CONSERVATION POTENTIAL AND DEMAND RESPONSE ASSESSMENTS

APPENDIX E

PUGET SOUND ENERGY

2023 Electric Progress Report

Contents

1. Introduction

We analyzed demand-side resource (DSR) alternatives in conservation potential and demand response assessments (CPA) to develop a supply curve as an input to the portfolio analysis. The portfolio analysis then determines the maximum energy savings we can capture without raising the overall electric or natural gas portfolio cost. This analysis identifies the cost-effective level of DSR to include in the portfolio.

We included the following demand-side resource alternatives in the CPA, which The Cadmus Group performed for this 2023 Electric Progress Report (2023 Electric Report) on behalf of PSE.

- **Codes and Standards (C&S):** These are no-cost energy efficiency measures that work their way to the market via new efficiency standards set by federal and state codes and standards. We included only those in place at the time of the CPA study.
- **Demand response (DR):** Demand response resources comprise flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost.
- **Distributed generation:** Distributed generation refers to small-scale electricity generators close to the source of the customer's load on the customer's side of the utility meter. This resource alternative includes combined heat and power (CHP) and rooftop solar.[1]
- **Distribution efficiency (DE):** Distribution efficiency involves conservation voltage reduction (CVR) and phase balancing. Voltage reduction reduces the voltage on distribution circuits to reduce energy consumption, so many appliances and motors can perform while consuming less energy. Phase balancing eliminates total current flow energy losses.
- **Energy efficiency measures:** We used this label for a wide variety of measures that result in a smaller amount of energy used to do a given amount of work. These include retrofitting programs such as heating, ventilation, and air conditioning (HVAC) improvements, building shell weatherization, lighting, and appliance upgrades.
- **Generation efficiency:**[2] This involves energy efficiency improvements at the facilities that house PSE generating plant equipment and where the loads that serve the facility are drawn directly from the generator, not the grid. These are parasitic loads — specific measures target HVAC, lighting, plug loads, and building envelope end-uses.

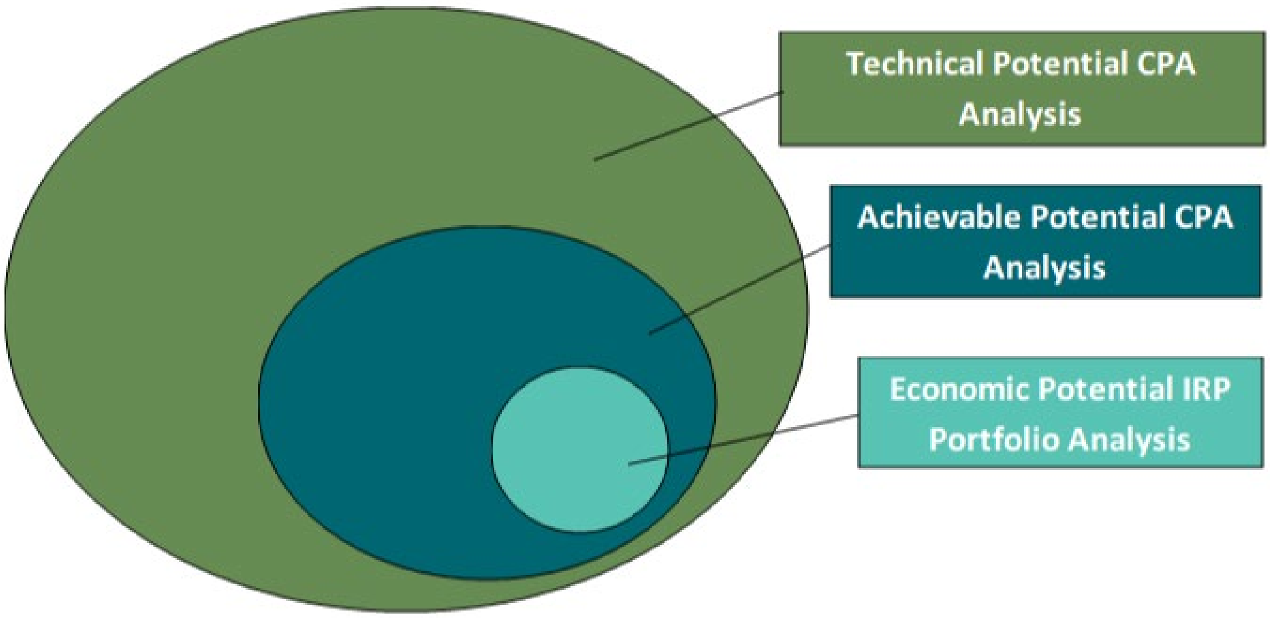
[1] In this report distributed solar photovoltaic (PV) is not included in the demand-side resources. Instead, it is handled as a direct no-cost reduction to the customer load. Solar PV subsidies are driving implementation and the subsidies are not fully captured with by the total resource cost (TRC) approach that is used to determine the cost-effectiveness of DSR measures. Under the TRC approach, distributed solar PV is not cost effective and so is not selected in the portfolio analysis. Treating solar as a no-cost load reduction captures the adoption of this distributed generation resource by customers and its impact on loads more accurately.

[2] Generation efficiency potential was studied in prior planning cycles, was relatively small and found to be not cost-effective and hence this resource is not included in this report.

2. Treatment of Demand-side Resource Alternatives

The CPA performed by the Cadmus Group on behalf of PSE develops two levels of demand-side resource conservation potential: technical potential and achievable technical potential. The 2023 Electric Report portfolio analysis then identifies the third level, economic potential. Figure E.1 shows the relationship between the technical, achievable, and economic conservation potentials.

Figure E.1: Relationship between Technical Achievable and Economic Potential

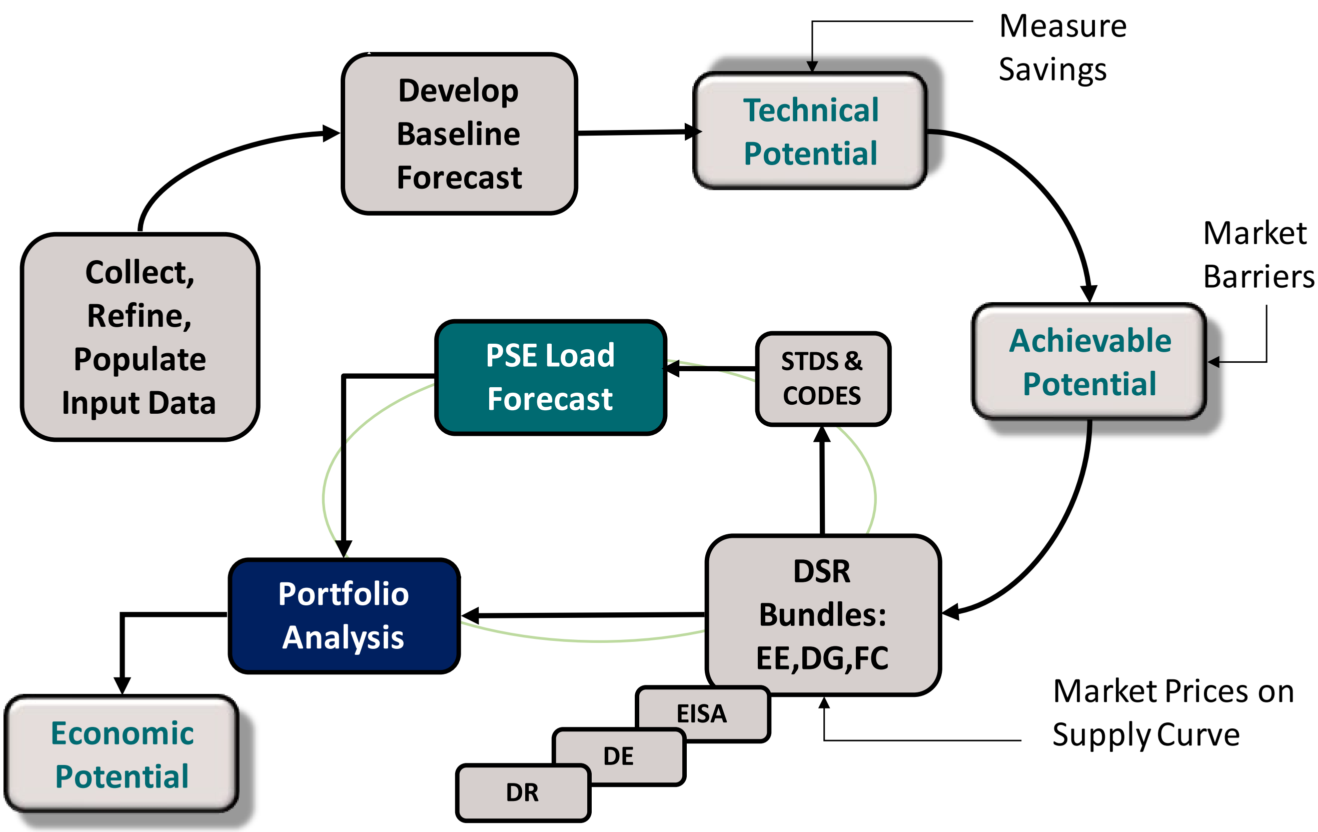


First, the CPA screened each measure for technical potential. This screen assumed we could capture all energy- and demand-saving opportunities regardless of cost or market barriers, which ensured the model surveyed the full spectrum of technologies, load impacts, and markets.

Second, we applied market constraints to estimate the achievable potential. Cadmus relied on customer response to past PSE energy programs, the experience of other utilities offering similar programs, and the Northwest Power and Conservation Council's most recent energy efficiency potential assessment to gauge achievability. For this report, PSE assumed achievable electric energy efficiency potentials of 85 percent in existing buildings and 65 percent in new construction.

We combined the measures into bundles based on levelized cost in the third step. This step produced a conservation supply cost curve in the portfolio optimization analysis to identify the bundles' economic potential (cost-effectiveness).

Figure E.2 Methodology to Assess Demand-side Resource Potential in the 2023 Electric Progress Report



➔ For the results of the Cadmus study, please see the excel file posted under Appendix E: Conservation Potential Assessment and Demand Response Assessment.

This appendix contains the conservation potential assessment report for the 2023 Electric Progress Report. It includes a detailed discussion of all the demand-side resource types mentioned, except for distribution efficiency, which PSE developed and discussed here.

3. Distribution Efficiency

We updated plans for distribution efficiency in this report to reflect 1) changes in technology required to maintain power quality and stability as the role of distribution efficiency grows and 2) the increase in amounts of the distributed generation entering the delivery system.

The original conservation voltage reduction (CVR) program we implemented in 2012–2013 utilized advanced metering infrastructure (AMI) meters that are now outdated and incompatible with the company-wide rollout of upgraded AMI technology that began in 2018. We expect to complete the rollout in 2023. In the meantime, selected substations that received the AMI upgrade can participate in the current CVR program.

We also have a second technology upgrade planned. The current CVR program is a static form of CVR that cannot react to compensate for changes in the distribution system produced by distributed resources such as battery storage, solar generation, and day ahead (DA) schemes. Because the static system cannot react and adjust to changing conditions in the distribution system, we are investing in automated distribution management system (ADMS) technology that we can program to automatically detect and anticipate changing conditions on the system. This technology allows the system to react fast enough to prevent damaging customers' power quality.

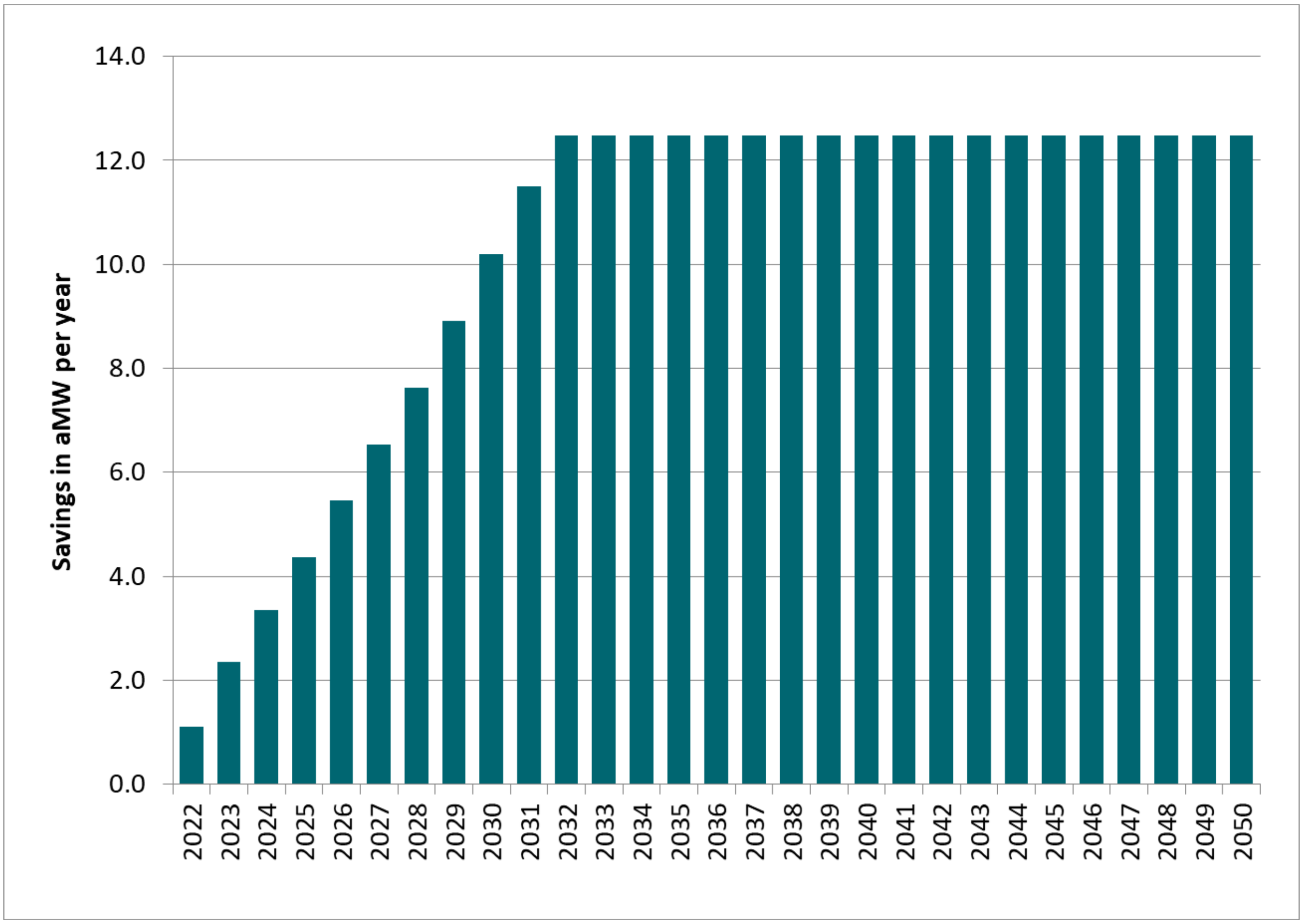
Once we implement the AMI and ADMS technologies, we will have the operational control system necessary to transition the CVR program to total Volt-Var Optimization (VVO). With its analytics and control intelligence, the ADMS will leverage AMI data at the end of line to dynamically optimize power delivery within the distribution network, minimize losses, and conserve energy. This system builds on dynamic voltage control by sensing and managing switched capacitors to optimize the power factor. VVO is a more sophisticated and extensive process than CVR but relies on similar principles.

We expect to complete the AMI rollout in 2023 and the ADMS software platform in 2026. We expect to begin piloting VVO in 2025. From 2023–2025, we will continue implementing the current static line drop compensation (LDC) CVR, but we may continue to encounter complications and risks due to changes in the distribution system that are already occurring.

Figure E.3 presents the expected cumulative savings throughout the 2023 Electric Progress Report planning horizon from CRV and VVO.

Eligible Substations: We started the current CVR program based on a study completed in 2007. That study identified approximately 160 substation banks with at least 50 percent residential customers as having the potential for energy savings using LDC CVR, based on typical customer usage patterns and the customer composition of the substations.

Figure E.3: Cumulative Savings in aMW from Distribution Efficiency (CVR+VVO)



CADMUS

Comprehensive Assessment of Demand-Side Electric Resource Potential (2024–2050)

Conservation Potential Assessment
Demand Response Assessment
Distributed Solar Assessment

August 31, 2022

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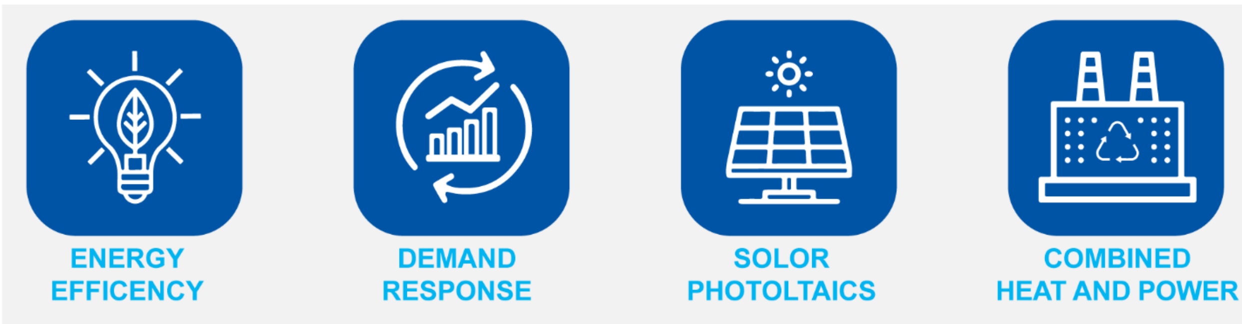
Acronyms and Abbreviations

Acronym	Definition
AMI	Advanced metering infrastructure
aMW	Average megawatt
ATB	Annual technology baseline
BPA	Bonneville Power Administration
BYOT	Bring your own thermostat
C&I	Commercial and industrial
CAC	Central air conditioner
CBECS	Commercial Building Energy Consumption Survey
CBSA	Commercial Building Stock Assessment
CETA	Clean Energy Transformation Act
CHP	Combined heat and power
Council	Northwest Power and Conservation Council
CPA	Conservation potential assessment
CPP	Critical peak pricing
dGen	Distributed Generation Market Demand
DLC	Direct load control
DRAC	Demand Response Advisory Committee
DRPA	Demand response potential assessment
ECM	Energy conservation measure
EISA	Energy Independence and Security Act
ERWH	Electric resistance water heater
EUL	Effective useful life
EV	Electric vehicle
EVSE	Electric vehicle supply equipment
FMY	Future meteorological year
FTE	Full-time equivalent
GEWH	Grid-enabled water heater
HPWH	Heat pump water heater
IRP	Integrated Resource Plan
NEEA	Northwest Energy Efficiency Alliance
NEI	Non-energy impact
NREL	National Renewable Energy Laboratory
O&M	Operation and maintenance
PGE	Portland General Electric
PSE	Puget Sound Energy
PV	Photovoltaic
RBSA	Residential Building Stock Assessment
RCS	*Residential Characteristics Study*
RCW	Revised Code of Washington
RTF	Regional Technical Forum
SME	Subject matter expert
T&D	Transmission and distribution
TMY	Typical meteorological year
TOU	Time of use
TRC	Total resource cost
UES	Unit energy savings
WAC	Washington Administrative Code
WSEC	Washington State Energy Code

Executive Summary

This report presents the results of an independent assessment of the technical and achievable technical potential for electric demand-side resources in the service territory of Puget Sound Energy (PSE) over the 27-year planning horizon from 2024 to 2050. This conservation potential assessment (CPA), commissioned by PSE as part of its integrated resource planning (IRP) process, is intended to identify demand-side resource potential in terms of energy efficiency, demand response, and distributed generation (including solar photovoltaics [PV] and combined heat and power [CHP]).



The results of this assessment will provide direct inputs into PSE's 2023 IRP and help PSE to identify cost-effective demand-side resources and design future programming. This study builds upon previous assessments of demand-side resources in PSE's territory and accomplishes several objectives:

FULFILLS STATUTORY REQUIREMENTS of Chapter 194-37 of the Washington Administrative Code (WAC), Energy Independence Act. The WAC requires that PSE identify all achievable, cost-effective, conservation potential for the upcoming ten years. PSE's public biennial conservation target should be no less than the *pro rata* share of conservation potential over the first ten years.[1] This study will help inform PSE targets.

SUPPORTS PSE'S COMPLIANCE with Washington State's Clean Energy Transformation Act (CETA), passed as Senate Bill 5116 in April 2019 (RCW 19.405),[2] by informing PSE's energy efficiency and demand response short- and long-term targets.

INFORMS PSE'S NEAR-TERM INTERIM TARGETS for its Clean Energy Implementation Plan as required by the CETA.

DEVELOPS UP-TO-DATE ESTIMATES OF ENERGY CONSERVATION datasets for the residential, commercial, and industrial sectors using measures consistent with the Northwest Power and Conservation Council's (Council) draft *2021 Northwest Conservation and Electric Power Plan* (*2021 Power Plan*), with the Regional Technical Forum (RTF), and with other data sources.

PROVIDES INPUTS INTO PSE'S IRP, which is completed every two years and determines the mixture of supply-side and demand-side resources required over the next 27 years to meet customer demand.

For this study, Cadmus incorporated the latest baseline and energy demand-side resource data from various PSE-specific sources (such as PSE program measure business cases); the work of other entities in

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1 Washington State Legislature. Energy Independence Act. Washington Administrative Code Chapter 194-37

2 Revised Code of Washington. Accessed August 24, 2022. "Chapter 19.405 RCW, Washington Clean Energy Transformation Act." https://app.leg.wa.gov/RCW/default.aspx?cite=19.405

the region, such as the Council, the Northwest RTF, and the Northwest Energy Efficiency Alliance (NEEA); and other secondary sources (such as various technical reference manuals). The methods we used to evaluate the technical and achievable technical energy efficiency potential draw upon best utility industry practices and remain consistent with the methodology used by the Council in its draft *2021 Power Plan* as this assessment was being updated (in January 2022). For the electric study Cadmus also estimated demand response potential to align with the Council's demand response methodology and to provide PSE with the data necessary to meet Washington State's CETA requirements, and we estimated distributed generation potential (including solar PV and CHP).

New in this CPA compared to prior CPAs, the electric study incorporates three additional considerations:

CLIMATE CHANGE	NON-ENERGY IMPACTS (NEIs)	NAMED COMMUNITIES

Cadmus adjusted weather-sensitive measures for the impacts of climate change, accounted for a wider range of NEIs, and estimated demand-side resource potential for named communities based on PSE's vulnerable population data. In addition, we assessed the impacts of recent state and local codes. All these topics are discussed in more detail in the main chapters of this report.

The PSE CPA results for natural gas energy efficiency potential (including transport customers and natural gas–to-electric impacts) can be found in a separate companion report titled *Comprehensive Assessment of Demand-Side Natural Gas Resource Potential (2024–2050)*.

Scope of the Analysis and Approach

This section outlines the scope of the energy efficiency, CHP, demand response, and rooftop solar PV potential analyses while briefly explaining the approach used for each analysis.

Energy Efficiency and Combined Heat and Power

Cadmus estimated the technical and achievable technical potential for more than 420 unique electric energy efficiency measures. We relied on PSE program data, RTF analysis, the Council's draft *2021 Power Plan* analyses, and regional stock assessments to determine the savings, costs, and applicability for each measure. We also incorporated feedback from PSE staff and regional stakeholders on the list of measures and measure assumptions.

Cadmus prepared 27-year forecasts of potential electric energy savings and peak demand reduction for each energy efficiency measure using an end use–based model. The assessment considers multiple sectors, segments, and vintages; distinguishes between lost opportunity and retrofit (discretionary) measures; and accounts for building energy codes as well as future state and federal equipment standards. Achievable technical potential estimates use assumptions that are consistent with the Council's draft *2021 Power Plan*: 85% to 100% of technical potential is achieved over the 27-year electric study horizon, and adoption curves are derived from the Council's draft *2021 Power Plan* ramp rates and 10-year ramp rates for discretionary measures (consistent with PSE's prior CPAs). A detailed discussion of the energy efficiency potential is covered under the *Energy Efficiency Potential* section of *Chapter 1. Energy Efficiency and Combined Heat and Power Potential*.

For the CHP analysis, Cadmus identified potential generation from nonrenewable and renewable CHP technologies in large commercial and industrial (C&I) facilities. We estimated CHP technical potential using generation and applicability data for reciprocating engines, microturbines, natural gas turbines, industrial biomass, and biogas. We determined achievable technical potential for these technologies using American Council for an Energy-Efficient Economy CHP favorability data[3] and an analysis of the recent U.S. Department of Energy "CHP Installation Database."[4] A detailed discussion of the CHP potential is covered under the *Combined Heat and Power Potential* section of *Chapter 1. Energy Efficiency and Combined Heat and Power Potential*.

Demand Response

Demand response programmatic options seek to help reduce peak demand during system emergencies or periods of extreme market prices and to promote improved system reliability. Cadmus focused on program options grouped into four areas: residential direct load control (DLC); commercial DLC; C&I curtailment; and price-based demand response. These options cover major customer segments and end uses in PSE's service territory and include residential DLC for space and water heating and space cooling, residential DLC electric vehicle supply equipment (EVSE), commercial DLC for space heating and cooling, C&I load curtailment, and residential and C&I critical peak pricing.

To estimate demand response potentials, Cadmus applied a hybrid top-down and bottom-up approach that began by using utility system loads, disaggregated into sector, segment, and applicable end uses. For each program, Cadmus first assessed potential impacts at the end-use level, then we aggregated these impacts to obtain estimates of technical potentials. With this approach, we applied market factors (such as the likelihood of program and event participation) to technical potentials to obtain estimates of market potentials. A detailed discussion of the demand response potential is covered under *Chapter 2. Demand Response Potential.*

Rooftop Solar PV

Cadmus' used the National Renewable Energy Laboratory's (NREL) Distributed Generation Market Demand (dGen) tool[5] to estimate technical and achievable market potential. We incorporated available data to assess solar PV potential for residential and commercial buildings, such as the power density of solar PV arrays and assumed future improvements in the efficiency of solar PV technology. NREL's dGen tool accounts for continuously changing economic conditions, such as declining technology costs,

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3 American Council for an Energy-Efficient Economy. n.d. "State-by-State CHP Favorability Index Estimate." http://aceee.org/sites/default/files/publications/otherpdfs/chp-index.pdf

4 U.S. Department of Energy. Last updated May 31, 2022. "Combined Heat and Power and Microgrid Installation Databases." https://doe.icfwebservices.com/chpdb/

5 National Renewable Energy Laboratory. Accessed August 24, 2022. "Distributed Generation Market Demand Model." https://www.nrel.gov/analysis/dgen/

changing tax credits, and electric rates over the study period. Cadmus developed the adoption diffusion-curve parameters based on PSE's historical adoption as well as PSE's near-term 2022 and 2023 projections. A detailed discussion of the rooftop solar PV potential is covered under *Chapter 3. Rooftop Solar PV Potential.*

Summary of Results

Table 1 shows the 27-year technical and achievable technical potential for each resource considered in this study. Electric demand-side resources represent nearly 556 average megawatts (aMW) of achievable technical potential and produce approximately 1,155 MW of winter peak savings. Energy efficiency has the highest energy-savings potential, with 548 aMW of cumulative achievable technical potential by 2050. The cumulative achievable technical potential includes both economic and non-economic potential.[6] All estimates of potential in this table are presented at the generator, which means they include line losses.[7]

Table 1. Summary of Energy Savings and Demand Reduction Potential, Cumulative 2050

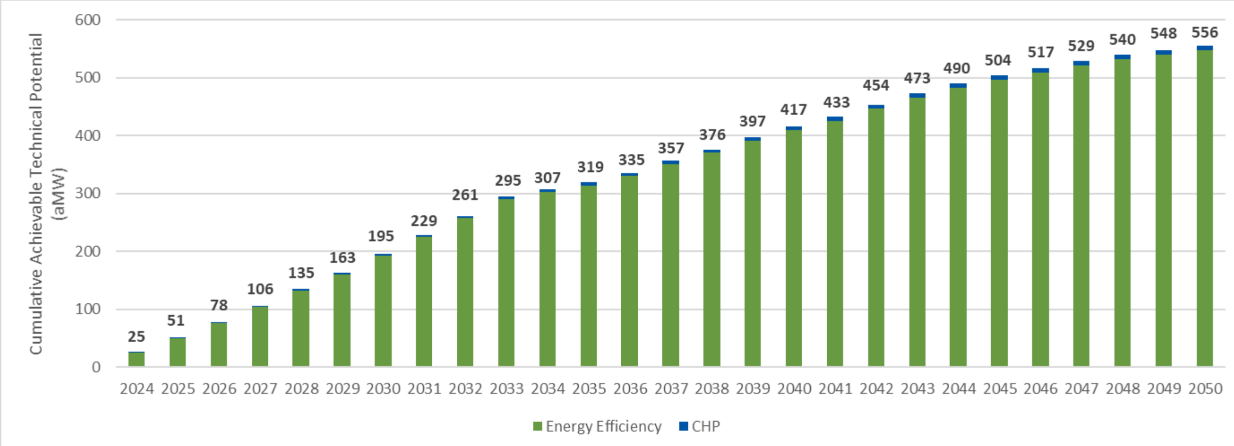
Resource	Energy (aMW)		Winter Coincident Peak Capacity (MW)	
	Technical Potential	Achievable Technical Potential	Technical Potential	Achievable Technical Potential
Energy Efficiency	640	548	831	706
Combined Heat and Power	230	8	287	10
Demand Response	N/A	N/A	N/A	439
Total	**870**	**556**	**1,118**	**1,155**

Figure 1 presents the achievable technical potential forecast for energy efficiency and CHP. More savings are achieved in the first 10 years of the study (2024 through 2033) than in the remaining 17 years because the study assumes that discretionary measure potential savings are acquired in the first 10 years (for a selected set of measures that are retrofit in existing homes and businesses). In the remaining years, additional savings come primarily from lost opportunity measures, such as equipment replacement and new construction.

6 PSE determines economic potential through the IRP optimization modeling process based on the achievable technical potential inputs from this study.

7 Cadmus assumed line losses of 7.8%.

Figure 1. Achievable Technical Potential Forecast, Cumulative 2024–2050



Energy Efficiency

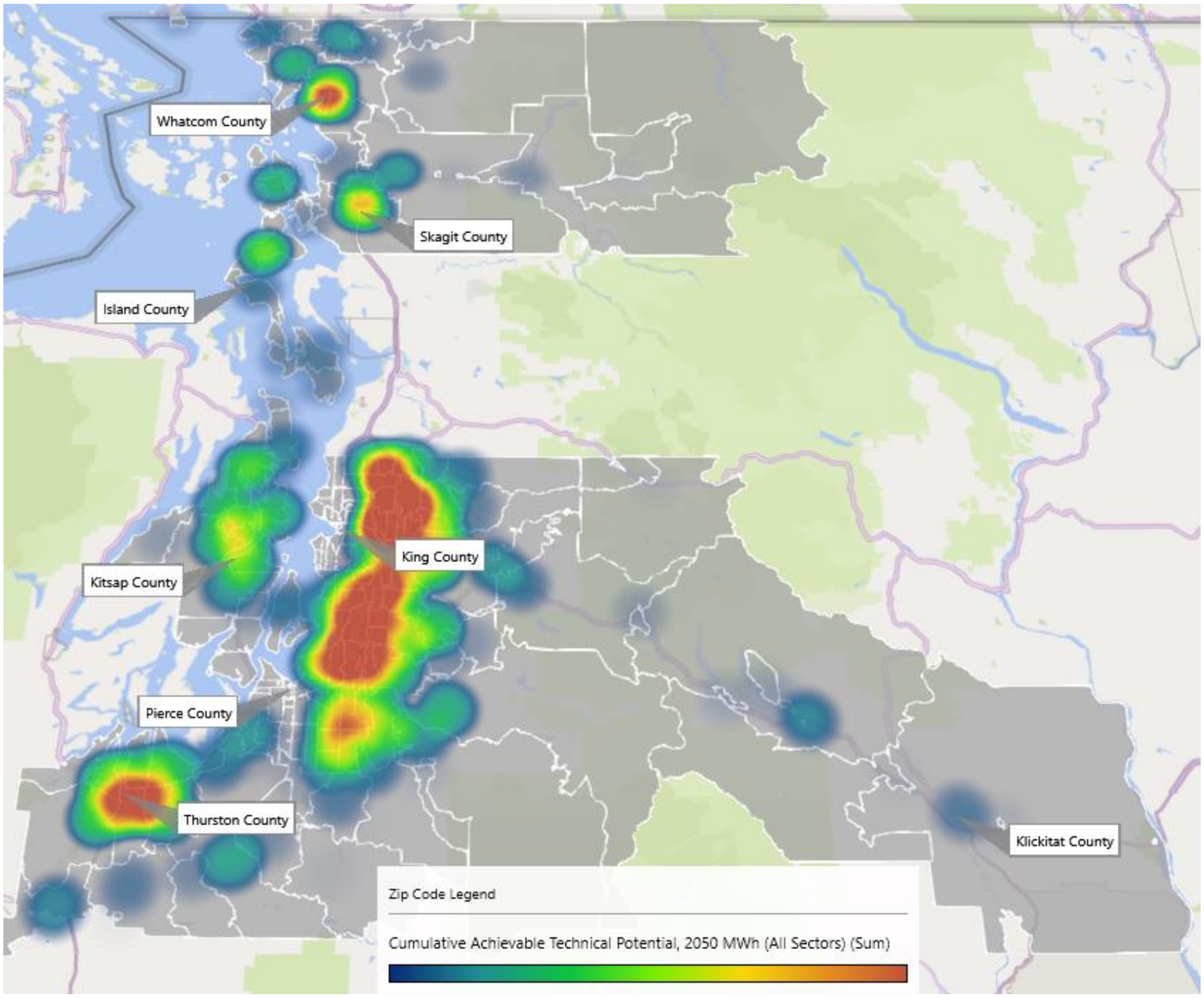
The total achievable technical potential for electric energy efficiency across all sectors is 548 aMW (Table 2). If the 27-year achievable technical potential is realized, it will produce a load reduction equivalent to 18% of PSE's 2050 baseline electric sales. Approximately 55% of this potential is in the residential sector, 42% in the commercial sector, and the remaining 3% in the industrial sector.

Table 2. Energy Efficiency by Sector, Cumulative 2050

Sector	2050 Baseline Sales (aMW)	Achievable Technical Potential	
		aMW	Percentage of Baseline Sales
Residential	1,818	298	16%
Commercial	1,149	231	20%
Industrial	119	18	16%
Total	**3,086**	**548**	**18%**

The achievable technical potential also can be displayed by zip code, where the potential is proportional to the number of PSE electric customers in each sector. As shown in Figure 2, most of the electric achievable technical potential occurs in King County.

Figure 2. Energy Efficiency Achievable Technical Heat Map by Zip Code — Energy (MWh), Cumulative 2050



Comparison to 2021 CPA – Energy Efficiency

Cadmus incorporated some changes in the 2023 energy efficiency analysis since the completion of PSE's previous CPA in 2021:

- Used an end-use–based approach instead of the units-based approach used in the 2021 CPA. This end-use approach is more dynamic for end-use scenario analysis and includes the ability to better account for climate change and natural gas–to-electric load impacts.
- Used PSE's most recent "2022 Demand Forecast" of energy and number of customers.
- Incorporated assumptions for savings, cost, and measure lives derived from PSE's 2022 measure business cases, RTF unit energy savings (UES), and draft *2021 Power Plan* supply curve workbook updates as of January 2022.

- Used the most recent PSE-specific data and regional stock assessments to determine saturations and applicability, including PSE's 2021 Residential Characteristics Study (RCS), NEEA's 2017 *Residential Building Stock Assessment II* (RBSA), and NEEA's 2019 *Commercial Building Stock Assessment* (CBSA)[8], which is PSE-specific for some segments.
- Accounted for the tightening Washington State Energy Code (WSEC) (RCW 19.27A.160),[9] which requires "… residential and nonresidential construction permitted under the 2031 state energy code achieve a 70% reduction in annual net energy consumption, using the adopted 2006 Washington state energy code as a baseline."
- Accounted for the 2018 WSEC residential electric heating provision that new construction homes with electric-zonal heating require ductless mini-split heat pumps.
- Accounted for updates in the Seattle Building Energy Code that require all new commercial buildings and large multifamily buildings above three stories to use clean electricity for space and water heating and to maximize building efficiency and on-site renewables like solar.[10]
- Accounted for ordinances passed by the city of Shoreline[11] and by the city of Bellingham[12] for promoting energy efficiency and the decarbonization of commercial and large multifamily buildings and requiring solar readiness for new buildings.

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8 Cadmus. May 21, 2020. *Commercial Building Stock Assessment 4 (2019)*. "CBSA 4 Appendix Tables (Weighted)." Prepared for Northwest Energy Efficiency Alliance. https://neea.org/resources/cbsa-4-appendix-tables-weighted

9 Revised Code of Washington. Accessed August 24, 2022. "RCW 19.27A.160 Residential and Nonresidential Construction— Energy Consumption Reduction—Council Report." https://app.leg.wa.gov/RCW/default.aspx?cite=19.27A.160

10 The implementation of the space and water heating measures took effect in January 2022. The rest of the code went into effect on March 15, 2021 (see February 4, 2021. "Seattle Bans Natural Gas in New Buildings." *The National Law Review* (Volume XII), Number 241. https://www.natlawreview.com/article/seattle-bans-natural-gas-new-buildings). The approved commercial WSEC update (April 2022) was not incorporated due to CPA timing that required the statewide implementation of similar requirements as the Seattle code update.

11 Ordinance No. 948 "Ordinance of the City of Shoreline, Washington Amending Chapter 15.05, Construction and Building Codes, of the Shoreline Municipal Code, to Provide Amendments to the Washington State Energy Code – Commercial, as Adopted by the State of Washington" took effect on July 1, 2022. The approved commercial WSEC update (April 2022) was not incorporated due to CPA timing that required statewide implementation of similar requirements as the Shoreline ordinance.

12 "Ordinance of the City of Bellingham Amending Bellingham Municipal Code Chapter 17.10 – Building Codes, to Provide Amendments to the Washington State Energy Code – Commercial, Promoting Energy Efficiency and the Decarbonization of Commercial and Large Multifamily Buildings and Requiring Solar Readiness for New Buildings" took effect on August 7, 2022. The approved commercial WSEC update (April 2022) was not incorporated due to CPA timing that required statewide implementation of similar requirements as the city of Bellingham ordinance.

- Accounted for recent changes to federal (residential air conditioning, residential and commercial heat pumps, residential lighting, and commercial direct expansion/packaged terminal air conditioners) and Washington State equipment standards, including products added to state standards by legislation.
- Accounted for the impacts of climate change by using *2021 Power Plan* data and PSE's load forecast and by adjusting weather-sensitive measures by applying Council typical meteorological year (TMY) to projected future meteorological year (FMY) adjustment factors to weather-sensitive RTF and PSE business case measures, by using residential air conditioning saturations to align with PSE load forecast projections (increasing over time), and by calibrating the CPA heating and cooling end uses with PSE's climate impacts within the annual load forecast.
- Considered a wider range of NEIs (such as comfort, productivity, and health) based on a recent study conducted for PSE.[13]
- Estimated the demand-side resource potential for named communities based on PSE's recent vulnerable population data, which has a somewhat similar overlay as highly impacted communities, defined by the Washington State Department of Health according to a ranking based on environmental burdens (including fossil fuel pollution and vulnerability to climate change impacts that contribute to health inequities) and best aligned with CPA geographic areas (county-level areas built up from block groups).

Table 3 shows a comparison of the 24-year achievable technical potential, expressed as a percentage of baseline sales, identified in the 2023 and 2021 CPAs. Overall, the 2023 CPA identified 13% lower electric achievable technical potential.

Table 3. Energy Efficiency Comparison of 2023 CPA and 2021 CPA, 24-Year Potential

Study	24-Year Achievable Technical Potential (Percentage of Sales)			Total Achievable Technical Potential (aMW)
	Residential	Commercial	Industrial	
2023 CPA	16%	20%	15%	521
2021 CPA	18%	19% [a]	8%	600

Note: This table compares 24-year results from 2023 CPA to the 2021 CPA. The 2023 CPA total achievable technical potential differs from the amount shown in Table 2, which presents the full 27-year potential study results. The wastewater segment was included in the commercial sector in the 2021 CPA but was included in the industrial sector in the 2023 CPA, following the Council's methodology. There was no separate water supply segment in the 2021 CPA, but there is a water supply segment in the industrial sector in the 2023 CPA, following the Council's methodology

[13] DNV Energy. September 30, 2021. *Puget Sound Energy Non-Energy Impacts Final Report*.

Several factors contributed to the significant changes in electric energy efficiency potential between the 2021 CPA and 2023 CPA:

NEW CONSTRUCTION

- Reductions in new construction (residential and commercial) achievable technical potential due to state and local code updates.

RESIDENTIAL

- Reduction in showerhead potential due to the Washington Administrative Code (WAC 51-56-0400).
- Smaller potential due to only incorporating lighting measures for vulnerable populations (~0.1 aMW).
- Lower heating loads and higher cooling loads due to incorporating climate change impacts. Overall, this impact lowered the potential (as more heating measures than cooling measures were impacted).
- Increase in water heater potential due to the addition of a Tier 4 no resistance, split-system heat pump water heater (HPWH).

COMMERCIAL

- Lower lighting potential (non-lighting control potential) due to using the *2021 Power Plan* commercial lighting characterization and incorporating PSE accomplishments.
- Increased potential with the addition of a dedicated outdoor air system – very high efficiency.
- Increased achievable technical potential in the industrial sector and lower achievable technical potential in the commercial sector due to re-classifying the wastewater segment to the industrial sector and adding the water supply segment to the industrial sector.

INDUSTRIAL

- Increase in potential due to re-classifying the wastewater segment to the industrial sector.
- Increase in potential with the addition of pump and fan measures in the industrial sector.
- Increase in potential with the addition of more lighting controls within the industrial sector.

Combined Heat and Power Potential

Table 4 illustrates the 27-year cumulative achievable technical potential from CHP technologies. Overall, Cadmus identified 7.91 aMW of potential from renewable and nonrenewable technologies.

Table 4. Combined Heat and Power Achievable Technical Potential Summary, Cumulative 2050

CHP Type	Total Achievable Technical Potential (aMW)
Reciprocating Engine	3.90
Natural Gas Turbine	1.31
Microturbine	1.22
Biogas (Anaerobic Digesters)	1.26
Industrial Biomass	0.23
Total	**7.91**

Comparison to 2021 CPA – Combined Heat and Power

Table 5 shows a comparison of the 24-year cumulative CHP achievable technical potential identified in the 2023 CPA to the 24-year cumulative CHP potential in the 2021 CPA. The slight decrease in CHP potential is the result of updates in the data sources.

Table 5. Combined Heat and Power Achievable Technical Potential Comparison of 2023 CPA and 2021 CPA

	2023 CPA (aMW) 24-Year	2021 CPA (aMW) 24-Year
CHP achievable technical potential	7.72	7.82

Demand Response Potential

Table 6 presents the winter and summer peak achievable technical potential for demand response programs. The total 27-year winter demand response potential is 439 MW, which is equivalent to nearly a 7.05% reduction in PSE's forecasted 2050 winter peak.

Table 6. Demand Response Potential by Program, 2050

Product	Winter Achievable Technical Potential (MW)	Percentage of PSE System Peak (Winter)	Summer Achievable Technical Potential (MW)	Percentage of PSE System Peak (Summer)
Residential Electric Resistance Water Heater (ERWH) DLC Switch	0	0.00%	0	0.00%
Residential ERWH DLC Grid-Enabled	32	0.52%	22	0.39%
Residential HPWH DLC Switch	0	0.00%	0	0.00%
Residential HPWH DLC Grid-Enabled	58	0.94%	29	0.53%
Residential HVAC DLC Switch	97	1.56%	50	0.90%
Residential Bring Your Own Thermostat (BYOT) DLC	108	1.74%	100	1.81%
Residential EVSE DLC Switch	42	0.67%	42	0.75%
Medium Commercial HVAC DLC Switch	18	0.30%	77	1.40%
Small Commercial HVAC DLC Switch	3	0.04%	5	0.10%
Small Commercial BYOT DLC	3	0.05%	4	0.07%
Commercial Curtailment	16	0.26%	20	0.36%
Industrial Curtailment	5	0.08%	5	0.09%
Residential Critical Peak Pricing	33	0.54%	74	1.35%
Commercial Critical Peak Pricing	21	0.34%	26	0.48%
Industrial Critical Peak Pricing	2	0.02%	2	0.03%
Total	**439**	**7.05%**	**455**	**8.24%**

Comparison to 2021 CPA – Winter Demand Response

Table 7 shows a comparison of the demand response potential identified in the 2023 and 2021 CPAs, by sector. The 2023 CPA identified more winter potential compared to the 2021 CPA.

Table 7. Demand Response Achievable Technical Potential Comparison of 2023 CPA and 2021 CPA, Winter

Sector	2023 CPA (MW) 24-Year	2021 CPA (MW) 24-Year
Residential	365	206
Commercial and Industrial	67	20
Total	**431**	**226**

Several of the Council's draft *2021 Power Plan* alignments and key modeling inputs updates contributed to the increase in demand response potential and differences in product levelized costs:

Draft 2021 Power Plan Alignments

- Accounted for demand response updates made following Demand Response Advisory Committee (DRAC) discussions (such as shorter product ramp rates).
- Aligned closer with draft *2021 Power Plan* product input assumptions, such as per-participant kilowatt impacts and program participation estimates. For example, participation assumptions increased for HPWH and grid-enabled ERWH DLC (from 24% to 50%), for residential HVAC switch (from 20% to 25%), for residential BYOT (from 20% to 35%), and for curtailment (from 3% to 15%).

Key Modeling Inputs Updates

- Updated equipment saturations based on new data, such as PSE's 2021 RCS, PSE's electric vehicle forecast, and estimates of energy efficiency measure adoption. Modeled electric HVAC, smart thermostats, electric water heating (ERWH versus HPWH), and electric vehicle (EV) saturations dynamically over the study's duration, incorporating anticipated growth in future years.
- Updated nonresidential segmentation data using PSE's 2021 nonresidential customer database to segment building types based on Standard Industrial Classification and North American Industrial Classification System identifiers. (The prior study used historical segment allocations based on 2014 data.)
- Updated product input assumptions based on Cadmus' literature research (where applicable).
- Split costs between seasons (which was not conducted for the prior study). This impacted the demand response per-product levelized cost estimates.
- Updated transmission and distribution (T&D) deferral costs from $16 per kilowatt-year to $75 per kilowatt-year. This impacted the levelized cost estimates.
- Did not model the residential behavioral product (which was included in the 2021 CPA) but did model small commercial BYOT (which was not included in the 2021 CPA).

Rooftop Solar PV Potential

For 2050 Cadmus identified solar PV nameplate capacity achievable technical potential of 645 MW in the residential sector (including vulnerable populations) and 778 MW in the commercial sector, which is equivalent to 74.1 aMW and 95.8 aMW of cumulative achievable energy potential for the residential and commercial sectors, respectively.

Comparison to 2021 CPA – Rooftop Solar PV

Table 8 shows a comparison of solar PV achievable technical potential identified in the 2023 and 2021 CPAs by sector. The 2023 CPA estimate through 2050 shows 1,087 MW (nameplate) more achievable technical potential than the 2021 CPA estimate through 2045. If compared over a similar 24-year period, the difference in potential is 730 MW. The increase in solar PV potential is primarily the result of updated historical adoption (within the past two years) and projected near-term adoption (2022 and 2023) that shows increased solar installations. This impacted the customer adoption diffusion model (dGen) to better align with historical adoption.

Table 8. Solar PV Achievable Technical Potential (Nameplate) Comparison of 2023 CPA and 2021 CPA

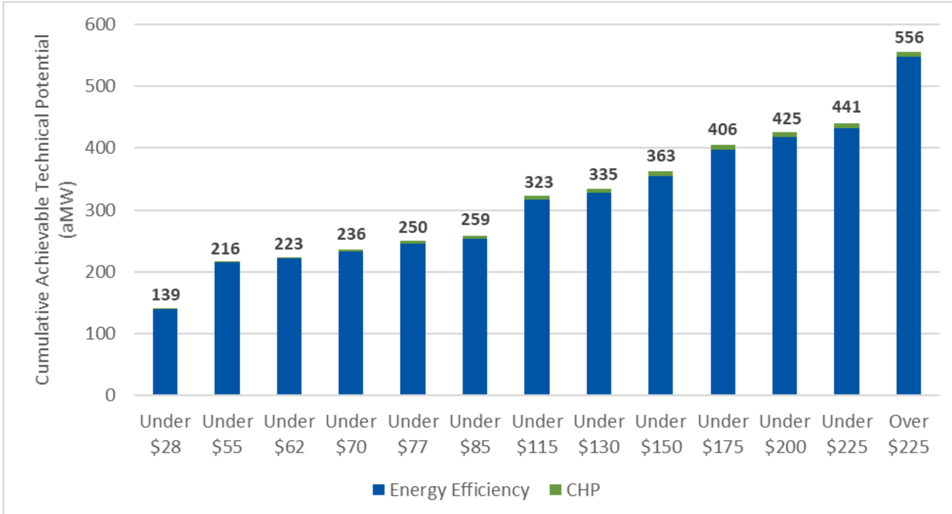
Sector	2023 CPA (MW) 27-Year	2021 CPA (MW) 24-Year
Residential	645	87
Commercial	778	249
Total	**1,423**	**336**

Incorporating Demand-Side Resources into PSE's Integrated Resources Plan

Cadmus grouped the achievable technical potential for energy efficiency and CHP shown above by the levelized cost of conserved energy for inclusion in PSE's IRP model. We calculated these costs over a 27-year study period. The *Integrated Resource Plan Input Development* section of *Chapter 4. Energy Efficiency Methodology Details* provides additional detail on the levelized cost methodology. Bundling resources into a number of distinct cost groups allows the model to select the optimal amount of annual demand-side resources based on expected load growth, energy prices, and other factors. Cadmus provides IRP input data by levelized cost bundle (or bins) and we did not incorporate an economic screen on the demand-side resources, rather we used the CPA IRP inputs within PSE's optimization modeling that select the least-cost (cost-effective) resource.

Cadmus spread the annual savings estimates over 8760-hour load shapes to produce hourly demand-side resource bundles as well as locational estimates by PSE service area zip code. In addition, we assumed that savings are gradually acquired over the year, as opposed to instantly happening on the first day of January. PSE provided intra-year demand-side resource acquisition schedules, which we used to ramp hourly savings across months. Figure 3 shows the annual cumulative combined potential for energy efficiency and CHP by each cost bundle considered in PSE's 2023 IRP.

Figure 3. Electric Supply Curve, Cumulative 27-Year Achievable Technical Potential



Similarly, Cadmus spread the annual savings estimates for rooftop solar PV over 8760-hour load shapes to produce hourly demand-side resource bundles. The demand response programs are a capacity-only resource. The annual capacity potential for each year of this study was incorporated into the IRP along with the net costs, which accounted for the estimated program costs and T&D deferral benefits.

Organization of This Report

This report presents the findings of demand-side electric resource potential assessment in several chapters and one appendix:

- *Chapter 1. Energy Efficiency and Combined Heat and Power Potential* includes an overview of the methodology Cadmus and PSE used to estimate technical and achievable technical potential as well as detailed sector, segment, and end-use–specific estimates of conservation potential with discussion of the top-saving measures in each sector. It also presents the estimates of technical and achievable technical CHP potential and levelized costs.
- *Chapter 2. Demand Response Potential* presents the winter and summer peak achievable technical potential for demand response programs.
- *Chapter 3. Rooftop Solar PV Potential* presents the solar PV nameplate capacity achievable technical potential.
- *Chapter 4. Energy Efficiency Methodology Details* describes Cadmus' combined top-down, bottom-up modeling approach for calculating technical and achievable technical potential by giving details on the steps for estimating energy efficiency potential.
- *Appendix A* gives detailed information on demand response potential by program and product option.

Chapter 1. Energy Efficiency and Combined Heat and Power Potential

PSE requires accurate estimates of technically achievable energy efficiency potential, which are essential for its IRP and program planning efforts. PSE then bundles these potentials in terms of the levelized costs of conserved energy so the IRP model can be used to determine the optimal amount of energy efficiency potential.

To support these efforts, Cadmus performed an in-depth assessment of technical potential and achievable technical potential for electric resources in the residential, commercial, and industrial sectors. The next section gives an overview of the methodology we used for this purpose, which is then described in greater detail in *Chapter 4. Energy Efficiency Methodology Details*. The methodology below is followed by an explanation of the considerations for the design of this potential study. Lastly, the results of energy efficiency and CHP potential assessment are presented in detail.

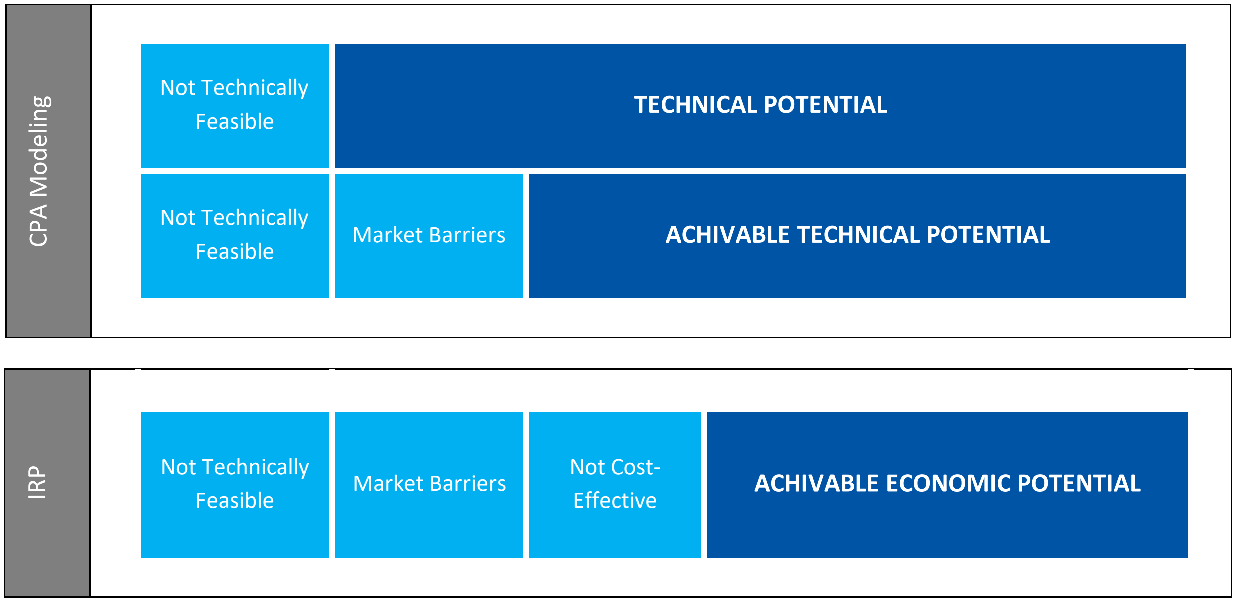
Energy Efficiency Potential

Consistent with the WAC requirements, Cadmus assessed two types of energy efficiency potential—technical and achievable technical. PSE determined a third potential—achievable economic—through the IRP's optimization modeling. These three types of potential are illustrated in Figure 4.

- ***Technical potential*** assumes that all technically feasible resource opportunities may be captured, regardless of their costs or other market barriers. It represents the total energy efficiency potential in PSE's service territory, after accounting for purely technical constraints.
- ***Achievable technical potential*** is the portion of technical potential assumed to be achievable during the study's forecast, regardless of the acquisition mechanism. For example, savings may be acquired through utility programs, improved codes and standards, and market transformation.
- ***Achievable economic potential*** is the portion of achievable technical portion determined to be cost-effective by the IRP's optimization modeling, in which either bundles or individual energy efficiency measures are selected based on costs and savings. The cumulative potential for these selected bundles constitutes achievable economic potential.

Cadmus provided PSE with forecasts of achievable technical potential, which PSE then entered as variables in the IRP's optimization model to determine achievable economic potential.

Figure 4. Types of Energy Efficiency Potential



The timing of resource availability is a key consideration in determining conservation potential. There are two distinct categories of resources:

- ***Discretionary resources*** are retrofit opportunities in existing facilities that, theoretically, are available at any point over the study period. Discretionary resources are also referred to as retrofit measures. Examples include weatherization and shell upgrades, economizer optimization, and low-flow showerheads.
- ***Lost opportunity resources***, such as conservation opportunities in new construction and replacements of equipment upon failure (natural replacement), are nondiscretionary. These resources become available according to economic and technical factors beyond a program administrator's control. Examples of natural replacement measures include HVAC equipment, water heaters, appliances, and replace-on-burnout lighting fixtures.

Cadmus analyzed three sectors—residential, commercial, industrial—and, where applicable, considered multiple market segments, construction vintages (new and existing), and end uses:

RESIDENTIAL	COMMERCIAL	INDUSTRIAL
SIX SEGMENTS Single family, multifamily, manufactured, single family - vulnerable population, multifamily - vulnerable population, and manufactured - vulnerable population segments	**EIGHTEEN SEGMENTS** Office, retail, and food sales segments further divided into categories based on building size, aligning with the *2021 Power Plan*	**TWENTY-ONE SEGMENTS** Paper, chemical, wood, hi-tech, and other manufacturing segment types that align with the *2021 Power Plan*

For this study, Cadmus defined PSE's named communities and equity to represent the vulnerable population and highly impacted communities within the PSE's service area (defined on the right). We reviewed the data available and determined that the vulnerable population data best aligned with the CPA geographic areas (such as the county level built up from block groups). Cadmus segmented PSE residential accounts for vulnerable populations by county and used PSE 2021 RCS data to inform equipment saturations and fuel shares for the vulnerable population (based on income).

Vulnerable Populations Attributes
Identified as socioeconomic factors including unemployment, high housing and transportation costs relative to income, low access to food and health care, and linguistic isolation. Includes sensitivity factors, such as low birth weight and higher rates of hospitalization.

Highly Impacted Communities
Ranks communities with environmental burdens including fossil fuel pollution and vulnerability to climate change impacts that contribute to health inequities. Includes any census tract with tribal lands.

Cadmus used an end-use approach to forecast energy efficiency potential in all three sectors, taking several primary steps:

- Developed the baseline forecast by determining the 27-year future energy consumption by segment and end use. Calibrated the base year (2023) to PSE's sector level, corporate sector, and market load forecast produced in 2022. Baseline forecast in this report include the estimated impacts of climate change and of codes and standards on commercial and residential energy usage.
- Estimated technical potential based on the incremental difference between the baseline load forecast and an alternative forecast reflecting the technical impacts of specific energy efficiency measures.
- Estimated achievable technical potential by applying ramp rates and achievability percentages to technical potential, described in greater detail in *Chapter 4. Energy Efficiency Methodology Details*.

There are two advantages offered by the approach we used for this 2023 CPA:

- Savings estimates were driven by a baseline forecast that is consistent with the assumptions used in PSE's adopted 2022 corporate load forecast.
- It helped to maintain consistency among all assumptions underlying the baseline and alternative forecasts for technical and achievable technical potential. The alternative forecasts changed relevant inputs at the end-use level to reflect energy conservation measure (ECM) impacts. Because estimated savings represented the difference between baseline and alternative forecasts, they could be directly attributed to specific changes made to analysis inputs.

Cadmus' methodology can be best described as a combined top-down, bottom-up approach for the residential and commercial sectors. As shown in Figure 5, we began the top-down component with the most current load forecast, adjusting for building codes, equipment efficiency standards, and market trends. Cadmus then disaggregated this load forecast into its constituent customer sectors, customer segments, and end-use components.

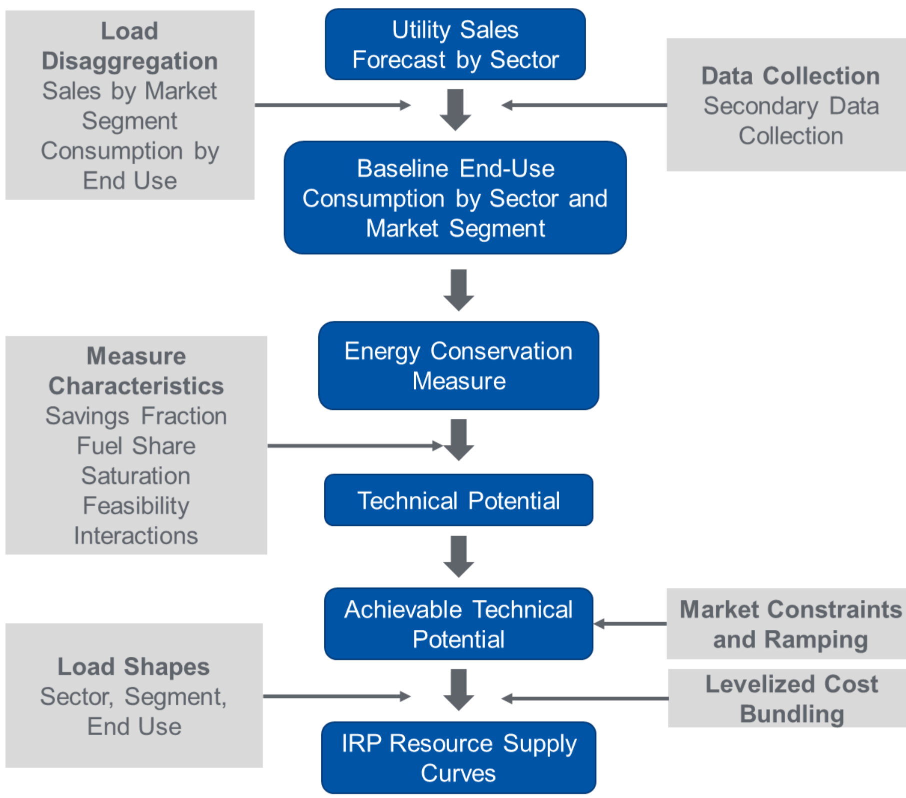
For the bottom-up component, Cadmus estimated electric consumptions for each major building end use and applied potential technical impacts of various ECMs to each end use. This bottom-up analysis includes assumptions about end-use equipment saturations, fuel shares, ECM technical feasibility, ECM cost, and engineering estimates of ECM unit energy consumption and UES.

For the industrial sector, Cadmus calculated technical potential as a percentage reduction to the baseline industrial forecast. We first estimated baseline end-use loads for each industrial segment, then calculated the potential using estimates of each measures' end-use percentage savings.

When characterizing measure and end-use consumptions, Cadmus used *2021 Power Plan* data (whenever possible) for weather-sensitive measures to account for climate change.[14] Next, we calibrated annual changes in residential and commercial heating and cooling end-use consumptions with PSE's climate impacts within annual load forecasts to reflect climate change on CPA estimates. Cadmus also used the projected residential air conditioning saturations within PSE load forecast projections.

A detailed description of the methodology can be found in *Chapter 4. Energy Efficiency Methodology Details*.

Figure 5. Conservation Potential Assessment Methodology



14 Cadmus applied climate change adjustment factors based Council data (TMY to projected FMY) to non-Council weather-sensitive RTF and PSE business case measures.

In the final step, Cadmus developed energy efficiency supply curves so that PSE's IRP portfolio optimization model could identify the amount of cost-effectiveness for energy efficiency. The portfolio optimization model required hourly forecasts of electric energy efficiency potential. To produce these hourly forecasts, Cadmus applied hourly end-use load profiles to annual estimates of achievable technical potential for each measure. These profiles are generally similar to the shapes the Council used in its draft *2021 Power Plan* supply curves and as the RTF used in its UES measure workbooks.

Considerations and Limitations

This study is intended to support PSE's program planning by providing insights into which measures can be offered in future programs as well as informing the program targets. Several considerations about the design of this potential study may cause future program plans to differ from this study's results:

- This potential study uses broad assumptions about the adoption of energy efficiency measures. Program design, however, requires a more detailed examination of historical participation and incentive levels on a measure-by-measure basis. This study can inform planning for measures PSE has not historically offered or can help PSE to focus program design on areas with remaining potential identified in this study.
- This potential study cannot predict market changes over time. Even though it accounts for changes in codes and standards over time, the study cannot predict future changes in policies, pending codes and standards, and which new technologies may become commercially available. PSE programs are not static and have the flexibility to address changes in the marketplace, whereas the potential study estimates the energy efficiency potential using information collected at a single point in time.
- This potential study does not attempt to forecast or otherwise predict future changes in energy efficiency measure costs. The study includes Council and RTF incremental energy efficiency measure costs, including for equipment, labor, and operation and maintenance (O&M), but it does not attempt to forecast changes to these costs during the course of the study (except where the Council will make adjustments). For example, changes in incremental costs may impact some emerging technologies, which may then impact both the speed of adoption and the levelized cost of that measure (impacting the IRP levelized cost bundles).
- This potential study does not consider program implementation barriers. Although it includes a robust, comprehensive set of efficiency measures, it does not examine if these measures can be delivered through incentive programs or what incentive rate is appropriate. Many programs require strong trade ally networks or must overcome market barriers to succeed.

Acknowledging the fact that these considerations and limitations have an impact on the CPA, it is also worth noting that RCW 19.285.040[15] requires PSE to complete and update a CPA every two years. PSE

[15] Revised Code of Washington. Accessed August 24, 2022. "RCW 19.285.040 Energy Conservation and Renewable Energy Targets." https://app.leg.wa.gov/RCW/default.aspx?cite=19.285.040&pdf=true

can address some of these considerations over time and mitigate short- and mid-term uncertainties by continually revising CPA assumptions to reflect changes in the market.

Energy Efficiency Potential - Overview

Table 9 shows 2050 forecasted baseline electric sales and potential by sector.[16] Cadmus' analysis indicates that 640 aMW of technically feasible electric energy efficiency potential will be available by 2050, the end of the 27-year planning horizon, which translates to an achievable technical potential of 548 aMW. Should all this achievable technical potential prove cost-effective and realizable, it will result in an 18% reduction in 2050 forecasted retail sales.

Table 9. Electric 27-Year Cumulative Energy Efficiency Potential

Sector	2050 Baseline Sales (aMW)	Achievable Technical Potential	
		aMW	Percentage of Baseline Sales
Residential	1,818	298	16%
Commercial	1,149	231	20%
Industrial	119	18	16%
Total	**3,086**	**548**	**18%**

Figure 6 shows each sector's relative share of the overall electric energy efficiency achievable technical potential. The residential sector accounts for roughly 55% of the total electric energy efficiency achievable technical potential, followed by the commercial (42%) and industrial (3%) sectors.

Figure 6. 27-Year Achievable Technical Potential by Sector

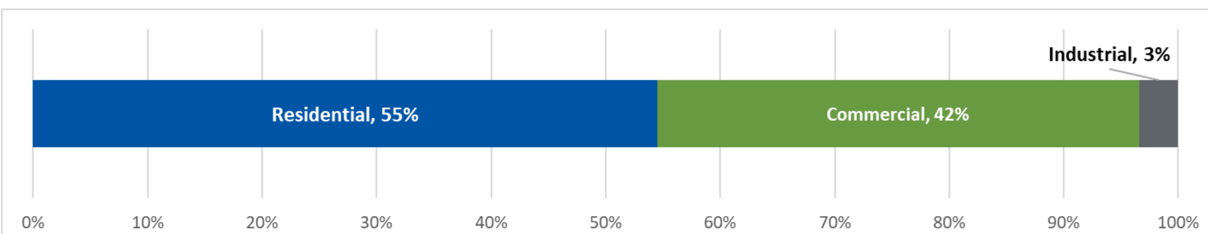


Figure 7 shows the relationship between each sector's cumulative (through 2050) electric energy efficiency achievable technical potential and the corresponding cost of conserved electricity.[17] For example, approximately 355 aMW of achievable technical potential exists at a cost less of than $150 per megawatt-hour.

16 These savings derive from forecasts of future consumption, absent any utility program activities. Note that consumption forecasts account for the savings PSE has acquired in the past, but the estimated potential is inclusive of—not in addition to—current or forecasted program savings.

17 In calculating the levelized costs of conserved energy, non-energy benefits are treated as a negative cost. This means some measures will have a negative cost of conserved energy, although incremental upfront costs would occur.

Figure 7. Electric 27-Year Cumulative Energy Efficiency Supply Curve

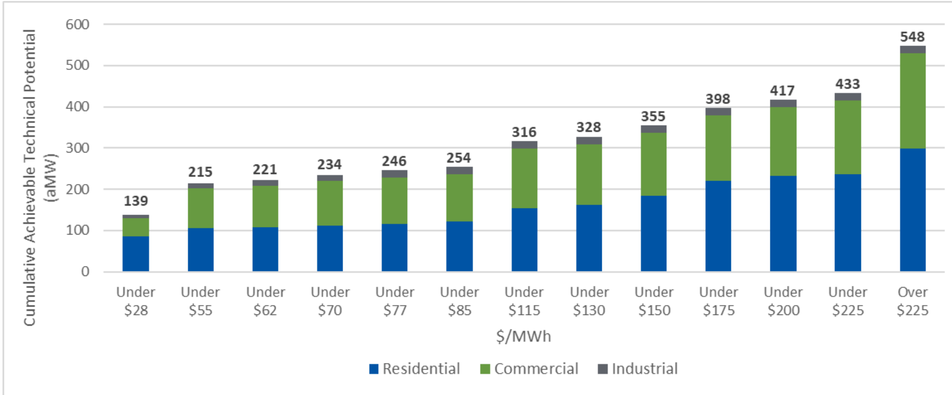
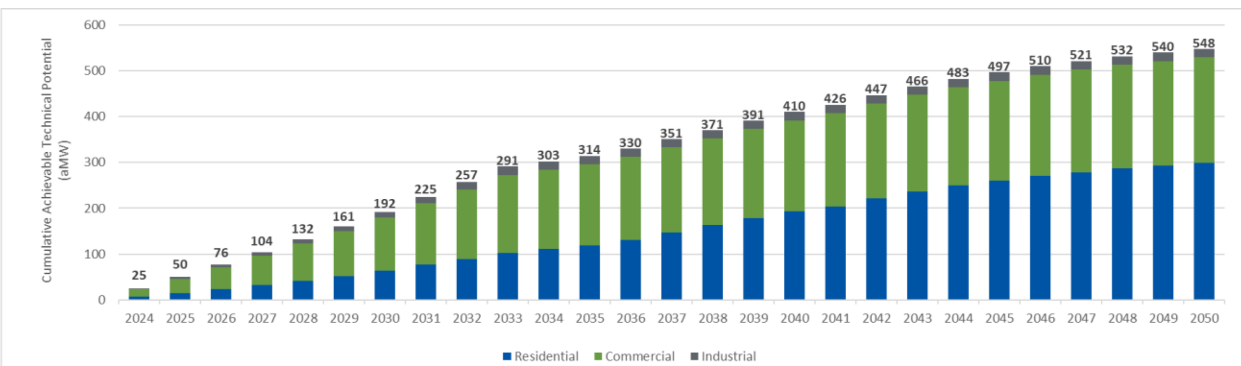


Figure 8 illustrates the cumulative potential that is available annually in each sector. As shown in the figure, more savings are achieved in the first 10 years of the study (2024 through 2033) than in the remaining years. For this study, Cadmus assumed that discretionary measure potential savings are acquired in the first 10 years (for a selected set of measures that are retrofit in existing homes and businesses). The 10-year acceleration of discretionary resources will lead to the change in slope after 2033, at which point lost opportunity resources offer most of the remaining potential.

Figure 8. Electric Energy Efficiency Potential Forecast

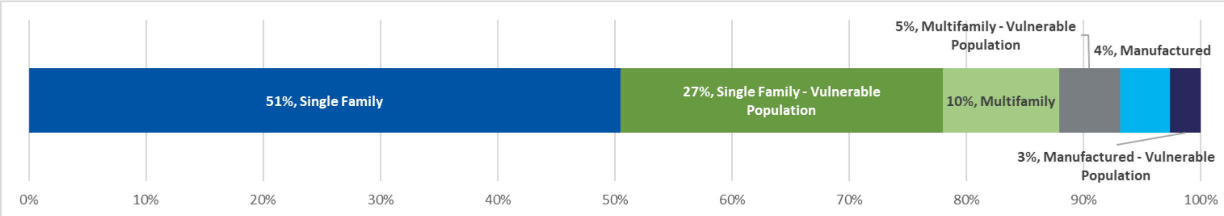


Energy Efficiency Potential - Residential Sector

By 2050, residential customers in PSE's service territory will likely account for approximately 59% of forecasted electric retail sales. The single-family, manufactured, and multifamily dwellings comprising this sector present a variety of potential savings sources, including equipment efficiency upgrades (such as heat pumps and refrigerators), improvements to building shells (via insulation, windows, and air sealing), and increases in domestic hot water efficiency (such as HPWHs).

As shown in Figure 9, single-family homes represent 78% of the total achievable technical residential electric potential followed by multifamily (15%) and manufactured homes (7%), with all categories including vulnerable populations. Each home type's proportion of baseline sales is the primary driver of these results, but other factors such as heating fuel sources and equipment saturations are important to determining potential.

Figure 9. Residential Electric Achievable Technical Potential by Segment



For example, a higher percentage of manufactured homes use electric heat compared to single-family and multifamily homes, which increases their relative share of the potential. However, manufactured homes also tend to be smaller than detached single-family homes, and they experience lower per-customer energy; therefore, the same measure may save less in a manufactured home than in a single-family home.

Space heating end uses represent the largest portion (36%) of achievable technical potential, followed by water heating (24%) and dryer (15%) end uses (Figure 10). Lighting, an end use with considerably low energy efficiency potential in the 2021 CPA, comprises only 2% of the total residential electric energy efficiency potential. This low potential is due to the updated Washington State standard (House Bill 1444) and greater penetration of screw-based LEDs in recent years. The total achievable technical potential for residential increases to 298 aMW over the study horizon (Figure 11).

Figure 10. Residential Electric Achievable Technical Potential by End Use

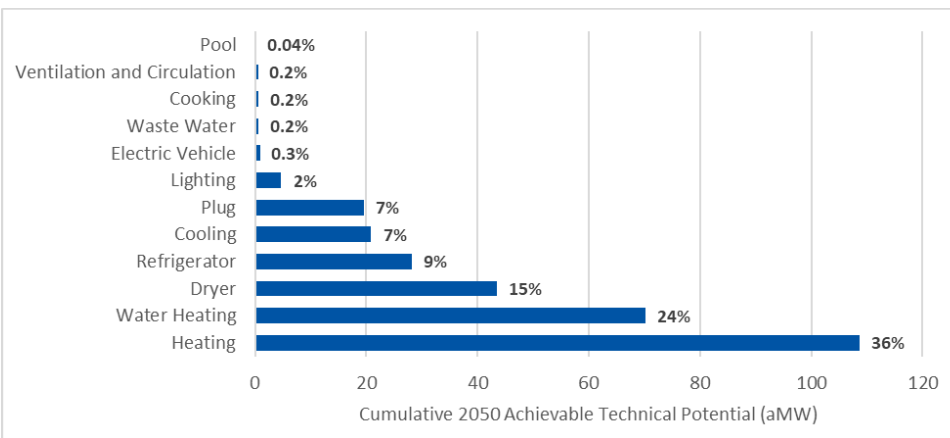


Figure 11. Residential Electric Achievable Technical Potential Forecast by End Use

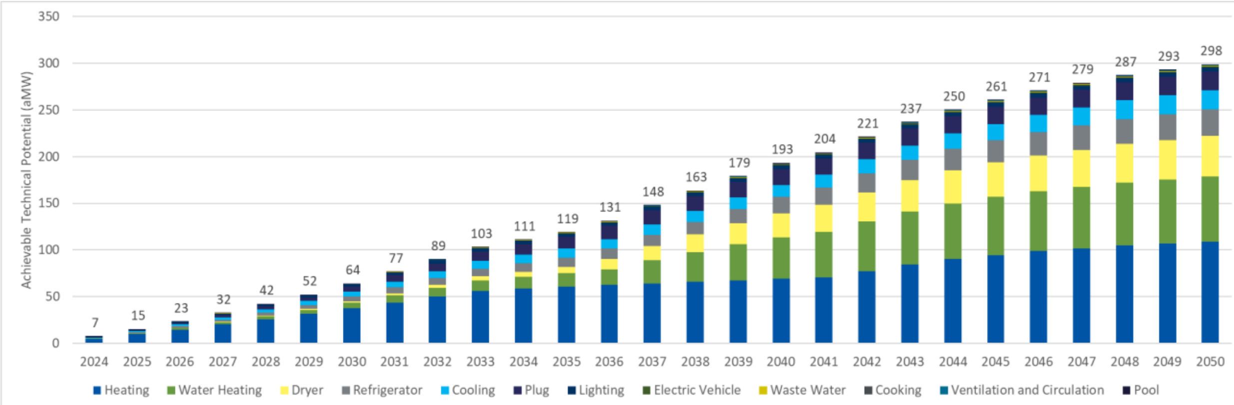


Table 10 lists the top 10 residential electric energy efficiency measures ranked in order of cumulative 27-year achievable technical potential. Combined, these 10 measures account for roughly 209 aMW, or approximately 70% of the total residential electric achievable technical potential. Heat pump dryers represent the measure with the highest energy savings and four of the top 10 measures reduce electric heating loads: this includes equipment measures (ductless heat pumps and air-source heat pumps) and a retrofit measure (smart thermostats). This list represents both economic and non-economic measures.

Table 10. Top Residential Electric Savings Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 27-year Achievable Technical Potential (aMW)
Heat Pump Dryer	4.0	43.0
Heat Pump Water Heater - Tier 4 - No Resistance, Split System	3.7	37.8
Zonal to Ductless Heat Pump	5.2	23.7
Heat Pump Water Heater - Tier 3	2.2	22.7
HVAC Upgrade - Heat Pump Upgrade to 12 HSPF/18 SEER	2.2	22.0
Refrigerator - ENERGY STAR 2022 Most Efficient	5.8	21.9
Install Ductless Heat Pump in House with Existing Forced Air Furnace - HZ1	2.9	13.5
Central Air Conditioner - Enhanced	1.8	10.9
Set Top Box - ENERGY STAR	3.4	7.4
Smart Thermostat	5.9	6.5

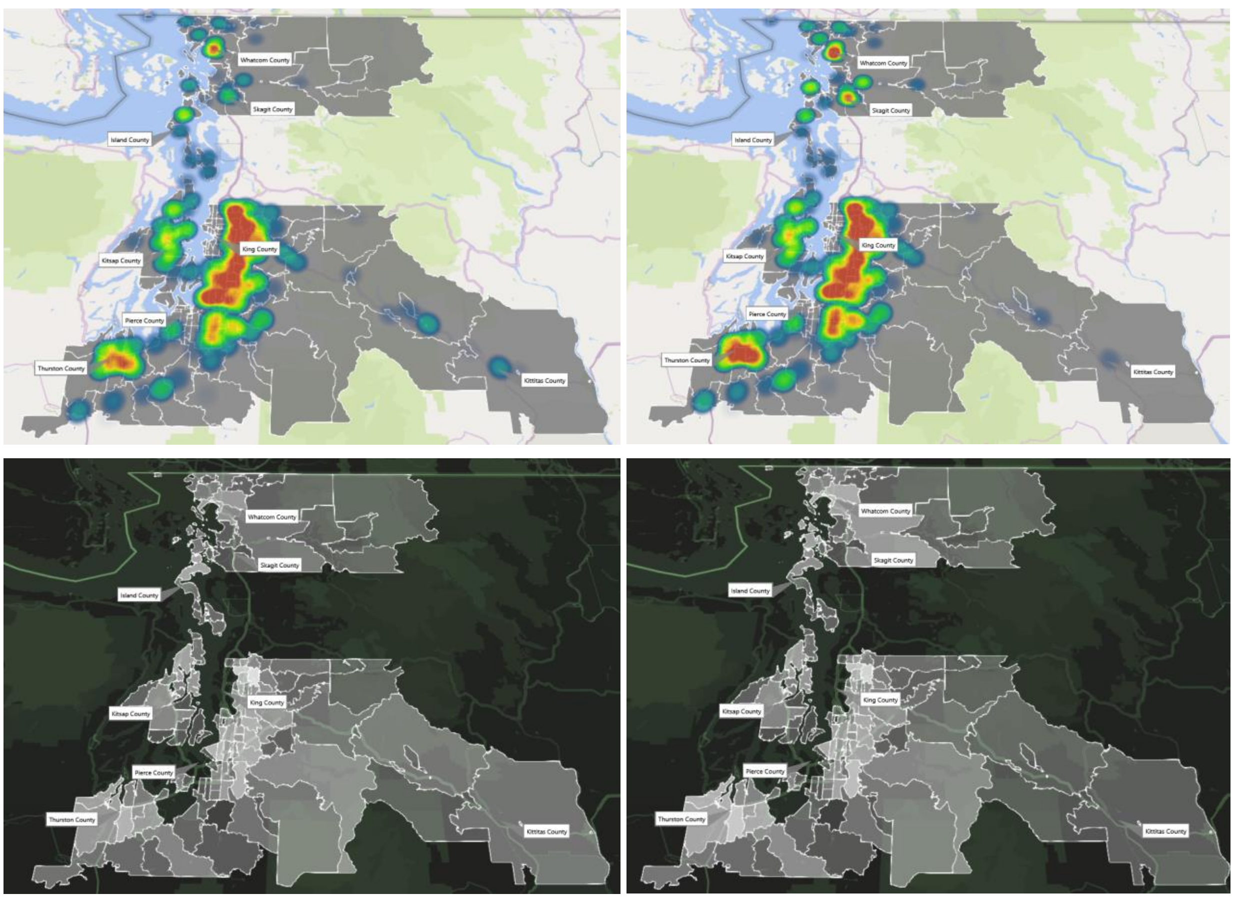
In addition to estimating potential for each residential housing segment, Cadmus estimated potential for vulnerable population customers within PSE's electric service territory. Cadmus segmented PSE residential accounts (single family, multifamily, and manufactured) for vulnerable populations by county. Cadmus also used PSE 2021 RCS data to inform equipment saturations and fuel shares for vulnerable populations (based on income). Table 11 provides the percentage of vulnerable population customers in each county in PSE's electric service territory.

Table 11. Percentage of Vulnerable Population Customers in Each County

County	Percentage of Vulnerable Population Customers
Island County	28%
King County	34%
Kitsap County	35%
Kittitas County	12%
Pierce County	38%
Skagit County	58%
Thurston County	41%
Whatcom County	42%

Figure 12 shows a heat map comparison of the achievable technical cumulative potential (2050) for the residential market rate (left images) and residential vulnerable population (right images) customer segments. Overall, there is little difference in the locational achievable potential (by zip code). However, the vulnerable population shows proportionally higher potential in Thurston, Whatcom, and Skagit counties when compared market rate customer population.

Figure 12. Residential Market Rate (Left) and Residential Vulnerable Population (Right) Heat Map



Cadmus derived UES estimates specifically for vulnerable population customers using low-income-specific measures from PSE's business cases:

- Weatherization: Attic, duct, floor, and wall insulation, air/duct sealing, single and double pane windows
- Water heating: water heater pipe insulation, integrated space and water heating system
- Smart thermostats

Cadmus also apportioned savings from non-low-income–specific PSE business case measures to vulnerable population customers for other measures, including advanced power strips, home energy reports, windows (double and triple pane with different U factors), and string lighting.

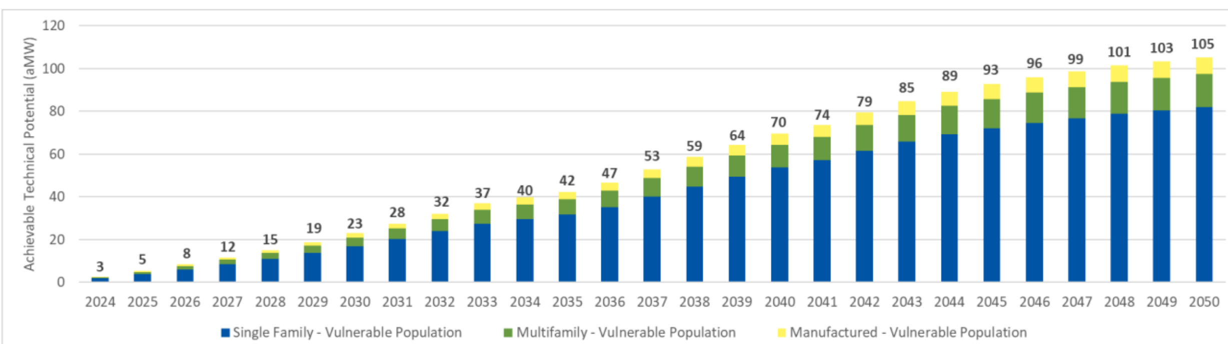
Table 12 shows the cumulative 10-year (through 2033) and 27-year (through 2050) achievable technical potential for PSE's vulnerable population customers by housing segment.

Table 12. Residential Vulnerable Population Customer Potential - Electric

Segment	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 27-Year Achievable Technical Potential (aMW)
Single Family - Vulnerable Population	27.5	82.0
Multifamily - Vulnerable Population	6.5	15.4
Manufactured - Vulnerable Population	3.0	7.9
Total	**36.9**	**105.2**

Figure 13 provides the cumulative residential vulnerable population electric achievable technical potential forecast by housing segment. The potentials that were shown above in Figure 11 include the vulnerable population customer potential shown in Figure 13.

Figure 13. Residential Achievable Technical Potential Forecast for Vulnerable Populations

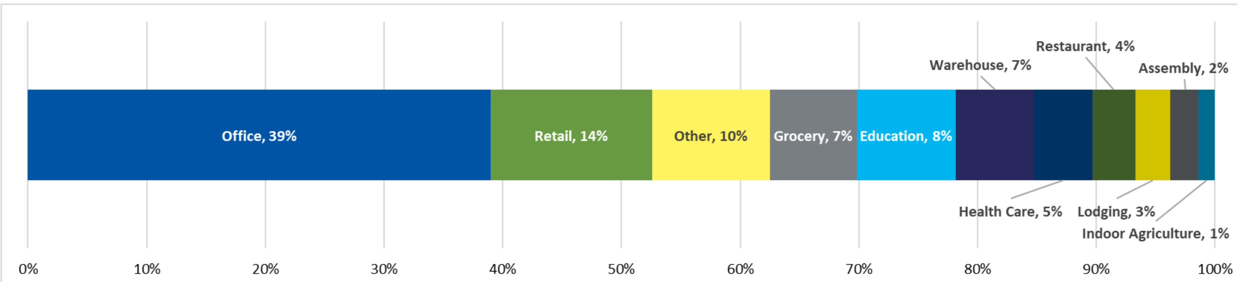


Energy Efficiency Potential - Commercial Sector

Based on the energy efficiency measure resources used in this assessment, electric energy efficiency achievable technical potential in the commercial sector will likely be 231 aMW over 27 years, which is approximately a 20% reduction in forecasted 2050 commercial sales.

As shown in Figure 14, the office and retail segments represent 39% and 14%, respectively, of the total commercial achievable technical potential. The “other” segment, which includes customers who do not fit into any of the categories and customers with insufficient information for classification, represents 10% of commercial achievable technical potential. Each of the remaining segments has less than 10% of commercial achievable technical potential.

Figure 14. Commercial Electric Achievable Technical Potential by Segment



As shown in Figure 15, lighting efficiency improvements represent the largest portion of achievable technical end-use savings potential in the commercial sector (39%), followed by ventilation and circulation (25%) and cooling (13%). Figure 16 presents the annual cumulative electric commercial achievable technical potential by end use.

Figure 15. Commercial Electric Achievable Technical Potential by End Use

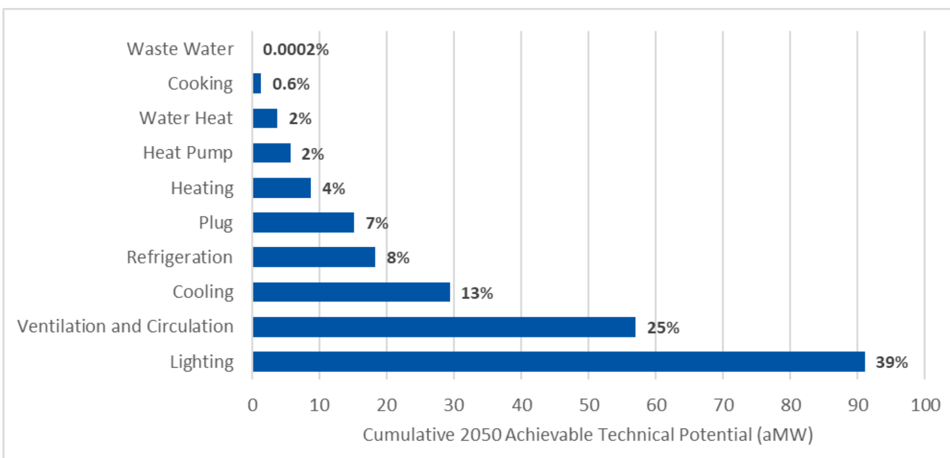


Figure 16. Commercial Electric Achievable Technical Potential Forecast

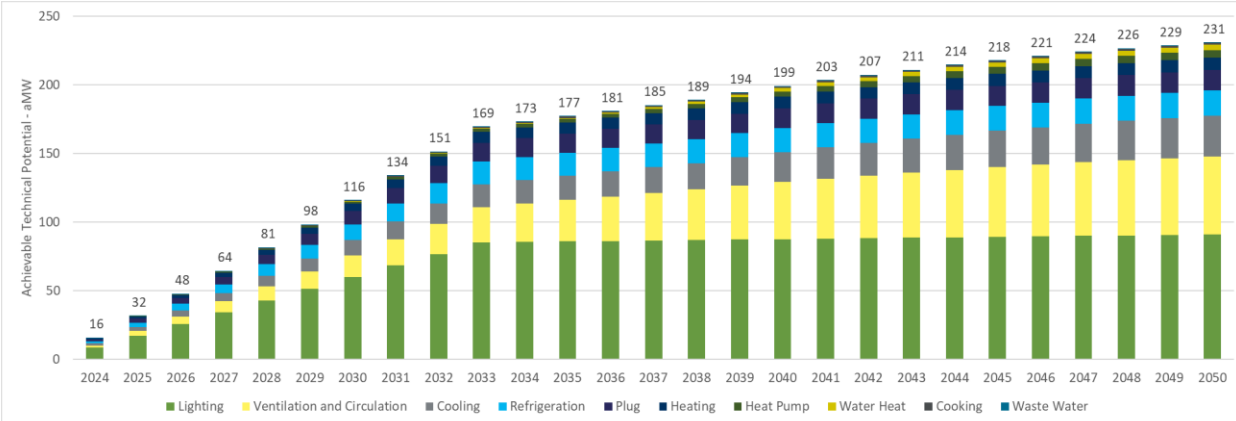


Table 13 lists the top 10 commercial electric energy efficiency measures ranked in order of cumulative 27-year achievable technical potential. Combined, these 10 measures account for 150 aMW, or approximately 65% of the total electric commercial achievable technical potential.

Table 13. Top Commercial Electric Savings Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 27-year Achievable Technical Potential (aMW)
Lighting - Interior - Control	46.59	51.35
Lighting - Interior - LED	20.43	20.48
Fan - Variable Speed Drive	3.03	15.12
Window - Upgrade	12.42	13.66
Cooling Direct Expansion	2.39	11.18
Exit Sign	8.11	8.43
Very High-Efficiency Dedicated Outside Air System	1.10	8.41
Lighting - Exterior - LED	6.47	7.02
Rooftop HVAC Controls - Advanced	6.88	6.98
Pump - Efficient	3.57	6.93

Energy Efficiency Potential - Industrial Sector

Cadmus estimated technical and achievable technical energy efficiency potential for major end uses in 21 major industrial sectors and for street lighting. It is worth noting that water supply and wastewater treatment are new segments in the industrial sector for this CPA, aligning with the draft *2021 Power Plan*. In prior CPAs (and previous power plans), these segments were considered part of the commercial sector. This change was made by the Council to better align with utility program functions, as utilities offer energy efficiency to the water and wastewater segments through their industrial programs. Across all industries, achievable technical potential is approximately 18 aMW over the 27-year planning horizon, corresponding to a 16% reduction of forecasted 2050 industrial electric retail sales.

Figure 17 shows 27-year electric industrial achievable technical potential by segment. Sewage treatment represents 21% of the total 27-year electric industrial achievable technical potential, followed by miscellaneous manufacturing (19%), streetlighting (14%), water supply (12%), and transportation equipment (10%). No other industry represents more than 5% of industrial electric achievable technical potential.

Figure 17. Industrial Electric Achievable Technical Potential Forecast

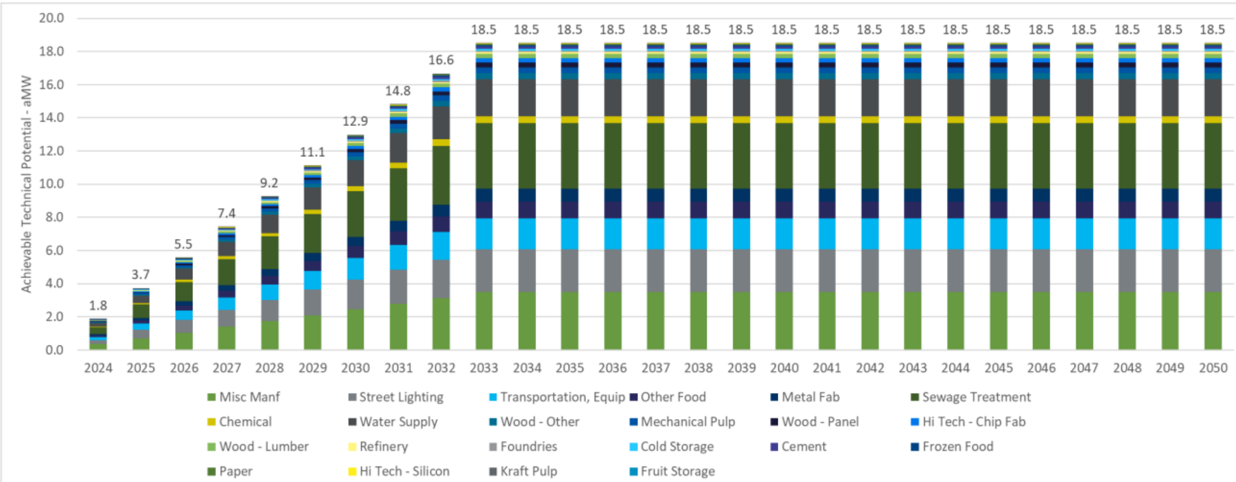


Table 14 presents electric cumulative 27-year achievable technical potential for the top 10 measures in the industrial sector. Cadmus derived these measures from the Council's draft *2021 Power Plan.* The top three measures combined—wastewater, water supply, and energy management—equal approximately 7.8 aMW of achievable technical potential, or roughly 43% of the industrial total.

Table 14. Top Industrial Electric Savings Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 27-year Achievable Technical Potential (aMW)
Wastewater	3.9	3.9
Water Supply	2.2	2.2
Energy Management	1.6	1.6
HVAC	0.9	0.9
Streetlight - HPS 100 Watt - Group Relamp - to LED 38 Watt - Retrofit	0.8	0.8
Lighting Controls	0.8	0.8
Energy Management Level 2	0.8	0.8
Streetlight - HPS 100 Watt - Group Relamp - to LED 53 Watt - Retrofit	0.7	0.7
Pump Optimization	0.6	0.6
Advanced Motors - Material Processing	0.5	0.5

The energy management category represents facility-wide adoption of energy efficiency, primarily through the Industrial Strategic Energy Management program and other similar programs offered by PSE.[18] In the draft *2021 Power Plan*, there are two levels of strategic energy management. The first level

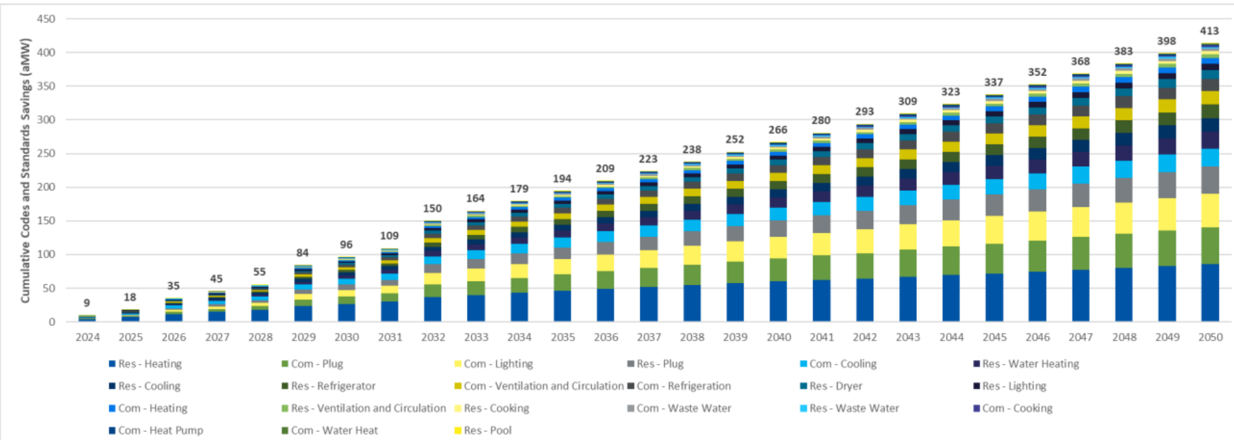
18 Puget Sound Energy. Accessed August 2022. "Industrial Strategic Energy Management (ISEM) program." https://www.pse.com/business-incentives/commercial-industrial-programs/industrial-strategic-energy-management

(known as energy management) is defined as the traditional achievable amounts of energy efficiency and at a cost realized through recent program activities. The second level of strategic energy management (known as energy management level 2) represents either future potential that is more difficult to achieve at smaller facilities or deeper achievements at facilities that have already achieved level 1. The cost of energy management level 2 is higher than the cost of energy management level 1.

Impacts of Codes and Standards

Figure 18 presents naturally occurring savings in PSE’s service area from the WSEC equipment standards and federal equipment standards, which is equal to 413 aMW in 2050.

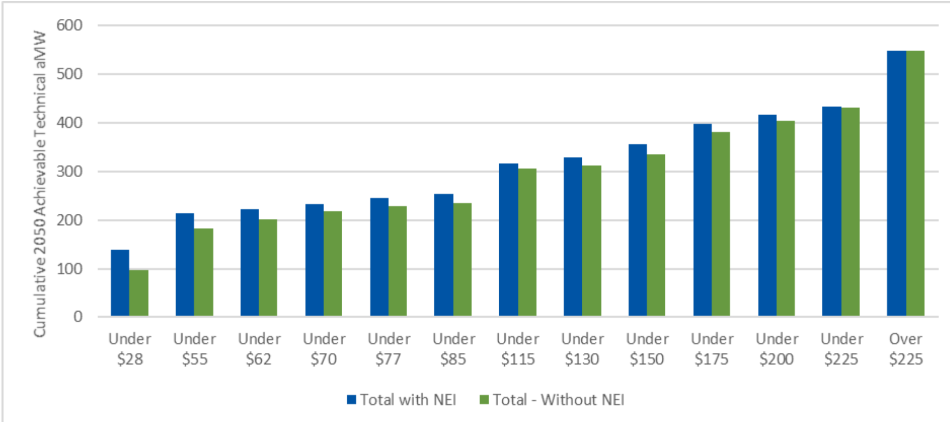
Figure 18. Electric Codes and Standards Potential Forecast



Non-Energy Impacts

In addition to the Council and RTF measures with NEIs (limited to water savings, O&M, and lifetime replacement), this CPA incorporated additional NEI data to inform the IRP levelized cost bundles. Cadmus based the NEI data on PSE’s recent program evaluation that included an assessment of program measure NEIs. Figure 19 shows a comparison of the cumulative 2050 achievable technical potential with and without the inclusion of these additional NEI data. The figure shows an increase in potential within the lower-cost bundles with less of an impact in the high-cost bundles.

Figure 19. Non-Energy Impacts on Levelized Cost, Cumulative 2050 Achievable Technical Potential



Combined Heat and Power Potential

CHP produces electricity and thermal energy at high efficiencies using different technologies and fuels. With CHP providing on-site power, losses are minimized and heat that would otherwise be wasted can be used in the form of process heating, steam, hot water, or even chilled water.[19]

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

Cadmus assessed applicable, technical CHP potential for the C&I sectors in PSE's 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 C&I market segments that have average monthly energy loads greater than approximately 30 kW.

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

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

[19] U.S. Environmental Protection Agency. Last updated June 1, 2022. "What Is CHP?" https://www.epa.gov/chp/what-chp

NON-RENEWABLE FUEL	RENEWABLE FUEL: BIOMASS	RENEWABLE FUEL: BIOGAS
• Reciprocating engines that cover a wide range of sizes • Microturbines that represent newer technologies with higher capital costs • Gas turbines that are typically large systems	Used in industries where site-generated waste products (such as lumber wood, panel wood, and other wood products) can be combusted in place of natural gas or other fuels. For this study, Cadmus assumed that the type of combustion processes in a CHP system (generally steam turbines) would generate electricity on the site. An industrial biomass system generally operates on a large scale, with a capacity greater than 1 MW.	Used with anaerobic digesters, which generate biogas—primarily consisting of methane, carbon dioxide, and hydrogen sulfide—from the decomposition of liquid or solid organic waste by microorganisms in an oxygen-free environment. Anaerobic digesters can be coupled with a variety of generators, including reciprocating engines and microturbines, and are typically installed at landfills, wastewater treatment facilities, livestock farms, and pulp and paper manufacturing facilities.

Cadmus calculated technical potential to determine the demand, or the number of eligible customers by segment and size in PSE's service area, then applied assumptions about CHP or biomass/biogas system sizes and performance. Table 15 lists the sources Cadmus referenced for each input. Recent studies completed for the California Self-Generation Incentive Program have the largest sample sizes (as it is the longest-running CHP program in the nation). Cadmus also reviewed studies from other regions and, where possible, benchmarked California Self-Generation Incentive Program data with other studies.

Table 15. Data Sources for Combined Heat and Power Technical Potential

Inputs	Source
Capacity Factor, Performance Degradation, Heat Recovery Rate	Itron. October 2015. *2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report].* Table 4-4: Summary of Operating Characteristics of SGIP Technologies. p. 4-13. https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/2/7889-20151119finalfullreport-1-.pdf
Measure Life	Marin, William, Myles O'Kelly, and Kurt Scheuermann. August 11–13, 2015. *Understanding Early Retirement of Combined Heat and Power (CHP) Systems: Going Beyond First Year Impacts Evaluations*. International Energy Program Evaluation Conference, Long Beach, California. https://www.iepec.org/wp-content/uploads/2015/papers/178.pdf
System Sizes	Self-Generation Incentive Program. Accessed January 2022. *Self-Generation Incentive Program Weekly Statewide Report.* https://www.selfgenca.com/documents/reports/statewide_projects
Number of Customers, Projected Sector Growth, Line Losses	PSE data
Existing CHP Capacity	U.S. Department of Energy. Last updated May 31, 2022. "Combined Heat and Power and Microgrid Installation Database." https://doe.icfwebservices.com/chpdb/
Customer Size Data	PSE data

Cadmus applied an achievable penetration rate to technical potential estimates to determine the market potential or likely future installations. Determining this rate involved reviewing a range of market penetration estimates, listed in Table 16. We examined historical trends in installed capacity for several states (including Washington), several technologies, and various fuel types using the

U.S. Department of Energy CHP Installation Database and reviewing states' favorability toward CHP as scored by the American Council for an Energy-Efficient Economy.

Table 16. Data Sources for Combined Heat and Power Achievable Technical Potential

Input	Source
Annual Market Penetration Rate	U.S. Department of Energy. Last updated May 31, 2022. "Combined Heat and Power Installation Database." https://doe.icfwebservices.com/chpdb/
	Navigant Consulting. June 30, 2017. *2017 IRP Demand-Side Management Conservation Potential Assessment Report.* Prepared for Puget Sound Energy. https://www.pse.com/-/media/PDFs/001-Energy-Supply/001-Resource-Planning/IRP17_AppJ.pdf
	U.S. Department of Energy. March 2016. *Combined Heat and Power (CHP) Potential in the United States.* https://www.energy.gov/sites/prod/files/2016/04/f30/CHP%20Technical%20Potential%20Study%203-31-2016%20Final.pdf
	ICF International. June 2012. *Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment*. Prepared for California Energy Commission. CEC-200-2012-002-REV. https://efiling.energy.ca.gov/GetDocument.aspx?tn=65855
	American Council for an Energy-Efficient Economy. n.d. "State-by-State CHP Favorability Index Estimate." http://aceee.org/sites/default/files/publications/otherpdfs/chp-index.pdf

Using the American Council for an Energy-Efficient Economy "State-by-State CHP Favorability Index Estimate," we identified the top three most favorable states for CHP (California, Connecticut, and Massachusetts) and calculated the percentage of technical potential installed per year in these states over the five-year period from 2012 through 2016. We also calculated this percentage for Washington State for comparison. To determine this percentage, Cadmus divided the capacity of CHP installed over the five-year period of 2012 through 2016 (from the U.S. Department of Energy CHP Installation Database) by the CHP potential (from the 2016 U.S. Department of Energy CHP Potential in the United States) then divided by five years. This provided an upper bound for the annual market penetration rate in PSE territory. Based on the benchmarking results (shown in Table 17), as well as the other data sources, we assumed an annual market penetration rate of 0.2% to provide the most likely and realistic achievable technical potential (0.2% is also the annual market penetration rate used for the 2021 CPA).

Table 17. Market Penetration for 2012–2016

State	Installed from 2012–2016 (MW)	Technical Potential (MW)	Percentage of Technical Potential Installed Per Year
Washington	**22.0**	**2,387**	**0.184%**
California	382.2	11,542	0.662%
Connecticut	15.1	1,214	0.248%
Massachusetts	40.2	3,028	0.265%

For each technology, Cadmus calculated several types of levelized cost from a total resource cost (TRC) perspective. Although assumptions varied between technologies, these sources were included in overall total resource levelized costs:

- Installation costs
- O&M costs assumed to occur annually, adjusted to the net present value
- Fuel costs (including total carbon adder)

- Incentives[20]
- Program administration costs

For the levelized cost analysis, Cadmus used the sources shown in Table 18 as well as the sources listed above for technical and achievable technical potential. To calculate the TRC, Cadmus used PSE's inflation rate of 2.5% to adjust future costs to present dollars. We divided costs by the system's production over its lifespan, obtaining the levelized cost of energy. Energy production includes PSE's average line loss factor of 7.8%, which represents avoided losses on the utility system, not energy losses from customer-sited units to the facility (which were assumed to be zero).

Table 18. Combined Heat and Power Levelized Cost Data Sources

Input	Source
State Cost Adjustment	RSMeans
Inflation and Discount Rate	PSE
Natural Gas Rates and Rate Forecasts	PSE
Installed Cost	U.S. Environmental Protection Agency. September 2017. "Catalog of CHP Technologies." https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf
O&M Cost	Itron. October 2015. *2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report].* Appendix A. https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/2/7889-20151119finalfullreport-1-.pdf
PSE Incentive	Puget Sound Energy. Last updated 2022. "Cogeneration/Combined Heat and Power (CHP)." https://www.pse.com/business-incentives/commercial-retrofit-grants/combined-heat-and-power
Program Administration Cost	PSE

Combined Heat and Power Technical Potential Results

Cadmus calculated technical CHP potential for new installations based on sources given above, including C&I customer data along with data on farms, landfills, and wastewater treatment facilities within PSE's service area. This resulted in a total estimated 27-year, system-wide technical potential of 230 aMW. Table 19 details technical potential by area, sector, and fuel. These results exclude previously installed CHP capacity throughout PSE's territory.[21]

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[20] Puget Sound Energy. Last updated 2022. "Cogeneration/Combined Heat and Power (CHP)." https://www.pse.com/business-incentives/commercial-retrofit-grants/combined-heat-and-power

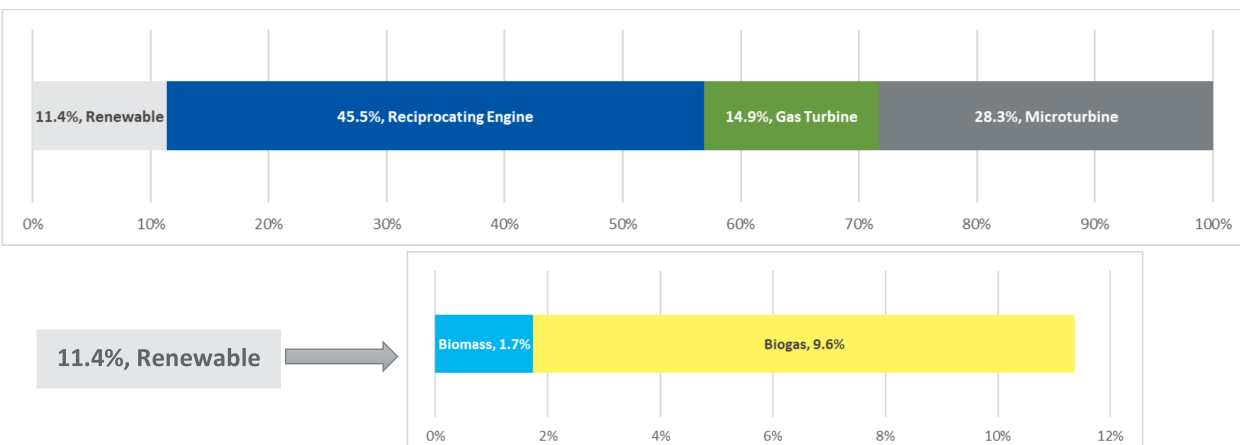
[21] U.S. Department of Energy. Last updated May 31, 2022. "Combined Heat and Power Installation Database." https://doe.icfwebservices.com/chpdb/

Table 19. Combined Heat and Power Technical Potential by Sector and Fuel (Cumulative in 2050)

PSE	Technical Potential
Commercial	
Natural gas aMW	142
Number of sites	1,528
Industrial	
Natural gas aMW	62
Number of sites	322
Biomass and biogas aMW	26
Number of sites	45
Industrial total aMW	88
Industrial total number of sites	367
Total	
Total aMW	230
Total number of sites	1,895

Cadmus divided total potential into different technologies (reciprocating engines, microturbines, natural gas turbines for natural gas–fueled systems, and renewables as biogas and biomass). Figure 20 shows the distribution of technical potential as a percentage of 2050 technical potential in average megawatts by these different technologies.

Figure 20. Percentage of 2050 Combined Heat and Power Technical Potential by Technology (in aMW)



Combined Heat and Power Achievable Technical Potential Results

Cadmus applied a market penetration rate of 0.20% per year to the technical potential data to determine achievable technical potential or likely installations in future years. We 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 described above. As shown in Table 20 and Table 21, the market penetration rate was applied to technical potential for each year to calculate equipment installations along with achievable technical potential over the next 27 years. Cadmus estimated a cumulative 2050 achievable technical potential of 7.91 aMW (9.89 MW of installed capacity) at the generator using PSE's line loss assumption of 7.8%.

Table 20. Combined Heat and Power 2050 Cumulative Achievable Technical Potential Equipment Installations

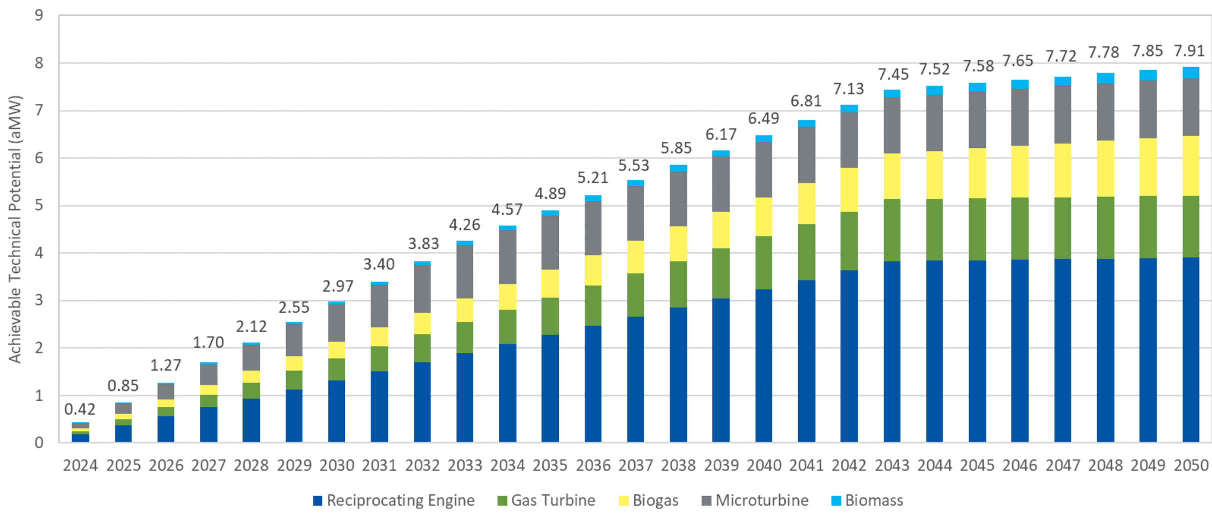
Technology	2050 Installs
Nonrenewable - Natural Gas (Total)	**49**
Reciprocating Engine	25
Gas Turbine	21
Microturbine	2
Renewables	**1**
Total CHP	**50**

Table 21. Combined Heat and Power 2050 Cumulative Achievable Technical Potential at Generator

Technology	2050 aMW	2050 MW
Nonrenewable - Natural Gas (Total)		
30–99 kW	1.15	1.43
100–199 kW	0.93	1.16
200–499 kW	1.19	1.48
500–999 kW	0.86	1.07
1–4.9 MW	1.33	1.66
5 MW+	0.98	1.23
Renewable - Biomass (Total)		
<500 kW	0.00	0.00
500–999 kW	0.00	0.00
1–4.9 MW	0.00	0.00
5 MW+	0.22	0.28
Renewable - Biogas (Total)		
Landfill	0.23	0.28
Farm	0.91	1.14
Paper Manufacturing	0.09	0.11
Wastewater	0.04	0.04
Total CHP	**7.91**	**9.89**

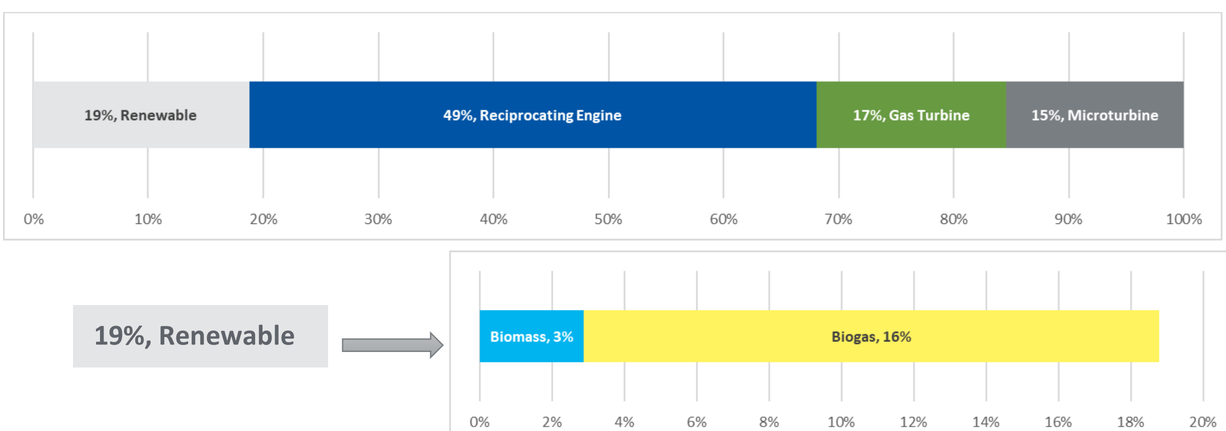
Figure 21 shows cumulative achievable CHP potential by year and technology. The decrease in the rate of adoption at year 2034 is caused by the assumed 10-year lifespan of microturbines. Further decrease in the adoption rate at year 2044 is observed due to the assumed 20-year lifespan of reciprocating engines and natural gas turbines. All three of these technologies are installed throughout the study horizon (2024 through 2050); microturbines do not begin to be decommissioned until 10 years after the start of the study, while reciprocating engines and natural gas turbines begin to be decommissioned 20 years after the start of the study. For microturbines, the rate for the first 10 years of the study is based on new installs and the rate after the first 10 years includes new installs as well as decommissioned systems. Similarly, for reciprocating engines and natural gas turbines, the rate for the first 20 years of the study is based on new installs and the rate after the first 20 years includes new installs as well as decommissioned systems.

Figure 21. Combined Heat and Power Cumulative Achievable Technical Potential by Year at Generation (aMW)



Of the 7.91 aMW of cumulative achievable technical potential, reciprocating engines made up 3.90 aMW (49%), natural gas turbines made up 1.31 aMW (17%), and microturbines made up 1.22 aMW (15%). The remaining 19% was for renewable technologies, which consisted of biogas (1.26 aMW) and biomass (0.23 aMW) systems. In 2050, total energy generated across all technologies is 69.3 GWh (with nonrenewable at 56.3 GWh and renewables at 13 GWh). Figure 22 shows the market potential of energy generation by each technology.

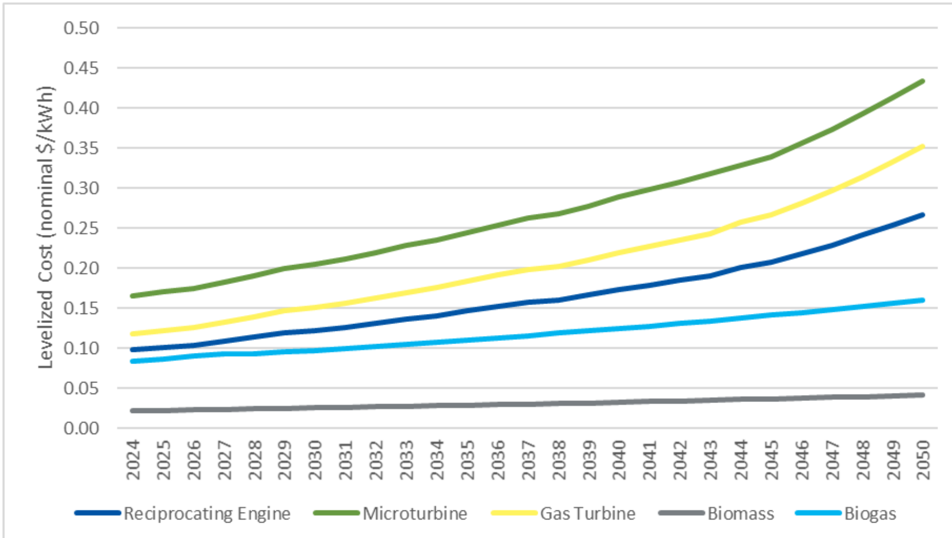
Figure 22. Breakout of Combined Heat and Power 2050 Cumulative Achievable Technical Potential



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 (2024 through 2050). Figure 23 shows the nominal levelized cost for units installed through the study period. The levelized cost increases 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 23. Nominal Levelized Cost by Technology and Installation Year



Chapter 2. Demand Response Potential

Demand response programmatic options help reduce peak demand during system emergencies or periods of extreme market prices and promote improved system reliability. Demand response programs provide incentives for customers to curtail loads during utility-specified events (such as DLC programs) or offer pricing structures to induce participants to shift load away from peak periods (such as critical peak pricing [CPP] programs).

Overview of Technical and Achievable Technical Potential Approach

Cadmus focused on programs aimed at reducing PSE's winter and summer peak demand. These programs include residential and commercial DLC HVAC, residential DLC water heat, residential EVSE, residential and C&I CPP, and C&I load curtailment and provide options for all major customer segments and end uses in PSE's service territory. Each of these programs may have more than one product option. For example, the residential DLC water heat program is available for customers with either a HPWH or ERWH. A water heater can also be grid-enabled or controlled by a switch.

We defined each demand response program and its associated product option(s) according to typical program offerings, with particular specifications such as program implementation methods, applicable segments, affected end uses, load reduction strategies, and incentives. The program assumptions are based on the inputs used in the draft *2021 Power Plan* with a few modifications to account for additional benchmarking.

Technical Potential Approach

Technical potential assumes 100% participation of eligible customers in all programs included in the assessment. Hence, technical potential represents a theoretical limit for unconstrained potential. Depending on the type of demand response product, Cadmus applied either a bottom-up or a top-down method to estimate technical potential.

Cadmus used the bottom-up method to assess potential for demand response programs that affect a piece of equipment in a specific end use, such as residential and commercial DLC space heat, residential DLC water heat, and residential EVSE. In the bottom-up method, we determined technical potential as the product of three variables: number of eligible customers, equipment saturation rate, and the expected per-unit (kilowatt) peak load impact.

The top-down method estimates technical potential as a fraction of the participating facility's total peak-coincident demand. Cadmus began these calculations by disaggregating system electricity sales by sector, market segment, and end use, then we estimated technical potential as a fraction of the end-use loads. Cadmus then estimated total potential by aggregating the estimated load reductions of the applicable end uses. We applied the top-down estimation method to demand response products that target the entire facility or load (rather than specific equipment), such as CPP and C&I demand curtailment.

Achievable Technical Potential Approach

Achievable technical potential reflects a subset of technically feasible demand response opportunities that are assumed to be reasonably obtainable based on market conditions and the end-use customers' ability and willingness to participate in the demand response market. There are two components for estimating achievable technical potential: market acceptance (or the participation rate) and the ramp rate. The participation rate is also broken down into program participation (the likelihood of the eligible population to enroll in a demand response program) and event participation (the probability that customers participating in a program will respond to a demand response event)—an important consideration in voluntary demand response programs.

Ramp rates reflect the time needed for product design, planning, and deployment. Ramp rates vary depending on the type of demand response product and the stage in the product's life cycle. Ramp rates indicate when the maximum achievable technical potential may be reached, but they do not affect the amount of maximum achievable technical potential.

Both the top-down and bottom-up methods calculate achievable technical potential as the product of technical potential and market acceptance. Both methods apply ramp rates in the same manner to account for program start-up and ramp-up.

Levelized Costs Calculations

In the context of demand response, the levelized cost of electricity represents the constant per-kilowatt-year cost of deploying and operating a demand response product, calculated as follows:

$$Levelized\ Cost\ of\ Electricity = \frac{Annualized\ Cost\ of\ Demand\ Response\ Product}{Achievable\ Annual\ Kilowatt\ Load\ Reduction}$$

Cadmus calculated levelized costs based on the TRC perspective, which includes all known and quantifiable costs related to demand response products and programs. The calculation of each demand response product's levelized cost accounts for the relevant, direct costs of a demand response product, including setup costs, program O&M costs, equipment cost, marketing cost, incentives, T&D deferral costs, a discount rate, and the product life cycle:

- **Upfront setup cost.** This cost item includes PSE's program development and setup costs for delivery of demand response products, prior to program implementation. Because upfront costs tend to be small relative to total program expenditures, they are expected to have a small effect on levelized costs.
- **Program O&M cost.** This cost item includes all expenses that PSE incurs annually to operate and maintain the program. Expenses may cover administration, event dispatching, customer engagement, infrastructure maintenance, managing opt-outs and recruiting new loads, and evaluation.
- **Equipment cost (labor, material, and communication costs).** This cost item includes all expenses necessary to enable demand response technology for each participating end user. This cost item only applies to each year's new participants. For programs that assume or require end users to already have demand response technology in place, this cost item would be zero.

- **Marketing cost.** This cost item includes all expenses for recruiting end users' participation in the program and only applies to new participants each year. For some programs (typically those run by third-party aggregators), the program O&M cost already includes this cost item.
- **Incentive.** This cost item covers all incentives offered to end users each year. Incentives may take the form of fixed monthly or seasonal bill credits or may be variable, tied to actual kilowatt load reduction. Cadmus only included a portion of the assumed incentive payment to eligible participants in the TRC levelized-cost calculation. We followed the same approach used by the Council in the draft *2021 Power Plan*, following protocols outlined in the *California Standard Practice Manual* and further modified by the DRAC and Council staff.
- **T&D costs.** Cadmus included a T&D deferral value of $74.70 per kilowatt-year as a negative cost item in the levelized cost calculations for each product.
- **Discount rate.** Cadmus used a 6.8% discount rate for all demand response products, consistent with PSE's resource planning assumptions.
- **Product life cycle.** Based on equipment control lifetimes, the life cycles for products with enabling equipment are limited by the enablement technology's effective useful life (EUL). For example, a BYOT program's product life cycle is equivalent to the EUL of a smart thermostat. All product life cycles were determined in this way except for pricing products: because these are based on rate structures, we assumed the program would be the length of the study duration.

Supply Curve Development

Demand response supply curves show the quantity-price relationships for the demand response products that are being considered at the end of the planning period. A supply curve shows the incremental and cumulative achievable technical potential for a set of demand response products, in the ascending order of their levelized costs.

Demand Response Potential

This section introduces the analysis scope for assessing demand response potential in PSE's electric service territory, followed by a summary of potential results of the demand response programs and detailed descriptions of each program, including the product options and associated input assumptions.

Scope of Analysis

Focused on reducing a utility's capacity needs, demand response programs rely on flexible loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost. These programs seek to help reduce peak demand and promote improved system reliability. In some instances, the programs may defer investments in delivery and generation infrastructure.

Demand response objectives may be met through a broad range of strategies, both price-based (such as CPP) and incentive-based (such as DLC) strategies. For this assessment, Cadmus considered 15 total demand response product options to estimate total achievable technical demand response potential in PSE's service area during peak load in winter and summer. These product options included multiple residential and commercial DLC products targeting cooling, heating, and water heating end uses as well as EVSE and C&I products such as demand curtailment contracts and CPP. In this study, event durations are defined as 40 hours per season (with 10, four-hour events per season).

Cadmus relied on the Council's draft *2021 Power Plan* and we reviewed recent demand response literature, including evaluations of pilots and programs in the Northwest and across the country, to determine the design for each demand response program. The product groups in this study often have multiple product options to capture the most common demand response product strategies. For example, customers participating in the residential DLC space heat program can either have a switch installed on the HVAC system in their home or let the utility communicate with the home's existing smart thermostat.

Summary of Resource Potential

Table 22 lists the estimated resource potentials for all winter demand response programs for the residential, commercial, and industrial sectors. The greatest achievable technical potential occurs in the residential sector from the DLC programs (for HVAC and water heat). Note that this analysis accounts for program interactions and overlap; therefore, the total achievable technical potential estimates are additive.

Table 22. Demand Response Achievable Technical Potential and Levelized Cost by Product Option, Winter 2050

Program	Product Option	Winter Achievable Technical Potential (MW)	Winter Percentage of System Peak	Levelized Cost ($/kW-year)
Residential DLC Water Heat	Residential ERWH DLC Switch	0	0.00%	$24
	Residential ERWH DLC Grid-Enabled	32	0.52%	-$28
	Residential HPWH DLC Switch	0	0.00%	$203
	Residential HPWH DLC Grid-Enabled	58	0.94%	$91
Residential DLC HVAC	Residential HVAC DLC Switch	97	1.56%	-$24
	Residential BYOT DLC	108	1.74%	-$56
Residential DLC EVSE	Residential EVSE DLC Switch	42	0.67%	$105
Commercial DLC HVAC	Medium Commercial HVAC DLC Switch	18	0.30%	-$33
	Small Commercial HVAC DLC Switch	3	0.04%	$0
	Small Commercial BYOT DLC	3	0.05%	-$36
C&I Curtailment	Commercial Curtailment	16	0.26%	-$28
	Industrial Curtailment	5	0.08%	-$37
Residential CPP	Residential CPP	33	0.54%	-$56
Commercial CPP	Commercial CPP	21	0.34%	-$57
Industrial CPP	Industrial CPP	2	0.02%	-$34
-	**Total**	**439**	**7.05%**	**NA**

Although PSE's electric distribution system incurs peak demand in winter, Cadmus also estimated the demand response potential for the summer season, shown in Table 23. The remainder of the results presented in this chapter focus on the winter demand response potential.

Table 23. Demand Response Achievable Technical Potential and Levelized Cost by Product Option, Summer 2050

Program	Product Option	Summer Achievable Technical Potential (MW)	Summer Percentage of System Peak	Levelized Cost ($/kW-year)
Residential DLC Water Heat	Residential ERWH DLC Switch	0	0.00%	$74
	Residential ERWH DLC Grid-Enabled	22	0.39%	-$4
	Residential HPWH DLC Switch	0	0.00%	$481
	Residential HPWH DLC Grid-Enabled	29	0.53%	$257
Residential DLC HVAC	Residential HVAC DLC Switch	50	0.90%	$52
	Residential BYOT DLC	100	1.81%	-$40
Residential DLC EVSE	Residential EVSE DLC Switch	42	0.75%	$105
Commercial DLC HVAC	Medium Commercial HVAC DLC Switch	77	1.40%	-$42
	Small Commercial HVAC DLC Switch	5	0.10%	$64
	Small Commercial BYOT DLC	4	0.07%	-$3
C&I Curtailment	Commercial Curtailment	20	0.36%	-$28
	Industrial Curtailment	5	0.09%	-$37
Residential CPP	Residential CPP	74	1.35%	-$66
Commercial CPP	Commercial CPP	26	0.48%	-$61
Industrial CPP	Industrial CPP	2	0.03%	-$35
-	**Total**	**455**	**8.24%**	**NA**

Cadmus constructed supply curves from quantities of estimated achievable technical demand response potential and per-unit levelized costs for each product option. Figure 24 shows the achievable technical potential (available during the system winter peak hours in 2050) as a function of levelized costs at the product option level.

The supply curve starts with the lowest cost product option—commercial CPP, which provides 21 MW of winter achievable technical potential at -$57 per kilowatt-year, levelized. The next lowest-cost product in the supply curve is the residential CPP product, which adds 33 MW of winter achievable technical potential at -$56 per kilowatt-year, levelized. Thus, PSE could acquire a total of 55 MW (with rounding) of winter demand response at a negative levelized cost.

These two most cost-effective demand response product options have negative costs due to the inclusion of deferred T&D costs in the TRC levelized cost calculation. Cadmus incorporated a T&D deferral value of $68.13 per kilowatt-year as a negative cost item in the levelized cost calculations for each product, resulting in negative net levelized costs for the majority of products.

Because residential EV DLC is the most expensive product option (with non-zero final year potential), PSE could acquire as much winter potential as achievable if it paid $105 per kilowatt-year (the levelized cost for the most expensive product option). However, PSE could acquire approximately 77% of the total achievable technical winter demand response potential at $0 per kilowatt-year or less due to the high deferred T&D costs.

Figure 24. Demand Response Achievable Technical Potential Supply Curve by Product Option, Winter

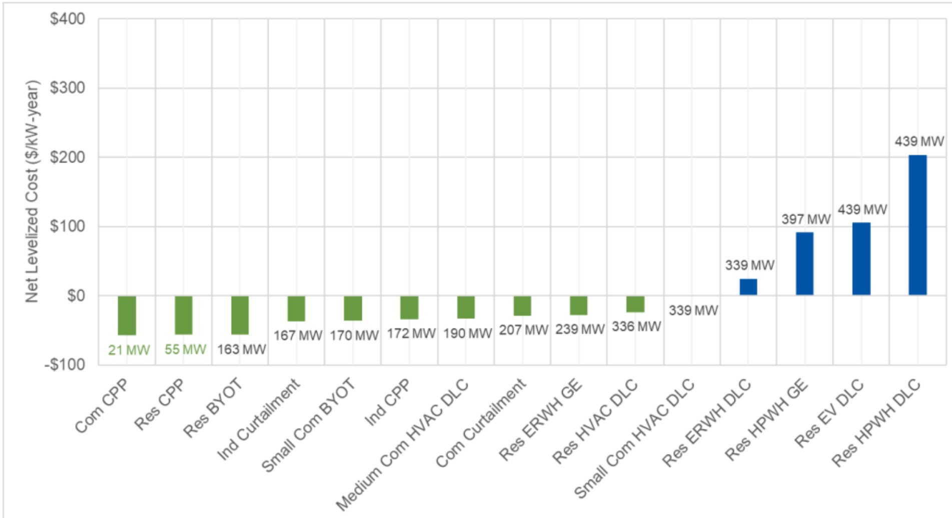


Figure 25 shows the acquisition schedule for achievable technical potential by product for winter. Product potential ramps up in the early years of the study by recruiting new participants and flatten out once market has reached maturity. For example, residential HVAC and water heating DLC make up much of the available winter demand response potential once the demand response market matures. It should be noted the demand response potential shown represents the achievable technical potential and includes both cost effective and non-cost effective demand response products.

Figure 25. Demand Response Achievable Technical Potential Forecast by Program, Winter

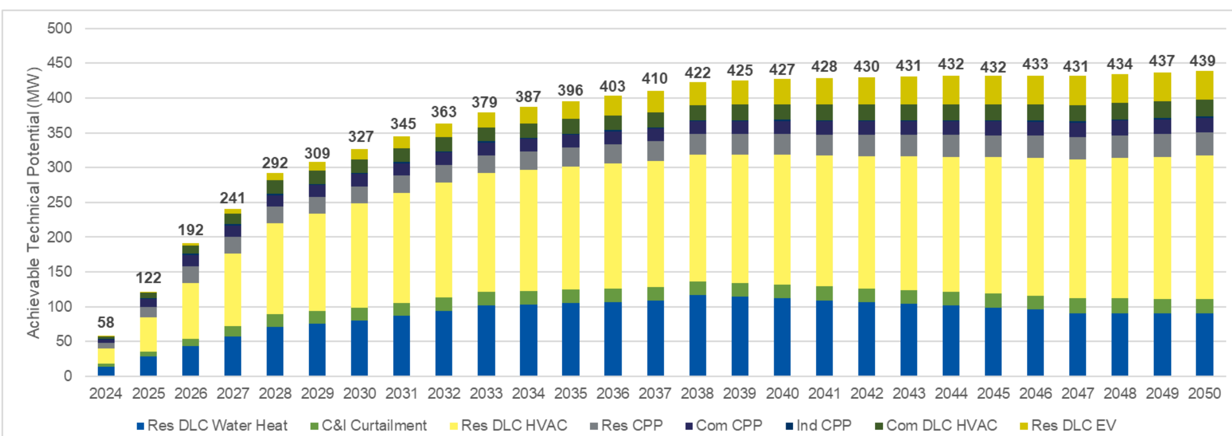
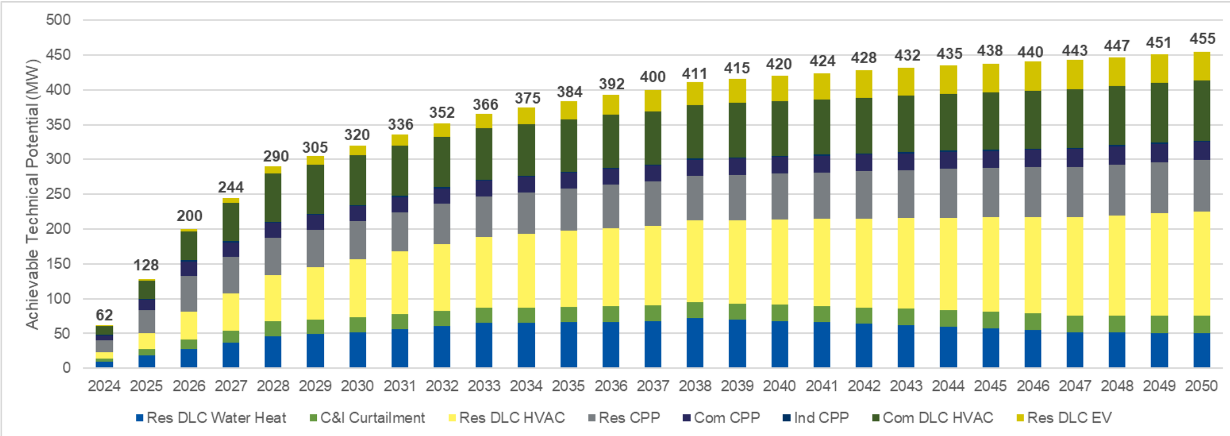


Figure 26 shows the acquisition schedule for achievable technical potential by program for summer. The dynamics in the summer are similar to those seen in the winter, though there are some key differences. For example, the water heating per unit peak demand impacts in the summer are lower compared to the winter per unit impacts. As a result, the overall potential is lower for water heating in the summer. Conversely, the commercial HVAC DLC and residential CPP also have more potential in summer than in the winter.

Figure 26. Demand Response Achievable Technical Potential Forecast by Program, Summer



Chapter 3. Rooftop Solar PV Potential

This chapter includes a discussion of the methodology and inputs for estimating technical and achievable technical rooftop solar PV potential, as well as the potential results for the commercial and residential sectors and vulnerable population segment.

Overview of Technical and Achievable Technical Potential Approach

This section describes the technical and achievable technical potential for rooftop solar PV (not including ground-mounted solar PV systems). Figure 27 briefly describes these potential estimate types.

Figure 27. Types of Estimated Potential

Rooftop Area Not Suitable for Development	**TECHNICAL POTENTIAL** Theoretical maximum system (nameplate) capacity deployed and energy produced accounting for available rooftop square footage including shading, solar PV panel production per square foot, and solar irradiation.	
Rooftop Area Not Suitable for Development	Not Adopted by Building Owners	**ACHIVABLE TECHNICAL POTENTIAL** Rooftop solar capacity deployed and energy produced based on simulations and economic parameters that affect the financial attractiveness from a customer perspective.

Technical Potential Approach

Technical potential represents the theoretical maximum developable rooftop solar PV capacity given the statewide rooftop square footage. Technical capacity potential excludes rooftop areas that are not suitable for development.[22] Technical energy production potential accounts for solar irradiation across PSE service territory and is measured in kilowatt-hours, megawatt-hours, or gigawatt-hours.

Technical potential is calculated by the dGen model using light detection and ranging data to calculate rooftop obstructions, rooftop azimuth, and rooftop tilt. The model also assumes that a percentage of the building stock is not suitable for rooftop solar development based on rooftop orientation or pitch. Finally, the model mines regional solar irradiation levels to calculate technical potential. Technical potential does not account for barriers to adoption, such as roof age, structural suitability, or electric code compliance.

[22] To be considered suitable for development, a roof plane is required to be at least 80% unshaded and it cannot be oriented to the northwest, north, or northeast. The dGen model does not account for changes in shading over time.

Achievable Technical Potential Approach

Achievable technical potential represents the simulated rooftop solar PV adoption on residential and commercial buildings and is based on three parameters:

- Existing rooftop solar deployment in an area of interest
- The assumed maximum market adoption based on the economic attractiveness of solar PV systems
- The technology diffusion rate throughout the population

Existing rooftop solar deployment refers to the historically adopted system capacity in PSE territory, by sector, through 2022. Economic attractiveness is a function of a range of model inputs, including technology costs, federal and state incentives, project financing, and utility compensation mechanisms (net metering or net billing). The technology diffusion rate throughout the population refers to the rate of adoption of rooftop solar PV and is determined by a Bass diffusion curve.

The Bass diffusion curve is determined by Bass diffusion coefficients, a key input used to simulate technology diffusion. For this study Cadmus recalibrated the Washington coefficients in the dGen model to PSE service territory trends based on historical adoption data.

Another key input impacting adoption is the maximum market adoption curve, used to provide the relationship between the maximum percentage of the market that adopts solar and the payback period. Achievable technical potential is a subset of technical potential, determined by the adoption parameters described above and limited by the amount of solar potential that can technically be installed given suitable rooftop space.

Methodology

This section describes the methodology and model inputs Cadmus used to estimate technical and achievable technical potential.

NREL dGen Model

To model technical potential and to simulate achievable rooftop solar PV potential, Cadmus used NREL's dGen model, which simulates the market adoption of rooftop solar PV systems. The model and underlying state-level datasets are available to the public. The dGen model uses a particular approach to estimate market adoption:

> NREL has made the model publicly available and provides the opportunity to adjust model inputs and underlying assumptions, as well as model logic. Cadmus reviewed the model inputs in detail and adjusted data inputs and model programming as appropriate. Details about the model mechanics can be found in the dGen documentation as well as on the NREL website at https://www.nrel.gov/analysis/dgen/

- Generates agents and assigns representative attributes based on population data[23]
- Applies technical resource characteristics—such as solar irradiance, rooftop square footage, rooftop pitch and orientation, and obstruction data—to each agent
- Conducts economic calculations using cash flow analysis and incorporating project costs, electric rates, net-metering or net billing considerations, and state and federal incentives
- Calculates market adoption based on Bass diffusion and project economics[24]

The dGen model provides market adoption results at the county, utility, and state levels. The model also produces estimates by sector and building segment through 2050.[25] Because model inputs can be varied, adoption scenarios can be generated by changing key inputs.

Approach for Technical Potential

The dGen model uses light detection and ranging data inputs to estimate the total rooftop area suitable for solar projects and calculates system capacity factors based on additional data inputs such rooftop orientation and solar irradiance. However, the model does not directly report technical potential estimates; rather, its outputs can be used to calculate the amount of capacity that could be deployed and amount of energy that could be produced. To calculate technical potential, Cadmus applied the system capacity per square footage model input assumption to the estimated developable rooftop (see the *Model Inputs* section for more details).[26] The technical system capacity changes over time based on assumed increases in solar panel efficiency and load growth associated with new buildings. To calculate

[23] An agent represents a group of customers with similar characteristics for the purpose of estimating solar adoption. Agents are statistically weighted together to represent commercial and residential populations.

[24] National Renewable Energy Laboratory (Sigrin, Benjamin, Michael Gleason, Robert Preus, Ian Baring-Gould, and Robert Margolis). February 2016. "The Distributed Generation Market Demand Model (dGen): Documentation."

[25] While aggregate outputs are available at various levels of granularity, these cannot necessarily be provided at any special resolution due to the sampling approach taken to generate population files. For example, building sector resolution is not available at the county level because not all counties include all building sectors in the sample-based population file.

[26] The NREL dGen model does not account for roof age, structural suitability, or electric code compliance. These factors can create barriers to solar adoption, especially for income-qualified customers.

technical generation potential, Cadmus applied the modeled system capacity factors to the calculated technical system capacity.

Approach for Vulnerable Populations

The dGen model does not simulate market adoption for vulnerable populations and does not characterize agents (representative customers) by vulnerability level. To generate vulnerable population estimates, Cadmus segmented the residential population into standard income and vulnerable population groups using PSE's *Residential Consumption Survey*. After reviewing survey data Cadmus found that only 3% of vulnerable population households had solar (we used a proxy of annual household incomes below $50,000 to identify vulnerable populations because a vulnerable population identifier was not available in the dataset). Accordingly, Cadmus adjusted the historical adoption of solar systems to reflect that adoption trend and adjusted Bass diffusion coefficients to reflect a much slower market adoption rate compared with the standard-income populations.

Approach for Multifamily Potential

The dGen residential model simulates the adoption of rooftop solar PV on multifamily buildings as a unit occupant decision, rather than a building owner decision. For this study Cadmus assumed that multifamily building rooftop solar potential is part of the commercial sector, given that building owners, rather than unit occupants, are the most likely adopters of rooftop solar systems. To estimate multifamily rooftop solar adoption, Cadmus calculated multifamily building technical potential, then applied an adoption rate from the commercial sector.

Approach for Renters

Cadmus reviewed data from the PSE *Residential Consumption Survey* and found that only 1% of households living in rental units had solar systems installed on their homes (this percentage may include homes where solar was installed before the home became a rental unit, but the data does not specify the situation). The very low adoption of rooftop solar on rental homes is consistent with the theory that the split incentive makes it unlikely that rooftop solar systems will be installed on rental homes. Accordingly, Cadmus removed renters from the agent file and did not simulate adoption for the renter population segment.

Approach for Small Systems

The dGen model sizes systems to achieve the maximum payback for a customer. Because the model sometimes generates system sizes that are unrealistically small, Cadmus removed systems from this analysis that were sized by dGen to be smaller than 1 kW.

Model Inputs

The dGen model contains a large volume of data inputs, including utility rates, customer populations, customer loads, project costs, financing conditions, and many others. Table 24 provides key dGen model inputs for the commercial and residential baseline models. For the vulnerable population residential model, Cadmus adjusted the market diffusion coefficients and kept the other residential inputs constant. The dGen model provides prepopulated tables with the model inputs, which are applied universally to all members of the population.

Table 24. Baseline Model Inputs

Model Input	Value	Notes/Source
Residential		
Federal investment tax credit	2020–2022: 26%; 2023: 22%; after 2023: 0%	U.S. Department of Energy
Loan term	30 years	NREL 2021 annual technology baseline (ATB) [a]
Interest rate	3.96%	NREL 2021 ATB [a]
Discount rate	3.67%	NREL 2021 ATB [a]
Down payment fraction	24.2%	NREL 2021 ATB [a]
Net metering	2022–2050	Set net metering through 2050 following discussions with PSE that other incentives would likely begin when PSE net-metering sunsets in 2029.
Solar costs (2021)	$3,197 per kilowatt	2021 costs are based on historical PSE program costs. Costs decline according to NREL 2021 ATB [a] “moderate” estimates.
Coefficient: *p* (innovation)	0.001	Used to simulate market adoption over time. Estimated based on PSE historical adoption data.
Coefficient: *q* (imitation)	0.25	
Residential Vulnerable Population Adjustment		
Coefficient: *p* (innovation)	0.0002	Used to simulate market adoption over time. Estimated based on PSE historical adoption data.
Coefficient: *p* (innovation)	0.005	
Commercial		
Federal investment tax credit	2020–2022: 26%; 2023: 22%; after 2023: 10%	U.S. Department of Energy
Loan term	30 years	NREL 2021 ATB [a]
Interest rate	3.96%	NREL 2021 ATB [a]
Discount rate	1.83%	NREL 2021 ATB [a]
Down payment fraction	24.1%	NREL 2021 ATB [a]
Net-metering	2022–2050	Set net metering through 2050 following discussions with PSE that other incentives would likely begin when PSE net-metering sunsets in 2029.
Solar costs (2021)	$1,677 per kilowatt	2021 costs are based on PSE program data. Costs decline according to NREL 2021 ATB [a] “moderate” estimates.
Coefficient: *p* (innovation)	0.0012	Used to simulate market adoption over time. Estimated based on PSE historical adoption data.
Coefficient: *q* (imitation)	0.16	

[a] National Renewable Energy Laboratory. Accessed May 2022. “Electricity Annual Technology Baseline (ATB) Data Download.” https://atb.nrel.gov/electricity/2021/data

Another modeling consideration is the distributed rooftop system adoption that has been historically deployed. These data provide a starting point for future simulated rooftop adoption. A key consideration is that each utility has specific starting points for solar adoption, which are then used as the starting point for future growth within that utility service area. Cadmus used PSE program data for past solar adoption estimates.

Rooftop Solar PV Potential

This section provides the results for technical and achievable rooftop solar potential in PSE service territory.

Technical Potential Results

Based on the analysis described in the *Methodology* section above, Cadmus estimated 20,498 MW as the total technical potential for PV installed on residential and commercial rooftops in PSE's service area through 2050. Much of this technical potential (61%) is in the residential sector and the remaining 39% is from the commercial sector. Each sector's technical potential is a function of the fraction of total roof area available and the total roof area. If the full technical potential were installed, it would generate approximately 2,413 aMW.

Table 25 provides the study period behind-the-meter PV technical potential with growth due to increases in building stock from 2024 to 2050 and increases in solar PV efficiency.

Table 25. Rooftop Solar PV Technical Potential

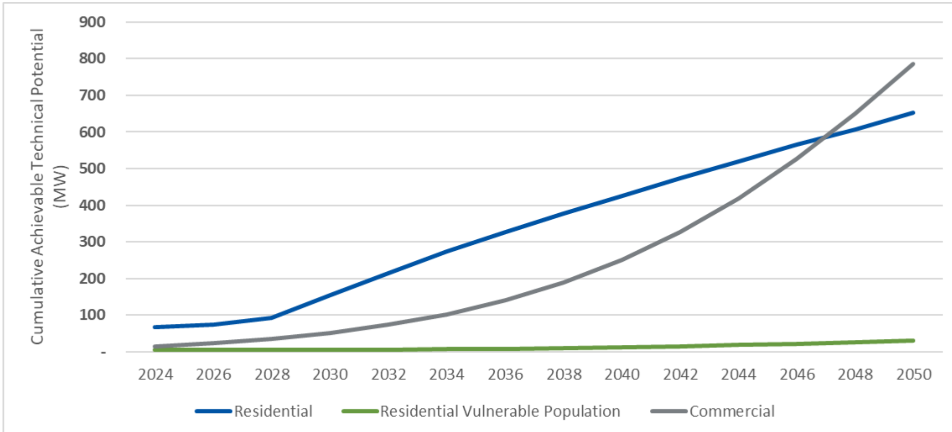
Sector	Total 2024 aMW	Installed Capacity 2024 MW	Total 2050 aMW	Installed Capacity 2050 MW
Residential	622	5,354	952	8,158
Residential - Vulnerable Population	327	2,810	500	4,281
Commercial	494	4,145	960	8,059
Total	**1,443**	**12,308**	**2,413**	**20,498**

Achievable Technical Potential Results

Cadmus simulated achievable technical potential from 2024 through 2050 using NREL's dGen tool, which applies a market diffusion approach under changing market conditions. Figure 28 shows the simulated market adoption trend by sector from 2024 through 2050. In total, the dGen tool predicts that in 2050 the market will adopt 1,423 MW of rooftop solar capacity, or approximately 7% of the estimated technical potential. Vulnerable populations make up a very small fraction of this achievable technical potential (2% of the 2050 total achievable technical potential), while the commercial sector makes up approximately 55% of the achievable technical potential, despite having a lower portion of the technical potential than the residential sector.

Historically, the residential sector has had a higher fraction of installed rooftop solar systems. However, through 2050 the achievable technical potential market adoption simulation shows a leveling off of residential adoption, while the commercial sector shows continued growth through 2050. Contributing factors to this trend include declining economic attractiveness for residential systems due to the phasing out of the federal investment tax credit and the low cost for commercial solar systems through 2050.

Figure 28. Rooftop Solar PV Achievable Technical Potential - Nameplate



In terms of achievable technical potential energy production, the adopted rooftop systems, as simulated by dGen, will produce 11.9 aMW (37.9 MW) in 2024 and increase to 169.9 aMW (1,422.7 MW) in 2050 (Table 26). The achievable 2050 energy production represents 7% of the technical potential for energy production (in average megawatts). The commercial sector has 56% of the achievable 2050 energy production potential (in average megawatts), while the residential sector has 44% of the achievable technical potential (vulnerable populations have 0.3% of the potential).

Table 26. Rooftop Solar PV Achievable Technical Potential

Sector	Total 2024 aMW	Installed Capacity 2024 MW (Nameplate)	Total 2050 aMW	Installed Capacity 2050 MW (Nameplate)
Residential	7.7	29.8	73.5	617.0
Residential Vulnerable Population	0.6	2.6	0.6	28.2
Commercial	3.9	5.5	95.8	777.5
Total	**11.9**	**37.9**	**169.9**	**1,422.7**

Chapter 4. Energy Efficiency Methodology Details

This chapter describes Cadmus' methodology for estimating the potential of demand-side resources in PSE's service territory between 2024 and 2050 and for developing supply curves for modeling demand-side resources in PSE's IRP. We describe the calculations for technical and achievable technical potential, identify the data sources for components of these calculations, and discuss key global assumptions. To estimate the demand-side resource potential, Cadmus analyzed many conservation measures across many sectors, with each measure requiring nuanced analysis. This chapter does not describe the detailed approach for estimating a specific measure's UES or cost, but it does show the general calculations we used for nearly all measures.

Cadmus' methodology for calculating energy efficiency potential can be best described as a combined top-down, bottom-up approach. We began the top-down component with the most current load forecast, adjusting for building codes, equipment efficiency standards, and market trends that are not accounted for through the forecast. Cadmus then disaggregated this load forecast into its constituent customer sectors, customer segments, and end-use components and projected the results out 27 years. We calibrated the base year (2023) to PSE's sector-load forecasts produced in 2022.

For the bottom-up component, we considered potential technical impacts of various ECMs and practices on each end use. We then estimated impacts based on engineering calculations, accounting for fuel shares (the proportion of units using electricity versus natural gas), current market saturations, technical feasibility, and costs. The technical potential presents an alternative forecast that reflects the technical impacts of specific energy efficiency measures. Cadmus then determined the achievable technical potential by applying ramp rates and achievability percentages to technical potential. The CPA methodology is described in detail in the following sections.

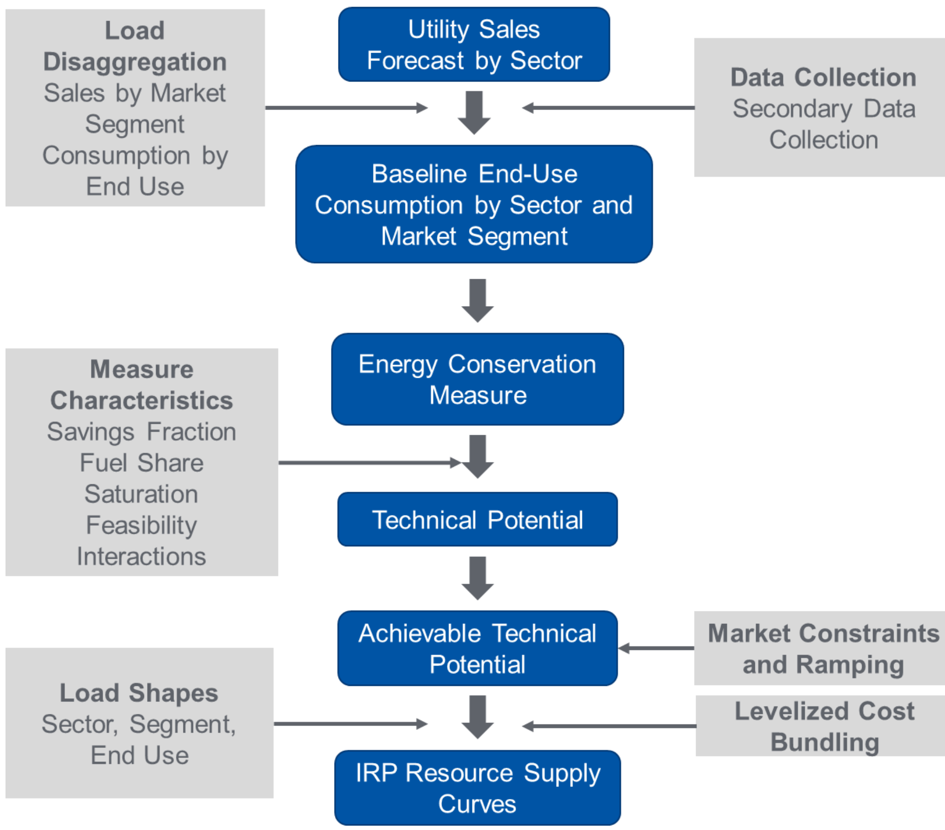
Cadmus followed a series of steps to estimate energy efficiency potential, described in detail in the subsections below:

- ***Market segmentation.*** Cadmus identified the sectors and segments for estimating energy efficiency potential. Segmentation accounts for variation across different parts of PSE's service territory and across different applications of energy efficiency measures.
- ***ECM characterization.*** Cadmus researched viable ECMs that can be installed in each segment. The description for this step below includes the components and data sources for estimating measure savings, costs, applicability factors, lifetimes, baseline assumptions, and the treatment of federal standards.
- ***Baseline end-use load forecast development.*** Cadmus developed baseline end-use load forecasts over the planning horizon and calibrated the results to the PSE's corporate forecast in the base year (2023).

- ***Conservation potential estimation.*** Cadmus forecasted technical potential, relying on the measure data compiled from prior steps and the achievable technical potential, which we based on technical potential and additional terms to account for market barriers and ramping.
- ***IRP input development.*** Cadmus bundled forecasts of achievable technical potential by levelized costs, so PSE's IRP modelers can consider energy efficiency as a resource within the IRP.

Figure 29 provides a general overview of the process and inputs required to estimate potential and develop conservation supply curves.

Figure 29. Overview of Energy Efficiency Methodology



Market Segmentation

Market segmentation involved first dividing PSE's electric service territories into sectors and market segments. Careful segmentation accounts for variation in building characteristics and savings across the service territory. To the extent possible, energy efficiency measure inputs reflect primary data, such as the NEEA 2019 CBSA, the NEEA 2017 RBSA, and the PSE RCS.

Considering the benefits and drawbacks of different segmentation approaches, Cadmus identified three parameters that produce meaningful and robust estimates:

- ***Service territories and fuel type.*** PSE's electric service territory
- ***Sector.*** Residential, commercial, and industrial
- ***Industries and building types.*** Three residential segments (and the corresponding vulnerable population segments), 18 commercial segments including indoor agriculture, and 21 industrial segments including water supply and sewage treatment and streetlighting

Table 27 lists the segments modeled for each sector.

Table 27. Segments Modeled

Residential	Commercial	Industrial
• Single Family • Multifamily • Manufactured • Multifamily - Vulnerable Population • Manufactured - Vulnerable Population • Single Family - Vulnerable Population	• Large Office • Medium Office • Small Office • Extra Large Retail • Large Retail • Medium Retail • Small Retail • School K–12 • University • Warehouse • Supermarket • Mini-Mart • Restaurant • Lodging • Hospital • Residential Care • Assembly • Other • Indoor Agriculture	• Mechanical Pulp • Kraft Pulp • Paper • Foundries • Food - Frozen • Food - Other • Wood - Lumber • Wood - Panel • Wood - Other • Cement • Hi Tech - Chip Fabrication • Hi Tech - Silicon • Metal Fabrication • Transportation Equipment • Refinery • Cold Storage • Fruit Storage • Chemical • Miscellaneous Manufacturing • Streetlighting • Sewage Treatment • Water Supply

Energy Conservation Measure Characterization

Technical potential draws upon an alternative forecast and should reflect installations of all technically feasible measures. To accomplish this, Cadmus chose the most robust set of appropriate ECMs by developing a comprehensive database of technical and market data that applied to all end uses in various market segments. Throughout this process, we calculated ECM savings as UES or measure percentage savings to estimate the end-use percentage savings. These measures' end-use percentage savings, when applied to the baseline end-use forecasts, produce estimates of energy efficiency potential.

The database included several measures:

- All measures in the PSE business case workbooks
- All measures in the Council's draft *2021 Power Plan* conservation supply curve workbooks
- Active UES measures in the RTF

Cadmus included only the Council and RTF measures applicable to sectors and market segments in PSE's service territory. For example, we did not characterize measures for the agriculture sector except indoor agriculture measures such as lighting. Cadmus added measures if the RTF workbooks were not included in the Council's draft *2021 Power Plan* or if the RTF workbooks had been updated since the Council's draft *2021 Power Plan* workbooks.

Cadmus classified the electric energy efficiency measures applicable to PSE's service territories into two categories:

LOST OPPORTUNITY	DISCRETIONARY
High-efficiency equipment measures directly affecting end-use equipment (such as high-efficiency domestic water heaters), which follow normal replacement patterns based on expected lifetimes	**Non-equipment (retrofit)** measures affecting end-use consumption without replacing end-use equipment (such as insulation). Such measures do not include timing constraints from equipment turnover—except for new construction—and should be considered discretionary, given that savings can be acquired at any point over the planning horizon.

Cadmus assumed that all high-efficiency equipment measures would be installed at the end of the existing equipment's remaining useful life; therefore, we did not assess energy efficiency potential for early replacement.

Each measure type had several relevant inputs.

Equipment and non-equipment measures:

- Energy savings: Average annual savings attributable to installing the measure, in absolute (kilowatt-hour per unit) and/or percentage terms
- Equipment cost: Full or incremental, depending on the nature of the measure and the application
- Labor cost: The expense of installing the measure, accounting for differences in labor rates by region and other variables
- Technical feasibility: The percentage of buildings where customers can install this measure, accounting for physical constraints
- Measure life: The expected life of the measure equipment
- Non-energy impacts (NEIs): The annual dollar savings per year associated with quantifiable non-energy benefits
- Savings shape: The hourly savings shape for each measure, which Cadmus assigned and then used to disaggregate annual forecasts of potential into hourly estimates

Non-equipment measures only:

- Percentage incomplete: The percentage of buildings where customers have not installed the measure, but where its installation is technically feasible, equal to 1.0 minus the measure's current saturation
- Measure competition: For mutually exclusive measures, accounting for the percentage of each measure likely installed to avoid double-counting savings
- Measure interaction: Accounting for end-use interactions (such as a decrease in lighting power density causing heating loads to increase)

Cadmus derived these inputs from various sources, though primarily through four main sources:

- NEEA CBSA IV, including PSE's oversample, where applicable
- NEEA RBSA II with PSE's oversample
- The Council's draft *2021 Power Plan* conservation supply curve workbooks
- The RTF UES measure workbooks

For many equipment and non-equipment inputs, Cadmus reviewed a variety of sources. To determine which source to use for this study, Cadmus developed a hierarchy for costs and savings:

1. PSE business cases
2. The Council's draft *2021 Power Plan* conservation supply curve workbooks, except in cases where a more recent version of RTF UES measure workbooks were submitted and not used in the Council's draft *2021 Power Plan*
3. RTF UES measure workbooks
4. Secondary sources, such as American Council for an Energy-Efficient Economy work papers, Simple Energy and Enthalpy Model building simulations, or various technical reference manuals

Cadmus also developed a hierarchy to determine the source for various applicability factors, such as the technical feasibility and the percentage incomplete. This hierarchy differed slightly for residential and commercial measure lists.

Non-Energy Impacts

In this CPA, Cadmus included a wider range of NEIs (such as health and safety, comfort, and productivity) compared to 2021 CPA to calculate NEIs, which resulted in additional NEIs for more measures. In 2021, PSE conducted an NEI evaluation study[27] to expand the NEIs; the full list is shown in Table 28.

[27] DNV Energy. September 30, 2021. *Puget Sound Energy Non-Energy Impacts Final Report*.

Table 28. List of Non-Energy Impacts

NEI Name	NEI Type	Definition
Residential		
Avoided Illness from Air Pollution	Societal	Modeled value of avoided particulate matter 2.5 microns or less associated with electricity generation at power plants (does not include carbon dioxide)
Bad Debt Write Offs	Utility	Reduction in cases of bad debt write offs
Calls to Utility	Utility	Reduction in number of calls to utility from customers
Carrying Cost on Arrearages	Utility	Reduced carrying cost on arrearages
Ease of Selling or Leasing	Participant	Participant-reported improved ability to sell or lease property due to increased performance and desirability
Fires/Insurance Damage	Participant	Avoided cost of fires based on insurance estimates
Health and Safety	Participant	Participant-reported costs from time off and lost pay due to fewer missed days of work/school, heat/cold stress, and other, resulting from measures installed in the home
Lighting Quality and Lifetime	Participant	Participant-reported value of improved lighting lumen levels, color, and steadiness
Noise	Participant	Participant-reported value associated with reduced amount of outside noise that can be heard inside the home
O&M	Participant	Modeled avoided time and costs associated with reduced maintenance, parts/repairs, service visits, and system monitoring
Other Impacts	Participant	Includes participant impacts not covered in the other categories such as reduced tenant turnover
	Utility	Includes rate discounts and price hedging, as well as low-income subsidies avoided
Productivity	Participant	Participant-reported value resulting from improved rest, sleep, and living conditions associated with energy efficiency improvements
Thermal Comfort	Participant	Increased comfort due to fewer drafts and even temperatures throughout the building
Commercial and Industrial		
Administrative Costs	Participant	Participant-reported avoided overhead costs associated with invoice processing, parts/supplies procurement, contractor coordination, and customer complaints
Avoided Illness from Air Pollution	Societal	Modeled value of avoided particulate matter 2.5 microns or less from electric power generation associated with electricity generation at power plant (does not include carbon dioxide)
Ease of Selling or Leasing	Participant	Participant-reported improved ability to sell or lease property due to increased performance and desirability
Fires/Insurance Damage	Participant	Avoided cost of fires based on insurance estimates
Lighting Quality and Lifetime	Participant	Participant-reported value of improved lighting lumen levels, color, and steadiness
O&M	Participant	Avoided time and costs associated with reduced maintenance, parts/repairs, service visits, and system monitoring
Other Impacts	Participant	Includes rent revenues, employee satisfaction, and other labor costs (defined as other labor at the company not covered in O&M, administrative costs, supplies, and materials). Also includes modeled value of decreased usage of fuel, propane, and other sources
Product Spoilage/Defects	Participant	Participant-reported value of avoided product losses (such as reduced food spoilage in grocery stores)

NEI Name	NEI Type	Definition
Productivity	Participant	Participant-reported value of improved workplace productivity resulting from improved rest and sleep related to improved living conditions
Sales Revenue	Participant	Participant-reported increased sales resulting from improved product
Supplies and Materials	Participant	Includes changes in the type, amount, or costs of materials and supplies needed
Thermal Comfort	Participant	Increased comfort due to fewer drafts and even temperatures throughout the building
Waste Disposal	Participant	Participant-reported costs to remove solid waste and landfill fees (such as fees to dispose of CFLs)
Water/Wastewater	Participant	Reduced water usage due to efficient equipment

PSE has been incorporating these NEIs into some business cases; however, at the time of this study being conducted there were still some business cases without this new NEI evaluation embedded. In addition, as mentioned above, Cadmus used draft *2021 Power Plan* and RTF UES workbooks when a business case was not available for a measure and some RTF and Council measures already had NEIs such as water savings, O&M, and lifetime replacement. Therefore, Cadmus developed the methodological hierarchy presented in Table 29 to account for all available NEI data for all measures applicable.

Table 29. Methodological Hierarchy for Non-Energy Impact Data Inclusion

Measure Type	CPA Action
PSE business case with existing NEI	Use existing business case NEI
PSE business case without existing NEI	Use NEI evaluation study data, if applicable
RTF/Council with existing NEI	Use RTF/Council data and NEI evaluation study data (excluding water savings, O&M, and lifetime replacement), if applicable
RTF/Council without existing NEI	Use NEI evaluation study data, if applicable

Measure Data Sources

By data input, Table 30 lists the primary sources referenced in the study.

Table 30. Key Measure Data Sources

Data	Residential Source	Commercial Source	Industrial Source
Energy Savings	PSE business cases; draft *2021 Power Plan* supply curve workbooks; RTF; Cadmus research	PSE business cases; draft *2021 Power Plan* supply curve workbooks; RTF; Cadmus research	Draft *2021 Power Plan* supply curve workbooks
Equipment and Labor Costs	PSE business cases; draft *2021 Power Plan* supply curve workbooks; RTF; Cadmus research	PSE business cases; draft *2021 Power Plan* supply curve workbooks; RTF; Cadmus research	Draft *2021 Power Plan* supply curve workbooks
Measure Life	PSE business cases; draft *2021 Power Plan* supply curve workbooks; RTF; Cadmus research	PSE business cases; draft *2021 Power Plan* supply curve workbooks; RTF; Cadmus research	Draft *2021 Power Plan* supply curve workbooks
Technical Feasibility	NEEA RBSA; Cadmus research	NEEA CBSA; Cadmus research	Cadmus research; Council’s industrial data
Percentage Incomplete	NEEA RBSA; PSE program accomplishments; Cadmus research	NEEA CBSA; PSE program accomplishments; Cadmus research	Cadmus research; Council’s industrial data

Data	Residential Source	Commercial Source	Industrial Source
Measure Interaction	PSE business cases; draft *2021 Power Plan* supply curve workbooks; RTF; Cadmus research	PSE business cases; draft *2021 Power Plan* supply curve workbooks; RTF; Cadmus research	Cadmus research
Non-Energy Impacts	PSE business cases; PSE's NEI evaluation study; [a] draft *2021 Power Plan* supply curve workbooks; RTF	PSE business cases; PSE's NEI evaluation study; [a] draft *2021 Power Plan* supply curve workbooks; RTF	Draft *2021 Power Plan* supply curve workbooks

[a] DNV Energy. September 30, 2021. *Puget Sound Energy Non-Energy Impacts Final Report*.

Incorporating Federal Standards and State and Local Codes and Policies

Cadmus' assessment accounted for changes in codes, standards, and policies over the planning horizon. These changes affected customers' energy-consumption patterns and behaviors, and they determined which energy efficiency measures would continue to produce savings over minimum requirements. Cadmus captured current efficiency requirements, including those enacted but not yet in effect.

Cadmus reviewed all local codes, state codes, federal standards, and local and state policy initiatives that could impact this potential study. For the residential and commercial sectors, we considered the local energy code (2018 Seattle Energy Code, 2018 WSEC, and 2018 RCW) as well as current and pending federal standards.

Cadmus reviewed the following codes, standards, and policy initiatives:

- **Federal standards.** All technology standards for heating and cooling equipment, lighting, water heating, motors, and other appliances not covered in or superseded by state and local codes.[28]
- **2018 Seattle Energy Code.** The code prohibits new commercial and multifamily buildings from using electric resistance or fossil fuels for space heating effective June 1, 2021, and from using electric resistance or fossil fuels for water heating effective January 1, 2022. All other code provisions took effect on March 15, 2021.[29]
- **2018 Washington State Energy Code (WSEC).** The code provides requirements for residential and commercial new construction buildings, except in cases where the 2018 Seattle Energy Code supersedes the Washington code, effective February 1, 2021.[30]
- **2009 Washington State Senate Bill 5854 and Revised Code of Washington (RCW 19.27A.160).** This code requires "… residential and nonresidential construction permitted under the 2031 state energy code achieve a 70% reduction in annual net energy consumption, using the adopted 2006 Washington state energy code as a baseline."

28 U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy. Accessed May 2022. "Standards and Test Procedures." https://www.energy.gov/eere/buildings/standards-and-test-procedures

29 City of Seattle, Office of the City Clerk. February 1, 2021. "Council Bill No: CB 119993. An Ordinance Relating to Seattle's Construction Codes." http://seattle.legistar.com/LegislationDetail.aspx?ID=4763161&GUID=A4B94487-56DE-4EBD-9BBA-C332F6E0EE5D

30 Washington State Building Code Council. Accessed May 2022. https://sbcc.wa.gov/

- **2018 Revised Code of Washington (RCW 19.260.040).** This code set minimum efficiency standards to specific types of products including computers, monitors, showerheads, faucets, residential ventilation fans, general service lamps, air compressors, uninterruptible power supplies, water coolers, portable air conditioners, high color rendering index fluorescent lamps, commercial dishwashers, steam cookers, hot food holding cabinets, and fryers. The effective dates vary by product with the 2018 RCW Revised Code of Washington signed on July 28, 2019.[31]
- **City of Shoreline Ordinance No. 948**. The "Ordinance of the City of Shoreline, Washington Amending Chapter 15.05, Construction and Building Codes, of the Shoreline Municipal Code, to Provide Amendments to the WSEC – Commercial, as Adopted by the State of Washington" adds a new section to Seattle Municipal Code 15.05 adopting the Washington Energy Code as adopted by the Building Council in Chapter 51-11 of the WAC with amendments addressing reductions of carbon emissions in new commercial construction. The ordinance took effect on July 1, 2022.
- **City of Bellingham Ordinance.** The "Ordinance of the City of Bellingham Amending Bellingham Municipal Code Chapter 17.10 – Building Codes, to Provide Amendments to the WSEC – Commercial, Promoting Energy Efficiency and the Decarbonization of Commercial and Large Multifamily Buildings and Requiring Solar Readiness for New Buildings" took effect on August 7, 2022.

The following policy driven initiatives (Seattle's Energy Benchmarking program, the Clean Buildings bill, and CETA) do not mandate an energy code or baseline for specific measures, rather they inherently speed up the rate of the adoption of energy efficiency through energy reduction requirements. PSE can also claim energy impacts through these initiatives; therefore, removing measures or adjusting baselines may not be appropriate within the context of the CPA. Since PSE already incorporates a 10-year ramp rate for most discretionary measures, this accelerated adoption essentially accounts for the majority of these initiatives.

- **Seattle's Energy Benchmarking program (Seattle Municipal Code 22.920).** This program requires owners of commercial and multifamily buildings (20,000 square feet or larger) to annually track and report energy performance to the city of Seattle. Though in effect since 2016, full enforcement of the program began on January 1, 2021.[32]
- **Clean Buildings bill (E3SHB 1257).** The law requires the Washington State Department of Commerce to develop and implement an energy performance standard for the state's existing

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[31] Washington State Legislature. December 7, 2020. *Revised Code of Washington*. "RCW 19.260.050 Limit on Sale or Installation of Products Required to Meet or Exceed Standards in RCW 19.260.040." https://app.leg.wa.gov/rcw/default.aspx?cite=19.260.050

[32] City of Seattle, Office of Sustainability and Environment. Accessed May 2022. "Energy Benchmarking." https://www.seattle.gov/environment/climate-change/buildings-and-energy/energy-benchmarking#:~:text=Seattle's%20Energy%20Benchmarking%20Program%20(SMC,to%20the%20City%20of%20Seattle.&text=Compare%20your%20building's%20energy%20performance,started%20saving%20energy%20and%20money

buildings, especially large commercial buildings (based on building square feet), and to provide incentives to encourage efficiency improvements. The effective date is July 28, 2019, with the building compliance schedule set to begin on June 1, 2026. Early adopter incentive applications began in July 2021.[33]

- **Clean Energy Transformation Act (194-40-330).** This act applies to all electric utilities serving retail customers in Washington and sets specific milestones to reach the required 100% clean electricity supply. The first milestone was in 2022, when each utility must have prepared and published a clean energy implementation plan with its own targets for energy efficiency and renewable energy.[34]

Treatment of Federal Standards

Cadmus explicitly accounted for several other pending federal codes and standards. For the residential sector, these included appliance, HVAC, and water-heating standards. For the commercial sector, these included appliance, HVAC, lighting, motor, and water-heating standards. Table 31 provides a comprehensive list of equipment standards we considered in this study. However, Cadmus did not attempt to predict how energy standards might change in the future.

Table 31. Electric Federal and State Standards Considered

Equipment Electric Type	New Standard	Sectors Impacted	Study Effective Date
Clothes Washer (top loading)	Federal standard 2015	Residential	March 7, 2015
Clothes Washer (front loading)	Federal standard 2018	Residential	January 1, 2018
Clothes Washer (commercial sized)	Federal standard 2013	Nonresidential	January 8, 2013
	Federal standard 2018		January 1, 2018
Computer	State standard 2019	Nonresidential/Residential	January 1, 2021
Dehumidifier	Federal standard 2012	Residential	October 1, 2012
	Federal standard 2019		June 13, 2019
Dishwasher	Federal standard 2013	Residential	May 30, 2013
Dishwasher (commercial)	State standard 2019	Nonresidential	January 1, 2021
Dryer	Federal standard 2015	Residential	January 1, 2015
Uninterruptible (External) Power Supply	Federal standard 2016	Nonresidential/Residential	February 10, 2016
	Federal standard 2017		July 1, 2017
	State standard 2019		January 1, 2021
Freezer	Federal standard 2014	Residential	September 15, 2014
Microwave	Federal standard 2016	Residential	June 17, 2016
Fryer and Steam Cooker	State standard 2019	Nonresidential	January 1, 2021
Refrigerator	Federal standard 2014	Residential	September 15, 2014
Automatic Commercial Ice Maker	Federal standard 2010	Nonresidential	January 1, 2010
	Federal standard 2018		January 28, 2018

[33] Washington State Department of Commerce. Accessed July 2022. "Clean Buildings." https://www.commerce.wa.gov/growing-the-economy/energy/buildings/

[34] Washington State Department of Commerce. Accessed July 2022. "Clean Energy Transformation Act." https://www.commerce.wa.gov/growing-the-economy/energy/ceta/

Equipment Electric Type	New Standard	Sectors Impacted	Study Effective Date
Commercial Refrigeration Equipment (semi-vertical and vertical cases)	Federal standard 2010	Nonresidential	January 1, 2010
	Federal standard 2012		January 1, 2012
	Federal standard 2017		March 27, 2017
Vending Machine	Federal standard 2012	Nonresidential	August 31, 2012
	Federal standard 2019		January 8, 2019
Walk-In Cooler	Federal standard 2014	Nonresidential	August 4, 2014
Walk-In Freezer	Federal standard 2017		June 5, 2017
Central Air Conditioner	Federal standard 2015 (no change for Northern region)	Residential	January 1, 2015
Heat Pump (air source)	Federal standard 2015	Residential	January 1, 2015
Packaged Terminal Air Conditioner and Heat Pump	Federal standard 2012	Nonresidential	October 8, 2012
	Federal standard 2017		January 1, 2017
Room Air Conditioner	Federal standard 2014	Residential	June 1, 2014
Single Package Vertical Air Conditioner and Heat Pump	Federal standard 2010 (phased in over six years)	Nonresidential	January 1, 2010
	Federal standard 2019		September 23, 2019
Small, Large, and Very Large Commercial Package Air Conditioner and Heat Pump	Federal standard 2010	Nonresidential	January 1, 2010
	Federal standard 2018		January 1, 2018
	Federal standard 2023		January 1, 2023
Fluorescent Lamp Ballast	Federal standard 2014	Nonresidential	November 14, 2014
General Service Fluorescent Lamp	Federal standard 2012	Nonresidential	July 14, 2012
	Federal standard 2018		January 26, 2018
Lighting General Service and Specialty Lamp	State standard 2019	Nonresidential/Residential	January 1, 2021
Metal Halide Lamp Fixture	Federal standard 2017	Nonresidential	February 10, 2017
Electric Motor (small)	Federal standard 2015	Nonresidential	March 9, 2015
Electric Motor	Federal standard 2010	Nonresidential	December 19, 2010
	Federal standard 2016		June 1, 2016
Furnace Fan	Federal standard 2019	Residential	July 3, 2019
Pump	Federal standard 2020	Nonresidential	January 27, 2020
Pre-Rinse Spray Valve	Federal standard 2019	Nonresidential	January 28, 2019
Showerhead	State standard 2019	Nonresidential/Residential	January 1, 2021
Water Heater >55 Gallons	Federal standard 2015	Nonresidential/Residential	April 16, 2015
Water Heater ≤55 Gallons	Federal standard 2015	Nonresidential/Residential	April 16, 2015

Additional Codes and Standards Considerations

Cadmus identified two considerations that impacted the characterization of this potential study. Starting with residential lighting, Cadmus reviewed the codes and standards and assessed the current situation related to LED lighting.

The Council's draft *2021 Power Plan* and RTF residential lighting workbooks account for the Washington State code requirement (House Bill 1444) of the Energy Independence and Security Act (EISA) backstop provision. Originally adopted from the federal standard, the EISA backstop provision requires higher-efficiency technologies (45 lumens per watt or better). Washington State did adopt the EISA backstop provision.[35] The savings in the draft *2021 Power Plan* and RTF workbooks specify a 45 lumens per watt baseline (for Washington).

As a result, Cadmus developed a special case for residential lighting. After reviewing the Council and RTF workbooks, Cadmus concluded that the 45 lumens per watt baseline should be changed to an LED baseline for the CPA. Currently, there are no lighting technologies on the market that meet the 45 lumens per watt requirement other than CFLs and LEDs. Furthermore, major manufacturers have phased out production of CFLs. The market is rapidly adopting LEDs (according to the RBSA saturations and Council and RTF projections), which are becoming the *de facto* baseline. Considering that LEDs are the only viable technology that meets Washington code, Cadmus used LEDs as the baseline for all standard-income applications but assessed the potential for vulnerable population homes. This adjustment to the lighting loads is effectively accounted for in PSE's baseline forecast and in the CPA.

Secondly, the 2018 WSEC includes both residential and commercial new construction prescriptive and performance path requirement options. The CPA characterizes efficiency improvements on a measure basis that align with the prescriptive path. The performance path includes the HVAC total system performance ratio requirement, defined as the ratio of the sum of a building's annual heating and cooling load compared to the sum of the annual carbon emissions from the energy consumption of the building's HVAC systems. The variability in the HVAC total system performance ratio from building to building cannot be easily captured in the CPA. For this study, Cadmus followed the prescriptive requirements in the 2018 WSEC.

Adapting Measures from PSE Business Cases, RTF, and Draft *2021 Power Plan*

To ensure consistency with methodologies employed by the Council and to fulfill requirements of WAC 194-37-070, Cadmus relied on ECM workbooks developed by the RTF and the Council to estimate measure savings, costs, and interactions. Additionally, Cadmus prioritized PSE's program business cases in developing measure characterization inputs. In most cases, the program business cases relied on the RTF and Council workbooks tailored to PSE's territory and program delivery experience. In adapting ECMs for this study, Cadmus adhered to three principles:

- **PSE Developed Business Cases:** The business cases were utilized as the primary data source for measure characterization inputs, where possible. Using these business cases allows better alignment between PSE program planning projections and potential estimates for applicable measures.
- **Deemed ECM savings in RTF or Council workbooks must be preserved:** PSE mainly relies on deemed savings estimates provided in RTF and Council workbooks to demonstrate compliance with Washington Energy Independence Act targets. Therefore, Cadmus sought to preserve these deemed savings to avoid possible inconsistencies among estimates of potential, targets, and reported savings.

[35] During the development of this study, the Biden-Harris Administration, through the U.S. Department of Energy, restated the EISA backstop with full enforcement until January 2023 (manufacture and import) and July 2023 (retail and distribution).

- **Use inputs specific to PSE's service territory:** Some Council and RTF workbooks relied on regional estimates of saturations, equipment characteristics, and building characteristics derived from the RBSA and CBSA. Cadmus updated regional inputs with estimates, calculated either from PSE's oversample of CBSA and RBSA or from estimates affecting the broader PSE area. This approach preserved consistency with Council methodologies while incorporating PSE-specific data.

Cadmus' approach for adapting PSE business cases, Council, and RTF workbooks varied by sector, as described in the following sections.

Residential and Commercial

Cadmus reviewed each residential Council workbook and extracted savings, costs, and measure lives for inclusion in this study. We largely derived the applicability factors (such as the current saturation of an ECM) from PSE's oversample of RBSA and CBSA, along with RBSA and CBSA public data associated to PSE heating and cooling climate zones. If Cadmus could not develop a PSE-specific applicability factor from the RBSA and CBSA, we used the Council's regional value.

In addition to extracting key measure characteristics, Cadmus identified each measure as an equipment replacement measure or a retrofit measure. There are two key distinctions between these two types of measures:

- We calculated savings for ***equipment replacement (lost opportunity) measures*** as the difference between measure consumption and baseline consumption. For instance, for the HPWH measure, Cadmus estimated the baseline consumption of an average market water heater and used the Council's deemed savings to calculate the consumption for a HPWH. This approach preserved the deemed savings in Council workbooks.
- We calculated savings for ***retrofit measures*** in percentage terms relative to the baseline end-use consumption but reflecting the Council's and RTF's deemed values. For instance, if the Council's deemed savings were 1,000 kWh per home for a given retrofit measure and Cadmus estimated the baseline consumption for the measure end use as 10,000 kWh, relative savings for the measure were 10%. Cadmus did not apply relative savings from the Council's workbooks to baseline end-use consumption because doing so would lead to per-unit estimates that differed from Council and RTF values.

Cadmus also accounted for interactive effects presented in Council and RTF workbooks. For instance, the Council estimated water heating, space heating, and space cooling savings for residential HPWHs—with space heating and cooling as the interactive savings. Because the installation of a HPWH represents a single installation, Cadmus employed a stock accounting model, which combined interactive and primary end-use effects into one savings estimate. Though Cadmus recognizes that this approach could lead to overstating or understating savings in an end use, in aggregate—across end uses—savings matched the Council's deemed values.

Cadmus generally followed the same approach with the commercial sector; however, because of the mixture of lighting measures considered in the Council's draft *2021 Power Plan*, Cadmus chose to model all commercial lighting measures as retrofits and none as equipment replacements. Savings and costs for these measures reflected this decision.

Industrial

Cadmus adapted measures from the Council's Industrial_Tool_2021P_v08 and IND_AllMeasures_2021P_V8 workbooks for inclusion in this study for several key industrial measure inputs:

- Measure savings (expressed as end-use percentage savings)
- Measure costs (expressed as dollars per kilowatt-hour saved)
- Measure lifetimes (expressed in years)
- Measure applicability (expressed in percentages)

Cadmus used all Council industry types and identified applicable end-uses using the Council's assumed distribution of end-use consumption in each industry.

Baseline End-Use Load Forecast Development

Creating a baseline forecast required multiple data inputs to accurately characterize energy consumption in PSE's service area. These are PSE's sector-level sales and customer forecasts, customer segments (business, dwelling, or facility types), end-use saturations (percentage of an end use [such as an air conditioner] present in a building), equipment saturations (such as the average number of units in a building), fuel shares (proportion of units using electricity versus natural gas), efficiency shares (the percentage of equipment below, at, and above standard), and annual end-use consumption estimates by efficiency levels.

PSE's sector-level sales and customer forecasts provided the basis for assessing energy efficiency potential. Prior to estimating potential, Cadmus disaggregated sector-level load forecasts by customer segment, building vintage (existing structures and new construction), and end use (all applicable end uses in each customer sector and segment).

After the market segmentation, Cadmus mapped the appropriate end uses to relevant customer segments. Upon determining appropriate customer segments and end uses for each sector, Cadmus determined how many units of each end use would be found in a typical home. End-use saturations represent the average number of units in a home and fuel shares represent the proportion of those units using electricity versus natural gas. For example, on average, a typical home has 0.9 clothes dryers (the saturation), and 85% of these units are electric (the fuel share).[36] Efficiency shares equal the current saturation of a specific type of equipment (of varying efficiency). Within an end use, these shares sum to 100%. For instance, the efficiency shares for the central air conditioner (CAC) end use may be 50% SEER 13, 25% SEER 15, and 25% SEER 16.

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[36] Saturations are less than 1.0 when some homes do not have the end use.

Then Cadmus calculated annual end-use consumption for each end use in each segment in the commercial and residential sectors using the following equation:

$$TEUC_{ij} = \sum ACCTS_i \times UPA_i \times SAT_{ij} \times FSH_{ij} \times ESH_{ije} \times EUI_{ije}$$

where:

$TEUC_{ij}$	=	The total energy consumption for end use j in customer segment i
$ACCTS_i$	=	The number of accounts/customers in customer segment i
UPA_i	=	The number of units per account in customer segment i (UPA_i generally equals the average square feet per customer in commercial segments, and 1.0 in residential dwellings, assessed at the whole-home level)
SAT_{ij}	=	The share of customers in customer segment i with end use j
FSH_{ij}	=	The share of end use j of customer segment i served by electricity
ESH_{ije}	=	The market share of efficiency level e in equipment for customer segment i and end use j
EUI_{ije}	=	The end-use intensity, or energy consumption per unit (per square foot for commercial, 1.0 for residential) for the electric equipment configuration ije

For each sector, Cadmus calculated the total annual consumption as the sum of $TEUC_{ij}$ across the end-uses, j, and customer segments, i.

Consistent with other conservation potential studies, and commensurate with industrial end-use consumption data, we allocated the industrial sector's loads to end uses in various segments based on the *Manufacturing Energy Consumption Survey* data available from the U.S. Energy Information Administration.[37]

Derivation of End-Use Consumption

End-use energy consumption estimates by segment, end use, and efficiency level (EUI_{ije}) provided one of the most important components in developing a baseline forecast. In the residential sector, Cadmus used estimates of unit energy consumption, representing annual energy consumption associated with an end use and represented by a specific type of equipment (such as a CAC or heat pump). We derived the basis for the unit energy consumption values from savings in the PSE business cases, most recent RTF UES workbooks, the Council's draft *2021 Power Plan* workbooks and savings analysis to calculate accurate consumption wherever possible for all efficiency levels of an end-use technology. When PSE business cases and RTF and Council workbooks did not exist for certain end uses, Cadmus used results from NEEA's 2018 RBSA PSE oversample, including RBSA public data for the same heating and cooling zone as PSE's territory, or conducted other research.

[37] U.S. Department of Energy, Energy Information Administration. 2018. *Manufacturing Energy Consumption Survey.*

For the commercial sector, Cadmus treated consumption estimates as end-use intensities that represented annual energy consumption per square foot served. To develop the end-use intensities, Cadmus developed electric energy intensities (total kilowatt-hours per building square foot) based on NEEA's 2019 CBSA (CBSA IV), based on PSE oversample and public data. Cadmus then benchmarked these electric energy intensities against various other data sources including the CBSA III, historical forecasted and potential study data from PSE, and historical end-use intensities developed by the Council and NEEA.

To distribute the energy intensities to end-use intensities, Cadmus used assumptions specific to each building segment and each end use:

- **Lighting.** For lighting, Cadmus analyzed CBSA IV's lighting power density (lighting wattage per square foot) multiplied by the Council's interior lighting hours of use by building type. Once we had calculated the lighting end-use intensity, we subtracted this portion of load from the total CBSA electric energy intensities (to estimate non-lighting intensities).
- **Non-lighting.** To distribute the remaining non-lighting CBSA electric energy intensities into end-uses, Cadmus used *Commercial Building Energy Consumption Survey* (CBECS)[38] 2012 microdata to calculate percentages of end-use intensities across various end-use groups by building types as defined by the Council. Cadmus used the CBSA fuel shares and end-use saturations to adjust the distributions of CBECS end-use intensities to better represent PSE's commercial service territory. These finalized CBECS end-use intensities—adjusted with CBSA values where possible—were the basis for most of the end-use intensities in the commercial sector.
- **Computers and servers.** Cadmus developed energy intensities by building type for two end-uses—computers (desktops and laptops) and servers—using the CBECS number of units per square foot multiplied by unit consumption.
- **University.** The CBSA IV data lacked information on university building type, and the schools building type represented only K–12, as designated by the Council. Cadmus developed a more accurate electric energy intensity specific to universities by calculating a ratio of the CBECS's university and school K–12 building types. Cadmus then used the CBSA school K–12 lighting power density and applied the Council's university lighting hours of use. Cadmus determined that the result was reasonable by benchmarking the university lighting end-use intensity developed for PSE against the ratio of CBECS university and school K–12 lighting loads.
- **Retail.** Low CBSA respondent counts and trying to match varying definitions of Council's building types caused concern, especially for the large and extra-large retail building types, so Cadmus combined the retail building types for the CBSA electric energy intensities and lighting power density.

38 U.S. Energy Information Administration. n.d. "2012 CBECS Survey Data." https://www.eia.gov/consumption/commercial/data/2012/

For the industrial sector, end-use energy consumption represented total annual industry consumption by end use, as allocated by the secondary data described above.

PSE Forecast Climate Change Alignment

Cadmus worked with the PSE load forecast team to adjust the residential and commercial baseline forecast to account for climate change impacts. First, Cadmus characterized the heating and cooling end-use consumptions using climate change adjustment factors based Council data (from TMY to Council-projected FMY) for any non-Council weather-sensitive RTF and PSE business case measures. For example, we based heat pump end-use consumptions on RTF estimates, adjusted using HVAC FMY to TMY ratios from Council-developed building simulations, as shown in Table 32.

Table 32. Residential Council Modeled HVAC FMY to TMY Ratios

Council Modeled Ratios	HVAC Ratio (FMY/TMY)
All Residential Heating – Heating Zone 1	80%
All Residential Cooling - Heating Zone 1	200%
All Residential Combined - Heating Zone 1	105%

The resulting heating and cooling end-use consumptions present the upper bound of the climate adjustment (final year estimate). Next, we calibrated the annual change in residential and commercial heating and cooling end-use consumptions with PSE's climate impacts within annual load forecasts to reflect climate change over the course of the study (where climate impacts increase over time). Cadmus also used the projected residential air conditioning saturations within PSE load forecast projections. We followed a similar process to determine the climate impacts for commercial heating and cooling end uses.

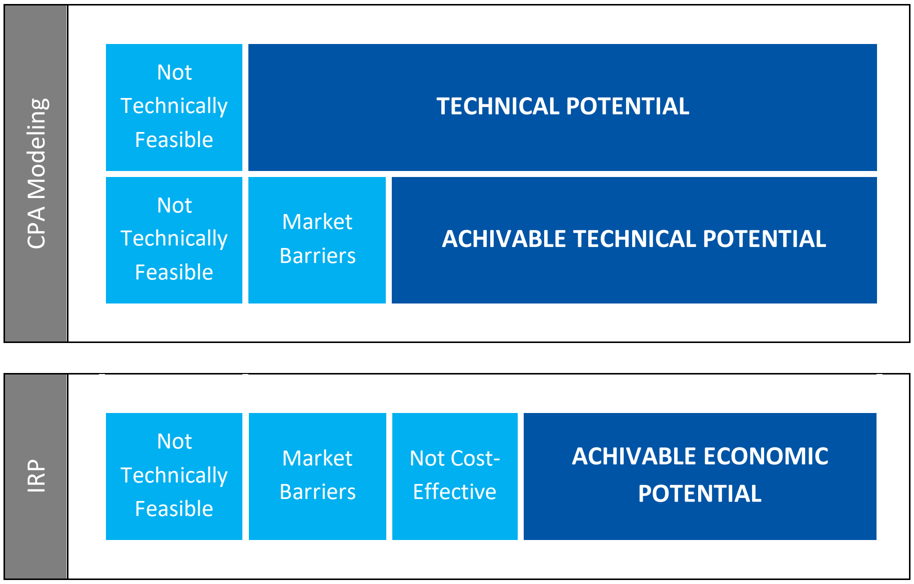
Conservation Potential Estimation

Cadmus estimated two types of conservation potential, and PSE determined a third potential—achievable economic—through the IRP's optimization modeling, as shown in Figure 30:

- ***Technical potential*** assumes that all technically feasible resource opportunities may be captured, regardless of their costs or other market barriers. It represents the total energy efficiency potential in PSE's service territory, after accounting for purely technical constraints.
- ***Achievable technical potential*** is the portion of technical potential assumed to be achievable during the study forecast, regardless of the acquisition mechanism. For example, savings may be acquired through utility programs, improved codes and standards, and market transformation.
- ***Achievable economic potential*** is the portion of achievable technical portion determined to be cost-effective by the IRP's optimization modeling, in which either bundles or individual energy efficiency measures are selected based on cost and savings. The cumulative potential for these selected bundles constitutes achievable economic potential.

Cadmus provided PSE with forecasts of achievable technical potential, which PSE then entered as variables in the IRP's optimization model to determine achievable economic potential. The following sections describe Cadmus' approach for estimating technical and achievable technical potential.

Figure 30. Types of Energy Efficiency Potential



Technical Potential

Technical potential includes all technically feasible ECMs, regardless of costs or market barriers. Technical potential divides into two classes: discretionary (retrofit) and lost opportunity (new construction and replacement of equipment on burnout).

- ***Discretionary resources*** are retrofit opportunities in existing facilities that, theoretically, are available at any point over the study period. Discretionary resources are also referred to as retrofit measures. Examples include weatherization and shell upgrades, economizer optimization, and low-flow showerheads.
- ***Lost opportunity resources***, such as conservation opportunities in new construction and replacements of equipment upon failure (natural replacement), are nondiscretionary. These resources become available according to economic and technical factors beyond a program administrator's control. Examples of natural replacement measures include HVAC equipment, water heaters, appliances, and replace-on-burnout lighting fixtures.

Another important aspect in assessing technical potential is, wherever possible, to assume installations of the highest-efficiency equipment that are commercially available. For example, for this study Cadmus examined Tier 3 and Tier 4 heat pump water heaters in residential applications. To assess technical potential, we assumed that, as equipment fails or new homes are built, customers will install Tier 4 HPWHs wherever technically feasible, regardless of cost. Where applicable, we assumed that Tier 3 would be installed in homes ineligible for Tier 4 units. Cadmus treated competing non-equipment measures in the same way, assuming installation of the highest-saving measures where technically feasible.

In estimating technical potential, it is inappropriate to merely sum savings from individual measure installations. Significant interactive effects can result from installations of complementary measures. For example, upgrading a heat pump in a home where insulation measures have already been installed can produce fewer savings than upgrades in an uninsulated home. Our analysis of technical potential accounts for two types of interactions:

- ***Interactions between equipment (lost opportunity) and non-equipment (discretionary or retrofit) measures:*** As equipment burns out, technical potential is based on assuming that equipment will be replaced with higher-efficiency equipment, reducing average consumption across all customers. Reduced consumption causes non-equipment measures to save less than they would have if the equipment had remained at a constant average efficiency. Similarly, savings realized by replacing equipment decrease upon installation of non-equipment measures.
- ***Interactions between two or more non-equipment (discretionary or retrofit) measures:*** Two non-equipment measures that apply to the same end use may not affect each other's savings. For example, installing a low-flow showerhead does not affect savings realized from installing a faucet aerator. Insulating hot water pipes, however, causes water heaters to operate more efficiently, thus reducing savings from those water heaters. Cadmus accounted for such interactions by stacking interactive measures, iteratively reducing the baseline consumption as measures were installed, thus lowering savings from subsequent measures.

Although, theoretically, all retrofit opportunities in existing construction—often called discretionary resources—could be acquired in the study's first year, this would skew the potential for equipment measures and provide an inaccurate assessment of measure-level potential. Therefore, Cadmus assumed that these opportunities would be realized in equal annual amounts over the 27-year planning horizon. By applying this assumption, natural equipment turnover rates, and other adjustments described above, we could estimate the annual incremental and cumulative potential by sector, segment, construction vintage, end use, and measure.

Cadmus' technical potential estimates drew upon best-practice research methods and standard utility industry analytic techniques. Such techniques remained consistent with the conceptual approaches and methodologies used by other planning entities (such as by the Council in developing regional energy efficiency potential) and remained consistent with methods used in PSE's previous CPAs.

Achievable Technical Potential

The achievable technical potential summarized in this report is a subset of the technical potential that accounts for market barriers. To subset the technical potential, Cadmus followed the approach of the Council and employed two factors:

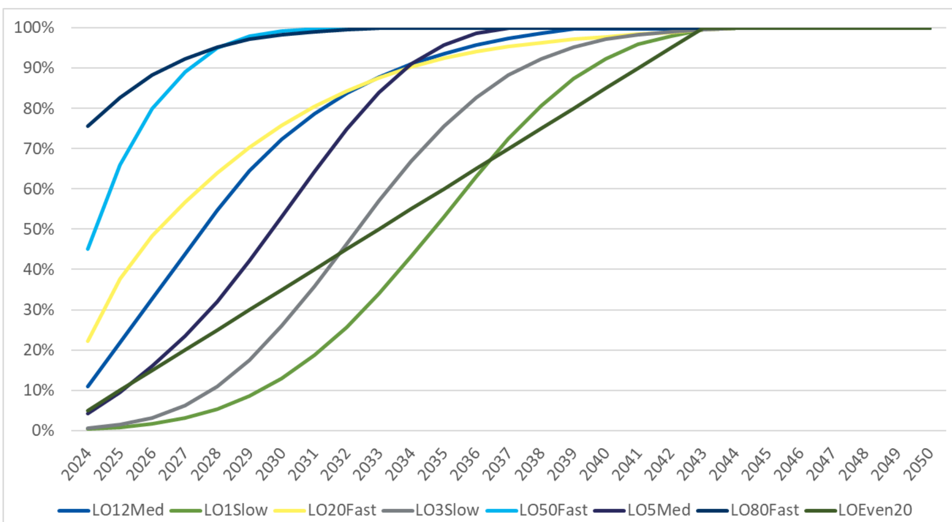
- **Maximum achievability factors** represent the maximum proportion of technical potential that can be acquired over the study horizon.
- **Ramp rates** are annual percentage values representing the proportion of cumulative 27-year technical potential that can be acquired in a given year (discretionary measures) or the proportion of technical annual potential that can be acquired in a given year (lost opportunity measures).

Achievable technical potential is the product of technical potential and both the maximum achievability factor and the ramp rate percentage. Cadmus assigned maximum achievability factors to measures based on the Council's draft *2021 Power Plan* supply curves. Ramp rates are measure-specific and we based these on the ramp rates developed for the Council's draft *2021 Power Plan* supply curves, adjusted to account for the 2024 to 2050 study horizon.

For most discretionary measures, Cadmus assumed that savings are acquired at an even rate over the first 10 years of the study. In other words, achievable technical potential for discretionary measures equals one-tenth of the total cumulative achievable technical potential in each of the first 10 years of the study (2024 through 2033). After 2033, most of the additional potential comes from loss opportunity measures. There were a few exceptions where we applied a custom rate (longer than 10 years) to discretionary measures based on PSE program data (such as for cooking measures).

For lost opportunity measures, we used the same ramp rates as those developed by the Council for its draft *2021 Power Plan* supply curves. However, the draft *2021 Power Plan* ramp rates only cover the 2024 to 2043 timeline. Because nearly all lost opportunity ramp rates approach 100%, we set ramp values for 2044 through 2050 to equal the 2043 value from the Council's draft *2021 Power Plan*. Figure 31 illustrates the lost opportunity Council ramp rates.

Figure 31. Lost Opportunity Council Ramp Rates



Integrated Resource Plan Input Development

Cadmus developed energy efficiency supply curves to allow PSE's IRP optimization model to identify the cost-effective level of energy efficiency. PSE's optimization model required hourly forecasts of electric energy efficiency potential. To produce these hourly forecasts, we applied 8760-hour end-use load shapes to annual estimates of achievable technical potential for each measure. These hourly end-use load profiles are generally the same as those used by the Council in its draft *2021 Power Plan* supply curves and by the RTF in its UES measure workbooks (including generalized shapes that we expanded to hourly shapes).

Cadmus worked with PSE to determine the format of inputs into the IRP model. We grouped energy efficiency and CHP potential into the levelized costs bundles shown in Table 33. The number and delineating values of the levelized cost bundles remain unchanged from the 2021 CPA.

Table 33. Electric Levelized Cost Bundles

Bundle	Electric Bundle ($/kWh)
1	($9,999.000) to $0.028
2	$0.028 to $0.055
3	$0.055 to $0.062
4	$0.062 to $0.070
5	$0.070 to $0.077
6	$0.077 to $0.085
7	$0.085 to $0.115
8	$0.115 to $0.130
9	$0.130 to $0.150
10	$0.150 to $0.175
11	$0.175 to $0.200
12	$0.200 to $0.225
13	$0.225 to $999.00

Cadmus derived the levelized cost for each measure using the following formula.

$$\text{Levelized Cost of Electricity (LCOE)} = \frac{\sum_{t=0}^{n} \frac{Expenses_t}{(1+i)^t}}{\sum_{t=0}^{n} \frac{E_t}{(1+i)^t}}$$

where:

- LCOE = The levelized cost of conserved energy for a measure
- n = The lifetime of the analysis (27 years)
- $Expenses_t$ = All net expenses in year *t* for a measure using the costs and benefits outlined in Table 34
- i = The discount rate
- n = The lifetime of the analysis (27 years)
- E_t = The energy conserved in year *t*

Cadmus grouped the achievable technical potential by levelized cost over the 27-year study horizon, allowing PSE's IRP model to select the optimal amount of energy efficiency potential given various assumptions regarding future resource requirements and costs. The 27-year total resource levelized cost calculation incorporates numerous factors, which are consistent with the expense components shown in Table 34.

Table 34. Levelized Cost Components

Type	Component
Costs	Incremental Measure Cost
	Incremental O&M Cost [a]
	Administrative Adder
Benefits	Present Value of NEIs [b]
	Present Value of T&D Deferrals
	Conservation Credit
	Secondary Energy Benefits

[a] Some measures may have a reduction in O&M costs, which is a benefit in the levelized cost calculation.

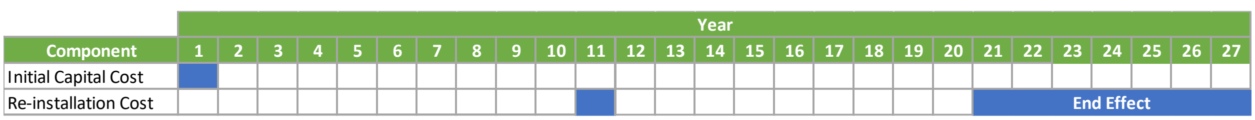
[b] Some NEIs are negative, and in those cases were treated as a cost within the levelized cost calculation.

Cadmus' approach for calculating a measure's levelized cost of conserved energy aligned with the Council's approach and incorporated several factors:

- ***Incremental measure cost.*** Cadmus considered the costs required to sustain savings over a 27-year horizon, including reinstallation costs for measures with EULs less than 27 years. If a measure's EUL extends beyond the end of the 27-year study, Cadmus incorporated an end effect that treats the levelized cost of that measure over its EUL as an annual reinstallation cost for the remainder of the 27-year period.[39]

  For example, Figure 32 shows the timing of initial and reinstallation costs for a measure with a 10-year lifetime in the context of the 27-year study horizon. The measure's final lifetime in this study ends after the study horizon, so the final seven years (Year 21 through Year 27) are treated differently by leveling measure costs over its 10-year EUL and treating these as annual reinstallation costs.

Figure 32. Illustration of Capital and Reinstallation Cost Treatment



- ***Incremental O&M benefits or costs.*** As with incremental measure costs, we considered O&M costs annually over the 27-year horizon. Cadmus used the present value to adjust the levelized cost upward for measures with costs above baseline technologies and downward for measures that decrease O&M costs.
- ***Administrative adder.*** Cadmus assumed a program administrative cost equal to 21% of incremental measure costs across all sectors.

39 In this context, EUL refers to levelizing over the measure's useful life. This is equivalent to spreading incremental measure costs over its EUL in equal payments assuming a discount rate equal to PSE's weighted average cost of capital (6.80%). Cadmus applied this method both to measures with an EUL of greater than 27 years and to measures with an EUL that extends beyond the study horizon at the time of reinstallation.

- ***Non-energy impacts.*** We treated these impacts as a reduction in levelized costs for measures that save resources, such as water or detergent, or that provide other benefits to users or the utility. For example, the value of reduced water consumption due to the installation of a low-flow showerhead reduces the levelized cost of that measure. The details of how we accounted for the NEIs are outlined in the *Energy Conservation Measure Characterization* section.
- ***The regional 10% conservation credit, capacity benefits during PSE's system peak, and T&D deferrals.*** Cadmus treated these factors similarly to how we treated reductions in the levelized cost for electric measures. The addition of this credit per the Northwest Power Act[40] is consistent with the Council's methodology and is effectively an adder to account for the unquantified external benefits of conservation when compared to other resources.
- ***Secondary energy benefits.*** We treated these benefits as a reduction in levelized costs for measures that save energy on secondary fuels. This treatment was necessitated by Cadmus' end-use approach to estimating technical potential. For example, consider the cost for R-60 ceiling insulation for a home with an electric central cooling system and a natural gas furnace. For the central cooling end use, Cadmus considered the energy savings that R-60 insulation produces for natural gas furnace systems, conditioned on the presence of electric central cooling, as a secondary benefit that reduces the levelized cost of the measure. This adjustment only impacts the measure's levelized costs: the magnitude of energy savings for the R-60 measure on the electric supply curve is not impacted by considering secondary energy benefits.

[40] Northwest Power and Conservation Council. January 1, 2010. "Northwest Power Act." http://www.nwcouncil.org/library/poweract/default.htm

Glossary of Terms

Cadmus compiled these definitions mostly from the *National Action Plan for Energy Efficiency Guide for Conducting Energy Efficiency Potential Studies and the State and Local Energy Efficiency Action Network*.[41]

Achievable economic potential: The subset of achievable technical potential that is economically cost-effective compared to conventional supply-side energy resources.

Achievable technical potential: The amount of energy that efficiency can realistically be expected to displace.

Benefit/cost ratio: The ratio (as determined by the TRC test) of the discounted total benefits of the program to the discounted total costs over some specified time period.

Conservation potential assessment (CPA): A quantitative analysis of the amount of energy savings that exists, proves cost-effective, or could potentially be realized by implementing energy-efficient programs and policies.

Cost-effectiveness: A measure of relevant economic effects resulting from implementing an energy efficiency measure. If the benefits of this selection outweigh its costs, the measure is considered cost-effective.

End use: A category of equipment or service that consumes energy (such as lighting, refrigeration, heating, and process heat).

End-use consumption: Used for the residential sector, this represents the per-unit energy consumption for a given end use, expressed in annual kilowatt-hours per unit.

End-use intensities: Used in the C&I sectors, this is the energy consumption per square foot for a given end use, expressed as annual kilowatt-hours per square foot per unit.

Energy efficiency: The use of less energy to provide the same or an improved service level to an energy consumer in an economically efficient way.

Effective useful life (EUL): An estimate of the duration of savings from a measure. EUL is estimated through various means, including the median number of years that energy efficiency measures installed under a program remain in place and operable. EUL is also sometimes defined by the date at which 50% of installed units remain in place and operational.

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[41] Schiller Consulting, Inc. (Schiller, Steven R.). 2012. *Energy Efficiency Program Impact Evaluation Guide. NAPEE Guide for Conducting Energy Efficiency Potential Studies and the State and Local Energy Efficiency Action Network.* www.seeaction.energy.gov

Levelized cost: The result of a computational approach used to compare the cost of different projects or technologies. The stream of each project's net costs is discounted to a single year using a discount rate (creating a net present value), divided by the project's expected lifetime output (in megawatt-hours).

Lost opportunity: Refers to an efficiency measure or efficiency program seeking to encourage the selection of higher-efficiency equipment or building practices than that typically chosen at the time of a purchase or design decision.

Measure: Installation of equipment, subsystems, or systems, or modifications of equipment, subsystems, systems, or operations on the customer side of the meter, designed to improve energy efficiency.

Portfolio: Either (a) a collection of similar programs addressing the same market, technology, or mechanisms or (b) the set of all programs conducted by one organization.

Program: A group of projects with similar characteristics and installed in similar applications.

Retrofit: An efficiency measure or efficiency program intended to encourage the replacement of functional equipment before the end of its operating life with higher-efficiency units (also called early retirement) or the installation of additional controls, equipment, or materials in existing facilities for reducing energy consumption (such as increased insulation, lighting occupancy controls, and economizer ventilation systems).

Technical potential: The theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints (such as cost-effectiveness or the willingness of end users to adopt the efficiency measures).

Total resource cost (TRC) test: A cost-effectiveness test that assesses the impacts of a portfolio of energy efficiency initiatives on the economy at large. The test compares the present value of efficiency costs for all members of society (including costs to participants and costs to program administrators) compared to the present value of benefits, including avoided energy supply and demand costs.

Appendix A. Detailed Demand Response Potential Results and Input Assumptions by Product Option

This section provides the detailed demand response achievable technical potential for each product option and their associated input assumptions. This section also provides additional context of each demand response product and it may operate within a utility program.

Residential Direct Load Control Water Heat

Water heating DLC programs directly control water heaters in customers' homes via load control switches. Communication between the utility and these switches can occur through advanced metering infrastructure (AMI), radio, consumer Wi-Fi connections to the internet, power line carriers, paging infrastructure, or through other web-based communications. Several other technologies, such as grid-enabled water heaters (GEWH) and water heater timers, exist for curtailing water heating energy usage during peak hours.

For this analysis, Cadmus assumed that participants in water heating DLC programs 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 (such as bill credits or lump-sum check payments) and can include incentives to cover the 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 kilowatt.

Product Options

All residential customers with electric storage water heaters are eligible to participate in the residential DLC water heat program. This analysis involves two product options for the residential DLC water heat program: load control switches and GEWHs. However, because the peak savings between ERWHs and HPWH differ, Cadmus split the eligible participants of these two product options between these two water heater types according to equipment saturations. This resulted in four product permutations for this simulated DLC water heat demand response program:

- ERWH – Load control switches
- ERWH – GEWH
- HPWH – Load control switches
- HPWH - GEWH

For the switch option, the utility installs the switch on customers' existing electric water heaters. The grid-enabled option is for customers who own a GEWH. These water heaters are manufactured with an ANSI/CTA-2045 port that allows a universal communication device to be plugged in, enabling a two-way connection to the utilities' grid infrastructure. One primary advantage of this built-in communication capability is the opportunity for greater participation in water heater DLC programs. These water heaters can also be controlled more often, potentially serving other utility grid needs.[42]

Washington State recently passed legislation that mandated for electric storage water heaters manufactured on or after January 1, 2021, to comply with the modular demand response communications interface standard, ANSI/CTA–2045-A, or equivalent.[43] As a result, all new electric storage water heaters after 2021 will be GEWH, and will thus be eligible for the GEWH product option. This analysis incorporates the estimated impacts of this legislation by shifting program participants from the switch products to the GEWH products over time for each water heater type.

This analysis also includes a stock turnover consideration. Cadmus assumed that HPWHs will be cost-effective and will replace ERWHs over time as they reach the end of their equipment lives. The water heating potential results from this study reflect this dynamic.

For peak event hours in summer and winter, Cadmus assumed that water heaters cycle 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.

Input Assumptions

Table A-1 provides the cost and impact assumptions that Cadmus used to estimate potential and levelized costs for the residential DLC water heat program.

Table A-1. Residential Direct Load Control Water Heat Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$75,000	Equal to 1 full-time equivalent (FTE) staff member at $150k per year, split evenly by season.
O&M Cost	$ per participant per year	$13	$26 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which aligns with the switch water heater product assumption, and based on consultation with the Council's Bonneville Power Administration (BPA) demand response subject matter expert (SME).
Equipment Cost	$ per new participant	Switches: $165	$330 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$473; Portland General Electric (PGE) (2019) =$300; PacifiCorp (2019) =$315; BPA (2018) =$315, which uses PacifiCorp's potential study (Applied 2017) estimate; the Council's consultation with the BPA demand response SME =$315; Snohomish (2017) =$280; PSE (2019) =$315.
		GEWH: $25	$50 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and RTF GEWH assumptions: RTF =$50.

[42] Bonneville Power Administration. November 9, 2018. *CTA-2045 Water Heater Demonstration Report.* https://neea.org/resources/cta-2045-water-heater-demonstration-project

[43] State of Washington. Passed April 18, 2019. *Certification of Enrollment: Second Substitute House Bill 1444.* http://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/House%20Passed%20Legislature/1444-S2.PL.pdf

Parameters	Units	Values	Notes
Marketing Cost	$ per participant	$15	$30 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =$50; BPA (2018) =$25, which uses the Navigant (2012) marketing cost; the Council's consultation with the BPA demand response SME =$25; Snohomish (2017) =$25; PSE (2019) =$25.
Incentives (annual)	$ per new participant per year	$5	$20 per season, 25% participant cost = $5 per season. The 25% assumption used in the TRC test is based on the Council's consultation with the BPA demand response SME. The Council's draft *2021 Power Plan* used an incentive of $15 per season for switch water heaters, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =$21 per season; BPA (2018) =$24 per season, which uses the higher end of the $24 to $25 range from Applied Energy Group (2017); the Council's consultation with the BPA demand response SME =$16 per season; Snohomish (2017) =$8 per season; PSE (2019) =$24 per season. Cadmus made the incentive align with the GEWH products and be more reflective of the Council's benchmarked values.
Incentives (one time)	$ per new participant	$0	Assumes zero sign-up incentive. Using the draft *2021 Power Plan* input assumptions.
Attrition	% of existing participants per year	5%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =5%, which uses the Snohomish (2017) =5% attrition; PSE (2019) =5%.
Eligibility	% of customer count (such as equipment saturation)	Varies by segment	Electric water heater saturations and ERWH/HPWH split based on updated residential consumer survey data and regionwide RBSA (2017) data. Grid-enabled growth rate based on the Council's draft *2021 Power Plan* demand response workbooks. HPWH saturation growth rate based on the Council's draft *2021 Power Plan* "Res-HPWH_v3" workbook.
Peak Load Impact	kW per participant (at meter)	ERWH Summer: 0.5 ERWH Winter: 0.75	ERWH Switch: Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PGE (2019) =0.4 for summer and 0.8 for winter; BPA (2018) =0.55 for summer and 0.75 for winter, which is from BPA end-use submetering studies. ERWH GEWH: The Council's draft *2021 Power Plan* used a peak load impact of 0.50 kW for both seasons. Cadmus found no clear evidence to discount grid-enabled per unit impacts relative to switch products. Therefore, we changed the peak load impact assumption to align with this product's switch counterpart.
		HPWH Summer: 0.122 HPWH Winter: 0.244	HPWH Switch: The Council's draft *2021 Power Plan* used a peak load impact of 0.15 kW for summer and 0.20 kW for winter. Cadmus found no clear evidence to differ grid-enabled and switch per-unit impacts for water heat products. Therefore, we changed the peak load impact assumption to align with this product's grid-enabled counterpart. HPWH GEWH: The Council's draft *2021 Power Plan* used a peak load impact of 0.10 kW for summer and 0.20 kW for winter. These values are based on grid emergency watt reductions for the morning period from Table 3 in BPA (2018), which Cadmus used to update the peak load impact values.
Program Participation	% of eligible customers	Switches: 25%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PGE (2019) =16%; PacifiCorp (2019) =15%; BPA (2018) =25%, which uses the high end of the range from Snohomish (2017) =20%; PSE (2019) =25%.
		GEWH: 25%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PSE (2019) =48%.

Parameters	Units	Values	Notes
Event Participation	% (switch success rate)	95%	Switches: The Council's draft *2021 Power Plan* used an event participation of 94%, which relied on DRAC input and benchmarked values: BPA (2018) =95%, which assumed the same event participation as for space heating DLC from Navigant (2012); Snohomish (2017) =94%; PSE (2019) =95%. Cadmus made the event participation 95% to align with other DLC products. GEWH: The Council's draft *2021 Power Plan* used an event participation of 94%, which relied on DRAC input and benchmarked values: Snohomish (2017) =94%; PSE (2019) =95%. Cadmus made the event participation 95% to align with other DLC products.
Ramp Period	Number of years to reach maximum potential	Switches: 5	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =5 years; Snohomish (2017) =5 years.
		GEWH: 10	Using the draft *2021 Power Plan* input assumptions. Consistent with other DLC products.
Program Life	Years	10	Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms. Pricing products have a longer program life compared to other products because they are based on rate structures and not DLC equipment.

Sources: For a full list of citations, see the ***References for Detailed Resource Potential Results Assumption Tables*** section. Note, these source notes provide additional context for the input assumptions selected for this analysis. In many cases, the selected inputs align with the draft *2021 Power Plan*'s input assumptions. Cadmus reviewed the sourcing information available in the draft *2021 Power Plan* to add context here, though the original documents referenced by the draft *2021 Power Plan* are not available in its source files. References in these tables for Avista (2019), BPA (2018), PacifiCorp (2012), PacifiCorp (2019), PGE (2020), PSE (2019), and Snohomish (2017) are referring to sourcing documented in the draft *2021 Power Plan*'s sourcing for demand response product input assumptions, which can be found here: https://www.nwcouncil.org/2021-power-plan-technical-information-and-data/.

Results

Table A-2 shows the final year potential and associated net levelized costs for this product category for the winter season.

Table A-2. Winter Residential Direct Load Control Water Heat Achievable Technical Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed per Season	Notification Type	Winter Levelized Cost ($/kW-year)	Winter Final Year Achievable Technical Potential (MW)
Residential DLC ERWH-Switch	10, 4-hour events	0 min	$24	0
Residential DLC ERWH-Grid-Enabled	10, 4-hour events	0 min	-$28	32
Residential DLC HPWH-Switch	10, 4-hour events	0 min	$203	0
Residential DLC HPWH-Grid-Enabled	10, 4-hour events	0 min	$91	58

Residential Direct Load Control HVAC

All residential customers with centralized electric heating are eligible for the winter HVAC DLC program, including customers with heat pumps and electric forced-air furnaces. Baseboard heaters remain ineligible because 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 through demand response programs. DLC programs have opt-out event participation once a customer elects to participate; for this analysis, Cadmus assumed that customers can opt out or override their participation in an event by readjusting their thermostat.

All residential customers with a CAC are eligible for the summer HVAC 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 because 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 (such as fans, cooling towers, and 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 analysis excludes such portable air conditioning devices.

Numerous cycling strategies currently exist for HVAC DLC programs, from conservative 25% cycling to aggressive 100% cycling. This study sets the cycling strategy at 50%, meaning that HVAC equipment targeted through these products cycle off for 50% of an event's duration (such as being on for 30 minutes then off for 30 minutes).

Cadmus assumed that participants in HVAC DLC programs are paid incentives at a fixed rate, independent of the number and duration of events called. We chose this incentive structure due to its simplicity: it provides customers with a higher level of certainty regarding their bill credit amounts than if the incentive were paid per event or per kilowatt, and if no events were called, as could happen in a year with particularly mild temperatures. These incentives can be delivered through several applicable channels (including bill credits or check incentives) and can include a one-time sign-up bonus to boost enrollment.

Product Options

For programs that target central electric space heating (such as heat pumps and electric forced-air furnaces) and space cooling (such as heat pumps and central air conditioners), load control switches or smart thermostats are connected to a digital internet gateway. Load control switches allow the utility to cycle electric heating equipment on and off during peak events while smart thermostats automatically set back temperature setpoints on heating or cooling systems. For this analysis, two product options are offered:

- BYOT (for customers with smart thermostats)
- Load control switches (for customers without smart thermostats)

The BYOT product is for residential customers who already have a Wi-Fi or smart thermostat installed. These types of thermostats enable the utility to communicate with the customer during peak events and automatically change the setpoint temperature on heating or cooling systems depending on the season. The HVAC DLC switch product controls the same end uses as BYOT but does so via switches that are installed directly onto the HVAC equipment, rather than through a smart thermostat.

This analysis incorporates two important equipment saturation growths:

- Increased cooling system growth saturation due to climate change
- Smart thermostat saturation growth over time shifting participants from being eligible for the HVAC DLC switch product to being eligible for the BYOT product

Cadmus assumed that residential DLC HVAC products will be available for four-hour duration events with up to 10 events per season.

Input Assumptions

Table A-3 lists the cost and impact assumptions that Cadmus used in estimating the potential and levelized costs for the residential DLC HVAC program.

Table A-3. Residential Direct Load Control HVAC Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$75,000	Equal to 1 FTE staff member at $150k per year, split evenly by season.
O&M Cost	$ per participant per year	BYOT: $4	$8 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: the Council's consultation with the BPA demand response SME =$8 for heating and $7 for cooling; PSE (2019) =$7.5 for heating.
		Switches: $10	$20 annually, weighted by relative shares of heating/cooling and split by region. Using the Council's draft *2021 Power Plan* input assumptions, based on benchmarked values: Avista (2019) =$13 for cooling; PacifiCorp (2019) =$11 for each season.
Equipment Cost	$ per new participant	BYOT: $0	Residential BYOT assumes that customers already have a smart thermostat installed.
		Switches: $230 annual	$230 annually, weighted by electric forced air furnace/air-source heat pump split. Using the draft *2021 Power Plan* input assumptions, where single-season equipment is given the full cost for that season (such as electric furnaces in winter) and heating/cooling equipment is given half the cost for both seasons.
Marketing Cost	$ per new participant	$35	BYOT: $70 annually, split evenly by season. The Council's draft *2021 Power Plan* used a marketing cost of $50 for winter and $35 for summer, which was based on the presumption that recruitment of participants may be more difficult in the winter. However, the program participation rate is higher in the winter. Cadmus made the marketing cost $35 for each season. Switches: The Council's draft *2021 Power Plan* used a marketing cost of $50 for winter and $35 for summer, based the presumption that recruitment during the winter may be more difficult. However, program participation for this product is greater in the winter than in the summer. Cadmus updated the marketing cost for winter to $35 to align with the summer marketing cost.
Incentives (annual)	$ per participant per year	BYOT Summer: $7 BYOT Winter: $7	BYOT: $20 annually, 35% participant cost = $7. The 35% assumption used in the TRC is based on the Council's consultation with the BPA demand response SME. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$20; PacifiCorp (2019) =$20.

Parameters	Units	Values	Notes
		Switch Summer: $7 Switch Winter: $11	Switch: $30 for winter, 35% participant cost = $10.5 for winter. $20 for summer, 35% participant cost = $7 for summer. The 35% assumption used in the TRC is based on the Council's consultation with the BPA demand response SME. The winter incentive is using the Council's draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked BPA (2018) annual incentive. The annual incentive from the previous demand response potential assessment (DRPA) is based on the following: Applied (2017) space heating DLC =$20; Navigant (2012) space heating DLC =$32; Global (2011) space heating DLC =$50.The Council's draft *2021 Power Plan* used an incentive of $30 for summer. The benchmarked values include Avista (2019) =$20; PacifiCorp (2019) =$20; the Council's consultation with the BPA demand response SME =$15.
Incentives (one time)	$ per new participant	BYOT: $4	$10 per season, 35% participant cost = $3.5 per season. The 35% assumption used in the TRC is based on the Council's consultation with the BPA demand response SME. The Council's draft *2021 Power Plan* used a one-time incentive value of $20 per season. The benchmarked value of $25 from PGE (2020) is a one-time incentive regardless of season. Cadmus updated the incentive to be split by season.
		Switches: $0	Using the draft *2021 Power Plan* input assumptions. Assuming no sign-up bonus for this product.
Attrition	% of existing participants per year	5%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =5% for heating and cooling, which was assumed to be the same as that of the water heater DLC product from the Snohomish (2017) =5% for heating; PSE (2019) =5% for heating.
Eligibility	% of customer count (such as equipment saturation)	Varies by segment	HVAC system and smart thermostat saturations based on residential consumer survey analysis using PSE-specific weights. Smart thermostat growth based on the draft *2021 Power Plan* workbook "Res-Tstats-v2," incorporating growth in CAC saturation over time.
Peak Load Impact	kW per participant (at meter)	BYOT Summer: 0.94 BYOT Winter: 1.95	The Council's draft *2021 Power Plan* used a peak load impact of 1.27 kW for summer and 1.09 kW for winter, which was evaluated results from PGE programs. Other residential HVAC DLC products had a higher winter impact than summer impact, so Cadmus performed additional benchmarking for this product to verify or refute this discrepancy. Winter impacts are based on the PSE residential DLC pilot's evaluated impact values for morning and evening. Cadmus weighted heating type–specific impacts using residential consumer survey equipment saturations. This value aligns well with or is slightly higher than the values in Cadmus and the Council's benchmarked sources. Summer impacts are based on the PGE residential BYOT pilot's evaluated impact values.
		Switches Summer: 0.59 Switches Winter: 1.2	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked peak load impacts for winter west and summer west from the previous DRPA for BPA (2018). Using Applied (2017) Oregon for winter west peak load impacts, Applied (2017) = 1 – 1.78. Using the average of the following for summer west: Brattle (2016) =0.80; Applied (2017) Oregon =0.43; Applied (2017) Washington =0.53. Selected west impact values only from the draft *2021 Power Plan* to be specific to PSE.

Parameters	Units	Values	Notes
Program Participation	% of eligible customers	BYOT Summer: 25% BYOT Winter: 35%	The Council's draft *2021 Power Plan* used a summer program participation of 20%, which is based on the PGE (2020) benchmarked value. Other benchmarking values included Avista (2019) =25%; PacifiCorp (2019) =25%; BPA (2018) =25%. To better reflect these benchmarked values, Cadmus updated the summer program participation to 25%. The winter value is based on the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PGE (2020) =16%; PacifiCorp (2019) =25%; BPA (2018) =25%; Snohomish (2017) =50%; PSE (2019) =20%.
		Switches Summer: 10% Switches Winter: 25%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked winter program participation from BPA (2018). Using the high end of the 15% to 25% range in Global (2011). The summer program participation is reflective of the following benchmarked data from the Council's draft *2021 Power Plan*: BPA (2018) =25%, which uses the Global (2011) estimate; PGE (2019) =12%; PacifiCorp (2019) =5%; BPA (2018) =5%.
Event Participation	%	BYOT: 70%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =80% for heating and cooling, which is using the IPL (2014) 21% opt-out rate and rounding it to 20%; Snohomish (2017) =62% for heating; PSE (2019) =80% for heating.
		Switches: 95%	The Council used an event participation of 94% for winter and 95% for summer. The summer event participation rate is from the benchmarked BPA (2018) data. The benchmarked values in the previous DRPA for BPA (2018) for space heating, CAC DLC, and programmable communicating thermostat programs range from 0.64 to 0.96. Navigant (2012) had 0.94, matching participation for the Con Edison (2012) CAC program. The winter participation rate is reflective of the benchmarked data: Snohomish (2017) =94%; PSE (2019) =94%; BPA (2018) =95%, which was used to align with the other DLC products. Cadmus made the event participation 95% to align with other DLC products.
Ramp Period	Number of years to reach maximum potential	BYOT: 3	The Council's draft *2021 Power Plan* uses a ramp rate of three years for this product.
		Switches: 5	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =5 years; PGE (2019) =5 years; Snohomish (2017) =5 years.
Program Life	Years	BYOT: 7	BYOT: Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms. Pricing products have a longer program life compared to other products because they are based on rate structures and not DLC equipment. Residential thermostat EUL based on the RTF (2022) workbook.
		Switches: 10	Switches: Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms. Pricing products have a longer program life compared to other products because they are based on rate structures and not DLC equipment.

Parameters	Units	Values	Notes
Sources: For a full list of citations, see the ***References for Detailed Resource Potential Results Assumption Tables*** section. Note, these source notes provide additional context for the input assumptions selected for this analysis. In many cases, the selected inputs align with the draft *2021 Power Plan*'s input assumptions. Cadmus reviewed the sourcing information available in the draft *2021 Power Plan* to add context here, though the original documents referenced by the draft *2021 Power Plan* are not available in its source files. References in these tables for Avista (2019), BPA (2018), PacifiCorp (2012), PacifiCorp (2019), PGE (2020), PSE (2019), and Snohomish (2017) are referring to sourcing documented in the draft *2021 Power Plan*'s sourcing for demand response product input assumptions, which can be found here: https://www.nwcouncil.org/2021-power-plan-technical-information-and-data/.			

Results

Table A-4 shows the final year potential and associated net levelized costs for this product category for the winter season.

Table A-4. Winter Residential Direct Load Control HVAC Achievable Technical Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed per Season	Notification Type	Winter Levelized Cost ($/kW-year)	Winter Final Year Achievable Technical Potential (MW)
Residential DLC Heat-Switch	10, 4-hour events	0 min	-$24	97
Residential DLC Heat-BYOT	10, 4-hour events	0 min	-$56	108

Residential Direct Load Control Electric Vehicle Supply Equipment

Residential EV charger demand response programs can be implemented to reduce EV charging in residential homes during peak hours. Networked Level 2 EV chargers allow customers to better manage their EV charging and offer PSE some ability to control and track EV charging patterns.

Product Description

EV owners can charge their EVs at home, though not all are expected to have an installed Level 2 charger. Cadmus assumed that most existing Level 2 chargers are not networked. Therefore, we focused on EV owners who currently charge at home but do not have a Level 2 charger installed. Through the residential EV DLC product option, PSE would pay for the incremental cost of installing a connected Level 2 charger. Through the residential EV DLC, PSE offers a financial incentive for residential EV owners to install a new networked Level 2 charger and pays an annual incentive in exchange for curtailing EV charging loads during peak events. Connected Level 2 chargers predominantly communicate via Wi-Fi or cellular service and can reduce 0% to 100% of output power in response to an event signal. Cadmus incorporated EV saturation growth into the potential modeling for this product based on forecasts provided by PSE. We assumed that events last up to four hours, with 10 events each season.

Input Assumptions

Table A-5 lists the cost and impact assumptions Cadmus used to estimate the potential and levelized costs for a residential EVSE program.

Table A-5. Residential Direct Load Control Electric Vehicle Supply Equipment Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$75,000	Equal to 1 FTE staff member at $150k per year, split evenly by season.
O&M Cost	$ per participant per year	$5	$10 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input. Benchmarked values included Avista (2019) =$11; PacifiCorp (2019) =$11.
Equipment Cost	$ per new participant	$140	$280 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input.
Marketing Cost	$ per new participant	$25	$50 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$50; PacifiCorp (2019) =$50.
Incentives (annual)	$ per participant per year	$8	$22 per season, 35% participant cost = $7.70 per season. The 35% assumption used in the TRC is consistent with the residential DLC HVAC and residential BYOT products. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$24 per season; PacifiCorp (2019) =$20 per season.
Incentives (one time)	$ per new participant	$0	Using the draft *2021 Power Plan* input assumptions.
Attrition	% of existing participants per year	5%	Using the draft *2021 Power Plan* input assumptions. Consistent with other DLC products: BPA (2018) =5%; Snohomish (2017) =5%; PSE (2019) =5%.
Eligibility	% of customer count (such as equipment saturation)	Varies by segment	AMI is 100% across all sectors by 2023 according to PSE (2022). Residential EV counts are estimated based on the EV sales forecast provided by PSE.
Peak Load Impact	kW per participant (at meter)	0.34	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =0.34; PacifiCorp (2019) =0.28. The Avista (2019) study is based off Avista's EVSE pilot program, where the measured value was 0.41 kW but only 82.5% of the participants were reached. Therefore, Cadmus used a lower peak load impact of 0.34 kW for this study. The PacifiCorp (2019) peak load impact was based off an EV pilot program for Xcel (2014) Energy.
Program Participation	% of eligible customers	20%	Using the draft *2021 Power Plan* input assumptions for single-family and manufactured homes, which relied on DRAC input and benchmarked values: PGE (2019) =20%; PacifiCorp (2019) =25%. The program participation in the PGE (2019) study was based on the demand response potential study conducted by The Brattle Group in 2016. For this study, Cadmus calibrated the program participation from the start year of 2023 to PGE's targets. Cadmus estimated the PacifiCorp (2019) program participation by scaling the time-of-use (TOU) participation by equipment saturations for EVs.
Event Participation	% (switch success rate)	95%	Using the draft *2021 Power Plan* input assumptions, consistent with other DLC products. This value aligns with the benchmarked values in the previous DRPA for BPA (2018). Space heating and CAC DLC and programmable communicating thermostat programs range from 0.64 to 0.96. Navigant (2012) had 0.94, matching participation for the Con Edison (2012) CAC program.

Parameters	Units	Values	Notes
Ramp Period	Number of years to reach maximum potential	5	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =5 years
Program Life	Years	10	Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms. Pricing products have a longer program life compared to other products because they are based on rate structures and not DLC equipment.

Sources: For a full list of citations, see the ***References for Detailed Resource Potential Results Assumption Tables*** section. Note, these source notes provide additional context for the input assumptions selected for this analysis. In many cases, the selected inputs align with the draft *2021 Power Plan*'s input assumptions. Cadmus reviewed the sourcing information available in the draft *2021 Power Plan* to add context here, though the original documents referenced by the draft *2021 Power Plan* are not available in its source files. References in these tables for Avista (2019), BPA (2018), PacifiCorp (2012), PacifiCorp (2019), PGE (2020), PSE (2019), and Snohomish (2017) are referring to sourcing documented in the draft *2021 Power Plan*'s sourcing for demand response product input assumptions, which can be found here: https://www.nwcouncil.org/2021-power-plan-technical-information-and-data/.

Results

Table A-6 shows the final year potential and associated net levelized costs for this product category for the winter season.

Table A-6. Winter Residential Direct Load Control Electric Vehicle Supply Equipment Achievable Technical Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed per Season	Notification Type	Winter Levelized Cost ($/kW-year)	Winter Final Year Achievable Technical Potential (MW)
Residential EV DLC	10, 4-hour events	0 min	$105	42

Commercial Direct Load Control HVAC

Commercial DLC programs operate similarly to most residential DLC programs. In this commercial DLC HVAC program, the utility directly reduces the electric HVAC load of small and medium commercial buildings (in the office or retail segments) during event hours via load control switches or smart thermostats. For this analysis, Cadmus assumed that four-hour events will be dispatched, with up to 10 events per season.

Program participants receive incentives at a yearly rate (though all payments may occur in one season), independent of the number and duration of events called. These incentives can be delivered through several applicable channels (including bill credits and check incentives).

Product Options

Commercial customers in the small or medium office or retail segments with electric space heating and cooling systems are eligible for the commercial DLC HVAC program. This analysis involved three product options by eligible commercial segments and enabling equipment:

- Small office and retail - Switch
- Small office and retail - BYOT
- Medium office and retail - Switch

Input Assumptions

Table A-7 lists the cost and impact assumptions Cadmus used in estimating potential and levelized costs for the commercial DLC HVAC program.

Table A-7. Commercial Direct Load Control HVAC Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$75,000	Equal to 1 FTE staff member at $150k per year, split evenly by season.
O&M Cost	$ per participant per year	Switches: $20	$40 annually. The Council's draft *2021 Power Plan* used an O&M cost of $18 for winter and $20 for summer. Cadmus found no clear evidence as to why winter would cost more than summer. Therefore, we updated the winter O&M cost to $20 per season.
		BYOT: $4	$8 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: the Council's consultation with the BPA demand response SME =$8 for heating and $7 for cooling; PSE (2019) =$7.5 for heating.
Equipment Cost	$ per new participant	Small Switch: $387 annual	$387 annually, where single-season equipment is given the full cost for that season (such as electric furnaces in winter) and heating/cooling equipment is given half the cost for both seasons. Using the draft *2021 Power Plan* input assumptions.
		Medium Switch $1,130 annual	$1,130 annually, where single-season equipment is given the full cost for that season (such as electric furnaces in winter) and heating/cooling equipment is given half the cost for both seasons. Using the draft *2021 Power Plan* input assumptions.
		BYOT: $0	Commercial BYOT assumes that customers already have a smart thermostat installed.
Marketing Cost	$ per new participant	Small Switch: $35	$69 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked marketing cost from BPA (2018). This value is the midpoint of the $63 to $75 range for small C&I from Applied (2017).
		Medium Switch: $43	$85 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =$75 to $90; BPA (2018) =$83, which used the midpoint of the $75 to $90 range for medium C&I from Applied (2017); PSE (2019) =$83.
		BYOT: $38	$75 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$75

Parameters	Units	Values	Notes
Incentives (annual)	$ per participant per year	Small Switch: $21	$76 annually, split evenly by season =$38 per season, 55% participant cost =$21 per season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =$38 per season, which is from Applied (2017); PacifiCorp (2019) =$38 per season.
		Medium Switch: $72	$130 per season, 55% participant cost = $71.5 per season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PacifiCorp (2019) =$128 per season; BPA (2018) =$128 per season, which is from Applied (2017); PSE (2019) =$128 for winter.
		BYOT: $22	$40 per season, 55% participant cost = $22 per season. Using the draft *2021 Power Plan* input assumptions: BPA (2018) =$38 per season; PacifiCorp (2019) =$38 per season.
Incentives (one time)	$ per new participant	Switches: $0	Using the draft *2021 Power Plan* input assumptions. Assuming no sign-up bonus for this product.
		BYOT: $6	$20 annually, split evenly by season. 55% participant cost = $5.5 per season. The Council's draft *2021 Power Plan* used a one-time incentive value of $20 per season. The benchmarked value of $25 from PGE (2020) is a one-time incentive regardless of season. Cadmus updated the incentive to be split by season.
Attrition	% of existing participants per year	5%	Assuming similar to residential BYOT and commercial HVAC switch products. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =5% for heating and cooling, which was assumed to be the same as that of the water heater DLC product from the Snohomish (2017) =5% for heating; PSE (2019) =5% for heating.
Eligibility	% of customer count (such as equipment saturation)	Varies by segment	HVAC system saturations based on the CBSA (NEEA 2020) analysis using PSE-specific weights. Thermostat saturations and growth based on the Council's draft "2021P Com-ConnectedThermostats_V2" workbook.
Peak Load Impact	kW per participant (at meter)	Small Switch Summer: 1.1 Small Switch Winter: 1.9	Summer: Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked peak load impacts from BPA (2018). The summer values are from Applied (2017), where east is using the midpoint values for Washington (1.3) and Idaho (1.2) and west is equal to the value for Oregon (1.1). Cadmus selected the west impact value to be specific to PSE. Winter: Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked peak load impacts from BPA (2018). Cadmus derived the winter values from the residential DLC space heating impact by applying the ratio of HVAC capacity sizes between residential and small commercial buildings. Cadmus calculated the average small commercial HVAC capacity from CBSA (2014) data (Navigant 2015). We selected the west impact value to be specific to PSE.

Parameters	Units	Values	Notes
		Medium Switch Summer: 12.3 Medium Switch Winter: 9.2	Summer: Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked peak load impacts from BPA (2018). The summer values are from Applied (2017), where east is using the midpoint values for Washington (15.2) and Idaho (13.2) and west is equal to the value for Oregon (12.3). Cadmus selected the west impact value to be specific to PSE. Winter: Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked peak load impacts from BPA (2018). Cadmus derived the winter values from the residential DLC space heating impact by applying the ratio of HVAC capacity sizes between residential and small commercial buildings. We calculated the average small commercial HVAC capacity from CBSA (2014) data (Navigant 2015), and selected the west impact value to be specific to PSE.
		BYOT Summer: 1.1 BYOT Winter: 1.9	Summer: Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =1.1 kW for west and 1.25 kW for east. We selected the west impact value to be specific to PSE. Winter: Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =1.87 kW for west and 2.5 1 kW for east. We selected the west impact value to be specific to PSE.
Program Participation	% of eligible customers	Switches: 10%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked program participation from BPA (2018). This value was from Global (2011).
		BYOT Summer: 25% BYOT Winter: 35%	The draft *2021 Power Plan* aligned commercial thermostat program participation assumptions with residential thermostat program participation assumptions. The Council's draft *2021 Power Plan* used a summer program participation of 20%, which is based on the PGE (2020) benchmarked value. Other benchmarking values included Avista (2019) =25%; PacifiCorp (2019) =25%; BPA (2018) =25%. To better reflect these benchmarked values, Cadmus updated the summer program participation to 25%. The winter value is based on the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: PGE (2020) =16%; PacifiCorp (2019) =25%; BPA (2018) =25%; Snohomish (2017) =50%; PSE (2019) =20%.
Event Participation	% (switch success rate)	Switches: 95%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked event participation from PSE (2019).
		BYOT: 70%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =80% for heating and cooling, which is using the IPL (2014) 21% opt-out rate and rounding it to 20%; Snohomish (2017) =62% for heating; PSE (2019) =80% for heating.
Ramp Period	Number of years to reach maximum potential	Switches: 5	Using the draft *2021 Power Plan* input assumptions.
		BYOT: 3	The Council's draft *2021 Power Plan* uses a ramp rate of three years for this product.

Parameters	Units	Values	Notes
Program Life	Years	Switches: 10 BYOT: 5	Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms. Pricing products have a longer program life compared to other products because they are based on rate structures and not DLC equipment. Commercial thermostat EUL based on RTF (2022b) workbook.

Sources: For a full list of citations, see the ***References for Detailed Resource Potential Results Assumption TablesError! Reference source not found.*** section. Note, these source notes provide additional context for the input assumptions selected for this analysis. In many cases, the selected inputs align with the draft *2021 Power Plan*'s input assumptions. Cadmus reviewed the sourcing information available in the draft *2021 Power Plan* to add context here, though the original documents referenced by the draft *2021 Power Plan* are not available in its source files. References in these tables for Avista (2019), BPA (2018), PacifiCorp (2012), PacifiCorp (2019), PGE (2020), PSE (2019), and Snohomish (2017) are referring to sourcing documented in the draft *2021 Power Plan*'s sourcing for demand response product input assumptions, which can be found here: https://www.nwcouncil.org/2021-power-plan-technical-information-and-data/.

Results

Table A-8 shows the final year potential and associated net levelized costs for this product category for the winter season.

Table A-8. Winter Commercial Direct Load Control HVAC Achievable Technical Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed per Season	Notification Type	Winter Levelized Cost ($/kW-year)	Winter Final Year Achievable Technical Potential (MW)
Small Commercial DLC Heat-Switch	10, 4-hour events	0 min	$0	3
Small Commercial DLC Heat-BYOT	10, 4-hour events	0 min	-$36	3
Medium Commercial DLC Heat-Switch	10, 4-hour events	0 min	-$33	18

Commercial and Industrial Curtailment

For the C&I curtailment product, PSE requests that large C&I customers curtail their loads at a predetermined level for a predetermined event duration. Event durations in similar programs across the country range from one hour to five hours. For this program, Cadmus assumed that the event duration lasts four hours, with up to 10 events called per season (for a total of 40 hours).

The incentive payments to participants can be tariff based or a supplemental payment contract (Cadmus considered payment contracts only):

- ***Tariff Based:*** Participants are assigned to a tariff with more favorable billing determinants in exchange for agreeing to have a portion of their load interrupted or operations curtailed in response to direction from the utility or grid operator.
- ***Payment Contract:*** Participants enter a separate contract with the utility or grid operator to curtail load upon request. Generally, the program administrator will specify the dispatch parameters and participants will commit to reducing a certain amount of load upon dispatch for one or more years.

Under a payment contract, customers receive payments to remain ready for curtailment, even if actual curtailment requests do not occur. Therefore, this product represents a firm resource.

Participating customers execute curtailment according to the curtailment agreement after the utility calls an event. The specifics of curtailment contracts vary: some allow customers to meet their pledged demand reductions by reducing load from any end use while others tie load reduction requirements to a specific end use or piece of equipment. Furthermore, these load reductions may be achieved through a utility-controlled DLC switch (known as curtailment with enablement) or through actions taken directly by the customer (known as curtailment without enablement). Historically, Northwest utilities have conducted commercial building, public facility, and industrial pilots that tested results both with and without enablement demand curtailment products. Both types of pilots have similar expected costs.

While there are multiple strategies and curtailment contract requirements that can be implemented to target large C&I loads, this study only includes payment contract curtailment products that can target all end-use loads. Though actual implementation methods may differ from the curtailment contracts modeled in this analysis, the potential captured by these products in this analysis can be considered representative of the potential that could be achieved through other implementation strategies.

Product Description

Cadmus assumed that eligible participants include customers with at least 150 kW of monthly average demand in all C&I segments, excluding small office, small retail, medium office, and medium retail. The percentage of load represented by end-use customers meeting this requirement varies across commercial segments.

Input Assumptions

Table A-9 lists the costs and impact assumptions Cadmus used to estimate the potential and levelized costs for the C&I curtailment program.

Table A-9. Commercial and Industrial Curtailment Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$75,000	Equal to 1 FTE staff member at $150k per year, split evenly by season.
O&M Cost	$ per kW pledged per year	Industrial: $5	$10 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked O&M cost from BPA (2018), assuming the low-end range of the $25 to $35 cost (O&M and incentives) per season of BPA's cost estimate. The O&M cost was $5 per season, while the remaining $20 per season was for incentives.
		Commercial: $15	$30 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked O&M cost from BPA (2018), assuming the high-end range of the $25 to $35 cost (O&M and incentives) per season of BPA's cost estimate. The O&M cost was $15 per season, while the remaining $20 per season was for incentives.

Parameters	Units	Values	Notes
Equipment Cost	$ per new kW pledged	$5	$10 annually split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked equipment cost from BPA (2018).
Marketing Cost	$ per new kW pledged	$0	Using the draft *2021 Power Plan* input assumptions. Consistent with the previous DRPA for BPA (2018), assuming that the marketing cost is included in the O&M costs.
Incentives (Annual)	$ per kW pledged per year	$40/kW + $150/MWh	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked annual incentive from BPA (2018). Split evenly between seasons, only 55% and 75% of the incentive is included in TRC for commercial and industrial, respectively.
Incentives (One Time)	$ per new kW pledged	$0	Using the draft *2021 Power Plan* input assumptions. Assuming no sign-up bonus for this product. Consistent with previous DRPA for BPA (2018).
Attrition	% of existing participants per year	5%	Using the draft *2021 Power Plan* input assumptions. Consistent with other demand response products.
Eligibility	% of segment/end-use load	Varies by segment	Using the draft *2021 Power Plan* input assumptions, which uses benchmarked load class eligibility and customer segmentation from PacifiCorp (2012) and the 2018 BPA DRPA.
Peak Load Impact	% of eligible segment/end-use load	25%	Using the draft *2021 Power Plan* input assumptions, which uses benchmarked load class eligibility and customer segmentation from PSE (2019) for commercial and from Avista (2019) =21%; BPA (2018) =52% for industrial.
Program Participation	% of eligible segment/end-use load	Industrial: 25%	The Council's draft *2021 Power Plan* used a program participation of 15%, which relied on DRAC input. This 25% assumption aligns with Cadmus' recent DRPA for BPA (Cadmus 2018). During this most recent BPA DRPA, after discussion with BPA staff, Cadmus updated the program participation to align with the assumption used in the previous DRPA, which showed that Northwest potential assessment results generally average 20% (Snohomish 2017; Applied 2017).
		Commercial: 15%	Conservative estimate in line with recommendations made by demand response DRAC utilities.
Event Participation	%	Industrial: 90%	Using the draft *2021 Power Plan* input assumptions.
		Commercial: 95%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked peak load impact from BPA (2018), where benchmarked event participation rates range from 52% (average rate from BPA 2012) to 95% (BPA and Energy Northwest 2016).
Ramp Period	Number of years to reach maximum potential	5	Using the draft *2021 Power Plan* input assumptions. Consistent with commercial demand curtailment, which is based off PacifiCorp (2019).
Program Life	Years	10	Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms. Pricing products have a longer program life compared to other products because they are based on rate structures and not DLC equipment.

Parameters	Units	Values	Notes

Sources: For a full list of citations, see the ***References for Detailed Resource Potential Results Assumption Tables*** section. Note, these source notes provide additional context for the input assumptions selected for this analysis. In many cases, the selected inputs align with the draft *2021 Power Plan*'s input assumptions. Cadmus reviewed the sourcing information available in the draft *2021 Power Plan* to add context here, though the original documents referenced by the draft *2021 Power Plan* are not available in its source files. References in these tables for Avista (2019), BPA (2018), PacifiCorp (2012), PacifiCorp (2019), PGE (2020), PSE (2019), and Snohomish (2017) are referring to sourcing documented in the draft *2021 Power Plan*'s sourcing for demand response product input assumptions, which can be found here: https://www.nwcouncil.org/2021-power-plan-technical-information-and-data/.

Results

Table A-10 shows the final year potential and associated net levelized costs for this product category for the winter season.

Table A-10. Winter Commercial and Industrial Curtailment Achievable Technical Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed per Season	Notification Type	Winter Levelized Cost ($/kW-year)	Winter Final Year Achievable Technical Potential (MW)
Commercial Curtailment	10, 4-hour events	Day-ahead (up to 2 hours ahead)	-$28	16
Industrial Curtailment	10, 4-hour events	Day-ahead (up to 2 hours ahead)	-$37	5

Residential Critical Peak Pricing

Under a CPP program, customers receive a discount on their retail rates during noncritical peak periods in exchange for paying premium prices during critical peak events. The critical peak price is determined in advance, which gives customers some degree of certainty about participation costs.

The program follows the basic rate structure of a TOU tariff, where the rate has fixed prices for usage during different blocks of time (typically on-, off-, and mid-peak prices by season). During CPP events, the normal peak price under a TOU rate structure is replaced with a much higher price, which is generally set to reflect the utility's avoided cost of supply during peak periods.

These programs typically use AMI data to monitor and calculate when a customer's consumption occurs. These programs do not offer direct incentives, as customers instead get the opportunity to shift their demand from more expensive peak times to less expensive times. Because AMI is necessary for billing purposes, all residential customers with AMI are eligible.

CPP rates take effect for only a limited number of times during peak seasons. When emergency or high market prices are in effect, the utility can invoke a critical peak event. The utility notifies customers that rates have become much higher than normal and encourages them to shed or shift load. Typically, notification is via email or text a day prior to the CPP event and the day of the event. For this analysis, Cadmus assumed that 10 CPP events are called with a duration of four hours each, for a total of 40 event hours during each season.

Product Options

There are several product options for CPP offerings. Residential rate-driven demand response CPP is a more targeted time-of-day pricing product (compared to a typical TOU product) that has a larger 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 a CPP program may have a 6:1 ratio. Additionally, CPP typically affects significantly fewer hours during the year (known as the critical peak periods) than TOU rates and comes with a higher incentive. The end goal of all pricing products, including CPP, is to shift customer behavior. For example, customers may turn off lights more diligently or wait to do laundry until after peak pricing ends regardless of whether they are in a CPP or TOU program. These pricing products often target large pools of customers, many of whom may have not participated in a demand response program before. As a result, these products can serve as opportunities to recruit new participants for other demand response programs.

Input Assumptions

Table A-11 provides the cost and impact assumptions Cadmus used in estimating the potential and levelized costs for the residential CPP program.

Table A-11. Residential Critical Peak Pricing Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$75,000	Equal to 1 FTE staff member at $150k per year, split evenly by season.
O&M Cost	$ per year	$37,500	$75,000 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$75,000; PacifiCorp (2019) =$75,000; BPA (2018) =$75,000, which uses Applied (2017) estimate; PSE (2019) =$75,000.
Equipment Cost	$ per new participant	$0	Assumes that AMI is fully developed for pricing programs. Using the draft *2021 Power Plan* input assumptions. Consistent with the DRPA for BPA (2018).
Marketing Cost	$ per new participant	$25	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$50; PacifiCorp (2019) =$50.
Incentives (annual)	N/A	$0	Using the draft *2021 Power Plan* input assumptions. This product is designed for customers to shift their energy use during peak periods to low demand periods based on lower rates. Therefore, incentives are not provided since the customer can obtain the lower rate prices.
Incentives (one time)	N/A	$0	
Attrition	% of existing participants per year	0%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked attrition from PSE (2019).
Eligibility	% of segment load	100%	AMI is 100% across all sectors by 2023 according to PSE (2022).

Parameters	Units	Values	Notes
Peak Load Impact	% of eligible segment load	Summer: 13% Winter: 7.5%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked peak load impacts from Avista (2019) and PacifiCorp (2019). These seasonal differences are also evident in PGE Flex 2.0 and PGE Test Bed Peak Time Rate. These sources represent a wide range of Pacific Northwest utilities.
Program Participation	% of eligible segment load	15%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: BPA (2018) =15%; PSE (2019) =15%. The benchmarked values from the previous DRPA for BPA (2018) are from Cadmus (2013) for Washington =5%; Cadmus (2017) =10%; Applied (2017) =17%; Brattle (2016) =29% (opt-in) or 90% (opt-out).
Event Participation	%	100%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked event participation from PSE (2019).
Ramp Period	Number of years to reach maximum potential	3	The Council's draft *2021 Power Plan* uses a ramp rate of three years for this product (2020).
Program Life	Years	Study Duration	Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms. Pricing products have a longer program life compared to other products because they are based on rate structures and not DLC equipment.

Sources: For a full list of citations, see the ***References for Detailed Resource Potential Results Assumption Tables*** section. Note, these source notes provide additional context for the input assumptions selected for this analysis. In many cases, the selected inputs align with the draft *2021 Power Plan*'s input assumptions. Cadmus reviewed the sourcing information available in the draft *2021 Power Plan* to add context here, though the original documents referenced by the draft *2021 Power Plan* are not available in its source files. References in these tables for Avista (2019), BPA (2018), PacifiCorp (2012), PacifiCorp (2019), PGE (2020), PSE (2019), and Snohomish (2017) are referring to sourcing documented in the draft *2021 Power Plan*'s sourcing for demand response product input assumptions, which can be found here: https://www.nwcouncil.org/2021-power-plan-technical-information-and-data/.

Results

Table A-12 shows the final year potential and associated net levelized costs for this product category for the winter season.

Table A-12. Winter Residential Critical Peak Pricing
Achievable Technical Potential and Levelized Cost by Product Option

Product Option	Number of Events and Hours Curtailed per Season	Notification Type	Winter Levelized Cost ($/kW-year)	Winter Final Year Achievable Technical Potential (MW)
Residential CPP	10, 4-hour events	Day ahead	-$56	33

Commercial Critical Peak Pricing

The commercial CPP product is similar to the residential CPP program: participants are encouraged to reduce or shift their demand during peak periods to low demand time periods through price signals.

These programs use AMI to monitor and calculate when a customer's consumption occurs. Different electric rates are then applied to a customer's load depending on when electricity is used—rates are higher during peak times and lower during off-peak times (relative to a traditional constant electric retail rate). As a consequence, these programs do not offer direct incentives, as customers instead get the opportunity to shift their demand from more expensive peak times to less expensive times. Because AMI data are necessary for billing purposes, all C&I customers with AMI are eligible.

Product Options

For this analysis, Cadmus only modeled a single product option within this category. This aligns with the granularity outlined by the Council's *2021 Power Plan*.

Input Assumptions

Table A-13 lists the cost and impact assumptions Cadmus used to estimate the potential and levelized costs for the commercial CPP program.

Table A-13. Commercial Critical Peak Pricing Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$75,000	Equal to 1 FTE staff member at $150k per year, split evenly by season.
O&M Cost	$ per year	$37,500	$75,000 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$75,000; PacifiCorp (2019) =$75,000; BPA (2018) =$75,000, which uses Applied (2017) estimate; PSE (2019) =$75,000.
Equipment Cost	$ per new participant	$0	Assuming AMI full deployment. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$0; PacifiCorp (2019) =$0; BPA (2018) =$0; PSE (2019) =$0.
Marketing Cost	$ per new participant	$100	$200 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked marketing cost from PSE (2019).
Incentives (annual)	N/A	$0	Using the draft *2021 Power Plan* input assumptions. Annual incentive from PSE (2019). This product is designed for customers to shift their energy use during peak periods to low demand periods based on lower rates. Therefore, incentives are not provided since the customer can obtain the lower rate prices.
Incentives (one time)	N/A	$0	
Attrition	% of existing participants per year	0%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked attrition from PSE (2019).
Eligibility	% of segment load	100%	AMI is 100% across all sectors by 2023 according to PSE (2022).

Parameters	Units	Values	Notes
Peak Load Impact	% of eligible segment load	8%	This value is based on the Council's draft *2021 Power Plan* corresponding summer BPA workbook. That value relied on the large C&I impacts assumed in the PacifiCorp (2019) potential study, which are industry estimates and are not regional: they are "based on experience with full-scale programs in the Northeastern U.S." Considering this and that the loads and behavior of potential participants for this product do not vary significantly between seasons, Cadmus aligned the peak load impacts for this product across seasons.
Program Participation	% of eligible segment load	18%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked program participation from PacifiCorp (2019).
Event Participation	%	100%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked program event participation from PSE (2019).
Ramp Period	Number of years to reach maximum potential	3	The Council's draft *2021 Power Plan* uses a ramp rate of three years for this product (2020).
Program Life	Years	Study Duration	Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms. Pricing products have a longer program life compared to other products because they are based on rate structures and not DLC equipment.

Sources: For a full list of citations, see the ***References for Detailed Resource Potential Results Assumption Tables*** section. Note, these source notes provide additional context for the input assumptions selected for this analysis. In many cases, the selected inputs align with the draft *2021 Power Plan*'s input assumptions. Cadmus reviewed the sourcing information available in the draft *2021 Power Plan* to add context here, though the original documents referenced by the draft *2021 Power Plan* are not available in its source files. References in these tables for Avista (2019), BPA (2018), PacifiCorp (2012), PacifiCorp (2019), PGE (2020), PSE (2019), and Snohomish (2017) are referring to sourcing documented in the draft *2021 Power Plan*'s sourcing for demand response product input assumptions, which can be found here: https://www.nwcouncil.org/2021-power-plan-technical-information-and-data/.

Results

Table A-14 shows the final year potential and associated net levelized costs for this product category for the winter season.

Table A-14. Winter Commercial Critical Peak Pricing Achievable Technical Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed per Season	Notification Type	Winter Levelized Cost ($/kW-year)	Winter Final Year Achievable Technical Potential (MW)
Commercial CPP	10, 4-hour events	Day ahead	-$57	21

Industrial Critical Peak Pricing

The industrial CPP program is similar to the residential and commercial CPP programs but is meant for industrial customers.

Product Options

Cadmus only modeled a single product option within this category. This aligns with the granularity outlined by the Council's *2021 Power Plan*.

Input Assumptions

Table A-15 lists the cost and impact assumptions Cadmus used in estimating potential and levelized costs for the industrial CPP program.

Table A-15. Industrial Critical Peak Pricing Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$75,000	Equal to 1 FTE staff member at $150k per year, split evenly by season.
O&M Cost	$ per year	$37,500	$75,000 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$75,000; PacifiCorp (2019) =$75,000; BPA (2018) =$75,000, which uses the Applied (2017) estimate; PSE (2019) =$75,000.
Equipment Cost	$ per new participant	$0	Assuming AMI full deployment. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and benchmarked values: Avista (2019) =$0; PacifiCorp (2019) =$0; BPA (2018) =$0; PSE (2019) =$0.
Marketing Cost	$ per new participant	$100	$200 annually, split evenly by season. Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked marketing cost from PSE (2019).
Incentives (annual)	N/A	$0	Using the draft *2021 Power Plan* input assumptions and annual incentive from PSE (2019). This product is designed for customers to shift their energy use during peak periods to low demand periods based on lower rates. Therefore, incentives are not provided since the customer can obtain the lower rate prices.
Incentives (one time)	N/A	$0	
Attrition	% of existing participants per year	0%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked attrition from PSE (2019).
Eligibility	% of segment load	100%	AMI is 100% across all sectors by 2023 according to PSE (2022).
Peak Load Impact	% of eligible segment load	8%	This value is based on the Council's draft *2021 Power Plan* corresponding summer BPA workbook. That value relied on the large C&I impacts assumed in the PacifiCorp (2019) potential study, which used assumptions that are industry estimates and are not regional: they are "based on experience with full-scale programs in the Northeastern U.S." Considering this and that the loads and behavior of potential participants for this product do not vary significantly between seasons, Cadmus aligned the peak load impacts for this product across seasons.
Program Participation	% of eligible segment load	18%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked program participation from PacifiCorp (2019).
Event Participation	%	100%	Using the draft *2021 Power Plan* input assumptions, which relied on DRAC input and the benchmarked event participation from PSE (2019).

Parameters	Units	Values	Notes
Ramp Period	Number of years to reach maximum potential	3	The Council's draft *2021 Power Plan* uses a ramp rate of three years for this product (2020).
Program Life	Years	Study Duration	Program life assumptions are based on the life of controlling equipment and when utilities may change control platforms. Pricing products have a longer program life compared to other products because they are based on rate structures and not DLC equipment.

Sources: For a full list of citations, see the ***References for Detailed Resource Potential Results Assumption Tables*** section. Note, these source notes provide additional context for the input assumptions selected for this analysis. In many cases, the selected inputs align with the draft *2021 Power Plan*'s input assumptions. Cadmus reviewed the sourcing information available in the draft *2021 Power Plan* to add context here, though the original documents referenced by the draft *2021 Power Plan* are not available in its source files. References in these tables for Avista (2019), BPA (2018), PacifiCorp (2012), PacifiCorp (2019), PGE (2020), PSE (2019), and Snohomish (2017) are referring to sourcing documented in the draft *2021 Power Plan*'s sourcing for demand response product input assumptions, which can be found here: https://www.nwcouncil.org/2021-power-plan-technical-information-and-data/.

Results

Table A-16 shows the final year potential and associated net levelized costs for this product category for the winter season.

Table A-16. Winter Industrial Critical Peak Pricing Achievable Technical Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed per Season	Notification Type	Winter Levelized Cost ($/kW-year)	Winter Final Year Achievable Technical Potential (MW)
Industrial CPP	10, 4-hour events	Day ahead	-$34	2

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