2021 PSE Integrated Resource Plan

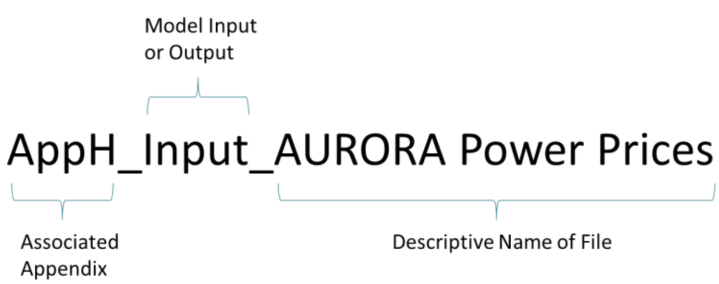
E Conservation Potential Assessment and Demand Response Assessment

The Conservation Potential Assessment and Demand Response Assessment developed by Cadmus Group for the IRP analysis evaluates the type and quantity of conservation measures available from utility programs, codes and standards, and customer-driven programs; demand response; and distributed solar generation.

APPENDIX E FILES

For the 2021 IRP, PSE is providing Microsoft Excel files containing input and output data in separate files instead of data tables directly in the Final IRP report. The direct access to the data provides usable files for stakeholders as opposed to stagnant tables in a PDF format. Technical limitations on how PSE is able to submit files to the WUTC and host files online for stakeholder access has prevented PSE from keeping the files organized in a series of folders. To overcome this, a descriptive naming system has been developed in order to identify different files. Figure E-1 provides an example of how the files will be named in Appendix H, Electric Analysis Inputs and Results. The same format is used for files from Appendix E. Each Excel file also contains a "Read_Me" sheet with specific details related to the data contained in that file.

Figure E-1: The naming scheme of Appendix H and Appendix E files.



Cadmus has provided additional files with the Conservation Potential Assessment of Appendix E. The files contain the underlying data of the conservation and demand response measures. The programs included in the Energy Efficiency file contain breakdowns into Industrial, Commercial, and Residential measures. For the 2021 IRP electric models, the classes are aggregated together and then the combined energy efficiency is used. Figure E-2 provides the file names of these datasets.

Figure E-2: The names of Appendix E files.

File Names	Description
AppE_Input_Energy Efficiency Potential	Contains the underlying data of the conservation bundles included in the 2021 IRP.
AppE_Input_Demand Response Potential	Contains the underlying data of the demand response programs included in the 2021 IRP.

CADMUS

Comprehensive Assessment of Demand-Side Resource Potentials (2022 – 2045):

Conservation Potential Assessment

Demand Response Assessment

Distributed Solar Assessment

December 4, 2020

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Acronyms and Abbreviations

Acronym	Definition
ACEEE	American Council for an Energy-Efficient Economy
AMI	Advanced Metering Infrastructure
aMW	Average megawatt
ASP	Annualized simple payback
ATB	Annual technology baseline
BYOT	Bring your own thermostat
C&I	Commercial and industrial
CBECS	Commercial Building Energy Consumption Survey
CBSA	Commercial Building Stock Assessment
CEE	Consortium for Energy Efficiency
CHP	Combined Heat and Power
Council	Northwest Power and Conservation Council
CPA	Conservation Potential Assessment
CPP	Critical peak pricing
DEER	California Database of Energy Efficient Resources
DLC	Direct Load Control
DOE	U.S. Department of Energy
DR	Demand response
DSR	Demand-side resources
EERE	Office of Energy Efficiency and Renewable Technology (U.S. Department of Energy)
EIA	U.S. Energy Information Administration
EISA	Energy Independence and Security Act
ERWH	Electric resistance water heater
EUL	Effective useful life
EV	Electric vehicle
EVSE	Electric vehicle service equipment
FTE	Full-time equivalent
GEWH	Grid-enabled water heater
HB	House Bill
HPWH	Heat pump water heater
HVAC	Heating, ventilation, and air conditioning
IFC	International Fire Code
IRP	Integrated resource plan
LCOE	Levelized cost of electricity
LED	Light-emitting diode
LI	Low income
LIDAR	Light detection and ranging
NEEA	Northwest Energy Efficiency Alliance
NPV	Net present value
NREL	National Renewable Energy Laboratory
O&M	Operations and maintenance
PCT	Programmable communicating thermostat
PSE	Puget Sound Energy
PV	Photovoltaic

Acronym	Definition
RBSA	Residential Building Stock Assessment
RCS	Residential Characteristics Study
RECS	Residential Energy Consumption Survey
RBSA	Residential Building Stock Assessment
RTF	Regional Technical Forum
T&D	Transmission and distribution
TLED	Tubular LED
TOU	Time of use
TRC	Total resource cost
TRM	Technical reference manual
UCT	Utility cost test
UES	Unit energy savings
WSEC	Washington State Energy Code

Executive Summary

Overview

This report presents the results of an independent assessment of the technical and achievable potential for electric and natural gas demand-side resources (DSR) in the service territory of Puget Sound Energy (PSE) over the 24-year electric planning horizon, from 2022 to 2045, and 20-year natural gas planning horizon, from 2022 to 2041. This conservation potential assessment (CPA), commissioned by PSE as part of its integrated resource planning (IRP) process, is intended to identify DSR potential from the perspectives of energy efficiency, demand response, and distributed generation (including solar photovoltaics and combined heat and power). The results of this assessment will help PSE identify cost-effective DSR and design future programming.

This study builds upon previous assessments of DSR resources in PSE's territory. It incorporates the latest baseline and DSR data from primary and secondary sources and is informed by the work of other entities in the region, such as the Northwest Power and Conservation Council (Council), the Northwest Regional Technical Forum (RTF), and the Northwest Energy Efficiency Alliance (NEEA). The methods used to evaluate the technical and achievable technical potential draw upon best utility industry practices and remain consistent with the methodology used by the Council in its assessment of regional conservation potentials in its most recently approved Seventh Northwest Conservation and Electric Power Plan (Seventh Plan). In addition, this work is also consistent with the draft 2021 Northwest Conservation and Electric Power Plan (2021 Plan) supply curves work that was under development as this assessment was being updated.

Scope of the Analysis and Approach

Energy Efficiency and Combined Heat and Power

The energy efficiency analysis included estimates of the technical and achievable technical potential for more than 400 unique electric and natural gas energy efficiency measures. Cadmus relied on PSE program data, RTF analysis, The Council's draft 2021 Plan and Seventh Plan analyses, and regional stock assessments to determine the savings, costs, and applicability for each measure. We incorporated feedback from PSE staff and regional stakeholders on the list of measures and measure assumptions.

Cadmus prepared 24-year forecasts of potential electric energy, peak demand, and a 20-year natural gas forecast of energy savings for each energy efficiency measure using a units-based method consistent with the Council's approach for its most recently approved plan (the Seventh Plan). The assessment considers multiple vintages (new and existing), distinguishes between lost opportunity and replace-on-burnout 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 Plan: 85-100% of technical potential is achieved over the 24-year electric and 20-year natural gas study horizons, and adoption curves are derived from the Council's draft 2021 Plan ramp rates.

The combined heat and power (CHP) analysis identifies potential generation from nonrenewable and renewable CHP technologies in large commercial and industrial facilities. We derived estimates of CHP technical potential using generation and applicability data for reciprocating engines, microturbines, gas turbines, industrial biomass, and biogas. We determined achievable potential for these technologies using American Council for an Energy-Efficient Economy (ACEEE) CHP favorability data and an analysis of the U.S. Department of Energy (DOE) CHP Installation Database.

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' analysis focused on program options that include residential direct load control (DLC) for space heat, room heat, water heat, and nonresidential load curtailment. These strategies include price- and incentive-based options for all major customer segments and end uses in PSE's service territory.

To estimate demand response potentials, this study 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, we first assessed potential impacts at the end-use level then aggregated these to obtain estimates of technical potentials. This allowed us to apply market factors, such as likely program and event participation, to technical potentials to obtain estimates of market potentials.

A detailed discussion of the demand response potential is covered under section 2 of this report.

Distributed Solar Photovoltaics

The solar PV analysis uses power density forecasts and estimates of the total available roof area for solar PV to develop forecasts of nameplate capacity. Solar PV achievable potential was determined using a bass diffusion equation that incorporates data on the adoption of customer driven solar PV in PSE's service territory and future price and PV efficiency forecasts to estimate customer payback over time.

A detailed discussion of the distributed solar potential is covered under section 3 of this report.

Summary of Results

Table 1 shows the technical and achievable potential for each resource considered in this study. Electric DSRs represent nearly 608 average megawatts (aMW) of achievable technical potential and could produce approximately 1,192 MW of winter peak savings. Energy efficiency has the highest energy-savings potential, with 600 aMW of cumulative achievable technical potential by 2045. Cadmus identified natural gas cumulative achievable technical potential of 174 million therms. All estimates of potential in this report are presented at the generator, meaning they include line losses.

Table 1. Summary of Energy and Demand Savings Potential, Cumulative 2045

Resource	Energy (aMW/Million Therms)		Winter Coincident Peak Capacity (MW)	
	Technical Potential	Achievable Technical Potential	Technical Potential	Achievable Technical Potential
Electric Resources				
Energy Efficiency	706	600	1,127	958

Resource	Energy (aMW/Million Therms)		Winter Coincident Peak Capacity (MW)	
	Technical Potential	Achievable Technical Potential	Technical Potential	Achievable Technical Potential
Demand Response	N/A	N/A	N/A	226
Combined Heat and Power	200	8	200	8
Electric Resources Total	**906**	**608**	**1,327**	**1,192**
Natural Gas Resources				
Energy Efficiency	204	174	N/A	N/A

Figure 1. and Figure 2. present the respective electric and natural gas achievable potential forecasts. More savings are achieved for both fuels in the first 10 years of the study (2022 through 2031) than in the remaining years because the study assumes all discretionary measure potential savings (i.e., measures that retrofit existing homes and businesses) are acquired in the first 10 years. In the remaining years, additional savings come from lost opportunity measures, such as equipment replacement and new construction.

Figure 1. Electric Achievable Technical Potential Forecast, Cumulative 2022 - 2045

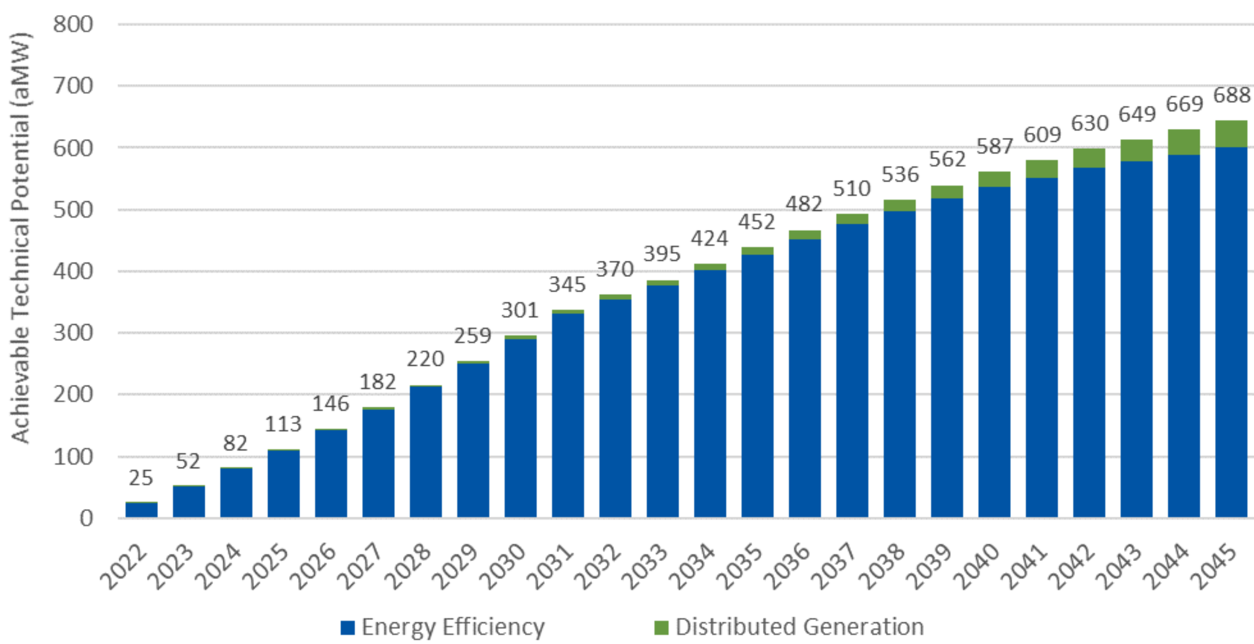
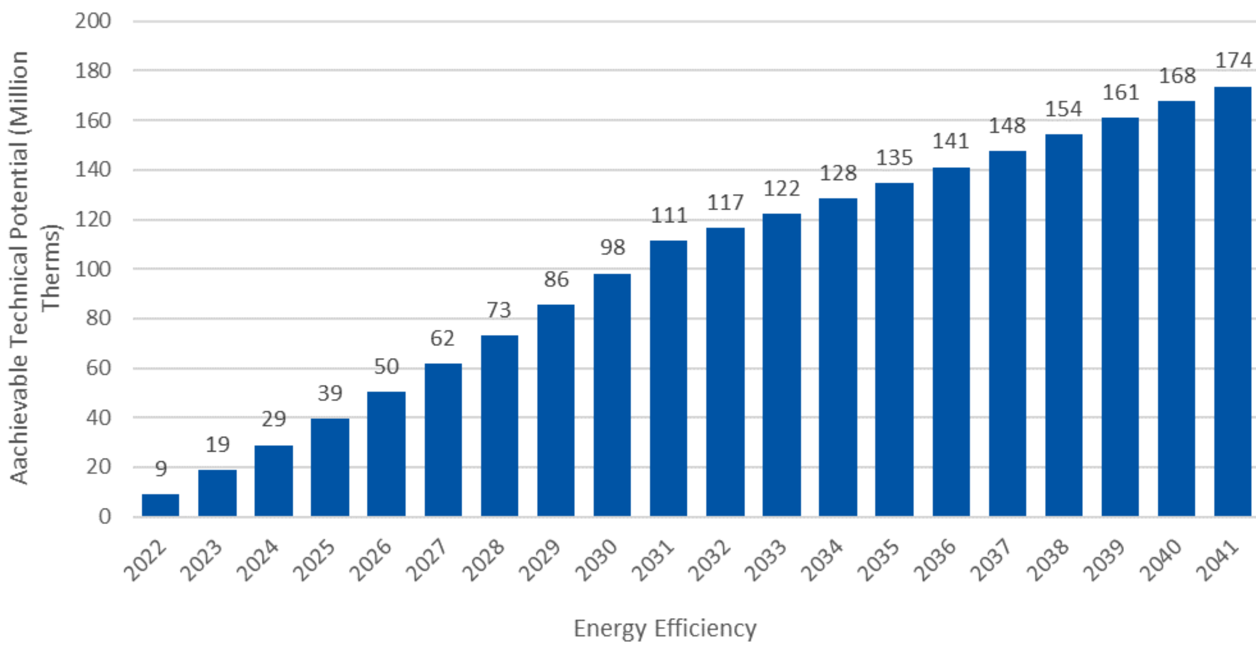


Figure 2. Natural Gas Achievable Potential Forecast, Cumulative 2022 - 2041



Energy Efficiency

The total achievable technical potential for electricity across all sectors is 600 aMW (Table 2). If the 24-year achievable potential is realized it will produce a load reduction equivalent to 18% of PSE's 2045 baseline electric sales. Approximately 56% of this potential is in the residential sector, 42% in the commercial sector, and the remaining 2% in the industrial sector.

Table 2. Electric Energy Efficiency by Sector, Cumulative 2045

Sector	2045 Baseline Sales (aMW)	Achievable Technical Potential	
		aMW	Percentage of Baseline Sales
Residential	1,846	339	18%
Commercial	1,339	250	19%
Industrial	122	10	8%
Total	**3,306**	**600**	**18%**

Cadmus identified approximately 174 million therms of natural gas energy efficiency achievable potential, with 147 million of these savings in the residential sector (Table 3). Overall natural gas achievable potential is equivalent to 15% of PSE's forecasted natural gas sales in 2041. Natural gas potentials were forecast out to 2041 while electricity was forecasted to 2045.

Table 3. Natural Gas Energy Efficiency by Sector, Cumulative 2041

Sector	2041 Baseline Sales (MM Therms)	Achievable Technical Potential	
		MM Therms	Percentage of Baseline Sales
Residential	757	147	19%

Sector	2041 Baseline Sales (MM Therms)	Achievable Technical Potential	
		MM Therms	Percentage of Baseline Sales
Commercial	362	25	7%
Industrial	22	2	8%
Total	**1,141**	**174**	**15%**

Comparison to 2019 CPA – Energy Efficiency

The 2021 energy efficiency analysis incorporates these changes since the completion of PSE's most recent previous CPA in 2019:

- Uses PSE's most recent F2020 Demand Forecast of energy and customers.
- Incorporates assumptions for savings, cost, and measure lives derived from PSE's 2020 measure business cases and RTF unit energy savings (UES) workbook updates as of January 31, 2020
- Uses the most recent PSE-specific and regional stock assessments to determine saturations and applicability, including PSE's 2017 Residential Characteristics Study (RCS), NEEA's 2018 Residential Building Stock Assessment (RBSA), and NEEA's 2014 Commercial Building Stock Assessment (CBSA)
- Accounts for changes to the Washington State Energy Code (WSEC) and Seattle Building Energy Code as well as recent changes to federal and Washington state equipment standards, including products added to state standards by legislation – House Bill 1444 (H.B. 1444) – passed in 2019 and signed into law by Governor Inslee
- Considers the impact of the Washington State Energy Performance Standard (HB1257) on commercial buildings by accelerating ramp rates for some commercial measures

Table 4 compares the 20-year achievable technical potential, expressed as a percentage of baseline sales, identified in the 2021 and 2019 CPAs. Overall, the 2021 CPA identified lower electric (-20%) and slightly lower natural gas (-2%) achievable technical potential.

Table 4. Energy Efficiency Comparison to Past CPAs

Study	20-Year Achievable Technical Potential (Percent of Sales)			Total Achievable Technical Potential (aMW and Million Therms)
	Residential	Commercial	Industrial	
Electric Resources				
2021 IRP	18%	18%	8%	552
2019 IRP	21%	16%	26%	692
Natural Gas Resources				
2021 IRP	19%	7%	8%	174
2019 IRP	20%	8%	17%	177

*This table compares 20-year results from 2021 CPA to the 2019 CPA. The 2021 CPA total electric achievable technical potential differs from the amount shown in Table 2, which presents the full 24-year electric potential study results

The following contribute to the significant decrease in electric energy efficiency potential:

- Exclusion of embedded data center measures which previously contributed 46 aMW of achievable potential in the 2019 CPA
- Updated forecast assumptions of the indoor cannabis market, previously assumed to grow at a rate of 3% per year within PSE's service territory, led to a 25 aMW reduction in potential (compared to the 2019 CPA)
- Incorporation of updated commercial LED lighting technology baselines, based on the Council's draft 2021 plan commercial lighting supply curves, which led to a 25 aMW reduction in potential (compared to the 2019 CPA)
- Re-classification of some industrial customers to the commercial sector
- Reductions in achievable potential due to the 2019 state equipment standards updates (HB 1444)

Combined Heat and Power

Table 5 illustrates the 24-year cumulative achievable technical potential from CHP technologies. Overall, Cadmus identified 7.8 aMW of potential from renewable and nonrenewable technologies.

Table 5. Combined Heat and Power Achievable Potential Summary, Cumulative 2045

CHP Type	Total Achievable Technical Potential (aMW)
Reciprocating Engine	4.0
Gas Turbine	1.1
Microturbine	1.0
Biogas (Anaerobic Digesters)	1.3
Industrial Biomass	0.4
Total	**7.8**

Comparison to 2019 CPA – CHP

Table 6 compares the 24-year cumulative CHP potential identified in the 2019 CPA to the 20-year cumulative CHP potential in the 2021 CPA. The decrease in CHP potential results from a lower, long-term electric commercial customer forecast compared to the 2019 CPA and re-allocation of commercial customer eligibility requirements across commercial building types.

Table 6. CHP Comparison to the 2019 IRP, Cumulative 2045 aMW

CHP Potential	2021 IRP	2019 IRP
Total	7.8	18

Demand Response

Table 7 presents the winter and summer peak achievable potential for demand response programs. Total 24-year winter demand response potential is 229 MW, which is equivalent to nearly a 4.5% reduction in PSE's forecasted 2045 winter peak.

Table 7. Demand Response Potential by Program, 2045

Product	Winter Achievable Potential (MW)	Percent of PSE System Peak (Winter)	Summer Achievable Potential (MW)	Percent of PSE System Peak (Summer)
Residential Critical Peak Pricing	66	1.3%	40	1.0%
Residential DLC Space Heating	53	1.1%	n/a	n/a
Residential DLC Space Cooling	n/a	n/a	55	1.4%
Residential DLC Water Heating	69	1.2%	69	1.7%
Commercial DLC Space Heating	12	0.2%	n/a	n/a
Commercial DLC Space Cooling	n/a	n/a	27	0.7%
Commercial and Industrial Curtailment	6	0.1%	8	0.2%
Commercial Critical Peak Pricing	2	< 0.1%	5	0.1%
Residential Electric Vehicle Service Equipment	9	0.2%	9	0.2%
Residential Behavioral	9	0.2%	5	0.1%
Total	**226**	**4.5%**	**218**	**5.4%**

Comparison to 2019 CPA – Winter Demand Response

Table 8 compares the demand response potential identified in the 2021 and 2019 CPAs, by sector. Overall, the 2021 CPA identified 7 MW less winter peak potential compared to 2019. Even though the total winter peak potential of 2021 and 2019 are comparable, it can be seen that the segment share of that potential has changed. Several factors contributed to higher residential demand response potential, including updates to end-use saturations for water heat, revised peak impacts from recent demand response evaluations, and the inclusion of new products (for instance, the 2021 CPA considered a residential behavioral product that was not considered in the 2019 study).

Table 8. Demand Response Achievable Potential Comparison of 2019 CPA and 2017 CPA

Sector	2021 CPA (MW)	2019 CPA (MW)	2017 CPA (MW)
Residential	206	180	109
Commercial and Industrial	20	53	79
Total	**226**	**233**	**188**

The following contribute to the decrease in commercial and industrial demand response potential:

- Revisions to customer participation assumptions for commercial and industrial demand curtailment, consistent with the Council's draft 2021 Plan demand response supply curves
- Updates to per event demand impacts for commercial and industrial demand curtailment, consistent with the Council's draft 2021 Plan demand response supply curves

Distributed Solar PV and Comparison to the 2019 CPA

Cadmus identified 87 MW of solar PV nameplate capacity achievable potential in the residential sector and 249 MW in the commercial sector (336 MW total). This is higher than the 231 MW of solar PV achievable potential identified in the 2019 assessment (Table 9) and is equivalent to 9.4 aMW and 26.8 aMW of cumulative achievable energy potential for the residential, and commercial sectors, respectively. The increase in solar PV potential is primarily the result of lower estimated costs for residential and commercial systems due to updated data sources.

Table 9. Solar PV Achievable Potential Comparison to 2019 IRP

Sector	Achievable Potential (MW)	
	2021 IRP	2019 IRP
Residential	87	34
Commercial and Industrial	249	196
Total	**336**	**231**

Incorporating DSR into PSE's IRP

The achievable technical potentials for EE and CHP shown above have been grouped by the levelized cost of conserved energy for inclusion in PSE's IRP model. These costs have been calculated over a 24-year program life for electric resources and over a 20-year program life for gas resources; the *Calculate Levelized Costs* section 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 DSR, based on expected load growth, energy prices, and other factors.

Cadmus spread the annual savings estimates over 8760-hour load shapes to produce hourly DSR bundles. In addition, we assumed savings are gradually acquired over the year, as opposed to instantly on the first day of January. PSE provided intra-year DSR acquisition schedules, which we used to ramp hourly savings across months. Figure 3. shows the annual cumulative combined potential for energy efficiency and combined heat and power by each cost bundle considered in PSE's 2021 IRP. Figure 4. shows annual DSR bundles for natural gas energy efficiency.

Figure 3. Electric Supply Curve – Cumulative 24-Year Achievable Potential

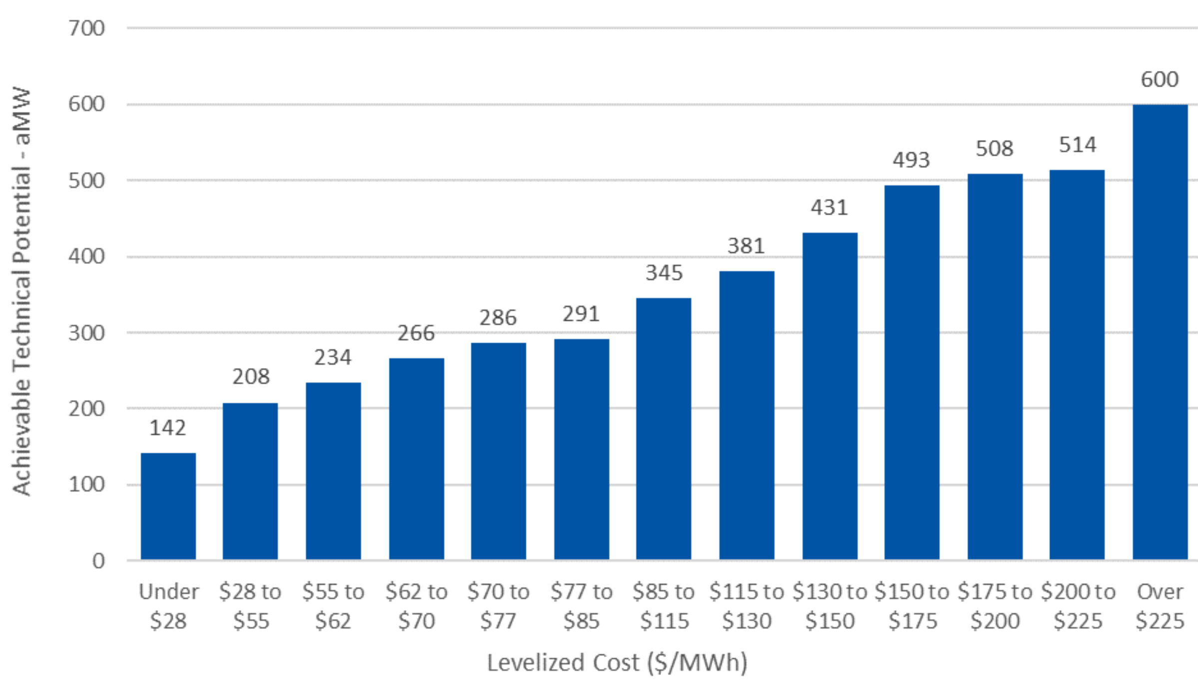
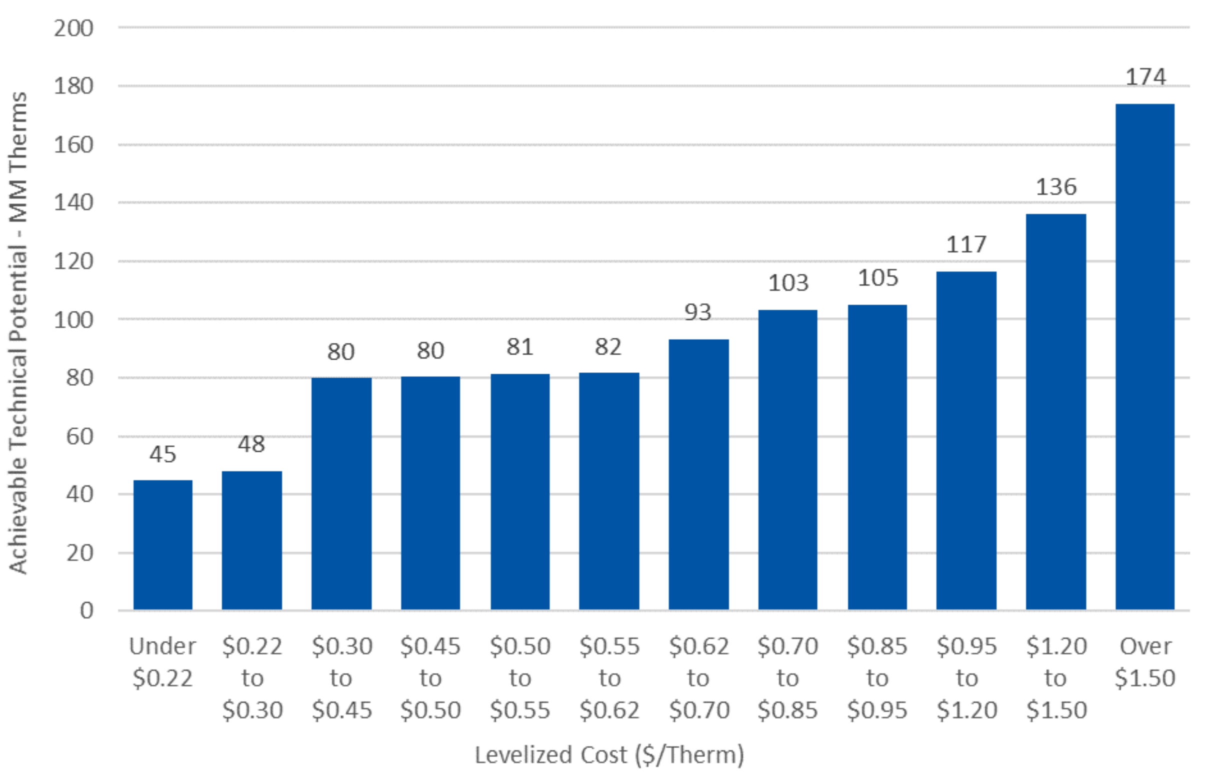


Figure 4. Natural Gas Supply Curve – Cumulative 20-Year Achievable Potential



Similarly, Cadmus spread the annual savings estimates for distributed solar over 8760-hour load shapes to produce hourly DSR bundles. These savings were input without any costs in the IRP, as these programs are customer driven and the IRP does not determine the cost-effective potential; the IRP accounts for the reductions to the demand forecast only.

Finally, the demand response programs are a capacity-only resource and were grouped by program and annual capacity. The capacities are cumulated over each year of the study, and the program costs are input as annual, incremental costs associated with the peak demand reductions that are added in a particular year.

Organization of This Report

This report has been organized in three main sections, and an appendix:

- Energy efficiency and combined heat and power
- Demand response, and
- Distributed solar PV
- Appendix A. IRP Sensitivities

Section 1. Energy Efficiency and Combined Heat and Power

This section describes Cadmus' methodology for estimating demand-side resources (DSR) potential in PSE's service territory between 2022 and 2045 and for developing supply curves for modeling DSR in PSE's integrated resource planning (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. Estimating DSR potential involves analyzing many conservation measures across many sectors, with each measure requiring nuanced analysis. This section does not describe the detailed approach for estimating a specific measure's unit energy savings (UES) or cost, but it does show the general calculations that were used for nearly all measures.

Overview of Technical and Achievable Potential

Cadmus assessed two types of potential—technical and achievable technical. PSE will determine a third potential—achievable economic—through the IRP's optimization modeling. The three types of potential are described as follows:

- ***Technical potential*** assumes that all technically feasible resource opportunities may be captured, regardless of their costs or other market barriers. It represents the total DSR potential in PSE's service territory, after accounting for purely technical constraints.
- ***Achievable technical potential*** is the portion of technical potential that is 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 DSR 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 were then entered as variables in the IRP's optimization model to determine achievable economic potential.

Figure 5. illustrates the three types of energy efficiency potential.

Figure 5. Types of Energy Efficiency Potential

The timing of resource availability is also 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 used a units-based approach to forecast energy efficiency potential in the residential and commercial sectors. This approach involved first estimating the number of units of an energy efficiency measure that are likely to be installed in each year then multiplying these unit forecasts by the measure's UES.

For the industrial sector, Cadmus used a top-down method calculating technical potential as a percentage reduction to the baseline industrial forecast. Baseline end-use loads are first estimated for each industrial segment, then the potential is calculated using estimates of each measures' end-use percentage savings.

Steps for Estimating Energy Efficiency Potential

Cadmus followed this series of steps, described in detail below this list, to estimate energy efficiency potential:

1. ***Market segmentation.*** This involved identifying 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.
2. ***Develop efficiency measure dataset.*** This required research into viable energy efficiency measures 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.
3. ***Develop unit forecasts.*** Unit forecasts vary by sector—number of homes for residential, square footage of floor space for commercial, energy for industrial, and poles for street lighting—and reflect the number of units that could be installed for each measure. Cadmus developed sector-specific methodologies to determine the number of units.
4. ***Calculate levelized costs.*** IRP modeling requires levelized costs for each measure, and in aggregate, to compare energy conservation to supply-side resources. The components and assumptions for the levelized-cost calculations are discussed below.
5. ***Forecast technical potential.*** Technical potential forecasts rely on the sector-specific unit forecasts and the measure data compiled from prior steps. The description below presents the general equation we used for calculating technical potential.
6. ***Forecast achievable technical potential.*** Achievable technical potential forecasts use an equation like the one we used to determine technical potential forecasts, with additional terms (described below) to account for market barriers and ramping.
7. ***Develop IRP inputs.*** Forecasts of achievable technical potential were bundled by levelized costs, so PSE's IRP modelers can consider energy efficiency as a resource within the IRP.

Figure 6. provides a general overview of the process and inputs required to estimate potential and develop conservation supply curves.

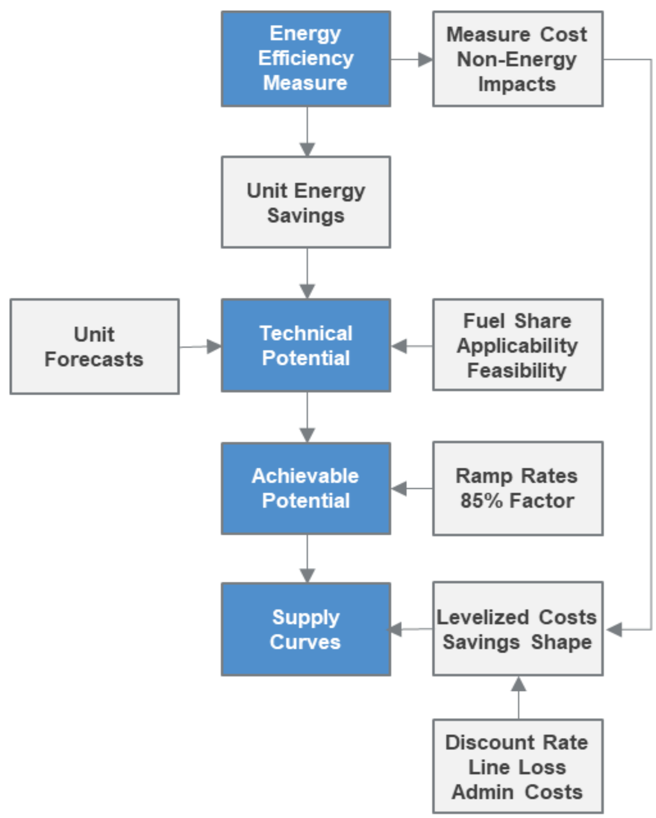


Figure 6. Overview of Energy Efficiency Methodology

Segmentation

Market segmentation involves first dividing PSE's gas and 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's 2014 Commercial Building Stock Assessment (CBSA), the 2018 Residential Building Stock Assessment (RBSA), and PSE's Residential Characteristics Study (RCS).

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

- ***Service territories and fuel.*** PSE's respective natural gas and electric service territories
- ***Sector.*** Residential, commercial, industrial, and street lighting
- ***Industries and building types.*** Three residential (with the corresponding low income (LI)) segments, 19 commercial, 19 industrial, and one street lighting segments

Table 10 lists the segments modeled for each sector.

Table 10. Segments Modeled

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

Energy Efficiency Measure Characterization

Overview and Components

Cadmus compiled energy efficiency datasets that include the UES, costs, measure lives, non-energy impacts, and applicability factors for each energy conservation measure. These datasets include several details for each measure permutation:

- ***Unit energy savings (UES).*** UES are a conservation measure's annual per-unit kilowatt-hour and/or therm savings. Cadmus relied on UES values from PSE's internal measure business cases, RTF UES workbooks, the Seventh Plan, and a limited set of draft 2021 Plan supply curves
- ***Costs and non-energy impacts.*** Costs include the incremental per-unit equipment (capital), labor, annual incremental operations and maintenance (O&M), and periodic (or avoided periodic) re-installation costs associated with installing an energy efficiency measure. Non-energy impacts are the annual dollar savings per year associated with quantifiable non-energy benefits (such as water).
- ***Effective useful lives (EUL).*** EUL is the expected lifetime (in years) for an energy efficiency measure from PSE's measure business cases, the Seventh Plan, draft 2021 Plan, or RTF.
- ***Applicability factors.*** Applicability factors reflect the percentage of installations that are technically feasible and the current saturation of an efficiency measure.
- ***End-use savings percentage (industrial only).*** The industrial sector's top-down approach to estimating potential requires assessments of the end-use percentage savings for each energy conservation measure. We relied on estimates included in the Council's Seventh Plan industrial tool for these values.
- ***Savings shape.*** We assigned an hourly savings shape to each measure, which we then used to disaggregate annual forecasts of potential into hourly estimates.

Accounting for Codes and Standards

Cadmus accounted for building energy codes and equipment standards by either embedding the impact of the standard in the UES estimate for above-standard equipment and/or by excluding measures that will be captured by the current code or standard. Cadmus accounted for the 2018 Washington State energy code (WSEC), effective November 1, 2020 for the residential and commercial sectors.

Table 11 and Table 12 list the federal and state electric and natural gas standards and their effective dates, respectively, that Cadmus considered. Most of these standards have either already been adopted or are scheduled to go into effect before this study's 2022 start date. Thus, equipment that meets the specifications of each respective standard were not included in estimates of energy efficiency potential. Generally, accounting for these standards reduced the total conservation potential.

Table 11. Electric Federal and State Standards

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)	1. Federal standard 2013	Nonresidential	1. January 8, 2013

Equipment Electric Type	New Standard	Sectors Impacted	Study Effective Date
	2. Federal standard 2018		2. January 1, 2018
Computers	State standard 2019	Nonresidential/Residential	January 1, 2021
Dehumidifier	1. Federal standard 2012	Residential	1. October 1, 2012
	2. Federal standard 2019		2. 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 Supplies	1. Federal standard 2016	Nonresidential/Residential	1. February 10, 2016
	2. Federal standard 2017		2. July 1, 2017
	3. State standard 2019		3. January 1, 2021
Freezer	Federal standard 2014	Residential	September 15, 2014
Microwave	Federal standard 2016	Residential	June 17, 2016
Fryers and Steam Cookers	State standard 2019	Nonresidential	January 1, 2021
Refrigerator	Federal standard 2014	Residential	September 15, 2014
Automatic Commercial Ice Makers	1. Federal standard 2010	Nonresidential	1. January 1, 2010
	2. Federal standard 2018		2. January 28, 2018
Commercial Refrigeration Equipment (semi-vertical and vertical cases)	1. Federal standard 2010	Nonresidential	1. January 1, 2010
	2. Federal standard 2012		2. January 1, 2012
	3. Federal standard 2017		3. March 27, 2017
Vending Machine	1. Federal standard 2012	Nonresidential	1. August 31, 2012
	2. Federal standard 2019		2. January 8, 2019
Walk-in Cooler	1. Federal standard 2014	Nonresidential	1. August 4, 2014
Walk-in Freezer	2. Federal standard 2017		2. 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	1. Federal standard 2012	Nonresidential	1. October 8, 2012
	2. Federal standard 2017		2. January 1, 2017
Room Air Conditioner	Federal standard 2014	Residential	June 1, 2014
Single Package Vertical Air Conditioner and Heat Pump	1. Federal standard 2010 (phased in over six years)	Nonresidential	1. January 1, 2010
	2. Federal standard 2019		2. September 23, 2019
Small, Large, and Very Large Commercial Package Air Conditioner and Heat Pump	1. Federal standard 2010	Nonresidential	1. January 1, 2010
	2. Federal standard 2018		2. January 1, 2018
	3. Federal standard 2023		3. January 1, 2023
Fluorescent Lamp Ballast	Federal standard 2014	Nonresidential	November 14, 2014
General Service Fluorescent Lamp	1. Federal standard 2012	Nonresidential	1. July 14, 2012
	2. Federal standard 2018		2. 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	1. Federal standard 2010	Nonresidential	1. December 19, 2010
	2. Federal standard 2016		2. 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

Table 12. Natural Gas Federal and State Standards

Equipment Natural Gas Type	New Standard	Sectors Impacted	Standard Effective Date
Boiler (residential sized)	1. Federal standard 2012	Nonresidential/ Residential	1. September 1, 2012
	2. Federal standard 2021		2. January 15, 2021
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)	1. Federal standard 2013	Nonresidential	1. January 8, 2013
	2. Federal standard 2018		2. January 1, 2018
Dishwasher	Federal standard 2013	Residential	May 30, 2013
Dryer	Federal standard 2015	Residential	January 1, 2015
Furnace (residential sized)	Federal standard 2015	Nonresidential/ Residential	November 19, 2015
Pool Heater	Federal standard 2013	Residential	April 16, 2013
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

Baseline Units Forecast

General Approach

Cadmus developed a 24-year forecast (2022 through 2045) of the number of electric units and a 20-year forecast (2022 through 2041) of the number of gas units that could feasibly be installed for each permutation of each energy efficiency measure researched in the previous step. Separate unit forecasts were developed for two types of lost opportunity measures (natural replacement and new construction) and one type of discretionary measures (retrofit):

- ***Natural replacement (lost opportunity) measures*** are installed when the equipment it replaces reaches the end of its EUL. Examples include appliances (such as clothes washers and refrigerators) and HVAC equipment (such as heat pumps and chillers).
- ***New construction (lost opportunity) measures*** are applied to homes and buildings that will be constructed over the study forecast. The unit forecast for new construction is driven by anticipated new home and new commercial construction, which we derived from utility customer forecasts and draft 2021 Plan regional forecasts.
- ***Retrofit (discretionary) measures*** encompass existing equipment or building upgrades that can theoretically be completed any time over the study forecast. Unlike natural replacement measures, the timing of retrofit savings is not determined by turnover rates. Examples of retrofit measures include weatherization and controls.

To determine measure-specific unit forecasts (used to estimate technical potential), four factors were considered:

- ***Sector unit forecasts*** are estimates of the number of homes (residential) or square footage of floor space (commercial) derived from PSE's customer database and load forecast data.

- ***Measure saturations (units per sector unit)*** are estimates of the number of units per sector unit (per home or per square foot) in PSE's natural gas and electric service territories. Where possible, Cadmus calculated these using data from the PSE 2017 RCS, CBSA, and RBSA.
- ***Applicability factors (technical feasibility percentage and measure competition share)*** are the percentage of homes or buildings that can feasibly receive the measure and the percentage of eligible installations, after accounting for competition with similar measures.
- ***Turnover rates (for natural replacement measures)*** are used to determine the percentage of units that can be installed in each year for natural replacement measures. The turnover rate equals 1 divided by the measure EUL.

Figure 7 illustrates the general equation Cadmus used to determine the number of units for each measure over the study forecast horizon. By default, the turnover rate for retrofit and new construction measures is 100%. (Turnover is not accounted for in these permutations.)

Figure 7. Unit Forecast Equation

To determine unit forecasts, Cadmus relied on data that represent PSE's service territories, as shown in Table 13. Following the table, we describe our approach for developing unit forecasts in each sector.

Table 13. Unit Forecast Components and Data Sources

Component	Data Source
Sector Units	PSE and U.S. Energy Information Administration (EIA) 861 data; U.S. Census Bureau American Community Survey; PSE RCS sample design file; PSE CIS data
Saturation	PSE 2017 RCS; Regional stock assessments (RBSA and CBSA)
Applicability Factor	PSE 2017 RCS; Regional stock assessments (RBSA and CBSA)
Turnover Rate	PSE, RTF, draft 2021 Plan, and Seventh Plan measure workbooks

Calculate Levelized Costs

Identified potential is grouped by levelized cost over a 24-year study horizon for electric resources and a 20-year horizon for natural gas resources, which allows PSE's IRP model to pick the optimal DSR amount, given various assumptions regarding future resource requirements and costs. The 24-year electric levelized-cost and 20-year natural gas levelized-cost calculations incorporate numerous factors, which are consistent with the Council's methodology and shown in Table 14.

Table 14. Levelized Cost Components

Type	Component
Costs	Incremental Measure Cost
	Incremental O&M Cost*
	Administrative Adder
Benefits	Present Value of Non-Energy Benefits
	Present Value of T&D Deferrals**
	Conservation Credit
	Secondary Energy Benefits

*Some measures may have a reduction in O&M costs, which is a benefit in the levelized cost calculation.
**For natural gas, this includes the deferred gas distribution benefits

In addition to the upfront capital cost and annual energy savings, the levelized-cost calculation incorporates several other factors, consistent with the Council's methodology:

- ***Incremental measure cost.*** This study considers the costs required to sustain savings over a 24-year horizon, including reinstallation costs for measures with useful lives less than 24 years. If a measure's useful life extends beyond the end of the 24-year study, Cadmus incorporates an end effect that treats the levelized cost of that measure over its EUL as an annual reinstallation cost for the remainder of the 24-year period.[1,2,3]

  For example, Figure 8 shows the timing of initial and reinstallation costs for an electric measure with a ten-year lifetime in context with the 24-year electric study horizon. The measure's final lifetime in this study ends after the study horizon, so the final four years (Year 21 through Year 24) are treated differently by leveling measure costs over its ten-year useful life and treating these as annual reinstallation costs.

Figure 8. Illustration of Capital and Reinstallation Cost Treatment

	Year																							
Component	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Initial Capital Cost																								
Re-Installation Cost																					End Effect			

- ***Incremental operations and maintenance (O&M) benefits or costs.*** As with incremental measure costs, O&M costs are considered annually over the 24-year horizon. The present value

1 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%).

2 This method is applied both to measures with a useful life of greater than 24 years and measures with a useful life that extends beyond study horizon at time of reinstallation.

3 This method also applies to the 20-year natural gas study horizon.

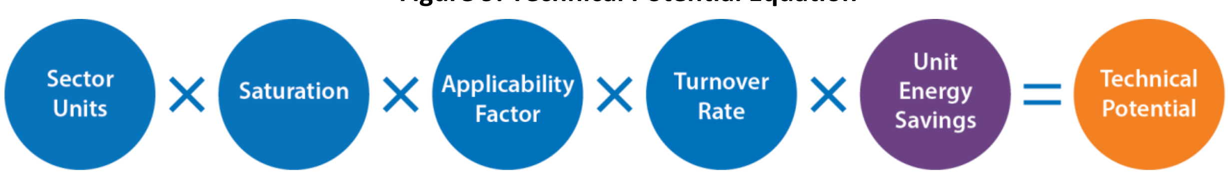
is used to adjust the levelized cost upward for measures with costs above baseline technologies and downward for measures that decrease O&M costs.

- ***Administrative adder.*** Cadmus assumed a program administrative cost equal to 20% of incremental measure costs for electric and gas measures across all sectors.
- ***Non-energy benefits.*** These benefits are treated as a reduction in levelized costs for measures that save resources, such as water or detergent. 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 regional 10% conservation credit, capacity benefits during PSE's system peak, and transmission and distribution (T&D) deferrals.*** These are similarly treated as reductions in levelized cost for electric measures. The addition of this credit per the Northwest Power Act is consistent with Council's methodology and is effectively an adder to account for unquantified external benefits of conservation when compared to other resources.[4]
- ***Secondary energy benefits.*** These benefits are treated as a reduction in levelized costs for measures that save energy on secondary fuels. This treatment is necessitated by Cadmus' end-use approach to estimating technical potential. For example, consider the cost for R-60 ceiling insulation for a home with a gas furnace and an electric cooling system. For the gas furnace end use, Cadmus considers the energy savings that R-60 insulation produces for electric cooling systems, conditioned on the presence of a gas furnace, as a secondary benefit that reduces the levelized cost of the measure. This adjustment impacts only the measure's levelized costs; the magnitude of energy savings for the R-60 measure on the gas supply curve is not impacted by considering secondary energy benefits.

Forecast Technical Potential

After compiling UES estimates and developing unit forecasts for each permutation of each energy efficiency measure, Cadmus multiplied the two to create 24-year forecasts of technical potential beginning in 2022. Figure 9 shows the equation for calculating technical potential. Blue components make up the measure unit calculation (shown previously in Figure 7.).

Figure 9. Technical Potential Equation



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

Forecast Achievable Potential

Achievable technical potential equals the product of a unit forecast, the measure UES, the maximum achievability factor, and ramp rate factors (Figure 10). Blue components are a part of the measure unit calculation. The purple component is a part of the technical potential calculation. The blue, purple, and orange components make up the achievable potential calculation.

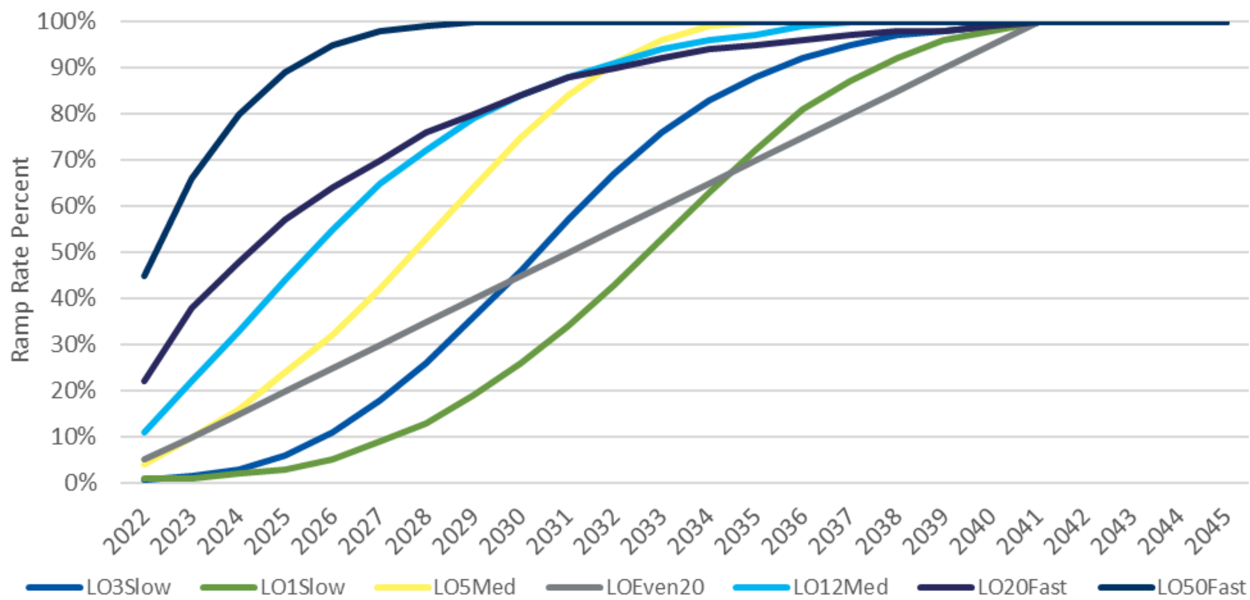
Figure 10. Equation for Estimating Achievable Technical Potential

As illustrated in Figure 10, achievable technical potential is the product of technical potential and both the maximum achievability factor and the ramp rate percentage. Cadmus used maximum achievability factors from the Council's draft 2021 Plan supply curves. Ramp rates are measure-specific and were based on the ramp rates developed for the Council's draft 2021 Plan supply curves but were adjusted to account for this study's 2022 to 2045 horizon.

For discretionary measures, Cadmus assumed all savings are acquired at an even rate over the first 10 years of the study. In other words, achievable potential for discretionary measures equals one-tenth of the total cumulative achievable potential in each of the first 10 years of the study (2022 through 2031). After 2031, there is no additional potential from discretionary measures.

For lost opportunity measures, we used the same ramp rates as those developed by the Council for its draft 2021 Plan supply curves. However, the draft 2021 Plan ramp rates cover only the 2022 to 2041 period of this study's horizon. Because nearly all lost opportunity ramp rates approach 100%, we set ramp values for 2041 through 2045 to equal the 2041 value from the Council's draft 2021 Plan. Figure 11 illustrates the lost opportunity ramp rates.

Figure 11. Lost Opportunity Ramp Rates



Develop IRP Inputs

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 and monthly forecasts of gas potential. To produce these hourly forecasts, we applied hourly end use load profiles 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 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 15 and Table 16. Whereas the 2019 CPA included only 10 bundles – with the highest cost bundle representing energy efficiency potential at a net total resource cost (TRC) levelized cost greater than $150 per megawatt-hour – the 2021 CPA update includes three additional bundles which add greater granularity for more expensive resources. The number and delineating values of the natural gas levelized cost bundles remain unchanged from the 2019 CPA.

Table 15. 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

Bundle	Electric Bundle ($/kWh)
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

Table 16. Natural Gas Levelized Cost Bundles

Bundle	Natural Gas Bundle ($/Therm)
1	($9,999.00) to $0.22
2	$0.22 to $0.30
3	$0.30 to $0.45
4	$0.45 to $0.50
5	$0.50 to $0.55
6	$0.55 to $0.62
7	$0.62 to $0.70
8	$0.70 to $0.85
9	$0.85 to $0.95
10	$0.95 to $1.20
11	$1.20 to $1.50
12	$1.50 to $999.00

Energy Efficiency Potential

Scope of Analysis

PSE requires accurate estimates of technically-achievable energy efficiency potential because they are essential for its IRP and program planning efforts. PSE then bundles these potentials in terms of levelized costs of conserved energy so the IRP model can determine the optimal amount of energy efficiency potential PSE should select.

To support these efforts, Cadmus performed an in-depth assessment of technical potential and achievable technical potential for electric and natural gas resources in the residential, commercial, and industrial sectors. The next section is in two parts—the first summarizes resource potential by fuel and sector and the second presents detailed results by fuel and sector.

Summary of Resource Potential – Electric

Table 17 shows 2045 forecasted baseline electric sales and potential by sector.[5] Cadmus' analysis indicates that 706 average megawatts (aMW) of technically feasible electric energy efficiency potential will be available by 2045, the end of the 24-year planning horizon, which translates to an achievable

[5] 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.

technical potential of 600 aMW. Should all this potential prove cost-effective and realizable, it will result in an 19% reduction in 2045 forecasted retail sales.

Table 17. Electric 24-Year Cumulative Energy Efficiency Potential

Sector	2045 Baseline Sales (aMW)	Achievable Technical Potential	
		aMW	Percentage of Baseline Sales
Residential	1,846	339	18%
Commercial	1,339	250	19%
Industrial	122	10	8%
Total	**3,306**	**600**	**19%**

Figure 12 shows each sector's relative share of the overall electric energy efficiency achievable technical potential. The residential sector accounts for roughly 57% of the total electric energy efficiency achievable technical potential, followed by the commercial (42%) and industrial (2%) sectors.

Figure 12. Electric 24-Year Achievable Technical Potential by Sector

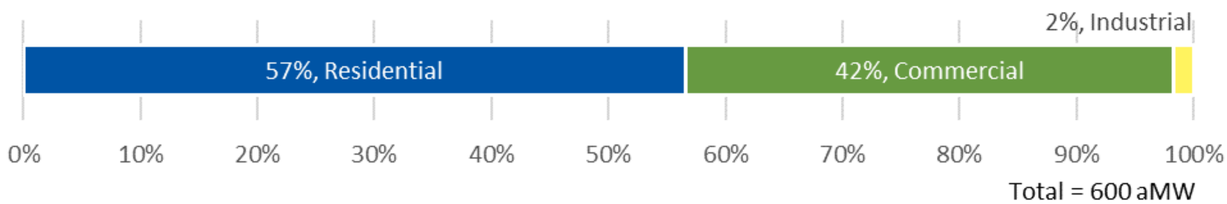


Figure 13 shows the relationship between each sector's cumulative (through 2045) electric energy efficiency achievable technical potential and the corresponding cost of conserved electricity.[6] For example, approximately 431 aMW of achievable technical potential exists, at a cost less than $150 per MWh.

[6] In calculating 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 13. Electric 24-Year Cumulative Energy Efficiency Supply Curve

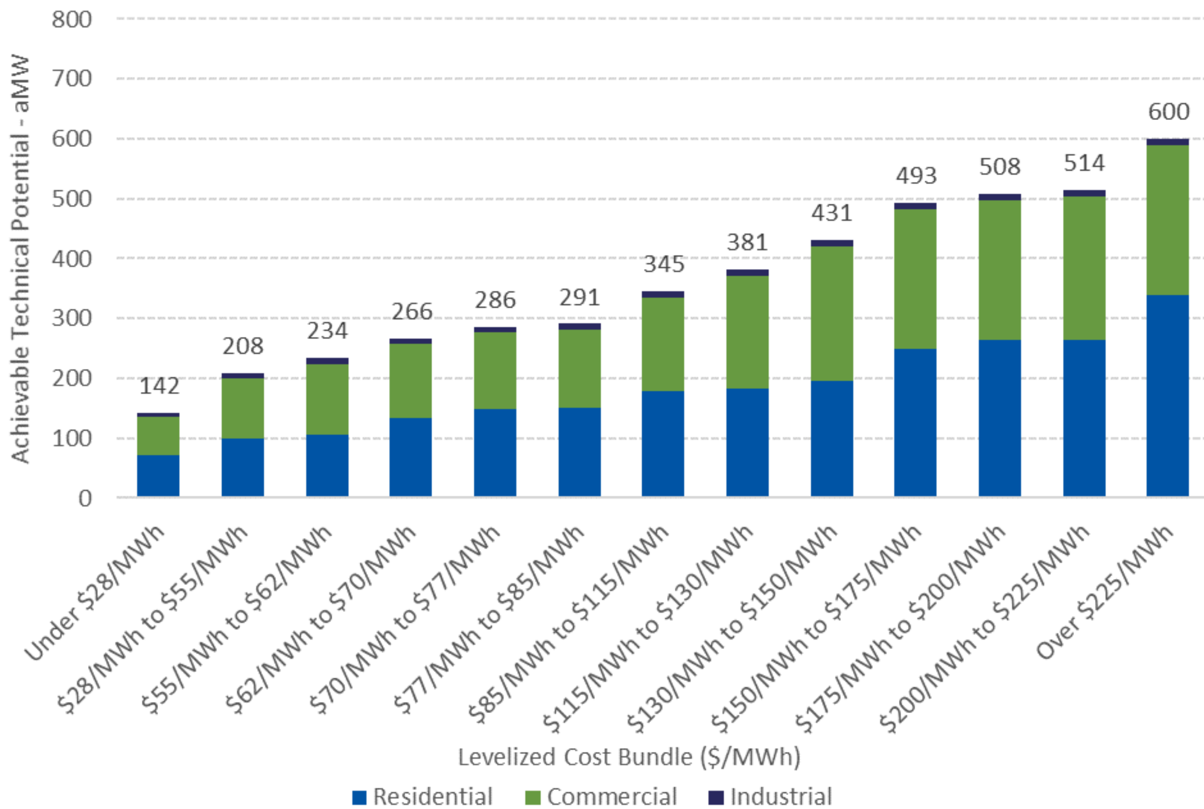
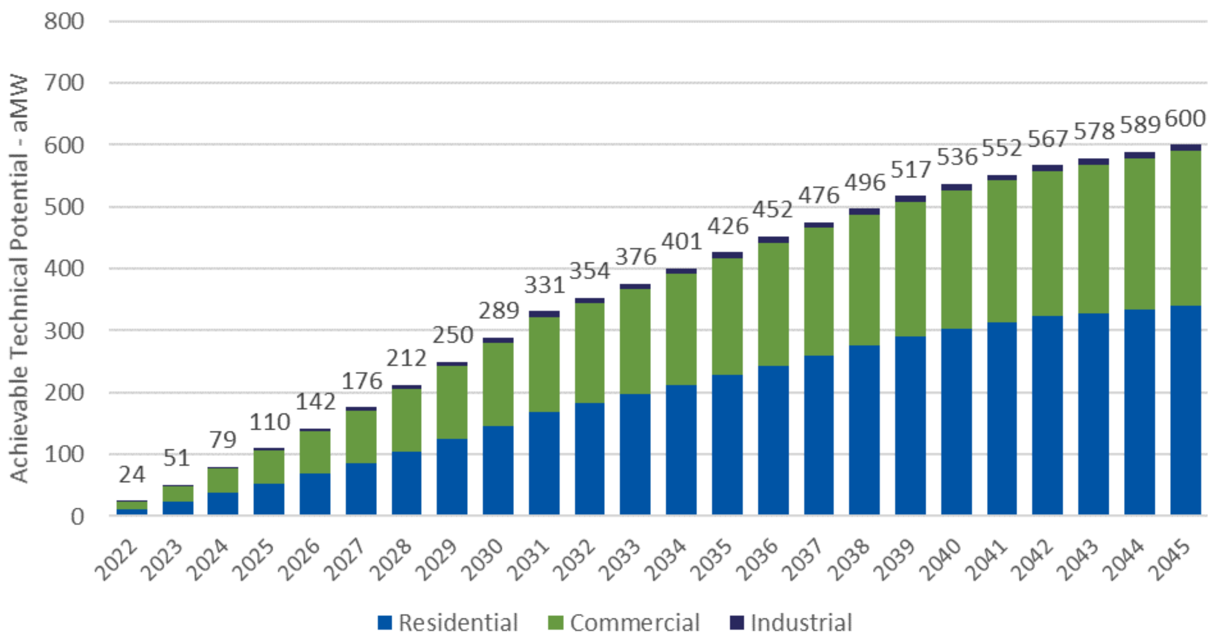


Figure 14 illustrates the cumulative potential annually available in each sector. The study assumes all discretionary resources will be acquired on a 10-year schedule between 2022 and 2031. The 10-year acceleration of discretionary resources will lead to the change in slope after 2031, at which point lost opportunity resources offer the only remaining potential.

Figure 14. Electric Energy Efficiency Potential Forecast



Summary of Resource Potential – Gas

Table 18 lists the 2041 forecasted baseline natural gas sales and potential by sector. The study results indicate roughly 174 million therms of achievable technical energy efficiency potential by 2041, the end of the 20-year planning horizon. Should all this potential prove cost-effective and realizable, it will amount approximately to a 15% reduction in 2041 forecasted retail sales.

Table 18. Natural Gas 20-Year Cumulative Energy Efficiency Potential

Sector	2041 Baseline Sales (MM Therms)	Achievable Technical Potential	
		MM Therms	Percentage of Baseline Sales
Residential	757	147	19%
Commercial	362	25	7%
Industrial	22	2	8%
Total	**1,141**	**174**	**15%**

Figure 15 shows the cumulative annual potential through 2041 available in each sector. The residential sector dominates natural gas potential with nearly 82% of total cumulative achievable technical potential, followed by commercial (17%) and industrial (1%).

Figure 15. Natural Gas 20-Year Achievable Technical Potential by Sector

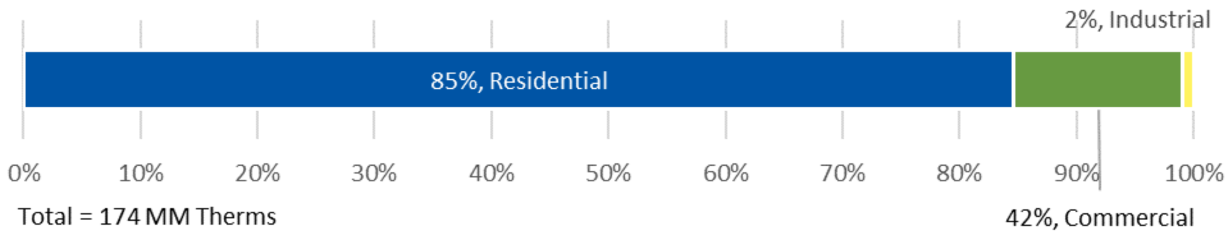


Figure 16 illustrates the relationship between identified natural gas achievable technical potential and its corresponding cost of conserved energy. For example, roughly 105 million therms of achievable technical potential will be available at a cost of less than $0.95 per therm.

Figure 16. Natural Gas 20-Year Cumulative Energy Efficiency Supply Curve

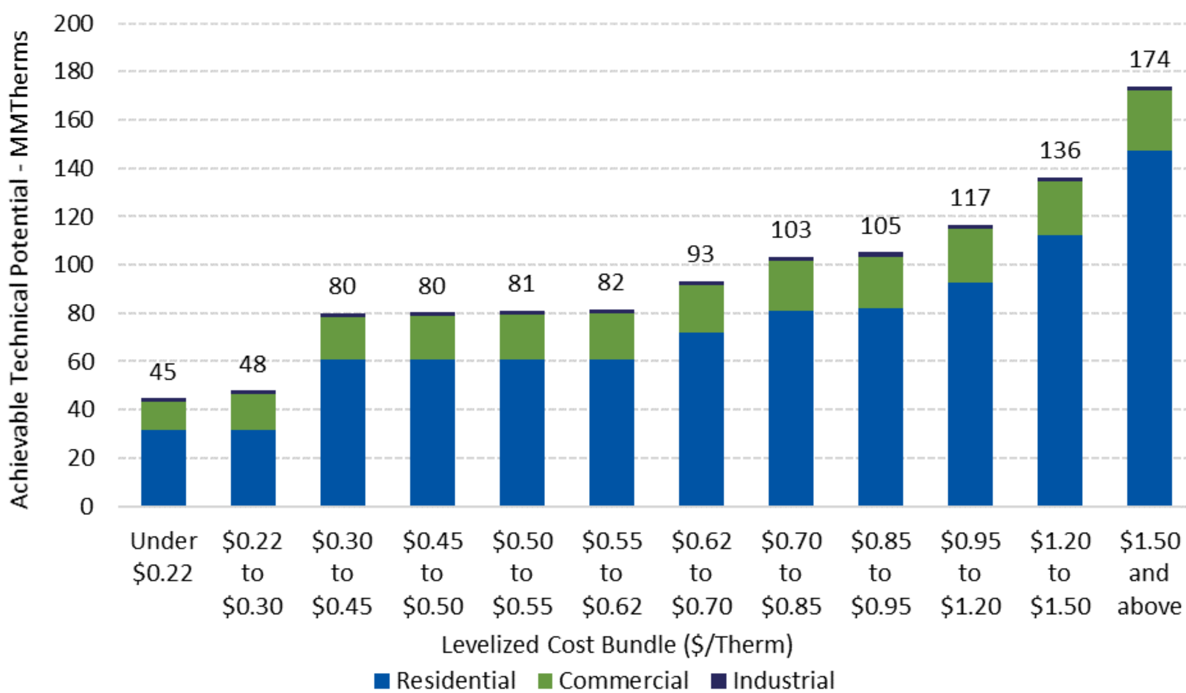
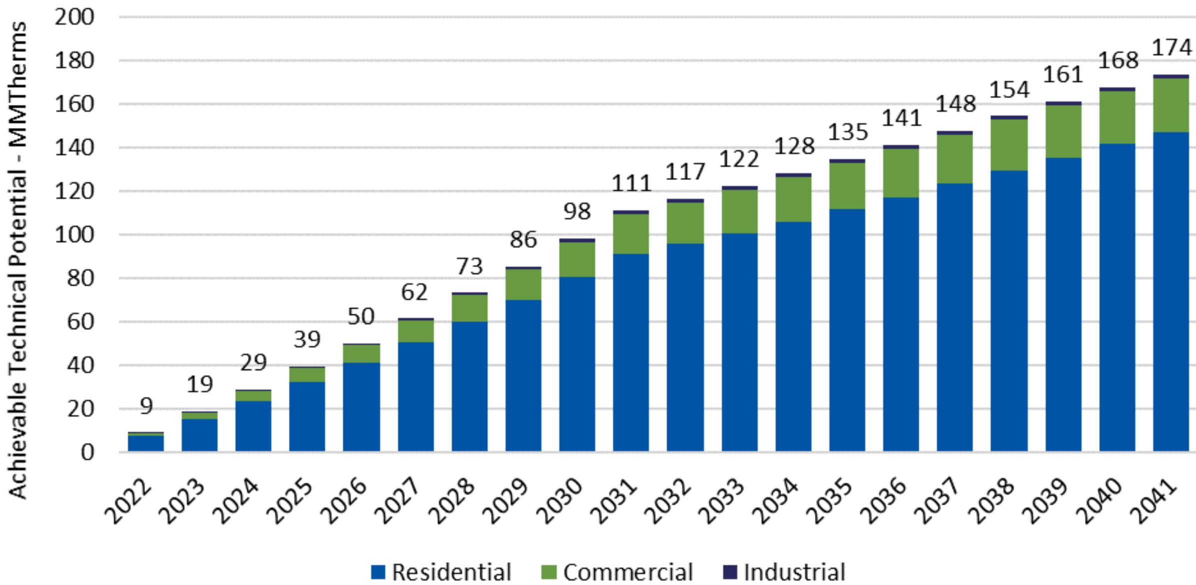


Figure 17 shows the cumulative potential available annually in each sector. As with electric potential, the study assumes all achievable discretionary opportunities will be acquired over the first 10 years of the study, from 2022 through 2031. Therefore, nearly 64% (111 MM therms) of the total natural gas achievable technical potential (174 MM therms) is achieved in the first ten years.

Figure 17. Natural Gas Energy Efficiency Potential Forecast



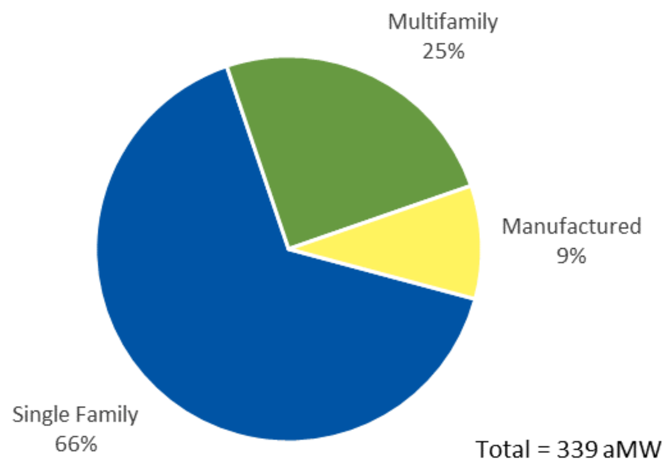
Detailed Resource Potential – Electric

Residential Sector – Electric

By 2045, residential customers in PSE's service territory will likely account for approximately 56% 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 (e.g., heat pumps, refrigerators), improvements to building shells (e.g., insulation, windows, air sealing), and increases in domestic hot water efficiency (e.g., heat pump water heaters).

As shown in Figure 18., single-family homes represent 66% of the total achievable technical residential electric potential, followed by multifamily (25%) and manufactured homes (9%). 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 play an important role in determining potential.

Figure 18. Residential Electric Achievable Potential by Segment



For example, a higher percentage of manufactured homes use electric heat than do other home types, 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 (42%) of achievable technical potential. Appliances and water heating each also represent 15% and 14% respectively of the total identified potential (Figure 19). Lighting, an end use with considerably higher amounts of energy efficiency potential in previous PSE studies, comprises only 1% of the total residential electric energy efficiency potential due to the updated Washington State standard (H.B. 1444) and greater penetration of screw-based LEDs in recent years. The total achievable technical potential for residential increases to 339 aMW over the study horizon (Figure 20).

Figure 19. Residential Electric Achievable Potential by End Use

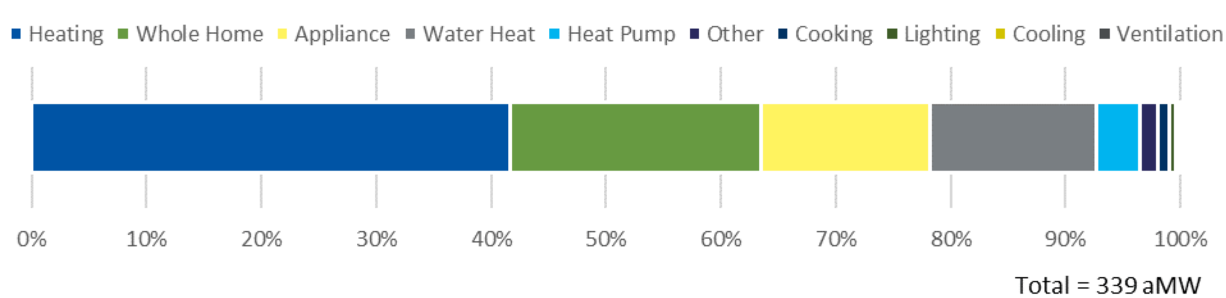


Figure 20. Residential Electric Achievable Potential Forecast

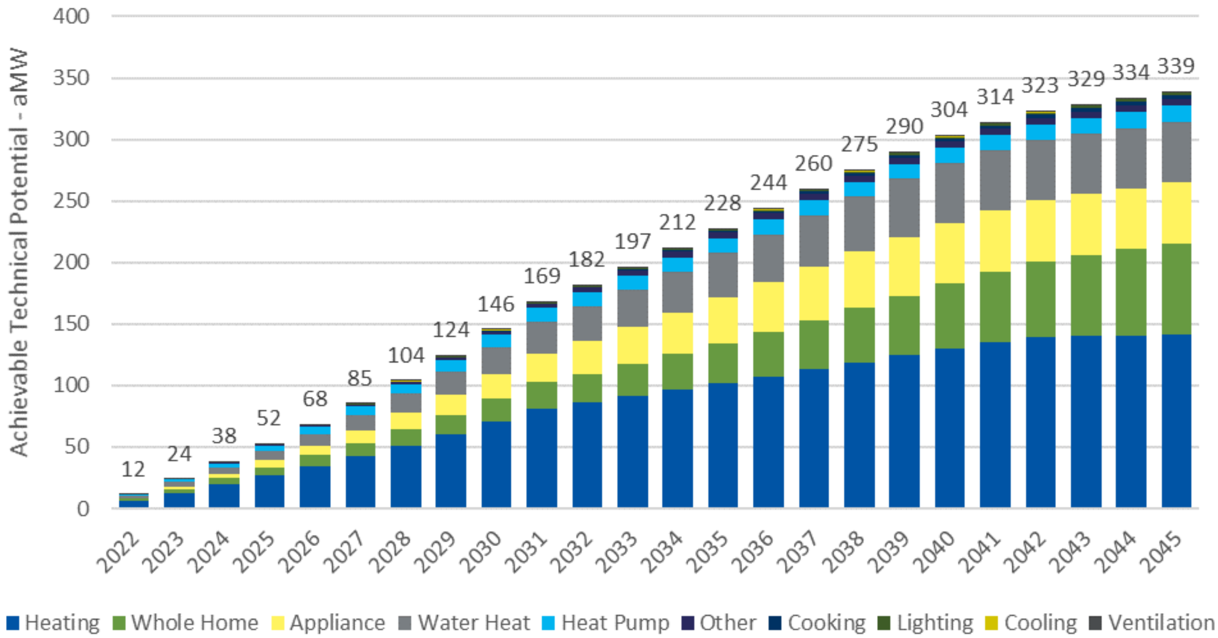


Table 19 lists the top 15 residential electric energy efficiency measures ranked in order of cumulative 24-year achievable technical potential. Combined, these 15 measures account for roughly 294 aMW, or approximately 87% of the total residential electric achievable technical potential. Various ductless heat pumps applications represent the measure group with the highest energy savings and eight of the top 15 measures reduce electric heating loads. These measures include equipment measures (i.e., ductless heat pumps and air-source heat pumps) and retrofit measures (i.e., windows, web-enabled thermostats, infiltration reduction, duct sealing, and wall insulation).

Table 19. Top Residential Electric Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 24-Year Achievable Technical Potential (aMW)
Ductless Heat Pump	16.3	58.0
Whole Home	5.2	57.7
Heat Pump Water Heater	11.2	34.5
Window	26.3	26.3
Clothes Dryer	8.2	17.0
Home Energy Report	16.6	16.6
Heat Pump	4.9	17.7
Clothes Washer	5.9	14.2
Refrigerator	5.1	12.7
Thermostat	9.5	9.5
Solar Water Heater	3.9	3.9
Ground Source Heat Pump	0.7	8.1
Duct Sealing and Insulation	5.4	5.4
Wall Insulation	7.2	7.2
Duct Sealing	4.9	4.9

Residential Low Income – Electric

In addition to estimating potential for each residential housing segment, Cadmus also estimated potential for low income customers within PSE's electric service territory. Our team derived estimates of low income customers using income and housing sector variables from PSE's 2017 RCS. Based on PSE qualifying monthly income limit from PSE's Weatherization Assistance program. Varies by number of household occupants and 2016 annual household income (before taxes) from PSE's 2017 RCS. Table 20 provides the percent each residential sector's low income customers.

Table 20. PSE Low Income Customers - Electric Service

Segment	Electric Low Income Customers as a Percent of Total Electric Housing Segment Customers
Single Family	15.4%
Multifamily	24.4%
Manufactured	35.6%

Cadmus derived unit energy savings estimates specifically for low income customers using low income specific measures from PSE's business cases. Low income customer specific measures included the following:

- Weatherization. Attic, floor, and wall insulation, whole-home ventilation, and air/duct sealing
- Water heating. Tier 3 heat pump water heaters and low-flow showerheads and aerators
- HVAC equipment. Ductless heat pumps and air source heat pumps
- Smart thermostats, refrigerator replacements, and mobile home replacements

The study also apportioned savings from non-low income specific measures to low income customers for other measures, including:

- clothes dryers and clothes washers
- advanced power strips
- home energy reports
- refrigerator/freezer recycling
- freezers
- ovens and microwaves

Table 21 shows the cumulative 10-year (through 2031) and 24-year (through 2045) achievable technical potential for PSE's low income customers by housing segment.

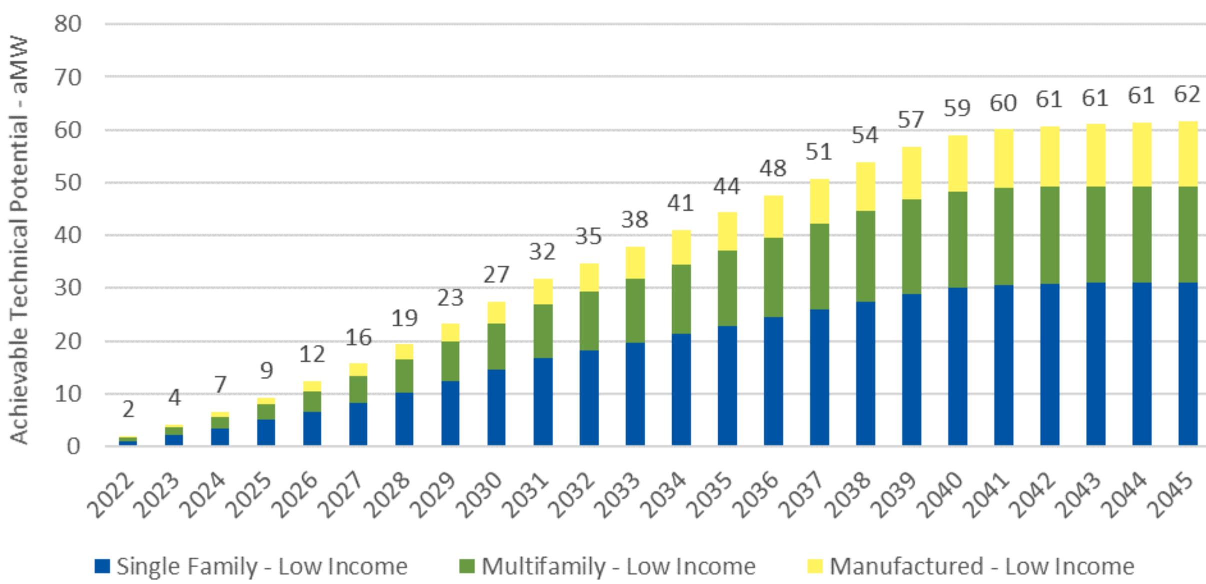
Table 21. Residential Low Income Customer Potential - Electric

Segment	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 24-Year Achievable Technical Potential (aMW)
Single Family - Low Income	16.8	31.0
Multifamily - Low Income	10.2	18.2

Segment	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 24-Year Achievable Technical Potential (aMW)
Manufactured - Low Income	4.8	12.3
Total	**31.8**	**61.6**

Figure 21 provides the cumulative residential low income electric achievable potential forecast by housing segment. The potentials shown in Figure 20 include the low income customer potential shown in Figure 21.

Figure 21. Residential Low Income Electric Achievable Potential Forecast

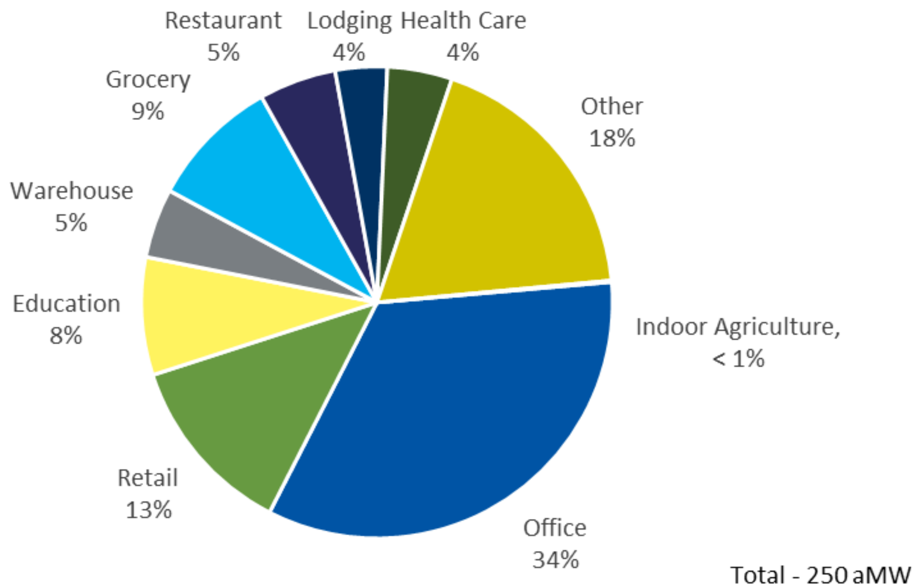


Commercial Sector - Electric

Based on the energy efficiency measure resources used in this assessment, electric energy efficiency achievable technical potential in the commercial sector will likely be 250 aMW over 24 years, which is approximately a 19% reduction in forecasted 2045 commercial sales.

As shown in Figure 22, the Office and Other segments represent 34% and 19%, respectively, of the total commercial achievable technical potential; no other single commercial segment represents more than 12% of commercial achievable technical potential. The Other segment includes customers that do not fit into any of the other categories and customers with insufficient information for classification.

Figure 22. Commercial Electric Achievable Potential by Segment



As shown in Figure 23, lighting efficiency improvements represent the largest portion for achievable technical end use savings potential in the commercial sector (39%), followed by other (29%), and cooling (8%) end uses. Lighting potential includes bringing existing buildings to code and exceeding code in new and existing structures. Figure 24 presents the cumulative electric commercial end use achievable technical by end use.

Figure 23. Commercial Electric Achievable Potential by End Use

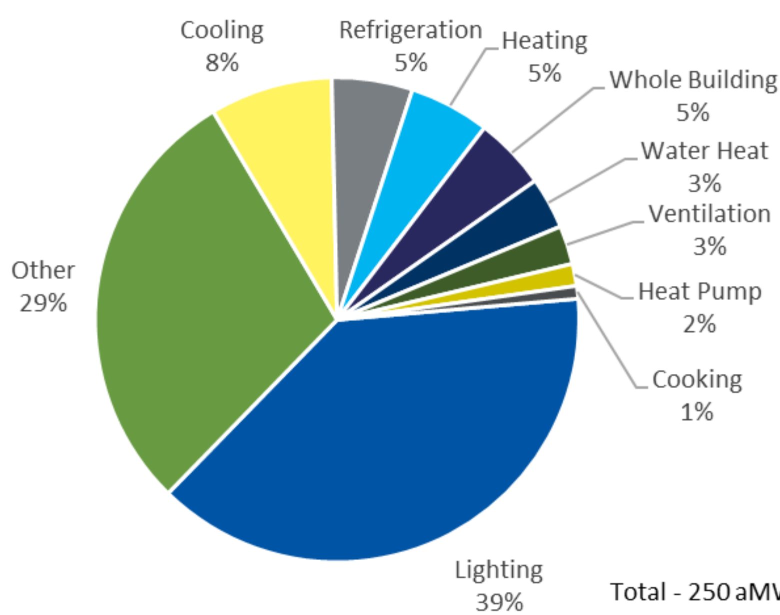


Figure 24. Commercial Electric Achievable Potential Forecast

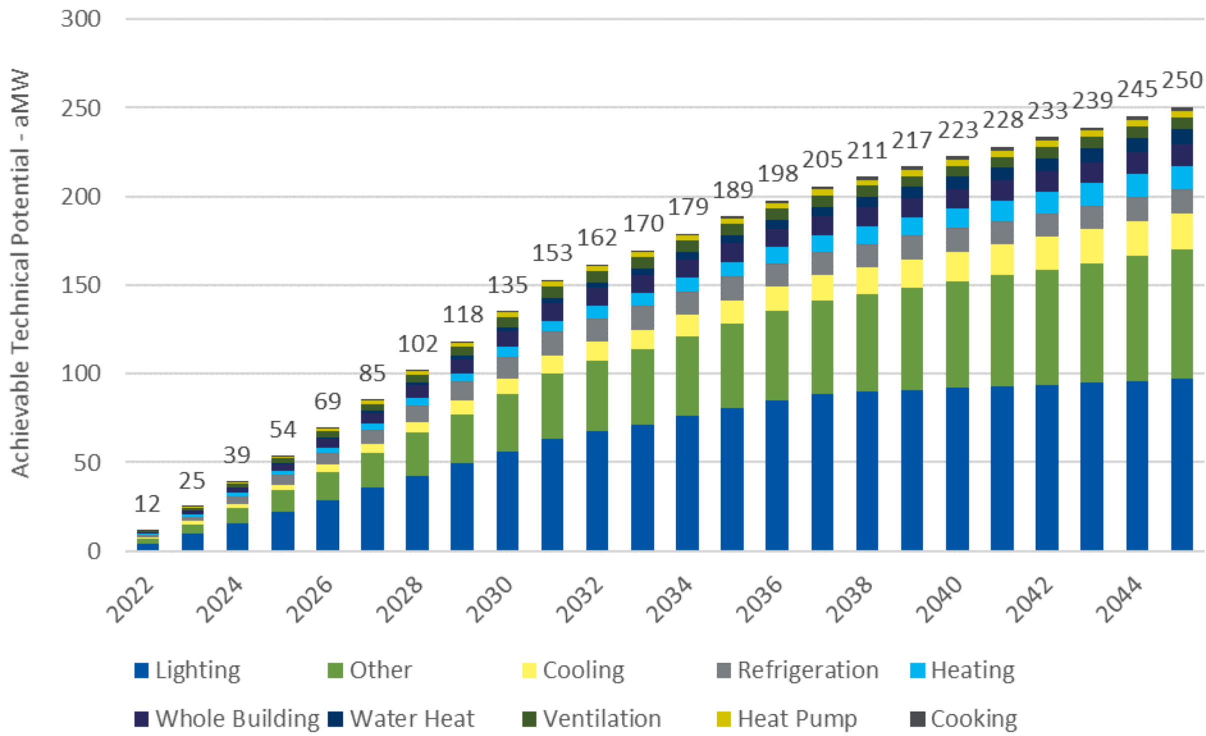


Table 22 lists the top 15 commercial electric energy efficiency measures ranked in order of cumulative 24-year achievable technical potential. Combined, these 15 measures account for 177 aMW, or approximately 71% of the total electric commercial achievable technical potential. Commercial LED lighting measures, including linear fixtures, high bay, and “other” applications including some measures falling outside of the top 15 commercial measures, account for approximately 97 aMW, or 39% of total commercial electric energy efficiency potential.

Table 22. Top Commercial Electric Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 24-Year Achievable Technical Potential (aMW)
LED Panel	27.5	44.8
Variable Speed Efficient Motor	11.6	40.4
Linear LED	7.7	18.4
Variable Refrigerant Flow	4.4	10.6
Wastewater	9.6	9.6
High Bay LED Panel	5.2	8.1
Circulator Pump (bronze or stainless, learning-run hours)	7.1	7.1
Refrigeration – Electrically Commutated Motor	6.7	6.7
Pool Heat Recovery	5.7	5.7
Showerhead	5.2	5.2
Commercial Strategic Energy Management	4.2	4.9
Parking Garage Lighting	4.5	4.5
LED Sign	4.5	4.5
Residential-type Advanced Heat Pump Water Heater EF2.8	1.0	4.3
LED Other	4.2	4.2

Industrial Sector – Electric

This study estimates technical and achievable technical energy efficiency potential for major end uses in 19 major industrial sectors Across all industries, achievable technical potential is approximately 10 aMW over the 24-year planning horizon, corresponding to an 8% reduction of forecasted 2045 industrial electric retail sales.

Figure 25 shows 24-year electric industrial achievable technical potential by segment. Miscellaneous manufacturing represents 29% of the total electric industrial achievable technical potential, followed by streetlighting (26%), food manufacturing (17%), and wood manufacturing (8%). No other industry represents more than 5% of industrial electric potential.

Figure 25. Industrial Electric Achievable Technical Potential Forecast

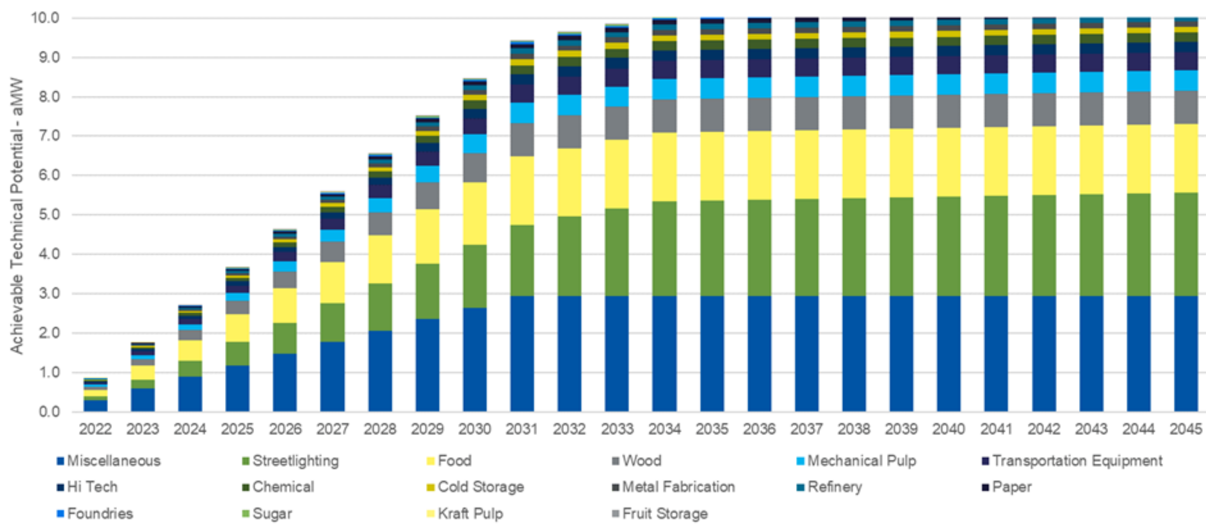


Table 23 presents electric cumulative 24-year achievable technical potential for the top 15 measures in the industrial sectors. Cadmus derived these measures from the Council's Seventh Power Plan and the top three measures combined—plant energy management, streetlighting, and energy project management—equal approximately 2.7 aMW of achievable technical potential, or roughly 27% of the industrial total.

Table 23. Top Industrial Electric Measures

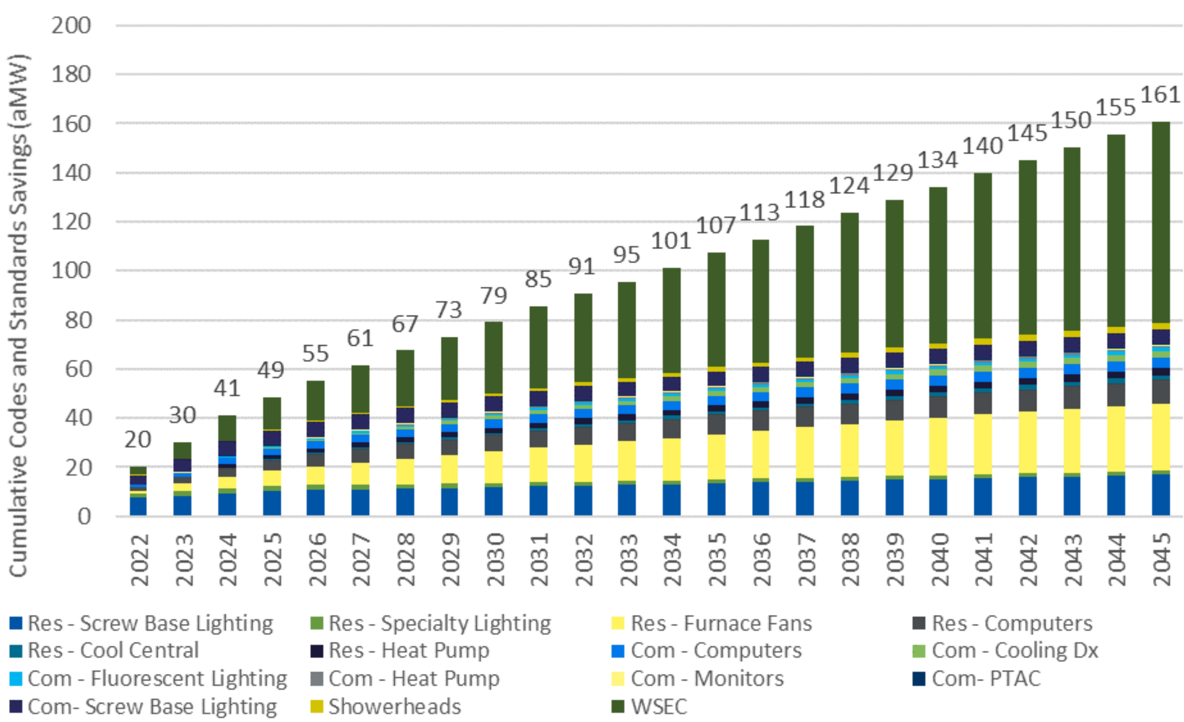
Reporting Group	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 24-Year Achievable Technical Potential (aMW)
Plant Energy Management	1.1	1.1
Streetlight - MH 400W - NR	0.7	0.9
Energy Project Management	0.7	0.7
Fan System Optimization	0.6	0.6
Integrated Plant Energy Management	0.6	0.6
Fan Equipment Upgrade	0.6	0.6
Pump System Optimization	0.5	0.5
Pump Equipment Upgrade	0.5	0.5

Reporting Group	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 24-Year Achievable Technical Potential (aMW)
Streetlight - HPS 250W - NR	0.3	0.4
Streetlight - HPS 100W - NR	0.3	0.4
Wood: Replace Pneumatic Conveyor	0.3	0.3
Clean Room: Change Filter Strategy	0.3	0.3
Material Handling VFD2	0.3	0.3
Streetlight - MH 200W - NR	0.2	0.2
Food: Cooling and Storage	0.2	0.2

Codes and Standards – Electric

Figure 26 presents naturally occurring savings in PSE's service area from Washington state energy codes and equipment standards and federal equipment standards. Overall, the Washington State Energy Code (WSEC) accounts for roughly two-thirds of total electric codes and standards savings, with approximately 82 aMW over the 24-year study horizon. Of these 82 aMW, the commercial WSEC accounts for roughly 35 aMW, whereas the residential WSEC accounts for approximately 47 aMW.

Figure 26. Electric Codes and Standards Potential Forecast



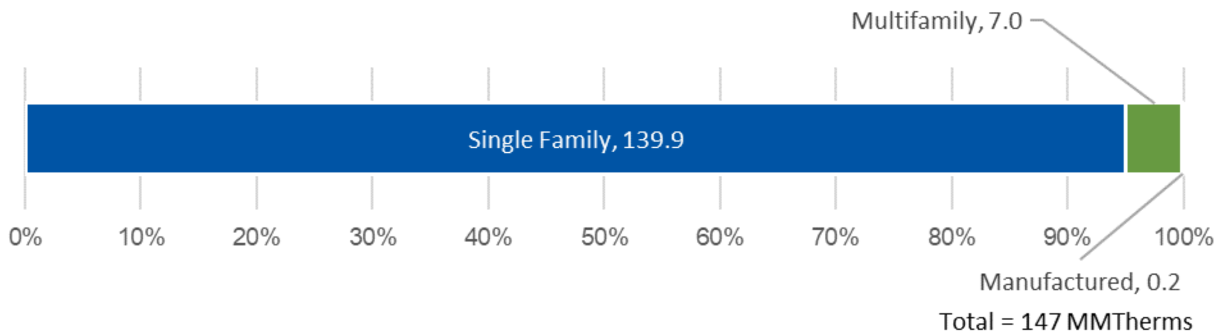
Detailed Resource Potential – Gas

Residential Sector - Gas

By 2041, residential customers will likely account for approximately 67% of PSE's natural gas sales. Unlike residential electricity consumption, there are relatively few natural gas-fired end uses (primarily space heating, water heating, and appliances including dryers and stove tops). Nevertheless, significant available energy savings opportunities remain. Based on the energy efficiency measures used in this assessment, achievable technical potential in the residential sector will likely provide about 147 million therms over 20 years, corresponding to a 19% reduction of forecasted 2041 retail sales.

Single-family homes account for 95% of the identified achievable technical potential, as Figure 27 shows. Less than 5% of total achievable technical potential occurs in multifamily and manufactured residences due to a lack of gas connections.

Figure 27. Residential Natural Gas Achievable Potential by Segment



As shown in Figure 28, space heating (59%), whole home measure (21%), and water heating (18%) end uses account for over 98% of the identified achievable technical potential, which combines high-efficiency equipment (such as condensing furnaces and water heaters) and retrofits (such as shell measures, smart thermostats, and duct and pipe insulation). Figure 29 shows the cumulative natural gas achievable technical potential by residential end use.

Figure 28. Residential Natural Gas Achievable Potential by End Use

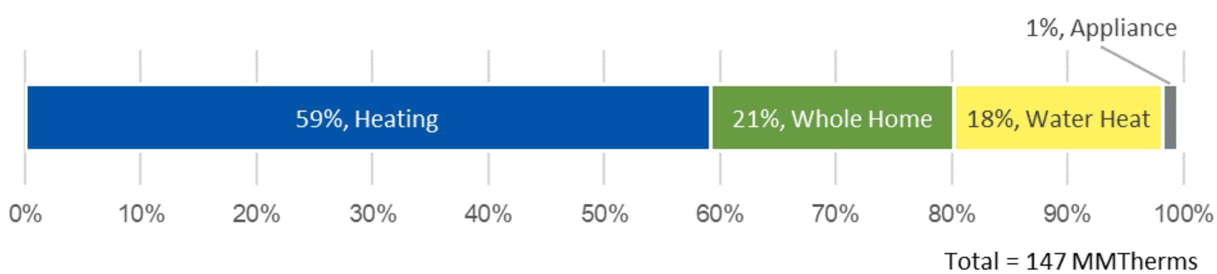


Figure 29. Residential Natural Gas Achievable Potential Forecast

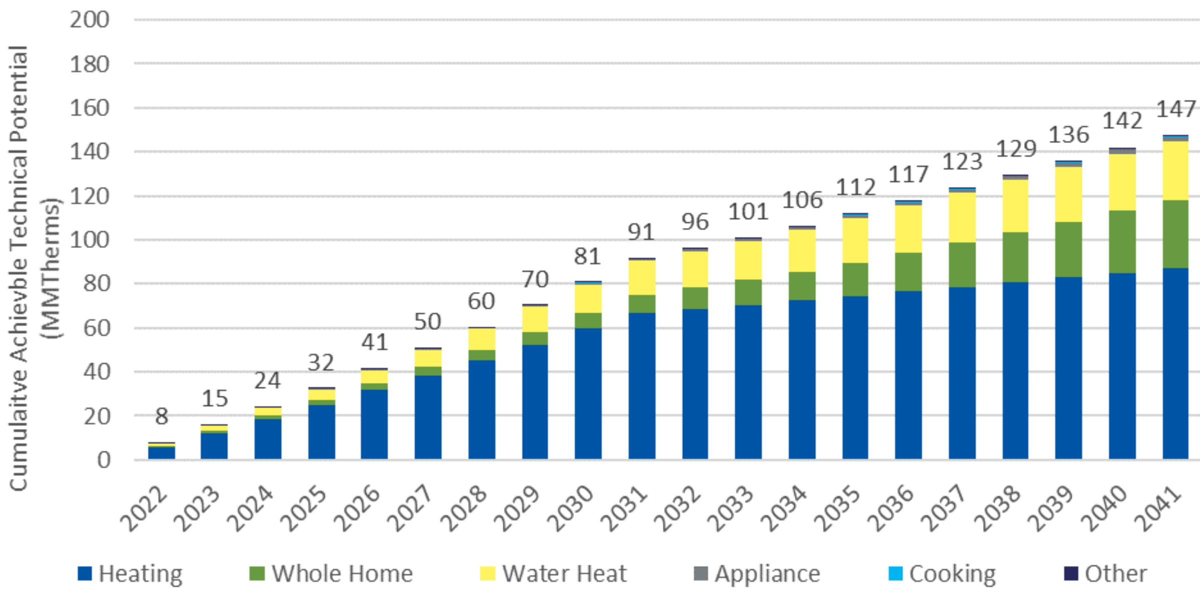


Table 24 shows the top 15 residential natural gas energy efficiency measures ranked in order of cumulative 20-year achievable technical potential. Combined, these 15 measures account for 136 million therms, or approximately 93% of the total residential achievable technical potential.

Table 24. Top Residential Gas Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (MM Therms)	Cumulative 20-Year Achievable Technical Potential (MM Therms)
Furnace	12.8	32.1
Whole Home	3.3	25.7
Water Heater	5.1	16.3
Thermostat	11.2	11.2
Window	10.5	10.5
Wall Insulation	7.3	7.3
Duct Sealing and Insulation	7.1	7.1
Duct Sealing	5.4	5.4
Home Energy Report	5.2	5.2
Thermostatic Restrictor Valve	3.1	3.1
Whole House Sealing	3.0	3.0
Floor Insulation	2.6	2.6
Showerhead	2.4	2.4
Aerators	2.3	2.3
Solar Water Heater	2.3	2.3

Residential Low Income – Gas

In addition to estimating potential for each residential housing segment, Cadmus also estimated potential for low income customers within PSE's natural gas service territory. Our team derived estimates of low income customers using income and housing sector variables from PSE's 2017 RCS. Based on PSE qualifying monthly income limit from PSE's Weatherization Assistance program. Varies by number of household occupants and 2016 annual household income (before taxes) from PSE's 2017 RCS. Table 25 provides the percent each residential sector's low income customers.

Table 25. PSE Low Income Customers - Gas Service

Segment	Electric Low Income Customers as a Percent of Total Electric Housing Segment Customers
Single Family	9.1%
Multifamily	8.3%
Manufactured	11.3%

Cadmus derived unit energy savings estimates specifically for low income customers using low income specific measures from PSE's business cases. Low income customer specific measures included the following:

- **Weatherization:** Attic, floor, and wall insulation, and air/duct sealing
- **Water heating**: ENERGY STAR tankless and storage water heaters, water heater pipe insulation, and low-flow showerheads and aerators
- **HVAC equipment:** Furnace replacements
- **Additional measures:** Smart thermostats and integrated space and water heating

The study also apportioned savings from non-low income specific measures to low income customers for other measures, including:

- clothes dryers and washers
- boilers
- home energy reports
- refrigerator/freezer recycling
- convection ovens

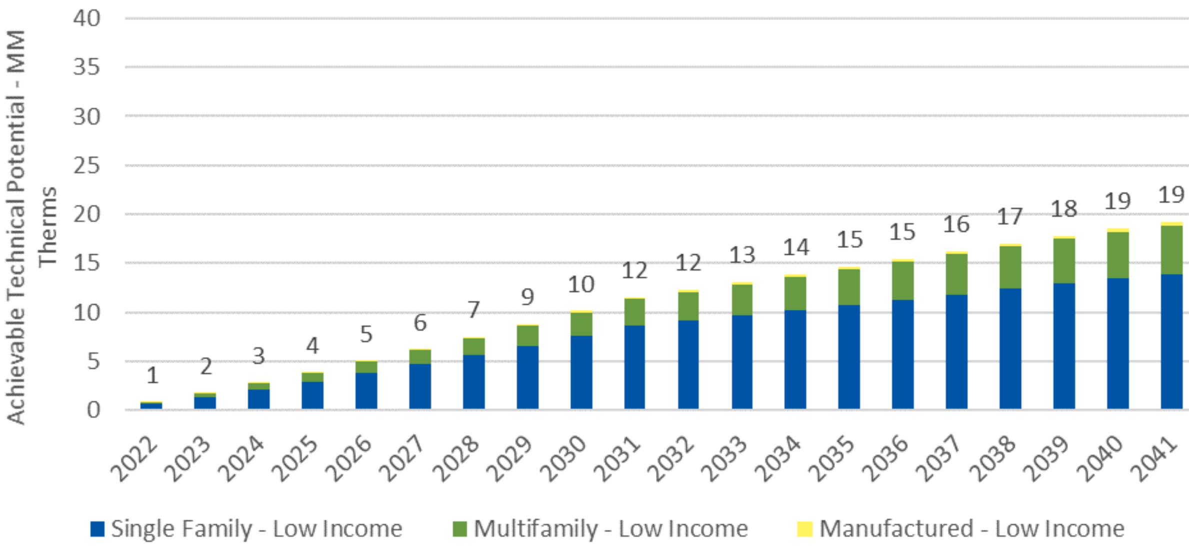
Table 26 shows the cumulative 10-year (through 2031) and 20-year (through 2041) natural gas achievable technical potential for PSE's low income customers by housing segment.

Table 26. Residential Low Income Customer Potential - Gas

Segment	Cumulative 10-Year Achievable Technical Potential (MM Therms)	Cumulative 20-Year Achievable Technical Potential (MM Therms)
Single Family - Low Income	8.6	13.8
Multifamily - Low Income	2.7	5.0
Manufactured - Low Income	0.2	0.4
Total	**11.6**	**19.2**

Figure 30 provides the cumulative residential low income natural gas potential forecast by housing segment. The potentials in Figure 29 include the low income customer potential shown in Figure 30.

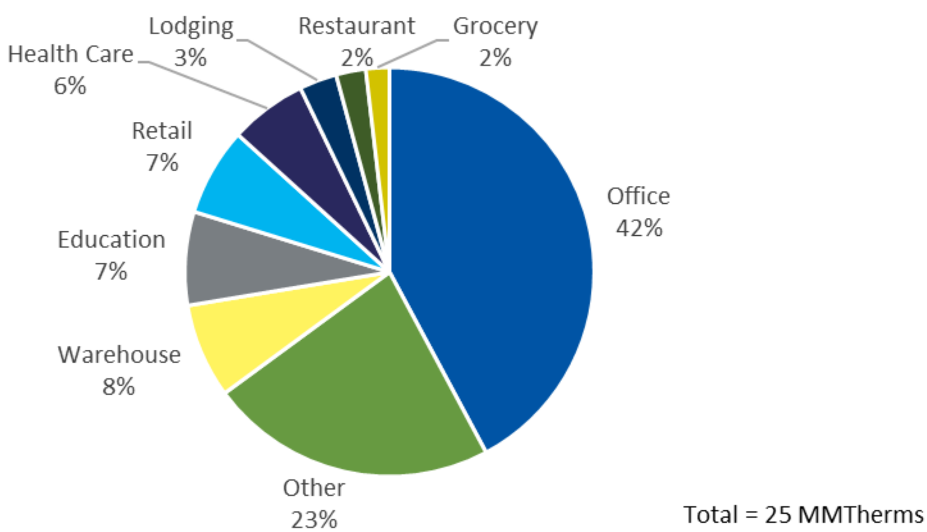
Figure 30. Residential Low Income Customer Potential - Gas



Commercial Sector – Gas

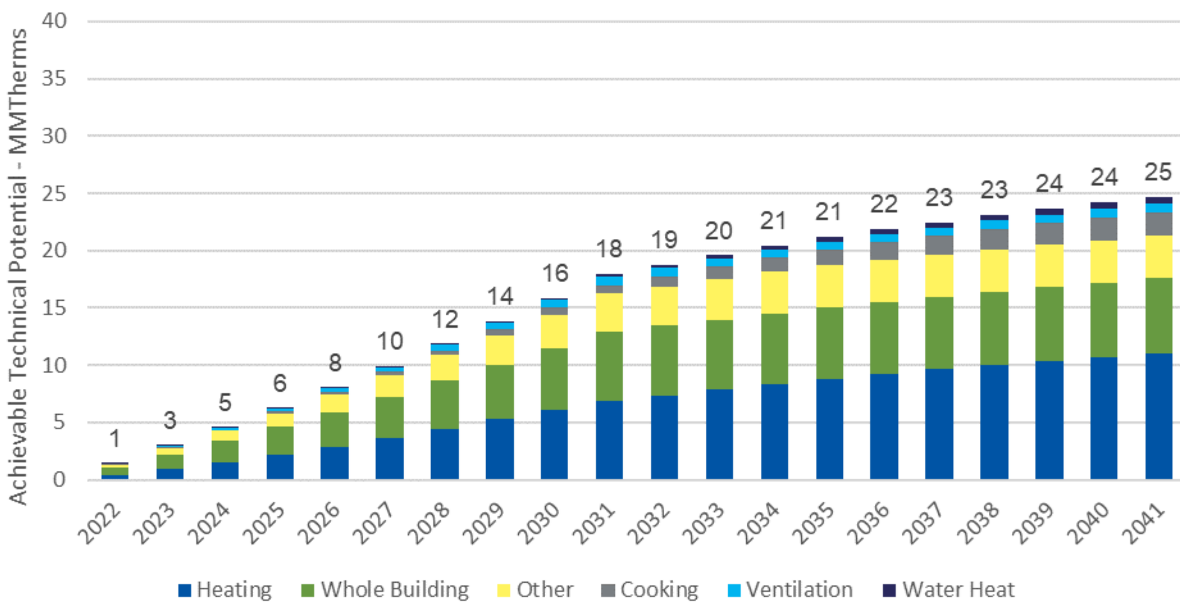
According to the resources used in this assessment, natural gas achievable technical potential in the commercial sector will likely be 25 million therms over 20 years, a 7% reduction in forecasted 2041 commercial retail sales. As shown in Figure 31., for natural gas customers, office buildings represent the largest portion of potential (42%), followed by other commercial facilities (23%), and warehouses (8%).

Figure 31. Commercial Gas Achievable Potential by Segment



As in the residential sector, far fewer gas-fired end uses exist compared to electric end uses. Space heating accounts for 44% of the identified commercial natural gas potential. The remaining potential is comprised mainly of whole building measures (27%),other end uses (15%), and water heating (11%), with the remaining potential coming from cooking (8%), and ventilation (3%), as shown in Figure 32.

Figure 33. Commercial Gas Achievable Potential Forecast



provides the commercial natural gas annual cumulative achievable technical potential by end use.

Figure 32. Commercial Gas Achievable Potential by End Use

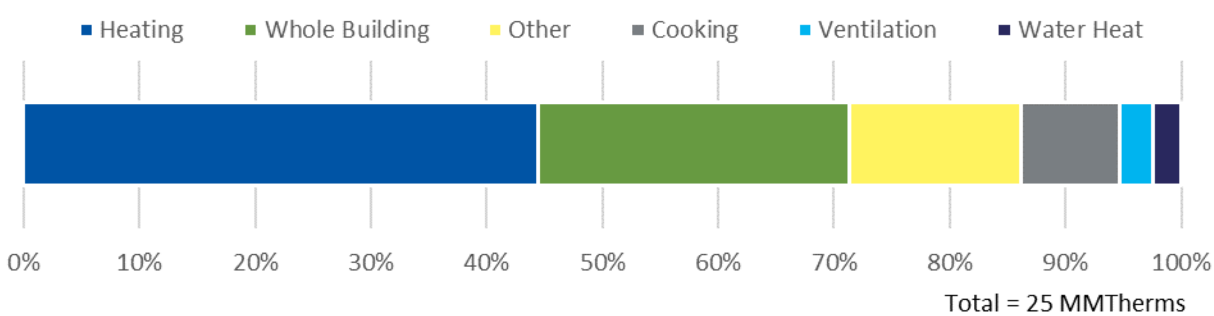


Figure 33. Commercial Gas Achievable Potential Forecast

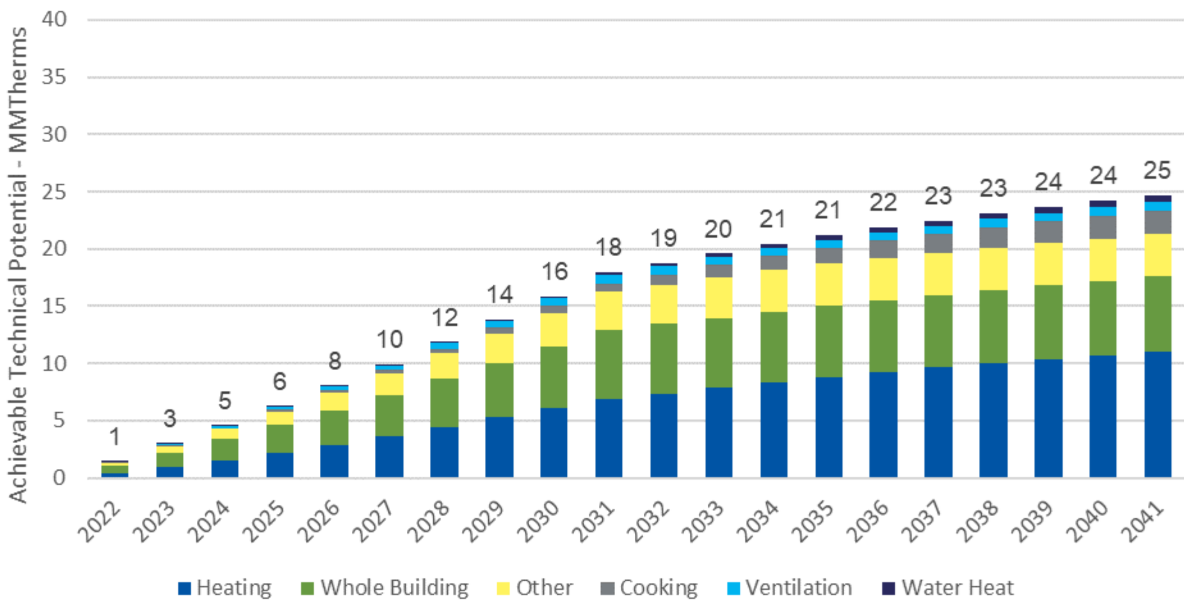


Table 27 shows the top 15 commercial natural gas energy efficiency measures ranked in order of cumulative 20-year achievable technical potential. Combined, these 15 measures account for approximately 18 million therms, or about 71% of the total natural gas commercial achievable technical potential.

Table 27. Top Commercial Gas Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (MM Therms)	Cumulative 20-Year Achievable Technical Potential (MM Therms)
Gas RTU Supply Fan VFD and Controller	3.0	3.0
Furnace LT 225 kBtuh High AFUE 92% Non-Weatherized	1.0	1.8
Furnace LT 225 kBtuh Premium AFUE 94% Non-Weatherized	0.8	1.9
Ozone Laundry	1.5	1.5
Pool Heat Recovery	2.4	2.4
DDC Energy Management	1.5	1.7
Commissioning Retro	1.5	1.5
Boiler 300 to 2500 kBtuh AFUE 95%	0.4	1.1
Clothes Washer	0.5	0.9
Boiler 300 to 2500 kBtuh AFUE 85%	0.3	0.8
DCV Kitchen	0.6	0.6
Oven Double Rack	0.2	0.6
Gas Water Heater 94% Efficient	0.2	0.5
Boiler 300 to 2500 kBtuh AFUE 79%	0.2	0.6
Convection Oven	0.2	0.5

Industrial Sector – Gas

Because electricity powers most industrial processes and end uses, the industrial sector represents a small portion of natural gas baseline sales and potential.

Across all industries, achievable technical potential totals approximately 1.7 million therms over 20 years. Although this represents 8% of forecasted 2041 industrial sales, it accounts for only 0.9% of the achievable technical potential across the three sectors. As shown in Figure 34, substantial achievable technical potential occurs in miscellaneous manufacturing (44%), transportation (17%), mechanical pulp (15%), and food production (10%).

Figure 34. Industrial Gas Achievable Technical Potential Forecast

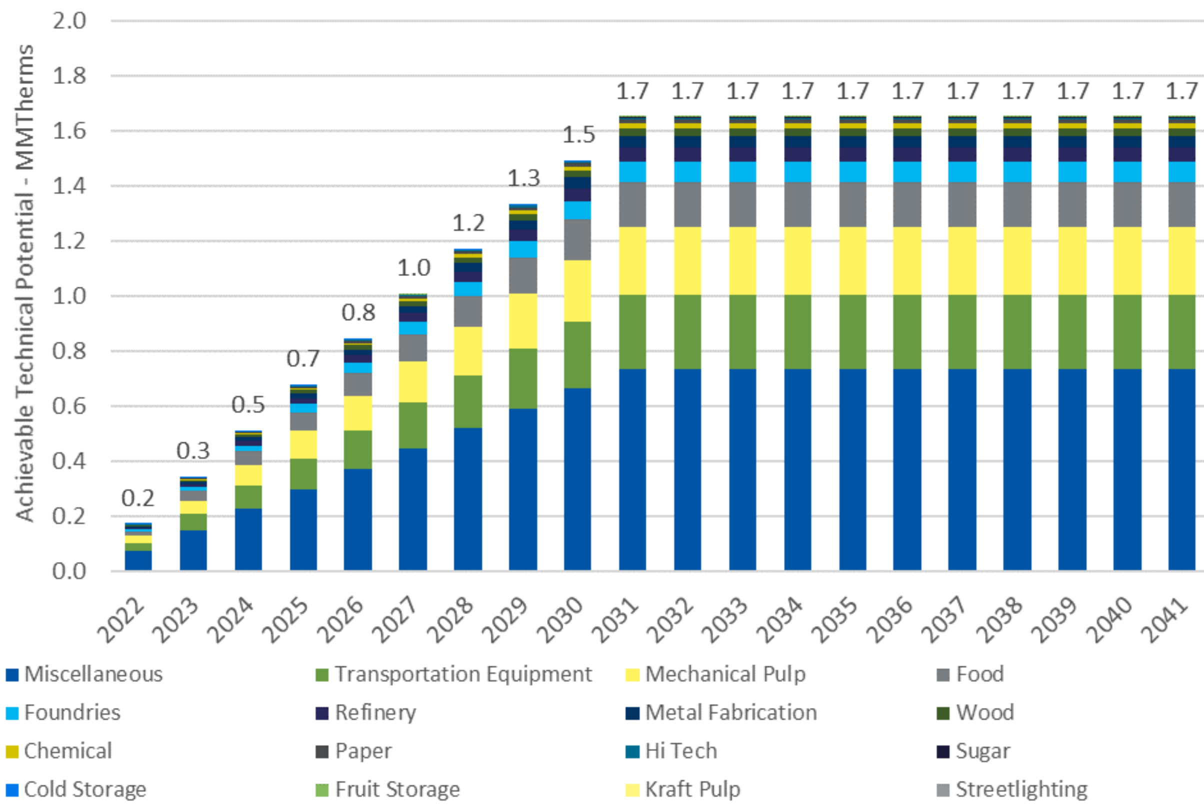


Table 28 lists the top 15 industrial natural gas energy efficiency measures ranked in order of cumulative 20-year achievable technical potential. Combined, these 15 measures account for approximately 1.4 million therms, or about 87% of the total natural gas industrial achievable technical potential.

Table 28. Top Industrial Gas Measures

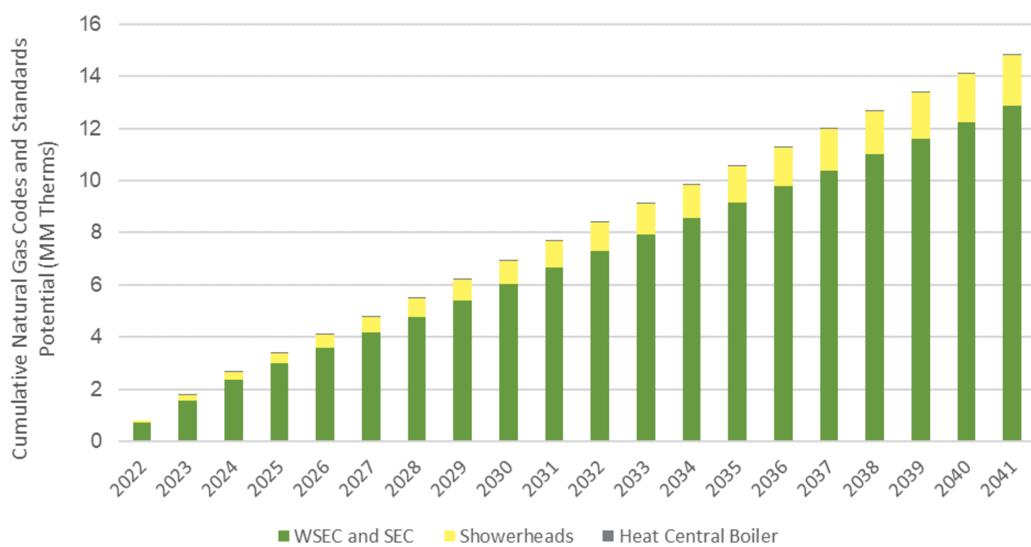
Measure Name	Cumulative 2031 Achievable Technical Potential (Therms)	Cumulative 2041 Achievable Technical Potential (Therms)
Equipment Upgrade - Replace Existing HVAC Unit with High Efficiency Model	196,537	196,537
Process Improvements to Reduce Energy Requirements	174,386	174,386
Improve Combustion Control Capability and Air Flow	138,408	138,408
HVAC Equipment Scheduling Improvements - HVAC Controls, Timers or Thermostats	114,484	114,484
Install or Repair Insulation on Condensate Lines and Optimize Condensate	110,464	110,464
Optimize Ventilation System	93,553	93,553
Waste Heat from Hot Flue Gases to Preheat	86,669	86,669
Heat Recovery and Waste Heat for Process	75,334	75,334

Measure Name	Cumulative 2031 Achievable Technical Potential (Therms)	Cumulative 2041 Achievable Technical Potential (Therms)
Equipment Upgrade - Boiler Replacement	71,916	71,916
Optimize Heating System to Improve Burner Efficiency, Reduce Energy Requirements and Heat Treatment Process	71,900	71,900
Building Envelope Infiltration Improvements	64,671	64,671
Building Envelope Insulation and Window/Door Improvements	62,980	62,980
Thermal Systems Reduce Infiltration; Isolate Hot or Cold Equipment	59,471	59,471
Replace Steam Traps	58,755	58,755
Repair and Eliminate Steam Leaks	53,159	53,159

Codes and Standards – Gas

Figure 35 presents naturally occurring natural gas savings in PSE's service area from Washington State energy codes and federal equipment standards. Overall, the WSEC represents most natural gas codes and standards savings, with approximately 13 million therms over the 20-year study horizon. The commercial and residential WSEC account for 6 million and 7 million therms, respectively.

Figure 35. Natural Gas Codes and Standards Forecast



Combined Heat and Power

CHP Technical Potential Approach

CHP technical potential represents total electric generation, if installing all resources in all technically feasible applications. Technical potential assumes 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 commercial and industrial 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 commercial and industrial market segments with average monthly energy loads greater than approximately 30 kW, which encompasses nearly all commercial and industrial facilities.

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)

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

- Reciprocating engines, which cover a wide range of sizes
- Microturbines, which represent newer technologies with higher capital costs
- Gas turbines, which typically are large systems

Cadmus analyzed the following **renewable-fueled systems:**

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

Cadmus calculated technical potential to determine the number of eligible customers by segment and size (i.e., demand) in PSE's service area then applied assumptions about CHP or biomass/biogas system sizes and performance. Table 29 lists the sources Cadmus referenced for each input. Recent studies completed for the California Self-Generation Incentive Program (SGIP) 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 SGIP data with other studies.

Table 29. Data Sources for CHP Technical Potential

Inputs	Source	Website Link (if available)
Capacity Factor, Performance Degradation, Heat Recovery Rate	Itron. *SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report].* Table 4-4: Summary of Operating Characteristics of SGIP Technologies. pp. 4-13. October 2015.	http://www.cpuc.ca.gov/General.aspx?id=7890
Measure Life	Marin, W., et al. *Understanding Early Retirement of Combined Heat and Power (CHP) Systems: Going Beyond First Year Impacts Evaluations*. 2015 International Energy Program Evaluation Conference, Long Beach.	https://www.iepec.org/wp-content/uploads/2015/papers/178.pdf
System Sizes	*Self-Generation Incentive Program Weekly Statewide Report.*	https://www.selfgenca.com/documents/reports/statewide_projects
Number of Customers, Projected Sector Growth, Line Losses	PSE data	N/A
Existing CHP Capacity	U.S. Department of Energy. "Combined Heat and Power Installation Database."	https://doe.icfwebservices.com/chpdb/
Customer Size Data	PSE data	N/A

CHP Achievable Potential Approach

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 using benchmarked estimates from recent studies, as listed in Table 30. We examined historic trends in installed capacity for several states (including Washington), technology, and fuel type using the U.S. Department of Energy (DOE) CHP Installation Database and reviewing states' favorability toward CHP as scored by the American Council for an Energy-Efficient Economy (ACEEE).

Table 30. CHP Achievable Potential Data Sources

Input	Source	Website Link (if available)
Annual Market Penetration Rate	U.S. Department of Energy. "Combined Heat and Power Installation Database."	https://doe.icfwebservices.com/chpdb/
	Navigant. *2017 IRP Conservation Potential Assessment IRPAG Meeting Draft DSM Results.* Prepared for Puget Sound Energy. January 2017.	https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=30&year=2016&docketNumber=160918
	U.S. Department of Energy. *Combined Heat and Power (CHP) Potential in the United States.* March 2016.	https://www.energy.gov/sites/prod/files/2016/04/f30/CHP%20Technical%20Potential%20Study%203-31-2016%20Final.pdf
	ICF International. *Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment*. Prepared for California Energy Commission. June 2012. CEC-200-2012-002-REV	http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf
	ACEEE. "State-by-State CHP Favorability Index Estimate."	http://aceee.org/sites/default/files/publications/otherpdfs/chp-index.pdf

Using the ACEEE 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 2012-2016. We also calculated this percentage for Washington state for comparison. This percentage is derived by dividing the capacity of CHP installed over the five-year period 2012-2016 (from the DOE CHP Installation Database) by the CHP potential (from the 2016 DOE CHP Potential in the United States) then dividing by five years. This provides an upper bound for the annual market penetration rate in PSE territory. Based on the benchmarking results (shown in Table 31) 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 potential.

Table 31. Market Penetration for 2012-2016

State	MW Installed 2012-2016	Technical Potential (MW)	Percent of Technical Potential Installed Per Year
Washington	15.1	2,387	0.126%
California	382.2	11,542	0.662%
Connecticut	15.2	1,214	0.248%
Massachusetts	40.2	3,028	0.265%

Levelized Costs

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

- Installation costs
- Federal tax credits and other rebates
- O&M costs assumed to occur annually, adjusted to the net present value
- Fuel costs

The levelized cost analysis used the sources shown in Table 32 as well as the sources listed above for technical and achievable potential. To calculate the TRC, Cadmus used PSE's inflation rate of 1.9% to adjust future costs to present dollars. The study divided costs by the system's production over its lifespan, obtaining the levelized cost of energy. Energy production includes PSE's average line loss factor of 6.80%, which represents avoided losses on the utility system, not energy losses from customer-sited units to the facility (assumed to be zero).

Table 32. CHP Levelized Cost Data Sources

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

Combined Heat and Power Results

Combined Heat and Power Technical Potential

Cadmus calculated technical CHP potential for new installations, based on sources described in the CHP Technical Potential Approach section of this report, including commercial and industrial customer data along with data on farms, landfills, and wastewater treatment facilities within PSE's power utility customer service area. This resulted in a total estimated 24-year, system-wide technical potential of 186 aMW (233 MW).

Table 33 details technical potential by area, sector, and fuel. These results exclude 83 MW of previous installed CHP capacity at eight facilities throughout PSE's territory.[7]

Table 33. CHP Technical Potential by Area, Sector, and Fuel (Cumulative in 2045)

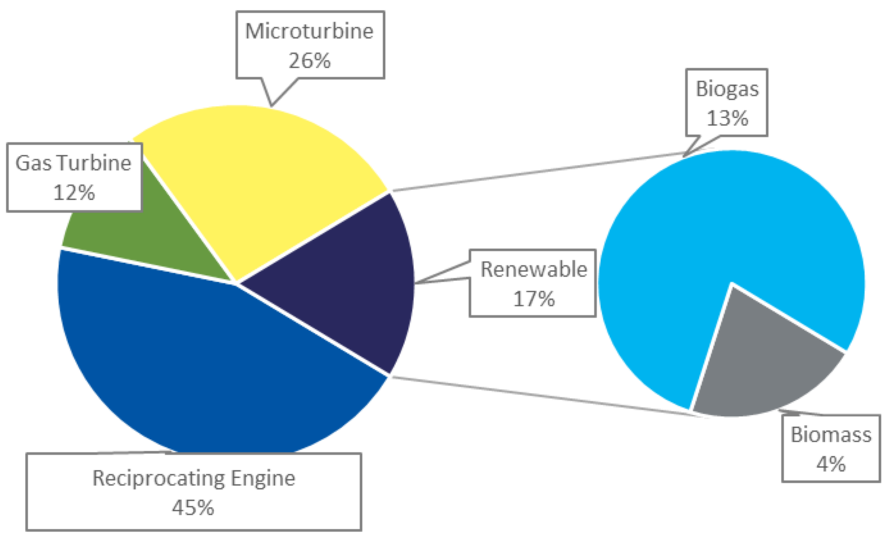
PSE	Technical Potential
Commercial	
Natural gas aMW	109
Number of sites	1,242
Industrial	
Natural gas aMW	56
Number of sites	293

[7] U.S. Department of Energy. "Combined Heat and Power Installation Database." Accessed July 5, 2018.

PSE	Technical Potential
Biomass and biogas aMW	35
Number of sites	67
Industrial total aMW	91
Industrial total number of sites	360
Total	
Total aMW	200
Total number of sites	1,602

The study based average energy production on unique capacity factors for each system type. To avoid double-counting opportunities across technologies, the study divided total potential for each size range into different technologies. Figure 36 shows the distribution of technical potential as a percentage of 2045 technical potential in aMW by these different technologies (e.g., reciprocating engines, microturbines, gas turbines, biomass, biogas).

Figure 36. Percentage of 2045 CHP Technical Potential in aMW by Technology



Combined Heat and Power Achievable Potential

Cadmus applied a market penetration rate of 0.20% per year to the technical potential data to determine achievable potential or likely installations in future years. The study based the assumed annual market penetration rate on secondary research of naturally occurring CHP installations in the region and on other CHP potential study reports, as described in the *CHP Achievable Potential Approach* section. As shown in Table 34 and Table 35, the market penetration rate was applied to technical potential for each year to calculate equipment installations along with achievable potential over the next 24 years. The study estimated a cumulative 2045 achievable potential of 7.82 aMW (9.78 MW of installed capacity) at the generator. We used PSE's line loss assumption of 6.8%.

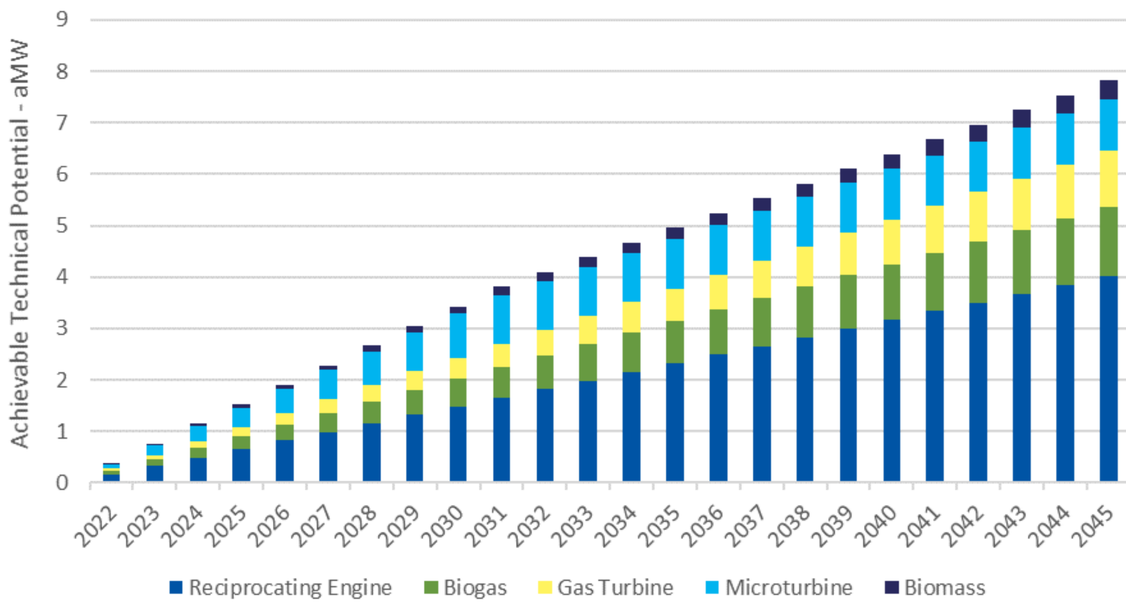
Table 34. CHP 2045 Cumulative Achievable Potential Equipment Installations

Technology	2045 Installs
Nonrenewable - Natural Gas (Total)	45
Reciprocating Engine	25
Gas Turbine	18
Microturbine	2
Renewables	2
Total CHP	47

Table 35. CHP 2045 Cumulative Achievable Potential at Generator

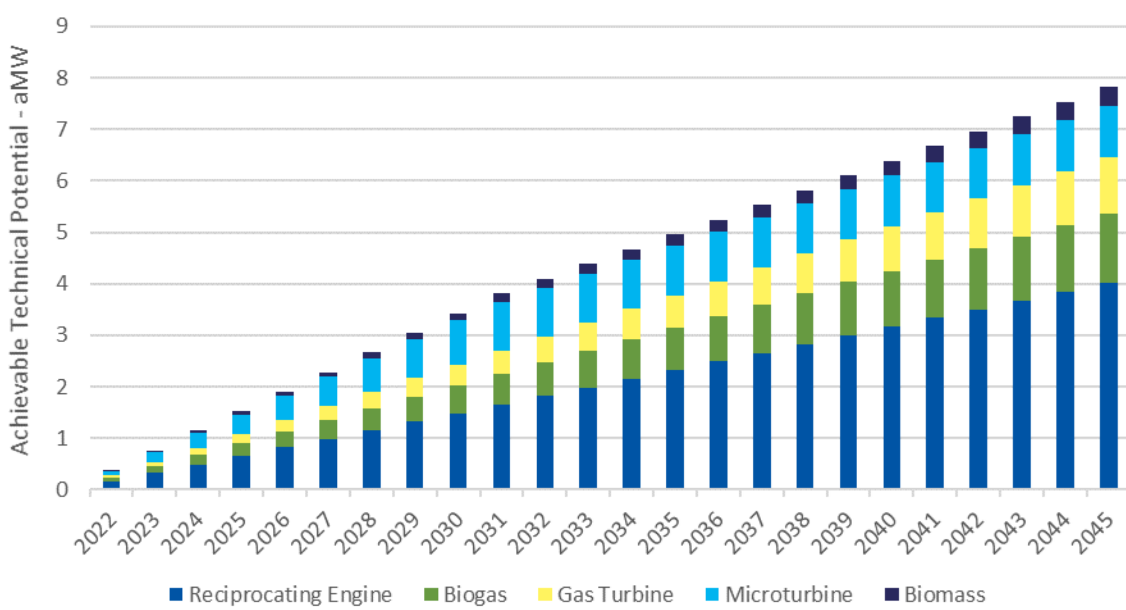
Technology	2045 aMW	2045 MW
Nonrenewable - Natural Gas (Total)		
30–99 kW	1.04	1.30
100–199 kW	0.83	1.04
200–499 kW	1.10	1.37
500–999 kW	0.76	0.96
1–4.9 MW	1.41	1.76
5 MW+	0.96	1.20
Renewable - Biomass (Total)		
< 500 kW	0.00	0.00
500-999 kW	0.00	0.00
1–4.9 MW	0.01	0.01
5 MW+	0.35	0.44
Renewable - Biogas (Total)		
Landfill	0.21	0.26
Farm	0.85	1.06
Paper Mfg	0.03	0.04
Wastewater	0.26	0.32
Total CHP	**7.82**	**9.78**

Figure 37. CHP Cumulative Achievable Potential by Year at Generation (aMW)



shows cumulative achievable CHP potential by year and technology. The decrease in the rate of adoption at year 2032 is caused by the assumed 10-year lifespan of microturbines. Microturbines are installed throughout the study horizon (2022-2045), but they don't begin to be decommissioned until 10 years after the start of the study. The rate for the first 10 years of the study is based on new installs, whereas the rate after the first 10 years includes new installs as well as decommissioned systems.

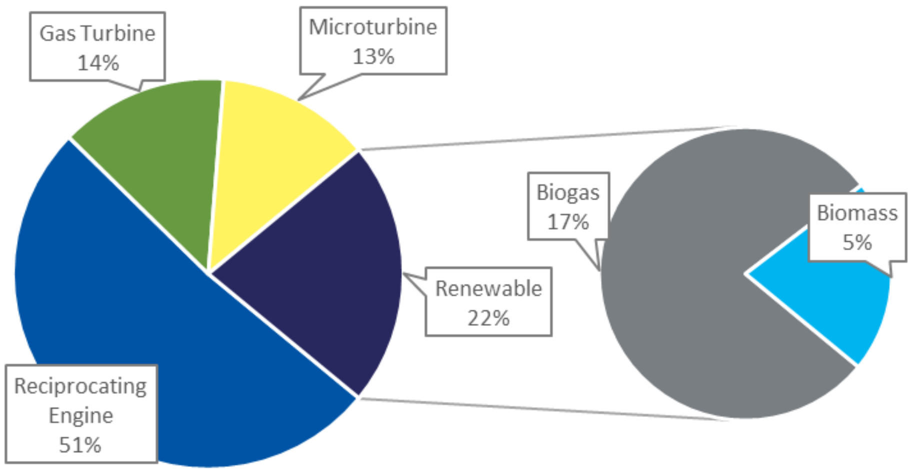
Figure 37. CHP Cumulative Achievable Potential by Year at Generation (aMW)



Of the 7.82 aMW of cumulative achievable potential, reciprocating engines made up 4.0 aMW (51%), gas turbines made up 1.3 aMW (14%), and microturbines made up 1.1 aMW (13%). The remaining 22%

of renewable technologies consisted of biogas (1.0 aMW) and biomass (0.4 aMW) systems. In 2045, total energy generated across all technologies is 68.5 GWh (i.e., nonrenewable at 53.5 GWh and renewable at 15 GWh). Figure 38 shows the market potential of energy generation by each technology.

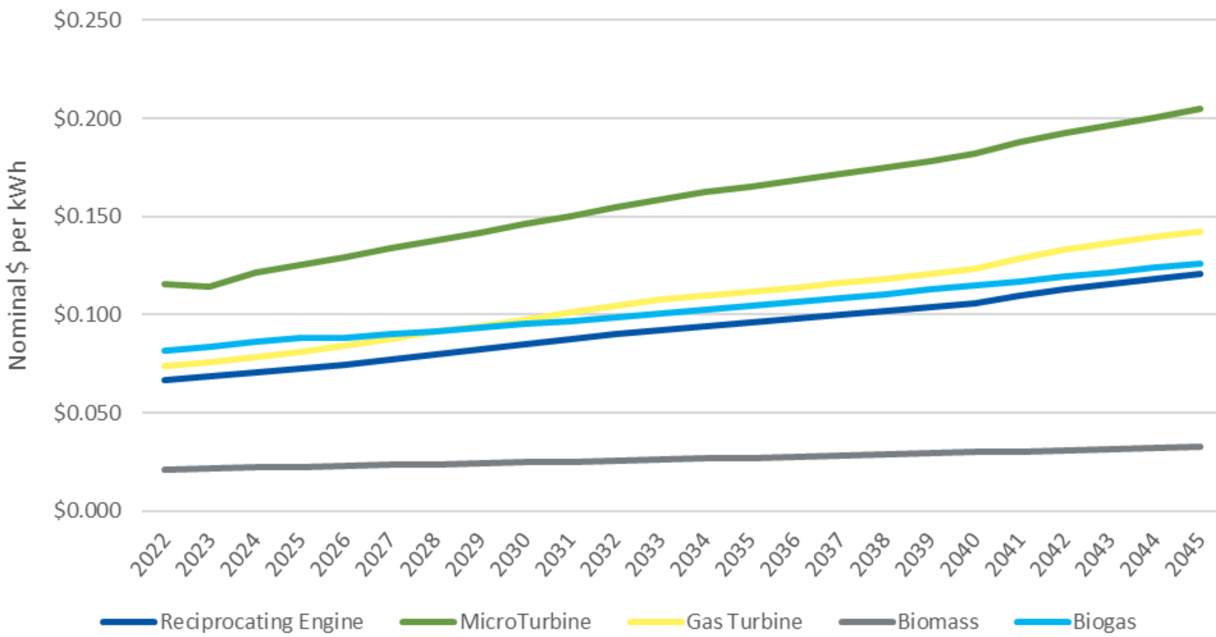
Figure 38. Breakout of CHP 2045 Cumulative Achievable Potential (GWh) at Generator



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 (2022 to 2045). Figure 41 shows the nominal levelized cost for units installed through the study period. The levelized cost increases slightly over time. For nonrenewable systems, the levelized cost increase results from increasing natural gas prices and inflation. For the renewable systems, the levelized cost increase results from inflation.

Figure 39. Nominal Levelized Cost by Technology and Installation Year



Section 2. Demand Response

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 (e.g., DLC programs) or offer pricing structures to induce participants to shift load away from peak periods (e.g., critical peak pricing (CPP) programs).

Overview of Technical and Achievable Potential

Cadmus' analysis focused on programs aimed at reducing PSE's winter peak demand. These programs include DLC space heat, DLC water heat, pricing, residential electric vehicle service equipment, residential behavioral, and nonresidential 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 nonresidential load curtailment program may offer customers a choice between manually turning off equipment to curtail loads or letting the utility communicate with an automated control system.

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. To design the programs, we conducted an extensive review of secondary sources that addressed existing and planned programs predominantly in the Northwest, such as demand response potential assessments, program descriptions, evaluation reports, and pilot and demonstration projects from other utilities.

Estimate Technical Potential

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, this study applies either a bottom-up or a top-down method to estimate technical potential.

This study uses the bottom-up method for assessing 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 electric vehicle service equipment. In the bottom-up method, technical potential is determined as the product of three variables: number of eligible customers, equipment saturation rate, and the expected per-unit (kW) peak load impact.

The top-down method estimates technical potential as a fraction of the participating facility's total peak-coincident demand. The calculation begins with disaggregating system electricity sales by sector, market segment, and end use then estimates technical potential as a fraction of the end-use loads. Total potential is then estimated by aggregating the estimated load reductions of the applicable end uses. The top-down estimation method is applied to demand response products that target the entire facility or load (rather than specific equipment), such as residential CPP, residential behavioral, commercial CPP, and commercial and industrial demand curtailment.

Estimate Achievable Potential

Achievable 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 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 potential may be reached, but they do not affect the amount of maximum achievable potential.

Both top-down and bottom-up methods calculate achievable potential as the product of peak load impact, program participation, and event participation, but note that event participation is assumed as 100% in involuntary load reduction programs such as DLC. Both methods apply ramp rates in the same manner to account for program start-up and ramp-up.

Calculate Levelized Costs

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

LCOE = (Annualized Cost of Demand Response Product) / (Achievable Annual Kilowatt Load Reduction)

This assessment calculated levelized costs based on the total resource cost (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 operation and maintenance costs, equipment cost, marketing cost, incentives, and transmission and distribution (T&D) deferral costs:

- **Upfront setup cost.** This cost item includes PSE's program development and setup costs for delivery of the subject demand response products, prior to program implementation. Because upfront costs tend to be small relative to total program expenditures, they can be expected to have a small effect on levelized costs.
- **Program operations and maintenance (O&M) cost.** This cost item includes all expenses that PSE incurs annually to operate and maintain the program. Expenses may cover administration, event dispatching, customer engagement, infrastructure maintenance, managing opt-outs and new recruiting of loads, and evaluation.
- **Equipment cost (labor, material, and communication costs).** This cost item includes all expenses necessary to enable demand response technology for each participating end user. The cost item applies only to each year's new participants. For some 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 applies only 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. This assessment included 100% of the assumed incentive payment to eligible participants in the TRC levelized-cost calculation
- **Transmission and distribution (T&D) costs.** A transmission and distribution deferral value of $15.15/kW-year was included as a negative cost item in the levelized cost calculations for each product.
- **Discount rate.** A 6.8% discount rate, consistent with PSE's resource planning assumptions, was used for all demand response products.
- **Product life cycle.** All demand response products were assessed with an assumed 24-year life cycle.

Develop Supply Curves

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 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

Focusing 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 time-of-use [TOU] or interruptible tariff) and incentive-based (such as DLC) strategies. This assessment considered 16 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 electric vehicle service equipment (EVSE), commercial and industrial products such as demand curtailment contracts and interruptible tariffs, and other non-dispatchable products such as residential behavior demand response.

Demand response potential estimates invariably require assumptions regarding program design – including the number and duration of events – even in instances where utilities, such as Puget Sound Energy, who currently do not offer demand response programs. For this study, Cadmus assumed an average of 40 hours of dispatch (ten, four-hour events) for DR products. Typically, larger commitments lead to lower potential estimates resulting from less load reduction capability over longer duration event and higher customer program attrition and lower customer event participation for higher numbers of events. Utility contracts with third-party DR service providers typically stipulate a limited number of events, event duration, and notification level for utility DR programs.

Cadmus reviewed recent demand response literature, including evaluations of pilots and programs in the Northwest and across the country, to design each demand response program. All but three of the evaluated product groups have two product options to capture the most common demand response product strategies from benchmarked studies. For example, customers participating in the residential DLC space heat program can either have a programmable communicating thermostat (PCT) installed in their home free of charge or let the utility communicate with the home's existing programmable PCT and receive a one-time bonus incentive.

Summary of Resource Potential

Table 36 lists the estimated resource potentials for all winter demand response programs for the residential, commercial, and industrial sectors during winter. The greatest achievable potential occurs in the residential sector from the DLC programs. Note that this analysis does not account for program interactions and overlap; therefore, the total achievable potential estimates may not be fully attainable upon implementation of all programs. The system peak load is calculated as the average of PSE's hourly loads during the 20 highest-load hours in the winter of 2019.

Table 36. Demand Response Achievable Potential and Levelized Cost by Product Option, Winter 2045

Program	Product Option	Winter Achievable Potential (MW)	Winter Percent of System Peak	Levelized Cost ($/kW-year)
Residential CPP	Res CPP-No Enablement	64	1.28%	-$3
	Res CPP-With Enablement	2	0.04%	-$8
Residential DLC Space Heat	Res DLC Heat-Switch	50	1.00%	$71
	Res DLC Heat-BYOT	3	0.06%	$61
Residential DLC Water Heat	Res DLC ERWH-Switch	11	0.21%	$126
	Res DLC ERWH-Grid-Enabled	58	1.15%	$81
	Res DLC HPWH-Switch	< 1	< 0.1%	$329
	Res DLC HPWH-Grid-Enabled	1	0.02%	$218
Commercial CPP	C&I CPP-No Enablement	1	0.03%	$86
	C&I CPP-With Enablement	1	0.02%	$81
Commercial DLC Space Heat	Small Com DLC Heat-Switch	7	0.13%	$64
	Medium Com DLC Heat-Switch	5	0.10%	$29
Commercial and Industrial Curtailment	C&I Curtailment-Manual	3	0.06%	$95
	C&I Curtailment-AutoDR	3	0.06%	$127
Residential EVSE	Res EV DLC	9	0.17%	$361
Residential Behavioral	Res Behavior DR	9	0.17%	$76

Although PSE's electric distribution system incurs peak demand in winter, Cadmus also estimated the demand response potential for the summer season, as Table 37 shows. The remainder of the results presented in the demand response section focus on the winter demand response potential.

Table 37. Demand Response Achievable Potential and Levelized Cost by Product Option, Summer 2045

Program	Product Option	Summer Achievable Potential (MW)	Summer Percent of System Peak	Levelized Cost ($/kW-year)
Residential CPP	Res CPP-No Enablement	39	1.0%	$5
	Res CPP-With Enablement	1	< 0.1%	< $1
Residential DLC Space Heat	Res DLC Heat-Switch	24	0.6%	$160
	Res DLC Heat-BYOT	31	0.8%	$61
Residential DLC Water Heat	Res DLC ERWH-Switch	11	0.3%	$158
	Res DLC ERWH-Grid-Enabled	58	1.4%	$81
	Res DLC HPWH-Switch	< 1	< 0.1%	$406
	Res DLC HPWH-Grid-Enabled	1	< 0.1%	$218
Commercial CPP	C&I CPP-No Enablement	9	0.2%	$117
	C&I CPP-With Enablement	18	0.5%	$17
Commercial DLC Space Heat	Small Com DLC Heat-Switch	4	0.1%	$95
	Medium Com DLC Heat-Switch	4	0.1%	$126
Commercial and Industrial Curtailment	C&I Curtailment-Manual	2	< 0.1%	$41
	C&I Curtailment-AutoDR	3	0.1%	$36
Residential EVSE	Res EV DLC	9	0.2%	$361
Residential Behavioral	Res Behavior DR	5	0.1%	$77

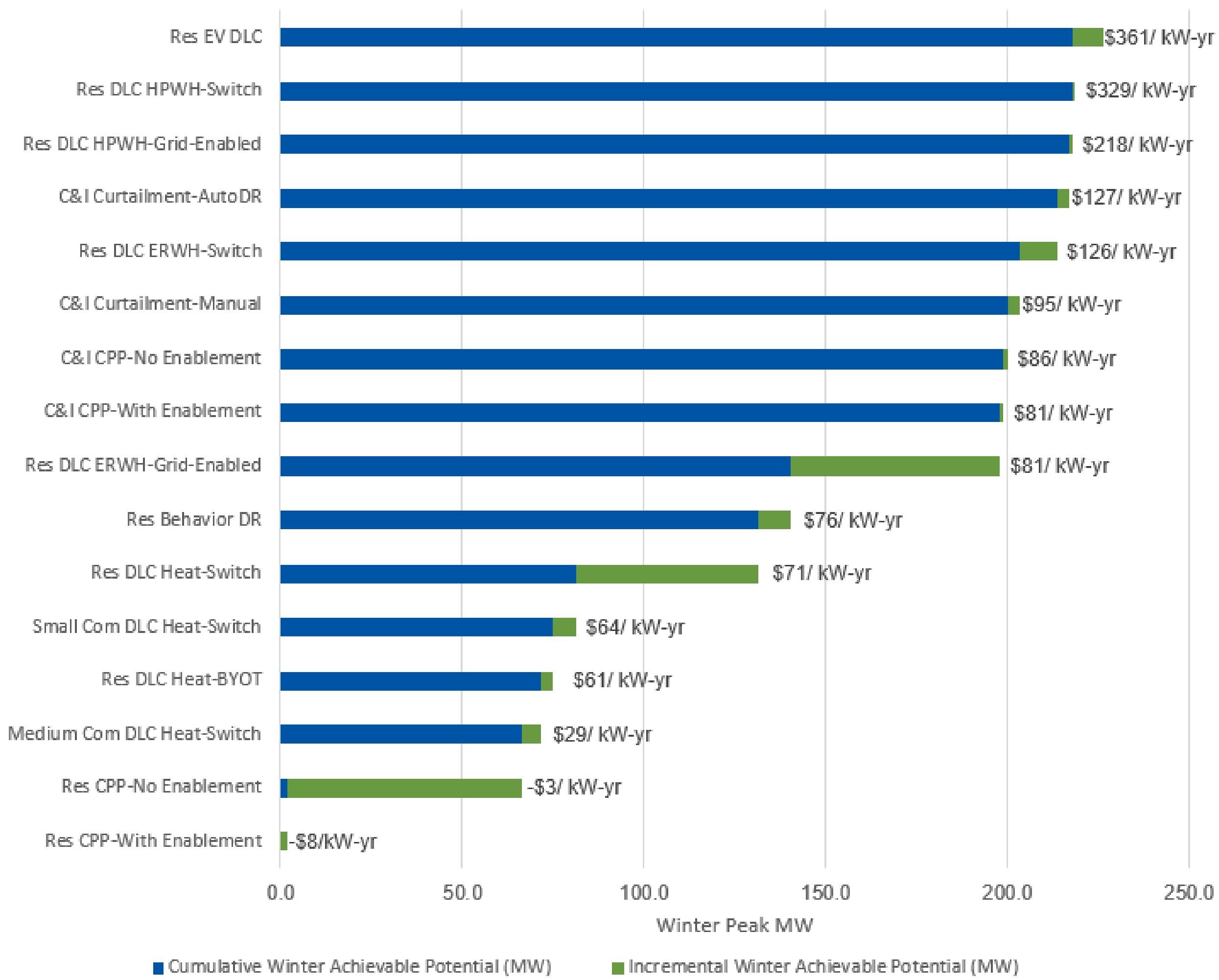
Cadmus constructed supply curves from quantities of estimated achievable technical demand response potential and per-unit levelized costs for each product option. Figure 40 shows the quantity of achievable potential (available during the system winter peak hours in 2045) as a function of levelized costs, at the product-option level. The green bars represent the incremental, achievable potential available for a product option at its associated levelized cost. The blue bars represent the cumulative achievable potential for the product options with lower levelized costs.

The supply curve starts with the lowest cost product option—residential CPP with enablement, which provides 2 MW of winter achievable potential at -$8 per kilowatt-year, levelized. The next lowest cost product in the supply curve is the same program but for the product option of no enablement, which adds 64 MW of winter achievable potential at -$3 per kilowatt-year, levelized. Thus, PSE could acquire a total of 66 MW of winter demand response at a negative levelized cost.

The two most cost-effective DR product options mentioned have negative costs due to the inclusion of deferred T&D costs in the TRC levelized cost calculation. Cadmus incorporated a transmission and distribution deferral value of $15.15/kW-year as a negative cost item in the levelized cost calculations for each product, resulting in negative values for products with very low costs. Without the inclusion of the T&D deferral value, the levelized costs of residential CPP with enablement and residential CPP with no enablement are $8 and $12, respectively.

Because residential EV DLC is the most expensive product option, PSE could acquire as much winter potential as achievable if it paid $361 per kilowatt-year (i.e., the levelized cost for the most expensive product option). However, PSE could acquire approximately 90% of the total achievable technical winter demand response potential at $95 per kilowatt-year, which is less than a third of the levelized cost of the most expensive product.

Figure 40. Demand Response Achievable Potential Supply Curve by Product Option



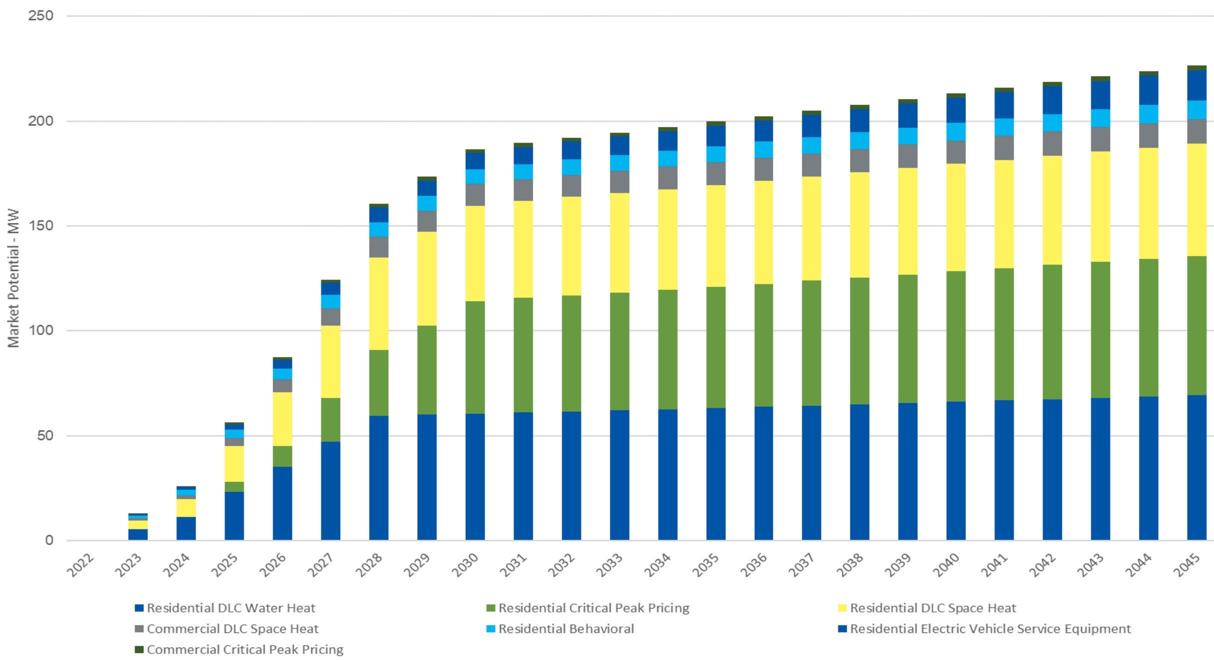
Cadmus assumes each program will require seven years of implementation before achieving the maximum achievable level of participation, allowing for an ample start-up period. Exceptions to this rule include:

- Residential Behavioral requires six years as this program would be an add-on to PSE's existing behavioral energy efficiency program, warranting a shorter ramp period than other DR programs.
- Residential Electric Vehicle Service Equipment requires five years to align with the 2021 Plan assumption to reach full program engagement.
- Residential DLC Heat – BYOT requires 5 years to align with ramp rate assumptions used in the 2021 Plan.

- CPP requires that PSE first establish a TOU tariff; therefore, the study assumed zero CPP participation until 2025.

Figure 41 shows the acquisition schedule for achievable potential by program.

Figure 41. Demand Response Achievable Potential Forecast by Program



Detailed Resource Potentials by Program and Product Option

This section provides the detailed demand response achievable potential and levelized cost for each program and its product options. For each program, Cadmus also describes the available product options and provides the costs and impact input assumptions.

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.

CPP rates take effect for only a limited number of times during the winter. 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. This analysis assumes that 10 critical peak price events are called, with a duration of four hours, for a total of 40 event hours during the winter.

Product Options

According to Cadmus' research of existing program studies across the nation, peak load impacts achieved by CPP programs vary depending on if the enabling technology, such as programmable communicating thermostats (PCTs), are integrated with the program. This analysis estimated two product options in the residential CPP program:

- No enablement (for customers without existing PCT)
- With enablement (for customers with existing PCT)

This analysis assumes that residential customers eligible for the with-enablement option have an existing PCT to control their central electric space heating equipment (i.e., electric furnace or air-source heat pump). During a critical peak event, these customers can reduce 40% of their space heat load, in addition to other end-use loads. All other residential customers are eligible for the no-enablement product option and achieve a relatively lower peak load impact.

Input Assumptions

Table 38 provides the cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the residential CPP program.

Table 38. Residential Critical Peak Pricing Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per year	$75,000	SDG&E (2017): $280,000; Applied (2017): $75,000. Assuming 0.5 FTE for the program.
Equipment Cost	$ per new participant	$0	No enablement: According to PSE (2018), AMI will be fully deployed in PSE's electric territory by 2023. Therefore, no equipment cost is incurred. With enablement: Because participant already has a PCT, no equipment cost is incurred.
Marketing Cost	$ per new participant	$25	Cadmus (2015): $25/new participant; Cadmus (2017): $25/new participant; Applied (2017): $50/new participant.
Incentives (annual)	N/A	$0	Program definition
Incentives (one time)	N/A	$0	Program definition
Attrition	% of existing participants per year	0%	N/A
Eligibility	% of segment load	Varies by product option and segment	No enablement: The proportion of residential customers who are not eligible for the with-enablement option. With enablement: The proportion of residential customers with a PCT (PSE's 2018 RCS) and have electric furnaces or air-source heat pumps (RBSA; heating zone 1).
Peak Load Impact	% of eligible segment load	Varies by product option and end use	No enablement: assuming 12% based on Cadmus (2015): 12%; Cadmus (2017): 12%; Applied (2017): 12.5%; and Brattle (2015): 14.8%.

Parameters	Units	Values	Notes
			With enablement: For cool central, heat central, and heat pump end uses, assuming 40% based on Oklahoma (2011): 38.8%; DTE (2014): 44.5%; Nexant (2017) 44.6%. For other end uses, assuming 12%.
Program Participation	% of eligible segment load	15%	Cadmus (2013b): 5%; Cadmus (2015): 10%; Cadmus (2017): 10%; Applied (2017): 17%; Brattle (2015): 29%.
Event Participation	N/A	No enablement: 100%	No enablement: peak load impact already takes into account of event participation.
		With enablement: 85%	With enablement: Customers can override the impact on their HVAC end uses by adjusting their PCTs.

Results

Residential CPP is the least expensive demand response program. As a tariff-based product, it does not offer incentives for load reductions. Without any enabling technology, residential CPP could obtain 64 MW of winter achievable potential by 2045 at -$3 per kilowatt-year, as shown in Table 39. Participating customers with enabling technology can provide even more peak load reductions, and—because PSE does not pay for the existing enabling technology—this peak load reduction is at a lower levelized cost of -$8 per kilowatt-year. Note that the potential results represent the load impact of a CPP event, during which only CPP prices are in effect.

Table 39. Residential Critical Peak Pricing Achievable Potential and Levelized Cost by Product Option

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
Res CPP-No Enablement	10 4-hour events	Day-ahead	-$3	64
Res CPP-With Enablement	10 4-hour events	Day-ahead	-$8	2

Residential Direct Load Control Space Heat

DLC programs seek to interrupt specific end-use loads at customer facilities through utility-directed control. When necessary, the utility, typically through a third-party contractor, is authorized to cycle or shut off participating appliances or equipment for a limited number of hours on a limited number of occasions. Customers do not have to pay for the control equipment or installation costs and typically receive incentives that are paid through monthly credits on their utility bills.

Product Options

For programs that target central electric space heating (i.e., heat pumps and electric forced-air furnaces), load control switches or PCTs 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 PCTs automatically set back temperature setpoints on heating systems. For this analysis, two product options are offered:

- Bring-your-own-thermostat (BYOT) (for customers with existing PCT)

- Load control switches (for customers without existing PCT)

DLC programs have mandatory event participation once a customer elects to participate in the program. However, for the PCT product option, this analysis assumes that customers are able to opt out or override their participation in an event by readjusting their thermostat.

Input Assumptions

Table 40 lists the cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the residential DLC space heat program.

Table 40. Residential Direct Load Control Space Heat Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per participant per year	$7.50	The annual program administrative cost assumes 1 FTE at $150,000 per year per 20,000 residential participants. In PSE's 2015 CPA, admin costs were 5% of total costs and vendor costs were 15% of total costs (Cadmus 2015).
Equipment Cost	$ per new participant	BYOT: $0	BYOT: Because participant already has a PCT, no equipment cost is incurred.
		Switches: $215	Switches: Based on Applied (2017): $215 ($115 for the switch and $100 for installation). Other sources include Potter (2017): $166 (for the control technology, installation, and communication platform); Global (2011): $170; Navigant (2012): $370; Navigant (2015a) for central air-conditioning DLC: $125-$189 (including $60 switch); Xcel (2016) for central air-conditioning DLC: $150-$200 (equipment).
Marketing Cost	$ per new participant	$25	Range for DLC programs: Navigant (2012) $25; Applied (2017) $50; Brattle (2014) $80; Applied (2017) $50.
Incentives (annual)	$ per participant per year	$40	Assuming $10/month for the season (i.e., November to February). Applied (2017): $20; Navigant (2012): $32; Global (2011): $50.
Incentives (one time)	$ per new participant	$0	N/A
Attrition	% of existing participants per year	5%	Consistent with the residential DLC water heat program.
Eligibility	% of customer count (e.g. equipment saturation)	Varies by product option and segment	BYOT: The proportion of residential customers with a PCT (PSE's 2018 RCS) and have electric furnaces or air-source heat pumps (RBSA; heating zone 1). Switches: The proportion of residential customers without a PCT (PSE's 2018 RCS) and have electric furnaces or air-source heat pumps (RBSA; heating zone 1).
Peak Load Impact	kW per participant (at meter)	BYOT: 1.09	Based on 2021 Plan Workbook "Inputs_Product_ResBYOT-Winter" peak load impact assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655872907903
		Switches: 1.2	Based on 2021 Plan Workbook "Inputs_Product_ResHeatSwch-Winter" peak load impact assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655862892198
Program Participation	% of eligible customers	20%	Navigant (2012), Applied (2017), and Brattle (2016) use 20%. Global (2011) gives low- and high-range of 15% - 25%.

Parameters	Units	Values	Notes
Event Participation	%	BYOT: 80%	BYOT: Customers can override the impact on their space heating by adjusting their PCTs (IPL 2014).
		Switches: 94%	Switches: Space heat and central air-conditioning DLC programs for switch success rate range from 64% (Navigant 2012) to 96% (ConEd 2012; NIPSCO 2016). Using Cadmus (2013b) assumption.

Results

Table 41 shows that the residential DLC space heating program could, by 2045, obtain 53 MW of achievable potential in the winter. The switches option provides most of the achievable potential, at a levelized cost of $71 per kilowatt-year. Although it cannot provide much achievable potential, the bring-your-own-thermostat option is cheaper, at a levelized cost of $61 per kilowatt year.

Table 41. Residential Direct Load Control Space Heat Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
Res DLC Heat-Switch	10 4-hour events	0-min	$71	50
Res DLC Heat-BYOT	10 4-hour events	0-min	$61	3

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) infrastructure, radio, consumer Wi-Fi connections to the internet, power line carrier, or paging infrastructure as well as 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.

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 grid-enabled water heaters. However, considering the peak savings between electric-resistance water heaters (ERWH) and heat pump water heaters (HPWH) differ, this analysis split the eligible participants of these two product options between these two water heater types according to equipment saturations. The result was the following four product permutations for this simulated DLC water heat DR program:

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

For the switches class of product options, the utility installs the switch on customers' existing electric water heaters. This study assumed water heaters are cycled off for 50% of the event's duration. Because 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 during the event. The assessment assumes this product option will be available for four-hour duration events with up to 10 events per year.

The other class of product options is for customers who own GEWH. These water heaters are manufactured with an ANSI/CTA-2045 port that allows a universal communication device to be plugged in, enabling two-way connection to the utilities' grid infrastructure. The primary advantages of this built-in communication capability include 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.[8]

Washington State recently passed legislation that mandated 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.[9] As a result, all new electric storage water heaters after 2021 will be GEWH and thus will be eligible for the GEWH product option. This analysis incorporates estimated impacts of this legislation by shifting most of the program participants to the GEWH products from the switch products over time for each water heater type.

Input Assumptions

Table 42 provides the cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the residential DLC water heat program.

Table 42. Residential Direct Load Control Water Heat Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per participant per year	$7.50	Assuming annual program O&M cost is 1 FTE at $150,000 per year per 20,000 residential participants.
Equipment Cost	$ per new participant	Switches: $315	Switches: Cadmus (2018) and Applied (2017). Range: Potter (2017) $350; Navigant (2015a): $106; Navigant (2012): $280 (space heat and water heat combined, additional $275 for gateway).

8 Bonneville Power Administration. CTA-2045 Water Heater Demonstration Report. November 9, 2018. Available online: https://www.bpa.gov/EE/Technology/demand-response/Documents/Demand%20Response%20-%20FINAL%20REPORT%20110918.pdf

9 State of Washington. Second Substitute House Bill 1444, Certification of Enrollment. An act relating to appliance efficiency standards; amending RCW 19.260.010, 19.260.030, 19.260.040, 19.260.050, 19.260.060, and 19.260.070; reenacting and amending RCW 19.260.020; adding a new section to chapter 19.260 RCW; creating a new section; and repealing RCW 19.27.170. Passed April 18, 2019. http://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/House%20Passed%20Legislature/1444-S2.PL.pdf

Parameters	Units	Values	Notes
		GEWH: $40	GEWH: According to BPA (2018), communication device cost per tank will drop from $100 to $15 over 20 years as volume increases. Assuming $40 per tank (Eustis 2018).
Marketing Cost	$ per new participant	$25	Range for DLC programs: Navigant (2012) $25; Applied (2017) $50; Brattle (2014) $80; Applied (2017) $50. According to BPA (2018), marketing cost per participant will drop from $150 to $25 over 20 years.
Incentives (annual)	$ per participant per year	$24	Assuming $2 per month for 12 months. Researched range: Applied (2017): $24-$25; Duke Energy (2015): $25; Navigant (2011): $8; BPA (2014): $4/month.
Incentives (one time)	$ per new participant	$0	N/A
Attrition	% of existing participants per year	5%	Cadmus (2011).
Eligibility	% of customer count (e.g., equipment saturation)	Varies by product option and segment	Electric water heat saturation was split between ERWH and HPWH based on RCS 2017 data. Ramp rate was adjusted to account for the growth in GEWH saturation over time. Methodology for ramp rate adjustment was informed by the 2021 Plan workbook "Inputs_Product_ResERWHDLCG-Winter". Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655867071789
Peak Load Impact	kW per participant (at meter)	ERWH: 0.58	ERWH: Cadmus (2015), Applied (2017), Navigant (2015a), and BPA (2014): 0.58 kW. Duke Energy (2015) 0.4 kW; Global (2011) 0.5 kW; Navigant (2011) 0.49 kW - 0.77 kW.
		HPWH: 0.24	HPWH: Based on weighted value from pilot results presented in March, 2018 (Eustis 2018).
Program Participation	% of eligible customers	Switches: 25%	Switches: Applied (2017) 15% - 23%; Global (2011) 15% - 25%; Navigant (2012) 20%; Navigant (2015a) 20% - 30% (realistic - max achievable).
		GEWH: 24%	GEWH: Based on BPA (2018) market transformation strategies. Program participation assumption adjusted down by half
Event Participation	% (switch success rate)	95%	Consistent with residential DLC space heat program.

Results

Table 43 presents assessment results for the residential DLC water heat program. The ERWH GEWH option could provide 58 MW of winter achievable potential by 2045, at a levelized cost of $81 per kilowatt-year. The ERWH load control switch option could add 11 MW of winter achievable potential at a levelized cost of $126 per kilowatt-year.

Table 43. Residential Direct Load Control Water Heat Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
Res DLC ERWH-Switch	10 4-hour events	0-min	$126	11
Res DLC ERWH-Grid-Enabled	Unlimited	0-min	$81	58
Res DLC HPWH-Switch	10 4-hour events	0-min	$329	0.2

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
Res DLC HPWH-Grid-Enabled	Unlimited	0-min	$218	1

Commercial Critical Peak Pricing

The commercial CPP program is similar to the residential CPP program but for small and medium commercial customers.

Product Options

Commercial customers in the small or medium office or retail segments are eligible for the commercial DLC space heat program. Small office customers were defined as having a building square footage of less than 20,000, while medium office customers were those with a building square footage between 20,000 and 100,000. For retail, these square footage definitions were under 5,000 and between 5,000 and 50,000 for small and medium customers, respectively. According to existing program studies across the nation, peak load impacts achieved by CPP programs vary depending on if enabling technology such as PCTs are integrated with the program. This analysis estimated two product options within the commercial CPP program:

- No enablement (for customers without existing PCT)
- With enablement (for customers with existing PCT)

This analysis assumes that small and medium commercial customers with an existing PCT to control their electric space heating equipment (i.e., electric furnace or air-source heat pump) are eligible for the with-enablement option and can reduce 7% of their space heat load during a critical peak event, in addition to other end-use loads. All other small and medium commercial customers are eligible for the no-enablement product option and achieve a lower peak load impact.

Input Assumptions

Table 44 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the commercial CPP program.

Table 44. Commercial Critical Peak Pricing Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per year	$75,000	SDG&E (2017): $280,000; Applied (2017): $75,000. Assuming 0.5 FTE.
Equipment Cost	$ per new participant	$0	No enablement: According to PSE (2018), AMI will be fully deployed in PSE's electric territory by 2023. Therefore, no equipment cost is incurred.
			With enablement: Because participant already has a PCT, no equipment cost is incurred.
Marketing Cost	$ per new participant	$50	Applied (2017): $50/new participant for small and medium commercial customers.

Parameters	Units	Values	Notes
Incentives (annual)	N/A	$0	Program definition
Incentives (one time)	N/A	$0	Program definition
Attrition	% of existing participants per year	0%	N/A
Eligibility	% of segment load	Varies by product option and segment	No enablement: The proportion of each segment's commercial customers that are not eligible for the with-enablement option.
			With enablement: The proportion of customers in small office, small retail, medium office, and medium retail with electric furnaces or air-source heat pumps (CBSA), assuming these customers have a PCT to control their heating load.
Peak Load Impact	% of eligible segment load	5%	No enablement: For small commercial customers, estimates ranged from 2.5% to 12.2% (Nexant 2017). For medium commercial customers, estimates ranged from 1.9% to 2.5% (Nexant 2017).
		7%	With enablement: Nexant (2017) reported 7% for participants with a PCT.
Program Participation	% of eligible segment load	10%	Assuming an opt-in program, estimates range from 2% (Cadmus 2015) to 18% (Applied 2017).
Event Participation	N/A	100%	Technical Potential already takes into account of event participation.

Results

Without any enabling technology, the commercial CPP program could obtain 1 MW of winter achievable potential by 2045 at $86 per kilowatt-year, as shown in Table 45. Participating customers with enabling technology can provide even more peak load reductions, and—because PSE does not pay for the existing enabling technology—they can provide the peak load reduction at a lower levelized cost, $81 per kilowatt-year.

Table 45. Commercial Critical Peak Pricing Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
C&I CPP-No Enablement	10 4-hour events	Day-ahead	$86	1
C&I CPP-With Enablement	10 4-hour events	Day-ahead	$81	1

Commercial Direct Load Control Space Heat

Commercial DLC programs operate similarly to most residential DLC programs. In this commercial DLC space heat program, the utility directly reduces the electric space heating load of small and medium commercial buildings (in the office or retail segments) during event hours via load control switches. This analysis assumes four-hour events will be dispatched, with up to 10 events per winter season, using a cycling strategy of 50%. This means space heating equipment cycles off for 50% of an hour and remains on for 50% of an hour (i.e., 30 minutes off and 30 minutes on).

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

Product Options

Commercial customers in the small or medium office or retail segments with electric space heating (i.e., electric furnace or air-source heat pump) are eligible for the commercial DLC space heat program. This analysis involved two product options by eligible commercial segments:

- Small office and retail
- Medium office and retail

Input Assumptions

Table 46 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the commercial DLC space heat program.

Table 46. Commercial Direct Load Control Space Heat Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per participant per year	$15	Assuming annual program O&M cost is 1 FTE at $150,000 per year per 10,000 small/medium commercial participants.
Equipment Cost	$ per new participant	Small: $387	Small: Applied (2017) for small C&I.
		Medium: $1,128	Medium: Applied (2017) for medium C&I.
Marketing Cost	$ per new participant	Small: $69	Small: Applied (2017) midpoint of $63-$75 for small C&I.
		Medium: $83	Medium: Applied (2017) midpoint of $75-$90 for medium C&I.
Incentives (annual)	$ per participant per year	Small: $38	Small: Applied (2017) for small C&I.
		Medium: $128	Medium: Applied (2017) for medium C&I.
Incentives (one time)	$ per new participant	$0	N/A
Attrition	% of existing participants per year	5%	Consistent with residential DLC programs.
Eligibility	% of customer count (e.g. equipment saturation)	Varies by segment	The proportion of customers in small office, small retail, medium office, and medium retail with electric furnaces or air-source heat pumps (CBSA).
Peak Load Impact	kW per participant (at meter)	Small: 1.87	Applied (2017) for WA for small and medium C&I (3.72 kW), adjusted to small C&I using a ratio of HVAC capacity sizes between small and medium C&I facilities (CBSA).
		Medium: 9.16	Applied (2017) for WA for small and medium C&I (3.72 kW), adjusted to medium C&I using a ratio of HVAC capacity sizes between small and medium C&I facilities (CBSA).
Program Participation	% of eligible customers	10%	Applied (2017): 2.3% - 3.4%; Global (2011): 10%; Brattle (2016): 14%; Navigant (2015a): 1-5%; and Brattle (2014): 15-42%.

Parameters	Units	Values	Notes
Event Participation	% (switch success rate)	95%	Consistent with residential DLC programs.

Results

Table 47 presents results for the commercial DLC space heat program, which could provide 12 MW of winter load reduction by 2045, at a levelized cost of $64 per kilowatt-year for small office and retail buildings and $29 per kilowatt-year for medium office and retail buildings.

Table 47. Commercial Direct Load Control Space Heat Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
Small Com DLC Heat-Switch	10 4-hour events	0-min	$64	7
Medium Com DLC Heat-Switch	10 4-hour events	0-min	$29	5

Commercial and Industrial Curtailment

For the commercial and industrial curtailment product, the utility requests that large commercial and industrial customers curtail their loads at a predetermined level for a predetermined period (i.e., the event duration). Event durations in similar programs across the country range from one hour to five hours. For this program, Cadmus assumes the event duration lasts four hours, and up to 10 events (for a total of 40 hours) could be called per season.

Participating customers execute curtailment after the utility calls the event. Customers may curtail any end-use loads to meet the curtailment agreement.[10] Although customers receive payments to remain ready for curtailment, actual curtailment requests may not occur. Therefore, this product represents a firm resource, and it assumes customers would be penalized for noncompliance. Because penalties exist, Cadmus assumes customers in the program will deliver a curtailed load that fulfills their contractual obligations 95% of the time (i.e., event participation).

Product Description

Cadmus assumes eligible participants include customers with at least 100 kW of monthly average demand in all commercial and industrial 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. Eligible customers can choose between two product options:

- Manual (where customers curtail loads during an event by manually turning off equipment)

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10 Cadmus assumed that participating customers could use standby generators to curtail load, similar to the assumption in Applied (2017).

- Automated (where customers install an automated control system that turns off certain pieces of equipment upon receiving the utility event dispatch signal)

Input Assumptions

Table 48 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the commercial and industrial curtailment program.

Table 48. Commercial and Industrial Curtailment Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per kW pledged per year	$60	Based on Cadmus (2018). Applied (2017) $71/kW (including utility and vendor costs); other benchmarked values were $27/kW (Frontier 2016) and $3/kW (Idaho Power 2015), which Cadmus assumes only included utility administrative costs.
Equipment Cost	$ per new kW pledged	Manual: $0	Manual: Assuming end users have the necessary equipment to participate.
		Automated: $310	Automated: Potter (2017)'s automated demand response enablement cost for large commercial customers (>200 kW).
Marketing Cost	$ per new kW pledged	$0	Already included in vendor management costs: Cadmus (2018); Applied (2017); Cadmus (2013b); Cadmus (2015).
Incentives (Annual)	$ per kW pledged per year	$20	California utilities have incentives that range from $4/kW (SMUD 2017) to $12/kW (Christensen 2016). Incentives from non-California utilities included $10/kW (Cadmus 2018) and $20/kW (Idaho Power 2015).
Incentives (One Time)	$ per new kW pledged	$0	N/A
Attrition	% of existing participants per year	0%	N/A
Eligibility	% of segment/end-use load	Varies by segment	Eligible customer size ranges from 100kW (SDG&E 2017; PG&E 2017b) to 200kW (Cadmus' 2018 study for Snohomish County PUD; Freeman 2013). Cadmus used 100kW as the eligible customer size, consistent with PSE's 2015 study (Cadmus 2015). Eligibility percentages were calculated using PSE customer demand data (Cadmus 2015).
Peak Load Impact	% of eligible segment/end-use load	25%	Based on 2021 Plan Workbook "Inputs_Product_NRCurtailCom-Winter" peak load impact assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655869156072
Program Participation	% of eligible segment/end-use load	3%	Based on 2021 Plan Workbook "Inputs_Product_NRCurtailCom-Winter" program participation assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655869156072 Assume half of eligible participants would participate in the Manual option while the other half would participate in the AutoDR option.
Event Participation	%	Manual: 95%	Manual: Benchmarked event participation rates range from 52% (BPA 2012) to 95% (Cadmus 2018; BPA 2016; Cadmus 2015).
		Automated: 98%	Automated: Assuming higher than the manual option.

Results

As shown in Table 49, the commercial and industrial curtailment program could, by 2045, obtain 6 MW of winter achievable potential at $95 per kilowatt-year from the manual product option and a similar amount of potential at $127 per kilowatt-year from the automated product option.

Table 49. Commercial and Industrial Curtailment Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
C&I Curtailment-Manual	10 4-hour events	Day-ahead (up to 2-hour-ahead)	$95	3
C&I Curtailment-AutoDR	10 4-hour events	0-min	$127	3

Residential Electric Vehicle Service Equipment

Residential EV charger demand response programs can be implemented to reduce EV charging in residential homes during peak hours. Networked level two 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. This study also assumes that most existing level 2 chargers are not networked. Therefore, this study focuses on EV owners that currently charge at home, but do not have a level 2 charger installed. The program would pay for the incremental cost of installing a connected level 2 charger. This study examines the potential of this program through the Residential EV DLC product option. Res EV DLC 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. This study assumes that events last up to four hours, for about 5 events during the winter.

Input Assumptions

Table 50 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the residential electric vehicle service equipment program.

Table 50. Residential Electric Vehicle Service Equipment Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	DLC: $150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per year	DLC: $150,000	Assuming 1 FTE.
Equipment Cost	$ per new participant	300	The Regional Technical Forum's researched incremental equipment cost of networked 240V level 2 charger compared to non-networked level 2 charger is $287 (Shum 2019).
Marketing Cost	$ per new participant	DLC: $30	City Light assumes this product requires higher marketing cost than the BPA assumption (Cadmus 2018a) for DLC products: $25 per new participant.

Parameters	Units	Values	Notes
Incentives (Annual)	$ per participant per year	DLC: $25	In line with incentives for residential DLC space heat and cool products.
Incentives (One Time)	$ per new participant	$0	N/A
Attrition	% of existing participants per year	5%	In line with BPA assumption (Cadmus 2018a) for DLC products.
Eligibility	% of customer count (e.g. equipment saturation)	36%	The number of EV owners is aligned with this study's assumptions for energy efficiency. The proportion of EV owners that already have a residential 240V AC level 2 charger (64%) is based on research by the Regional Technical Forum (Shum 2019).
Peak Load Impact	kW per participant (at meter)	0.34	Based on 2021 Plan Workbook "Inputs_Product_ResEVSEDLC-Winter" peak load impact assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655868985770
Program Participation	% of eligible customers	DLC: 25%	In line with assumptions for DLC products.
Event Participation	%	95%	Based on 2021 Plan Workbook "Inputs_Product_ResEVSEDLC-Winter" event participation assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655868985770

Results

As shown in Table 51, the residential electric vehicle service equipment program could, by 2045, obtain 9 MW of winter achievable potential at $361 per kilowatt-year.

Table 51. Residential Electric Vehicle Service Equipment Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
Res EV DLC	10 4-hour events	Day-ahead	$361	9

Residential Behavioral

Residential behavior demand response encourages customers to save energy during peak day events through behavioral changes. Participants receive notice (via an email or automated phone message), which includes ways to save energy and reduce peak consumption. The notice is given 24 hours prior to an event. This product does not offer incentives but dispatches fewer events (for emergency use) compared to DLC products.

Product Description

This analysis modeled one product option based on benchmarked data and information from PGE’s Flex Pricing and Behavioral Demand Response Pilot (Cadmus 2018c).

Input Assumptions

Table 52 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the residential behavioral program.

Table 52. Residential Behavioral Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per kW pledged per year	$67	BPA assumption (Cadmus 2018) of $89/kW-year (or $4/participant) assumes implementing Res Behavior DR as a stand-alone product. However, Cadmus assumes it would cost $67/kW-year (or $3/participant) to add Res Behavior DR to PSE's existing energy efficiency behavioral program.
Equipment Cost	$ per new kW pledged	$0	Participants must have a device to receive messages.
Marketing Cost	$ per new kW pledged	$0	Included in O&M costs.
Incentives (Annual)	$ per kW pledged per year	$0	In line with BPA assumption (Cadmus 2018a).
Incentives (One Time)	$ per new kW pledged	$0	In line with BPA assumption (Cadmus 2018a).
Attrition	% of existing participants per year	3.2%	PGE Flex Pricing and Behavioral Demand Response Pilot (Cadmus 2018c).
Eligibility	% of segment/ end-use load	100%	Assume all residential customers will have advanced meter by 2023
Peak Load Impact	% of eligible segment/end-use load	1.2%	PGE Flex Pricing and Behavioral Demand Response Pilot (Cadmus 2018c).
Program Participation	% of eligible segment/end-use load	20%	In line with BPA assumption (Cadmus 2018a).
Event Participation	%	100%	Peak load impact percentage accounts for event participation rate.

Results

As shown in Table 53, the residential behavioral program could, by 2045, obtain 9 MW of winter achievable potential at $76 per kilowatt-year.

Table 53. Residential Behavioral Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
Res Behavior DR	10 4-hour events	Day-ahead (non-dispatchable)	$76	9

Section 3. Distributed Solar PV

Technical Potential Approach

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

Available Roof Area

We calculated the available roof area based on building square footage (RBSA[11] and CBSA[12]), number of floors (obtained from the CBSA), and a count of PSE customers. By dividing the overall square footage of each building category (single-family residential, K-12 school, etc.) by the number of floors, we estimated the roof area available for each type of building, as shown in Table 54. The estimated number of floors is an average, based on the number of floors reported by facility owners participating in the survey, rather than archetypal examples of each building type.

Table 54. Available Roof Area by Building Type

Building Type	Building Unit Floor Area (Square Feet)	Estimated Floors	Roof Area per Unit (Square Feet)	Customers in 2045
Large Office	229,882	12.0	19,085	2,708
Medium Office	41,759	3.1	13,404	11,599
Small Office	4,798	1.6	3,071	85,972
Extra Large Retail	280,351	1.4	196,246	139
Large Retail	94,426	1.4	66,098	537
Medium Retail	13,333	1.4	9,412	5,588
Small Retail	2,170	1.3	1,655	7,042
School K-12	36,550	1.6	23,100	3,458
University	121,328	1.6	76,679	2,599
Warehouse	34,314	1.5	22,529	6,957
Supermarket	49,734	1.3	37,300	1,749
Mini-Mart	2,116	1.1	1,996	1,202
Restaurant	9,727	1.2	8,447	8,772
Lodging	31,385	4.9	6,341	1,851
Hospital	80,979	2.0	39,803	366
Residential Care	89,214	2.0	43,851	358
Assembly	13,631	2.0	6,667	3,705
Other	22,415	2.0	10,964	19,507
Total Commercial				**164,109**
Single Family	1,284	1.6	934	752,283
Single Family Low Income	1,284	1.6	934	136,417
Multifamily Low Rise			371	231,646
Multifamily Low Rise Low Income			371	74,929
Multifamily High Rise			227	42,211
Multifamily High Rise Low Income			227	13,654
Manufactured	1,269	1.0	1,446	59,938

11 RBSA 2018 dataset of PSE oversample.

12 Based on CBSA 2014 data of all utilities within the "urban" subset.

Building Type	Building Unit Floor Area (Square Feet)	Estimated Floors	Roof Area per Unit (Square Feet)	Customers in 2045
Manufactured Low Income	1,269	1.0	1,446	33,158
Total Residential				**1,344,234**

Adjusted Available Area

The available raw area cannot be used directly to estimate technical potential because not every roof is suitable for solar PV. To account for factors such as unsuitable roof orientation, shading, and obstructions, Cadmus relied on PSE's 2017 assessment of potential that utilized Light Detection and Ranging (LIDAR) data from the National Renewable Energy Laboratory's (NREL's) rooftop solar PV technical potential study and filtered it to match PSE's service territory. In addition, Cadmus applied a reduction in available roof area due to Washington's adoption of the 2012 International Fire Code (IFC) Article 605.11.3, which requires that the minimum roof area be maintained for safe access by emergency personnel.[13] An addendum requires that PV arrays "shall be located no higher than 18 inches (457 mm) below the ridge in order to allow for fire department rooftop operations."[14] Although this is less stringent than similar codes adopted in California and other jurisdictions, it nevertheless limits the available roof area for installing PV modules. Cadmus estimated this would reduce the available square footage by 5% for residential applications. Table 55 provides the estimated technical constraints applied to each sector.

Table 55. Technical Constraints Assumptions by Sector

Sector/Building Type	Technical Constraints Assumptions
Residential	26% based on LIDAR data and IFC Article 605.11.3
Commercial	51% based on LIDAR data and IFC Article 605.11.3

Module Power Density

Cadmus determined the average module power density in the PSE region through a review of installed PV system data provided by PSE. Using model number lookups for modules installed in 2018 and 2019, we determined the 2018 average module watts per square foot. Cadmus estimated future module power density using the trends in module efficiency increases from the International Roadmap for Photovoltaic. [15] Module power density in 2018 was 17.3 W_p/square foot, the estimated power density in 2022 is 18.5 W_p/square foot and the estimated power density in 2045 is 21.1 W_p/square foot.

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13 Washington State Department of Enterprise Services, State Building Code. https://fortress.wa.gov/ga/apps/sbcc/Page.aspx?nid=14

14 Ibid.

15 International Technology Roadmap for Photovoltaic. https://itrpv.vdma.org/web/itrpv/download

Electricity Generation

Once the potential solar PV direct current capacity was established, we converted this figure into annualized electricity (kilowatt-hour) generation. To approximate the generation profile of a typical PV system in PSE's service territory, Cadmus calculated an average capacity factor in kWh/kW_{DC} from the PSE's 2020 solar production database. The result is an average electricity generation figure, normalized to installed capacity, which accounts for specific regional characteristics for PSE's service territory.

Achievable Potential Approach

After calculating the technical potential that provides a theoretical upper bound on PV capacity growth, Cadmus considered relevant market factors (e.g., current costs, projected future cost trends, past adoption) to determine likely PV growth for PSE's service territory. To assess achievable potential, Cadmus first examined sector, end-use load, and customer economics for PV adoption in terms of simple payback. We applied these metrics to calculate achievable potential for two policy-based scenarios, considering the impacts of federal tax credits, incentives, and policies. The examination included the following scenarios:

- **Business-as-Usual Scenario.** This scenario reflects the base case with all current policies and incentives locked in place as written, including incentive amounts, expiration dates, and similar characteristics. Although this may not represent the most realistic scenario, this can provide a strong baseline for considering policy alternatives and planning scenarios. This includes several key policies:
    - Federal Investment Tax Credit: The ITC provides a 30% PV tax credit through 2019, with 26% in 2020, 22% in 2021, and expiring on December 31, 2021 for residential PV but reduced to 10% for commercial building PV thereafter.
    - Washington State Sales Tax Exemption: Solar PV equipment was exempt from a 6.5% Washington State Sales Tax. This benefit expired on September 30, 2017 and is not included in the business-as-usual scenario.
    - Washington State Renewable Energy System Cost Recovery Program (Production Incentive): The Production Incentive provided a variable, production-based incentive up to $5,000 per year for PV systems. The incentive level ranged from $0.15/kWh to $0.54/kWh, depending on the customer's eligibility for a variety of incentive adders (e.g., using equipment manufactured in Washington). PSE terminated this incentive December 12, 2019 and it is also not included in this study.
- **Advanced Cost Decline Scenario.** This scenario models a more rapid rate of cost decline while maintaining all the same financial incentives as the Business-as-Usual scenario. The cost decline is based on NREL's 2020 Annual Technology Baseline's[16] (ATB) advanced cost forecast compared to the moderate cost forecast used in the business-as-usual scenario.

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[16] NREL provides an annual set of modeling input assumptions for energy technologies, known as the Annual Technology Baseline, including residential and commercial PV. Available online: https://atb.nrel.gov

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

$$ASP = \frac{Net\ Costs\ (after\ incentives)}{Annual\ Energy\ Savings + Production\ Incentive\ Payments - Annual\ O\&M}$$

Although this equation is conceptually simple, the mix of incentives and cost projections added complexity to the calculations.

Installed costs. Cadmus based these assumptions of installed PV system costs on a variety of public data sources. Cadmus reviewed cost forecasts of both residential and commercial solar installations. These costs do not include any incentives, they are based on full costs of an installation. The PV $/Watt cost estimates for this study were developed from three major sources:

- 2020 EnergySage reported costs for installed residential solar PV systems in Washington state[17]
- 2020 Wood Mackenzie U.S. Solar Market Insight Full Report, 2019 Year in Review for nation-wide commercial solar PV systems[18]
- 2020 NREL ATB forecasts for residential- and commercial-scale PV pricing estimates to 2050[19]

Cadmus used a combination of these sources to validate and forecast $/watt. The projected installed dollar per watt is shown in Figure 42 over the planning horizon.

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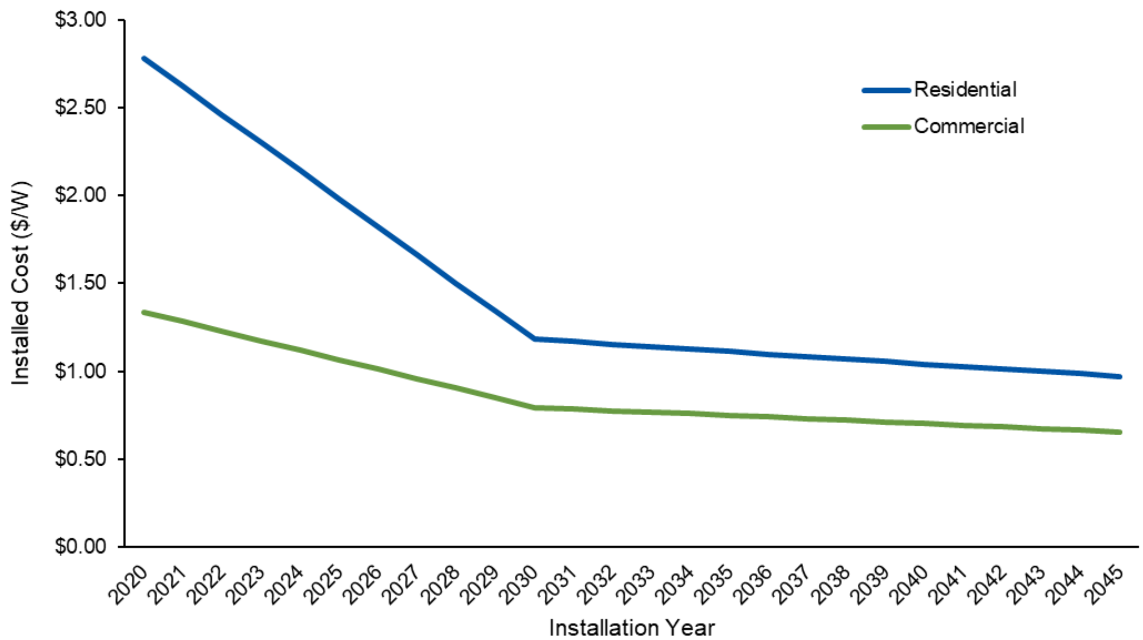
17 EnergySage is an online marketplace for residential solar installations that gathers real quotes from installers. This online marketplace was used to validate solar prices. EnergySage available online: https://www.energysage.com/solar-panels/solar-panel-cost/wa/

18 Wood Mackenzie, U.S. Solar Market Insight Full Report, 2019 Year in Review, March 2020. Available online: https://www.woodmac.com/reports/power-markets-us-solar-market-insight-2019-year-in-review-395500

19 NREL provides an annual set of modeling input assumptions for energy technologies, known as the Annual Technology Baseline, including residential and commercial PV. Available online: https://atb.nrel.gov

Figure 42. Projected Installed PV Costs by Sector (2020-2045)



Market penetration rates. Predicting which portion of technically feasible sites will install PV systems during the assessment period is a complex process, driven by many policy, economic, and technical factors beyond the direct control of PSE. These factors can be effectively modeled using their impacts on a quantitative metric (such as customer simple paybacks) and run for a variety of prototypical scenarios. This model estimates (a percentage of) market penetration as a function of customer payback. The following equation provided the curve used in analysis:

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

where MP equals the percentage of market adoption, and ASP equals the annual simple payback (years).

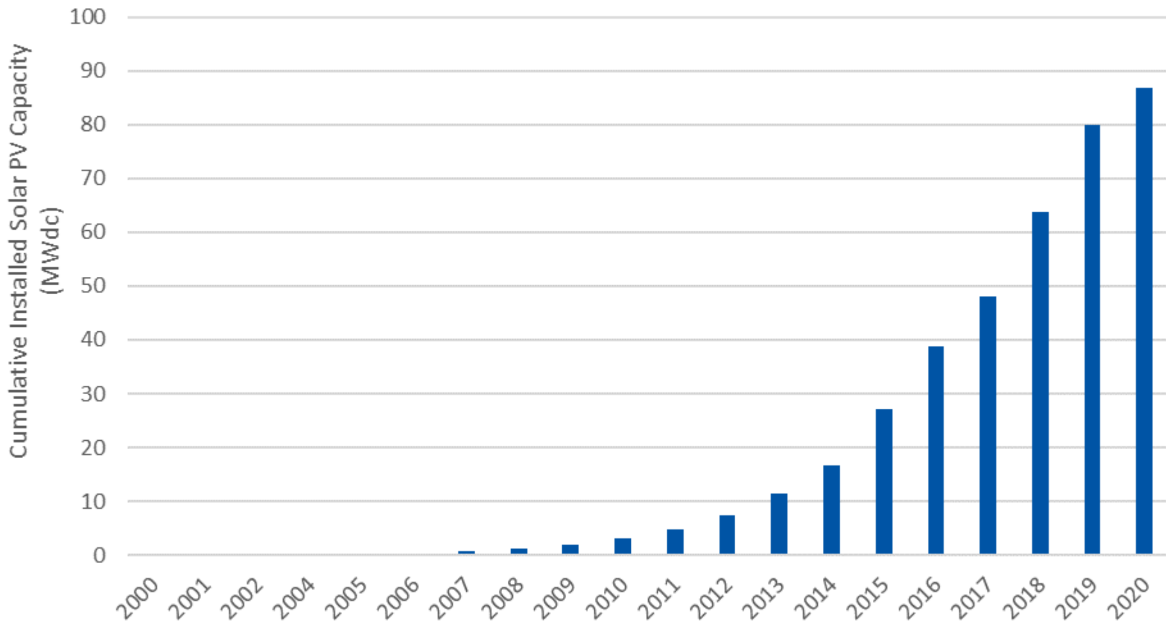
For this analysis, Cadmus calculated ASP from the end-use customers' perspectives, including all relevant incentives and fitting the curve to historical adoption rates. This curve-fitting process allowed Cadmus to account for, broadly speaking, regional attitudes and bias that might lead end-use customers to adopt solar at a given ASP level (the above equation shows these empirical factors as A and *B).*

After running the two scenarios of the plausible ranges in achievable potential, Cadmus relied on the base scenario to represent most realistic and current rate adoption. We used hourly profiles based on NREL's PVWatts calculator for the residential, commercial, and industrial sectors combined with the achievable base scenario potential to determine the PSE's IRP 8760 inputs.

Historical Solar PV Installations

As previously noted, the study estimated solar PV market potential for new installations from 2022 through 2045. This potential is in addition -- not inclusive of – the amount of solar PV capacity previously installed by customers in PSE's service territory. Figure 43 provides the cumulative installed solar PV capacity from 2000 through the first six months of 2020. Overall, the cumulative installed capacity is equal to 87 MW_{dc}. Nearly 60 MW, or 69% of the total, have been installed since 2016.

Figure 43. Historical Solar PV Installed Capacity, MW_{dc} through 2020



Distributed Solar PV Potential

Technical Potential Results

Based on the analysis described in the previous sections, Cadmus estimated 22,330 MW as the total new technical potential for PV installed on residential and commercial rooftops in PSE's service area over the 24 year study horizon. 71% of this technical potential arose in the commercial sector with the remaining 29% came from the residential sector. Each sector's technical potential is a function of the fraction of total roof area available and the total roof area. In this case, the residential sector accounted for a smaller percentage of the technical potential because only a modest proportion of total available area for this sector is likely to be suitable for PV installations. If the full technical potential were installed, it would generate approximately 2,362 aMW. This estimate derives from specific capacity factors for PSE (0.117 for residential and commercial), calculated using PSE's 2020 solar production database.

Table 56 provides the study period behind-the meter PV technical potential with growth due to increases in building stock from 2022 to 2045.

Table 56. PV Technical Potential (2022-2045)

Sector	Total 2022 aMW	Installed Capacity 2022 MW	Total 2045 aMW	Installed Capacity 2045 MW
Residential	534	4,560	697	6,584
Commercial	1,305	11,142	1,665	15,746

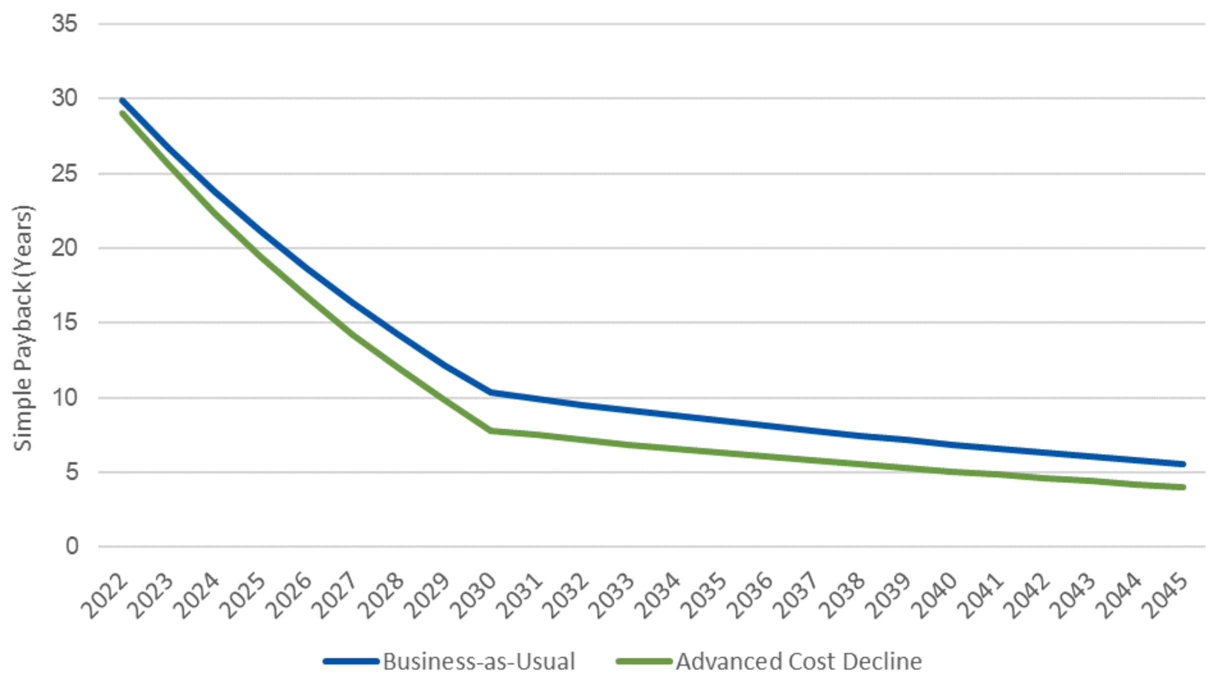
Sector	Total 2022 aMW	Installed Capacity 2022 MW	Total 2045 aMW	Installed Capacity 2045 MW
Total	**1,840**	**15,701**	**2,362**	**22,330**

Achievable Potential Results

Historically, the PV market has been heavily influenced by policy and incentive decisions, but, over time, future incentives may play a lesser role. For example, projects continue to be completed in California, even though major incentives have ended, and more projects continue to be completed under the Federal Public Utility Regulatory Policies Act. To model the influence of this policy shift away from incentives on the PV market potential within PSE's territory, Cadmus developed two scenarios reflecting the impact of only changes in upfront capital costs on customer paybacks and, by extension, market potentials. Unsurprisingly, the rate of decline in system capital cost heavily influences PV's achievable potential. In this section, Cadmus summarizes the results for each scenario (the business-as-usual and the advanced cost decline scenario).

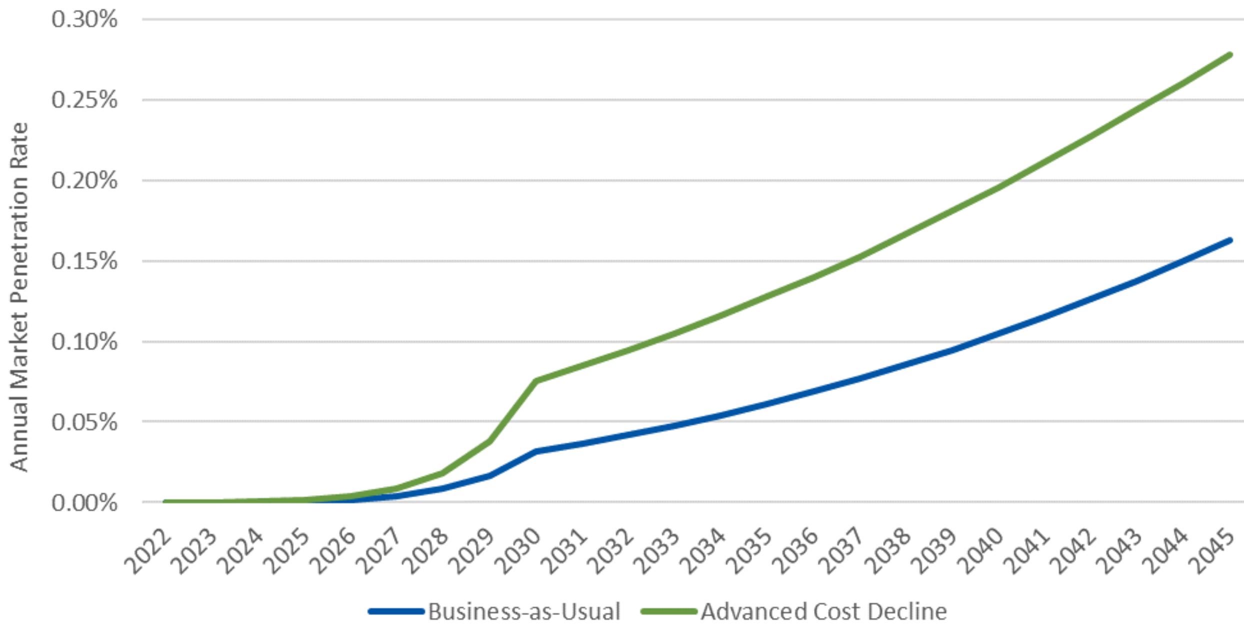
Figure 44 shows the impact of these scenario choices on expected customer payback periods (residential). The business-as-usual scenario shows a payback period of 30 years at the beginning of the study period and dropping to 6 years by 2045 primarily due to lower capital costs. The advanced cost decline scenario drops from a 29-year payback period in 2022 to 4 years in 2045.

Figure 44. Residential PV Simple Payback Projections Under Two Policy Scenarios



As a result, these varying payback periods have an impact on the likely adoption of PV systems. As discussed in the PV Achievable Potential Approach, Cadmus modeled a percentage of market penetration as a function of customer payback. Figure 45 shows the annual market penetration rate for the residential sector of each adoption scenario. Having lower PV costs is a major driver to increased market adoption.

Figure 45. Residential PV Annual Market Penetration Rate Under Two Policy Scenarios



Overall, across PSE's service area (residential and commercial), achievable potential will grow steadily year by year under both adoption scenarios, as shown in Figure 46. The advanced cost decline scenario results in achievable technical potential in 2045 of over 1.8 times that of the business-as-usual scenario.

Figure 46. Solar PV Total Cumulative Achievable Potential by Scenario

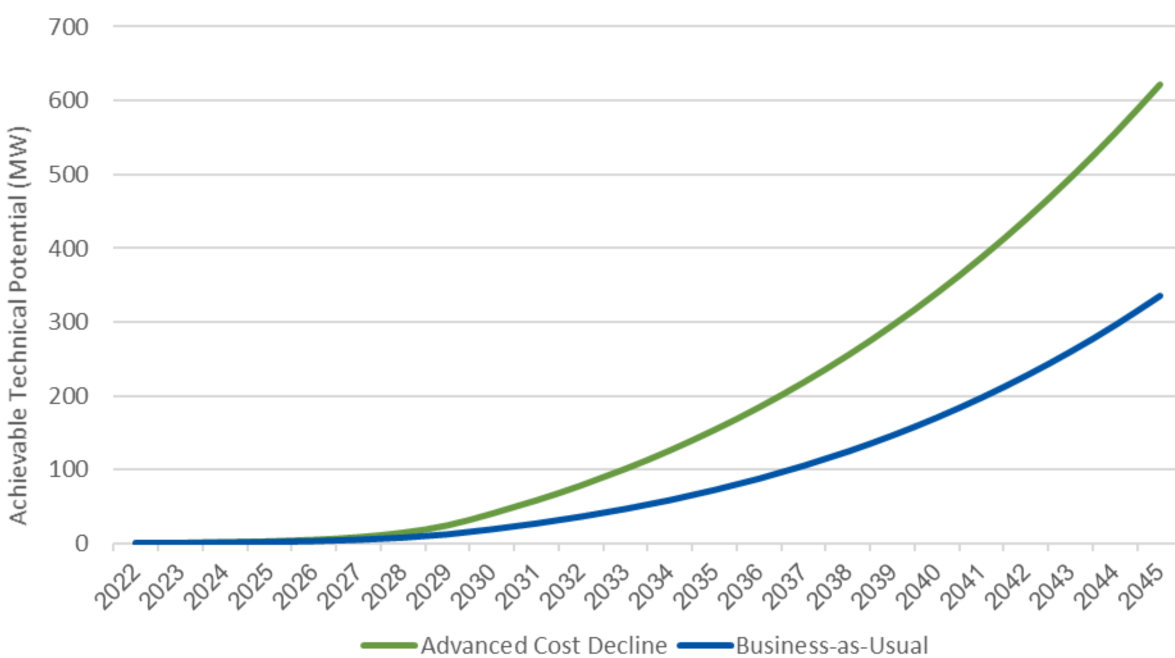


Table 57 summarizes the achievable potential results for each scenario. Cadmus relied on the business-as-usual scenario to represent the most realistic adoption rate for the IRP.

Table 57. Achievable Potential Results by Scenario and Sector, 2045 MW

Scenario	Residential MW	Commercial MW	Total MW
Business-as-Usual	87	249	336
Advanced Cost Decline	165	457	622

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Appendix A. IRP Sensitivities

This appendix provided comparisons of various electric and natural gas IRP sensitivies to the base case potentials presented throughout this report.

Electric IRP Sensitivities

Following engagements with stakeholders, PSE requested Cadmus to create four additional sensitivity scenarios for electric measures. The scenarios included are:

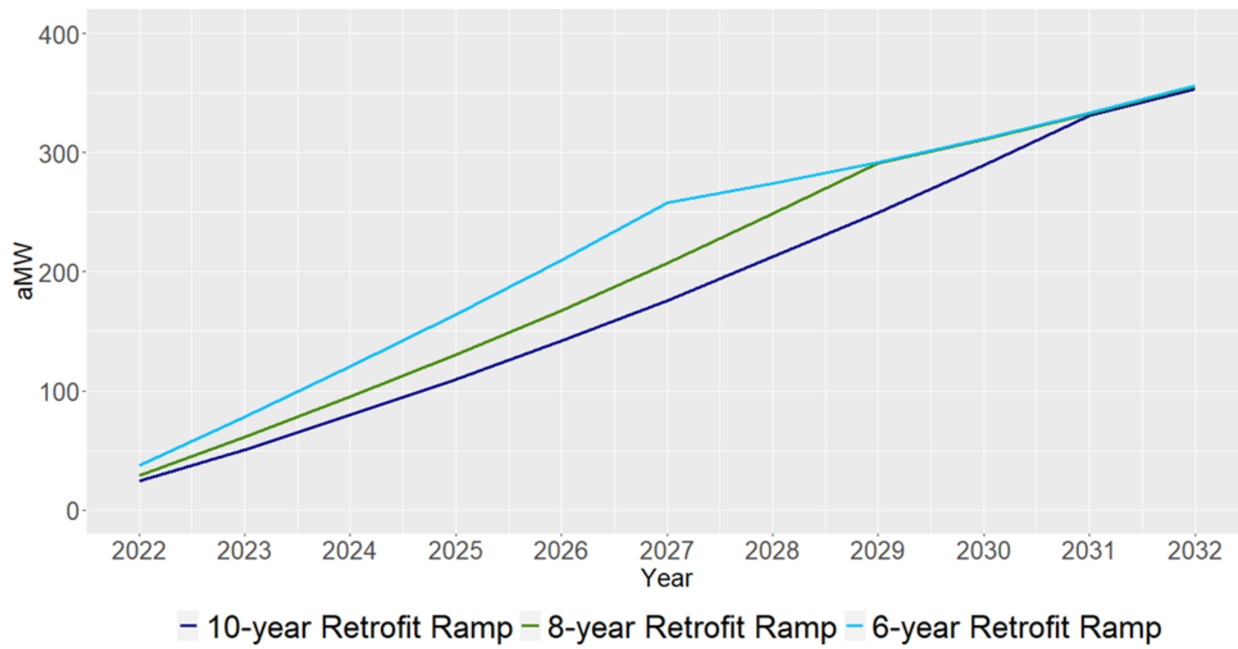
- **The 6-Year Retrofit Ramp Scenario** estimates potential using an accelerated ramp rate for discretionary measures, so all discretionary potential is obtained in the first 6 years of the study.
- **The 8-Year Discretionary Ramp Scenario** estimates potential using an accelerated ramp rate for discretionary measures, so all discretionary potential is obtained in the first 8 years of the study.
- **Societal Discount Rate Adjusted Scenario** utilizes a discount rate of 2.5%.
- **Non-energy Impact Adjusted Scenario** calculates the non-energy impact based on the EPA estimate for the cost of non-energy impacts of $0.02/kWh. [20]

Cadmus compared the results of these scenarios to the base scenario, with a 10-year retrofit ramp rate, to determine the impact of the scenarios on overall electric energy efficiency achievable potential.

Figure A-1 shows the impact of the differing ramp rate scenarios on the distribution of the cumulative energy efficiency achievable potential over the first ten years of the potential study.

[20] The Environmental Protection Agency estimates the per kWh non-energy benefits to be 2 cents for the PNW region.

Figure A-1. 10-Year Cumulative Energy Efficiency Achievable Potential (aMW)



The differing ramp rates for discretionary measures result in 43% of the 24-year electric achievable energy efficiency potential being achieved in the first 6 years and 48% of the 24-year electric achievable energy efficiency potential being achieved in the first 8 years**.** It is important to note that the 24-year cumulative electric achievable energy efficiency potential is equivalent across all scenarios and the differing ramp rates only have an impact on the distribution of the potential within the potential study horizon.

Table A-1 provides a comparison of the 6-year cumulative achievable potential from the base scenario with a 10-year retrofit ramp rate to the scenario with a 6-year retrofit ramp rate.

Table A-1. Comparison of 6-Year Electric Energy Efficiency Cumulative Achievable Potential for IRP Sensitivity Ramp Rate Scenarios (aMW)

Year	10-year Retrofit Ramp Achievable Potential (aMW)	6-year Retrofit Ramp Achievable Potential (aMW)	Percent Change Compared to 10-year Retrofit Ramp
2027	176.09	257.59	46.3%

In the first 6 years of the potential study, 176 aMW of cumulative achievable potential is obtained in the base scenario. In the 6-year retrofit ramp rate scenario, the cumulative achievable potential in the first six years is 46% greater with a value of 256 aMW.

Table A-2 provides a comparison of the 8-year cumulative achievable potential from the base scenario with a 10-year retrofit ramp rate to the scenario with an 8-year retrofit ramp rate.

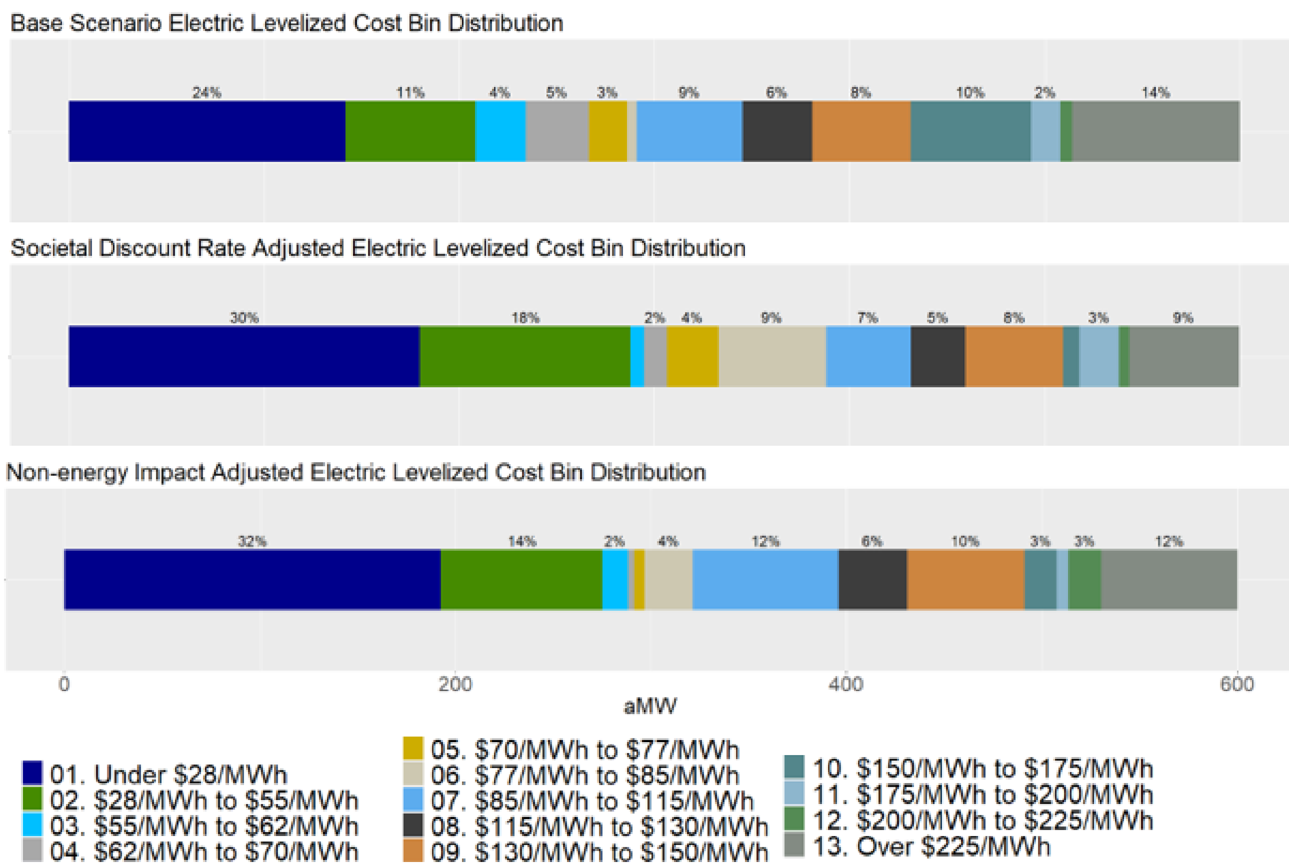
Table A-2. Comparison of 8-Year Electric Energy Efficiency Cumulative Achievable Potential for IRP Sensitivity Ramp Rate Scenarios (aMW)

Year	10-year Retrofit Ramp Achievable Potential (aMW)	8-year Retrofit Ramp Achievable Potential (aMW)	Percent Change Compared to 10-year Retrofit Ramp
2029	249.68	290.86	16.5%

In the first 8 years of the potential study, 250 aMW of cumulative achievable potential is obtained in the base scenario. In the 8-year retrofit ramp rate scenario, the cumulative achievable potential in the first eight years is 17% greater with a value of 291 aMW.

Figure A-2 shows the impact of the societal discount rate adjusted scenario and the non-energy impact adjusted on the electric levelized cost bin distribution when compared to the base scenario. Note that the base scenario has a discount rate of 6.8%.

Figure A-2. Comparison of Levelized Cost Bin Distribution for 24-Year Cumulative Achievable Potential in IRP Sensitivity Scenarios (aMW)



The non-energy impact adjusted scenario and the societal discount rate adjusted scenario have 13% and 11%, respectively, more of the 24-year cumulative electric achievable potential with a levelized cost under $55/MWh. This equates to about 80 and 67 more aMW, respectively, of 24-year cumulative achievable potential than the base scenario under $55/MWh. Additionally, in the societal discount rate adjusted and the non-energy benefit adjusted scenarios, the cost bin designated by a levelized cost greater than $225/MWh is reduced by 56 aMW and 69 aMW, respectively, and is no longer the second largest bin.

Gas IRP Sensitivities

PSE requested Cadmus to create four additional sensitivity scenarios for natural gas measures. The scenarios included are:

- **The 6-Year Retrofit Ramp Scenario** estimates potential using an accelerated ramp rate for discretionary measures, so all discretionary potential is obtained in the first 6 years of the study.
- **The 8-Year Discretionary Ramp Scenario** estimates potential using an accelerated ramp rate for discretionary measures, so all discretionary potential is obtained in the first 8 years of the study.
- **Societal Discount Rate Adjusted Scenario** utilizes a discount rate of 2.5%.

Cadmus compared the results of these scenarios to the base scenario, with a 10-year retrofit ramp rate, to determine the impact of the scenarios on overall natural gas energy efficiency achievable potential.

Figure A-3 shows the impact of the differing ramp rate scenarios on the distribution of the cumulative energy efficiency achievable potential over the first ten years of the potential study.

Figure A-3. 10-Year Cumulative Energy Efficiency Achievable Potential (Therms)

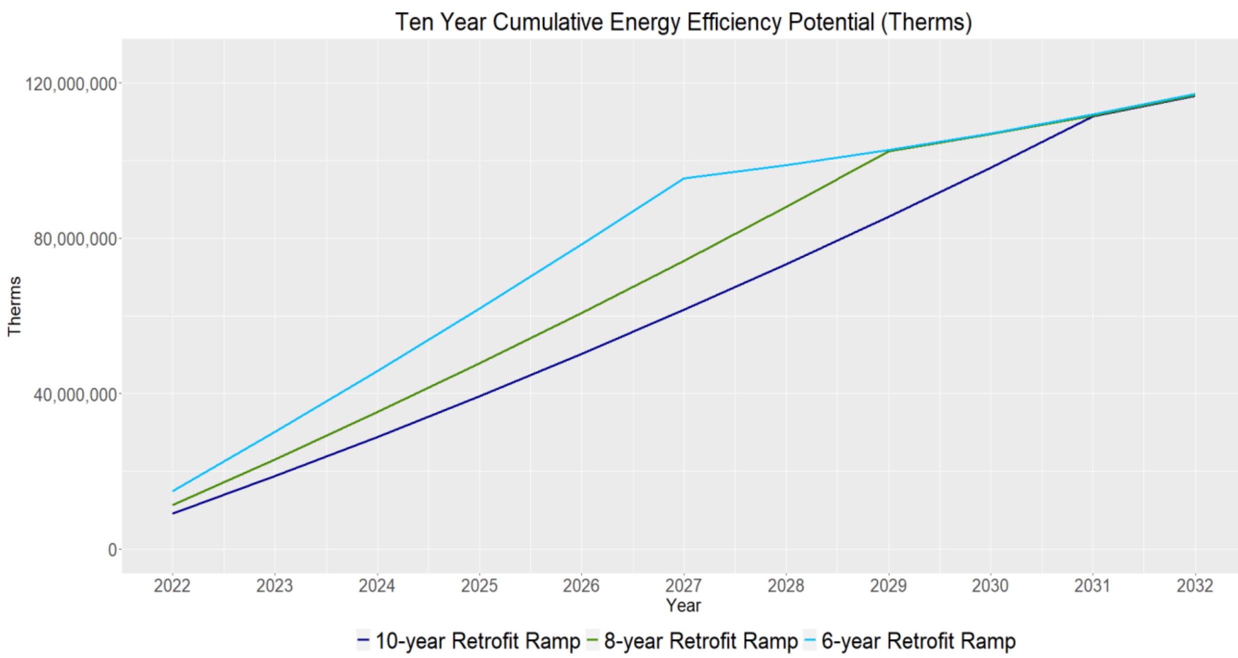


Table A-3 provides a comparison of the 6-year cumulative achievable potential from the base scenario with a 10-year retrofit ramp rate to the scenario with a 6-year retrofit ramp rate.

Table A-3. Comparison of 6-Year Natural Gas Energy Efficiency Cumulative Achievable Potential for IRP Sensitivity Ramp Rate Scenarios (Therms)

Year	10-year Retrofit Ramp Achievable Potential (Therms)	6-year Retrofit Ramp Achievable Potential (Therms)	Percent Change Compared to 10-year Retrofit Ramp
2027	61,576,169	95,411,744	54.9%

In the first 6 years of the potential study, 61.6 million therms of cumulative achievable potential are obtained in the base scenario. In the 6-year retrofit ramp rate scenario, the cumulative achievable potential in the first six years is 54.9% greater with a value of 95.4 million therms.

Table A-4 provides a comparison of the 8-year cumulative achievable potential from the base scenario with a 10-year retrofit ramp rate to the scenario with an 8-year retrofit ramp rate.

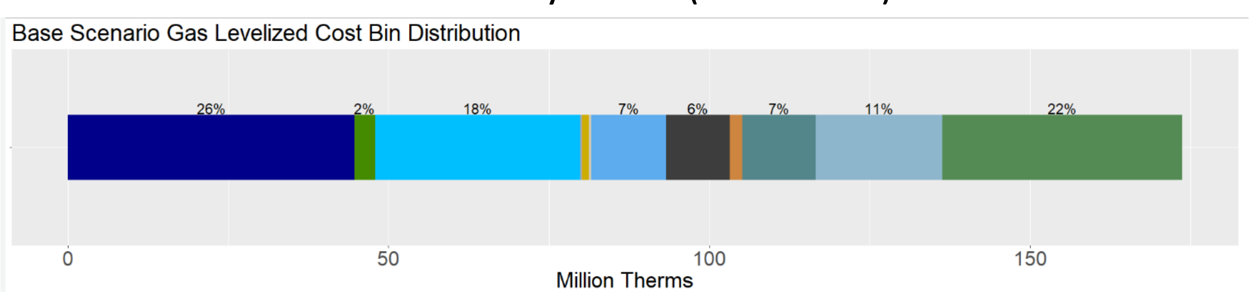
Table A-4. Comparison of 8-Year Natural Gas Energy Efficiency Cumulative Achievable Potential for IRP Sensitivity Ramp Rate Scenarios (Therms)

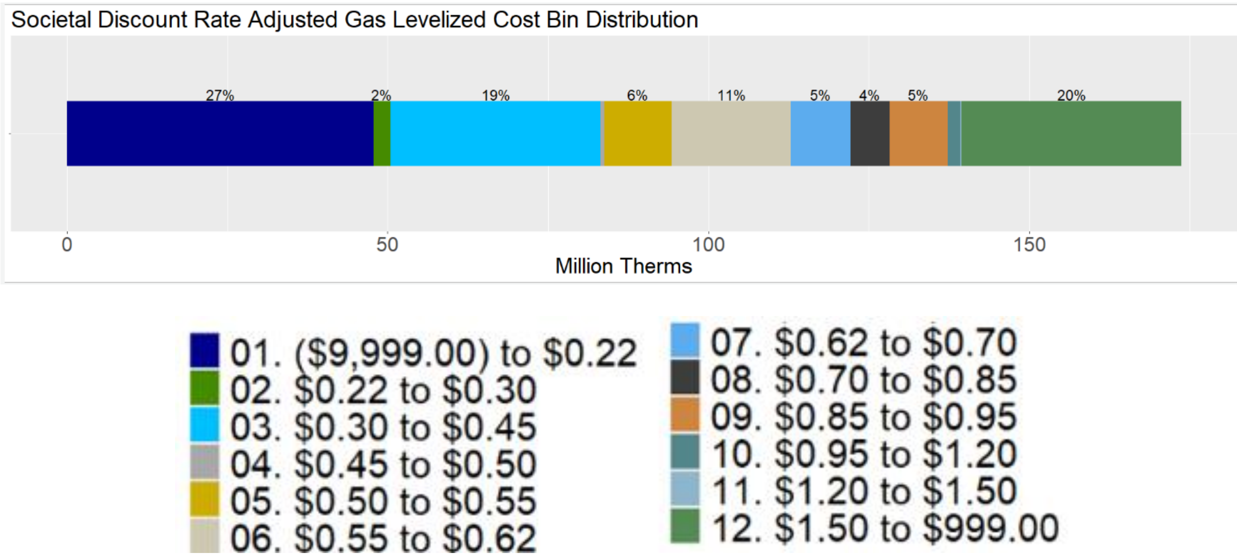
Year	10-year Retrofit Ramp Achievable Potential (Therms)	8-year Retrofit Ramp Achievable Potential (Therms)	Percent Change Compared to 10-year Retrofit Ramp
2029	85,553,452	102,425,509	19.7%

In the first 8 years of the potential study, 85.6 million therms of cumulative achievable potential is obtained in the base scenario. In the 8-year retrofit ramp rate scenario, the cumulative achievable potential in the first eight years is 19.7% greater with a value of 102.4 million therms.

Figure A-4 shows the impact of the societal discount rate adjusted scenario on the natural gas levelized cost bin distribution when compared to the base scenario. Note that the base scenario has a discount rate of 6.8%. When the societal discount rate is used the amount of cumulative 20-year achievable potential in the least expensive cost bin increases by one percent and the highest cost bin potential decreases by a percent compared to the base scenario. The greatest change in levelized cost bin distribution occurs across cost bins five to eleven (levelized costs $0.50 - $1.50). In the societal discount rate scenario, there is more cumulative achievable potential in the lower of these cost bins compared to the base scenario.

Figure A-4. Comparison of Levelized Cost Bin Distribution for 20-Year Cumulative Achievable Potential in IRP Sensitivity Scenarios (Million Therms)





Cost bins that make up less than 2% of the 20-Year Cumulative Achievable Potential are not labeled on the horizontal bar charts

Appendix B. Gas-to-Electric Potential Scenario

Executive Summary

Public policies that are intended to make the transition of energy product and end use away from fossil fuels are affecting electric and gas utilities across the country, including in California, New York, Rhode Island, Massachusetts, and Minnesota. The new Washington State Clean Energy Transformation Act (CETA), Senate Bill 5116-2019-20, enacted May 2019, lays out the utility requirements for making the transition to 100% greenhouse gas-neutral generation by 2030.

This new policy, as well as other possible policies affecting gas use in Washington state, could have a direct impact on the electric system needs as well as the customers of Puget Sound Energy (PSE). For the purpose of supporting IRP decarbonization scenario analysis, Cadmus modeled a gas-to-electric conversion scenario that investigates PSE's electric system load impacts and customer costs of PSE customer conversions from natural gas to electric end uses from 2022 through both 2030 and 2045.

Cadmus used data from the 2021 conservation potential assessment (CPA), PSE customer database, the PSE Residential Characteristics Survey (RCS), the Commercial Building Stock Assessment (CBSA), and other sources to calculate these potential impacts. Cadmus also conducted additional research to determine cost and load impacts of some equipment types.

Table B-1 shows the cumulative annual electric energy impacts to PSE's system of converting natural gas equipment for each customer sector. As shown in the table, the biggest impact in 2030 and 2045 is in the residential sector, which accounts for 53% and 60% of the total cumulative energy impacts in 2030 and 2045, respectively. These impacts represent additional electric energy loads of 7.9% and 35.5% compared to the total PSE electric load forecast in 2030 and 2045, respectively.

Table B-1. Cumulative Annual Electric Energy Impacts in 2030 and 2045, MWh

Sector	2030	2045
Residential	996,501	3,517,799
Commercial	666,018	1,826,011
Industrial	111,319	252,763
Total	**1,773,837**	**5,596,573**

The energy impacts presented in Table B-1 and throughout Appendix B represent energy impacts at generation, thereby accounting for transmission and distribution line losses from the generator to the customer meter. The study assumed a line loss rate of 6.8% for all customer classes.

Table B-2 presents the cumulative annual winter peak demand impacts to PSE's system of converting natural gas equipment for each customer sector. The commercial and residential sectors contribute 63% and 33% of the 2030 peak demand increase, respectively, but by 2045, the residential sector accounts for 68% of the total peak demand increase compared to 30% from the commercial sector. Combined, these impacts represent additional electric peak demands of 6% and 17% in 2030 and 2045, respectively.

Table B-2. Cumulative Annual Electric Peak Demand Impacts in 2030 and 2045, MW

Sector	2030	2045
Residential	207	708
Commercial	108	311
Industrial	13	29
Total	**328**	**1,048**

Table B-3 shows the cumulative annual impacts of converting natural gas equipment to electric for each customer sector. The values in the table represent the cumulative natural gas throughput reductions from the gas-to-electric conversions. The residential sector accounts for 68% and 73% of the total natural gas reductions in 2030 and 2045, respectively.

Table B-3. Cumulative Annual Natural Gas Impacts in 2030 and 2045, Therms

Sector	2030	2045
Residential	-167,979,794	-636,439,120
Commercial	-75,375,044	-225,596,733
Industrial	-2,857,517	-6,487,974
Total	**-246,212,356**	**-868,523,827**

The natural gas reductions in Table B-3 represent a decrease of 21% and 74% in 2030 and 2045, respectively, compared to PSE's total 2019 natural gas sales. Similar to the CPA, the gas to electric conversion scenario developed for the IRP does not include PSE's commercial or industrial gas transport customers. The next section of Appendix B describes the methods employed by Cadmus to estimate the gas-to-electric conversion potential.

Methods

Cadmus calculated the energy, peak demand, and cost impacts of converting natural gas to electric equipment within PSE's natural gas service territory. Because PSE's natural gas service territory includes not only PSE electric customers but also electric customers of Seattle City Light, Snohomish County Public Utility Department (PUD), Tacoma Power, and Lewis County PUD, PSE natural gas customer conversions to electric end uses will inevitably affect these other utilities' electric systems. However, for the purpose of this IRP and this gas to electric scenario, our electric energy and peak demand potential estimates apply only to PSE's electric service territory and exclude the impacts on other electric utilities.

We applied different analytical approaches for the residential and commercial sectors than for the industrial sector. For the residential and commercial sectors, we counted the number of natural gas equipment units in PSE's service area and applied the energy, demand, and cost impacts to these units. In the industrial sector, our approach involved a top-down method. We calculated the total industrial gas load and then converted these loads into electric energy and peak demand.

Residential and Commercial Sectors

Cadmus calculated the number of natural gas equipment units that could be converted to electric equipment in PSE's service area for both existing equipment and new construction. We took PSE's customers counts and forecasts and applied equipment saturation rates and fuel shares in each year of the study horizon (2022–2045) plus a base year (2021). We then matched each natural gas unit to an equivalent electric equipment and applied annual energy consumption, peak demand, and cost assumptions to the electric equipment to calculate the total impact of conversion. Figure B-1 shows the calculation methodology applied to the residential and commercial sectors.

Figure B-1. Residential and Commercial Impacts Calculation Methodology

To mitigate the peak demand impacts of additional winter space heating loads to the electric system, the Cadmus team modeled existing residential construction natural gas furnace replacements assuming the use of a hybrid air-source heat pump with natural gas backup that switches from electric space heating to natural gas when the outdoor air temperature is equal to or less than 35 degrees Fahrenheit. To estimate annual electric impacts, we relied on a similar stock turnover algorithm as was used in the CPA, where it is assumed that baseline equipment is replaced at a rate of one divided by the equipment's effective useful life. In other words, for end use equipment with a 10-year measure life, 10% (1/10) of the existing equipment stock is replaced in a given year.

In addition to the stock turnover algorithm, potential impacts of natural gas to electric conversions were constrained by the rate at which assumed baseline (natural gas) equipment would be replaced by electric equipment. For example, the study assumed that heat pump technologies, including hybrid heat pumps with gas backup and heat pump water heaters, would achieve a market replacement rate of 50% in 2030 and 100% by 2045. In other words, of all the gas furnaces in existing residential homes modeled to reach the end of their useful life in 2030, the scenario assumed half of these would be replaced by hybrid heat pump units, while the remaining half would be replaced by gas furnaces. Over time, the study assumed a linear increase from roughly 5% replacements in the first year, to 50% by 2030, and 100% by 2045 for heat pump technologies. Using a similar methodology as the CPA, Cadmus assumed that existing gas furnace replaced with gas furnaces would remain eligible for replacement with hybrid units later in the study horizon once the replacement unit's effective useful life expires.

Residential and Commercial Data Sources

Cadmus used PSE customer counts and forecasts, residential equipment saturation and fuel share data from PSE's 2017 Residential Customer Survey (RCS), commercial equipment saturation data from the 2021 PSE CPA, and the 2014 CBSA to estimate gas equipment counts. Cadmus used PSE's current CPA to determine the energy impacts of equipment conversion. To assess the peak demand impacts, Cadmus used each equipment's hourly end-use profile and combined these with PSE's high load hour definition to determine the coincident peak impacts. Table B-4 lists the data sources used to analyze conversion impacts in the residential and commercial sectors.

Table B-4. Data Sources for the Residential and Commercial Analysis

Analysis Component	Data Sources
Residential, Commercial, and Industrial Customer Counts	2020 PSE customer counts, PSE customer forecasts
Residential Equipment Fuel Shares and Saturations	2017 RCS
Commercial Equipment Fuel Shares and Saturations	2014 CBSA
Residential Electric Equipment Consumption	2021 PSE CPA
Commercial Electric Equipment Consumption	2021 PSE CPA
Residential Electric Equipment Peak Demand	2021 PSE CPA, end use load shapes
Commercial Electric Equipment Peak Demand	2021 PSE CPA, end use load shapes
Residential Electric Equipment Costs	2021 PSE CPA, Cost research (RSMeans and online research)
Commercial Electric Equipment Costs	2021 and 2015 PSE CPA, Cost research (RSMeans and online research)

Equipment Counts

Cadmus used 2020 PSE customer counts to estimate the number of natural gas equipment units that would be converted to electric equipment. We projected the 2020 customer counts for the 24 years of the study horizon (2022-2045) plus a base year (2021) using PSE's forecast growth estimates. Cadmus used customer growth forecasts to calculate the effects of new construction that did not involve gas connections.

To calculate the number of non-electric equipment units, Cadmus applied equipment fuel shares and saturations to the PSE customer counts at the segment level. We first calculated the number of customers in each residential and commercial customer segment then applied segment-specific fuel shares and equipment saturations.[21] Our analysis also accounted for the proportion of natural gas customers with existing cooling equipment to avoid overestimating the cooling load from new heat pump equipment.

Residential Electric Equipment Impact Calculations and Assumptions

Cadmus counted equipment units for these residential natural gas furnaces, boilers, water heaters, clothes dryers, and cooking equipment. We then applied the energy, peak demand, and costs of similar electric equipment to calculate impacts across the service area. Residential heating equipment costs include the costs to upgrade a home's electric panel to accommodate new electric heating equipment.

To replace a natural gas forced air furnace, Cadmus added an additional cost to account for decommissioning the old equipment and venting, line sets, duct work and pad, and any new required electrical outlets (i.e. 220 volt circuits).[22] These additional costs equaled about $2,088 for single family homes, which account for 92% of PSE's existing customer homes with natural gas service.

Table B-5 shows the range of assumptions we used to calculate the energy, demand, and cost impacts of converting the various residential natural gas equipment types to electric equipment for each customer segment. The second column of the table shows the relevant electric equipment we assumed would replace the natural gas equipment. Other columns show the various energy (kWh), demand (kW), and cost metrics we applied to calculate the total system impacts.

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21 Residential segments include single-family, multifamily, and manufactured homes. Commercial segments include assembly, hospital, large office, large retail, lodging, medium office, medium retail, minimart, other, restaurant, school K-12, small office, small retail, supermarket, warehouse, extra-large retail, residential care, and university.

22 Cost data based on RSMeans 2019 (https://www.rsmeans.com/) and online services that assess construction costs in the Seattle area (i.e., homewyse.com, homeadvisor.com, homeguide.com, inchcalculator.com). These costs include installation and materials such as panels, wires, and conduit at the existing panel location. This study does not account for existing wire upgrades and panel placement per code requirements or varying permit fees in different jurisdictions.

Table B-5. Residential Equipment Energy, Peak Demand, and Cost Assumptions

Natural Gas Equipment	Electric Equipment	Construction	Annual kWh	Winter kW	Incremental Cost
Furnace	Hybrid Heat Pump	Existing	1,805 to 4,359	0.38 to 0.91	$1,874 to $10,874
Furnace	Heat Pump – Cold Climate	New	2,715 to 6,213	0.69 to 1.58	-$407 to $8,757
Boiler	Ductless Heat Pump	Existing, New	2,331 to 5,946	0.54 to 1.38	-$2,693 to $4,518
Clothes Dryer	Clothes Dryer	Existing, New	922	0.13	$117
Cooking	Cooking	Existing, New	178	0.03	-$510
Tank Water Heater	Heat Pump Water Heater	Existing, New	995 to 1844	0.019 to 0.36	$1,454
Tankless Water Heater	Heat Pump Water Heater	Existing, New	995 to 1844	0.019 to 0.36	$815

As shown in Table B-5, the incremental costs show a negative cost impact for some new construction applications. The baseline condition includes natural gas heating equipment (e.g., furnaces and boilers) as well as portion of buildings with electric cooling equipment. As a result, the baseline costs of the heating and cooling (e.g., furnaces and boilers with cooling systems) costs more than the converted electric equipment installations.

Commercial Electric Equipment Impact Calculations and Assumptions

For the commercial sector, Cadmus counted equipment units for natural gas furnaces, boilers, commercial cooking equipment, and water heating. We then calculated the energy, peak demand, and cost impacts of converting this equipment by applying the electric energy consumption, peak demand, and costs of similar electric equipment.

Table B-6 shows the assumptions we used to calculate the energy, demand, and cost impacts of converting the various natural gas equipment types to electric equipment. The second column shows the relevant electric equipment we assumed would replace the natural gas equipment. Other columns show the energy (kWh), demand (kW), and cost metrics we applied to calculate the total system impacts. The table provides values on a per building basis and the ranges represent the diversity of the commercial building stock. The commercial cooking equipment end use includes a number of equipment options (e.g., fryer, broilers, steamers, conventional ovens, and convection ovens); therefore, to minimize the complexity of the scenario analysis, we assessed commercial cooking loads in aggregate.

Table B-6. Commercial Equipment Energy, Peak Demand, and Cost Assumptions

Natural Gas Equipment	Electric Equipment	Construction	Annual kWh	Winter kW	Incremental Cost
Furnace	Hybrid Heat Pump	Existing, New	1,625 to 264,039	0.34 to 55.18	$17,418 to $232,245
Furnace	Heat Pump – Cold Climate	Existing, New	444 to 376,364	0.18 to 118.82	$13,315 to $177,227
Boiler	Heat Pump	Existing, New	444 to 242,805	0.18 to 76.66	$9,443 to $198,299
Cooking	Cooking	Existing, New	4,176 to 79,151	0.53 to 10.74	$0 to $10,079
Tank Water Heater	Heat Pump Water Heater	Existing, New	429 to 161,812	0.06 to 21.68	-$4,541 to $7,899

Industrial Sector

Similar to the 2021 CPA, Cadmus used a top-down method to estimate the new electric industrial load. We calculated the total industrial non-electric space heating load by proportioning 2019 industrial customer natural gas sales using data from PSE's 2021 CPA. We did not evaluate natural gas process loads for this study and focused only on space heating equipment. Depending on the industrial segment, the natural gas space heating load as a percentage of total facility load ranged from 0% (fruit storage) to 55% (miscellaneous manufacturing).

Overall, industrial natural gas space heating load presented about 34% of the natural gas load. This study assumed all space heating load can be converted to electric equipment such as electric resistance, electric boilers, and heat pumps. This analysis would represent the upper end of the space heating load that can be converted and, as a result, Cadmus limited the convertible industrial gas load to 30%.

To convert the non-electric space heating equipment into electric space heating equipment, Cadmus applied equipment coefficients of performance ratios and converted the non-electric MMBtu into electric kWh. For simplicity, we assumed a non-electric coefficient of performance of 0.80 (i.e., similar to federal standards for boiler and furnace thermal efficiency requirements) and electric coefficient of performance of 1.20. The electric equipment coefficient of performance assumes a mix of equipment including heat pumps.

The industrial analysis included one base scenario and did not evaluate multiple efficiency scenarios. It should be noted, the customer forecast of industrial customer declines from year to year. Therefore, the industrial load analysis applied only to existing construction conversion scenario. As noted previously, Cadmus also excluded industrial gas transport customers from this analysis.

Load Impacts

Cadmus assessed the electric load impacts of PSE customers' conversion of natural gas to electric equipment from 2022 through 2045. We calculated these load impacts in terms of energy and winter and summer peak demand. We also calculated the energy and peak impacts by end use.

Electric Energy Impacts

Table B-7 shows the energy impacts by sector and end use group of converting natural gas to electric equipment in 2030 and 2045. Within the residential sector, air source heat pumps – applied only to new construction – and hybrid heat pumps (considered only for existing construction applications) combined for over 500,000 MWh of incremental cumulative load through 2030 and more than 1.6 million MWh by 2045. Conversion of natural gas water heating to electric heat pump water heaters accounted for approximately 271,0000 MWh of incremental load cumulative through 2030 and more than 1.1 million MWh by 2045.

Table B-7. Sector and End Use Cumulative Annual Electric Energy Impacts in 2030 and 2045, MWh

Sector	End Use	2030	2045
Residential	Heat Pump	316,606	766,057
	Hybrid	196,845	898,333
	Water Heat	270,778	1,160,318
	Other	212,271	693,091
	Residential Sub-total	**996,501**	**3,517,799**
Commercial	Heat Pump	47,035	151,455
	Hybrid	84,854	276,997
	Water Heat	69,010	214,360
	Other	465,118	1,183,199
	Commercial Sub-total	**666,018**	**1,826,011**
Industrial	**Industrial Sub-total**	111,319	252,763
Total	**Total**	**1,773,837**	**5,596,573**

The other end use loads listed in Table B-7 include cooking, dryers, and residual space heating loads not directly accounted for when comparing the bottom-up calculations of end use saturations and loads to the overall PSE natural gas forecast. Examples of these residual loads include secondary gas heating sources, including secondary furnaces, fireplaces, hearths, and additional gas use including but not limited to outdoor cooking and pool heating. As a simplifying assumption, Cadmus assumed conversion of these natural gas to electric loads using the hybrid heat pump conversion factor, which equated to roughly 8.6 kWh/therm.

Peak Demand Impacts

Cadmus calculated the peak demand impacts in PSE's total service area as shown in Table B-8, which provides the winter and summer peak demand impacts by sector and end use group of converting natural gas to electric equipment in 2030 and 2045. The residential sector accounted for 63% of the total new winter peak demands through 2030 and 68% through 2040.

Table B-8. Sector and End Use Cumulative Annual Electric Demand Impacts in 2030 and 2045, MW

Sector	End Use	Winter		Summer	
		2030	2045	2030	2045
Residential	Heat Pump	81	195	45	109
	Hybrid	41	188	27	125
	Water Heat	44	190	28	115

Sector	End Use	Winter		Summer	
		2030	2045	2030	2045
	Other	42	136	13	43
	Residential Sub-total	**207**	**708**	**114**	**393**
Commercial	Heat Pump	16	51	1	3
	Hybrid	29	94	2	6
	Water Heat	10	30	7	21
	Other	54	137	50	128
	Commercial Sub-total	**108**	**311**	**60**	**158**
Industrial	Other	13	29	13	29
Total	**Total**	**328**	**1,048**	**186**	**580**

Natural Gas Reduction Impacts

In addition to the impacts from natural gas to electric conversions on PSE's electric system, Cadmus also calculated the associated natural gas throughput reductions at the equipment, end use, and sector levels. Table B-9 shows the cumulative sector and end use natural gas reductions through 2030 and 2045. The largest impacts occurred within the residential sector and, more specifically, its space heating end uses. Overall the residential sector accounted for 68% and 73% of the cumulative 2030 and 2045 natural gas reductions, respectively, while accounting for approximately 54% and 56% of PSE's baseline forecast sales without decarbonization in 2030 and 2045.

Table B-9. Sector and End Use Cumulative Annual Natural Gas Reductions in 2030 and 2045, therms

Sector	End Use	2030	2045
Residential	Space Heat	-94,830,995	-366,996,249
	Water Heat	-44,122,297	-143,784,672
	Other	-29,026,503	-125,658,200
	Residential Sub-total	**-167,979,794**	**-636,439,120**
Commercial	Space Heat	-34,419,512	-111,892,867
	Water Heat	-11,232,973	-35,016,824
	Other	-29,722,559	-78,687,042
	Commercial Sub-total	**-75,375,044**	**-225,596,733**
Industrial	Other	-2,857,517	-6,487,974
Total	**Total**	**-246,212,356**	**-868,523,827**

The values in Table B-9 are negative to reflect that the natural gas to electric scenario results in natural gas throughput reductions.

Calculate Levelized Costs

To incorporate the gas to electric scenario results in PSE's IRP scenario, Cadmus developed levelized cost estimates for the natural gas reductions, which PSE modeled comparably to energy efficiency. The potential is grouped by levelized cost over a 24-year period the natural gas reductions. The 24-year natural gas levelized-cost calculations incorporate numerous factors, which are shown in Table B-10.

Table B-10. Levelized Cost Components

Type	Component
Costs	Incremental Measure Cost
	Administrative Adder
	Present Value of T&D Deferrals*

*For natural gas, this includes the deferred gas distribution benefits

Cadmus did not incorporate the costs associated with additional electric energy loads or the need to potentially acquire new generation or to expand the existing transmission and distribution to meet the new electric peak demands as PSE's IRP model accounts for these variables.

In addition to the upfront capital cost and annual energy savings, the levelized-cost calculation incorporates several other factors, consistent with the Council's methodology:

- ***Incremental measure cost.*** This study considers the costs required to sustain savings over a 24-year horizon, including reinstallation costs for measures with useful lives less than 24 years. If a measure's useful life extends beyond the end of the 24-year study, Cadmus incorporates an end effect that treats the levelized cost of that measure over its EUL as an annual reinstallation cost for the remainder of the 24-year period.[23,24]
- ***Incremental operations and maintenance (O&M) benefits or costs.*** As with incremental measure costs, O&M costs are considered annually over the 24-year horizon. The present value is used 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 20% of incremental measure costs for electric and gas measures across all sectors.

Compared with energy efficiency, Cadmus did not incorporate any non-energy benefits, the regional 10% conservation adder, or secondary energy benefits in the gas to electric levelized cost calculations.

23 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%).

24 This method is applied both to measures with a useful life of greater than 24 years and measures with a useful life that extends beyond study horizon at time of reinstallation.