Comprehensive Assessment of Demand-Side Resource Potentials (2016-2035)

November 1, 2015

Puget Sound Energy
10885 NE 4th St.
Bellevue, WA 98004

The Cadmus Group, Inc.

An Employee-Owned Company • www.cadmusgroup.com

Prepared by:
Lakin Garth
Aquila Velonis
Jessica Aiona
Ken Lyons
Hossein Haeri

Cadmus

Table of Contents

Tables

Figures

Acronyms

AFUE	Annual fuel utilization efficiency
AMI	advanced meter infrastructure
BPA	Bonneville Power Administration
C&I	Commercial and industrial
CALMAC	California Measurement Advisory Council
CPECS	Commercial Buildings Energy Consumption Survey
CBSA	Commercial Building Stock Assessment
CHP	Combined heat and power
CPP	Critical peak pricing
CRP	Cost Recovery Program
DEER	Database of Energy Efficiency Resources
DHW	Domestic hot water
DLC	Direct load control
DOE	U.S. Department of Energy
DSM	Demand-side management
DSR	Demand-side resources
EIA	Energy Information Administration
EISA	Energy Independence and Security Act
EM&V	Evaluation, measurement, and verification
EUL	Expected useful life
FERC	Federal Energy Regulatory Commission
FTE	Full-time equivalent
GWh	Gigawatt-hours
IHD	In-home display
IOU	Investor-owned utility
IREC	Interstate Renewable Energy Council
IRP	Integrated resource planning
ITC	Investment tax credit
LCOE	Levelized cost of energy
NEEA	Northwest Energy Efficiency Alliance
O&M	Operations and maintenance
OG&E	Oklahoma Gas & Electric
OPALCO	Orcas Power and Light Cooperative
PCT	Programmable communicating thermostat
PV	Photovoltaic
RCS	Residential characteristic survey
RTF	Regional Technical Forum
RTU	Rooftop unit
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SEEM	Simple Energy Enthalpy Model

SMUD	Sacramento Municipal Utility District
T&D	Transmission and distribution
TOU	Time of use
TRC	Total resource cost
UEC	Unit energy consumption
VAV	Variable air volume
Wp	Peak watts
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 20-year planning horizon, from 2016 to 2035. PSE commissioned this assessment as part of its biennial integrated resource planning (IRP) process.

Building upon PSE's 2014–2033 assessment of DSR resources, this assessment incorporates PSE's programmatic accomplishments in the intervening years. Further, it presents updates of 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 (the 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 the Sixth Northwest Conservation and Electric Power Plan (Sixth Plan).

Summary of Results

Table 1 presents the technical and achievable technical potentials identified in this study. As shown, electric DSRs account for 706 aMW and 1,394 winter peak MW of achievable technical potential by 2035. These potentials represent 22% of retail energy sales and 20% of winter peak demand.[1] Similarly, achievable technical natural gas potential accounts for 17% of forecasted 2035 retail sales. High-level potentials by resource follow this summary table, and more detailed results are presented in the body of this report.

All values are reported at generator and assume line loss of 6.9% for electric resources and 0.8% for gas resources. In addition, the numbers discussed in this report do not account for intra-year ramping. DSR bundles used as input into PSE's IRP analysis do reflect intra-year ramping, as discussed in the General Approach and Methodology section, under About Hourly DSR Estimates.

[1] Demand response potentials do not account for program interactions; thus, this potential would likely be reduced if multiple programs were competing for participants.

Table 1. Summary of Energy and Capacity Saving Potentials, Cumulative in 2035

Resource	Energy (aMW/Million Therms)		Winter Coincident Peak Capacity (MW)	
	Technical Potential	Achievable Technical Potential	Technical Potential	Achievable Technical Potential
Electric Resources				
Energy Efficiency	781	622	1,218	970
Fuel Conversion	222	61	630	141
Demand Response	N/A	N/A	N/A	263
Distributed Generation	N/A	22	N/A	20
Electric Resources Total	**1003**	**706**	**1,848**	**1,394**
Natural Gas Resources				
Energy Efficiency	331	225	N/A	N/A

Energy Efficiency

Table 2 shows 2035 forecasted baseline electric sales and potential by sector. Study results indicate 781 aMW of technically feasible electric energy efficiency potential will be available by 2035, the end of the 20-year planning horizon. Upon taking market constraints into account, this translates to an achievable technical potential of 622 aMW. Provided that all of this potential proves cost-effective and realizable, it will result in a 20% reduction in 2035 forecast retail sales.

Consistent with the Council's method, this study assumes that 85% of electric resources will be achievable over time. However, due to the timing of lost opportunity resource acquisition, achievable technical potential is less than 85% of technical potential (described in greater detail in General Approach and Methodology).

Table 2. Electric Energy-Efficiency Potential by Sector, Cumulative in 2035

Sector	2035 Baseline Sales (aMW)*	Technical Potential		Achievable Technical Potential	
		aMW	Percentage of Baseline Sales	aMW	Percentage of Baseline Sales
Residential	1,616	390	24%	304	19%
Commercial	1,409	360	26%	293	21%
Industrial	129	30	23%	26	20%
Total	**3,154**	**781**	**25%**	**622**	**20%**

* These baseline sales values are the post-standards, calibrated forecasts.

Table 3 shows 2035 forecasted baseline natural gas sales and potential by sector. Study results indicate roughly 331 million therms of technically feasible natural gas energy efficiency potential by 2035, translating to an achievable technical potential of 225 million therms. If all of this potential proves cost-effective and realizable, it will result in a 17% reduction in 2035 forecasted retail sales.

Table 3. Natural Gas Energy-Efficiency Potential by Sector, Cumulative in 2035

		Technical Potential		Achievable Technical Potential	
Sector	2035 Baseline Sales (Million Therms)	Million Therms	As Percent of Baseline	Million Therms	As Percent of Baseline
Residential	844	217	26%	140	17%
Commercial	440	108	25%	81	18%
Industrial	23	6	27%	5	20%
Total	**1,307**	**331**	**25%**	**225**	**17%**

Comparison to 2013 IRP

This energy efficiency potential assessment largely updates the analysis conducted for PSE's 2013 IRP. However, a number of differences between this assessment and the 2013 IRP have led to differences in technical and, thus, achievable technical potential. These differences are:

- Utilization of PSE's most recent energy and sales forecasts
- Incorporation of assumptions, data, and new measures from the RTF
- Adjustments to remaining potential, based on PSE's actual 2012–2013 and projected 2014–2015 energy efficiency program accomplishments
- Updated data on measure costs, savings, lifetime, and applicability
- Adjustments to end use equipment saturation, efficiency share, technical feasibility, and percent incomplete values resulting from the incorporation of PSE-specific data from NEEA's Residential Stock Building Assessment (RBSA)
- Incorporation of new codes and standards
- Use of Simple Energy and Enthalpy Model (SEEM) 94 building simulations[2]

Table 4 compares electric and natural gas technical potentials of the two studies by sector. At an aggregate level, the 2015 study indicates an electric technical potential that is approximately 9% (67 aMW) higher than the 2013 IRP (781 aMW in the 2015 IRP versus 714 aMW in the 2013 IRP).

Table 4. Comparison of Energy-Efficiency Technical Potential, 2013 IRP to 2015 IRP

	Electric (aMW)		Natural Gas (Million Therms)	
Sector	2013 IRP	2015 IRP	2013 IRP	2015 IRP
Residential	356	390	226	217
Commercial	331	360	120	108
Industrial	28	30	4	6

[2] Regional Technical Forum. "Simplified Energy Enthalpy Model." Available online at: http://www.nwcouncil.org/energy/rtf/measures/support/SEEM/Default.asp. SEEM94 was the most recent version at the time of analysis of potentials.

Total	**714**	**781**	**350**	**331**

The following four factors largely drive this increase in electric energy efficiency technical potential, listed in order of their absolute magnitude:

1. Commercial lighting potential increased by 31% from 131 aMW to 171 aMW. The increase in potential for this end use is due to the inclusion of linear LED tubes in standard and high bay applications in the 2015 IRP that were not included in the 2013 IRP.
2. Residential water heating potential increased 26% from 95 aMW to 119 aMW. The measures primarily comprising this total are:
   - Heat Pump Water Heater – RTF Tier 2 (52 aMW)
   - Solar Hot Water Heater (17 aMW)
   - Heat Pump Water Heater – RTF Tier 1
   - Low-Flow Showerheads (10 aMW)

   The increase in potential for this end use is primarily driven by two factors:
   - The RBSA indicates a lower saturation of efficient electric hot water heaters than previously assumed.
   - The fuel share of electric water heaters among PSE's electric single-family customers was increased from 34% to 41%.based on RBSA results.
3. Residential lighting potential increased 41% from 43 aMW to 60 aMW. This change is primarily caused by the shift in technical potential from CFLs to LEDs as the market for LEDs has matured due to availability of more affordable lamp options since the 2013 IRP. In addition, the RBSA has provided us with data to update assumptions about the relative share of standard versus specialty lamps. As the relative share of specialty lamps has increased from 13% to 38% for single-family homes since the 2013 IRP update, so too has the lighting potential, since these lamps are mostly exempt from the 2007 Energy Independence and Security Act (EISA) standards that affect the standard lamp baselines.
4. Residential appliance potential has increased 19% from 56 aMW to 67 aMW. This change is primarily due to the inclusion of a new measure—heat pump dryers. This new measure contributes an additional 16 aMW to the increase in technical potential.

The study indicates lower natural gas technical potential (331 MM therms versus 350 MM therms). As illustrated in Table 4 above, potential has decreased by roughly 9 MM therms in the residential sector and 12 MM therms in the commercial sector. These differences are primarily due to the reduction in potential as a result of PSE programmatic achievements in 2012-2013 and anticipated 2014-2015 savings.

Fuel Conversion

The fuel conversion analysis estimates available potential from converting electric equipment to natural gas for two main groups in PSE's natural gas service territory—customers who do not currently have natural gas service and customers who do have natural gas service but retain electric equipment (e.g., water heaters or appliances) that could be converted to natural gas. Table 5 shows the available technical and achievable technical potential in 2035 for each customer type.

Table 5. Summary of Fuel Conversion Potentials, Cumulative in 2035

	Technical Potential		Achievable Technical Potential	
Customer Type	**Electric Savings (aMW)**	**Additional Gas Usage (million therms)**	**Electric Savings (aMW)**	**Additional Gas Usage (million therms)**
Electric - Only	159	11	45	4
Existing Gas Customer	63	4	16	1
Total	**222**	**15**	**61**	**5**

Based upon the results of a survey in support of the 2009 IRP, the maximum percent achievable for fuel conversion is assumed to be 63%. Furthermore, based on the results of the survey and previous PSE experience, it is assumed, within the residential sector, of the new gas customers that convert a space heater, 70% will also convert a water heater, and 5% will convert a range and/or dryer. For existing gas customers, all will convert a water heater, and 5% will convert a range and/or dryer. Similar percentages are assumed for the water heating conversions in the commercial sector.

Comparison to 2013 IRP

As with energy efficiency, this analysis largely updates the 2013 IRP. The analysis builds upon the same revised data cited above, including baseline data, PSE's sales and customer forecasts, and measure assumptions. Table 6 compares estimated technical and achievable technical potential with the 2013 IRP. This study indicates a decrease in technical and achievable technical potential.

Table 6. Comparison of Fuel Conversion Potential, 2013 IRP to 2015 IRP

	Technical Potential (aMW)		Achievable Technical Potential (aMW)	
Customer Type	**2013 IRP**	**2015 IRP**	**2013 IRP**	**2015 IRP**
Electric-Only	165	159	45	45
Existing Gas Customer	75	63	16	16
Total	**240**	**222**	**62**	**61**

Demand Response

Table 7 presents estimated winter resource potentials for all demand response resources for the residential, commercial, and industrial sectors. The total market potential available in the winter is 181 MW, equating to 4.5% of winter peak.

Table 7. Demand Response Market Technical Potential, MW in 2035

Sector	Winter Market Potential (MW)	Percent of System Peak - Winter
Residential	115	2.9%

Sector	Winter Market Potential (MW)	Percent of System Peak - Winter
Commercial	62	1.6%
Industrial	5	0.1%
Total	**181**	**4.5%**

Comparison to 2013 IRP

This study focuses on the same program strategies as the 2013 IRP. By sector, Table 8 compares estimated market potential during peak periods.

Table 8. Comparison of Demand Response Achievable Technical Potential, 2013 IRP to 2015 IRP

Sector	Winter (MW) 2013 IRP	Winter (MW) 2015 IRP
Residential	130	115
Commercial	78	62
Industrial	4	5
Total	**213**	**181**

The results of the two studies exhibit the largest differences in the residential sector and commercial sectors, where potentials have decreased relative to the 2013 IRP. These differences result from decreases in overall potential achieved through the residential DLC programs (which have been based on the pilot program PSE implemented from 2009 through 2011) and commercial curtailment.

Distributed Generation

With the exception of solar photovoltaic (PV), this study does not estimate distributed generation potentials; rather, it updates costs for individual distributed generation technologies and incorporates these in the 2015 IRP. For detailed potentials from the 2015 IRP analysis, see Cadmus' 2008 report.[3]

Comparison to the Sixth Plan

This study employed methodologies consistent with the Sixth Plan to estimate available energy efficiency potential (see Appendix A for a detailed comparison of methodologies). Additionally, Cadmus conducted a thorough review of the baseline and measure assumptions used by the Council, including costs, savings, applicability, and current saturations. Although this study relied on data specific to PSE's service territory whenever possible, where appropriate, it incorporated Council assumptions.

[3] http://www.pse.com/SiteCollectionDocuments/2009IRP/AppL1_IRP09.pdf.

By applying PSE's share of regional sales, by sector, to the Council's regional potential, one can estimate the Sixth Plan's share of potential in PSE's service territory. However, a number of factors must be considered in comparing that allocated potential to this study's results:

- The Council, by necessity, relied on average regional data whereas this study used primary data from PSE's service territory. Therefore, allocating regional potential based on sales may not account for PSE's unique service territory characteristics (such as customer mix, use per customer, end-use saturations, fuel shares, and current measure saturations). Similarly, some industries included in the Sixth Plan may not exist in PSE's service territory.
- PSE and the Council relied on unique baseline energy forecasts, each of which served as a major driver in the respective potential estimates.
- Both studies assessed potential over a 20-year period; however, the Sixth Plan began in 2010, while this study's estimation of potential began in 2016.
- Due to the timing of the Sixth Plan's release, not all upcoming codes and standards were removed from the potential (most notably, new standards relating to commercial lighting and residential water heating, as described in General Approach and Methodology).
- The Sixth Plan, completed in 2010, used data sources current at that time. In addition to using the PSE-specific data noted above, this study used more current data, particularly for measure costs.

Incorporation of DSR into PSE's IRP

The achievable technical potentials 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 20-year program life; the General Approach and Methodology 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 8,760 hour load shapes to produce hourly DSR bundles for electric energy efficiency resources and monthly load shapes for gas. 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. See About Hourly DSR Estimates in the General Approach and Methodology section for additional detail.

Figure 1 shows the annual cumulative combined potential for energy efficiency, fuel conversion, and distributed generation by each cost bundle considered in PSE's 2015 IRP. Figure 2 shows electric achievable potential by resource type. Figure 3 shows annual DSR bundles for natural gas energy efficiency.

Figure 1. Annual Electric DSR Bundles by Cost Group

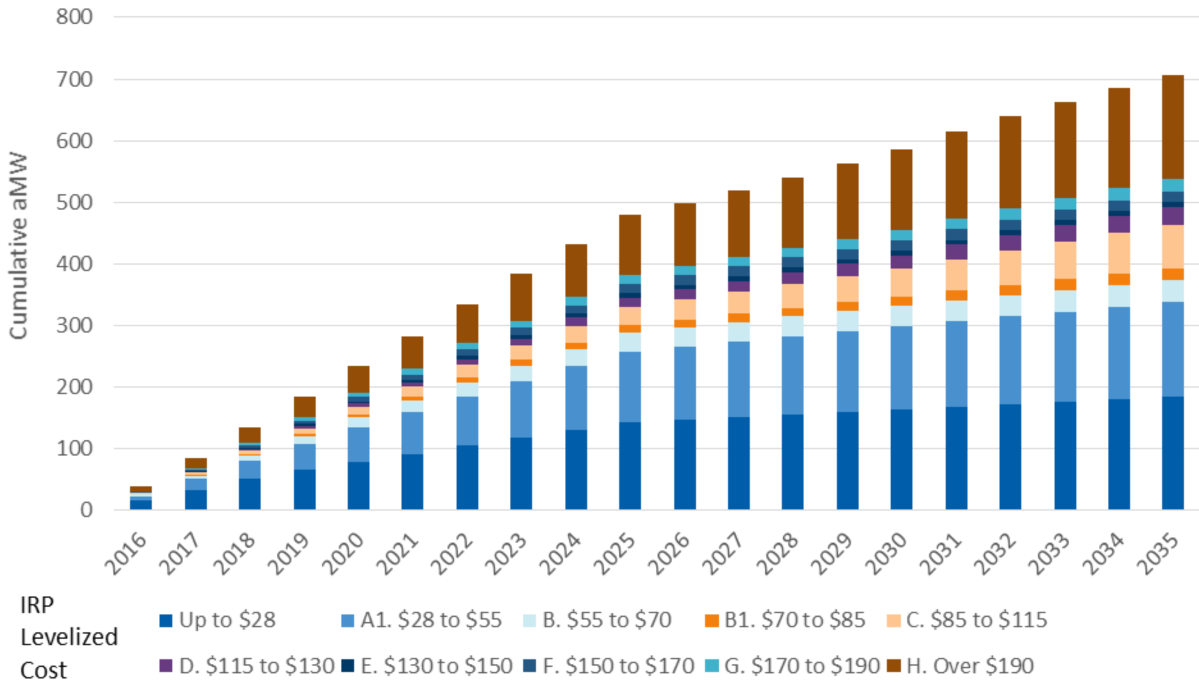


Figure 2. Electric Achievable Potential by Resource Type

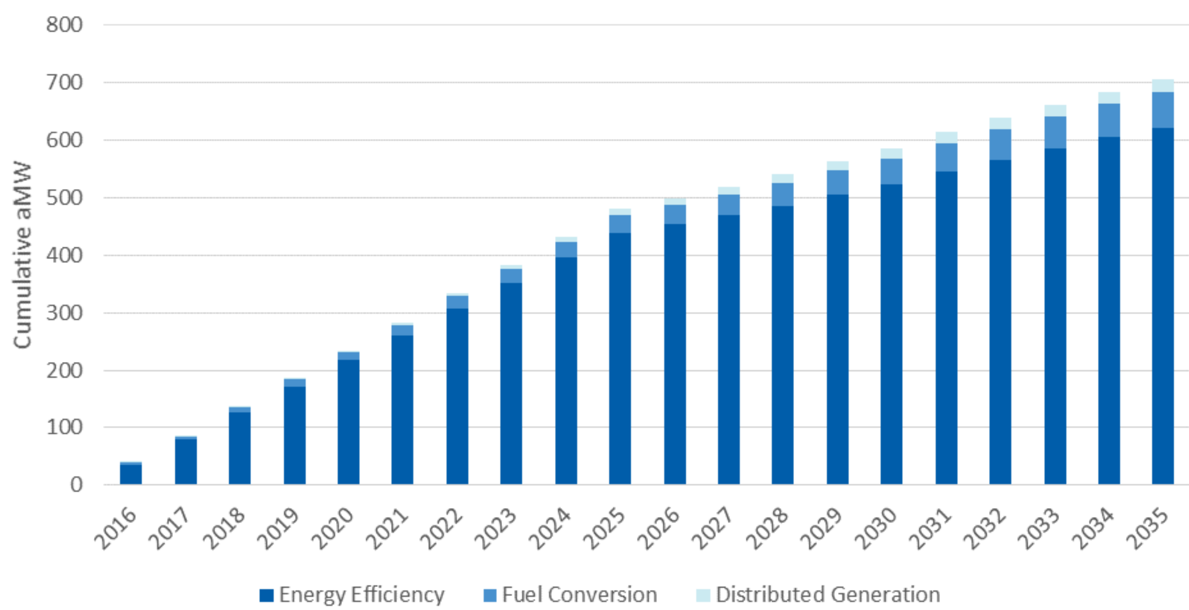
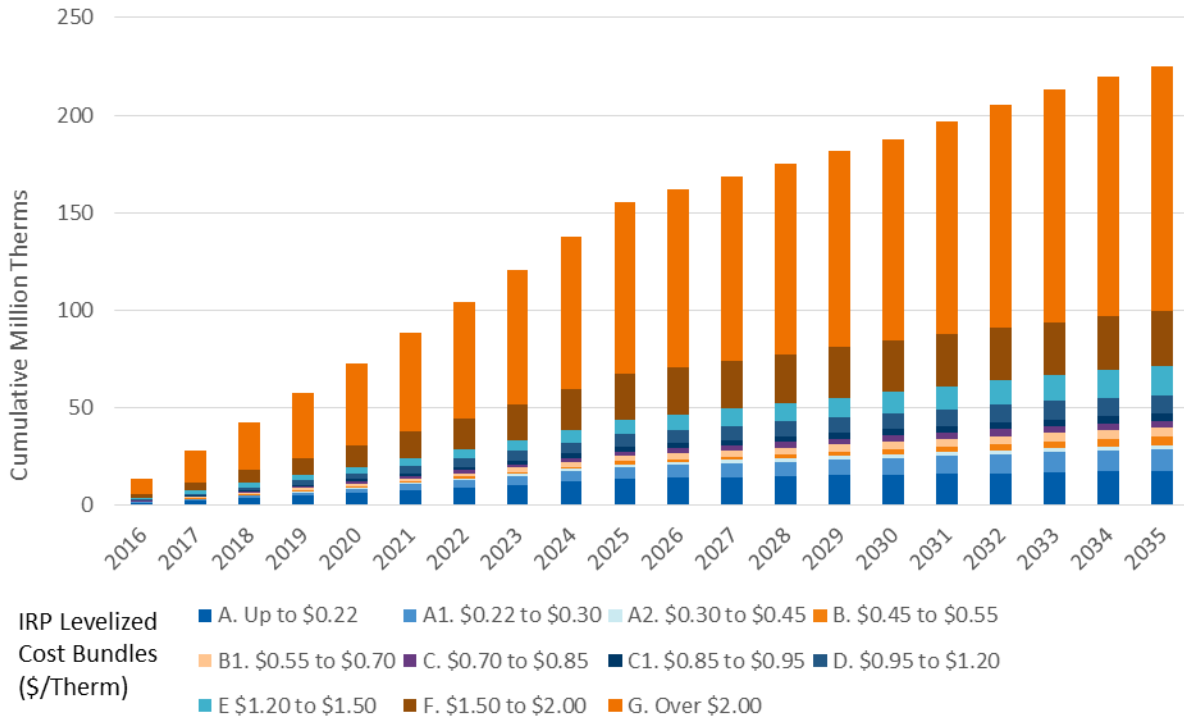


Figure 3. Annual Natural Gas DSR Bundles by Cost Group



In addition to the energy efficiency, fuel conversion, and distributed generation bundles shown above, PSE includes three other resource bundles in its IRP:

- The expected effects of codes and standards (including EISA and U.S. Department of Energy [DOE] standards). PSE includes "standards" bundles in both gas and electric IRP models.
- Capacity-only impacts of demand response.
- Savings associated with distribution efficiency improvements (which fall outside the scope of this study).

Organization of the Report

The body of this report has been organized in four sections. The first describes the general methodology for assessing potential used for each resource type; the remaining three sections present the key assumptions and results for each resource. The document's appendices present additional technical information and descriptions of data used and their sources.

General Approach and Methodology

This report describes the technologies, data inputs, data sources, data collection processes, and assumptions used in calculating technical and achievable technical long-term potentials.

General Approach

The demand-side resources (DSR) analyzed in this study differ with respect to technology, availability, types of load impact, and target consumer markets. Analysis of their potentials, therefore, requires using customized methods to address the unique characteristics of each resource. These methods, however, spring from the same conceptual framework and seek to achieve estimates of two distinct types of potential—technical and achievable technical, which are defined here:

- ***Technical potential*** assumes that all technically feasible resource opportunities may be captured, regardless of their costs or other market barriers. Notably, the concept of technical potentials proves less relevant to some resources, such as demand response since, from a strictly technical point of view, nearly all end-use loads may be subject to interruption or displacement by on-site generation.
- ***Achievable technical*** potential is defined as the portion of technical potential that might be assumed achievable in the course of the planning horizon, regardless of the acquisition mechanism. (For example, savings may be acquired through utility programs, improved codes and standards, or market transformation.)

In addition to the quantity of available potential, the timing of resource availability presents a key consideration. For this analysis, resources can be split into two distinct categories:

- ***Discretionary resources*** are retrofit opportunities in existing facilities that, theoretically, remain available at any point over the course of the study period.
- ***Lost opportunity resources*** have pre-determined availability, such as replacements after equipment failure and opportunities in new construction.

About Levelized Costs

Identified potential is grouped by levelized cost over the 20-year study horizon, allowing the Puget Sound Energy (PSE) integrated resource planning (IRP) model to pick the optimal DSR amount, given various assumptions regarding future resource requirements and costs. The 20-year levelized cost calculation incorporates numerous factors, which are consistent with the Northwest Power and Conservation Council (the Council) methodology and shown in Table 9.

Table 9. Levelized Cost Components

Type	Component
Costs	Incremental Measure Cost
	Incremental O&M Cost*
	Administrative Adder
Benefits	PV 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 effectively treated as a benefit in the levelized cost calculation.

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 20-year horizon, including reinstallation costs for measures with useful lives less than 20 years. If a measure's useful life extends beyond the end of the 20-year study, Cadmus incorporates an end effect that treats the levelized cost of that measure over its useful life (EUL)[4] as an annual reinstallation cost for the remainder of the 20-year period.[5]

  For example, Figure 4 shows the timing of initial and reinstallation costs for a measure with an eight-year lifetime in context with the 20-year study. The measure's final lifetime in this study ends after the study horizon, so the final four years (Year 17 through Year 20) are treated differently by levelizing measure costs over its eight-year useful life and treating these as annual reinstallation costs.

Figure 4. 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
Initial Capital Cost																				
Re-installation Cost																	End Effect			

- ***Incremental operations and maintenance (O&M) costs or benefits.*** As with incremental measure costs, O&M costs are considered annually over the 20-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.

4 This refers to levelizing over the measure's useful life, equivalent to spreading incremental measure costs over its EUL in equal payments assuming a discount rate of PSE's weighted average cost of capital.

5 This method is applied both to measures with a useful life of greater than 20 years and those with a useful life that extends beyond the twentieth year at the time of reinstallation.

- ***Administrative adder.*** Cadmus assumed a program administrative cost equal to 20% of incremental measure costs for electric measures across all sectors. For gas measures, Cadmus assumed program administrative costs of 15% in the residential sector and 25% for the commercial and industrial (C&I) sectors.
- ***Non-energy 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*** 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 methodology and is effectively an adder to account for unquantified external benefits of conservation when compared to other resources.[6] In th2 2015 IRP the 10% conservation credit was applied to the gas measures as well.
- ***Secondary energy 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 of R-60 ceiling insulation for a home with a gas furnace and an electric cooling system. For the gas furnace end use, Cadmus considers 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.

Data Sources

The full assessment of resource potential required the compilation of a large set of measure-specific technical, economic, and market data obtained from secondary sources and through primary research. The study's main data sources included:

- ***PSE internal data.*** These encompass historical and projected sales and customers, hourly load profiles, and historic and projected DSR accomplishments.
- ***Primary data.*** This study relied on several data sources specific to PSE's service territory and customers, including the Northwest Energy Efficiency Alliance (NEEA) 2011 Residential Building

[6] Northwest Power & Conservation Council. "Northwest Power Act." Available online: http://www.nwcouncil.org/library/poweract/default.htm.

Stock Assessment (RBSA), 2010 Residential Characteristic Survey, 2008 Fuel Conversion Survey, and the NEEA 2007 Commercial Building Stock Assessment (CBSA).[7]

- ***Secondary Pacific Northwest sources*.** Several Northwest entities provided data critical to this study, including the Council, the Regional Technical Forum (RTF), and NEEA. Information derived from these sources included technical information on measure savings, costs, and lives; hourly end-use load shapes (to supplement building simulations described above); and commercial building and energy characteristics.
- ***Building Simulations:*** This study required building simulations (using the Simple Energy Enthalpy Model [SEEM]) for the residential sector, with separate models created for each customer segment, and construction vintage.[8]
- ***Additional Secondary Sources.*** The study relied on a number of secondary sources to characterize measures, assess baseline conditions, and benchmark results against other utilities' experiences. These sources included the California Energy Commission's Database of Energy Efficiency Resources (DEER), ENERGY STAR®, the Energy Information Administration (EIA), and various utilities' annual and evaluation reports on energy efficiency and demand-response programs.

Energy Efficiency

The methodology used for estimating the technical and achievable technical energy efficiency potential draws upon standard industry practices, and proves consistent with the Council's assessments of conservation potentials for the Sixth Northwest Regional Power Plan (Sixth Plan). The general approach, shown in Figure 5 on the next page, illustrates how baseline and efficiency data have been combined to develop estimates of potential for use in PSE's IRP process.

The study considers three types of potential—naturally occurring, technical, and achievable technical.

Naturally occurring conservation refers to reductions in energy use that occur due to normal market forces, such as technological change, energy prices, market transformation efforts, and improved energy codes and standards. This analysis accounted for naturally occurring conservation in three ways:

- First, the assessment accounted for gradual efficiency increases due to the retirement of older equipment in existing buildings and the subsequent replacement with units that meet minimum standards at that time. For some end uses, the technical potential associated with certain

---

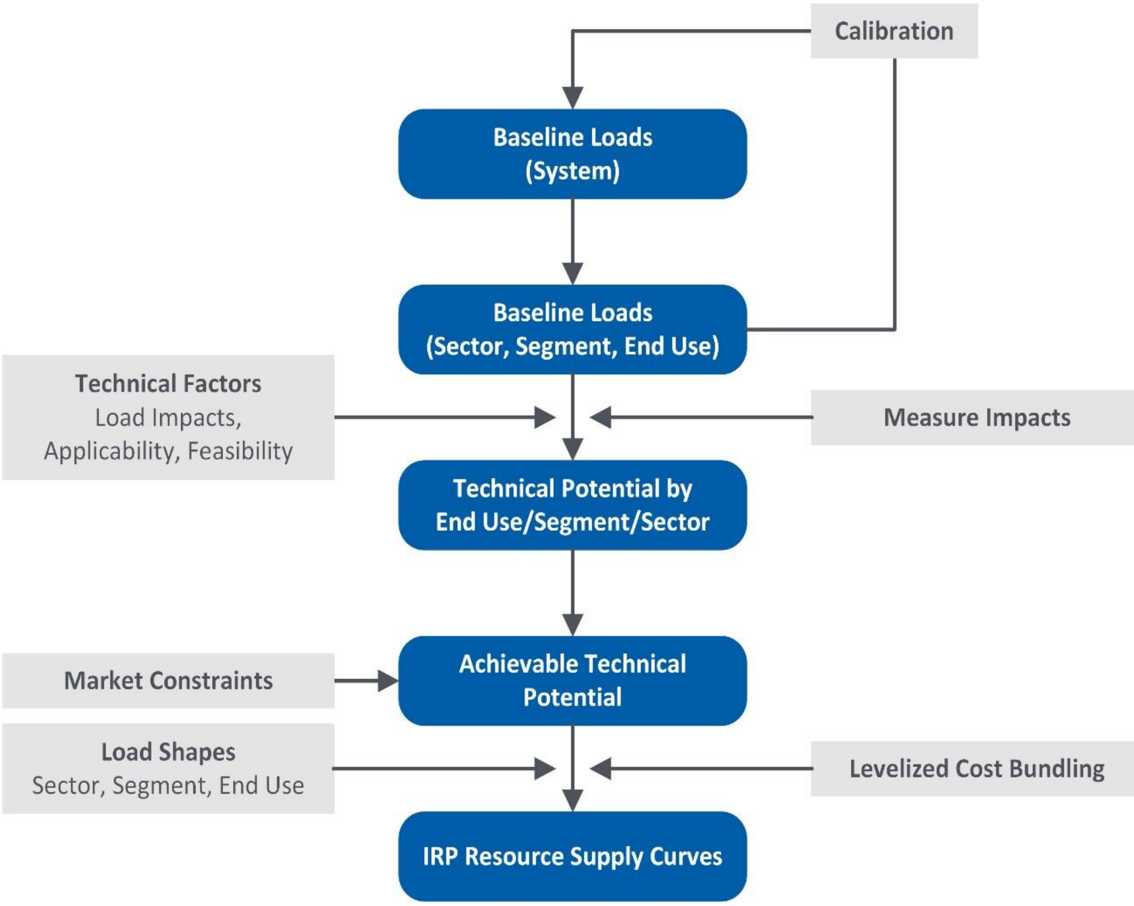
7 The first two studies are not publicly available. Northwest Energy Efficiency Alliance. *2007 Commercial Building Stock Assessment (CBSA).* Available online: http://neea.org/resource-center/regional-data-resources/commercial-building-stock-assessment.

8 Regional Technical Forum. "Simplified Energy Enthalpy Model." Available online at: http://www.nwcouncil.org/energy/rtf/measures/support/SEEM/Default.asp.

energy-efficient measures assumed a natural adoption rate. For example, savings associated with ENERGY STAR appliances accounted for current trends in customer adoption.

- Second, energy consumption characteristics of new construction reflected current state-specific building codes.

Figure 5. General Methodology for Assessment of Energy-Efficiency Potentials



- Third, the assessment accounted for improvements to equipment efficiency standards that are pending and will take effect during the planning horizon. The assessment did not, however, forecast changes to standards that have not passed; rather, it treated these at a "frozen" efficiency level.
- These impacts resulted in a change in baseline sales, from which the technical and achievable technical potential could be estimated.

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

This study's technical potential estimations for energy efficiency resources drew upon best-practice research methods and standard analytic techniques in the utility industry. Such techniques remained consistent with conceptual approaches and methodologies used by other planning entities, such as those of the Council in developing regional energy efficiency potential, and remained consistent with methods used in PSE's 2009, 2011, and 2013 assessments.

Achievable technical potential represents the portion of technical potential that might reasonably be achievable in the course of the 20-year planning period, given the possibility that market barriers could impede customer adoption. At this point, it does not consider cost-effectiveness, because identified levels of achievable technical potential principally serve as planning guidelines and information for the IRP process.

Developing sound utility IRPs requires knowledge of alternative resource options and reliable information on the long-run resource potential of achievable technologies. Demand-side management (DSM) resource potential studies principally seek to develop reasonably reliable estimates of the magnitude, costs, and timing of resources likely available over the planning horizon's course; they do not, however, provide guidance as to *how* or by *what means* identified resources might be acquired. For example, identified potential for electrical equipment or building shell measures might be attained through utility incentives, legislative action instituting more stringent efficiency codes and standards, or other means.

The resources considered for this study include energy efficiency measures that fall outside of PSE's traditional programs but that are currently or may be considered market transformation initiatives by NEEA. Televisions and heat pump dryers are examples of measures that are included in this study and that NEEA has pursued or is considering pursuing via market transformation.

Overview to Estimating Energy Efficiency Potential

Estimating energy efficiency potential draws on a sequential analysis of various energy-efficient measures in terms of technical feasibility (technical potential) and expected market acceptance, considering normal barriers possibly impeding measure implementation (achievable technical potential). The assessment followed three primary steps:

- ***Baseline forecasting.*** Determining 20-year future energy consumption by state, sector, market segment, and end use. The study calibrated the base year, 2015, to PSE's sector load forecasts. As described above, the baseline forecasts shown in this report include the Cadmus team's estimated impacts of naturally occurring potential.[9]

[9] The Cadmus team's baseline forecast accounted for codes and standards not embedded in PSE's load forecast. Due to these adjustments, 2035 baseline sales presented in this report may not match PSE's official load forecast.

- ***Estimation of alternative forecasts of technical potential.*** Estimating technical potential, based on alternative forecasts, which reflect technical impacts of specific energy-efficient measures.
- ***Estimation of achievable technical potential.*** Achievable technical potential calculated by applying ramp rates and an achievability percentage to the technical potential, as this section later describes in detail.

This approach offered two advantages:

- First, savings estimates would be driven by a baseline calibrated to PSE's base year (2015) sales. Although subsequent baseline years may differ from PSE's load forecast, comparisons to PSE's sales forecast helped control for possible errors. Other approaches may simply generate the total potential by summing estimated impacts of individual measures, which can result in total savings estimates representing unrealistically high or low baseline sales percentages.
- Second, the approach maintained consistency among all assumptions underlying the baseline and alternative (technical and achievable technical) forecasts. The alternative forecasts changed relevant inputs at the end-use level to reflect impacts of energy-efficient measures. Because estimated savings represented the difference between the baseline and alternative forecasts, they could be directly attributed to specific changes made to analysis inputs.

Developing Baseline Forecasts

As shown, the first step entails creating a baseline (no-DSR) forecast. In the residential and commercial sectors, the analysis relies on a bottom-up forecasting approach, beginning with annual consumption estimates by segment, end use, and equipment efficiency level. Average base-year use per customer can then be calculated from saturations of equipment, fuel, and efficient equipment. Comparisons to PSE's historical use per customer validates these estimates, and a forecast of future energy sales can then be created based on expected new construction and equipment turnover rates.

In the industrial sector, as standard practice, PSE's industrial forecast has been disaggregated to end uses, based on data available from the EIA'S Manufacturing Energy Consumption Survey.[10]

To bundle potential by cost, Cadmus collected data on measure costs, savings, and market size at the most granular level possible. Within each fuel and sector, the study distinguished between customer segments or facility types and their respective applicable end uses. We then conducted the analyses for these customer segments:

- 6 residential segments (existing and new construction for single-family, multifamily, and manufactured homes)
- 22 commercial segments (11 building types within the existing and new construction vintages)

[10] Energy Information Administration (EIA). "Manufacturing Energy Consumption Survey (MECS)." Available online: http://www.eia.gov/consumption/manufacturing/index.cfm

- 17 industrial segments (17 facility types, treated only as an existing construction vintage)

Estimating Technical Potential

An important aspect of technical potential is that it assumes installation of the highest-efficiency equipment, wherever possible. For example, this study examines solar water heaters, heat pump water heaters, and efficient storage water heaters in residential applications with technical potential, assuming that, as equipment fails or new homes are built, customers will install solar water heaters wherever technically feasible regardless of cost. Where applicable, heat pump water heaters are assumed to be installed in homes ineligible for solar water heaters. Efficient storage water heaters are assumed to be installed in home ineligible for neither solar water heaters nor heat pump water heaters. The study treats competing non-equipment measures in the same way, assuming installation of the highest-saving measures, where technically feasible.

In estimating technical potential, one cannot merely sum up savings from individual measure installations, as significant interactive effects can result from installation of complementary measures. For example, upgrading a heat pump in a home where insulation measures have already been installed can produce fewer savings than in an uninsulated home.

Analysis of technical potential accounts for two types of interactions:

- ***Interactions between equipment and non-equipment measures.*** As equipment burns out, technical potential assumes it will be replaced with higher-efficiency equipment, reducing average consumption across all customers. Reduced consumption causes non-equipment measures to save less than they would have had equipment remained at a constant average efficiency. Similarly, savings realized by replacing equipment decrease upon installation of non-equipment measures.
- ***Interactions between non-equipment measures.*** Two non-equipment measures applying to the same end use may not affect each other's savings. For example, installing a low-flow showerhead does not affect savings realized from installing a faucet aerator. Insulating hot water pipes, however, would cause water heaters to operate more efficiently, thus reducing savings from either measure. This assessment accounts for this interaction by "stacking" interactive measures—iteratively reducing baseline consumption as measures are installed, thus lowering savings from subsequent measures.

Although, theoretically all retrofit opportunities in existing construction (often called "discretionary" resources) could be acquired in the study's first year, this would skew the potential for equipment measures and provide an inaccurate picture of measure-level potential.

Therefore, the study assumes realizations for these opportunities in equal annual amounts, over the 20-year planning horizon. By applying this assumption, natural equipment turnover rates, and other adjustments (described above), the study estimates annual incremental and cumulative potential by state, sector, segment, construction vintage, end use, and measure.

To estimate technical potential, Cadmus developed a comprehensive list of measures for all sectors, segments, and end uses. For the residential and commercial sectors, the study began by reviewing a broad range of energy-efficient measures. These measures were then screened to include only measures fitting these criteria:

- Commonly available
- Based on a well-understood technology
- Applicable to PSE's buildings and end uses

Industrial sector measures drew upon the Council's Sixth Plan and other general process improvement categories.[11]

As shown in Table 10, the study encompasses 350 unique electric energy-efficient measures and 153 unique gas energy-efficient measures. When expanded across segments, end uses, and construction vintages, this results in over 7,500 measures. (Appendix B.2 provides a comprehensive list of measures included in the analysis, with inputs and outputs provided in Appendix B.3.)

Table 10. Energy-Efficient Measure Counts by Fuel

Sector	Electric Measure Counts	Gas Measure Counts
Residential	145 unique 1142 permutations across segments	82 unique 581 permutations across segments
Commercial	159 unique 3288 permutations across segments	63 unique 1432 permutations across segments
Industrial	46 unique 979 permutations across segments	8 unique 125 permutations across segments

For every measure permutation contained in the study, the following key inputs, varying by segment and end use, were compiled:

- ***Measure savings.*** Energy savings associated with a measure as a percentage of the total end-use consumption. Sources include engineering calculations, energy simulation modeling, the RTF, the Council's Sixth Plan, and secondary sources such as ENERGY STAR and DEER.
- ***Measure costs.*** Per-unit cost (full or incremental, depending on the application) associated with measure installations. Sources include the Council's Sixth Plan, the RTF, DEER, RS Means, and merchant websites.
- ***Measure life.*** The measure's expected useful life (EUL). Sources include the Council's Sixth Plan, the RTF, DEER, and DSM program evaluations.

11 Industrial improvements derive from a variety of practices and specific measures, defined in the U.S. Department of Energy's Industrial Assessment Centers Database. Available online: http://www.iac.rutgers.edu/database/.

- ***Measure applicability.*** A general term encompassing a number of factors, such as the technical feasibility of installation, the measure's current saturation, measure interactions, competition, and projected market share. Where possible, applicability factors draw upon PSE survey data and account for PSE's energy efficiency program accomplishments.

The study created an alternate sales forecast, incorporating the effects of all technically feasible measures—the difference between this forecast and the baseline forecast represents the technical potential. This method allowed for long-term estimates of technical potential by measure, while accounting for changes in baseline conditions inherent in the baseline forecast.

The energy efficiency measures included in the study may not have a direct one-for-one correlation to the measures offered by PSE's programs and, for some measures, the per-unit savings for program measures may differ from the per-unit values assumed in the CPA. The primary reason for this discrepancy is that program measures depend on the delivery mechanism employed whereas the CPA remains agnostic to choices regarding the method of delivery. The best example of this type of discrepancy is for residential lighting measures. PSE's programs may have multiple savings values for the same LED or CFL depending upon whether the utility's customer acquires the bulb via retail or through direct install. Often times, the retail measure will include a "storage rate" or other adjustment factors that de-rate the per-unit savings values that would ultimately accrue to the program. Since the intent of the CPA is to estimate the remaining technical potential—and not to estimate the remaining program potential—it makes sense to ignore this adjustment.

Incorporation of Upcoming Codes and Standards

Electric

Although Cadmus' analysis does not attempt to predict how energy codes and standards may change, it captures information about enacted legislation, even if the legislation does not take effect for several years. The most notable, recent efficiency regulation has been the 2007 EISA, which set new standards for general service lighting, motors, and other end-use equipment. Capturing the effects of this legislation proved especially important, as residential lighting has played a large role in PSE's energy efficiency programs over the past several years.

EISA requires general service lighting to become roughly 30% more efficient than current incandescent technology, with standards phased in by wattage from 2012 to 2014. In addition to the 2012 phase-in, EISA contains a backstop provision that requires still higher-efficacy technologies, beginning in 2020.

Although the residential lighting backstop provision have the largest effect on potential, this study explicitly accounts for several other codes and standards. For the residential sector, these include dryer, freezer, heat pumps, and water heating standards. For the commercial sector, these include metal halide lamp fixtures, small electric motors, screw base incandescent bulbs, and water heating standards.

Table 11 provides a comprehensive list of standards enacted or pending starting in 2014 that Cadmus considered in this study. Standards prior to 2014 have been accounted for, such as commercial linear fluorescents, commercial electric motors, and residential ranges and ovens. It is worth noting that this study assumed the commercial linear fluorescent baseline is T-8 fixtures. Through discussions with PSE program staff, the future planning impact savings assume the baseline is T-8 with zero percent saturation of the T-12 fixtures.

Table 11. Enacted or Pending Standards Accounted For – Electric End Uses

Equipment Type	Existing (Baseline) Standard	New Standard	Sectors Impacted	Study Effective Year
Appliances				
Clothes washer	Federal standard 2007	Federal standard 2015	Residential	2016*
Clothes washer	Federal standard 2007	Federal standard 2018	Residential	2018
Dishwasher (residential style)	Federal standard 2010	Federal standard 2013	Commercial/Residential	2014*
Dryer	Federal standard 2011	Federal standard 2015	Residential	2015
Freezer (residential style)	Federal standard 2001	Federal standard 2014	Commercial/Residential	2015*
Refrigerator (residential style)	Federal standard 2001	Federal standard 2014	Commercial/Residential	2015*
Cooking				
Microwave	Existing conditions (no federal standard)	Federal Standard 2016	Residential	2016
HVAC				
Heat pump (air source)	Federal standard 2006	Federal standard 2015	Residential	2017**
Room air conditioners	Federal standard 2000	Federal standard 2014	Residential	2015*
Lighting				
Lighting general service lamp (EISA)	Existing conditions (no federal standard prior to EISA 2007)	Federal standard 2014 (phased in over three years)	Commercial/Residential	2014
Lighting general service lamp (EISA backstop provision)	Existing conditions (no federal standard prior to EISA 2007)	Federal standard 2020	Commercial/Residential	2020
Metal halide lamp fixtures	Federal standard 2009	Federal standard 2017	Commercial	2018*
Motors				
Small electric motors	Federal standard 1987	Federal standard 2015	Commercial	2016*
Water Heaters				

Equipment Type	Existing (Baseline) Standard	New Standard	Sectors Impacted	Study Effective Year
Water heater > 55 gallons	Federal standard 2004	Federal standard 2015	Commercial/Residential	2016*
Water heater ≤ 55 gallons	Federal standard 2004	Federal standard 2015	Commercial/Residential	2016*

*To estimate the potential, Cadmus assumed standards taking effect mid-year will begin on January 1 of the following year.
**Due to the uncertainty created by the litigation, DOE will not enforce this standard until July 1, 2016.

To ensure an accurate assessment of remaining potential, Cadmus created a new forecast, netting out the effect of future standards (shown in Figure 6 and Figure 7). This forecast drew upon a strict interpretation of the legislation, assuming that affected end uses would be replaced with technologies meeting minimum federal standards.

Figure 6. Residential Forecasts Before and After Adjusting for Standards

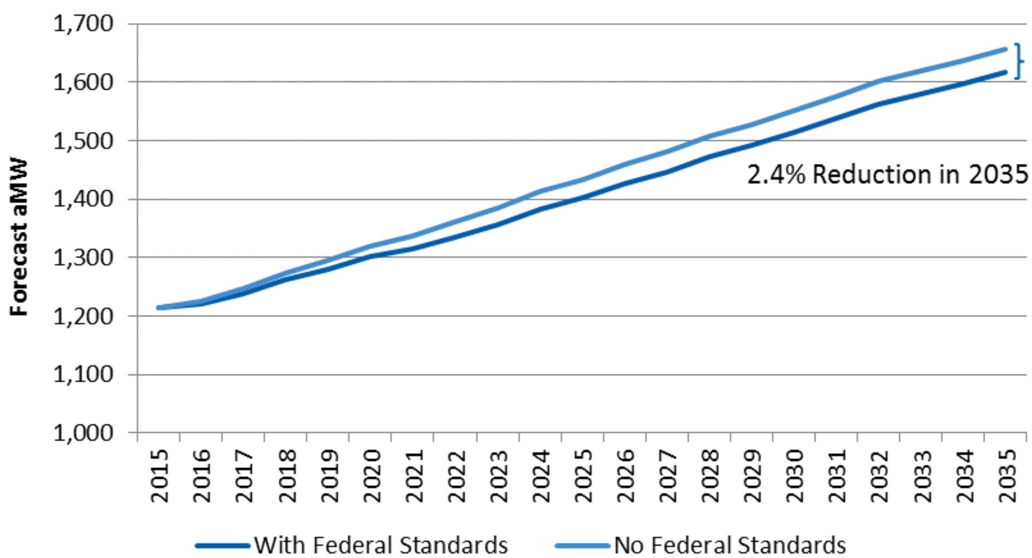
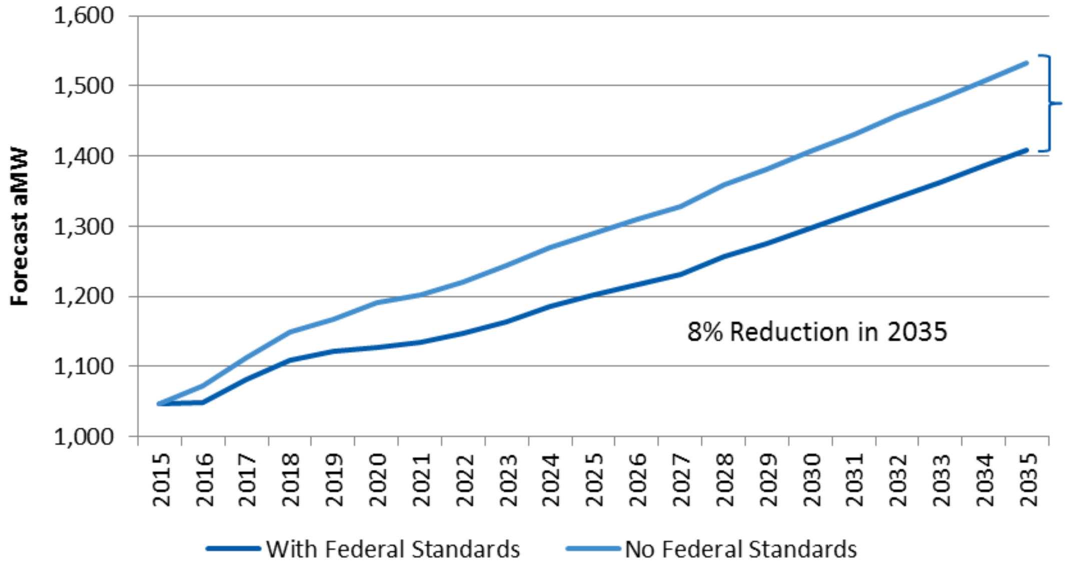


Figure 7. Commercial Forecasts Before and After Adjusting for Standards



After accounting for enacted and pending federal standards, the residential base case forecast fell by 2.4% in 2035, whereas the commercial base case forecast fell by 8%. Lighting standards primarily drove this lower consumption. The preceding figures indicate a drop in 2020 consumption due to the pending EISA backstop provision, which requires standard screw base bulbs to have a minimum efficacy of 45 lumens per watt.

Figure 8 and Figure 9 break out the impacts of federal standards on forecasted sales in each year of the study, by end use, for the residential and commercial sectors.

Figure 8. Impacts of Standards by End Use—Residential Sector

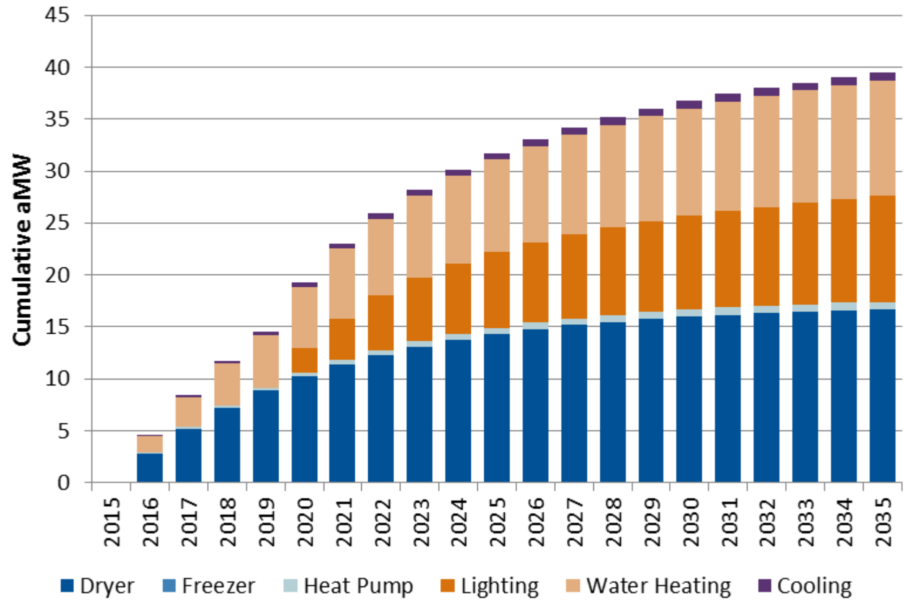
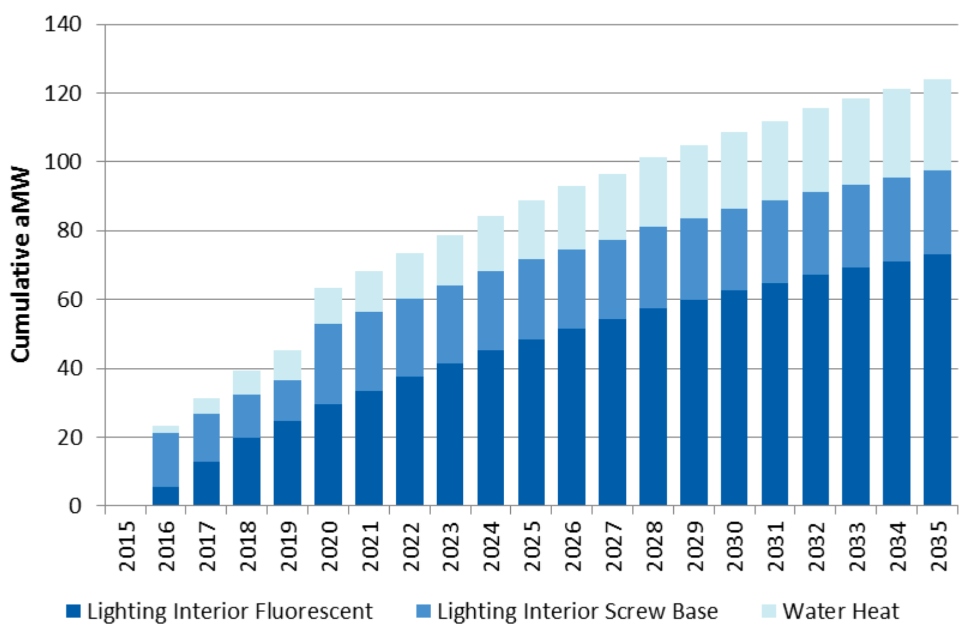


Figure 9. Impacts of Standards by End Use—Commercial Sector



Gas

Cadmus also captured the impact of DOE rulings on minimum efficiencies for water heaters and dryers. Overall, gas standards have a small impact on consumption. Standards reduce 2035 residential consumption by 20 million therms (2.3%) in the residential sector and 9 million therms (2.0%) in the commercial sector. If savings from the impact of standards were included in technical potential, they would account for 8% of residential savings and 4% of commercial savings in 2035.

Table 12 shows the enacted or pending standards for gas end uses. Previous standards prior to 2014 have been accounted for such boilers, furnaces, and residential ranges and ovens commercial electric motors, and residential ranges and ovens. It is worth noting that the new furnace legislation requiring 90% AFUE has been halted and the effective date is to be determined. The likely effective date is to be 2021 at the soonest. Therefore, the existing standard has been assumed for this study.

Table 12. Enacted or Pending Standards Accounted For – Gas End Uses

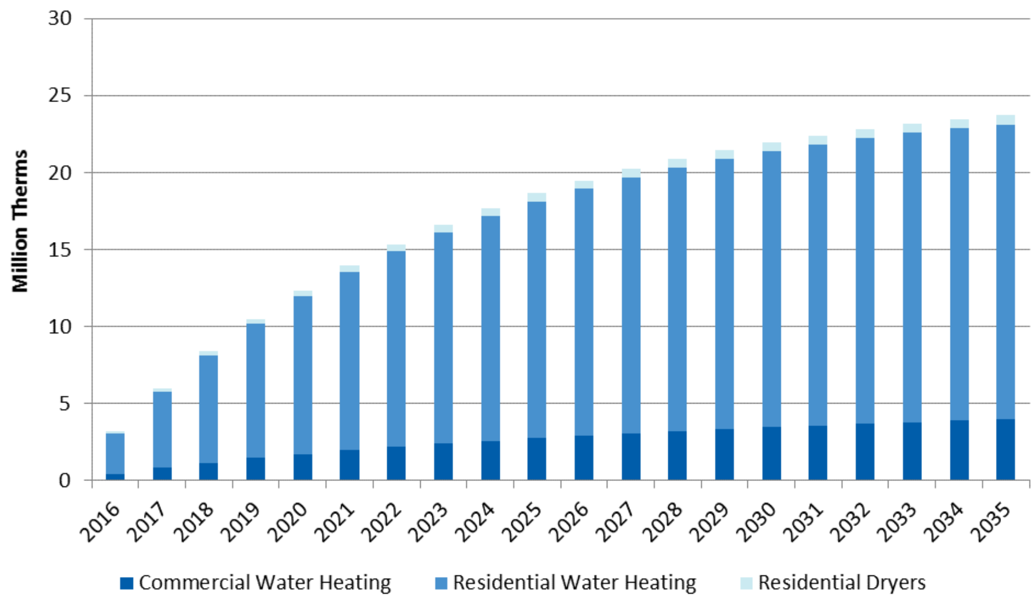
Equipment Type	Baseline	Standard	Sector	Study Year Effective
Water Heat				
Water Heater > 55 gallons	Federal standard 2004	Federal standard 2015	Commercial/Residential	2016*
Water Heater ≤ 55 gallons	Federal standard 2004	Federal standard 2015	Commercial/Residential	2016*
Appliances				
Dryer	Federal Standard 2011	Federal Standard 2015	Residential	2015

*To estimate the potential, Cadmus assumed standards taking effect mid-year will begin on January 1 of the following year.

Figure 10 shows the impacts of federal gas equipment standards. By 2035, 97% of savings due to the standards comes from water heating (and 3% comes from dryers).

Similar to electric, Cadmus created a gas standards bundle for inclusion in PSE's 2015 IRP. This bundle is treated as a zero-cost "must take" bundle. Including this bundle reduced technical potential compared to the 2013 IRP; savings that were previously captured by measures in the 2013 IRP are captured by standards in the 2015 IRP.

Figure 10. Impacts of Federal Gas Equipment Standards



Naturally Occurring Conservation

Cadmus' baseline forecast is inclusive of naturally occurring conservation, which refers to reductions in energy use that occur due to normal market forces, such as technological change, energy prices, market transformation efforts, and improved energy codes and standards. These impacts resulted in a change in baseline sales from which the technical and achievable technical potential were then estimated.

This analysis accounted for naturally occurring conservation in four ways:

- The potential associated with certain energy-efficient measures assumes a natural adoption rate and is net of current saturation. For example, the total potential savings associated with ENERGY STAR appliances accounts for current trends in customer adoption. As such, the total technical potential from ENERGY STAR appliances is reduced from the 2013 IRP and these savings are reflected in the baseline energy forecast.
- The assessment has accounted for gradual increases in efficiency due to retirement of older equipment in existing buildings, followed by replacement with units meeting or exceeding minimum standards at the time of replacement.
- The assessment has accounted for pending improvements to equipment efficiency standards that will take effect during the planning horizon, as discussed above. The assessment does not, however, forecast changes to standards that have not yet been passed.
- New construction consumption characteristics reflect the Washington State Energy Code (WSEC) that went into effect in 2011. All energy-efficient measures in this study meet or exceed WSEC and, where applicable, energy savings are calculated using a WSEC baseline. For example, current building code requires R-49 ceiling insulation, so energy savings for all ceiling insulation measures are calculated with R-49 as a baseline. Consequently, this study does not attribute

savings to ceiling insulation levels below R-49 in new construction. It should be noted that building codes have the smallest impact of the four classes of naturally occurring conservation given that they apply only to new construction.

Achievable Technical Potential

Achievable technical potential can be defined as the portion of technical potential expected to be reasonably achievable over the course of a planning horizon. This estimate accounts for likely acquisition rates and market barriers to customer adoption, but it does not address cost-effectiveness or acquisition mechanisms (e.g., utility programs, codes and standards, market transformation). Thus, the savings a utility can expect to acquire cost-effectively may be substantially lower than the achievable technical potential estimate.

This study, consistent with the Council's Sixth Plan, assumes an 85% achievability factor for electric energy efficiency. For lost opportunity measures, this number (applied directly to the total technical potential for discretionary measures) ramps in at a rate determined by the technology and its useful life. Given this ramp-up, less than 85% of the lost opportunity potential will be acquired over the planning horizon, consistent with the Council's methodology.[12]

Due to higher upfront equipment costs for gas resources, Cadmus assumes 75% of the technical potential can be achieved over the planning horizon.

As previously discussed, lost opportunity measures experience inherent technical ramping, which are based on new construction and equipment turnover rates. In contrast, discretionary opportunities can be acquired at any point.

This study assumes all achievable electric and gas discretionary measures can be acquired within 10 years. (PSE considered this 10-year accelerated ramp-in for discretionary measures as a reasonable representation of the overall energy savings acquisition rate for resource planning analyses. Actual market ramp rates will vary for specific measures.)

Fuel Conversion

In the study's context, fuel conversion refers to electric savings opportunities involving substitution of natural gas for electricity through replacements of space heating systems, water heating equipment, and appliances. The study considers fuel conversion for existing single-family homes, existing and new multifamily buildings, and existing and new commercial facilities—the segments considered most likely and able to convert.

---

12 This remains consistent with the Council's assumption that 65% of lost opportunity resources can be acquired, as discussed in its report, *A Retrospective Look at the Northwest Power and Conservation Council's Conservation Planning Assumptions.* April 2007. Available online: http://www.nwcouncil.org/library/2007/2007-13.htm.

Cadmus' analysis extends the energy efficiency analysis described above, identifying applicable equipment and customers based on these criteria:

- Customers must be within PSE's combined service territory (i.e., areas where PSE provides both electricity and natural gas).
- Customers must be existing gas customers or on a gas main.
- For existing construction, customers must have a ducted system for space heating conversion.
- New natural gas equipment must meet energy efficiency program criteria (e.g., 95% AFUE furnace, ENERGY STAR water heater).

Once eligible populations for each equipment type could be identified, we compiled measure costs and savings, consistent with the energy efficiency analysis. We accounted for additional upfront costs required due to natural gas conversion (e.g., line extensions, piping). We treated the cost of natural gas consumed over the life of a measure, based on forecasted avoided costs, as an O&M cost and included it in the calculation of the cost of conserved electricity.

As with energy efficiency, the technical potential assumes all eligible pieces of equipment can be converted to natural gas. Achievability draws upon results from PSE's 2008 fuel conversion survey, which asked customers about the likelihood they would participate at various incentive levels. Using results of this survey, this analysis assumes that 63% of technical potential can be achieved; this is the value associated with self-reported customer participation, if PSE covered the entire incremental cost of conversion. Available potential is assumed to be acquired in equal amounts annually over the 20-year planning horizon.

Demand Response

Demand response programmatic options seek to achieve the following:

- Help reduce peak demand during system emergencies or periods of extreme market prices
- Promote improved system reliability

Benefits from demand response resources accrue by providing incentives for customers to curtail loads during utility-specified events (e.g., direct load control [DLC]), or by offering pricing structures to induce participants to shift load away from peak periods (e.g., critical peak pricing programs).

Cadmus' analysis focused on program options that include residential DLC for space heat, room heat, and nonresidential load curtailment. These strategies include price- and incentive-based options for all major customer segments and end uses within PSE's service territory, with the list informed by the 2013 IRP, PSE's demand response pilot program experience, and programs offered by other utilities.

General Approach

This study utilizes a hybrid, top-down, and bottom-up approach for estimating demand response potentials.

The approach began by using utility system loads, disaggregated into sector, segment, and applicable end uses. For each program, Cadmus first assessed potential impacts at the end-use level. End-use load impacts then could be aggregated to obtain estimates of technical potentials. This allowed market factors, such as likely program and event participation levels, to be applied to technical potentials to obtain estimates of market potentials. General analytic steps involved in estimating market potential (with the exception of the residential DLC programs) are:

1. Define customer sectors, market segments, and applicable end uses. In estimating the load basis, the study first defined customer sectors, customer segments, and applicable end uses, similar to those used in estimating energy efficiency potentials. System loads were disaggregated into three sectors—residential, commercial, and industrial. The study further broke each sector down by market segment (as shown in Table 13), and end use (such as cooking, cooling, heating, heat pumps, HVAC, lighting, plug load, refrigeration, space heat, and hot water heating).

Table 13. Customer Sectors and Segments

Residential	Commercial	Industrial
Single Family	Dry Goods Retail	Chemical Manufacturing
Multifamily	Grocery	Electronic Equipment Manufacturing
Manufacture Homes	Hospital	Fabricated Metal Products
	Hotel/Motel	Food Manufacturing
	Multifamily Common Area	Industrial Machinery
	Office	Miscellaneous Manufacturing
	Other	Nonmetallic Mineral Products
	Restaurant	Paper Manufacturing
	School	Petroleum Refining
	University	Plastics, Rubber Products
	Warehouse	Primary Metal Manufacturing
		Printing-related Support
		Streetlights
		Transportation Equipment Manufacturing
		Wastewater
		Water
		Wood Products Manufacturing

2. Compile utility-specific sector/end-use loads. Establishing reliable estimates of demand response potentials depended on correct characterizations of sector, segment, and end-use loads. The study developed load profiles for each end use and determined contributions to system peak of each end use, based on end-use load shapes.
3. Screen customer segments for eligibility. This step involved screening customer segments for applicability of specific program strategies. For example, only customers with maximum monthly

demand of at least 100 kW could be considered eligible for the nonresidential load curtailment program.

4. Estimate technical potential. Technical potential for each program was assumed to be a function of customer eligibility in each class, affected end uses in that class, and the expected strategy impact on targeted end uses. Analytically, technical potential (TP) for each demand-response program option (p) was calculated as the sum of impacts at the end-use level (e), generated in customer sector (s) by:

$$TP_p = \sum_{es} TP_{pes}$$

and

$$TP_{pes} = LE_{ps} \times LI_{pes}$$

where,

LE_{ps} (load eligibility) represented the portion of customer sector (s) loads (MW) applicable for program option (p), referenced as "Eligible Load" in the program assumptions.

LI_{pes} (load impact) was the percentage reduction in end-use load (e) for each sector (s) resulting from the program (p), referenced as "Technical Potential as % of Load Basis" in the program assumptions.

5. Estimate market potential. Market potential accounted for customers' ability and willingness to participate in capacity-focused programs, subject to their unique business or household priorities, operating requirements, and economic (price) considerations. Market potential estimates derived from adjusting the technical potential by two factors—expected program participation rates (the percentage of customers likely to enroll in the program) and expected event participation rates (the percentage of customers that will participate in a demand response event—applicable to programs such as the residential DLC program). Market potential for the program option (MP_p) was calculated as the product of technical potential for the customer sector (s), program participation (sign-up) rates (PP_{ps}), and expected event participation (EP_{ps}) rates:

$$MP_p = TP_{ps} \times PP_{ps} \times EP_{ps}$$

6. Estimate costs and develop supply curves. The levelized cost ($/kW-year) of each program option was calculated using estimates of program development, technology, incentive, ongoing maintenance, administration, and communications costs.

Residential DLC

Residential DLC proves unique in that, unlike other demand response options, it affects specific end uses and equipment (e.g., room heaters and water heaters). Therefore, market potential may be quantified more directly as the product of four variables:

- The number of eligible customers
- Expected per unit (kW) impacts

- Equipment saturation rate
- Expected program participation

Derivation of Per-Unit Impacts

PSE implemented a DLC pilot program from October 2009 through September 2011. This pilot program targeted residential customers with electric space or room heat and/or electric water heat. DLC switches were installed on the customers' heating systems and/or water heaters so these end uses could be cycled on and off during peak events. Cadmus relied on the kW impact per switch, as reported in PSE's 2011 Evaluation, Measurement, and Verification (EM&V) Report,[13] to calculate the market potential for a full-scale program. As the EM&V report calculated impacts for morning, afternoon, and evening events, Cadmus weighted these results based on the composition of the top 20 system hours during which events would be called in a full-scale program. The general program assumptions in Chapter 4 provide per-switch impacts.

Equipment Saturation Rates

Equipment saturation represents the percentage of customers eligible for participating in the program (i.e., to participate in the DLC program, a customer must have an electric furnace or electric room heat). Equipment saturation levels for each residential customer segment were derived from PSE data and were consistent with saturations used to estimate energy-efficiency potential.

Expected Participation

Due to the rarity of electric heating DLC programs, and the minimal data existing on participation rates for such programs, Cadmus relied on the average participation rate for national DLC cooling programs and on PSE's experience.

Distributed Generation

With the exception of solar PV, this study did not re-estimate distributed generation potentials. However, Cadmus has updated the costs of the other distributed generation resources, with results presented in a summary table in the Distributed Generation section later in this report. For detailed information regarding distributed generation potentials, see Cadmus' 2008 report.[14]

Incorporation of Demand Side Resources into PSE's IRP

In addition to the energy efficiency, fuel conversion, and distributed generation resource bundles, PSE included three other resource bundles in its IRP:

- The expected effects of codes and standards (including EISA)
- Capacity-only impacts of demand response

13 Evaluation, Measurement, and Verification (EM&V) Report.

14 http://www.pse.com/SiteCollectionDocuments/2009IRP/AppL1_IRP09.pdf.

- Savings associated with distribution of efficiency improvements (outside the scope of this study)

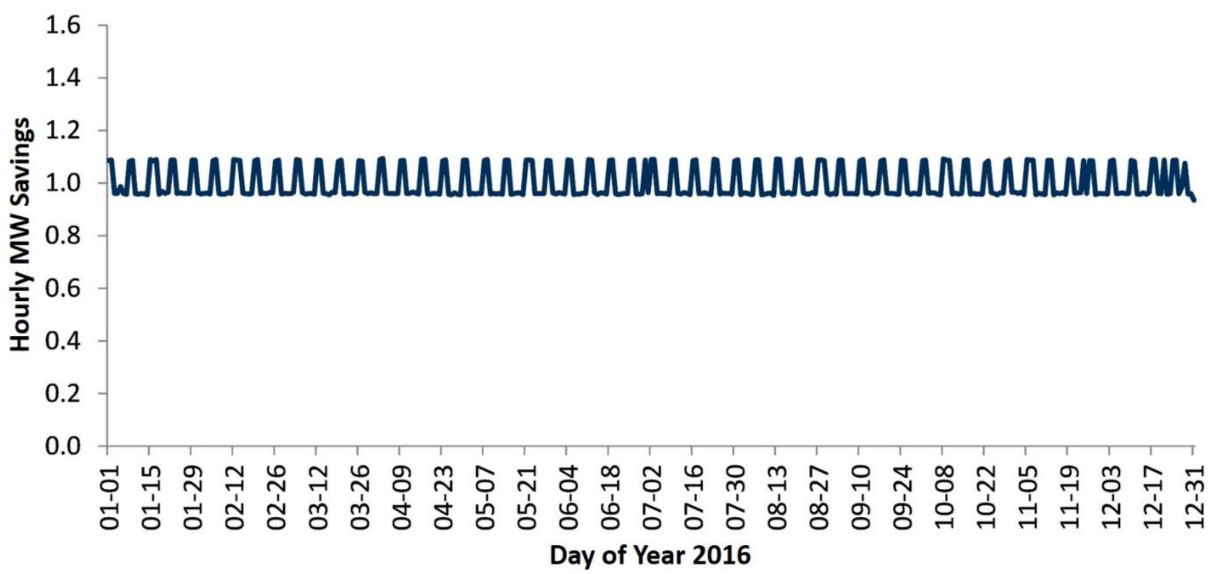
In this section, Cadmus presents how it derived hourly inputs for PSE's IRP model from the annual estimates developed for each of the energy efficiency, fuel conversion, and distributed generation resource bundles.

About Hourly DSR Estimates

Annual reporting of energy savings is appropriate from the perspective of energy efficiency programs and Washington Initiative 937 (I-937) compliance.[15] But from a resource planning perspective, the focus must shift to hourly energy savings. However, simply spreading the annual DSR over an hourly load shape is not sufficient. In this section, Cadmus discusses its methodology for allocating annual savings to an hourly level for the 2015 IRP.

Cadmus developed hourly DSR estimates for each resource bundle in two steps. First, we spread the annual achievable technical potential for each measure over an hourly load shape. As an example, Figure 11 shows hourly savings for a residential lighting measure with 1 aMW of achievable potential in the year 2016. This represents hourly savings from the perspective of the I-937 compliance.

Figure 11. Example - Compliance Perspective Year 2016 Hourly Savings Spread

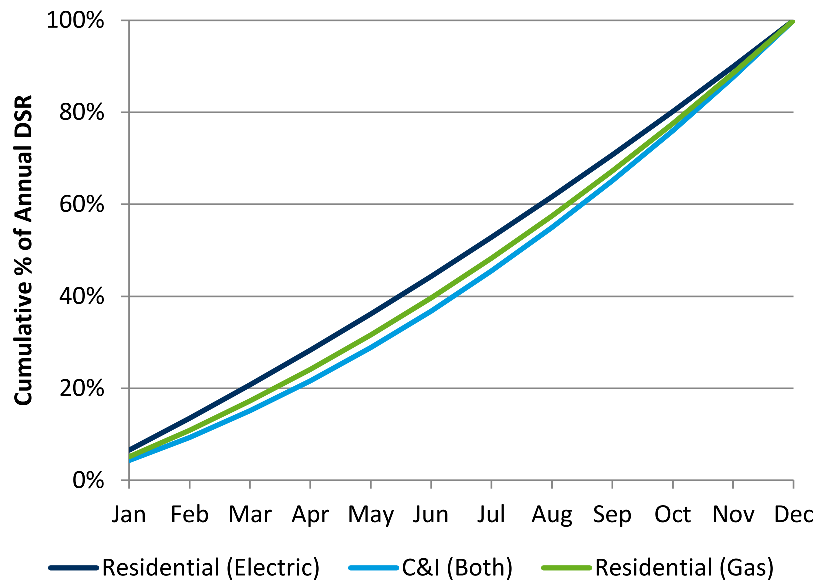


However, as this figure shows, this perspective implicitly assumes that all of the 1 aMW of annual savings are obtained in 2016 on the first hour of January 1, 2016. Realistically, this is not attainable and overstates the actual amount of DSR available in a given hour, especially early in the year.

15 Washington Initiative 937, a clean energy initiative passed in 2006. Available online: http://www.secstate.wa.gov/elections/initiatives/text/i937.pdf.

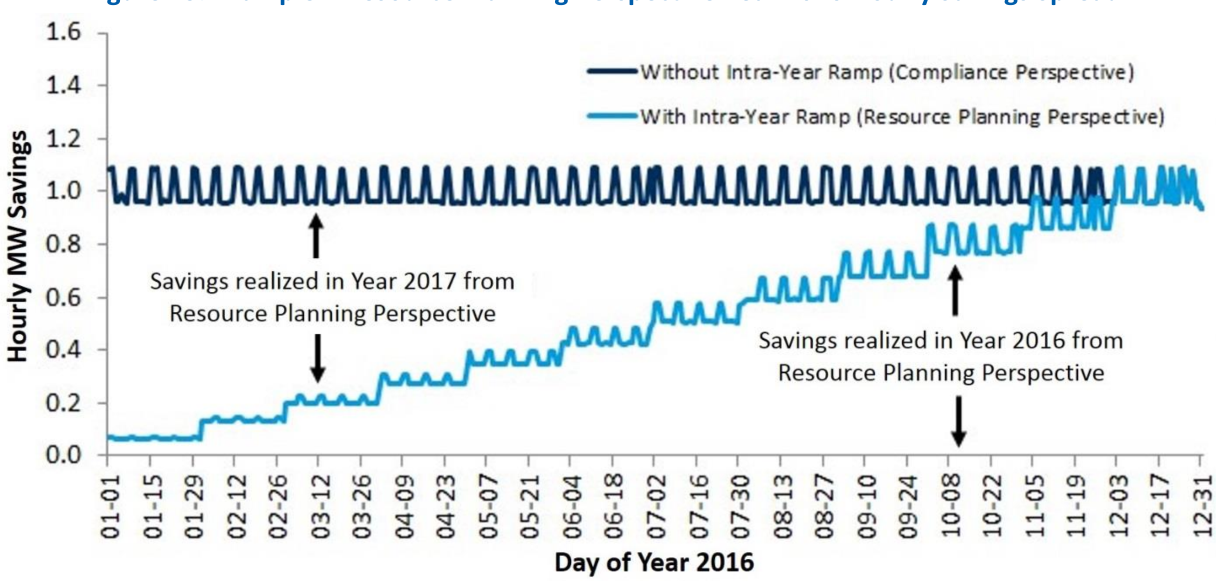
Consequently, PSE provided Cadmus an intra-year schedule based on historic trends in DSR acquisition that PSE used to ramp the achievable technical potential throughout the year. As shown in Figure 12, the fraction of annual DSR available in a given month grows throughout the year until it reaches 100% in December.

Figure 12. Intra-Year Ramping by Sector and Fuel



In the second step of the process, Cadmus laid the intra-year ramping over the hourly savings from the first step so the IRP model explicitly assumes that only a small fraction of the annual savings is available in the month of January. Using the same 1 aMW example, the result is shown in Figure 13.

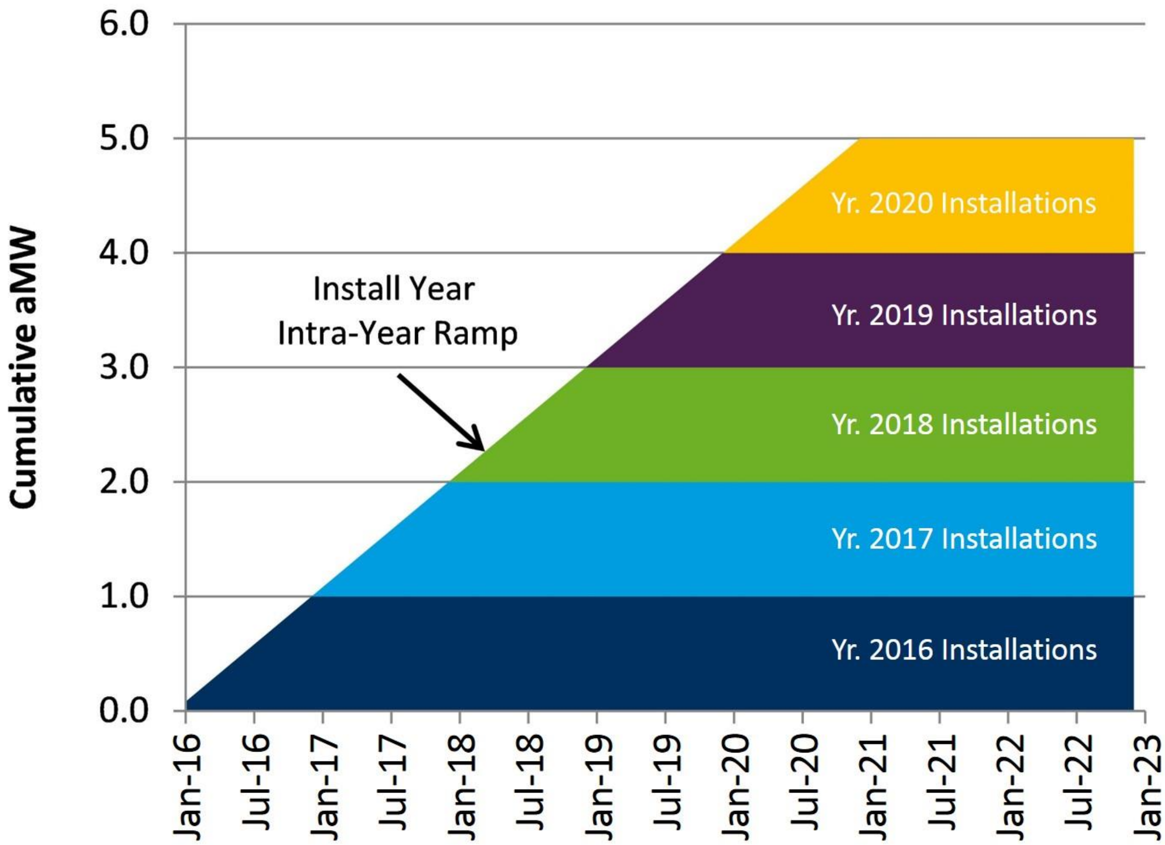
Figure 13. Example – Resource Planning Perspective Year 2016 Hourly Savings Spread



Cadmus notes that in this example the year 2016 energy savings, after applying intra-year ramping, is approximately one half of the savings without intra-year ramping because of the way in which those savings were acquired throughout the year. From a resource planning perspective, the “missing” half of the savings from measures installed in 2016 are realized in 2017. (Not shown in Figure 13 are the savings from measures installed during calendar year 2015 that are realized in 2016; those savings are reflected in the load forecast.) The ramped savings shape shown in Figure 13 is applicable only for the first year that a measure is installed. The IRP model assumes full savings beyond the first year of installation.

Figure 14 shows a stylized example of this concept, assuming that the same measure used in the examples above has 1 aMW of annual, incremental achievable technical potential in each of the years 2016 through 2020.

Figure 14. Example: Intra-Year Ramping Beyond Year of Installation



Energy Efficiency Potentials

Scope of Analysis

PSE seeks accurate estimates of available energy efficiency potential, essential for its IRP and program planning efforts. 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. PSE could then bundle these potentials in terms of levelized costs of conserved energy so that the IRP model can determine the optimal amount of energy efficiency potential PSE should select.

The next section is in two parts—summaries of resource potentials by fuel and detailed results by fuel and sector.

Summary of Resource Potentials—Electric

Table 14 shows 2035 forecasted baseline electric sales and potential by sector.[16] Cadmus' analysis indicates that 781 aMW of technically feasible electric energy efficiency potential will be available by 2035, the end of the 20-year planning horizon. This translates to an achievable technical potential of 622 aMW. Should all of this potential prove cost-effective and realizable, it will result in a 20% reduction in 2035 forecasted retail sales.

Table 14. Electric Energy Efficiency Potential by Sector, Cumulative in 2035

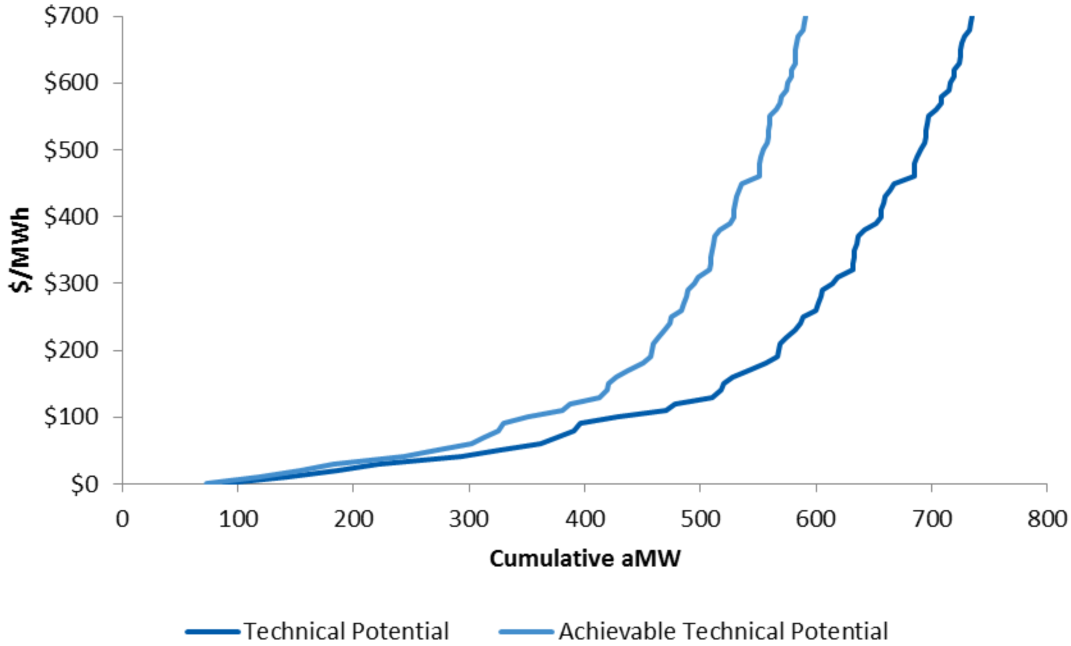
		Technical Potential		Achievable Potential	
Sector	2035 Baseline Sales (aMW)	Technical Potential (aMW)	Percentage of Baseline Sales	Achievable Technical Potential (aMW)	Percentage of Baseline Sales
Residential	1,616	390	24%	304	19%
Commercial	1,409	360	26%	293	21%
Industrial	129	30	23%	26	20%
Total	3,154	781	25%	622	20%

Figure 15 illustrates the relationship between identified technical potential and achievable technical potential and the corresponding cost of conserved electricity.[17] For example, approximately 413 aMW of achievable potential exists, at a cost of less than or equal to $130 per MWh.

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

[17] In calculating levelized costs of conserved energy, non-energy benefits are treated as a negative cost. This leads to some measures having a negative cost of conserved energy, although incremental upfront costs would occur.

Figure 15. Electric DSR Supply Curves—Cumulative in 2035*[a]



*The maximum cumulative technical potential shown in this figure is less than technical potential reported in Table 14 because resources above $700/MWh are not shown.

Figure 16 shows the cumulative potential annually available in each sector. The study assumes all discretionary resources will be acquired on a 10-year schedule between 2016 and 2025. The 10-year acceleration of discretionary resources will lead to the change in slope after 2025, at which point lost opportunity resources offer the only remaining potential.

Figure 16. Electric Energy Efficiency Acquisition Schedule by Sector

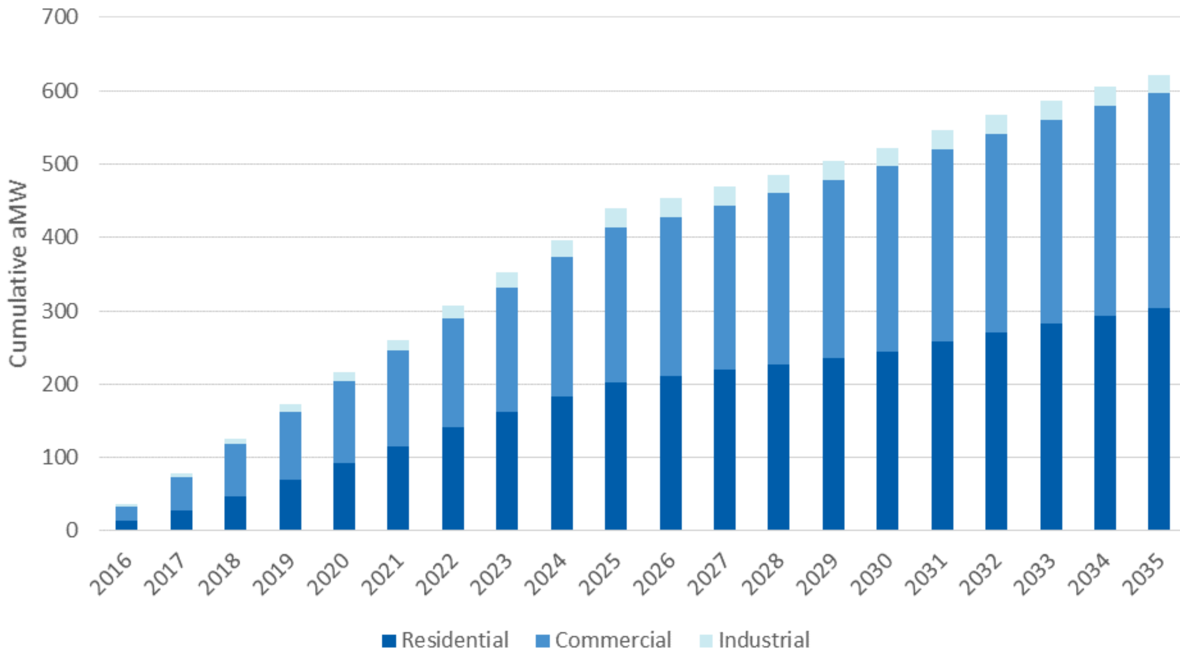
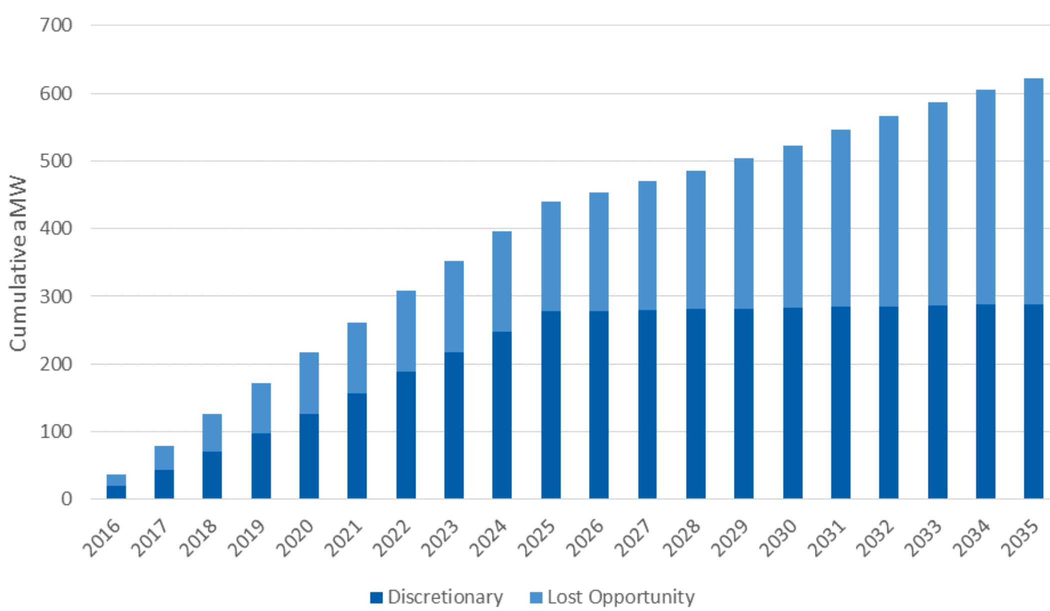


Figure 17 shows cumulative annual achievable electric savings by resource type (discretionary versus lost opportunity). Overall, discretionary measures account for 46% of cumulative savings in 2035, and lost opportunity measures account for the remaining 54%.

Figure 17. Electric Cumulative Annual Achievable Technical Potential by Resource Type



Summary of Resource Potentials—Natural Gas

Table 15 illustrates the 2035 forecasted baseline natural gas sales and potential by sector. As shown, study results indicate roughly 331 million therms of technically feasible energy efficiency potential by 2035, the end of the 20-year planning horizon. This translates to an achievable technical potential of 225 million therms. Should all of this potential prove cost-effective and realizable, it will amount to a 17% reduction in 2035 forecasted retail sales.

Table 15. Natural Gas Energy-Efficiency Potential by Sector, Cumulative in 2035

		Technical Potential		Achievable Technical Potential	
Sector	2035 Baseline Sales (Million Therms)	Million Therms	As Percentage of Baseline	Million Therms	As Percentage of Baseline
Residential	844	217	26%	140	17%
Commercial	440	108	25%	81	18%
Industrial	23	6	27%	5	20%
Total	1,307	331	25%	225	17%

Figure 18 illustrates the relationships between identified technical potential and achievable technical potential and the corresponding costs of conserved energy. For example, roughly 48 million therms of achievable potential will be available, at a cost of less than $1 per therm.

Figure 18. Natural Gas DSR Potential Supply Curves, Cumulative in 2035

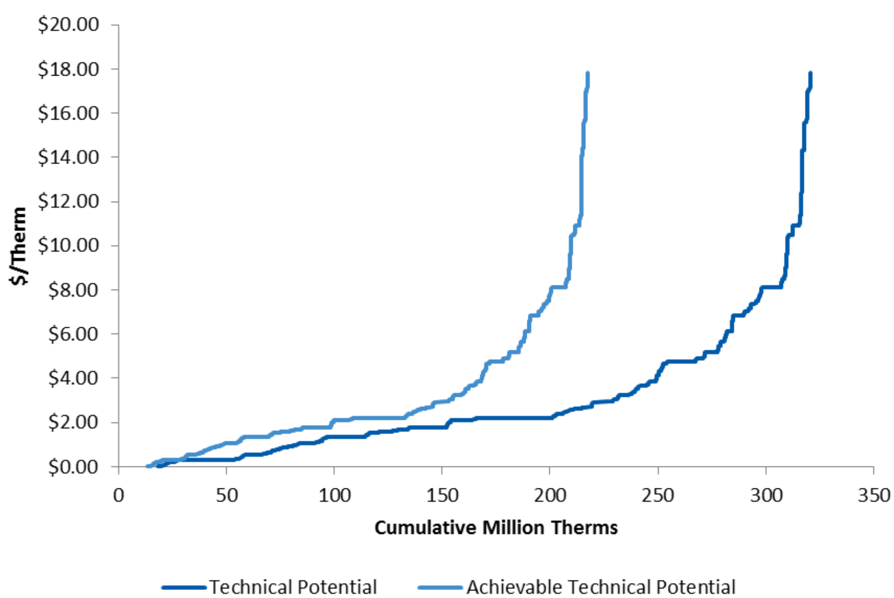


Figure 19 shows the cumulative potential annually available in each sector. As with electric potential, the study assumes all achievable discretionary opportunities will be acquired over 10 years.

Figure 19. Natural Gas Energy-Efficiency Acquisition Schedule by Sector

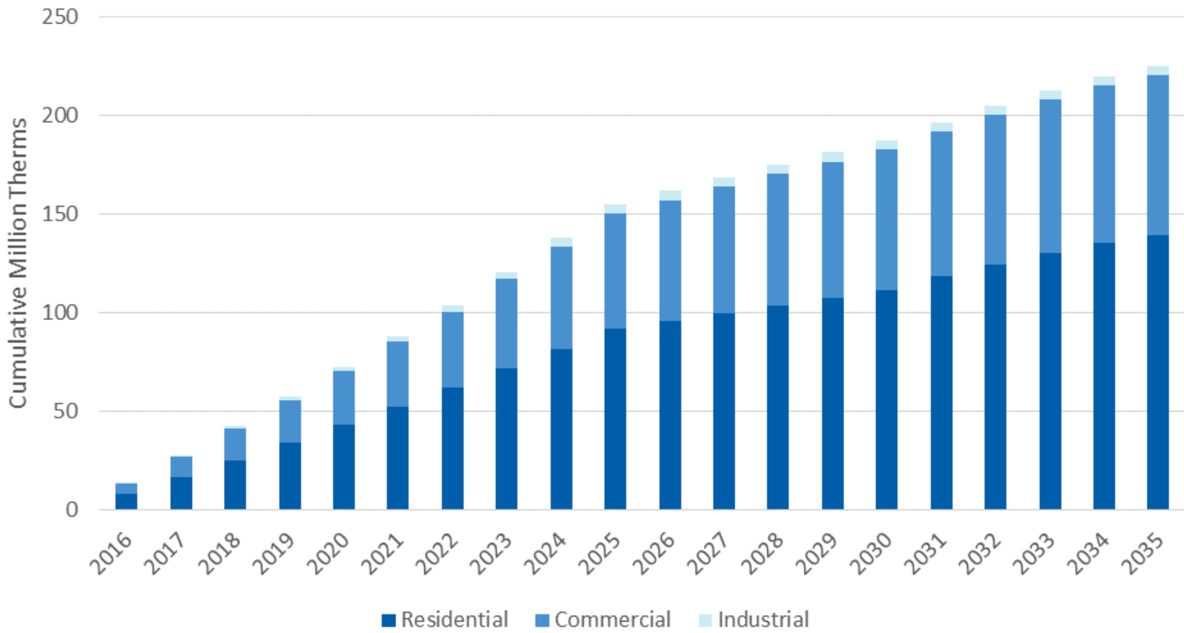
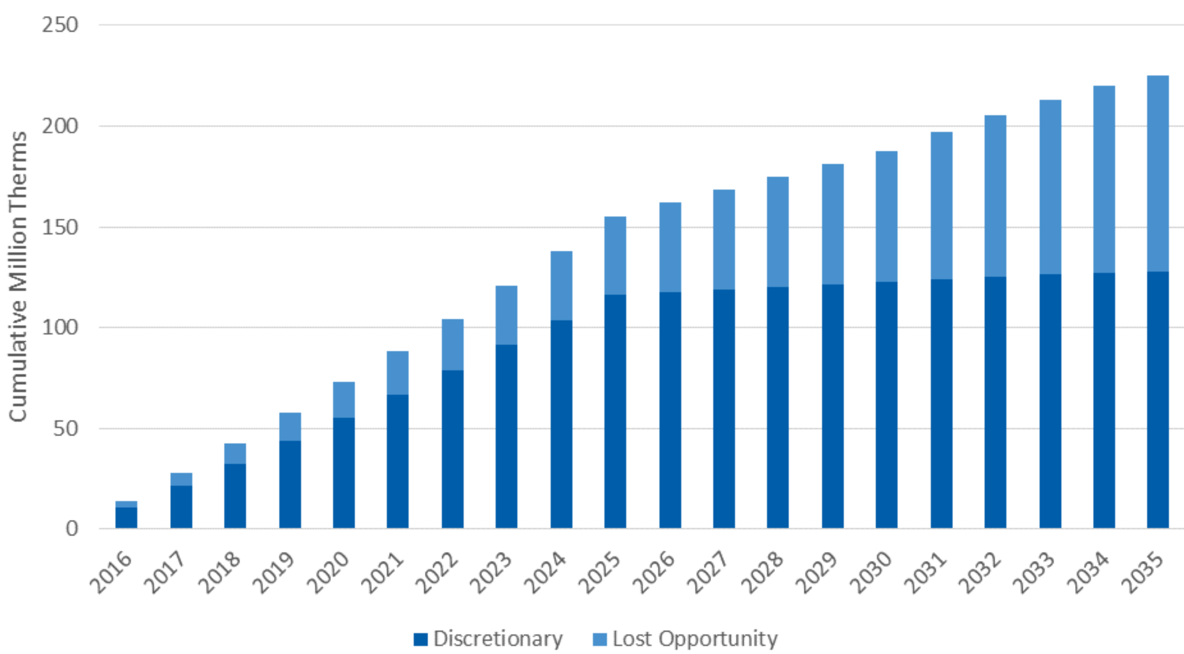


Figure 20 shows cumulative annual gas achievable technical potential by resource type (discretionary versus lost opportunity). In 2035, discretionary measures account for 57% of cumulative savings and lost opportunity measures account for the remaining 43%.

Figure 20. Gas Cumulative Annual Achievable Technical Potential by Resource Type



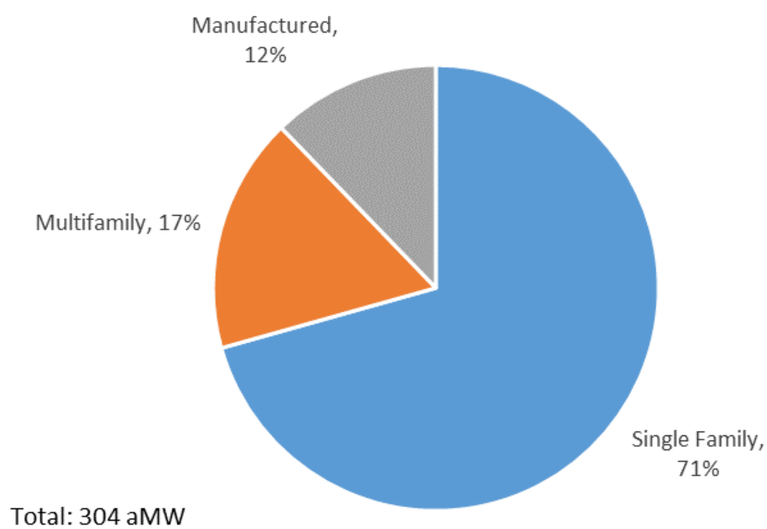
Detailed Resource Potentials

Residential Sector—Electric

By 2035, residential customers in PSE's service territory will likely account for nearly one-half of baseline 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 lighting efficiency (e.g., CFLs and LEDs). As described in the General Approach and Methodology section, the expected impacts of new lighting standards established through EISA have been removed from the potential presented in this section.

As shown in Figure 21, single-family homes represent 71% of the total achievable technical residential electric potential, followed by multifamily (17%) and manufactured homes (12%). 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 21. Residential Electric Achievable Technical Potential by Segment, Cumulative in 2035



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. (Volume II, Appendix B.3 provides a comprehensive list of the factors impacting segment-level energy efficiency potential.)

Water heating end uses represent the largest portion (29%) of achievable technical potential. Heating, lighting, and appliances each also represent over 15% of the total identified potential. A considerable amount of energy efficiency potential remains in the lighting end use, even after EISA effects have been removed from the baseline forecast. Figure 22 shows the total achievable technical potential by end-use group. Table 16 presents detailed potentials by end use. (Volume II, Appendix B.3 provides additional details regarding the savings associated with the specific measures assessed within each end use.)

Figure 22. Residential Electric Achievable Technical Potential by End Use, Cumulative in 2035

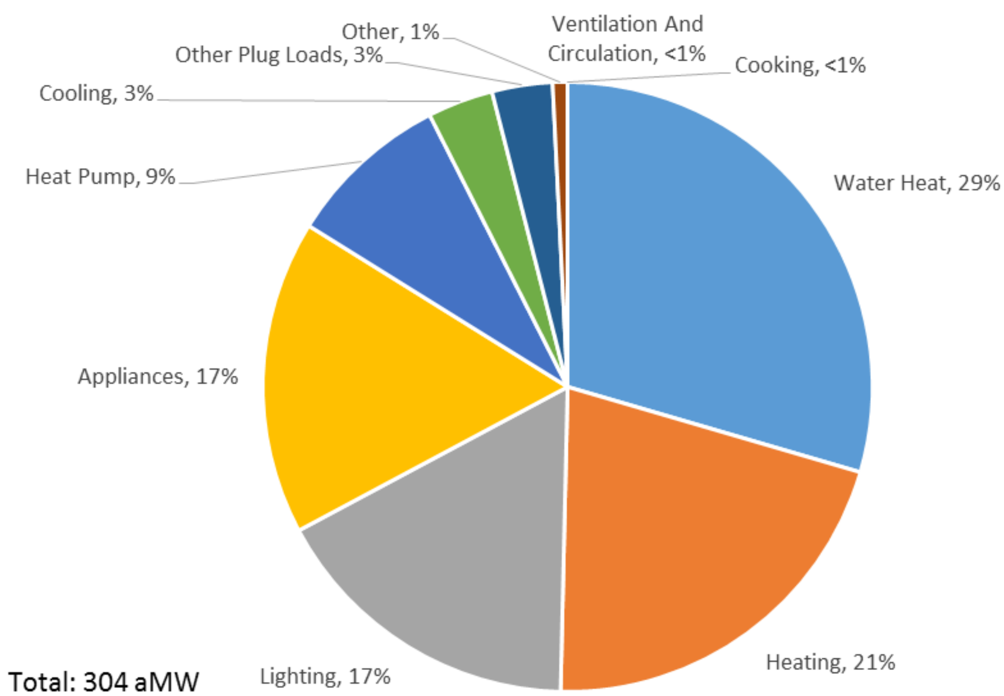
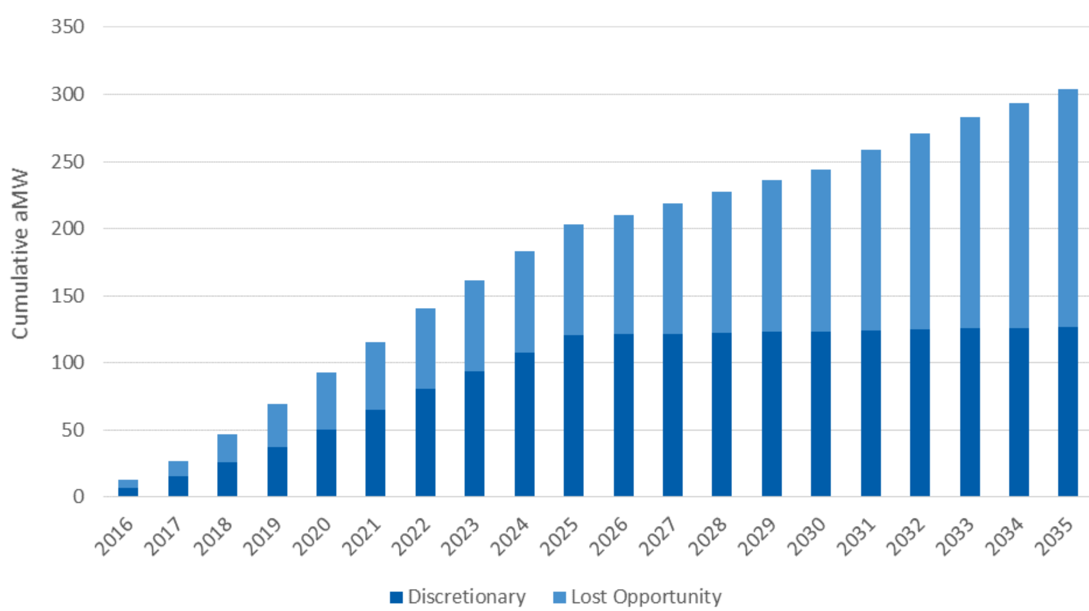


Table 16. Residential Electric Potential by End Use, Cumulative in 2035

End Use	Baseline Sales (aMW)	Technical Potential		Achievable Technical Potential	
		aMW	Percentage of Baseline Sales	aMW	Percentage of Baseline Sales
Appliances	207	67	32%	50	24%
Consumer Electronics	222	0	0%	0	0%
Cooking	17	0	1%	0	1%
Cooling	22	13	58%	11	49%
Heat Pump	84	35	42%	26	31%
Heating	213	78	37%	63	30%
Lighting	112	60	53%	51	45%
Other	6	3	54%	2	41%
Other Plug Loads	396	12	3%	10	2%
Plug Load	22	0	0%	0	0%
Ventilation And Circulation	77	3	4%	1	1%
Water Heat	237	119	50%	89	38%
Total Residential	**1,616**	**390**	**24%**	**304**	**19%**

Figure 23 shows annual cumulative achievable technical potential by resource type for the sector. Discretionary measures, acquired in equal increments over a 10-year period, account for 42% of the 20-year cumulative achievable technical potential. Lost opportunity measures account for the other 58% of the potential.

Figure 23. Residential Electric Annual Cumulative Achievable Technical Potential by Resource Type

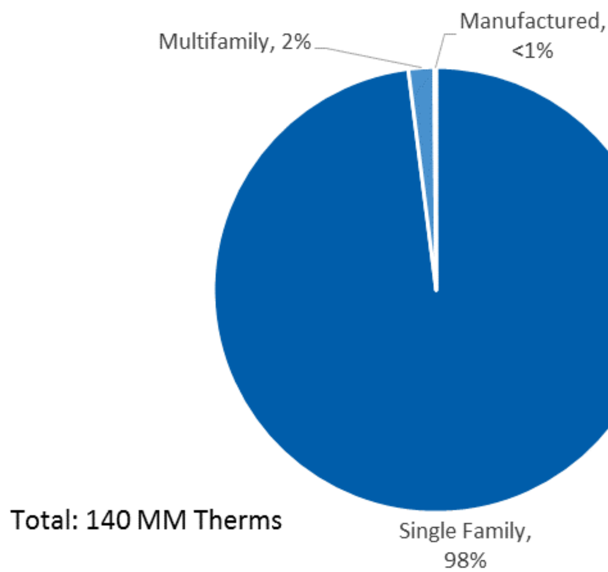


Residential Sector—Natural Gas

By 2035, residential customers will likely account for over 65% 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); however, 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 140 million therms over 20 years, corresponding to a 17% reduction of forecasted 2035 sales.

Single-family homes account for 98% of the identified achievable technical potential, as shown in Figure 24. Less than 2% of total achievable technical potential occurs in multifamily and manufactured residences due to a lack of gas connections.

Figure 24. Residential Natural Gas Achievable Technical Potential by Segment, Cumulative in 2035



As shown in Figure 25, space heating and water heating end uses account for over 99% of the identified achievable technical potential, which combines high-efficiency equipment (such as condensing furnaces and water heaters) and retrofits (such as shell measures, duct and pipe insulation, and low-flow showerheads). Table 17 presents detailed potentials by end use.

Figure 25. Residential Natural Gas Achievable Technical Potential by End Use, Cumulative in 2035

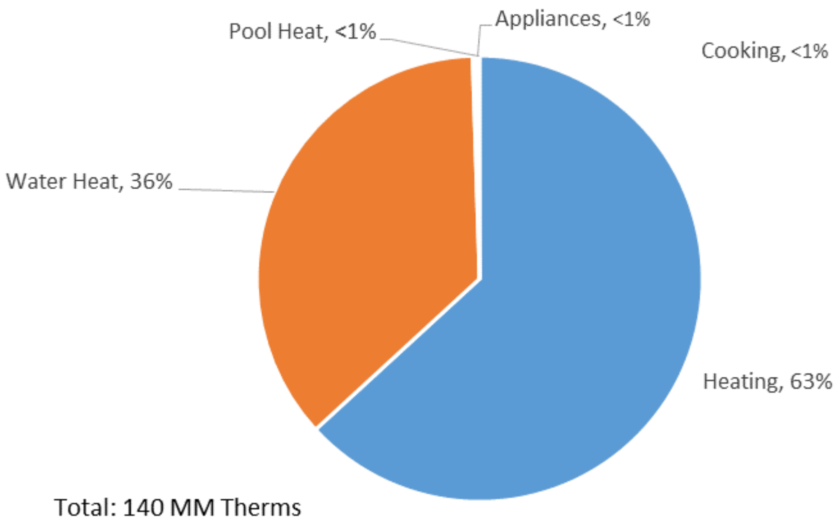
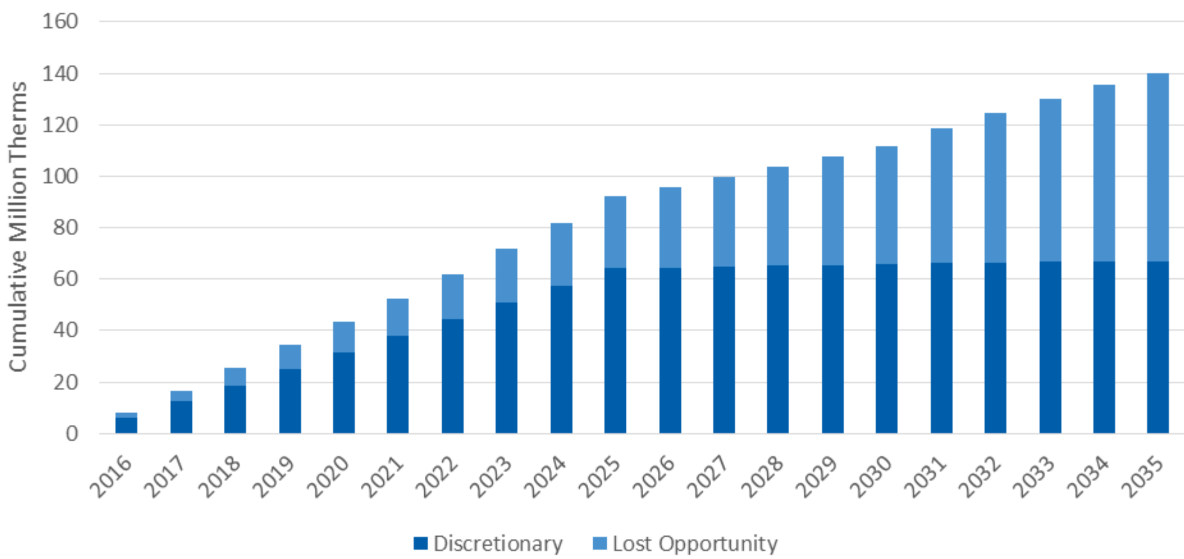


Table 17. Residential Natural Gas Potential by End Use, Cumulative in 2035

		Technical Potential		Achievable Technical Potential	
End Use	Baseline Sales (Million Therms)	Million Therms	Percentage of Baseline Sales	Million Therms	Percentage of Baseline Sales
Heating	535	139	26%	88	17%
Water Heat	178	77	43%	51	29%
Cooking	11	1	9%	0	3%
Appliances	3	0	9%	0	7%
Pool Heat	3	0	5%	0	4%
Total Residential	**730**	**217**	**30%**	**140**	**19%**

Figure 26 shows residential natural gas annual cumulative achievable technical potential by resource type. Discretionary measures, acquired in equal increments over a 10-year period, account for 48% of the 20-year cumulative, achievable technical potential.

Figure 26. Residential Natural Gas Annual Cumulative Achievable Technical Potential by Resource Type

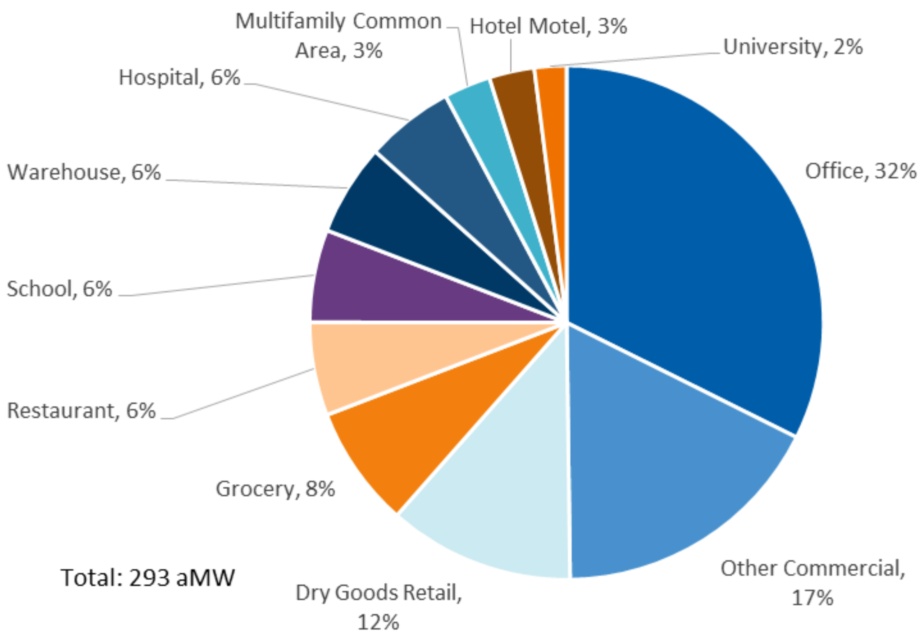


Commercial Sector—Electric

Based on resources included in this assessment, electric achievable technical potential in the commercial sector will likely be 293 aMW over 20 years, a 21% reduction in forecasted 2035 commercial sales.

As shown in Figure 27, offices represent slightly less than one-third (32%) of the available potential. "Other commercial" facilities also represent a large portion of available potential (17%). The other commercial segment includes customers not fitting into the other categories and customers with insufficient information for classification.

Figure 27. Commercial Electric Achievable Technical Potential by Segment, Cumulative in 2035



As shown in Figure 28, lighting efficiency improvements represent the largest portion by far of achievable technical potential in the commercial sector (48%), followed by ventilation and circulation (11%), cooling (9%), and refrigeration (8%). The large lighting potential includes bringing existing buildings to code and exceeding code in new and existing structures.

Table 18, which follows, shows distributions of baseline sales and savings across end uses.

Figure 28. Commercial Electric Achievable Technical Potential by End Use, Cumulative in 2035

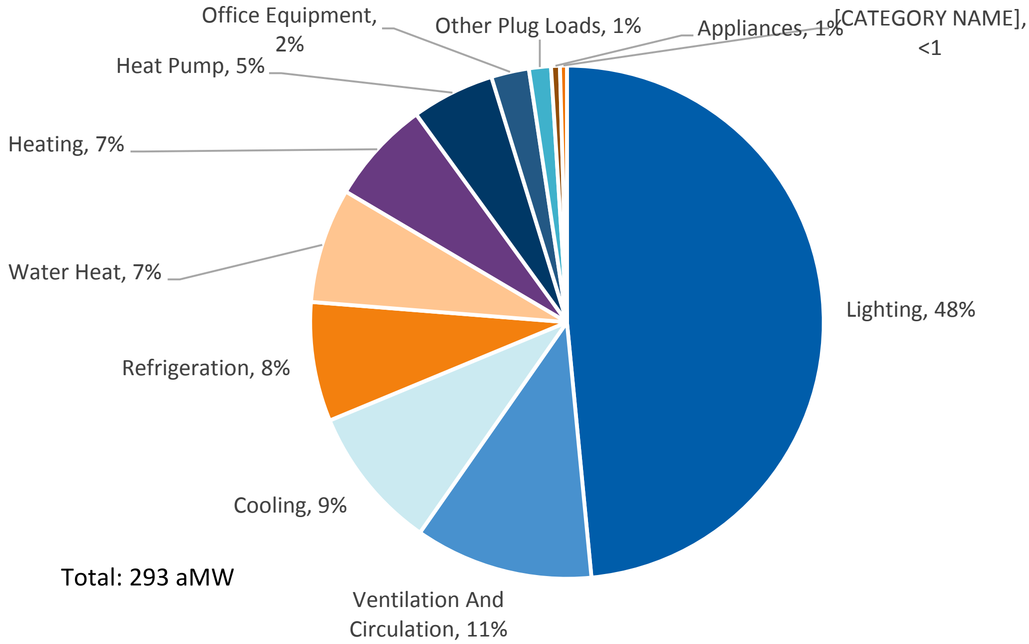
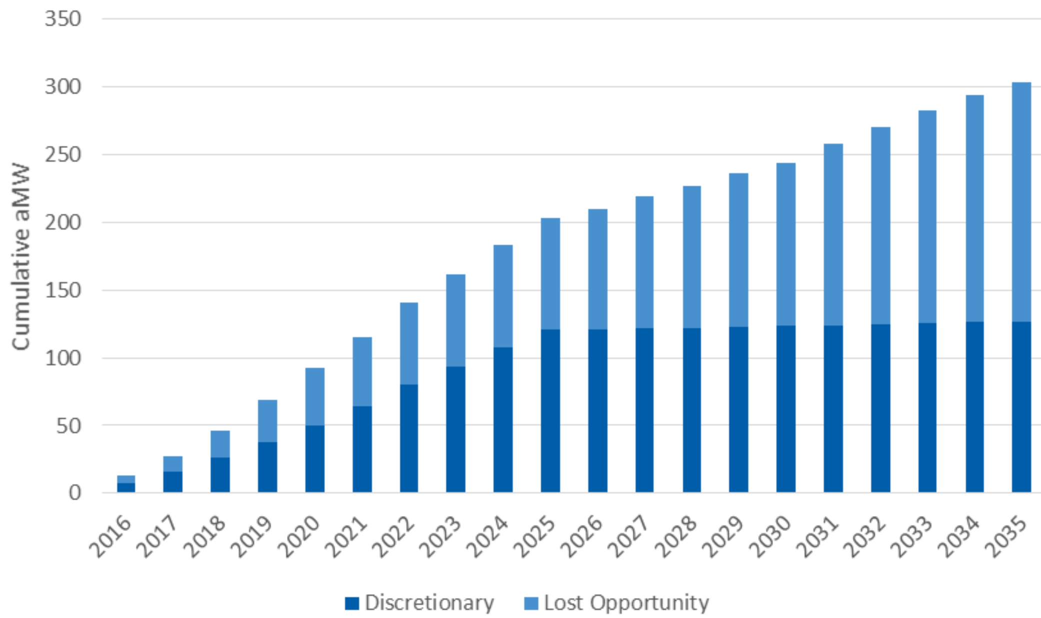


Table 18. Commercial Electric Potential by End Use, Cumulative in 2035

End Use	Baseline Sales (aMW)	Technical Potential		Achievable Technical Potential	
		aMW	Percentage of Baseline Sales	aMW	Percentage of Baseline Sales
Appliances	7	2	29%	2	25%
Consumer Electronics	1	0	0%	0	0%
Cooking	1	2	9%	1	8%
Cooling	17	32	42%	26	35%
Heat Pump	75	19	38%	15	30%
Heating	51	23	31%	19	26%
Lighting	73	171	25%	142	21%
Office Equipment	678	8	12%	7	10%
Other Plug Loads	67	5	6%	4	5%
Plug Loads	13	0	0%	0	0%
Refrigeration	74	26	35%	22	30%
Ventilation And Circulation	199	39	20%	33	17%
Water Heat	71	33	47%	21	30%
Total Commercial	**1,409**	**360**	**26%**	**293**	**21%**

Figure 29 shows commercial electric annual cumulative achievable technical potential by resource type. Discretionary measures, acquired in equal increments over a 10-year period, account for 42% of the 20-year cumulative achievable technical potential.

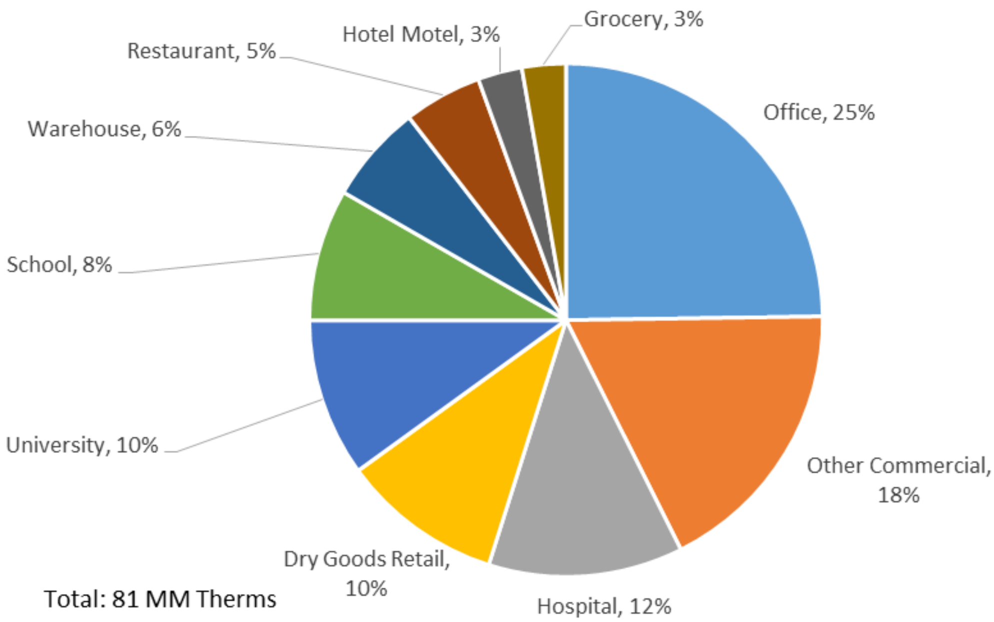
Figure 29. Commercial Electric Annual Cumulative Achievable Technical Potential by Resource Type



Commercial Sector—Natural Gas

Based on resources included in this assessment, natural gas achievable technical potential in the commercial sector will likely be 81 million therms over 20 years, an 18% reduction in forecasted 2035 commercial sales. Achievable technical natural gas potential in the commercial sector represents about 36% of the total identified potential across all sectors. As shown in Figure 30, for natural gas customers, office buildings represent the largest portion of potential (25%). Significant amounts of achievable technical potential exist in miscellaneous facilities (18%) and education buildings (18%).

Figure 30. Commercial Natural Gas Achievable Technical Potential by Segment, Cumulative in 2035



As in the residential sector, far fewer gas-fired end uses exist than electric end uses. Space heating accounts for 75% of the identified potential; the remaining potential is mostly in water heating (22%), with small amounts in cooking and pool heating (as shown in Figure 31 and Table 19).

Figure 31. Commercial Natural Gas Achievable Technical Potential by End Use, Cumulative in 2035

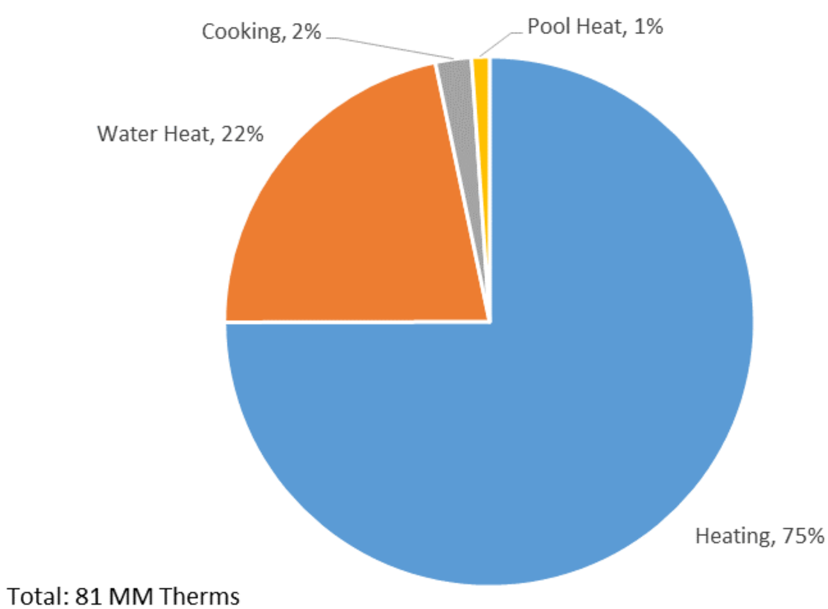
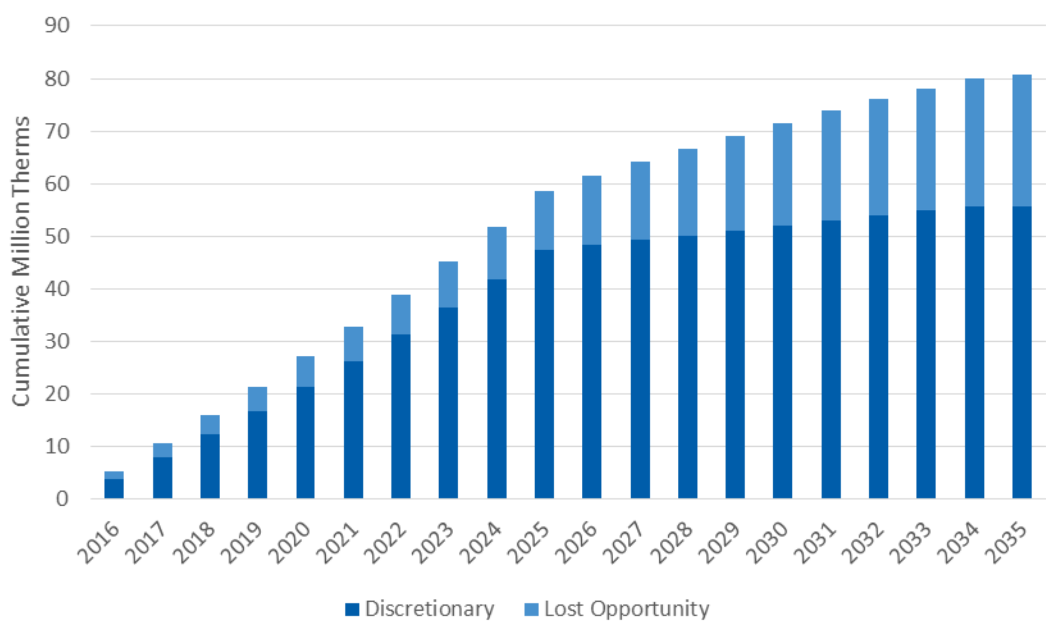


Table 19. Commercial Natural Gas Potential by End Use, Cumulative in 2035

End Use	Baseline Sales (Million Therms)	Technical Potential		Achievable Technical Potential	
		Million Therms	Percentage of Baseline Sales	Million Therms	Percentage of Baseline Sales
Heating	274	81	30%	61	22%
Water Heat	87	23	27%	18	20%
Cooking	62	2	4%	2	3%
Pool Heat	17	1	7%	1	5%
Total Commercial	**440**	**108**	**25%**	**81**	**18%**

Figure 32 shows commercial natural gas annual cumulative achievable technical potential by resource type. Discretionary measures, acquired in equal increments across a 10-year period, account for 69% of 20-year cumulative achievable technical potential.

Figure 32. Commercial Natural Gas Annual Cumulative Achievable Technical Potential by Resource Type

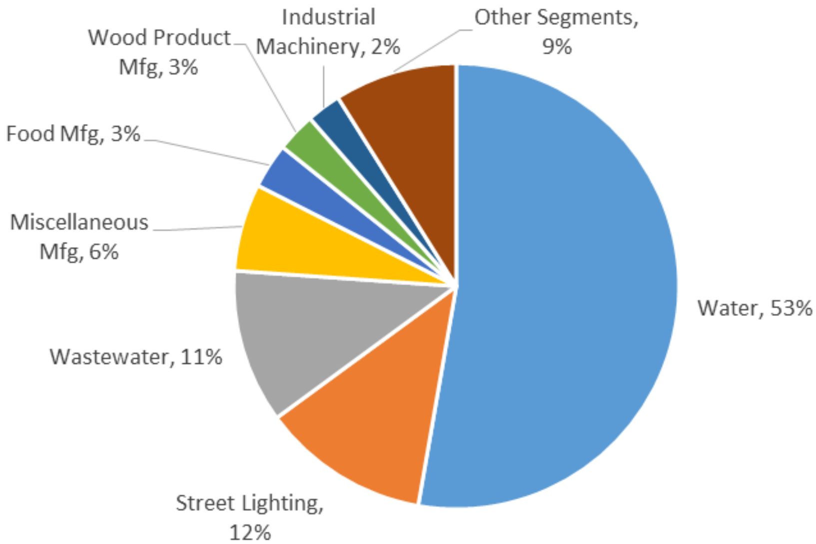


Industrial Sector—Electric

The study estimates technical and achievable technical energy efficiency potential for major end uses within 17 major industrial sectors. (Volume II, Appendix B.1. provides a list of these industries, along with baseline information.) Across all industries, achievable technical potential totals approximately 26 aMW over the 20-year planning horizon, corresponding to a 20% reduction of forecasted 2035 industrial consumption.

Figure 33 shows 20-year industrial achievable technical potential by segment.

Figure 33. Industrial Sector Electric Achievable Technical Potential by Segment



Other Segments includes Printing Related Support, Transportation Equipment Mfg, Fabricated Metal Products, Paper Mfg, Nonmetallic Mineral Products, Electrical Equipment Mfg, Plastics and Rubber Products, Chemical Mfg, Petroleum Coal Products, and Primary Metal Mfg.

As shown in Figure 34, the majority (52%) of electric achievable technical potentials in the industrial sector results from pumps. Street lighting measures (14%) and fans (13%) also comprise significant portions of available technical potential. A small amount of additional potential exists for lighting and other facility improvements. Table 20 presents detailed potentials by end use. All industrial measures should be considered discretionary, with savings acquired over a 10-year time frame.

Figure 34. Industrial Electric Achievable Technical Potential by End Use, Cumulative in 2035

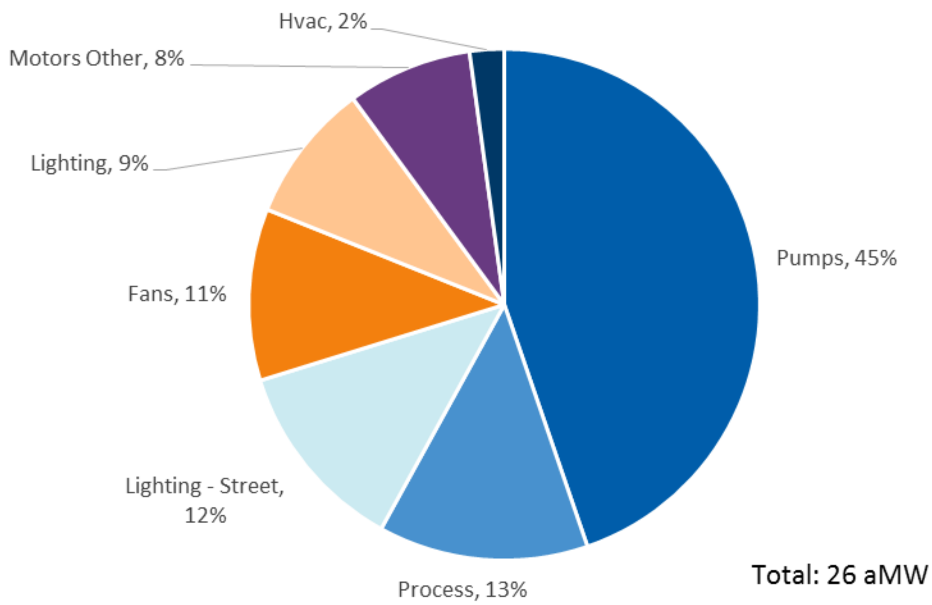


Table 20. Industrial Electric Potential by End Use, Cumulative in 2035

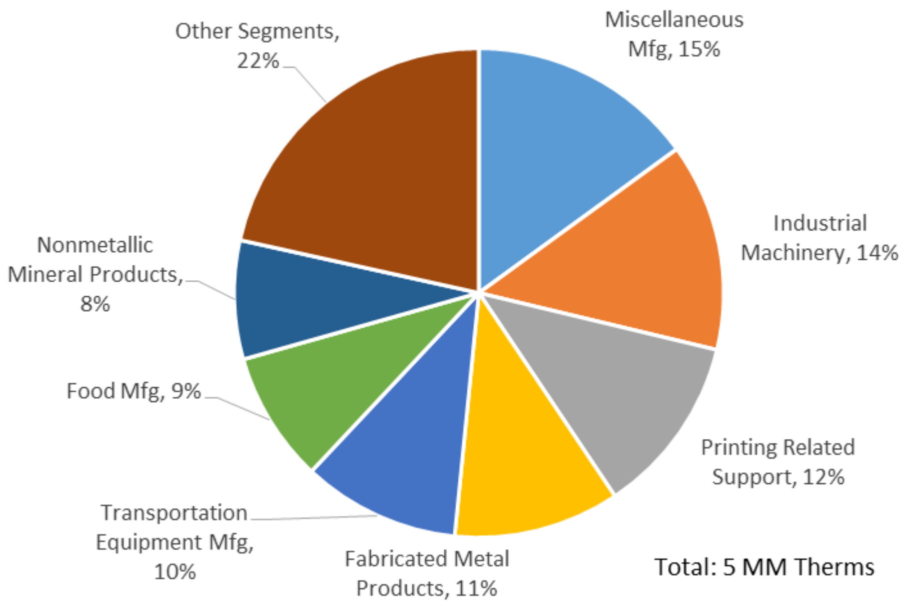
End Use	Baseline Sales (aMW)	Technical Potential		Achievable Technical Potential	
		aMW	Percentage of Baseline Sales	aMW	Percentage of Baseline Sales
Fans	9	3	38%	3	32%
HVAC	11	1	6%	1	5%
Indirect Boiler	1	0	0%	0	0%
Lighting	9	3	31%	2	27%
Lighting - Street	8	4	44%	3	37%
Motors Other	16	2	15%	2	12%
Other Plug Loads	11	0	0%	0	0%
Process	26	4	16%	3	13%
Pumps	39	14	35%	11	30%
Total	**129**	**30**	**23%**	**26**	**20%**

Industrial Sector—Natural 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 5 million therms over 20 years. Although this represents 20% of forecasted 2035 industrial sales, it accounts for only 2% of the achievable technical potential across the three sectors. As shown in Figure 35, substantial achievable technical potential occurs in miscellaneous manufacturing (15%), machinery (14%), metals (11%), and transportation equipment manufacturing (10%).

Figure 35. Industrial Natural Gas Achievable Technical Potential by Segment, Cumulative in 2035



Other Segments includes Computer Electronic Mfg, Wood Product Mfg, Electrical Equipment Mfg, Plastics Rubber Products, Chemical Mfg, Primary Metal Mfg, Paper Mfg, Petroleum Coal Products, and Water/Wastewater.

Two-thirds of achievable technical potential derive from process improvements. As shown in Figure 36 and Table 21, the remaining potential occurs in HVAC and boiler improvements**.** All industrial measures should be considered discretionary, with savings acquired over a 10-year time frame.

Figure 36. Industrial Natural Gas Achievable Technical Potential by End Use

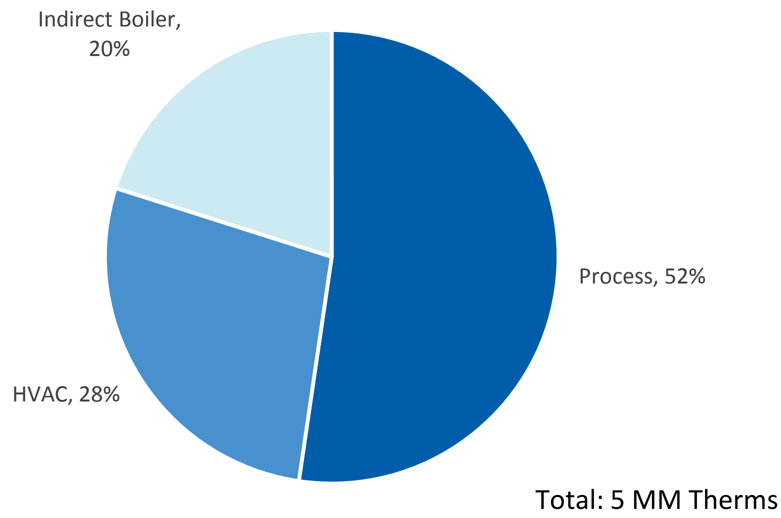


Table 21. Industrial Natural Gas Potential by End Use, Cumulative in 2035

		Technical Potential		Achievable Technical Potential	
End Use	Baseline Sales (Million Therms)	Million Therms	Percentage of Baseline Sales	Million Therms	Percentage of Baseline Sales
Process	10	3	33%	2	25%
HVAC	7	2	26%	1	20%
Indirect Boiler	6	1	19%	1	15%
Total Industrial	**23**	**6**	**27%**	**5**	**20%**

Fuel Conversion Potentials

Scope of Analysis

In the context of this assessment, fuel conversion refers to electricity-saving opportunities involving substitution of natural gas for electricity through replacement of space heating systems, water heating equipment, and appliances.

Where PSE provides both gas and electric service, this study examines fuel conversion potentials for existing residential single-family homes, existing and new commercial buildings, and new multifamily structures. Analysis includes three end uses for single-family and multifamily homes—space heating, water heating, and appliances (clothes dryers and cooking ranges). For new multifamily homes, the analysis includes the potential from converting electric baseboard heating to natural gas furnaces. For commercial buildings, the analysis examines only space and water heating end uses.

Summary of Resource Potentials

The calculations of fuel conversion technical potentials in this assessment assume conversion of all applicable customers and end uses.

As part of the 2009 IRP, Cadmus conducted a survey of residential customers that asked customers about their willingness to switch from an electric heating system to a gas heating system. Approximately 63% of respondents indicated they would be likely or highly likely to convert from electric to gas space heating if the utility paid 100% of the cost. With this result, we would assume the achievable technical potential to represent 63% of the technical potential. In the absence of comparable primary data, this analysis used the same percentage for the commercial sector.

Based on survey results and on previous PSE experiences, 70% of the new residential-sector gas customers converting a space heater would also convert a water heater and 5% would convert a range and/or dryer. For existing gas customers, all would convert a water heater and 5% would convert a range and/or dryer. The analysis assumes similar percentages for water heating conversions in the commercial sector.

Estimates indicate 207 aMW cumulative electric technical potential from fuel conversion by 2035. Acquisition of the indicated electricity savings will, however, result in increased gas consumption of about 15 million therms by 2035. After adjusting for the achievability described above, the total achievable technical electric savings potential of fuel conversion in 2035 is estimated at just over 57 aMW. This achievable technical potential corresponds to increased gas consumption of about 5 million therms.

Table 22 and Table 23 show, respectively, technical and achievable technical potential by customer type and market segment.

Table 22. Fuel Conversion Potentials by Customer Type, Cumulative in 2035

Customer Type	Technical Potential: Electric Savings (aMW)	Technical Potential: Additional Gas Usage (Million Therms)	Achievable Technical Potential: Electric Savings (aMW)	Achievable Technical Potential: Additional Gas Usage (Million Therms)
Electric - Only	159	11	45	4
Existing Gas Customer	63	4	16	1
Total	**222**	**15**	**61**	**5**

Table 23. Fuel Conversion Potentials by Market Segment, Cumulative in 2035

Market Segment	Technical Potential: Electric Savings (aMW)	Technical Potential: Additional Gas Usage (Million Therms)	Achievable Technical Potential: Electric Savings (aMW)	Achievable Technical Potential: Additional Gas Usage (Million Therms)
Single-Family	193	8	46	2
Multifamily	7	0	3	0
Commercial	22	6	11	3
Total	**222**	**15**	**61**	**5**

Detailed Resource Potentials

Residential Sector

The fuel conversion potential for single-family homes targets existing customers. The multifamily conversion targets both existing and new construction, with the new construction market size cumulative over 20 years, as estimated from PSE's customer forecast and assuming a consistent percentage of multifamily homes. The potential residential market size accounts for the current measure saturations. For example, some existing single-family homes already have a gas water heater, so these customers would not be considered for water heater conversion. In addition, the potential market size for new construction excludes the percentage of customers who have historically had gas systems.

Measures Considered

Cadmus' analysis of fuel conversion considers opportunities for three major end uses in residential dwellings—central heating, water heating (including conversion to integrated space and water heating units), and appliances (clothes dryer and oven). For space heating conversions, the study's treatment of multifamily homes differs slightly from single-family homes that use baseboard heating systems:

- For new multifamily buildings, the study examined conversion of room (or zonal) heating systems to natural gas furnaces.
- For existing single-family buildings, the study does not consider the cost of converting an existing baseboard system to a central system, given the high cost of installing the necessary ductwork.

Clothes dryers and cooking ranges were the only appliances considered in this study. Table 24 shows applicable measures and their assumed technical specifications. These measures are equivalent to those used for the Energy Efficiency section of this report, and detailed descriptions can be found in Volume II, Appendix B.

Table 24. End Uses and Measures Assessed

Segment	End Use	Gas Measure	Electric Baseline
MF, SF	Dryer	Dryer - Advanced Energy	Dryer - Federal Standard 2015
MF, SF	Cooking	Cooking Oven - Advanced Efficiency	Federal Standard 2012 Cooking Oven
MF, SF	Space Heating: Baseboard	Wall Heater 84% Efficiency	Electric Baseboard
MF, SF	Space Heating: Baseboard	Gas Fireplace	Electric Baseboard
MF, SF	Space Heating: Baseboard, Water Heating	Boiler	Baseboard Heating, Electric Water Heater, 55 gal.
MF, SF	Space Heating: Ducted	95% Furnace	Electric Furnace
MF, SF	Space Heating: Ducted, Water Heating	Integrated Space & Water Heat	Electric Furnace, Electric Water Heater, 55 gal.
MF, SF	Water Heating	WH (>67% EF)	Electric Water Heater, 55 gal.
MF, SF	Water Heating	Tankless WH	Electric Water Heater, 55 gal.
SF	Zone Heating: Baseboard	Wall Heater 84% Efficiency	Electric Baseboard

MF = multifamily, SF = single-family, WH = water heater, EF = energy factor

Gas Availability

In terms of service extension costs, gas availability and its implications are important considerations in determining the potential for fuel conversion. A major factor in determining the cost of new gas service is whether an electric-only customer is on a gas main. For existing single-family customers, the study used data from multiple sources (including PSE's 2010 RCS) to determine availability.[18]

PSE currently provides gas to approximately 49% of single-family homes in its electric service area. Customers currently receiving gas service from PSE can be considered candidates only for *additional* gas-using equipment, without imposing additional line extension costs. Using PSE's RCS to estimate the total number of gas-heated, single-family homes with electric water heaters and other appliances, Cadmus estimated over 45,000 existing gas homes were eligible for conversion.

Of electric customers without PSE gas service, approximately one-third reside in PSE's gas service territory. Based on the latest data available from PSE, approximately 24% of these customers are located on a gas main, 9% are a short distance (50 feet) from a gas main, and 18% are a moderate distance

[18] Puget Sound Energy. *Residential Characteristic Survey.* 2010.

(200 feet) from a gas main. The remaining customers are too far from a gas main to be considered eligible for conversion.

For new electric multifamily customers, approximately 14% reside in PSE combination territory, with one-quarter on a main and one-quarter near a main. Of the customers within the combination territory, approximately 15% will install baseboard heating systems without programmatic intervention (and thus can be considered part of the conversion potential).

Conversion Costs and Savings

This study uses the total resource cost (TRC) approach to assess conversion costs. The TRC calculates the installed cost of the gas measure, less the cost of an equivalent electric measure, and includes gas line extension costs.

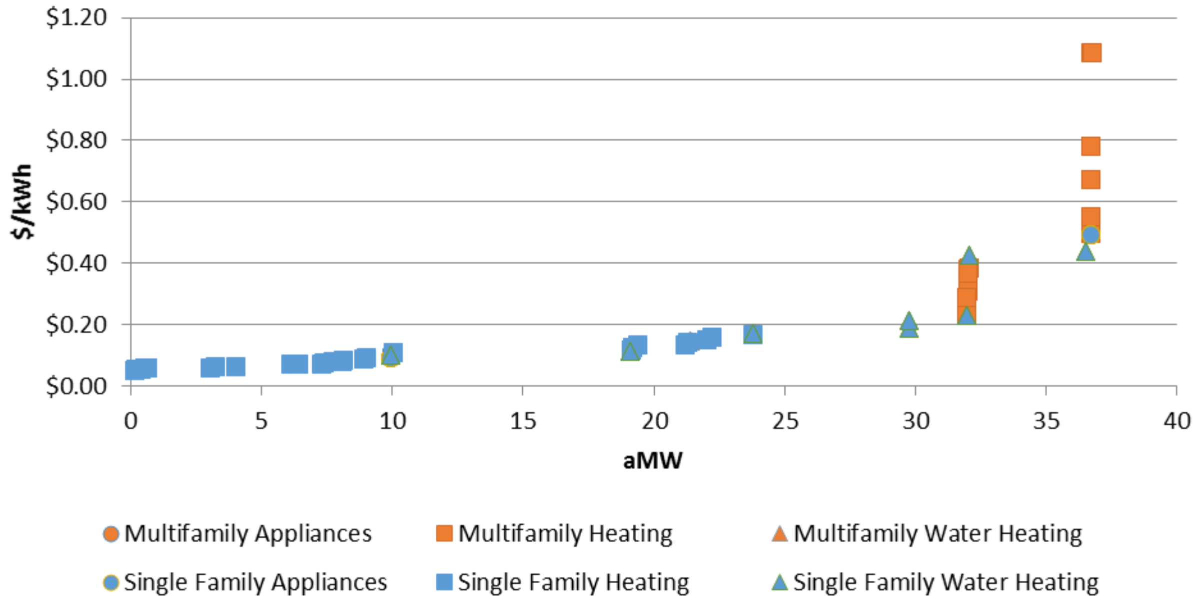
For electric-only customers, connecting a house to a gas main will probably require a service line extension that costs $3,406. Customers a short distance (50 feet) from a gas main experience would incur an additional $2,000 cost. Customers a moderate distance (200 feet) from a main would incur an additional $12,000 cost over the initial $3,406.

For this assessment, Cadmus analyzed the cost of line extensions for gas furnaces. However, because water heaters may be converted without the furnace, we included a proportional amount for water heating measures. An appliance end use would have an additional cost for interior piping (estimated at $200 per piece of equipment, according to local HVAC contractors in 2008).[19]

Figure 37 shows cumulative electric savings, categorized by home type and end use and distributed by levelized cost. We based these conversion savings estimates on the same assumed levels of unit energy consumption (UEC) as we used in the energy efficiency analysis (described in Energy Efficiency Potentials section). Calculation of levelized cost includes increased gas usage, which is counted as an ongoing annual O&M cost. For baseline values, the study uses electric UECs (kWh/year) and gas UECs (therms/year) from the baseline forecast for existing single-family and existing and new multifamily homes.

[19] Cadmus interviewed several HVAC contractors selected from PSE’s Contract Referral Service List in 2008. Add complete source of Cadmus study.

Figure 37. Residential Fuel Conversion Supply Curve, Cumulative in 2035



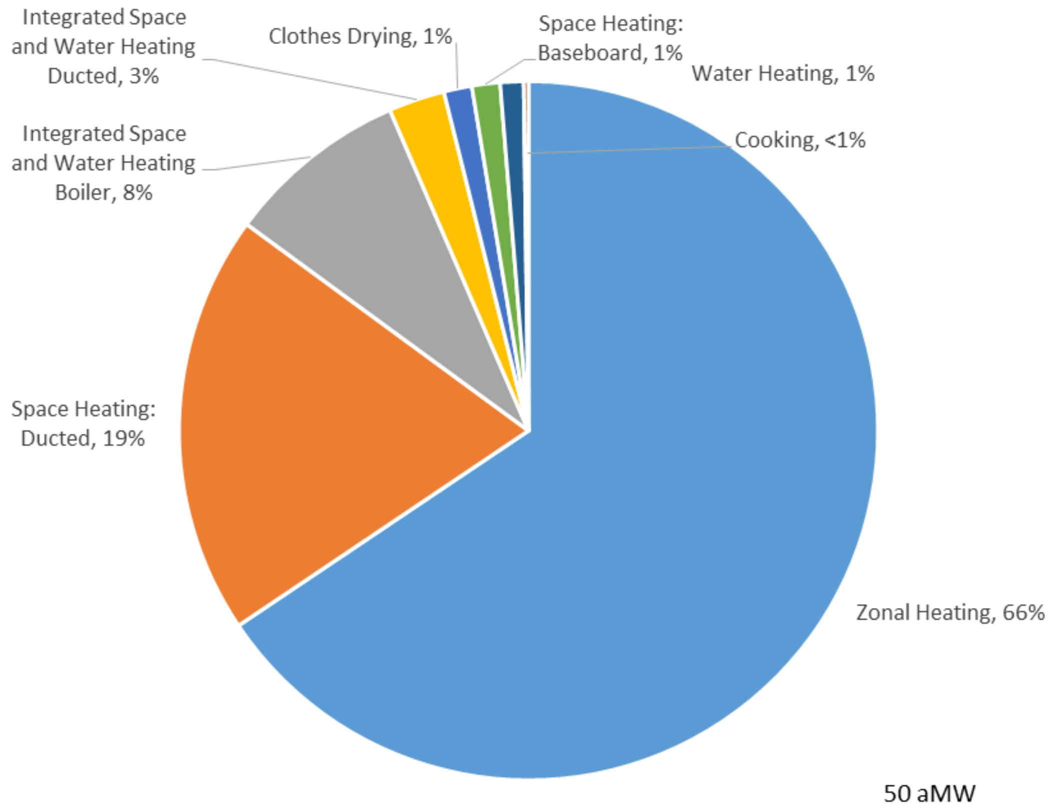
Potential

Table 25 and Figure 38 provide the technical and achievable technical conversion potential in 2035 for the residential sector (single-family and multifamily dwellings), by end use.

Table 25. Residential Fuel Conversion Potential by End Use, Cumulative aMW in 2035

End Use	Technical Potential	Achievable Technical Potential
Clothes Drying	20	1
Cooking	3	0
Space Heating: Baseboard	17	1
Integrated Space and Water Heating Boiler	13	4
Space Heating: Ducted	31	10
Integrated Space and Water Heating Ducted	42	1
Zonal Heating	59	33
Water Heating	16	1
Total	**200**	**50**

Figure 38. Residential Fuel Conversion Achievable Technical Potential by End Use, Cumulative 2035



Commercial Sector

The fuel conversion potential for the commercial sector includes conversion of equipment in existing buildings and new facilities.

Measures Considered

For existing facilities in the commercial sector, the measures considered include 95% AFUE furnaces and high-efficiency water heaters (≥0.67 EF storage and EF=0.82 tankless). The new construction segment includes the same measures, plus the additional measures provided in Table 26.

Table 26. New Construction Additional End Uses and Measures Assessed

Segment	End Use	Gas Measure	Electric Baseline

Segment	End Use	Gas Measure	Electric Baseline
All Com	Space Heating	Furnace - Premium Efficiency	Electric Furnace
All Com	Space Heating	Gas PACs	Packaged RTU
All Com	Space Heating, Water Heating	Integrated Space Heating and Water Heating	Packaged RTU, Electric Water Heater, 50 gal.
All Com	Space Heating, Water Heating	Integrated Space Heating and Water Heating	Packaged Rooftop VAV w/ Electrical Resistance Reheat & Electric Water Heater, 50 gal.
All Com	Space Heating: Ducted	Furnace - Premium Efficiency	Electric Furnace
All Com	Water Heating	ENERGY STAR Storage	Electric Water Heater, 50 gal.
All Com	Water Heating	ENERGY STAR Tankless	Electric Water Heater, 50 gal.

RTU = rooftop unit, VAV = variable air volume

Gas Availability

Data from the 2007 CBSA,[20] coupled with PSE's commercial customer database, provided market shares by territory and end use.

Of existing electric-only commercial customers, approximately 60% are in PSE gas territory, with around 25% of those on a main line. Expectations for new customers are approximately 32% within the combination service territory, 25% on a gas main, 9% a short distance (50 feet) from a gas main, and 18% a moderate distance (200 feet) from a gas main. The remaining customers will be too far from a gas main to be considered for conversion.

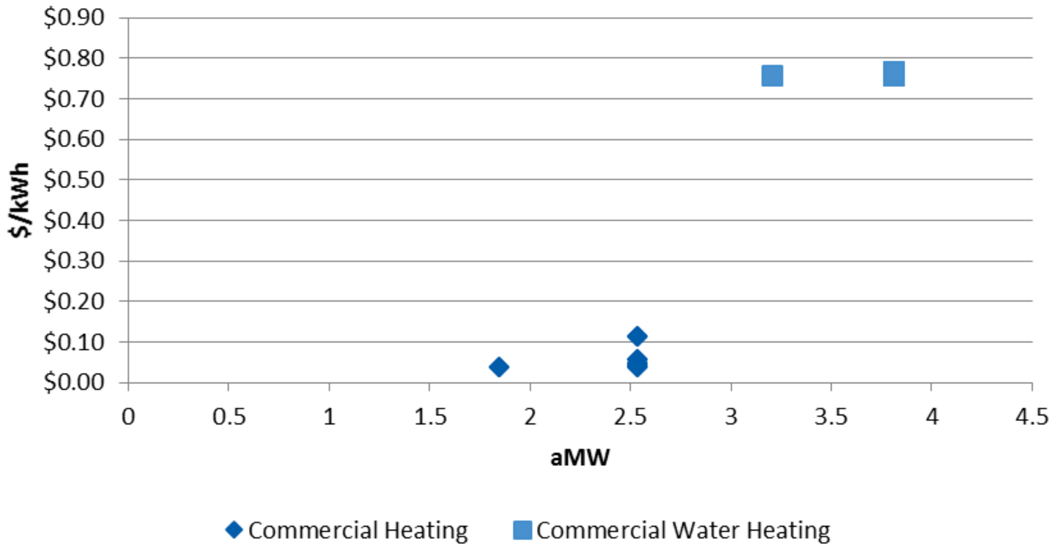
Conversion Costs and Benefits

The analysis estimates conversion savings based on assumed UEC levels, consistent with those used in the energy efficiency analysis described in the Energy Efficiency Potentials section. Increased gas use, counted as an ongoing annual O&M cost, is included in the calculation of levelized cost. For baseline values, the analysis uses electric UECs (kWh/year) and gas UECs (therms/year) from the baseline forecast.

Figure 39 shows cumulative electric savings, by end use, distributed by levelized cost. Similar to the residential sector, the service-line connection cost applies only to existing customers for the furnace cost. For simplicity, commercial buildings assume energy consumption as the weighted average of all segments, based on the likelihood of equipment being used in the given facility.

[20] Northwest Energy Efficiency Alliance. *2007 Commercial Building Stock Assessment (CBSA).* Available online: http://neea.org/resource-center/regional-data-resources/commercial-building-stock-assessment.

Figure 39. Commercial Fuel Conversion Supply Curve, Cumulative in 2035



Potential

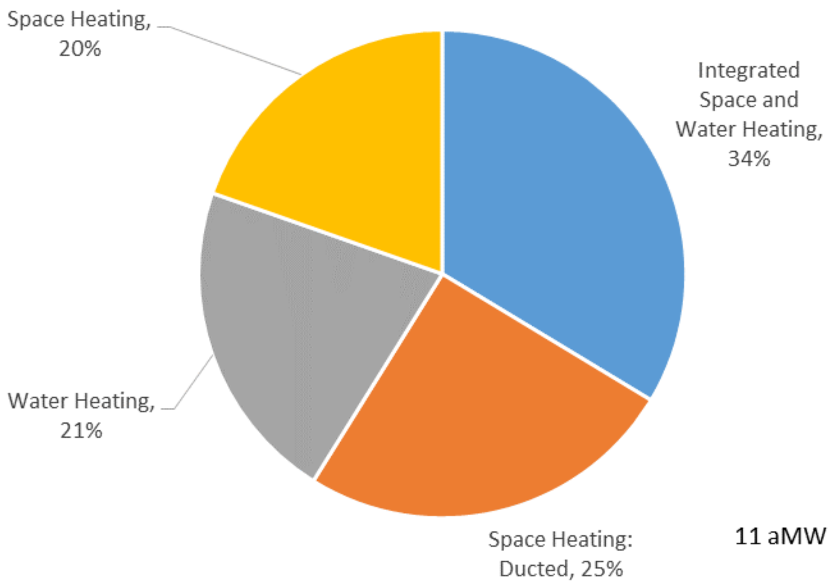
Table 27 and Figure 40 show the technical and achievable technical conversion potential in 2035 by end use.

Table 27. Commercial Fuel Conversion Potential by End Use, Cumulative aMW in 2035

End Use	Technical Potential	Achievable Technical Potential
Space Heating*	4	2
Space Heating: Ducted**	6	3
Integrated Space and Water Heating	6	4
Water Heating	5	2
Total	**22**	**11**

* Represents both furnace and gas warm-up heat conversions in new construction.
** Represents conversion for electric furnaces in existing buildings.

Figure 40. Commercial Fuel Conversion Achievable Technical Potential by End Use, Cumulative in 2035



Demand Response Potentials

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-varying rates or interruptible tariffs) and incentive-based (such as DLC) strategies. This assessment utilizes three demand response strategies:

- ***DLC*** programs allow a utility to interrupt or cycle electrical equipment and appliances remotely at a customer's facility. This study assesses DLC program potential for two programs in the residential sector:
  - A combination program of central electric heating (including heat pumps) and electric water heating; and
  - A combination program of room heating and electric water heating.
- ***Nonresidential Load Curtailment*** programs refer to contractual arrangements between a utility and a third-party aggregator that works with utility customers. The third-party aggregator typically guarantees a specific curtailment level during an event period, achieving load reduction by working with utility customers that agree to curtail or interrupt their loads in whole or part when requested. In most cases, customers must participate once enrolled in the program and incentives are paid per curtailed kW. Cadmus' analysis of these programs assumes they target nonresidential customers with average monthly loads greater than 100 kW. Customers may use backup generation to meet displaced loads.
- ***Critical Peak Pricing*** (CPP) or extreme-day pricing refers to programs aiming to reduce system demand by encouraging customers to reduce their loads for a limited number of hours during the year. When such events occur, customers may curtail their usage or pay substantially higher-than-standard retail rates. CPP programs integrate a pricing structure similar to a time-of-use (TOU) program, though CPPs use more extreme pricing signals during critical events. This assessment examines CPP options for both the residential and commercial sectors.

As this study updates the 2013 IRP, the program options listed above largely have been based on that assessment, with revisions based on PSE's input. After Cadmus reviewed new demand response literature including recent program evaluations on programs across the country as well as on PSE's pilot programs, updates were made to each program. This section details the design specifications and assumptions underlying the analysis for each program strategy.

Summary of Resource Potentials

Table 28 presents estimated resource potentials for all demand-response strategies for the residential, commercial, and industrial sectors during winter. The greatest market potential occurs in the residential sector, due to the DLC programs. Notably, this analysis does not account for program interactions and overlap; thus, the total market potential estimates may not be fully attainable upon implementation of all program strategies. The system peak is based on PSE's average load in the top 20 hours.

Table 28. Demand Response Market Potential, MW in 2035

Sector	Winter Market Potential (MW)	Percent of System Peak – Winter
Residential	115	2.9%
Commercial	62	1.6%
Industrial	5	0.1%
Total	181	4.5%

Resource Costs and Supply Curves

Resource acquisition costs fall into multiple categories, including infrastructure, administration, maintenance, data acquisition, hardware costs, marketing expenses, and incentives

Cadmus developed estimates for each expense category within each program using PSE's program data and experience, and using secondary sources, such as reports on similar programs offered by other utilities. In developing estimates of levelized costs, the study allocates program expenses annually over the program's expected life cycle, and discounts by PSE's cost of capital (7.77%). The ratio of this value and the discounted kW reduction produces the levelized per-kW cost for each program.

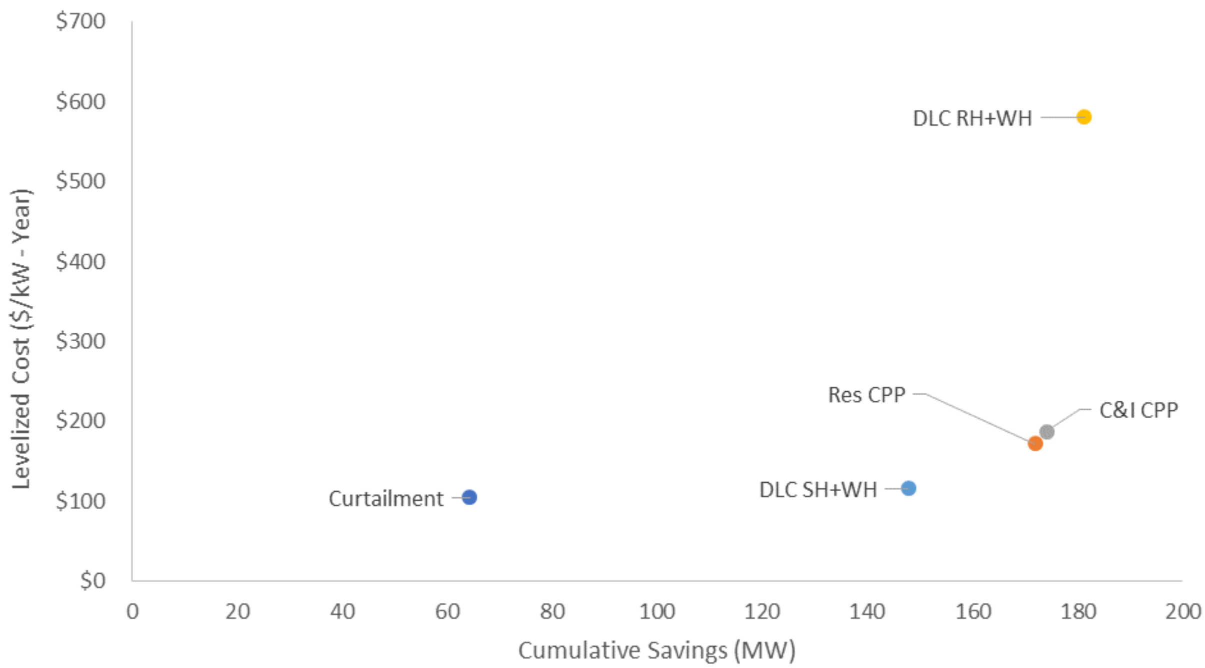
Table 29 displays per-unit ($/kW per year) costs by program for the estimated market potential during the winter season. Estimates find the Load Curtailment program for large, nonresidential customers to be the least-expensive option, with a levelized cost of $105/kW per year, while, due to high technology installation costs, the residential DLC—room and water heat program proves the most costly, with a levelized cost of $581/kW per year.

Table 29. Demand Response Market Potential and Levelized Costs, MW in 2035

Program Strategy	Achievable Potential (MW)	Levelized Cost ($/kW-year)
Residential Direct Load Control - Space and Water Heat	84	$115
Residential Direct Load Control - Room and Water Heat	7	$581
Residential Critical Peak Pricing	24	$172
Commercial & Industrial Critical Peak Pricing	2	$187
Commercial & Industrial Curtailment	64	$105
Total	**181**	

Cadmus constructed supply curves from quantities of estimated market potential and per-unit costs for each program option. Figure 41 shows the quantity of market demand-response potential available during winter peak hours in 2035 as a function of levelized cost.

Figure 41. 20-Year Achievable Supply Curve for Demand Response



Resource Acquisition Schedule

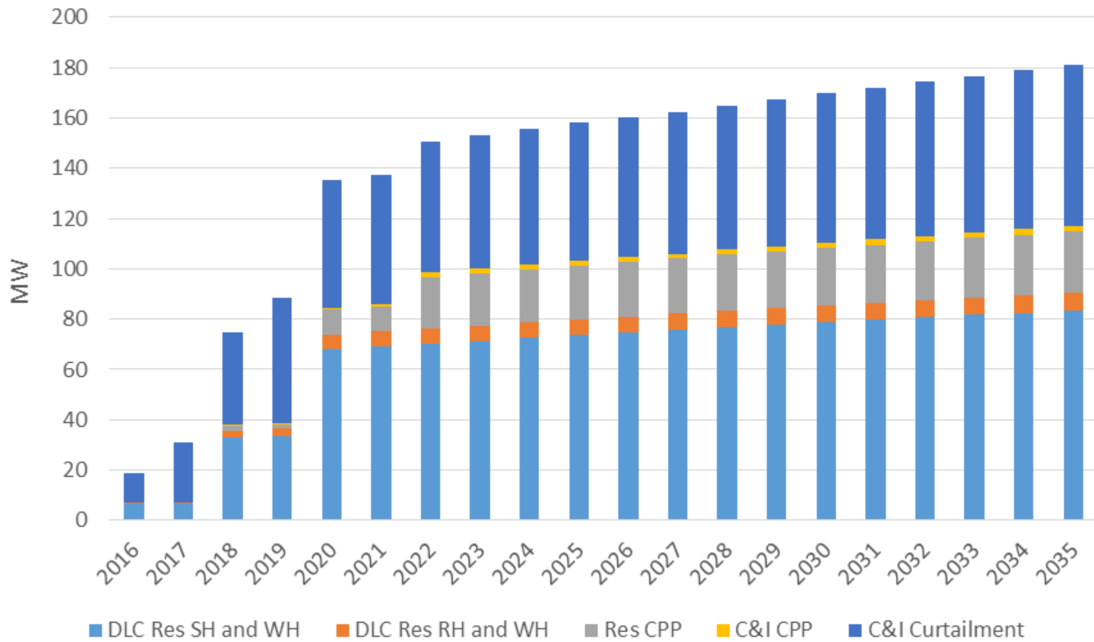
Cadmus assumes each program will require an ample start-up period before achieving full participation. Therefore, each program option has an associated ramp rate, as described here:[21]

- The curtailment program is assumed to begin in 2016 and reach maximum participation in 2019.
- Residential DLC programs and the Residential CPP program will start in 2016 as two-year pilot programs. In 2018, the programs will begin to grow to full participation by 2020. This schedule has been partially dictated by PSE's schedule for installing advanced metering infrastructure (AMI) in the residential sector.
- The CPP programs are assumed to start as a three-year pilot 2018 to account for the time required to create a new tariff and to place necessary infrastructure. In 2020, the programs will begin to ramp up, growing to full deployment by 2022.

Figure 42 shows the acquisition schedule for achievable potential impacts in winter.

[21] Once programs reach full participation, impacts continue to grow due to forecasted load growth.

Figure 42. Demand Response Annual Achievable Technical Potential by Strategy - Winter



Detailed Resource Potentials by Program Strategy

Residential DLC

DLC programs seek to interrupt specific end-use loads at customer facilities through utility-directed control. When deemed necessary, the utility, 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 they typically receive incentives, paid through monthly credits on their utility bills.

For such programs, load control switches or PCTs are connected to a digital internet gateway. Load control switches allow two-way communication enabling PSE to cycle end uses on and off during peak events, while PCTs automatically set-back temperature set points on heating and water heating systems. Historically, DLC programs have mandatory event participation once a customer elects to participate in the program; however, voluntary event participation has become an option for some programs where the control systems allow customers to opt-out or override their participation in an event once it has been called.

Because PSE's system peak occurs in the winter, this assessment focuses on two DLC programs controlling heating loads. Although residential DLC programs for air conditioning have become well-established programs in the nation, central and room heating DLC programs remain a relatively new idea, with minimal data available through secondary research. The winter peak limits program comparability to other summer peaking programs. However, lessons learned in summer peaking programs can inform PSE program participation and design.

PSE implemented a space-and-water-heating DLC pilot from 2009 through 2011. In addition to PSE's pilot program, there are several regional pilots Cadmus researched including the Bonneville Power Administration (BPA) Kootenai pilot, which included space heat and water heat; the BPA Orcas Power and Light Cooperative (OPALCO) pilot for water heat; and two Portland General Electric (PGE) pilots for space and water heat. Additionally, Minnesota commissioned a study of demand response potential and snapback effects including a space heating demand response program. Due to the minimal secondary data available for such programs, some summer DLC program assumptions have been adapted to supplement PSE's pilot data for this assessment.

Central Heating and Water Heating

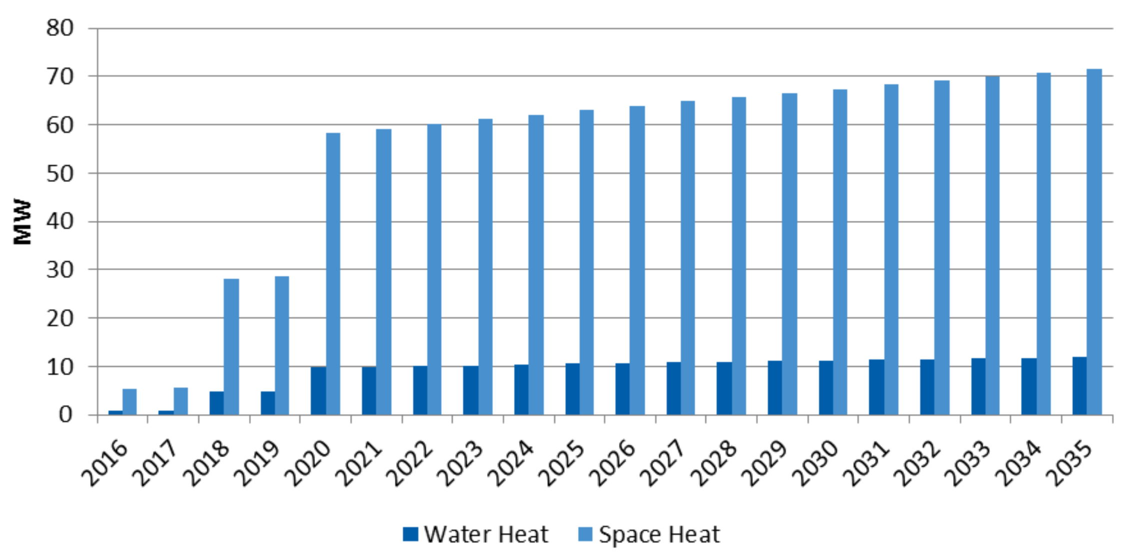
Table 30 shows the market potential results by end use and the levelized program cost. Although this program primarily focuses on reducing the winter peak, water heaters will be available for control in the summer.

Table 30. Space Heat Direct Load Control Results

End Use	Market Potential (MW 2035)	Percent of System Peak – Winter	Levelized Cost($/kW)
Central Heat	72	1.8%	$115
Water Heat	12	0.3%	
Total	84	2.1%	

Figure 43 shows the achievable potential over a 20-year period based on an acquisition schedule for a two-year pilot program, starting in 2016 and ramping up to full participation in 2020.

Figure 43. Space and Water Heat Direct Load Control Acquisition Schedule



Utility incentives for residential DLC programs can vary greatly, from a free programmable thermostat, to a set incentive amount per month, to a 15% discount on customers' summer electricity bills (which may range from $50 to $60 annually for many participants). This analysis assumes incentives set at $32/year for central heat cycling, with an additional $8 for water heating control. Program assumptions including attrition, event impacts, costs, incentives and participation are listed here:

- ***Attrition*** of 5% (program research ranges from 2% to 5%).
- ***Event impacts*** of 1.74 kW heating and 0.57 kW domestic water heater (DWH) from the pilot.
- ***Administration costs*** of 5%.
- ***Vendor costs*** of 15%.
- ***Technology costs*** of $280 per DHW switch, $370 per PCT, and $275 per gateway. These costs are based on PSE's pilot program and are inclusive of installation costs. (Program research ranged from $175/DWH switch to $600 for an installed PCT.)
- ***Marketing costs*** per customer are $25 based on 0.5 hours of a full-time employee (FTE), at $50 per hour, used in planning. Research ranged from $10 to $92, most of which were based upon FTE values; E Source benchmarking showed that marketing costs were equivalent to 9% of total program costs.[22]
- ***Incentive cost*** of $32 for each customers enrolled with the space heating program plus an additional $8 for customers who enroll in the water heater program (research ranges from $10 to $75).
- ***Communication costs*** of $7 per customer to account for the communication of a one-way transmission system.
- ***Program participation*** assumes that the program can reach 20% of eligible single-family and manufactured customers (program research ranged from 13% to 25%).
- ***Event participation*** of 94% (program research ranged from 70% room air conditioners to 95% for central air conditioners).

Room Heating and Water Heat Direct Load Control Results

Table 31 shows the market potential in winter at generation by end use and the levelized cost. Potential is much smaller for the room heating program compared to the space heating program because there is a lower saturation of room heaters and the per-participant impacts are also smaller. As with the central heating, greater potential exists in the winter, since the heating load occurs at that time.

Table 31. Room and Water Heat Direct Load Control Results

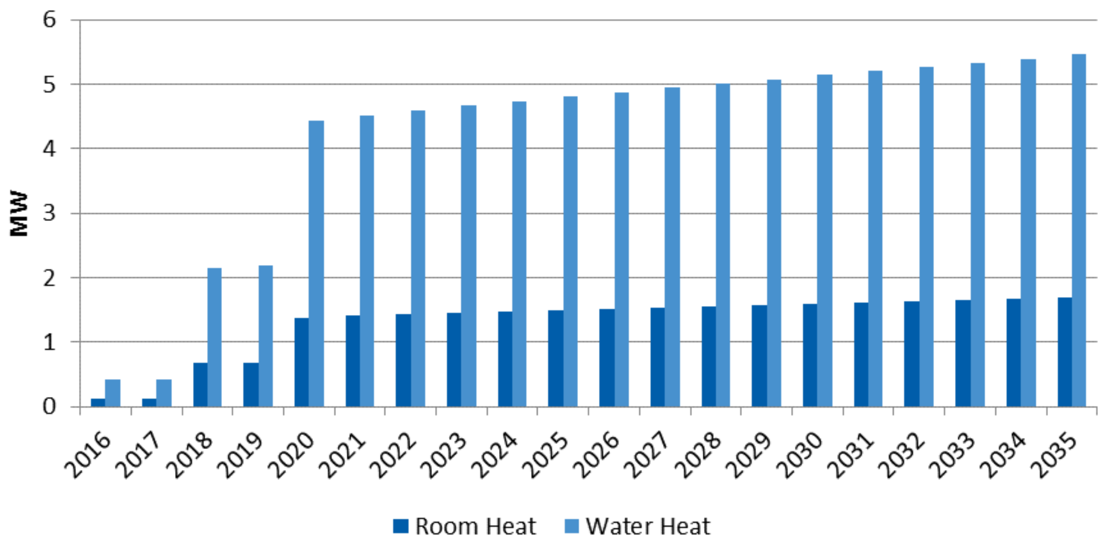
End Use	Market Potential (MW 2035)	Percent of System Peak – Winter	Levelized Cost($/kW)
Central Heat	2	0.1%	$581
Water Heat	5	0.1%	

[22] Nelson, Jonathan, and Rachel Reiss Buckley. *Hot or Not? DLC Program Benchmarking Results for the 2012 E Source Direct Load Control Program Study.* E Source Focus Report, EDRP-F-41. August 16, 2012.

End Use	Market Potential (MW 2035)	Percent of System Peak – Winter	Levelized Cost($/kW)
Total	7	0.2%	

Figure 44 shows the achievable potential over a 20-year period based on an acquisition schedule for a two-year pilot program, starting in 2016 and ramping up to full participation in 2020.

Figure 44. Room Heating and Water Heat Direct Load Control Acquisition Schedule



All cost assumptions remain consistent with the central heating program with the exception that each participant is assumed to have two room heaters controlled through the program. Program assumptions which differ from the room heat program include event impacts, technology costs (number of units) and program participation. Those assumptions are:

- ***Event impacts*** of 0.05 kW for room heating and 0.58 kW DWH from the pilot were used. Regional pilots had DWH of 0.65 kW to 0.69 kW for PGE and 0.45 to 0.50 kW for BPA OPALCO.[23]
- ***Technology costs*** of $280/baseboard heating switch and DWH switch and a $275 gateway cost.

---

[23] Navigant Consulting Inc. *2011 EM&V Report for the Puget Sound Energy Residential Demand Response Pilot Program.* February 6, 2012.
Portland General Electric Company. *Direct Load Control Pilot: Pilot Evaluation and Impact Measurement.* October 22, 2004.
Portland General Electric Company. *Direct Load Control Pilot For Electric Space Heat: Pilot Evaluation and Impact Measurement.* October 22, 2004.
Cadmus, *Evaluation of OPALCO's Residential Demand Response Pilot.* Prepared for Bonneville Power Administration. 2013.

- ***Program participation*** assumes that program can reach 20% of eligible single-family and manufactured customers (program research ranged from 13% to 25%). It is assumed that each customer will have two room heaters enrolled through the program.

Nonresidential Load Curtailment

Load curtailment programs use contractual arrangements between the utility, a third-party aggregator that implements the program, and utility commercial customers who agree to curtail or interrupt their operations (in whole or part) for a predetermined period when requested by the utility. In most cases, mandatory participation or liquidated damage agreements are required once the customer enrolls in the program; however, the terms of each contract limit the number of curtailment requests—both in total and on a daily basis.

Generally, customers are not paid for individual events but receive compensation through a fixed monthly amount per kW of pledged curtailable load or through a rate discount. Typically, contracts require customers to curtail their connected load by a set percentage (typically from 15% to 20%) or a predetermined level (e.g., 100 kW). Such programs often involve long-term contracts, with penalties for noncompliance, which range from simply dropping the customer from the program to more punitive actions such as requiring the customer to repay the utility for the committed (but not curtailed) energy at market rates.

For this study, Cadmus assumes commercial customers with a monthly demand of at least 100 kW qualify for such a program. Backup generation plays a key role in potential savings associated with the curtailment program. Because these participants can turn on a backup generator during critical peak times, they experience minimal burdens. In many utility programs (excluding those in California), customers may use backup generators to meet curtailment requirements; this assessment includes such customers.

For aggregated curtailment programs, the burden to achieve the contracted savings at a set price is the aggregator's responsibility, reducing the role of PSE to administer the program. As such, Cadmus has relied on third-party aggregator pricing to inform the analysis.

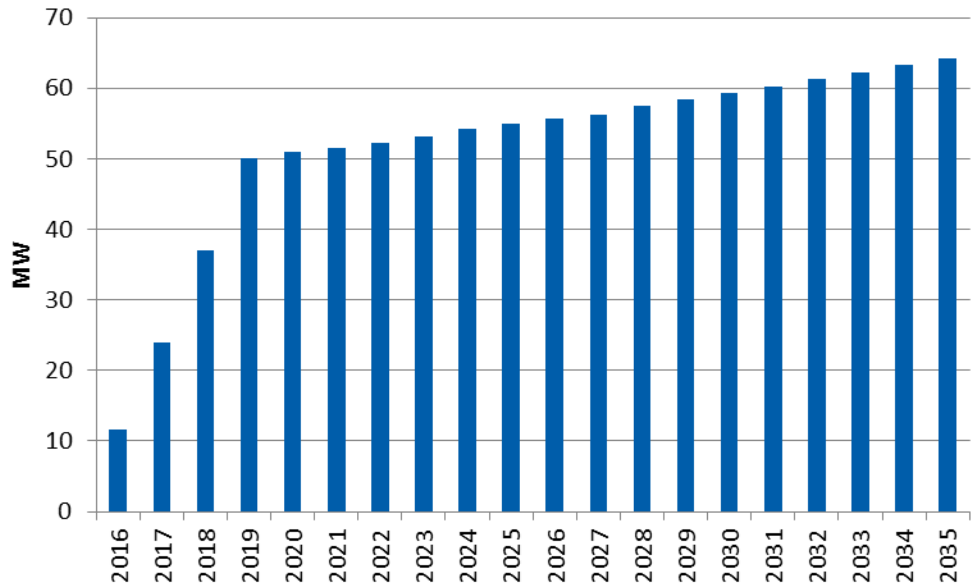
Table 32 shows the market potential at generation for the load curtailment program as well as the levelized cost.

Table 32. Load Curtailment Results

Program	Market Potential (MW 2035)	Percent of System Peak – Winter	Levelized Cost ($/kW)
Load Curtailment	64	1.6%	$105

Figure 45 shows the achievable potential over a 20-year period based on an acquisition schedule of 25% participation in 2016, ramping to full participation by 2019.

Figure 45. Load Curtailment Acquisition Schedule



Typically, curtailment programs run through third-party aggregators, which charge a set $/kW fee. This assessment considers utility administrative costs in addition to third-party aggregator costs. Detailed program assumptions, including values and sources from which potential and levelized costs have been derived are:

- ***Administration costs*** of 5% administrative costs are rolled into the $/kW cost.
- ***Technology costs*** are not applicable as included in third-party aggregator bid.
- ***Marketing costs*** are not applicable as included in third-party aggregator bid.
- ***Incentive cost*** are not applicable as included in third-party aggregator bid.
- ***Overhead costs*** are not applicable as included in third-party aggregator bid.
- ***Vendor Costs*** of $80/kW based on third-part aggregator bid.
- ***Event impacts*** assumes that customers will curtail approximately 30% of their load.
- ***Program participation*** – 20% of programs across the country are experiencing participation rates from 4% (the MidAmerican Curtailment Program has 4.5%) to 30% (Georgia Power and Indiana Michigan Power Company).[24]
- ***Event participation*** at 95%.

[24] MidAmerican study, Georgia Power study, Indiana Michigan Power Company study.

Critical Peak Pricing

Under a CPP program, customers receive a discount on their retail rates during non-critical peak periods in exchange for paying premium prices during critical peak events. The peak price, however, is determined in advance, providing customers with 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, generally set to reflect the utility's avoided cost of supply during peak periods.

CPP rates only take effect for a limited number of times during the year. In times of emergency or high market prices, the utility can invoke a critical peak event, notifying customers that rates have become much higher than normal and encouraging customers to shed or shift load. Most CPP programs provide advanced notice in addition to event criteria (such as a threshold for forecasted weather temperatures) to help customers plan their operations. One attractive feature of the CPP program is the absence of a mandatory curtailment requirement.

A CPP rate offers a benefit over a standard TOU rate in that an extreme price signal can be sent to customers for a limited number of events. For several reasons, utilities have found typically greater demand reductions during these events than during TOU peak periods:

- Customers under CPP rates often use automated controls, triggered by a signal from the utility.
- The higher CPP rate serves as an incentive for customers to shift load away during the CPP event period.
- The relative rarity of CPP events may encourage short-term behavioral changes, resulting in reduced consumption during the events.

As the CPP rate only applies on select days, this raises a number of questions about when a utility can call an event, for how long, and how often. The rules governing utility dispatch of CPP events vary widely by utility and by program, with some utilities reserving the right to call an event at any time, while others must provide notice one day before the event. This analysis assumes five critical peak price events are called during winter with a duration of four hours, for a total of 40 event hours.

Table 33 shows the estimated market potential by sector for winter.

Table 33. CPP Technical and Achievable Technical Potential, MW in 2035

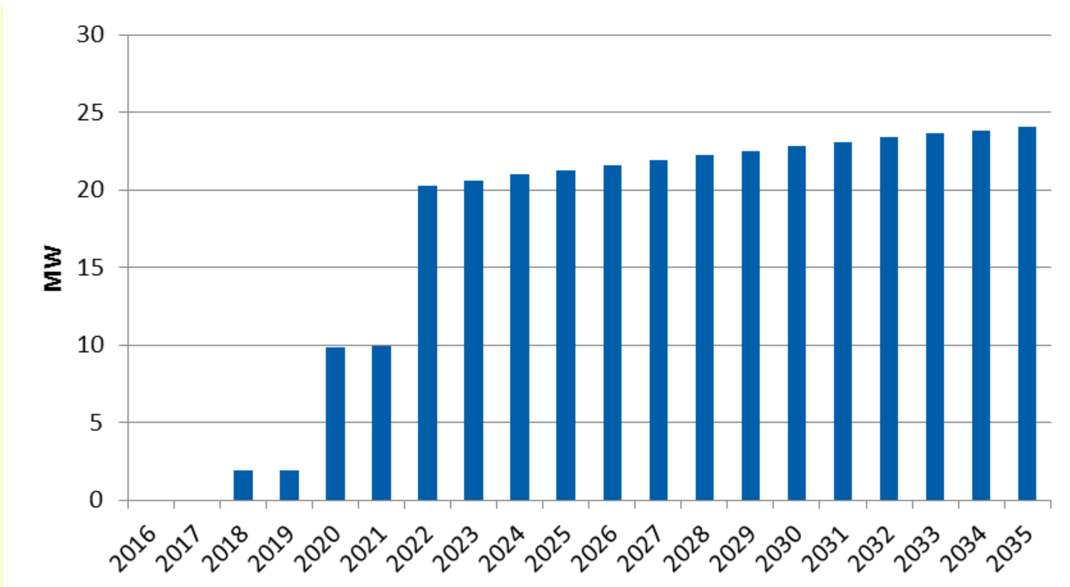
Sector	Market Potential (MW 2035)	Percent of System Peak – Winter	Levelized Cost ($/kW)
Residential	24	0.6%	$172
Commercial	2.1	0.1%	$187
Industrial	0.1	0.0%	
Total	**26**	**0.7%**	

Residential CPP

To develop potential estimates for PSE's CPP program, Cadmus relied on data from several CPP programs currently implemented across the nation. Critical peak pricing program studies have shown that 12% to 38% of peak demand can be reduced for participating customers depending upon program rate design and if enabling technology such as PCTs are combined integrated with the program.[25] Cadmus' study assumes a 12% load reduction with 10% participation and 100% event participation consistent with benchmarking of both fully implemented programs and pilot programs.

Figure 46 shows the market potential for the residential CPP program, based on an acquisition schedule that begins with a two-year pilot program in 2018, accounting for the time necessary to create a new tariff and to put AMI infrastructure in place. This will likely be followed by two years of increased participation, reaching full participation in 2022.

Figure 46. Residential CPP Acquisition Schedule



Residential Critical Peak Pricing Assumptions

Cadmus used these assumptions to analyze the residential CCP program.

- ***Administration costs*** of 15%.
- ***Technology costs (per new participant)*** of $220 for AMI and capital communication. AMI costs were in the range of $165 (Ameren) to $226 (FERC data).[26]

[25] See benchmarking sources in programs assumptions below.

[26] Ameren Illinois. *Advanced Metering Infrastructure (AMI) Cost / Benefit Analysis.* June 2012. Federal Energy Regulatory Commission. *Assessment of Demand Response & Advanced Metering Staff Report.* October 2013.

- ***Marketing costs (per new participant)*** of $25 marketing costs are based on one-half hour of staff time valued at $50 per hour (fully loaded).
- ***Incentive cost (per participant)*** are not applicable as there are no customer incentives; customers may have a lower bill than they would have on a standard rate.
- ***Program startup costs*** of $400,000, assuming there are costs incurred for internal labor, research, and IT/billing system changes.
- ***Eligible Load (%)*** 100% as all residential customers are eligible.
- ***Technical Potential*** of 12% with current programs without enabling technology (PCTs). This is in the range of Green Mountain Power (11%) and Sioux Valley Energy (24%).[27,28]
- ***Program participation*** of 10%. SMUD pilot reached 5% of customers while OG&E reached 20% of customers during full implementation.[29,30]
- ***Event participation*** of 100% event participation, captured in the average load impact.

Nonresidential CPP

To develop potential estimates for PSE's CPP program, Cadmus relied on data from several CPP programs currently implemented. These data indicate generally low participation rates for commercial customers, ranging from 0.1% to 3.5% in California and OG&E achieved 2%. Therefore, Cadmus considers a 2% participation rate reasonable for PSE.

Figure 47 shows the market potential for the nonresidential CPP program, based on an acquisition schedule that begins with a two-year pilot program in 2018, accounting for the time necessary to create a new tariff and to put AMI infrastructure in place. This will likely be followed by two years of increased participation, reaching full participation in 2022.

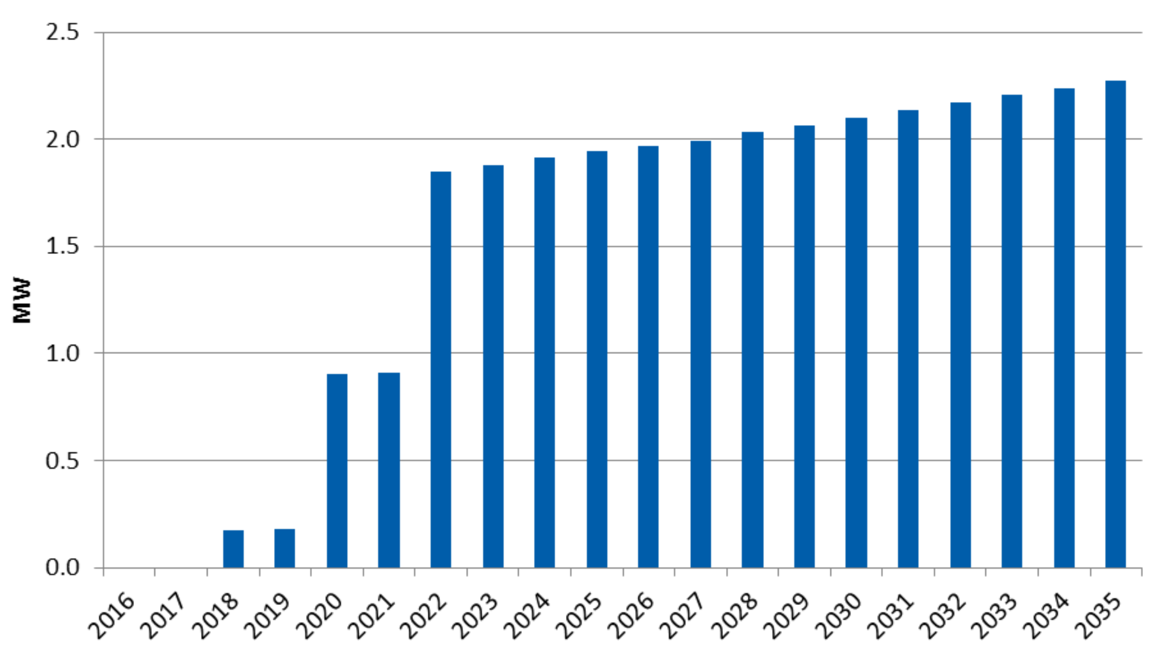
27 Blumsack, S., Hines, P. *Analysis of Green Mountain Power Critical Peak Events During the Summer/Fall of 2012*. Prepared for Green Mountain Power. November 19, 2013.

28 Power System Engineering, Inc. *EmPOWER Critical Peal Pricing Pilot Assessment*. Prepared for Sioux Valley Energy. March 12 2012.

29 SMUD. *SmartPricing Options Interim Evaluation.* Prepared for U.S. Department of Energy Lawrence Berkeley National Laboratory. October 23, 2013.

30 EnerNOC. *OG&E Smart Study Together Impact Results*. Prepared for OG&E. April 27, 2012.

Figure 47. Nonresidential CPP Acquisition Schedule



The residential CPP program has a start-up cost of $400,000, as a new rate structure will be put in place. Additionally, the program will require AMI and communications costs of $220 per participant. Marketing costs remain consistent with other program assumptions, and the program does not offer incentives due to its rate-based structure. Detailed assumptions of values and sources from which potential and levelized costs have been derived are listed below.

Commercial Critical Peak Pricing Assumptions

Cadmus used the following assumptions to analyze the commercial CCP program.

- ***Administration costs*** of 15%.
- ***Technology costs (per new participant)*** of $220 for AMI plus capital communication. AMI costs were in the range of $165 (Ameren) to $226 (FERC data).[31,32]
- ***Marketing costs (per new participant)*** of $500. Assumes 10 hours of effort by staff valued at $50 per hour. An additional hour per year is assumed for ongoing marketing and customer support.
- ***Incentive cost (per participant)*** is not applicable as there are no customer incentives; customers may have a lower bill than they would have on a standard rate.

---

[31] Ameren Illinois. *Advanced Metering Infrastructure (AMI) Cost / Benefit Analysis*. June 2012.

[32] Federal Energy Regulatory Commission. *Assessment of Demand Response & Advanced Metering Staff Report.* October 2013.

- ***Program startup costs*** of $400,000, assuming there are costs incurred for internal labor, research, and IT/billing system changes.
- ***Eligible Load (%)*** as 100% of all C&I customers are eligible.
- ***Technical Potential*** of 5%. In 2011 load impacts ranged by utility; PG&E averaged 5.9%, SCE averaged 5.7%, and SDG&E averaged 5.8%.[33,34] In 2013, OG&E achieved 12%.[35]
- ***Program participation*** of 2%. Participation rates in an opt-in CPP program are typically low. In 2005, California experienced 1.1% participation rate across the state, which accounted for a total of 2.9% of peak load being enrolled.[36] Results for specific utilities include 3.5% for PG&E and 2% for OG&E.[37]
- ***Event participation*** of 100% event participation is captured in the average load impact.

---

33 FSC Group. *2009 Load Impact Evaluation for Pacific Gas and Electric Company's Residential SmartRate Peak Day Pricing and TOU Tariffs and SmartAC Program*. Prepared for Pacific Gas and Electric Company. April 1, 2010.

34 FSC Group. *Southern California Edison's 2012 Demand Response Load Impact Evaluations Portfolio Summary*. Prepared for Southern California Edison. April 1, 2013. FSC Group. *2012 Ex Post and Ex Ante Load Impact Evaluation of San Diego Gas & Electric Company's Summer Saver Program and Peak Time Rebate Program for Summer Saver Customers.* Prepared for San Diego Gas & Electric Co. April 1, 2013.

35 EnerNOC. *OG&E Smart Study Together Impact Results.* Prepared for OG&E. April 27, 2012.

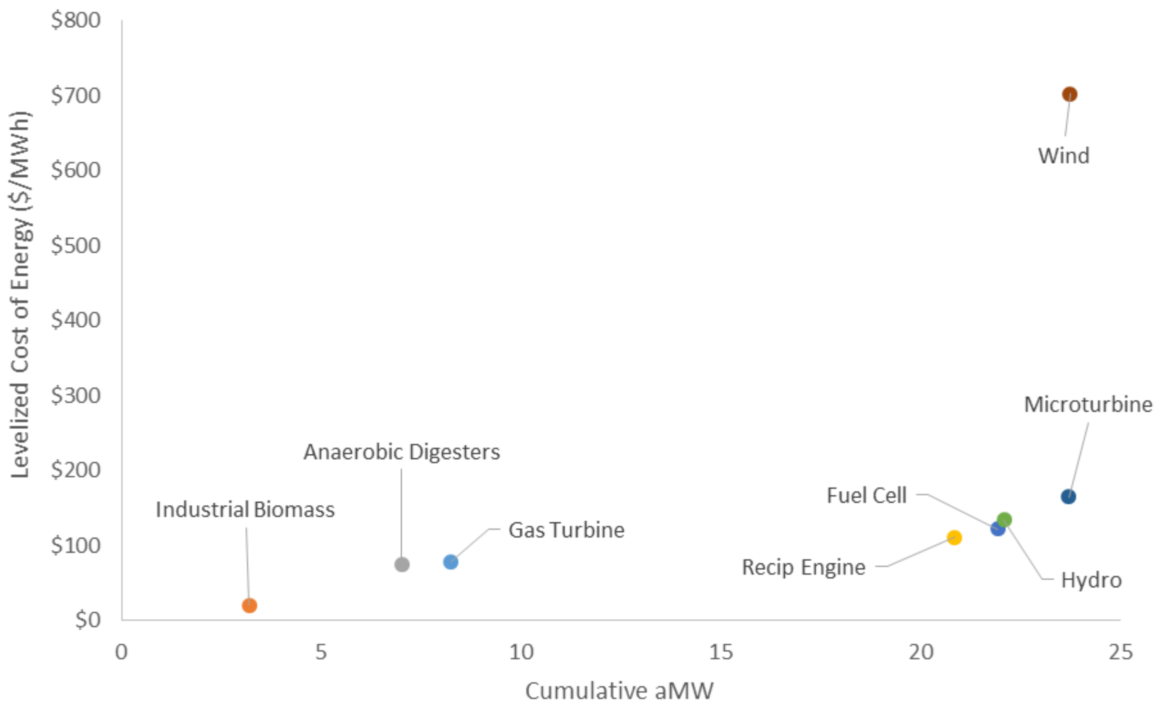
36 Study in California.

37 U.S. Energy Information Administration (EIA). *Annual Energy Outlook 2014 (AEO2014)*. Available online: http://www.eia.gov/forecasts/aeo/. Beck, R.W. *Distributed Renewable Energy Operating Impacts and Valuations Study*. 2009.

Distributed Generation

This study does not include estimations for distributed generation potentials. For detailed information regarding distributed generation potentials, see Cadmus' 2008 report.[38] We have, however, updated the costs of the distributed generation resources for this study, thus impacting the supply curves for PSE's 2015 IRP. Figure 48 illustrates the resulting supply curve.

Figure 48. 20-Year Achievable Supply Curve for Distributed Generation



The levelized cost of energy (LCOE) for many of the distributed generation technologies stayed constant or slightly decreased from the 2013 IRP to the 2015 IRP, as shown in Table 34. One exception was the small increase in levelized cost of small wind.

38 http://www.pse.com/SiteCollectionDocuments/2009IRP/AppL1_IRP09.pdf.

Table 34. A Comparison of the Levelized Cost of Energy Results from the 2013 IRP and 2015 IRP

Category	DG Technology	2013 IRP LCOE ($/kWh)	2015 IRP LCOE ($/kWh)
CHP - Renewable	Anaerobic Digesters	$0.08	$0.08
	Industrial Biomass	$0.02	$0.02
CHP - Non-renewable	Reciprocating Engine	$0.12	$0.11
	Micro turbine	$0.18	$0.16
	Fuel Cell	$0.12	$0.12
	Gas Turbine	$0.09	$0.08
Small Hydro	Hydro	$0.11	$0.13
Small Wind	Wind	$0.63	$0.70

Figure 49 shows the cumulative potential available in each year of this study, by levelized cost bundle.

Figure 49. Annual Achievable Distributed Generation Potential by Levelized Cost Bundle