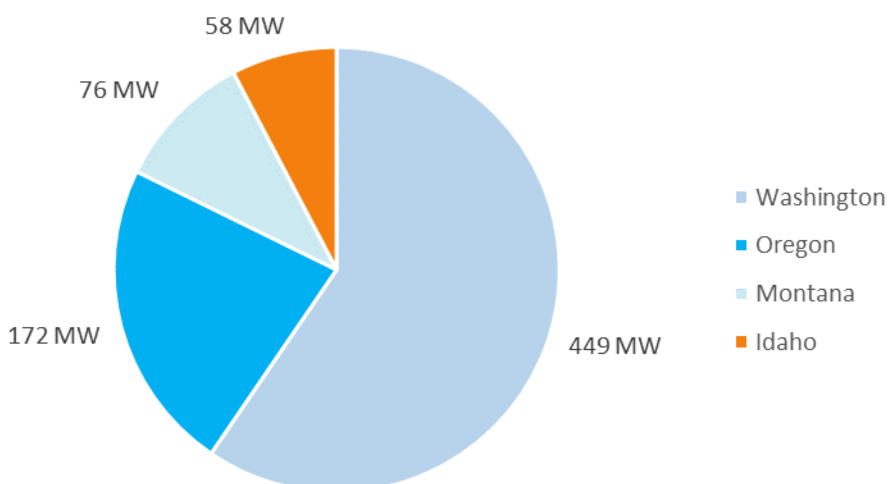
As shown in Figure D-5 for the de-escalating incentive scenario, the residential simple payback for PV systems varies considerably across states and time periods. Though Oregon and Washington initially are the most cost-effective states, once the relevant incentives are no longer in effect, the gap narrows, and other states become relatively attractive for customers seeking to install solar PV. Idaho, for example, becomes substantially more cost-effective over the study period. Though Idaho offers minimal incentives, the combination of falling installation costs, a higher-than-average rate of increase in electric rates, and comparatively strong solar resources causes Idaho to become cost-competitive for PV without any form of notable incentive. To an extent, falling installation costs and escalating electricity rates will improve the cost-effectiveness of PV in each state over the study period.

Figure D-5. Comparison of Residential Simple Payback Periods by State and Year for the De-Escalating Incentive Scenario



As shown in Figure D-6, areas with more attractive PV system economics not only serve as major adoption drivers; they also contribute more to PV's overall achievable potential. This is, however, largely based on initially low payback periods for customers in Washington and Oregon via the current incentives, with relatively modest contributions from Idaho and Montana (most of which occurs later in the study period as adoption rates increase with falling costs in Idaho and Montana).

Figure D-6. Business as Usual Case Achievable Potential by State



Overall, across BPA's service area, achievable potential will remain relatively flat under the BAU scenario, with increased adoption expected in the late 2020s as simple payback periods fall into a 15-year range due to falling solar PV costs, as shown in Figure D-4.

Figure D-7. Total, Cumulative Achievable Potential by Scenario, BTM Solar PV

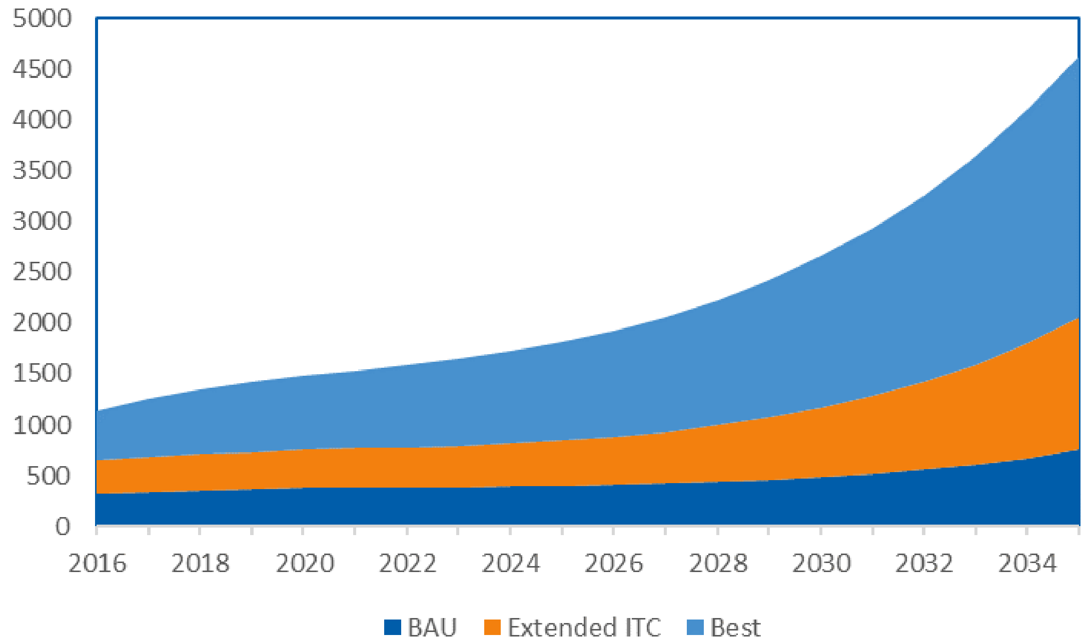


Table D-7 summarizes the market potential results for each scenario and state.

Table D-7. Achievable Potential of Behind-the-Meter Solar PV (MW)*

Scenario	Total	Washington	Oregon	Idaho	Montana
Business as Usual	**755**	449	172	58	76
Extended ITC	**1,300**	663	375	105	156
Best	**2,570**	1,799	510	105	156

*These estimates include rooftop and ground-mounted BAU PV potentials.

Notably, a mix of key incentives across the region have significantly affected past solar development; if continued, they would drastically increase the overall achievable potential. These key incentives include the following:

- Washington production (CRP) incentive
- Oregon Renewable Energy Tax Credit

This combination of incentives has served as a key driver of positive consumer economics, which have stimulated PV installations during the past few years. Continuing them would increase the size of the residential BPA service area's PV market nearly four-fold by the end of the study period. Termination of these incentives will cause PV installations to remain flat or increase only slightly.

Subsequent to completing this analysis, the U.S. has imposed a new tariff that will effectively add 30% to the cost of imported PV modules. It is important to note that, despite the similarity of the 30% tariff and the Investment Tax Credit, they are not comparable. The tariff applies only to module costs, which are a diminishing fraction of total system costs, while the tax credits apply to the total system cost. The tariff, while having some impact, remains small compared to the benefits of the Investment Tax Credit.

Though the majority of U.S. PV installations currently use imported modules, the overall industry trend of falling module and installation prices and the relatively short lifetime of the tariffs (four years, including a stepdown to 15%) means that this change will likely have a modest impact on overall regional potential. In addition, with much of the total regional potential occurring in Washington, where customers receive higher incentives for using locally manufactured modules, the overall regional impact may be even lower than average for other parts of the U.S.

9.4. Combined Heat and Power Methodology

Renewable and non-renewable, customer-sited CHP generation may not reduce a building's energy consumption or peak demand. Rather, it benefits the electric grid by reducing the amount of energy required from utility-owned resources. CHP systems generate electricity and use waste heat for thermal loads (such as space or water heating), and it can be used in buildings with coincident thermal and electric loads or in facilities with combustible biomass or biogas. CHP is often used as a peak reduction source, like DR, which is why it is analyzed in this report.

Natural gas-fueled CHP applications include college dormitories or hotels using waste heat to supplement a boiler, recreation centers using waste heat to warm a pool, or industrial facilities requiring heat for processing materials or for steam production. In examining renewable system potential, Cadmus focused on landfills, livestock farms, and wastewater treatment facilities.

The University of Oregon installed a 7,500 kW CHP system to provide backup power and building heating or cooling, should normal resources become unavailable. Through the Eugene Water and Electric Board (EWEB) which has been a leader in testing emerging distributed energy resources strategies, the university also has recently successfully tested the system during DR events in a DER aggregation demonstration project. This demonstration was sponsored by BPA Power and aggregated by Energy Northwest. The operations staff at the University of Oregon demonstrated that they can consistently run the system at its generation target within 30 minutes of receiving an event notification. This is just one example of how BPA has used CHP for peak reduction purposes.

9.4.1. CHP Technical Potential

CHP technical potential represents total electric generation, if installing all resources in all technically feasible applications. Technical potential assumes every end-use customer in BPA's customer utilities' service territories—if meeting CHP energy demand requirements—installs a system. This largely unrealizable potential should be considered a theoretical construct.

Cadmus assessed applicable, technical, and CHP potential for public, commercial, industrial, and agricultural sectors within BPA's customer utility service area. Traditionally, CHP systems have been installed in hospitals, schools, universities, military bases, and manufacturing facilities; they can be used, however, across nearly all commercial and industrial market segments with average monthly energy loads greater than approximately 30 kW, which encompasses nearly all C&I facilities.

CHP can be broadly divided into two subcategories, based on the fuels used:

- Non-renewable CHP, typically using natural gas
- Renewable systems using biologically derived fuel (biomass or biogas)

Cadmus analyzed the following non-renewable, natural gas-consuming CHP systems:

- Reciprocating engines
- Microturbines
- Gas turbines

Reciprocating engines cover a wide range of sizes, while gas turbines typically are large systems. Microturbines represent newer technologies with higher capital costs.

Cadmus did not analyze the potential for fuel cells, which use natural gas or biogas, converting it to hydrogen and generating electricity from electrochemical reactions of hydrogen and oxygen. Fuel cells operate at a higher electrical conversion efficiency than reciprocating engines, microturbines, or gas turbines and have lower emissions. They present, however, a newer CHP technology with higher capital costs. Cadmus recommends analyzing fuel cell potential in future studies, as costs have declined and applications are similar to those for other CHP technologies.

Cadmus analyzed the following renewable-fueled, industrial biomass systems and anaerobic digester biogas systems, described below:

- **Industrial biomass systems:** Used in industries where site-generated waste products can be combusted in place of natural gas or other fuels (e.g., lumber, pulp, and paper manufacturing). This analysis assumed combustion processes included in a CHP system (generally, steam turbines) to generate electricity on site. An industrial biomass system generally operates on a large scale, with a capacity greater than 1 MW.
- **Anaerobic digesters** create methane gas (i.e., biogas fuel) by breaking down liquid or solid biological waste. Anaerobic digesters can be coupled with a variety of generators, including reciprocating engines and microturbines, and typically are installed at landfills, wastewater treatment facilities, and livestock farms and feedlots.

Cadmus calculated technical potential to determine the number of eligible customers by segment and size (i.e., demand) within BPA's service area, and then applied assumptions about CHP or biomass/biogas system sizes and performance.

CHP Technical Potential Data Sources

Table D-8 lists sources that Cadmus referenced for each input. Recent studies completed for the California Self-Generation Incentive Program (SGIP) addressed large sample sizes (as the longest-running CHP program in the nation). Cadmus also reviewed studies from other regions and, where possible, benchmarked SGIP data with other studies—particularly those adjacent to BPA's service area (i.e., Puget Sound Energy's Integrated Resource Plan).

Table D-8. Data Sources for CHP Technical Potential

Inputs	Source	Website Link (if available)
Capacity Factor; Performance Degradation; Heat Recovery Rate	Itron. *SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report].* Table 4-4: Summary of Operating Characteristics of SGIP Technologies. pp. 4-13. October 2015.	http://www.cpuc.ca.gov/General.aspx?id=7890
Measure Life	Marin, W., et al. *Understanding Early Retirement of Combined Heat and Power (CHP) Systems: Going Beyond First Year Impacts Evaluations*. 2015 International Energy Program Evaluation Conference, Long Beach	https://www.iepec.org/wp-content/uploads/2015/papers/178.pdf
System Sizes	*Self-Generation Incentive Program Weekly Statewide Report.* Accessed September 18, 2017.	https://www.selfgenca.com/documents/reports/statewide_projects
Number of Customers; Projected Sector Growth; Line Losses	NWPCC Seventh Power Plan sector level growth rates; BPA Utility Load Data	7th Plan: https://nwcouncil.app.box.com/v/7thplanconservationdatafiles
Existing CHP capacity	DOE. "Combined Heat and Power Installation Database." Accessed June 22, 2017.	https://doe.icfwebservices.com/chpdb/

Typically, one of the first steps in determining technical potential assesses customers' eligibility based on their demand. Customer size data, however, were unavailable so Cadmus assumed *all* C&I facilities were eligible. The study accounted for this in calculating an achievable penetration rate to determine achievable potential.

CHP Achievable Potential

Cadmus applied an achievable penetration rate to technical potential estimates to determine the market potential or likely future installations. This included reviewing a range of market penetration estimates using benchmarked estimates from other recent studies. Additionally, Assessment 2, the companion DR Barriers Assessment, included relevant survey and interview questions to collect Northwest-specific data for developing payback models (such as that detailed above for solar PV). Cadmus explored and considered all options before selecting the best assumption on market penetration to estimate achievable CHP potential.

CHP Achievable Potential Data Sources

Cadmus compiled information from several sources in determining annual market penetration rates, as summarized in Table D-9. This included examining historic trends in installed capacity by state, technology, and fuel type using the U.S. Department of Energy (DOE) CHP Installation Database and reviewing states' favorability towards CHP as scored by the American Council for an Energy-Efficient Economy (ACEEE). To inform a payback model, Cadmus reviewed potential studies from other regions and collected data regarding customers' interest in CHP during Assessment 2 efforts.

Table D-9. Data Sources for CHP Achievable Potential

Input	Source	Website Link (if available)
Annual market penetration	DOE. "Combined Heat and Power Installation Database." Accessed June 22, 2017.	https://doe.icfwebservices.com/chpdb/
	Assessment 2 Surveys and Interviews	N/A

Input	Source	Website Link (if available)
rate	Navigant. *2017 IRP Conservation Potential Assessment IRPAG Meeting Draft DSM Results.* Prepared for Puget Sound Energy. January 2017.	https://pse.com/aboutpse/EnergySupply/Documents/Navigant_PSE_CPA_IRPAG_Meeting_2017-01-23.pdf
	ICF, International. *Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment*. Prepared for California Energy Commission. June 2012. CEC-200-2012-002-REV	http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf
	ACEEE. "State-by-State CHP Favorability Index Estimate." Accessed June 28, 2017.	http://aceee.org/sites/default/files/publications/otherpdfs/chp-index.pdf

CHP Levelized Cost

For each technology, Cadmus calculated the levelized cost from a total resource cost (TRC) perspective. Though assumptions varied between technologies, overall total resource levelized costs included the following:

- Installation costs
- Federal tax credits and other rebates not considered transfer payments from BPA's perspective
- O&M costs assumed to occur annually, adjusted to the net present value
- Fuel costs (using the Council's natural gas futures forecast)

To calculate the TRC, Cadmus used BPA's inflation rate of 1.9% to adjust future costs to present dollars. The study divided costs by the system's production over its lifespan, obtaining the levelized cost of energy. Energy production includes BPA's average line loss factor of 9.056%, which represents avoided losses on the utility system, not energy losses from customer-sited units to the facility (assumed to be zero).

CHP Levelized Cost Data Sources

Cadmus used the sources shown in Table D-10 for the levelized cost analysis, in addition to sources listed above for technical and achievable potential.

Table D-10. CHP Levelized Cost Data Sources

Input	Source	Website Link (if available)
State Cost Adjustment	R.S. Means	N/A
Inflation and Discount Rate	BPA	N/A
Gas Rates and Gas Futures	Northwest Power and Conservation Council. *Fuel Price Forecast: Revised Fuel Price Forecasts for the Seventh Power Plan.* Table 1: Proposed Natural Gas at Henry Hub Price Range ($2012/MMBTU). pp. 11. July 2014.	https://www.nwcouncil.org/media/7113626/Council-FuelPriceForecast-2014.pdf
Installed Cost	U.S. Environmental Protection Agency. "Catalog of CHP Technologies." March 2015.	https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf
O&M Cost	Itron. *SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*. Appendix A. October 2015.	http://www.cpuc.ca.gov/General.aspx?id=7890
State and Federal Incentives and Tax Credits	U.S. Environmental Protection Agency. "dCHPP (CHP Policies and Incentives Database)." Accessed June 22, 2017.	https://www.epa.gov/chp/dchpp-chp-policies-and-incentives-database

9.5. Combined Heat and Power Results

9.5.1. Combined Heat and Power Technical Potential

Cadmus calculated technical CHP potential for new installations, based on sources described in the Combined Heat and Power Methodology section of this report, including commercial and industrial customer data along with data on farms, landfills, and wastewater treatment facilities within BPA's power utility customer service area. This resulted in a total estimated 20-year, system-wide technical potential of 199,978 MW.

Table D-11 details technical potential by area, sector, and fuel (in MW). These results exclude 1,576 MW of already existing CHP capacity installed at 45 facilities throughout BPA's territory.[24]

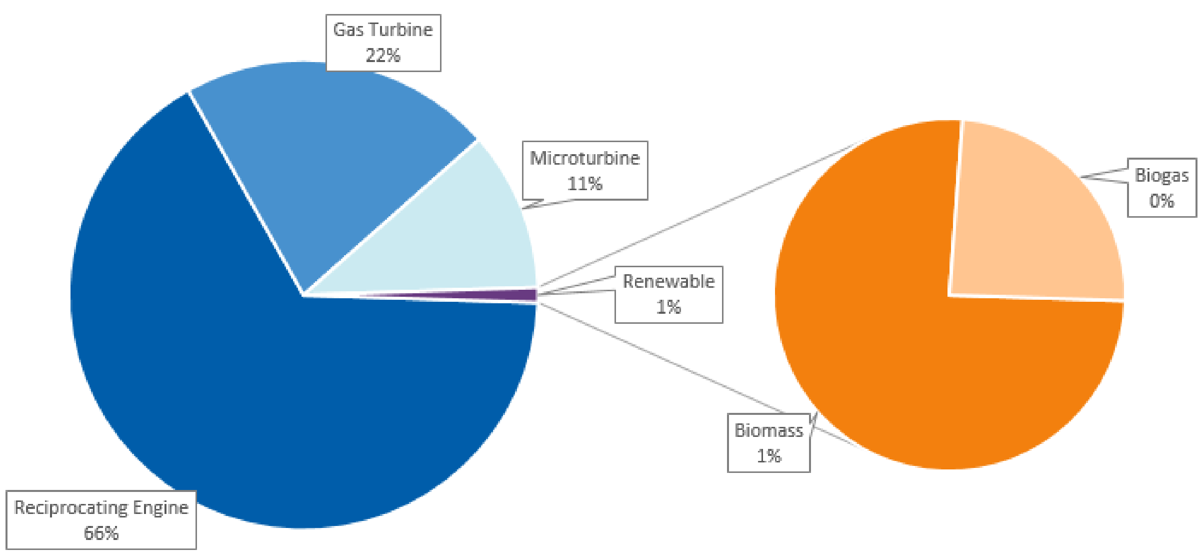
[24] U.S. Department of Energy. "Combined Heat and Power Installation Database." Accessed June 22, 2017.

Table D-11. CHP Technical Potential by Area, Sector, and Fuel (Cumulative in 2036)

BPA	Total Technical Potential	Technical Potential West	Technical Potential East
Commercial			
Natural gas MW	181,311	126,766	54,544
Number of sites	317,409	221,907	95,501
Industrial			
Natural gas MW	16,619	7,122	9,497
Number of sites	29,113	12,468	16,645
Biomass and biogas MW	2,049	725	1,323
Number of sites	1,277	297	979
Industrial total MW	18,668	7,848	10,820
Industrial total number of sites	30,389	12,765	17,624
Total			
Total MW	199,978	134,614	65,364
Total number of sites	347,798	234,672	113,126

The study based average energy production on unique capacity factors for each system type. To avoid double-counting opportunities across technologies, the study divided total potential for each size range into different technologies. Figure D-8 shows the distribution of technical potential as a percentage of 2036 technical potential in MW by these different technologies (e.g., reciprocating engines, microturbines, gas turbines, biomass, biogas).

Figure D-8. Percentage of 2036 CHP Technical Potential in MW by Technology



9.5.2. Combined Heat and Power Achievable Potential

Cadmus applied a market penetration rate of 0.10% per year to the technical potential data to determine achievable potential or likely installations in future years. The study based the assumed annual market penetration rate on secondary research of naturally occurring CHP installations in the region and on other CHP potential study reports. As shown in Table D-12 and Table D-13, the market penetration rate was applied to technical potential for each year to calculate equipment installations along with market potential over the next 20 years. The study estimated a cumulative 20-year market potential of 3,734 MW at the generator. This study used a BPA line loss assumption of 9.056%.

Table D-12. CHP 2036 Cumulative Achievable Potential Equipment Installations

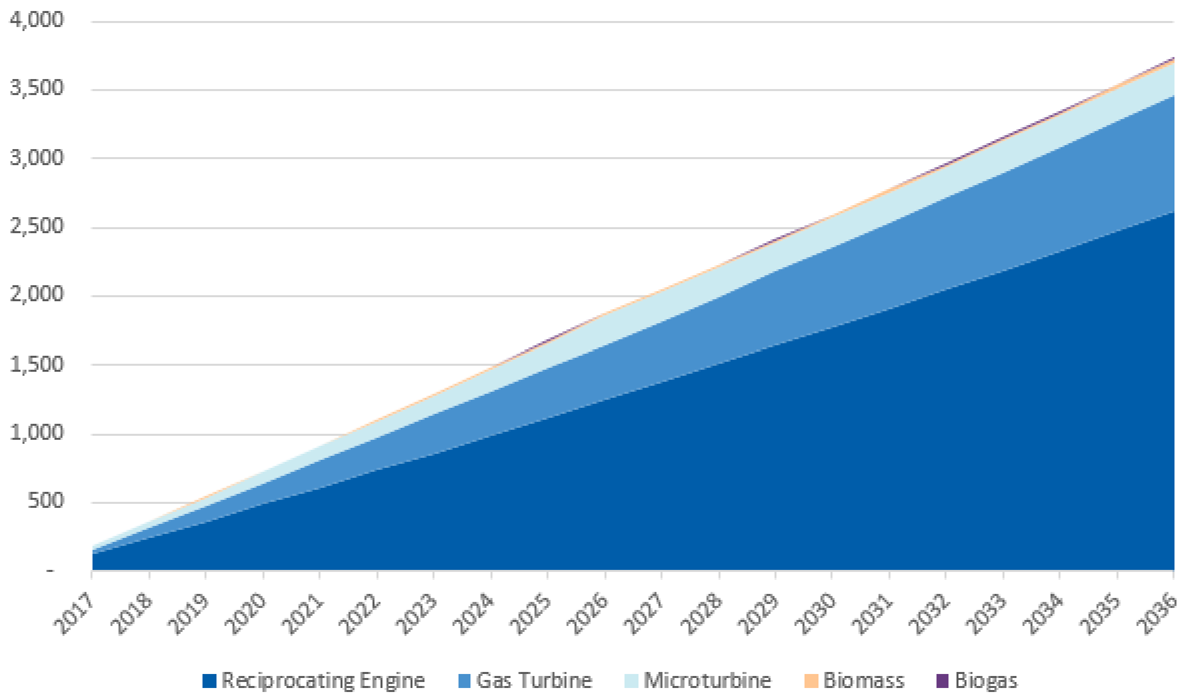
Technology	Total 2036 Installs	2036 Installs—West	2036 Installs—East
Nonrenewable—Natural Gas (Total)	**5,279**	**3,593**	**1,685**
Reciprocating Engine	3,815	2,599	1,216
Gas Turbine	433	295	138
Microturbine	1,030	699	331
Renewables	**22**	**5**	**17**
Total CHP	**5,301**	**3,598**	**1,702**

Table D-13. CHP 2036 Cumulative Achievable Potential (MW) at Generator

Technology	Total 2036 MW	2036 MW—West	2036 MW—East
Nonrenewable—Natural Gas (Total)	**3,695**	**2,517**	**1,178**
30–99 kW	19	13	6
100–199 kW	142	96	45
200–499 kW	403	274	128
500–999 kW	743	506	237
1–4.9 MW	2,017	1,374	643
5 MW+	371	253	118
Renewable—Biomass (Total)	**30**	**12**	**18**
< 500 kW	0	0	0
500-999 kW	0	0	0
1–4.9 MW	1	0	1
5 MW+	28	11	17
Renewable—Biogas (Total)	**10**	**2**	**8**
Landfill	0	0	0
Farm	9	1	8
Wastewater	0	0	0
Total CHP	**3,734**	**2,531**	**1,203**

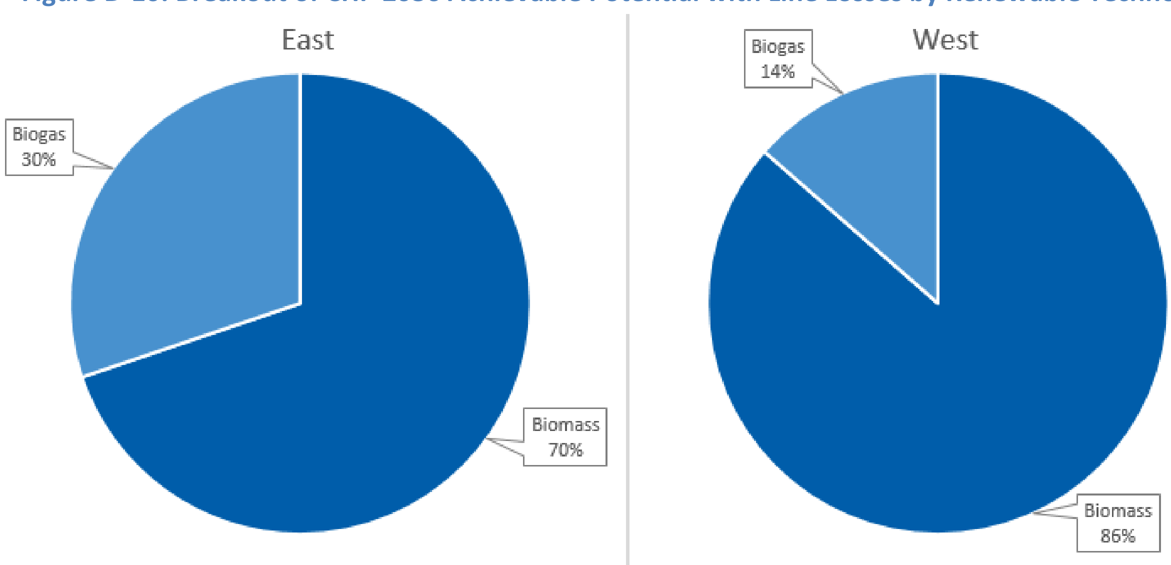
Figure D-9 shows cumulative achievable CHP potential by year and technology.

Figure D-9. CHP Cumulative Achievable Potential by Year at Generation (MW)



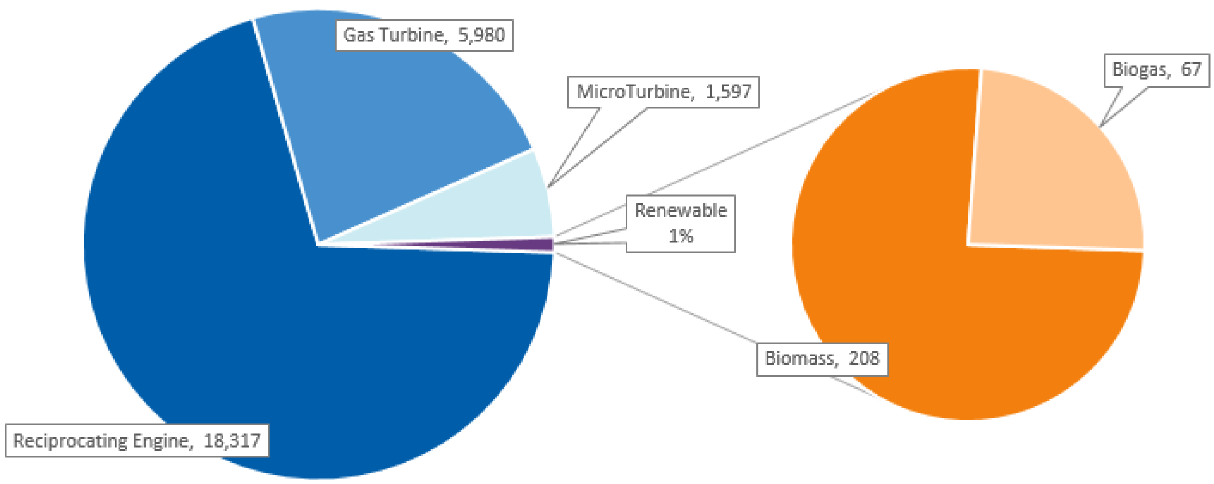
Nonrenewable technologies similarly contributed to the achievable potential capacity for the east and west areas. Reciprocating engines made up 70% of the potential capacity, gas turbines made up 23%, and microturbines made up 6%. The remaining 1% (corresponding to 40 MW) consisted of biomass and biogas systems, and the breakout differed between east and west, as shown in Figure D-10.

Figure D-10. Breakout of CHP 2036 Achievable Potential with Line Losses by Renewable Technology



In 2036, total energy generated across all technologies was 26,168 GWh (i.e., nonrenewable at 25,893 GWh and renewable at 275 GWh). Figure D-11 shows the market potential of energy generation by each technology.

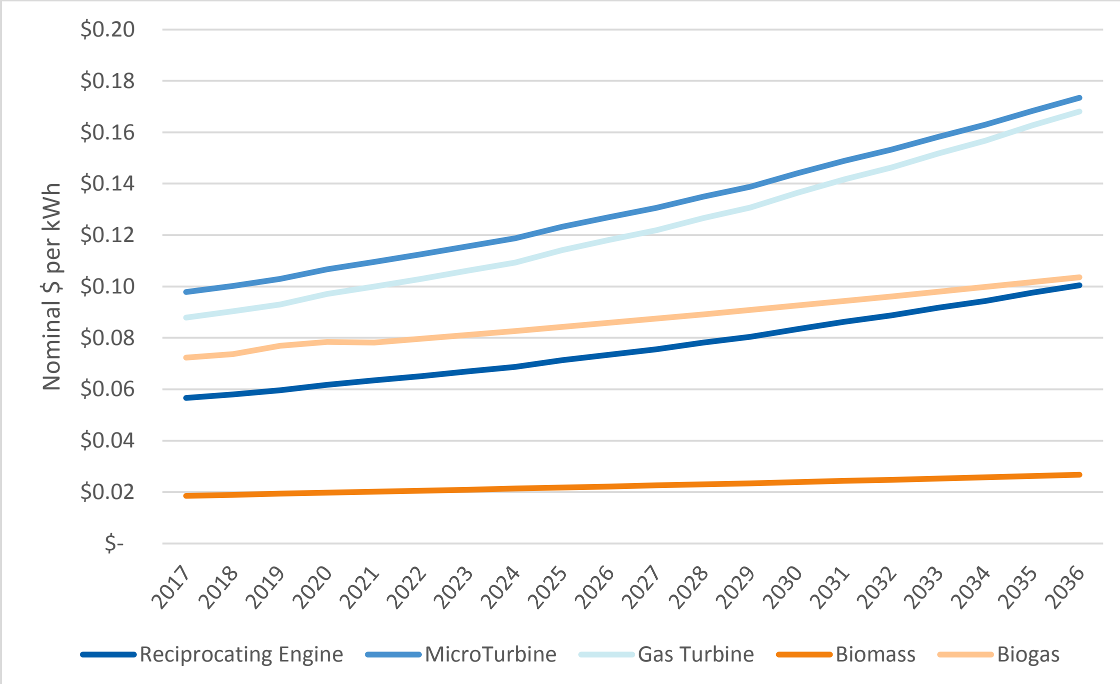
Figure D-11. Breakout of CHP 2036 Cumulative Achievable Potential (GWh) at Generator



9.5.3. Combined Heat and Power Levelized Cost Results

Cadmus calculated the levelized cost, based on the TRC perspective, for each technology configuration in each installation year (2017 to 2036). Figure D-12 shows the nominal levelized cost for units installed through the study period. The levelized cost increases slightly over time. For nonrenewable systems, the levelized cost increase results from increasing natural gas prices and inflation. For the renewable systems, the levelized cost increase results from inflation.

Figure D-12. Nominal Levelized Cost by Technology and Installation Year



9.6. Distributed Standby Generation Methodology

Since 1999, PGE has successfully used distributed standby generation (DSG) in the Northwest, paralleling its first distributed generator at MacLaren Youth Correctional Facility at 500 kW. Since then, PGE's Dispatchable Standby Generation program has added over 100 MW of capacity. Other BPA demonstration and operational projects have utilized DSG (e.g., Olympic Peninsula Project, Orcas Power & Light Energy Partners Program, Smart Grid Demonstration Project).

9.6.1. Standby Generation Technical Potential

Determining the potential for standby generation involves researching building counts in customer segments that currently have installed or are likely to install diesel standby generators over 500 kW as well as estimating the total generation capacity for each customer segment. Typical customer segments include, but are not limited to, airports, cold storage warehouses, data centers, high-tech manufacturing facilities, hospitals, military bases, prisons, refineries, utility offices and control centers, waste treatment facilities, and water pumping stations.

This is not an exhaustive list of customer segments. However, these customer segments have been the most likely to participate as experienced in the PGE diesel standby generation program. By matching facility types with typical generation capacities, projections of total backup generation capacity can be estimated for each building segment in BPA's service area. Accumulating generation capacities for each building segment allowed Cadmus to determine the aggregated total potential generation for this assessment.

Cadmus applied a typical generation capacity for each building segment under consideration. Through conversations with standby generation industry experts, the study determined the set of standard generator sizes as 500 kW, 750 kW, 1,000 kW, 1,500 kW, 2,000 kW, and 3,000 kW. Although generators smaller than 500 kW can be used for a dispatchable standby generation program, interconnecting and controlling smaller generators tends to be less cost-effective. As a result, this potential assessment focused on generators of 500 kW and above. While some generators use natural gas or propane fuel, such generators are significantly more expensive, and it is rare to see a generator above 500 kW use these fuels. For this assessment, Cadmus assumed all generators of this size range would be exclusively fueled with diesel.

Standby Generation Targeted Market Segment

Cadmus determined the technical potential for each building segment by multiplying the building count by the typical generator size for that segment. Looking up corresponding standard industrial classification (SIC) codes in the Melissa (2017) online database, Cadmus determined building counts for each segment, taking the resulting list of building counts by state and city and cross-referencing these with the list of cities in BPA's service area. Cadmus adjusted each city's building counts by the percentage of the city's zip codes falling within BPA's territory. The typical generation capacity for each building segment arose from estimates based on a Cadmus employee's 12-year experience (as a PGE employee) in managing PGE's standby generation program; this represents a rough midpoint within a large range of generator sizes. The typical generator represented mostly new generators or major renovations, not the installed base of all generators. The sum of each building segment's technical potential equaled the final technical potential at the end of the project implementation period.

Table D-14. Typical Generation Capacity Used for Calculation of Technical Potential

Customer Segment	Typical Capacity of Generator(s) (kW)
Airports	5,000
Cold Storage Warehouses	750
Data Centers	2,000
High Tech Manufacturing	1,000
Hospitals	2,000
Military Facilities	1,000
Prisons	500
Refineries	750
Waste Treatment	1,000
Water Treatment	1,000

9.6.2. Standby Generation Achievable Potential

After estimating the total capacity of current and future diesel backup generators in BPA's service area, Cadmus used a prototypical DSG program (based on the program operated by PGE). To calculate achievable potential, the study applied a success rate adjustment to the technical potential, which reflected the fraction of facilities by type that would likely participate in such a program. Cadmus determined a unique success rate for each customer segment from interviews with contacts experienced with the program.

Via this hypothetical program, customers with existing generators or newly installed generators could participate in a DSG program. Through consulting with contacts, however, Cadmus found many customers participating in such programs were in the process of installing a new generator. This resulted from the cost and difficulty of replacing existing auto-transfer switches on an existing generator system that might not have sufficient room for larger paralleling switchgear. Typically, customers installing a new generator were about three times as likely to participate as those with existing systems. Cadmus incorporated these frequencies into the overall success rates for each customer segment.

The achievable potential for each customer segment is the product of the technical potential and the success rate for that customer segment, and the sum of each customer segment's individual potentials equals the total achievable potential.

Due to restrictions on diesel generator use enforced by the U.S. Environmental Protection Agency (EPA),[25] Cadmus limited the analysis generator run times to 50 hours per year and assumed Tier 4 engines, except for resilience purposes. EPA defines Tier 4 gensets as compression-ignition, nonroad engines with a model year of 2011 or later for systems larger than 500 kW. EPA standards for these engines cover a range of different emission types.[26]

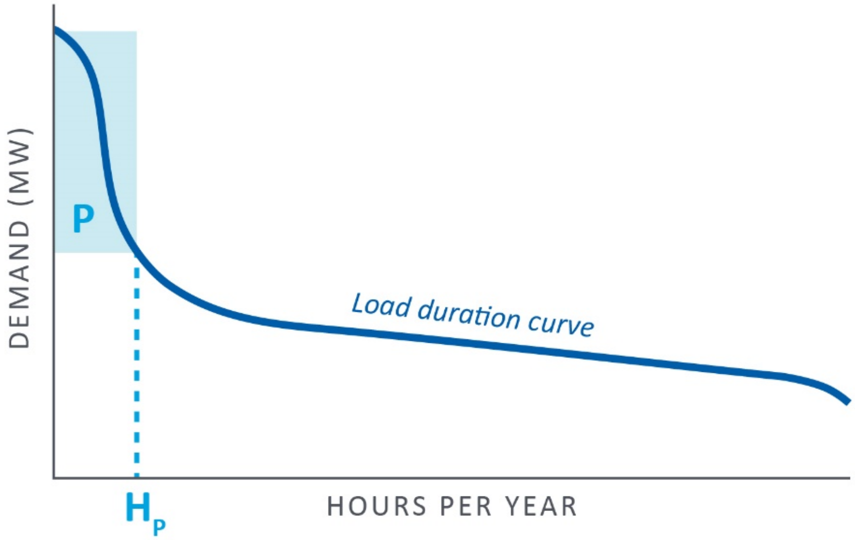
The DSG programs' primary objectives were to supply operating reserves and DR. Cadmus based achievable potential on this restricted run time, modifying it to fulfill the needs for operating reserves by BPA's utility customers. Utilities within the Western Electricity Coordinating Council's operating territory must carry 5% reserves for hydro resources and 7% reserves for thermal resources;[27] so these values limited the total achievable potential when applied to the utility's existing resources. In addition, Cadmus capped these generators' DR use at expected needle-peak DR needs, as shown in Figure D-13. Cadmus also capped DR by a conservative 38 hours of annual runtime due to testing and other requirements for the 50-hour run-time limit.

[25] The National Emission Standards for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE) are outlined in the Code of Federal Regulations under 40 CFR 63 Subpart. Source: EPA 2017.

[26] The definition and emissions standards for Tier 4 gensets can be found in the Electronic Code of Federal Regulations Title 40 Part 1039. Source: EPA 2017

[27] For more information see "WECC Standard BAL-STD-002-0 – Operating Reserves." Available online: http://www.nerc.com/files/bal-std-002-0.pdf

Figure D-13. Needle Peak Load (Targeted by Diesel Standby Generation Program)



Standby Generation Targeted Customer Segment Achievable Potential

Cadmus determined the number of achievable standby generator projects for each building segment by multiplying the building count by the expected program success rate for that segment. Cadmus then multiplied the resulting achievable building count by the typical generator size to determine the total achievable potential for each building segment.

Table D-15 shows expected program success rates for each building segment. (As noted, Cadmus determined expected program success rates through PGE employee experience). These success rates were meant as conservative estimates, considering the variability and unknowns of the range of utilities and territories covered by BPA. Success rates are the percentages of buildings willing to participate in the program and install the system initially (as opposed to the success rate per event). We are assuming that BPA would not be paying for paralleling switchgear and grid integration costs, as PGE did. Each customer segment's success rate is meant to exclude any customers with generators less than 500kW and to exclude any customers unwilling to participate in a standby generation program.

Table D-15. Customer Segment Success Rates for Calculation of Achievable Potential

Customer Segment	Success Rate
Airports	100%
Cold Storage Warehouses	10%
Data Centers	25%
High Tech Manufacturing	30%
Hospitals	30%
Military Facilities	5%
Prisons	10%
Refineries	5%
Waste Treatment	25%
Water Treatment	30%

Standby Generation Achievable Potential by Program Year

To estimate yearly growth in standby generation capacity over the program timeline, Cadmus applied a ramp-up rate similar to PGE's standby generation program. Under PGE's program, operators achieved about 10 MW of installation capacity per year. Assuming a similar rate of installations by BPA's eight largest-slice customer utilities, the BPA standby generation program could expect to achieve about 80 MW of installed capacity per program year.

Standby Generation Levelized Costs

Cadmus calculated the levelized cost from a total resource perspective, including the following:

- Installation costs of the paralleling switchgear and communications
- O&M costs assumed to occur annually, adjusted to the net present value
- Fuel costs (using the EIA's diesel fuel futures forecast for the Northwest)

Use of standby diesel generators for utility power results in an associated increase in atmospheric emissions due to changes in generation types.

Standby generation programs limit participation only in capacity payment-based program structures, where monthly payments are made based on availability; standby generation programs cannot participate in energy-based pay-for-performance program structures due to restrictions on generator run times set by EPA.

To calculate TRCs, Cadmus used BPA's 1.9% inflation rate to adjust future costs to present dollars. The study then divided each system's production over its lifespan to obtain the levelized cost of energy. Energy production included BPA's assumed line loss factor of 9.056%, with the line loss value representing avoided losses on the utility system (not energy loss from the customer-sited unit to the facility, which was assumed to be zero). Cadmus assumed 20 hours of annual operation (out of a maximum allowable 38 hours) and a project lifetime of 25 years. For this resource's capital costs, Cadmus assumed the customer would provide the generator, whether new or existing.

After consulting with PGE staff to determine the capital and O&M costs on a per-MW basis, Cadmus derived annual fuel consumption from the technical specification of a typical 1 MW diesel standby generator. The following equations provided the calculated dispatch price:

$$\begin{aligned} &Total\ CapEx\ per\ MW \\ &\qquad = (paralleling\ switchgear\ \&\ dispatch\ communication\ cost) \\ &\qquad /MW\ capacity \end{aligned}$$

$$\begin{aligned} &Dispatch\ Price\ (\$/MWh) \\ &\qquad = ((Annual\ capital\ carrying\ cost/MW)\ +\ (Annual\ fuel\ cost/MW) \\ &\qquad +\ (Annual\ O\&M\ costs/MW))/(20\ hrs) \end{aligned}$$

9.7. Standby Generation Results

9.7.1. Standby Generation Technical Potential

Cadmus calculated technical standby diesel generation potential, based on methods and sources described in the Methodology section, resulting in a total, estimated, system-wide technical potential of over 1,900 MW. Table D-16 details technical potential by customer segment (in MW).

Using the Melissa online database, Cadmus conducted a search of building counts in each customer segment based on applicable SIC codes. For example, according to the database search of SIC code 7374 (‘data processing and preparation’), Cadmus found that the Data Centers customer segment had 445 buildings in the BPA service area.

Because the Melissa online database does not disclose the size of standby generators in each building, Cadmus made an assumption about the size of these standby generators based on a Cadmus employee’s 12-year experience (as a PGE employee) in managing PGE’s standby generation program. As a result of this assumption, the number of standby generators in this analysis may be smaller than the actual number of generators at these facilities. For example, although there are more than one airport in BPA’s service area, Cadmus assumed that airports besides the Seattle-Tacoma International Airport are not likely to have standby generators large enough (e.g., at least 500 kW) to participate in this standby generation program.

Table D-16. Standby Generation Technical Potential by Customer Segment

Customer Segment	Building Count	Total Technical Potential (MW)
Airports	1	5
Cold Storage Warehouses	19	14
Data Centers	445	890
High Tech Manufacturing	85	85
Hospitals	384	768
Military Facilities	14	14
Prisons	8	4
Refineries	36	27
Waste Treatment	8	8
Water Treatment	102	102
Total	**1,102**	**1,917**

9.7.2. Standby Generation Achievable Potential

Cadmus applied an industry success rate to the technical potential data to determine achievable potential or likely installations in future years for each customer segment under consideration. As a result, the achievable building counts and corresponding achievable potential are lower due to the applied success rate. This resulted in an aggregate achievable standby generation potential of 520 MW. Table D-17 details achievable potential by customer segment (in MW).

Table D-17. Standby Generation Achievable Potential by Customer Segment

Customer Segment	Achievable Building Count	Total Achievable Potential (MW)
Airports	1	5
Cold Storage Warehouses	2	1
Data Centers	111	223
High Tech Manufacturing	26	26
Hospitals	115	230
Military Facilities	1	0
Prisons	1	0
Refineries	2	1
Waste Treatment	2	2
Water Treatment	31	31
Total	**291**	**520**

Note: Diesel generators tapped for a DSG program would be capped at a maximum of 38 hours of program runtimes per year due to restrictions set by EPA and facility operating requirements.

Table D-18 demonstrates aggregate achievable potential by program year when applying a ramp rate of 80 MW per year. At this rate, the total achievable potential of 520 MW would be reached in seven years.

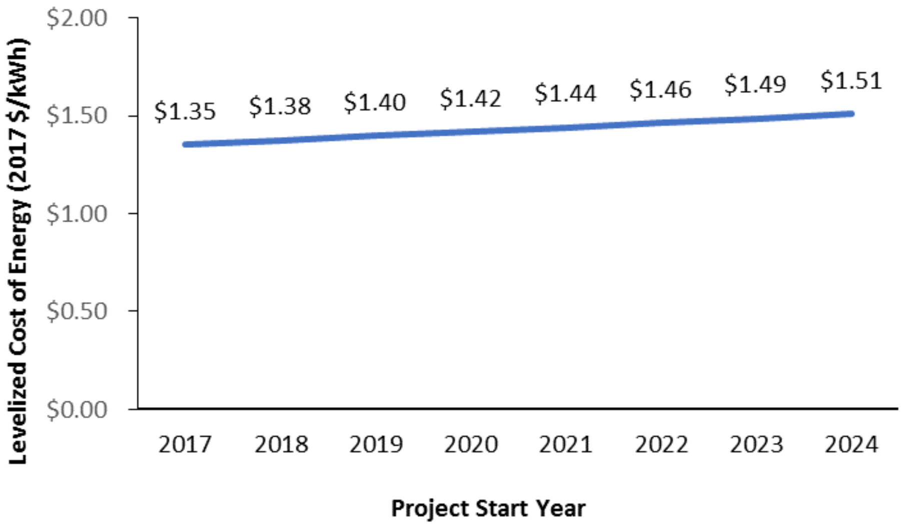
Table D-18. Annual Achievable Capacity for a Standby Generation Program

Program Year	Total Achievable Capacity (MW)	Incremental Installed Capacity (MW)
1	80	80
2	160	80
3	240	80
4	320	80
5	400	80
6	480	80
7	520	39

9.7.3. Standby Generation Levelized Cost Results

Cadmus calculated the levelized cost of energy (LCOE) for a standby generation project, based on the methods and sources described in the Methodology section for each installation year of a seven-year program span (2018–2024). Figure D-14 shows the LCOE of a system installed in each year of the program period. The calculated levelized cost is based on the TRC perspective.

Figure D-14. LCOE for a 1 MW Standby Generation System by Project Year



Decisions on whether to utilize DSG should not be based on LCOE as standby generation has very high levelized costs, given that generators are used for very short time periods during the year. Cadmus assumed 20 hours of power generation throughout the year as part of a standby generation program (out of a maximum allowable 38 hours).

What makes standby generation economically beneficial is its ability to apply DSG for capacity savings or reserves in the event other generation or DR systems fail. For BPA's Power customers, the valuation of deploying standby generation depends, among other factors, on the extent to which standby generation can help the utility keep its load within its scheduled capacity requirement.

10. Appendix E. Energy Storage

Energy storage covers a broad array of technologies that utilize potential energy or stored energy types. These include chemical, kinetic, gravitational, electrical, or thermal energy (e.g., batteries, flywheels, electric water heaters, super capacitors, compressed air, electrolyzed hydrogen fuel, pumped water). Currently, electrochemical energy offers the most active market for energy storage, with other technologies offering specific, niche uses but currently not providing significant storage growth capability or fast-falling costs sufficient for consideration in this analysis.

Instead, this study focuses on the burgeoning energy storage systems (ESS) market. These systems offer significant storage capabilities and flexible control operations and may be located on a distributed basis almost anywhere—from residential garages to utility substations. Where defined, ESS as examined in this study include various chemistries in lithium-ion technologies and salt-water batteries to vanadium-flow batteries. The study provides a description and example of storage's value stacking benefits for the commercial market and presents a scenario of technical potential for residential storage growth, based on projected solar rooftop growth.

As a study benchmark, Cadmus focused on providing costing and pricing curves for a sample of high-potential storage use cases that BPA planners or public BPA Power customers might adapt for their modeling needs over the next year or two.

10.1. Storage Scope and Methods

Cadmus limited these energy storage evaluations to electrochemical systems that appear to offer the most benefit for BPA's system, drawing upon professional experience and discussions with BPA. Due to scope limitations, Cadmus could not examine all potential use cases that might become available for the BPA system.

Cadmus considered thermal storage systems (e.g., water heaters, ice, molten salt, ceramics) as part of the DR potential due to their close linkage with end-use loads. The study did not consider chemical storage such as hydrogen (in the electrolyzed/hydrogen storage/fuel cell combination) or kinetic storage (such as pumped hydro or flywheels). The analysis did not include hydrogen, pumped hydro, or flywheels due to limited market development and specific niche

Shell Energy North America—Pumped Storage Hydropower

Washington's Department of Ecology and Shell have partnered in a project titled "Hydro Battery Pearl Hill," which will include an above-ground reservoir built on top of a bluff 1,400 feet above Rufus Woods Lake and a "framed, floating membrane" in the lake that will:

"…hold water that would be pumped up to the reservoir when power costs and demand are low, such as in the middle of the night, and then released when needed to generate electricity at a powerhouse that would be built on a dock on the lake. A transmission line would connect the powerhouse to nearby Grant County Public Utility District transmission lines. The plant would be small by utility standards—5 megawatts of generating capacity."

Excerpts from "Water Storage, Water Power" (John Harrison, Northwest Power and Conservation Council: https://www.nwcouncil.org/news/blog/shell-energy-pearl-hill-project-september-2017/)

applications that limited broad deployment in BPA's territory. Consequently, ESS references apply only to electrochemical systems (e.g., various lithium-ion chemistries, vanadium-flow, lead-acid batteries, various salt-water batteries).

For BPA's service area and its large-scale operations, ESS possess advantages and limitations that present unique challenges when estimating the technical and achievable potential of energy storage. Tremendous efforts by numerous researchers, including several national laboratories and the Electric Power Research Institute (EPRI), have sought to identify the many benefits that energy storage can provide to the electric system in addition to instances where these benefits can overlap, depending on the service, use case, and business cases under consideration. Compared with the traditional demand-side management (DSM), which predominately focuses on how education and financial incentives can modify customers' demand for energy, promoting energy storage for grid benefits requires ongoing verification of energy storage activity.

Given the relatively nascent adoption of ESS, appropriate terminology and usage definitions are important. For this project, Cadmus uses EPRI's key term and variable definitions used in 2013's *Cost-Effectiveness of Energy Storage* paper, written for the California Public Utility Commission.

For this study, energy storage presents challenges in the traditional approach of determining technical potential and evaluating market potential/achievable potential. Determining technical potential requires a significant amount of BPA Power customer operational data at the transmission, distribution, and end-user operational levels. Going forward, these operational data must be collected to begin building a solid foundation for determining technical potential. For this report, Cadmus focused on defining data needs that can help build a solid foundation for assessing future technical potential.

Market potential is based on the entire size of a market for a product at a specific time. It represents a product's upper limits in the market and is usually measured by sales values or sales volumes. In the Northwest, a true market does not yet exist for ESS: no significant sales values or sales volumes can be measured. Markets have started to emerge in parts of the country with significant volumes of rooftop solar PV and where significant demand charges can be reduced. For example, in Southern California, where commercial demand charges are about $40 per kilowatt, or on the East Coast where they are $20 to $30 per kilowatt, commercial energy storage has started to establish a foothold. Currently, Northwest utility demand charges, and C&I customer demand charges, where they exist at all, average between $3 and $7 per kilowatt; so ESS developers must wait for significant demand charge increases or provide power customers with incentives to develop market interest in the Northwest.

Depending on the usual definitions of a market, strict purchases by BPA Power customers for operational objectives do not constitute a market for suppliers such as ABB, Siemens, or Eaton. A market will emerge only when many BPA Power customers purchase equipment for the same operational objectives, and only then will competition occur among new market entrants.

Power customers could consider non-wires alternatives as a broad definition of an energy storage market when significant adoption occurs with consistency. In BPA's case, non-wires alternatives may be defined at the transmission or distribution levels. Frameworks addressed in this study represent both, describing what might constitute potential markets at the transmission system and at the distribution feeder.

Achievable potential also includes evaluating the technology and system readiness to best use the technology, but, most importantly, it describes the purchasers' willingness to buy. Numerous pilot projects around the country provide clues regarding technology readiness, and a tremendous amount of research examines appropriate use cases (NREL 2013, DOE 2013, RMI 2015, NREL 2015, Hart 2016, Sandia 2017), but appropriate use cases have yet to be developed for the Pacific Northwest. This study begins to change that, but work must continue. For the reasons described, Cadmus focuses on four market segments:

1. Residential PV growth rates and the complimentary benefits of residential storage and PV
2. The commercial building market, with behind-the-meter deployments
3. The utility market, with opportunities at BPA Power customer substations
4. The potential for transmission benefits from energy storage

As residential PV and associated ESS have started to show market potential, Cadmus has provided both estimates for this market segment. For other segments to develop technical and achievable potentials, more joint data planning must be conducted by BPA Power customers. In addition, though the third and fourth items listed above are not yet considered significant markets, they represent opportunities to achieve operational objectives, such as the use of storage as a non-wires alternative. Though more work will be required to explore technical and achievable potential for these use cases, Cadmus formulated a methodology to address these, as described in more detail below, including forecasted price curves.

10.1.1. Energy Storage Use Case Definition

Table E-1 provides a proposed approach for ESS potential estimation by market segment.

Table E-1. Overview of Cadmus' Evaluation Approach by Market Segment

<table>
<tr><th>Market Segment</th><th>Primary Value Stream</th><th>Secondary Value Streams</th><th>Key Components</th></tr>
<tr><td>Residential</td><td>Resilience</td><td>Capacity</td><td>Estimate market based on solar PV customers
Apply archetype technology</td></tr>
<tr><td>Commercial/ Industrial</td><td rowspan="2">Distribution Reliability Upgrade Investment Deferral</td><td rowspan="2">Capacity
Voltage support
Regulation
Reserves
Resilience</td><td>Identify constrained network elements and cost savings.
Determine expected incentives
Target key C&I facilities
Estimate relevant ESS applications and adoption rates</td></tr>
<tr><td>Distribution/ Substation</td><td>Similar to C&I, but with reduced emphasis on incentives and customer adoption</td></tr>
<tr><td>Transmission</td><td>Congestion relief or Investment Deferral</td><td>As determined by transmission needs</td><td>Identify key nodes on the BPA system that would benefit from energy storage attributes; this make take the form of constrained lower kV transmission lines or at line interchange points, with Power customers to be determined by SME interviews</td></tr>
</table>

10.1.2. Storage System Pricing Forecast Overview

At this development stage, Cadmus' key focus for energy storage potential involved forecasted capacity pricing (i.e., the dollar-per-kilowatt of installed cost) over the study period, not the LCOE. As technology prices fall, adoption rates will rise, and more applicable use cases will emerge. As part of the interview process with BPA operational staff, Cadmus introduced an example of a fully installed storage LCOE price of $300 per megawatt. BPA responded, saying divide that by 10, and perhaps it could compete with other system alternatives. This large differential may seem insurmountable for storage in the Northwest, but the unique use-case mix for storage may speed up the cost-effectiveness timeline.

For example, upon placing a large storage plant at the transmission level to relieve congestion, BPA would be required to pay the storage plant's full cost, plus the significant cost of interconnection with a custom substation, even though that storage plant might not achieve 100% use in that location due to a limited need for congestion relief.

If combining the storage system with a bulk wind or natural gas power plant, storage could be used to assist with ramp rate support or frequency regulation, and capacity could be used at critical times to reduce congestion on the transmission system. If cost sharing could be achieved with the power plant, this would reduce the storage system's cost to BPA. The same cost sharing could occur between BPA Power and Transmission, sharing an ESS for different seasonal business uses, or between BPA Power and its customer public utilities (e.g., BPA Power using an ESS for power marketing purposes and the local utility using the ESS for distribution system investment deferral). This sharing of ESS costs across multiple value streams is often referred to as shared use, value stacking, or stacked benefits.

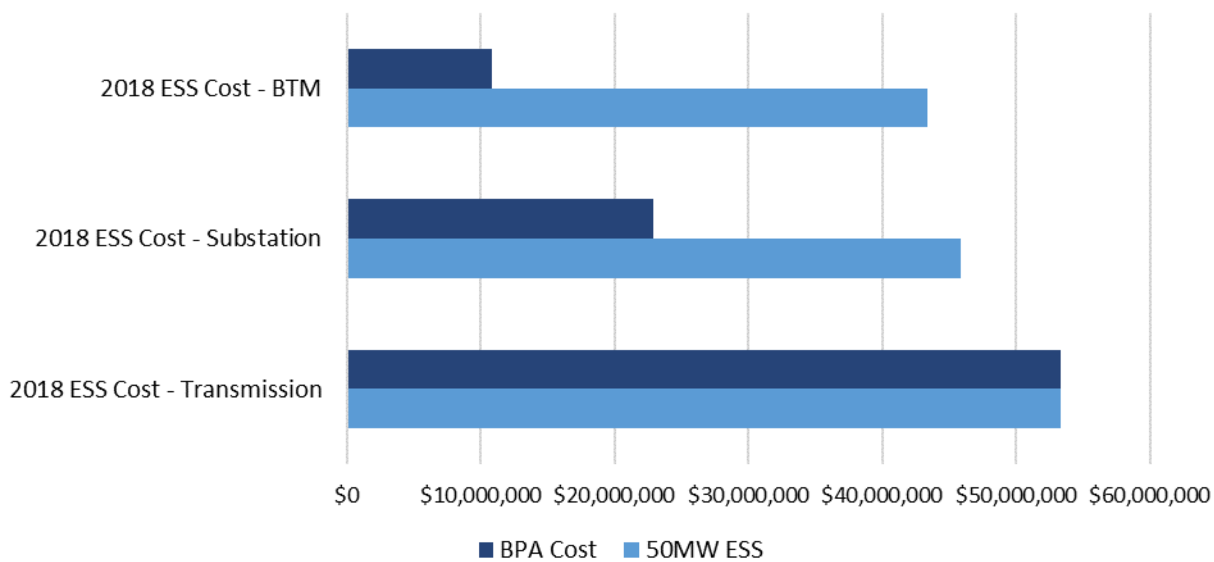
If storage becomes more distributed and located at distribution substations, more use cases could be created. For example, ESS within the distribution system offers non-wires alternatives opportunities, which can benefit the combined transmission and distribution system. This also would make more significant cost sharing available to BPA as, in some cases, energy storage could reduce BPA's demand charges for the distribution Power customer, support its non-wires alternative objectives, and provide operational benefits. BPA could tap into this opportunity by co-funding projects or by including storage scheduling rate operations in its wholesale tariff.

As storage becomes greatly distributed and pushed further down the electrical power grid to the customer level, more cost-sharing opportunities exist, with benefits shared among BPA, the distribution Power customer, and the end user. Further, opportunities exist for significant ESS costs borne by end users due to the gains in grid resilience and outage avoidance that customers with energy storage can enjoy. More distributed storage at the end-user level would result in a much higher use of the energy storage resource and lower costs to BPA over the direct application of storage at the transmission level. Consequently, at some point along the distributed storage supply and cost curve, BPA's cost for storage would be significantly lower than the direct deployment option.

With this approach, lack of direct ESS control by BPA would reduce some benefits, but, using the best combination of pricing and distributed operational controls, storage could be used efficiently for transmission operations even if the ESS is in the basement of a commercial building.

Figure E-1 shows the cost sharing benefits of distributed storage. Note that these values are intended only for illustration purposes and are not yet based on actual results. The magnitude of benefits, however, is based on real-world examples, where vendors-offered behind-the-meter (BTM) storage for commercial building demand savings with a 50% shared savings benefit.

Figure E-1. Illustrative Benefits of Distributed Storage Cost Sharing



As seen in this example, distributing energy storage closer to loads would reduce the amount of capital that BPA would need to provide. Although counter to rules of thumb for economies of scale, BTM installations can be the most cost-effective means of deploying storage because of how costly step-up transformers for interconnecting storage to distribution and transmission infrastructure can be. These costs can dramatically outweigh the costs of communicating and coordinating with distributed storage systems. Current first costs would run BPA $1,067 per kilowatt at the transmission level, and the equivalent storage cost (to BPA) could be substantially reduced through appropriate cost sharing of stacked benefits with distributed storage. Further, as benefits would accrue across the whole spectrum of users (transmission and distribution entities and end users), broad adoption of storage would become more likely.

Pricing Forecast for Evaluation Period

Cadmus based its market segment storage pricing forecasts on a lithium-ion battery purchased price forecast (Gupta 2017). Lithium-Ion costs were extrapolated from 2022 to 2037 as shown in Table E-2. From these base prices, Cadmus obtained local price quotes from vendors and conducted literature reviews from other projects around the country to determine a close-to-market price for the Pacific Northwest. This analysis includes a price forecast for each of the four market segments, which each use the base lithium-ion price from the GTM report. The base price is modified based on the balance-of-system (BOS) costs for each segment, adjusted using engineering judgment to the appropriate use-case and installation level.

Table E-2. GTM Lithium-Ion Price Forecast

Year	Lithium-Ion Battery Price ($/kWh)	Percentage Decrease
2012	$800	-
2013	$625	-22%
2014	$490	-22%
2015	$370	-24%
2016	$281	-24%
2017	$241	-14%
2018	$217	-10%
2019	$198	-9%
2020	$180	-9%
2021	$165	-8%
2022	$152	-8%
2023	$135	-11%
2024	$120	-11%

Year	Lithium-Ion Battery Price ($/kWh)	Percentage Decrease
2025	$112	-7%
2026	$105	-6%
2027	$100	-5%
2028	$95	-5%
2029	$86	-9%
2030	$81	-6%
2031	$77	-5%
2032	$74	-4%
2033	$71	-4%
2034	$69	-3%
2035	$68	-1%
2036	$67	-1%
2037	$67	0%

10.1.3. Value Stacking Demand Response Pricing Analysis for Storage Behind-the-Meter

Installing energy storage behind the meter offers a major benefit because, from that location, it can serve both the facility (local load) and the distribution system. DR programs offer a mechanism by which BPA Power customers could leverage and even encourage the adoption of energy storage resources installed by customers. In C&I scenarios, where time-of-use (TOU) billing with peak demand charges are common, energy storage offers an opportunity to shift the load at the meter to achieve bill savings. Some institutions, in some contexts, may even procure large storage systems as an alternative to diesel generators. The financial benefits offered by bill management and resiliency may not be enough to justify storage installation at today's market prices, but including DR participation and payments may make such projects profitable.

To better understand the ESS potential to serve as a BTM DR resource, Cadmus examined a scenario of a Seattle hospital considering installation of a two-hour, 1,000 kW capacity battery system. Cadmus used StorageVET, an evaluation and simulation tool hosted by EPRI, to analyze the financial prospects of energy storage projects and determine how varying DR prices affect profitability potential. Table E-3, Table E-4, and Table E-5 include system parameters, financial parameters, and retail bill prices, respectively. Note that Cadmus used an annual discount rate of 10% to reflect the hospital's financial requirement for investing in this project; this annual discount rate is a higher rate than commonly used for utility-funded projects.

Table E-3. Parameters Defining Technical Specifications and Operational Performance of an Energy Storage System

Project System Parameter	Value
Charge Capacity (kW)	1,000
Discharge Capacity (kW)	1,000
Energy Storage Capacity (kWh)	2,000
Charge Efficiency (%)	94.87
Discharge Efficiency (%)	94.87
Round-Trip Efficiency (%)	90.00
Charge Ratio (%)	70
Self-Discharge Rate (%/hr)	0.5
Reserve Capacity for Back Up (%)	10
Project Life (years)	10

Table E-4. Parameters Defining Financial Conditions for the Project

Project Financial Parameter	Value
Capital Costs ($/kW)	1,000
Fixed Operating Expenses ($/kW-yr)	19.5
Debt Amount (%)	50
Equity Amount (%)	50
Debt Rate (%)	6.18
Fixed Annual Return on Equity (%)	11.47
Federal Tax Rate (%)	35
State Tax Rate (%)	8.84
Annual Discount Rate (%)	10

Table E-5. Parameters Describing the Retail Bill Tariff

Project Financial Parameter	Value
Energy Price ($/kWh), Off-Peak	$0.0575
Energy Price ($/kWh), On-Peak	$0.0865
Monthly Time-Sensitive Demand Charge ($/kW), Off-Peak	$0.29
Monthly Time-Sensitive Demand Charge ($/kW), On-Peak	$3.29
Monthly Facilities Related Demand Charge ($/kW)	$0.27
Tariff Fixed Monthly Fee ($/Month)	$909.15

Cadmus assumed that at least 10% of the battery's full energy capacity would never be used and would be available for backup power. Cadmus selected this rather low 10% value to determine how much the system could generate in bill savings and DR program payments when given a large percentage of the energy capacity. Realistically, if deploying a system as a resource for back-up power, a larger portion of the storage capacity would be reserved and not accessible for other services.

Cadmus used the time-series data shown in Figure E-2 and Figure E-3 to predefine the end user and BPA Power customer loads. All simulations included five DR peak days per year and a minimum discharge duration of at least one hour.

Figure E-2. Hourly Usage Data on Hospital Taken from DOE Commercial Reference; Building Models Based on Typical Metrological Year for Seattle

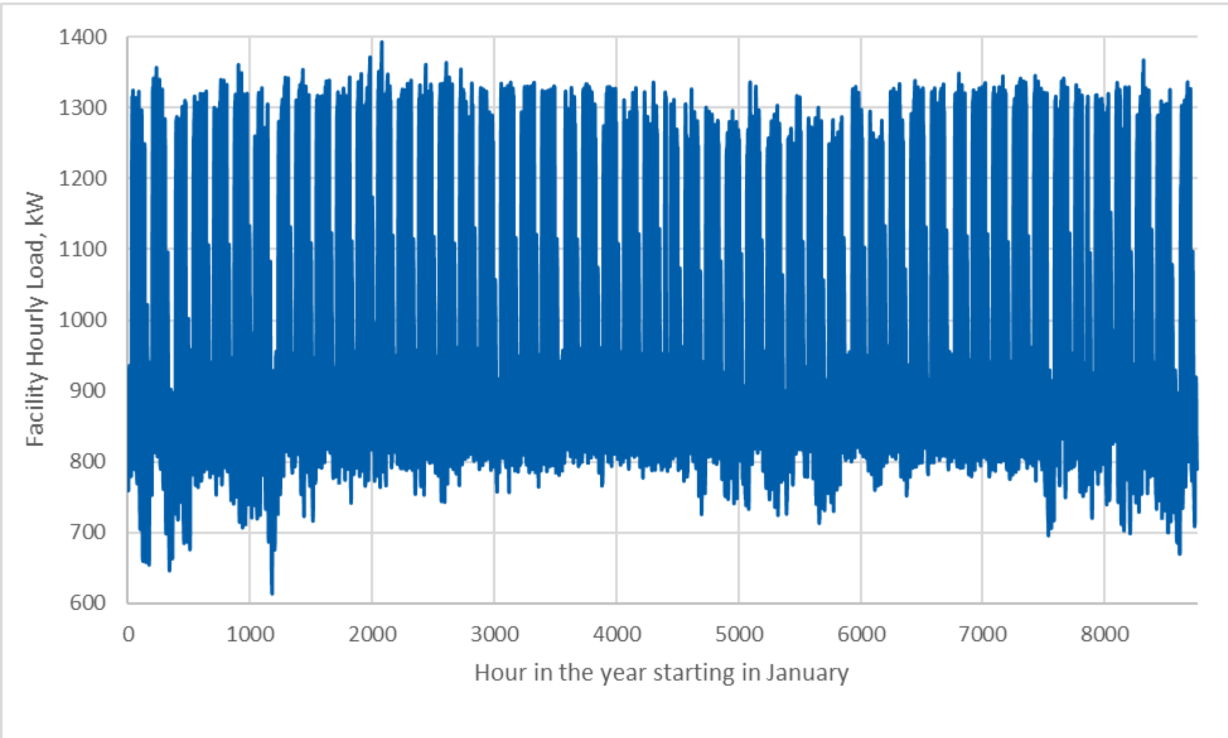
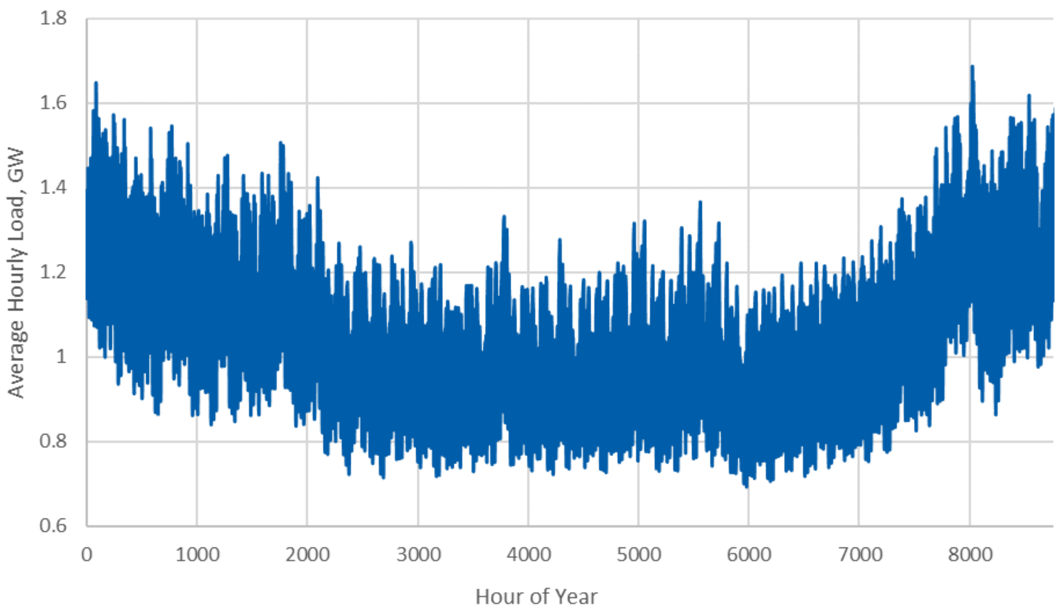


Figure E-3. Total System Load for Seattle City Light from 2016, Supplied by BPA

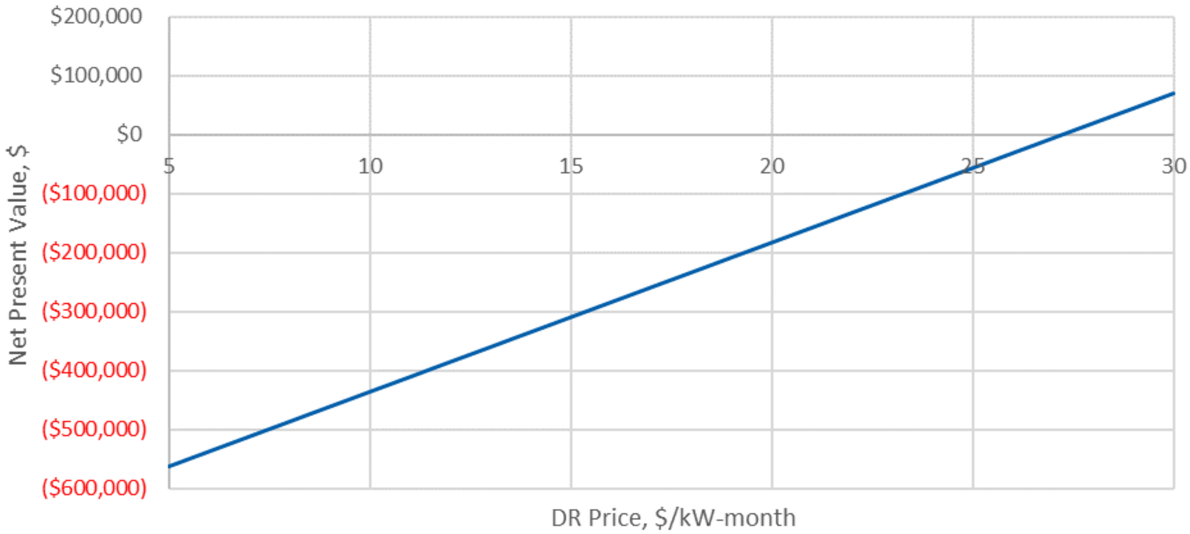


Under current pricing projections, Cadmus assumed that, in 2017, the capital cost for installing two-hour duration energy storage would be roughly $1,000 per kilowatt of capacity as the all-in cost for the whole-system. Therefore, a 1,000 kW-capacity system (battery and BOS) would require a total investment of $1 million. As already shown in Table E-3, the lifetime of the project is 10 years, during which time provisions to ensure constant capacity are assumed to be unneeded.

By varying the price at which DR participation is compensated, the value could be determined at which the project would become profitable. It is unrealistic to assume that DR participation prices would remain constant throughout the year but, for the purposes of this analysis, Cadmus used that assumption to more clearly indicate the influence of each value.

Assuming the C&I storage investment cost is $1,000/kW, Figure E-4 shows the project's profitability as the payment for DR participation increases. The project becomes profitable only when the DR price increases beyond $27.19/kW-month.

Figure E-4. Net Present Value of Plotted Project Versus Price for Participating in DR Program



As the price in capital cost would continue to drop, the DR price at which this project becomes profitable also drops. To determine how much DR program participation would influence the financials for installing a storage system at lower capital costs, Cadmus considered three cases in which capital cost factors were set to $1,000 per kilowatt of capacity, $500 per kilowatt of capacity, and $200 per kilowatt of capacity. For each value, Cadmus varied the DR price to determine the point at which the project would become profitable (Figure E-5).

Figure E-5. Net Present Value of the Project at Various Capital Cost Factors and DR Prices

As shown, lower capital costs substantially reduced the required DR price to make the project profitable. At $1,000 per kilowatt of capacity, the breakeven DR price occurred at $20.39 per kilowatt month. When the capital cost factor dropped in half, to $500 per kilowatt of capacity, the breakeven DR price would become $10.31. Finally, at $200 per kilowatt month—lower than any value the study projected for the next two decades, the breakeven DR price dropped to $4.26 per kilowatt month. With declining capital costs, the analysis shows that achieving much lower DR prices from ESS resources is possible. Further work must be conducted to investigate the various ways in which storage systems can be leveraged to offer multiple value streams and, in doing so, allocate the resource's capital cost among more stakeholders.

10.1.4. Defining the Methodology for Storage Technical and Achievable Potential

The following sections outline methods for estimating the technical and achievable potential for energy storage.

Residential Energy Storage Methodology

For DR purposes, energy storage installed at a residence can be coordinated to discharge power into distribution systems at ideal times to reduce the net load on BPA Power customer–owned equipment. For DR programs for the home and home automation systems, the control of battery activity could theoretically be influenced by the distributed energy resources management system that is coordinating other controllable loads in the home. Cadmus did not analyze this option alone as a market segment; instead, the study focused on the potential to add storage to newly installed residential PV where grid resiliency benefits and potential tax benefits make storage more likely. Once that storage system becomes part of the home's systems, BPA Power customers' DR programs may take advantage of that resource.

Residential Technical Potential

The present—and foreseeable—market for residential energy storage in the Northwest does not provide a financial value stream that is likely to be attractive without providing significant incentives to residential end users when only grid charging is available. Given this, Cadmus expects that the residential market for storage will be driven by end users who are already installing solar PV on their homes and in locations where ESS charging can occur with free energy from the sun and where those customers desire modest backup power that an ESS will provide. Currently, for new PV installations that include an ESS, vendors can include the cost of the system when calculating tax incentives, making it even easier to adopt ESS on new installations.

To estimate the potential for this market, Cadmus conducted a literature review and assessed data on existing solar incentive programs and interconnection applications to estimate what fraction of new solar PV installations are likely to include an ESS.

There are two standard configurations for integrating residential PV system with ESS: AC coupled and DC coupled solar and storage systems. With the primary focus on providing the end user with backup power (energy resilience) in relatively equal roundtrip efficiencies, each category defines its own advantages and disadvantages. In addition to estimating the expected market size, Cadmus identified a representative technology (such as the Tesla Powerwall or Solar Edge's StorEdge) and applied it to the projected market size to estimate the overall potential for residential BTM energy storage.

Based on Cadmus' experience with and knowledge of residential solar PV systems, the report assumed derating factors of 90% for total buildings with specific electrical upgrade needs and 95% for total buildings with specific spatial requirements. These factors are multiplied by potential estimates to account for these considerations. For example, if a hypothetical technical potential estimate is 10 MW, an estimated 5% of sites with spatial constraints would reduce the estimate to 9.5 MW.

Residential Achievable Potential

For BTM energy storage, Cadmus collected data on equipment installed from existing regional solar incentive programs, such as those managed by the Energy Trust of Oregon. Cadmus used these data to calculate the proportion of solar projects, by sector, which include ESS, and applied this proportion to calculate the achievable potential for BTM solar and storage. As the expected value proposition for these systems is based on energy resilience, and this value stream has been in place for many years already, Cadmus expected these past installation rates to be similar for the remainder of the study period, absent the presence of any new incentives or value streams or marked changes in grid reliability that might drive further investment in energy resilience.

Cadmus determined the feasibility of the residential buildings for ESS based on the total amount of buildings feasible for solar PV, multiplied by a derating factor due to building electrical upgrade needs, multiplied by another derating factor due to spatial considerations (such as homeowner association requirements).

Unlike the C&I, substation, and transmission market segments, Cadmus could develop the technical and achievable potential for residential storage based on these methods. Please see the 10.2.5 Residential ESS Potential Results section for more details.

Recommendations for Residential ESS Further Study

For the PV rooftop spatial factor enhancement, Cadmus would need to determine what percentage of the residential buildings that are feasible for solar PV system have space limitations and limitations imposed by a homeowner's association. To determine that, additional data requests will be necessary.

Commercial and Industrial Energy Storage Methodology

For the purposes of this study, the majority of BTM commercial and industrial (C&I) energy storage projects are assumed to be deployed for purposes of energy resilience where a backup generator is not a feasible option either due to environmental regulatory constraints, or cannot be economically justified.

Commercial and Industrial Technical Potential

The present and foreseeable market for energy storage in the Northwest presents a challenging financial value stream that is not currently attractive to C&I end users without significant incentives. In regions with high demand charges, such as New York and California, end users are proactively adopting ESS as a means of reducing utility costs at high peak demand facilities.

However, with low demand charges and low capacity prices in the Northwest, the primary driver of ESS deployment at C&I facilities will likely be driven by BPA Power customers' efforts to mitigate or defer other, more expensive, infrastructure improvements. Given this, we expect the most likely path of higher adoption to be a combination of end-user incentives for distribution system deferral and end use customers interested in resiliency.

To estimate the potential for ESS at C&I facilities, the analyst would request data from BPA's Power customers and their distribution system planners, including a thorough review of five-year and 10-year infrastructure upgrade plans, to identify planned upgrades to C&I-oriented feeders, substations, and associated network components. The focus would be on upgrades that have the potential to be deferred or replaced by ESS projects installed BTM on end-user property and under end-user ownership and control.

Cadmus expects that the following types of end users will be the most likely to install ESS:

- Large multishift C&I facilities
- Industrial parks and other areas with high concentrations of C&I facilities
- Facilities served by feeders, transformers, and substations requiring high-cost, capacity-based upgrades
- Facilities with resilience requirements to address low redundancy of current generation systems

The analyst would then estimate the technical potential for storage power and energy capacity deployed by C&I businesses using the following equations:

$$TP_{Power} = \sum_i L_{max,i} - L_{min,i} + L_{crit.base,i}$$

$$TP_{Energy} = \sum_i \left(L_{max,i} - L_{min,i}\right) * \left(T_{peak\ hours,i} + k_{crit.var,i} * T_{crit.var\ hours,i}\right) + \left(L_{crit.base,i} * T_{crit.base\ hours,i}\right)$$

Where:

TP_{Power}	=	Power capacity technical potential, kW
$L_{max,i}$	=	Maximum load for customer i, kW
$L_{min,i}$	=	Minimum load for customer i, kW
$L_{crit.base,i}$	=	Critical baseload for customer i, kW
TP_{Energy}	=	Energy capacity technical potential, kWh

$T_{peak\ hours,i}$	=	The number of hours of peak load that equals energy usage during peak periods
$k_{crit.var,i}$	=	The portion of the variable load that is considered critical for customer i
$T_{crit.var\ hours,i}$	=	The duration of time critical variable loads is required to be powered, hours
$T_{crit.base\ hours,i}$	=	The duration of time critical base loads is required to be powered, hours

Commercial and Industrial Achievable Potential

To assess C&I achievable potential requires developing adoption rates. These adoption rates consider similar ESS type customer adoption statistics from nearby locations or at least other areas of the US. They also take into account any potential incentives that BPA Power customers may offer through sharing of their distribution system deferral benefits. Any such incentives would likely accelerate the deployment of BTM ESS technologies and thereby defer or preclude the upgrade of transmission and distribution facilities. If an appropriate level of data was not available from a literature review and discussions with BPA, the analyst could conduct a brief survey among C&I end users in targeted areas to determine adoption rates with different scenarios of available incentive levels.

Determining the total BTM capacity and the type of ESSs most likely to be deployed would require using the analyst's engineering and utility experience, as well as close collaboration with BPA and their Power customers' in-house distribution experts. This could include an evaluation of both the upgrade(s) required to the Power customer's grid system and those required for the ESS facility.

Using the approach described below in the Substation and Utility Distribution Level Energy Storage Methodology section, the analyst could determine the wired costs of substation and distribution system upgrades. These wired costs would provide an estimate of what the BPA Power customer would need to spend to mitigate the constraint in the substation or feeder. The analysis could then prioritize the C&I storage measures that would likely result in a large cost savings to BPA Power customer through investment deferral.

Investment deferral should not be taken alone when determining customer incentives. The analyst should also consider all revenue streams or financial savings a business could realize by owning and operating an ESS at its facility. Ultimately, the analyst could compare the expected cost-effectiveness of BTM ESS with the cost of ESS identified in the other market segments to provide a ranked stack of ESS deployments that demonstrate the lowest-cost mix of ESS resources that achieve transmission and distribution deferral goals at lowest cost.

Substation and Utility Distribution Level Energy Storage Methodology

Determining the potential for storage at the distribution level requires collecting information from BPA Power customers about heavily loaded feeders in their service area that will require an upgrade in the planning horizon. This requires BPA Power customers to provide data on distribution feeders they believe will require a capital upgrade over the study period.

Energy storage that is installed at points of interconnection directly tied to a substation or distribution infrastructure, such as a feeder segment, and that is under control of the local utility, has the potential to offer cost-competitive investment deferral in addition to improvements to resiliency and power quality. Systems with power capacities ranging in size from kilowatts to megawatts are currently being deployed with sufficient multi-hour energy capacities to offer reliable investment deferral, ancillary services, and congestion relief.

Characteristics and Proposed Technical Potential Approach

This market segment includes BPA Power customer–owned electric substations in BPA's service area where the ESS is connected at the distribution level either at the substation or on a feeder segment. Cadmus' price analysis for this market segment includes the standard BOS used in the BTM market segment and includes additional switchgear and transformers to interconnect the storage system to the distribution system at 12.47 kV.

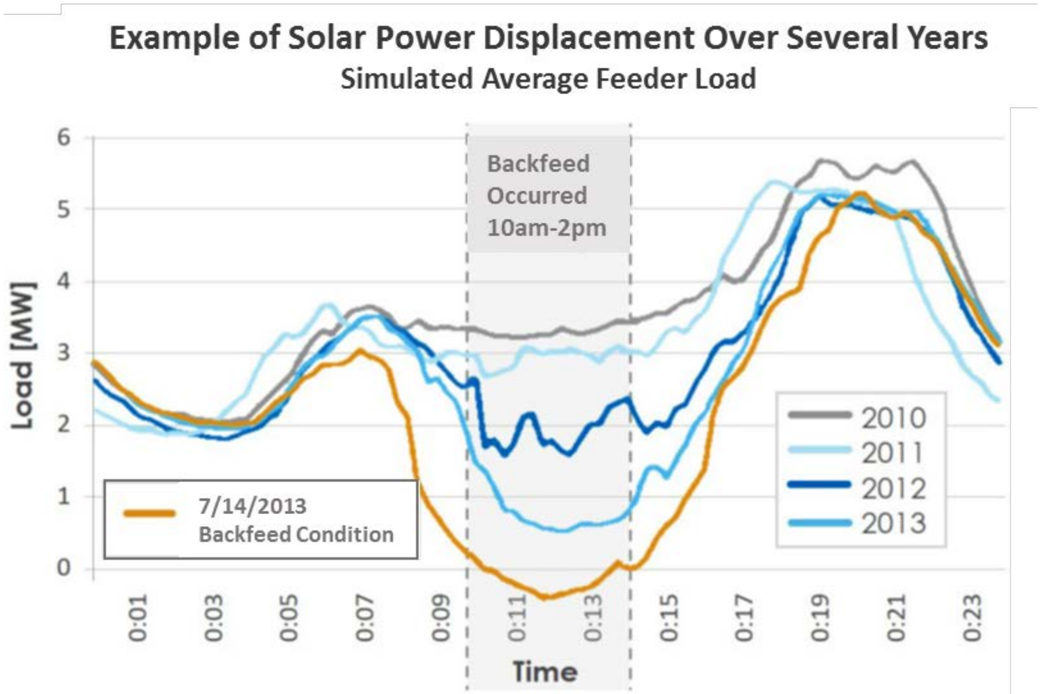
At this level, storage systems would typically have 3 MW to 10 MW nameplates to provide these feeder benefits:

1. Supply whole feeder backup for high-reliability zones
2. Make fast and easy substation control operations, for volt VAR benefits
3. Provide a large energy store for duck curve remediation (see Figure E-7)
4. Promote good non-wires alternative options by supporting any DR operations
5. Be used for frequency regulation when not used for other use cases
6. Provide flexibility so storage can be switched to different feeders as needed.

The primary use cases for BPA are to support management of high-reliability zones, support and integrate with DR use, and provide feeder peaking benefits. As solar growth continues in the Northwest, storage can be used to reduce ramp rates and peaks that occur in the evening as solar power falls off as the sun sets.

Figure E-6 shows how displacement of summer feeder load can be displaced with solar power during the day but needs to be quickly replaced with grid power in the evening as solar production drops and loads peak around 6:00 p.m. to 9:00 pm. This effect is known as the "duck curve."

Figure E-6. Duck Curve Forms as Solar Power Displaces More Loads During Midday



Power customer distribution planners would use their available planning models (load flow/power flow models) to identify needed infrastructure upgrades, future duck curves, or other issues. Data provided from these models allow an analyst to model opportunities that might supplement or replace conventional grid equipment with energy storage applications. This ensures, to the extent possible without a detailed site-by-site engineering study, that the estimated potential for ESS technologies will resolve the issues prompting the planned infrastructure upgrades.

Achievable Potential

ESS economics are modeled from the BPA Power customer perspective, using chosen incentive levels and estimated with all cost-effective energy storage projects for each substation- and/or feeder-constrained zone. The analyst can then use cost estimates from BPA Power customer or use engineering data to estimate the wired costs of substation and distribution system upgrades. These wired costs provide an estimate of what a BPA Power customer would have to spend to mitigate constraints in the substation or feeder.

From this, an analyst could estimate three incentive levels and associated adoption rates to apply to the potential: no incentive, medium incentives, and high incentives. Achievable potential estimates can be based on any of the incentive levels, but generally are based on those most likely to be implemented.

After determining the number of constrained substations and feeders, the analyst should consider if other options may already offer investment deferral and grid services (e.g., DR, distributed generation) by coordinating with other non-wires alternative options.

The analyst can then characterize the full population of substations using the following criteria:

- Regulations and storage restrictions throughout BPA
- Critical upgrades (e.g., those to capacity and regulations) in the next 10 years
- Levelized costs for the proposed ESS

By applying these adoption rates to estimates of technical potential, the analyst can estimate a more realistic value for achievable potential of deploying energy storage integrated with distribution infrastructure.

The analyst could then determine the amount of MW load reduction from the non-wires storage alternatives needed for each feeder or substation regarding existing and projected future loading at the peak period (as provided by the BPA Power customer), through the following equation:

$$LRT_p = EL_p - FL_p$$

Where:

LRT_p	=	Load reduction target at peak period
EL_p	=	Existing loading at peak period
FL_p	=	Future loading at peak period

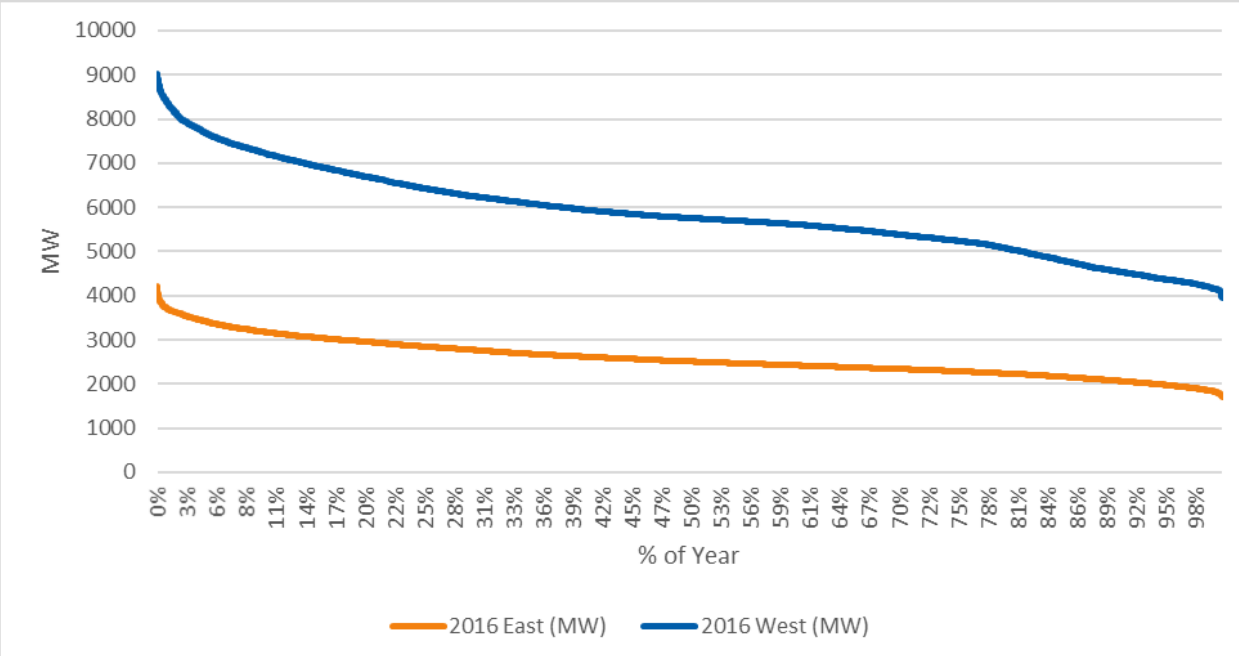
Existing loading (EL_p) minus future loading (FL_p) results in the loading reduction target necessary to off-load the feeder or substation sufficiently to defer installation of a new feeder or substation equipment.

The analyst could develop load reduction duration needs at peak, presented as load duration curves, from substation metering data for individual feeders or totalized from multiple substation meters. BPA Power customers could provide BPA with their peak period information and load duration curves (from SCADA data or distribution modeling software).

Figure E-8 shows a representative load duration curve for the BPA's east and west areas. By examining specific load duration curves on a substation, transformer, or feeder showing steeply sloping curves and the resulting peaking needs, a storage system with sufficient power and energy capacity can be proposed to provide large reductions in peak demand. This information can be combined with other non-wires alternatives to obtain combined benefits.

Results from all these analyses should provide both technical and achievable potential of ESS installations at substations and may be compared side by side with results obtained from the C&I customer-side BTM market segment in an attempt to provide the same non-wires benefits, only from a more distributed market segment.

Figure E-7. 2016 Load Duration Curves for East and West Areas



Substation Level Storage Example with Capacity Avoided Cost Proxy

As shown in Figure E-8, storage pricing at this level was built up from the GTM research brief by totaling the balance of system costs from the grid and adding the additional substation equipment needed to interconnect the storage at the distribution level (Gupta 2017). The values displayed are cost-per-kilowatt values. It is worth noting that this example does not include utility control costs such as distributed energy resource management systems.

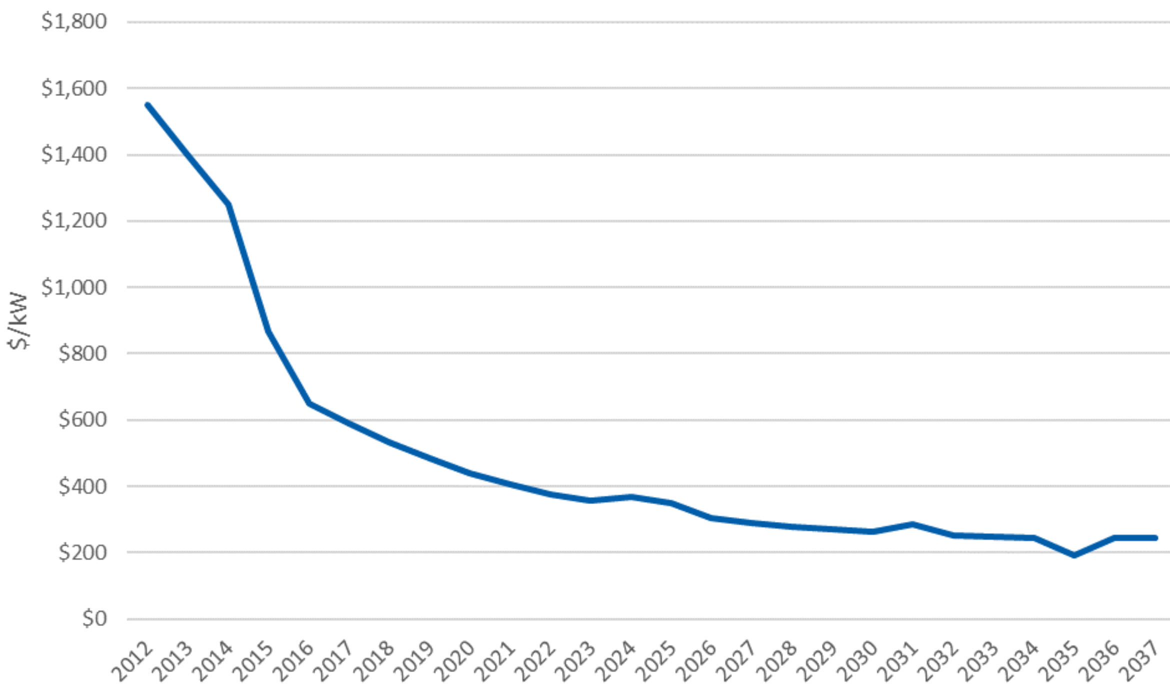
The balance-of-system costs total to $1,550 in 2012, which dramatically drop to below $600 in 2018 due to declining inverter/power conversion system costs (as shown in Figure E-8). Cadmus completed several sensitivities of balance-of-system costs—there have been some significant improvements in balance-of-system costs from 2013 through 2017. However, future total system costs are projected to decline more moderately as shown in Figure E-8. The following details the balance-of-system cost-per-kilowatt components of the substation storage example:

- **Hardware costs** include inverters, software, container, containerization (includes more than ten sub-components), SCADA/controller.
- **Engineering, procurement and construction (EPC) costs** include six sub-component costs.
- **Soft costs** include interconnection (excluding high-voltage interconnection or substation upgrade), overhead expenses, and customer acquisition costs.
- **Other unique project-specific costs** such as microgrids, multiport inverters, and solar coupled with storage. ESS Balance of System Costs

- **Additional cost components (front-of-meter)** include transformer and switchgear.

It is worth noting this example does not include utility control costs such as distributed energy resource management systems.

Figure E-8. Energy Storage System Balance of System Costs



At the substation level, Cadmus determined and plotted the total price forecast, as shown in Figure E-9, which includes forecasted price curves for a 30-minute storage product, a two-hour storage product, and a four-hour storage product installed at the substation level.

Figure E-9. Price Forecast for 30-Minute, 2-Hour, and 4-Hour System Durations at the Substation Level

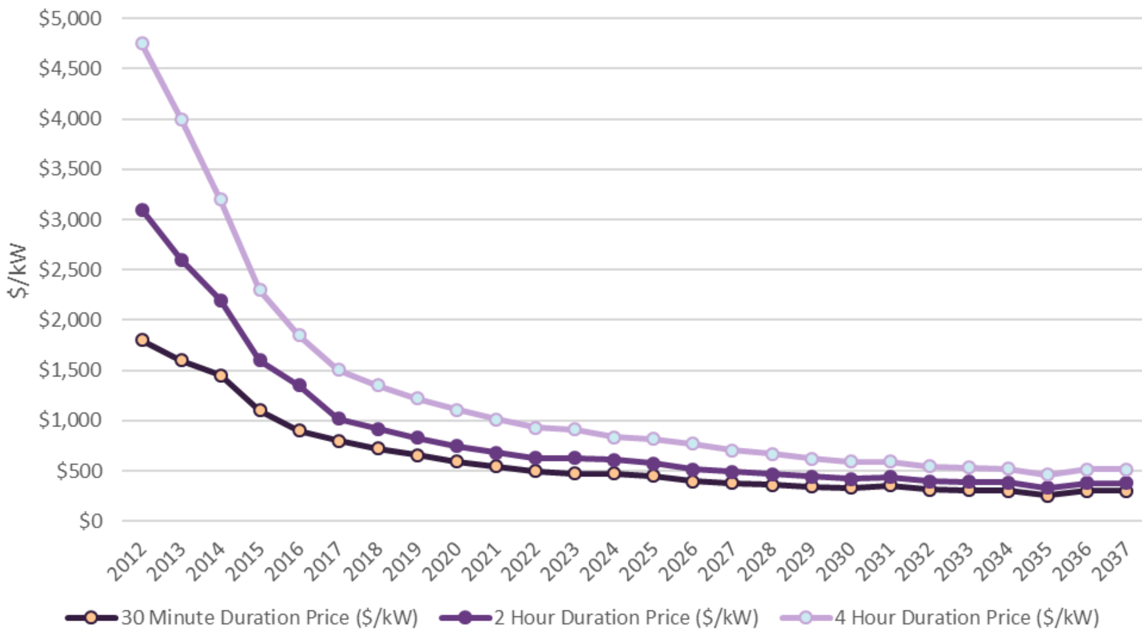


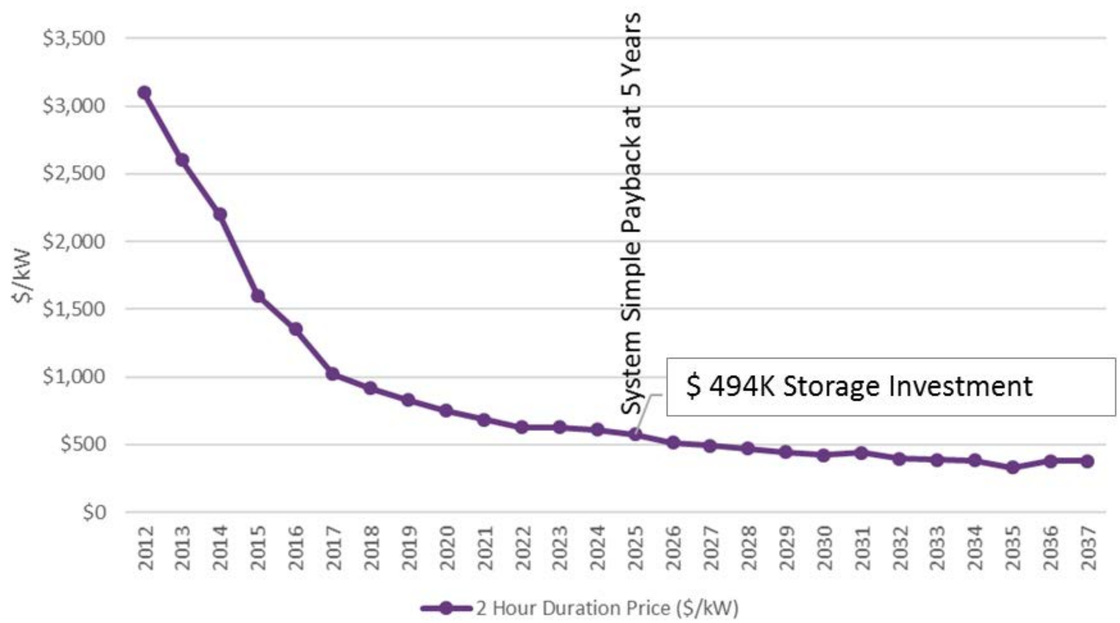
Table E-6 provides a case study example using a simple payback approach at four points in time. Cadmus developed a "proxy" for cost of capacity by assuming a BPA power customer has reached or exceeded a demand level such that they incurred a demand charge. We realize most power customers do not reach this level, but if they did the avoided capacity proxy cost could equal $10 per kW. For simply a starting point, we utilized a BPA demand charge from PF-18 Priority Firm Power Rate Customers as the "proxy" for this assumed avoided cost of capacity.

For the simple payback analysis of storage, we held the capacity cost constant, assumed the system battery life was 10 years, and the system size would be 1,000 kW. As shown in Table E-6, if a two-hour energy storage product can reduce monthly avoided capacity costs for a power customer at the 1 MW level, a simple payback at five years is achieved with a $494,043 investment per MW made in energy storage in the year 2025. Figure E-10 shows the forecasted cost curve of substation level storage and the point near 2025 where the storage system achieves a 5 year or less payback under these assumptions.

Table E-6. Example Capacity Cost Avoidance Using Substation Storage

Year	System Cost	Annualized Simple Payback (Years)
2017	$1,020,000	8.5
2020	$749,000	6.2
2025	$494,043	4.1
2030	$373,806	3.1

Figure E-10. Forecast for 2-Hour Storage Product with Simple Payback



Transmission-Level Energy Storage Methodology

In some cases, energy storage may be a valuable addition to a transmission system that faces excessive congestion or opportunities of deferral. Such systems must have very large power capacities but could have a variety of energy capacities depending on the types of service being provided.

Recommendations for Determining Technical Potential

The technical potential of energy storage at the transmission level should be focused on transmission zones that have one of two conditions:

- ***Too much load that needs to be reduced at times:*** In this condition, energy storage can help to reduce congestion. With too much load, the ESS will be optimized for discharging energy into the system over significant periods of time.
- ***Too much energy at intermittent times that reduces adequate flow of power on the transmission system:*** In this condition with too much generation, the ESS will be optimized for charging and with extra storage capacity to collect and store the excess power to be scheduled at another time.

For transmission-level storage, the use of large, four-hour or greater battery systems should be considered for analysis. In addition, storage plant sizes of at least 50 MWs should be analyzed.

The following equations show a basis for determining the megawatt load reduction needed for each transmission segment or zone of the current and projected future loading provided by the BPA at the constrained hours or peak generation hours:

$$LRT_p = CL_p - FL_p$$

$$GAT_p = CL_p - FL_p$$

Where:

LRT_p	=	Load reduction target at critical hours
GAT_p	=	Generation absorption target at critical hours
CL_p	=	Current loading at critical hours
FL_p	=	Future loading at critical hours

The current loading minus the future loading results in the loading reduction target needed to off-load the transmission segment sufficiently to mitigate a remedial action scheme or to avoid installing upgraded equipment. The analyst could base the peak load reduction duration on load duration curves developed from transmission segment or element metering data. BPA should develop critical or peak period information and load duration curves from transmission tagging, energy management system (EMS) data, or transmission modeling software.

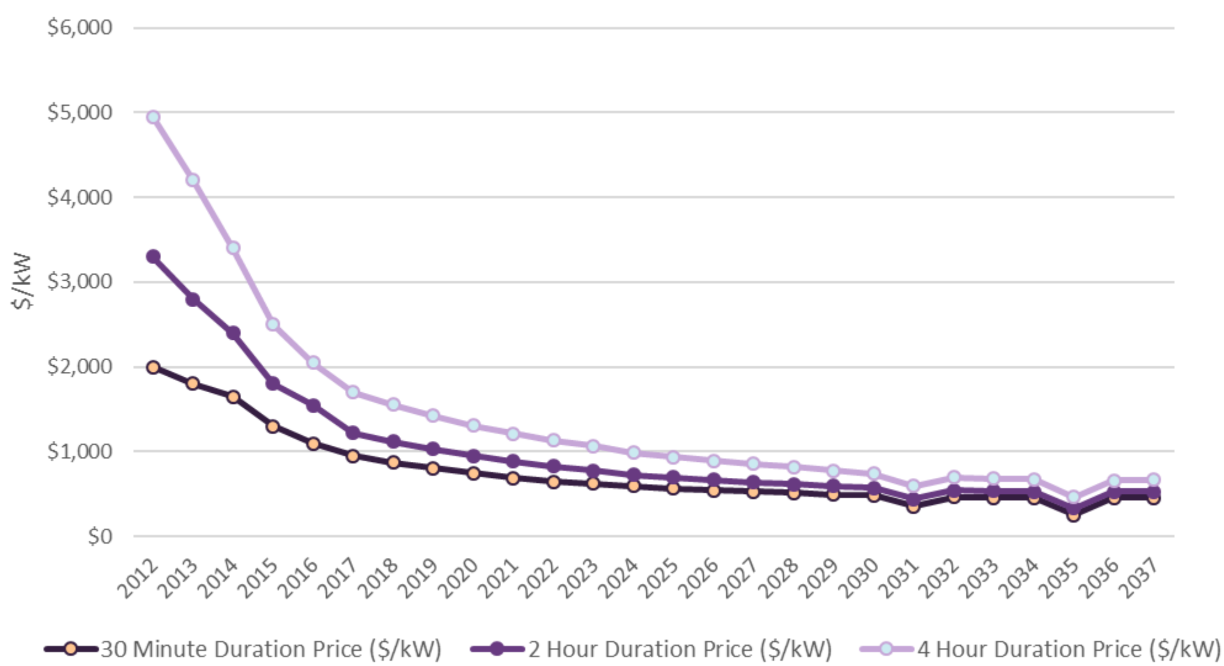
Pricing Estimates Transmission Level

With current production capabilities, large deployments of transmission-level energy storage are problematic and will likely have long lead times as production facilities work to achieve gigawatt delivery capabilities. However, Tesla with 20MWs, Greensmith Energy with 20MWs and AES Energy Storage with 30MWs recently installed three large-scale lithium-ion battery projects totaling 70 megawatts combined from the three manufacturers. The installations were installed quickly to address projected energy shortages from the Aliso Canyon gas leak. Also, vanadium flow batteries show promise for transmission level storage due to their long life, low costs, safety, long duration discharge periods, large-scale units, unlimited cycles, and lower environmental hazards, but have yet to be demonstrated at scale required for transmission performance. That too maybe changing with the announcement in July 2017 that a brine4power redox flow system will be set up in the Jemgum gas storage facility in Germany to make use of two huge underground salt caverns. The cavities are currently used to store natural gas and have a volume of 3.5 million cu ft. The result is a potential battery capacity of up to 120 MW and 700 MWh.

There is limited information about the interconnection approaches for energy storage at the multiple MW transmission level for both discharging and charging, Cadmus' initial attempts at cost analysis assumes that balance-of-system costs at the transmission level are similar to applying multiple distribution substation–sized storage systems of 10 MW capacities and tying them together at the 13-kV level into a transmission substation located at a constrained element.

Cadmus' closest proxy was a large solar plant interconnected at the 115 kV or 260 kV level. Cadmus based the initial costing on this scenario so that both distribution level balance-of-system costs and a transmission-level substation is included. More experience is necessary to determine better cost estimates at this level. Figure E-11 provides Cadmus' best-estimate cost curve for a transmission-level 50 MW to 100 MW lithium ion battery storage system.

Figure E-11. Transmission-Level Pricing Curves for 50 MW to 100 MW



Achievable Potential Methodology

Transmission level storage achievable potential is determined entirely by BPA transmission planning and engineering departments based on need and budgets. One recommendation might be the issuing of a request for information (RFI) or a more binding request for offers (RFO) to see what market players would be interested and their available quantities and prices for transmission scale storage. The analyst can support these developments by assisting with a tipping point analysis of ESS. This analysis must be supplemented with additional analytics on engineering estimates for ESS. These analyses will allow BPA's transmission team to determine the time frame when ESS costs reach a level such that they are part of an optimal solution to address a potential transmission need.

10.2. Assessment Results

Cadmus' focus for this study was to provide cost projections of energy storage and to assess methodologies for determining technical potential and achievable potential rather than to develop a firm potential estimate. The exception was residential energy storage combined with solar, for which Cadmus conducted technical and achievable potential (as described below).

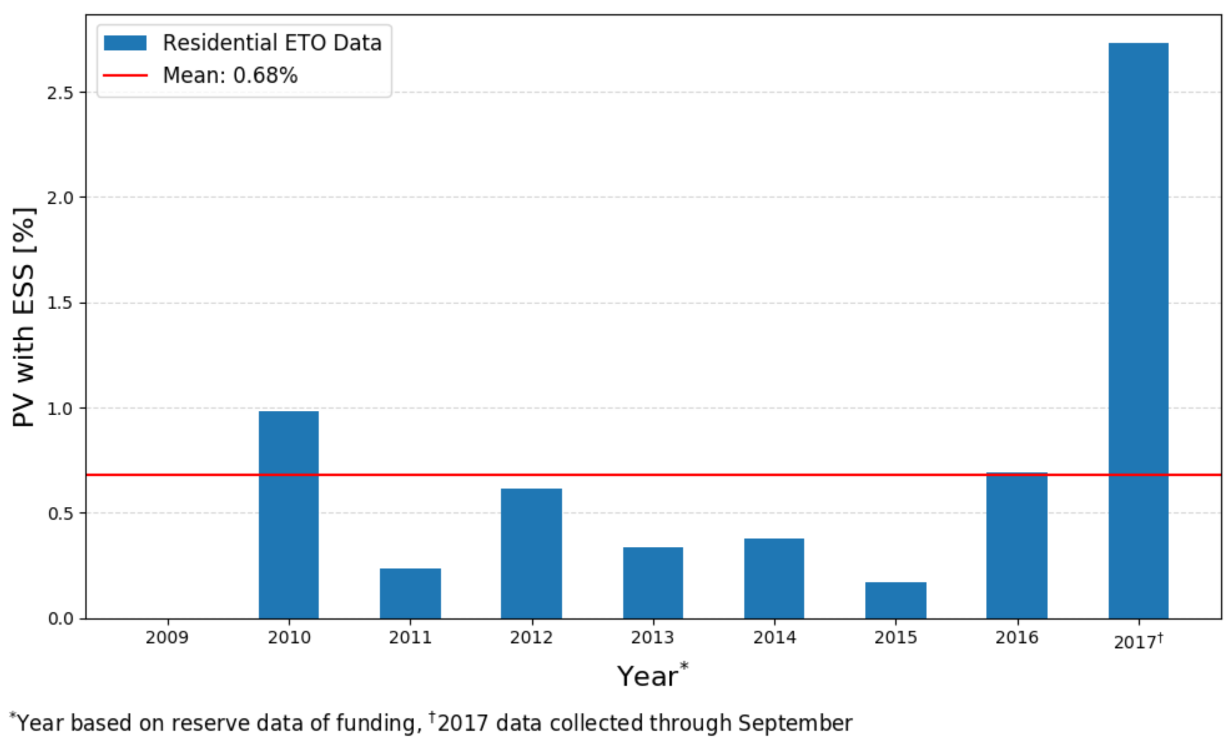
As an additional focus, Cadmus identified the needs and necessary infrastructure to gather data for future studies and research for each of the four market segments considered. Cadmus also prepared detailed price curves over the study period to allow BPA modelers to use these curves in their models to adequately represent storage in their forecasts and in their non-wires analyses. This will help with a challenge relayed during interviews with BPA staff, who said that storage prices are challenging for analysts to determine.

Also, as mentioned in the methodology section, Cadmus focused only on battery technologies for that analysis, with an emphasis on lithium-ion technologies, which is the current energy storage market leader. For water heating and other thermal technology, these forms of energy storage are included in the Demand Response section.

10.2.1. Residential ESS Potential Results

The Energy Trust of Oregon provided Cadmus with a dataset detailing the funding and installation of residential PV systems in Portland General Electric and Pacific Power territories between 2009 and 2017. This dataset included whether an energy storage system was installed and only contained information about systems that were purchased as part of a rebate program. Figure E-12 displays the percentage of PV installations accompanied by storage.

Figure E-12. Energy Trust of Oregon Residential PV with ESS



Adoption rates have historically been low, ranging from 0% to just over 2.5%. Cadmus expects these rates to remain low and the installation of storage to be driven by consumer interest in resilience. Cadmus used the following equation to calculate achievable potential:

$$AP = \sum TP_i * C_{electrical,i} * C_{spatial,i}$$

Where:

AP = The total achievable potential for all residences

TP_i = The individual technical potential for each building, i, deemed feasible for solar PV

$C_{electrical,i}$ = The derating factor for unfeasible buildings due to various electrical upgrade needs

$C_{spatial,i}$ = The derating factor for unfeasible buildings due to spatial limitations

To calculate the technical potential of storage, Cadmus used the technical rooftop potential in megawatts of PV, as presented in Table E-7. Cadmus calculated an average system size of 5.3 kW using the data provided by the Energy Trust of Oregon and used this value to estimate the technical potential of PV in terms of the number of systems. Cadmus then used the average percentage of PV installations that were accompanied by storage (as shown in Figure E-12 above) to approximate the number of storage systems, and multiplied the number of systems by the power in kilowatts specified for a single Tesla Powerwall. The choice of a single Powerwall is based on Tesla's recommendation for a 2,400-square foot home with a 5 kW PV system. Cadmus calculated the achievable potential of storage by applying derating factors for electrical infrastructure and spatial limitations of 0.90 and 0.95, respectively. Results are presented in Table E-7.

Table E-7. Residential Storage Potential

Estimate	Total	Washington	Oregon	Idaho	Montana
PV Rooftop Potential (MW)	6,137	4,057	1,274	463	343
Number of PV Systems*	1,157,925	765,472	240,377	87,358	64,717
Number of Energy Storage Systems**	7,874	5,205	1,635	594	440
Energy Storage Technical Potential (MW)***	39	26	8	3	2
Energy Storage Achievable Potential (MW)+	34	22	7	3	2

Assumption (source)

* Average 5.3 kW per PV system (Energy Trust data)

** 0.68% of PV systems install storage (Energy Trust data)

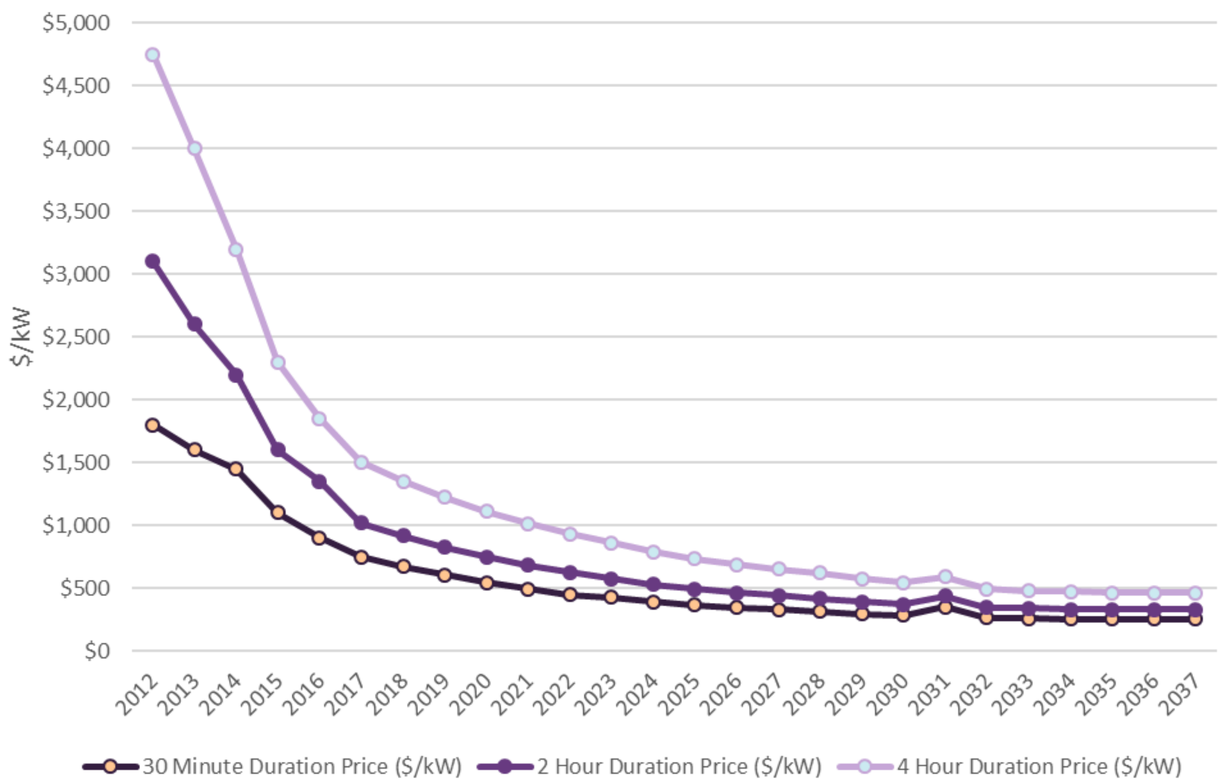
*** Average 5 kW per storage system (continuous power output rating of single Tesla Powerwall)

\+ 0.9 electrical factor, 0.95 spatial factor (Cadmus)

Pricing Estimates Residential Level

For residential applications, the balance-of-system costs is determined from the Tesla Powerwall or similar system pricing and includes installation costs. The value remaining after subtracting the estimated lithium-ion cell cost represents the container cost, supporting power conversion system, and installation costs. Cadmus determined the total price forecast, as plotted in Figure E-13, which includes forecasted price curves for a 30-minute storage product, a two-hour storage product, and a four-hour storage product.

Figure E-13. Residential Energy Storage System Price Curves by Duration Category ($/kW)



11. Appendix F. BPA's Public Power Customers in the Assessment Scope

Number	BPA Power and Federal Customer	Area	State
1	A&B Irrigation District	East	ID
2	Albion	East	ID
3	Alcoa, Inc.	West	WA
4	Alder Mutual Light Company	West	WA
5	Ashland	West	OR
6	Asotin County PUD	East	WA
7	Bandon	West	OR
8	Benton County PUD	East	WA
9	Benton Rural Electric Association	East	WA
10	Big Bend Electric Cooperative	East	WA
11	Blachly-Lane Electric Coop	West	OR
12	Black Canyon Irrigation District	East	ID
13	Blaine	West	WA
14	Bonners Ferry	East	ID
15	Brewster Flat Irrigation District	East	ID
16	Bridgeport Bar Irrigation District	East	ID
17	Burley	East	ID
18	Burley Irrigation District	East	ID
19	Canby Utility Board	West	OR
20	Cascade Locks	East	OR
21	Central Electric Cooperative	East	OR
22	Central Lincoln PUD	West	OR
23	Centralia	West	WA
24	Cheney	East	WA
25	Chewelah	East	WA
26	Clallam County PUD	West	WA
27	Clark Public Utilities	West	WA
28	Clatskanie PUD	West	OR
29	Clearwater Power Company	East	ID
30	Columbia Basin Electric Cooperative	East	OR
31	Columbia Power Cooperative Association	East	OR
32	Columbia Rural Electric Association	East	WA
33	Columbia River PUD	West	OR
34	Consolidated Irrigation District No. 19	East	WA
35	Consumers Power	West	OR
36	Coos-Curry Electric Cooperative	West	OR
37	Coulee Dam	East	WA
38	Cowlitz County PUD	West	WA
39	Declo	East	ID
40	Douglas Electric Cooperative	West	OR
41	Drain	West	OR
42	East Columbia Basin Irrigation District	East	WA
43	East End Mutual Electric	East	ID
44	East Greenacres Irrigation District	East	ID

Number	BPA Power and Federal Customer	Area	State
45	Eatonville	West	WA
46	Ellensburg	East	WA
47	Elmhurst Mutual Power & Light	West	WA
48	Emerald PUD	West	OR
49	Emmett Irrigation District	East	ID
50	Energy Northwest	East	WA
51	Eugene Water and Electric Board	West	OR
52	Fairchild Air Force Base	East	WA
53	Fall River Rural Electric Cooperative	East	ID
54	Falls Irrigation District	East	ID
55	Farmers Electric Cooperative	East	ID
56	Ferry County PUD No. 1	East	WA
57	Flathead Electric Cooperative	East	MT
58	Forest Grove	West	OR
59	Fort Hall BIA Irrigation District	East	ID
60	Franklin County PUD	East	WA
61	Glacier Electric Cooperative	East	MT
62	Grant County PUD*	East	WA
63	Grays Harbor County PUD	West	WA
64	Greater Wenatchee Irrigation District	East	WA
65	Harney Electric Cooperative	East	OR
66	Hermiston	East	OR
67	Heyburn	East	ID
68	Hood River Electric Cooperative	East	OR
69	Idaho County Light & Power	East	ID
70	Idaho Falls Power	East	ID
71	Inland Power & Light	East	WA
72	Jefferson County PUD	West	WA
73	Kalispel Tribal Utilities	East	WA
74	Kittitas County PUD	East	WA
75	Klickitat County PUD	East	WA
76	Kootenai Electric Cooperative	East	ID
77	Lake Chelan Irrigation District	East	WA
78	Lakeview Light & Power	West	WA
79	Lane Electric Cooperative	West	OR
80	Lewis County PUD	West	WA
81	Lincoln Electric Cooperative	East	MT
82	Lost River Electric Cooperative	East	ID
83	Lower Valley Energy	East	ID
84	Mason County PUD No. 1	West	WA
85	Mason County PUD No. 3	West	WA
86	McCleary	West	WA
87	McMinnville	West	OR
88	Midstate Electric Cooperative	East	OR
89	Milner Irrigation District	East	ID
90	Milton	West	WA

Number	BPA Power and Federal Customer	Area	State
91	Milton-Freewater	East	OR
92	Minidoka	East	ID
93	Minidoka Irrigation District	East	ID
94	Mission Valley Power	East	MT
95	Missoula Electric Cooperative	East	MT
96	Modern Electric Cooperative	East	WA
97	Monmouth	West	OR
98	Nespelem Valley Electric	East	WA
99	Northern Lights	East	ID
100	Northern Wasco PUD	East	OR
101	Ochoco (Crooked River) Irrigation District	East	OR
102	Ohop Mutual Light Company	West	WA
103	Okanogan County Electric Cooperative	East	WA
104	Okanogan County PUD No. 1	East	WA
105	Orcas Power & Light Cooperative	West	WA
106	Oregon Trail Electric Company	East	OR
107	Oroville-Tonasket Irrigation District	East	WA
108	Owyhee Ditch Irrigation District	East	ID
109	Owyhee Irrigation District	East	ID
110	Pacific County PUD No. 2	West	WA
111	Parkland Light & Water	West	WA
112	Pend Oreille County PUD No. 1	East	WA
113	Peninsula Light Company	West	WA
114	Plummer	East	ID
115	Port Angeles City Light	West	WA
116	Port of Seattle (SeaTac Airport)	West	WA
117	Port Townsend Paper Corporation	West	WA
118	Quincy Columbia Basin Irrigation District	East	WA
119	Raft River Rural Electric Cooperative	East	ID
120	Ravalli County Electric Cooperative	East	MT
121	Richland	East	WA
122	Riverside Electric Company	East	ID
123	Roza Irrigation District	East	WA
124	Rupert	East	ID
125	Salem Electric	West	OR
126	Salmon River Electric Cooperative	East	ID
127	Seattle City Light	West	WA
128	Skamania County PUD	West	WA
129	Snohomish County PUD	West	WA
130	Soda Springs	East	ID
131	South Board of Control Irrigation District	East	ID
132	South Columbia Basin Irrigation District	East	WA
133	South Side Electric Lines	East	ID
134	Spokane Tribal Irrigation District	East	WA
135	Springfield Utility Board	West	OR
136	Steilacoom	West	WA

Number	BPA Power and Federal Customer	Area	State
137	Sumas	West	WA
138	Surprise Valley	East	OR
139	Tacoma Power	West	WA
140	Tanner Electric Cooperative	West	WA
141	The Dalles Irrigation District	East	OR
142	Tillamook PUD	West	OR
143	Troy	East	MT
144	Tualatin Valley Irrigation District	West	OR
145	Umatilla Electric Coop	East	OR
146	Umpqua Indian Utility Cooperative	West	OR
147	United Electric Coop	East	ID
148	US DOE NETL (Albany)	West	OR
149	US DOE Richland	East	WA
150	US Navy - Bangor	West	WA
151	US Navy - Bremerton	West	WA
152	US Navy - Naval Station Everett - Radio Station Jim Creek	West	WA
153	Vera Water & Power	East	WA
154	Vigilante Electric Coop Inc.	East	MT
155	Wahkiakum County PUD	West	WA
156	Wasco Electric Cooperative	East	OR
157	Weiser	East	ID
158	Wells Rural Electric Co.	East	NV
159	West Oregon Electric Cooperative	West	OR
160	Whatcom County PUD	West	WA
161	Whitestone Irrigation District	East	WA
162	Yakama Power	East	WA

* A small portion of Grant County near Grand Coulee Dam is served with BPA power and energy.