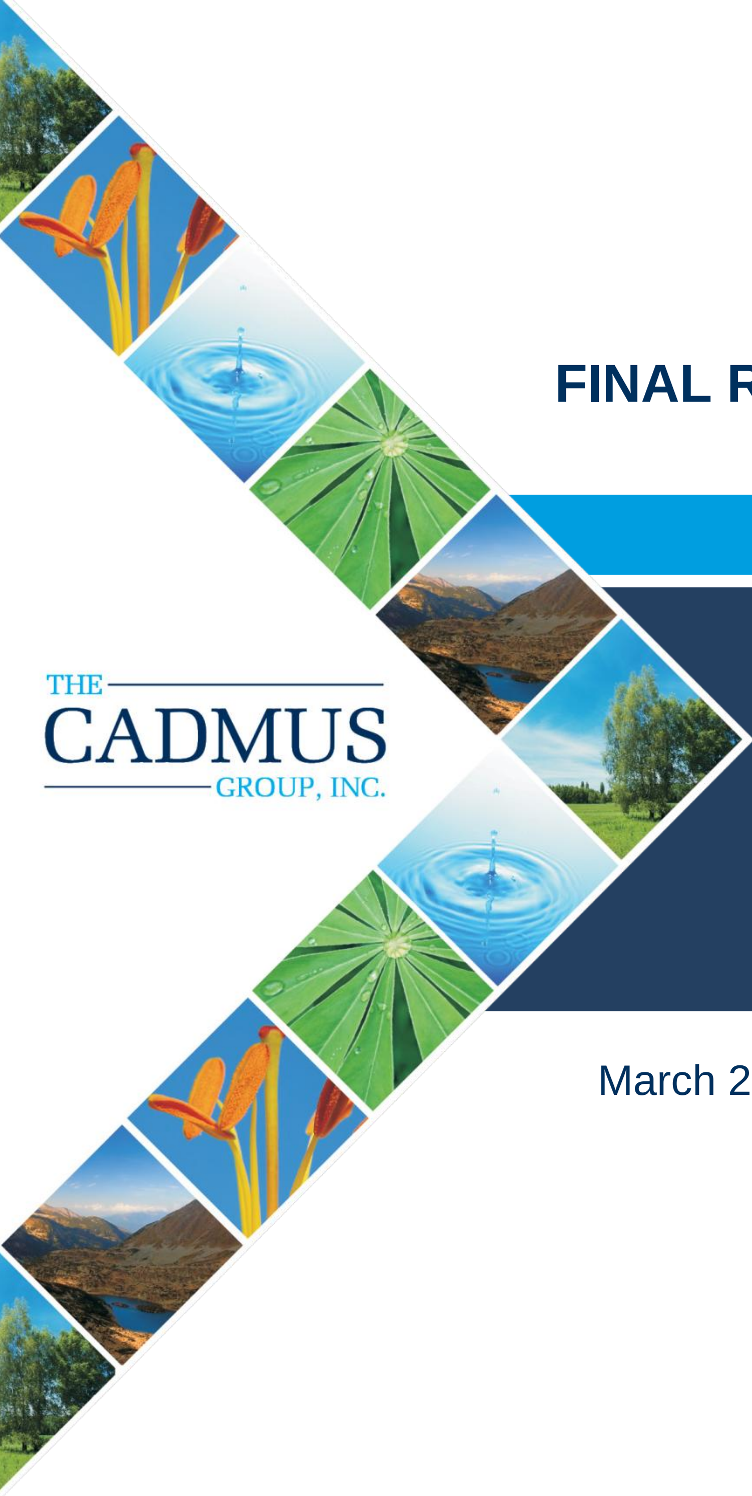

FINAL REPORT

Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources, 2013-2032 Volume I

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TABLE OF CONTENTS: VOLUME I

LIST OF TABLES

LIST OF FIGURES

TABLE OF CONTENTS: VOLUME II

DEFINITION OF TERMS

aMW	Average Megawatt
AC	Air Conditioning
C&I	Commercial and Industrial
CBECS	Commercial Building Energy Consumption Survey
CBSA	Commercial Building Stock Assessment
CHP	Combined Heat and Power
Council	Northwest Power and Conservation Council
CPP	Critical Peak Pricing
CSI	California Solar Initiative
DBB	Demand Buyback
DEER	Database of Energy Efficient Resources
DLC	Direct Load Control
DSM	Demand-side Management
EIA	Energy Information Administration
EISA	Energy Independence and Security Act of 2007
EPA	Environmental Protection Agency
EUIs	End-use Intensities
EUL	Effective Useful Life
FC	Fuel Cell
GT	Gas Turbine
HVAC	Heating Ventilation and Air Conditioning
IRP	Integrated Resource Plan
ITC	Investment Tax Credit (federal)
LCOE	Levelized Cost of Energy
LMOP	Landfill Methane Outreach Program
MT	Microturbine
MW	Megawatt
NEEA	Northwest Energy Efficiency Alliance
O&M	Operations and Maintenance
PV	Photovoltaic
RE	Reciprocating Engine
RECS	Residential Energy Consumption Survey
RTF	Regional Technical Forum
RTP	Real-time Pricing
RUL	Remaining Useful Life
SEEM	Simple Energy and Enthalpy Model
SGIP	Self-Generation Incentive Program
SWH	Solar Water Heating

TES	Thermal Energy Storage
TOU/TOD	Time of Use/Time of Day
TRC	Total Resource Cost
UCT	Utility Cost Test
UEC	Unit Energy Consumption
WH	Water Heating
WHP	Waste Heat-to-Power
WWTF	Wastewater Treatment Facility

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EXECUTIVE SUMMARY

Overview

Since 1989, PacifiCorp has developed biennial Integrated Resource Plans (IRPs) to identify an optimal mix of resources that balance considerations of cost, risk, uncertainty, supply reliability/deliverability, and long-run public policy goals. The optimization process accounts for capital, energy, and ongoing operation costs as well as the risk profiles of various resource alternatives, including: traditional generation and market purchases, renewable generation, and demand-side management (DSM) resources such as energy efficiency, and demand response or capacity-focused resources. Since the 2008 IRP, DSM resources have competed directly against supply-side options, allowing the IRP model to guide decisions regarding resource mixes, based on cost and risk.

This study, conducted by the Cadmus Group, Inc. (Cadmus), in collaboration with Nexant , Inc. (Nexant), primarily seeks to develop reliable estimates of the magnitude, timing, and costs of DSM resources likely available to PacifiCorp over a 20-year planning horizon, beginning in 2013. The study focuses on resources realistically achievable during the planning horizon, given normal market dynamics that may hinder resource acquisition. Study results will be incorporated into PacifiCorp's 2013 IRP and subsequent DSM planning and program design efforts. This study serves as an update of similar studies completed in 2007 and 2011.[1]

For resource planning purposes, PacifiCorp classifies DSM resources into four categories, differentiated by two primary characteristics: reliability and customer choice. These resources can be defined as: Class 1 DSM (firm, capacity focused), Class 2 DSM (energy efficiency), Class 3 DSM (non-firm, capacity focused), and Class 4 DSM (educational).

From a system-planning perspective, Class 1 DSM resources can be considered the most reliable, as they can be dispatched by the utility. In contrast, behavioral changes, resulting from voluntary educational programs included in Class 4 DSM, tend to be the least reliable. With respect to customer choice, Class 1 DSM and Class 2 DSM resources should be considered involuntary in that, once equipment and systems have been put in place, savings can be expected to flow. Class 3 and Class 4 DSM activities involve greater customer choice and control. This assessment estimates potential from Class 1, 2, and 3 DSM.

In addition to the three DSM resource classifications, this study also estimates potential from supplemental resources, which fall outside PacifiCorp's classification of DSM and include renewable and nonrenewable customer-sited generation. For this study, supplemental resources include: combined heat and power (CHP), solar photovoltaics (PV), and solar water heaters (SWH).

This study excludes an assessment of Oregon's Class 2 DSM (energy-efficiency) potential and supplemental resource potential for SWHs, as this potential has been captured in assessment

[1] Both studies can be found at: http://www.pacificorp.com/es/dsm.html

work conducted by the Energy Trust of Oregon (Energy Trust), which provides energy-efficiency potential in Oregon to PacifiCorp for resource planning purposes.

Summary of the Results

The study includes two distinct types of energy-focused resources: Class 2 DSM (energy-efficiency); and supplemental (customer-sited generation).

The Cadmus team estimates a cumulative, system-wide, technical potential for Class 2 DSM savings of 819 average megawatts (aMW)[2] over the 20-year planning horizon: 2013 to 2032 (as shown in Table ES-1). Collectively, 884 aMW (excluding Oregon) of energy-focused resource potential can be assumed to be reasonably achievable, once normal market and program delivery constraints are accounted for.

For Class 2 DSM resources, this potential is called achievable technical potential, though also known as market potential for supplemental resources (including on-site solar and CHP).[3] Achievable technical Class 2 DSM resources account for 73% (648 aMW) of the energy-focused resource potential, and the market potential of supplemental resources (including on-site solar and CHP) account for the remaining 27% (236 aMW). These results represent avoided utility generation, rather than savings at the customer meter, and therefore account for appropriate transmission and distribution losses.

Table ES-1. Energy-Focused Resource Potential (aMW in 2032): Technical and Achievable Technical/Market by Resource and Service Territory

Resource Class/Service Territory	Technical Potential	Achievable Technical or Market Potential**
Rocky Mountain Power		
Class 2 DSM Resource	707	560
Supplemental Resource	4,094	168
Rocky Mountain Power Subtotal	**4,801**	**728**
Pacific Power		
Class 2 DSM Resource*	112	88
Supplemental Resource*	1,885	68
Pacific Power Subtotal	**1,997**	**156**
PacifiCorp System Total	**6,797**	**884**

* Excludes Oregon for Class 2 DSM and solar water heaters (supplemental resource).
** Class 2 DSM resource potential is stated as achievable technical potential; supplemental resource potential is stated as market potential.
Note: Individual results may not sum to the total due to rounding.

2 Average megawatt (aMW), a unit of energy used for planning purposes in the Pacific Northwest, is calculated as the ratio of energy (MWh) and the number of hours in the year (8760). One aMW equals 8,760 MWh.

3 Achievable technical potential uses an estimate of potential, based on a theoretical maximum adoption. Market potential is based on actual adoption rates.

Table ES-2 shows estimates of coincident peak demand impacts from the identified resources.[4] These impacts have not been adjusted to account for resource competition and/or interactions and, therefore, cannot be considered additive in nature.

For example, if all Class 2 DSM (energy-efficiency) resources were acquired, they would reduce the load basis from which Class 1 and 3 DSM (capacity-focused resources) impacts could be calculated. In addition, Class 1 and 3 DSM programs are not mutually exclusive; thus, the overall peak impact from capacity or demand-focused programs would be less if accounting for all interactions.

Again, achievable technical potential is used to represent the quantity of Class 2 DSM resources that can reasonably be acquired *through any means* within the planning period, while market potential is used to represent the quantity of Class 1 and 3 DSM and supplemental resource technical potential deemed reasonably achievable *through utility programmatic activity*. The projected potential for Class 1 DSM products includes PacifiCorp's current program offerings, as the load forecast did not account for these programs' impacts. However, the load forecast reflects the impacts of existing Class 3 DSM offerings; therefore, this report's market potential results should be considered incremental to the impacts from PacifiCorp's existing Class 3 DSM offerings.

Table ES-2. Peak Demand Reduction Potential (MW in 2032): Technical and Achievable Technical/Market by Resource and Service Territory

Resource Class/Service Territory	Technical Potential**	Achievable Technical or Market Potential*
Rocky Mountain Power		
Class 1 DSM Resource	N/A	488
Class 2 DSM Resource	1,339	1,078
Class 3 DSM Resource	N/A	45
Supplemental Resource	10,023	367
Rocky Mountain Power Subtotal	**N/A**	**1,978**
Pacific Power		
Class 1 DSM Resource	N/A	116
Class 2 DSM Resource***	200	163
Class 3 DSM Resource	N/A	20
Supplemental Resource	5,012	149
Pacific Power Subtotal	**N/A**	**448**
PacifiCorp System Total	**N/A**	**2,426**

* Class 2 DSM resource potential is stated as achievable technical potential; supplemental resource potential is stated as Market Potential.

** Technical potential was not calculated for Class 1 and 3 DSM resources.

*** Excludes Oregon.

[4] Coincident peak impacts are determined based on savings during the top 40 system hours for Class 2 DSM and supplemental resources. Class 1 and 3 impacts, defined by assumed program operation hours, are not truly additive.

Capacity-Focused (Class 1 and Class 3) DSM Resources

Market potential results from the Class 1 and 3 DSM resources, provided in Table ES-2 and Table ES-3 (below), break down by resource class, sector, and territory. They represent an assessment of load management opportunities/products within PacifiCorp's service territories within each resource class. As noted, totals are not additive, as the programs have a lower overall peak impact when accounting for all interactions. Additionally, Class 1 DSM resources include impacts that are already captured/managed through current program offerings, while Class 3 DSM results are incremental to current time-varying rate program offerings.

Table ES-3. Class 1 and Class 3 (Capacity-focused) DSM Resource Market Potential by Customer Sector and Service Territory (MW in 2032)

	Rocky Mountain Power	Pacific Power	PacifiCorp System
Class 1 DSM—"Firm"			
Residential	151	41	192
Small Commercial	1	1	2
Large Commercial	55	42	97
Industrial	70	22	92
Irrigation	210	11	221
Subtotal	**488**	**116**	**604**
Class 3 DSM—"Non-Firm"			
Residential	19	7	26
Small Commercial	0	0	0
Large Commercial	5	4	8
Industrial	12	2	14
Irrigation	11	7	18
Subtotal	**45**	**20**	**66**
Total	**533**	**137**	**670**

The irrigation sector accounts for 37% of total Class 1 market potential, and the residential sector contributes another 32%. Currently, PacifiCorp operates residential direct load control (DLC) air conditioning and irrigation DLC programs in Rocky Mountain Power's service territory.

Based on research by the Cadmus team into similar programs' participation, these existing programs in Rocky Mountain Power's service territory appear to be fully subscribed, and future incremental market potential realized through these programs will likely be driven by load growth, rather than increases in existing customer participation. Though system-wide, 66 MW of Class 3 DSM market potential is much lower than that available for Class 1 resources, the potential for Class 3 DSM products is incremental to savings achieved by PacifiCorp's current time-varying rate programs. Chapter 2 discusses current Class 3 DSM program impacts in greater detail.

Energy-Focused (Class 2 Energy Efficiency) DSM Resources

As shown in Table ES-4, system-wide achievable technical potential for Class 2 DSM (energy-efficiency) resources has been estimated at 648 aMW, representing 79% of identified technical potential for this resource in five of PacifiCorp's six state service areas (excludes Oregon).

Table ES-4. Class 2 DSM (Energy-Efficiency) Resource Achievable Technical Potential by Customer Sector and Service Territory (Cumulative aMW in 2032)

Sector	Rocky Mountain Power	Pacific Power*	PacifiCorp System*	PacifiCorp As Percent of 2032 Baseline Sector Sales*
Residential	151	39	190	15%
Commercial	200	34	234	15%
Industrial	195	12	207	9%
Irrigation	10	3	13	10%
Street Lighting	3	0	4	30%
Total	**560**	**88**	**648**	**12%**

* Potential and baseline sales do not include Oregon.
Note: Individual results may not sum to the total due to rounding.

The commercial sector accounts for the largest share of achievable energy-efficiency savings at 234 aMW, followed by the industrial sector at 207 aMW. Projections indicate an additional 207 aMW of electricity savings available in the residential, irrigation, and street lighting sectors.

Resource opportunities, however, may differ in terms of value (when screened for economic potential in the company's integrated resource planning process). For instance, street lighting savings occur during off-peak periods, and these may have less value than other efficiency measures. Discretionary resources (i.e., retrofit opportunities) account for 488 aMW (75%) of energy-efficiency achievable technical potential across all sectors. The remaining potential is associated with lost opportunity resources, namely new construction and replacement of existing equipment at the end of its normal life cycle.

Supplemental Resources

Table ES-5 provides supplemental resource potential, with an estimated 236 aMW of market potential across PacifiCorp's system. Resources considered include CHP, solar PV, and SWH. Market adoption rates have been based on recent adoption rates for the technologies included.

Table ES-5. Supplemental Resource Market Potential by Technology and Service Territory (Cumulative aMW in 2032)

Market Potential	Rocky Mountain Power	Pacific Power	PacifiCorp System
CHP	123	45	168
Solar: PV	43	23	65
Solar Water Heating*	2.6	0.7	3.3
Total	**168**	**68**	**236**

Note: Individual results may not sum to the total due to rounding.
* Potential does not include Oregon in Pacific Power territory (those data are provided to the company by the Energy Trust).

Comparison to 2011 Assessment

As noted, this assessment builds upon studies completed in 2007 and 2011. This section reviews key differences between the current study findings and those presented in the 2011 Assessment.

Class 1 and 3 DSM

This study considered a set of eight Class 1 and Class 3 program options, while the 2011 Assessment analyzed two additional resources: real-time pricing (RTP), and thermal energy storage (TES). This study did not conduct additional analyses of these resource options, as RTP is considered a competing, less common, alternative to other price-based options, and little (or no) change has been made to TES technologies (a relatively high-cost program option)[5] since the 2011 Assessment was completed. For resources assessed in this study, basic assumptions underlying potential and per-unit cost calculations were updated to reflect more recent market data, information on similar programs offered by other utilities, and PacifiCorp's experience with its currently operating programs. Additionally, in the 2011 Assessment, winter potential was assessed, while this study focuses only on reducing system load during summer hours.

This study's analysis of capacity-focused resources identified 670 MW of market potential during system summer peak periods, compared with 1,137 MW estimated in the 2011 Assessment (which included both summer and winter peak periods). The current study indicated the market potential for Class 1 DSM to be 604 MW, comparable to the 623 MW of market potential identified in the 2011 Assessment. Class 3 potential dropped from 514 MW to 66 MW, driven by a drop of nearly 290 MW in potential for the irrigation time-of-use (TOU) option, approximately 114 fewer MW of potential for critical-peak pricing (CPP), and 21 fewer MW for demand buyback (DBB). The large difference in irrigation TOU market potential was a result of assuming voluntary, rather than mandatory, participation, while lower CPP and DBB potential primarily resulted from decreases in estimated program participation and is consistent with recent actual program experience.

In an effort to better understand the potential contributions from Class 3 DSM resource offerings (existing and new) the current study includes an assessment of impacts from PacifiCorp's existing time-varying rate structures, such as the mandatory residential block rates and nonresidential TOU tariffs. A review of secondary literature on customer responses to changes in price indicated a range of elasticities, making it difficult to determine a point estimate for impacts of existing rate structures. However, analysis results indicated these price structures reduce PacifiCorp's peak system load by 69 MW to 250 MW annually. Because these impacts are embedded in current loads, Class 3 potentials identified in this study are incremental to impacts of existing price structures.

Class 2 DSM

For the Class 2 DSM analysis, the following items served as key drivers of changes:

- Accounting for newly enacted codes and standards, even if not yet in effect;
- Adjusting for PacifiCorp's actual and projected DSM program accomplishments from 2010 through 2012;
- Incorporating adjustments to measure savings, based on recent evaluation results, including data available from the Regional Technical Forum (RTF);

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5 The 2011 Assessment found TES costs to be over $250/kW-yr.

- Applying 2011 customer information to determine segmentation; and
- Utilizing 2012 load and customer forecasts.

Together, these changes decreased total, system-wide, 20-year, Class 2 DSM achievable technical potential from 1,156 aMW to 648 aMW, or 44%. Chapter 3 provides further details on the primary contributors to the decrease in Class 2 DSM achievable technical potential.

Supplemental Resources

For supplemental resources, system-wide 20-year market potential increased by 58 aMW, from 178 aMW to 236 aMW, or a 33% decrease. Solar PV primarily drove this increase, rising from 8 aMW in the 2011 Assessment to 65 aMW in the current study based on a change in the assumed penetration rate. The 2011 Assessment assumed at most 0.02% of solar PV technical potential was achievable in any year for all states, an estimate also used in the current study for states not currently offering programs. For states where programs are offered, this percentage is 0.14% for the residential sector and 0.08% for the commercial sector, based on experience in California and Oregon. CHP market potential also increased from 146 aMW to 168 aMW. In the current study, the estimate of market potential was refined to focus on installations in PacifiCorp's service territory rather than on adoption rates from other jurisdictions (used in the 2011 Assessment).

Conversely, 20-year market potential for solar water heaters decreased by 19 aMW relative to the 2011 Assessment largely due to using programmatic data to estimate market potential, rather than maximum achievability estimates from the Northwest Power and Conservation Council's (the Council's) 6th Power Plan. This dropped market potential as a percent of technical potential from 85% to 15%.

INTRODUCTION

Background

Since 1989, PacifiCorp has developed biennial Integrated Resource Plans (IRPs) to identify an optimal mix of resources, balancing considerations of cost, risk, uncertainty, supply reliability/deliverability, and long-run public policy goals. The optimization process accounts for capital, energy, and ongoing operation costs as well as the risk profiles of various resource alternatives, including: traditional generation and market purchases, renewable generation, and demand-side management (DSM) resources such as energy efficiency and demand response or capacity-focused resources. Since the 2008 IRP, demand-side management (DSM) resources have competed directly against supply-side options, allowing the IRP model to make decisions regarding the resource mix based on cost and risk. Thus, this study does not assess cost-effectiveness.

Study Objectives and Scope

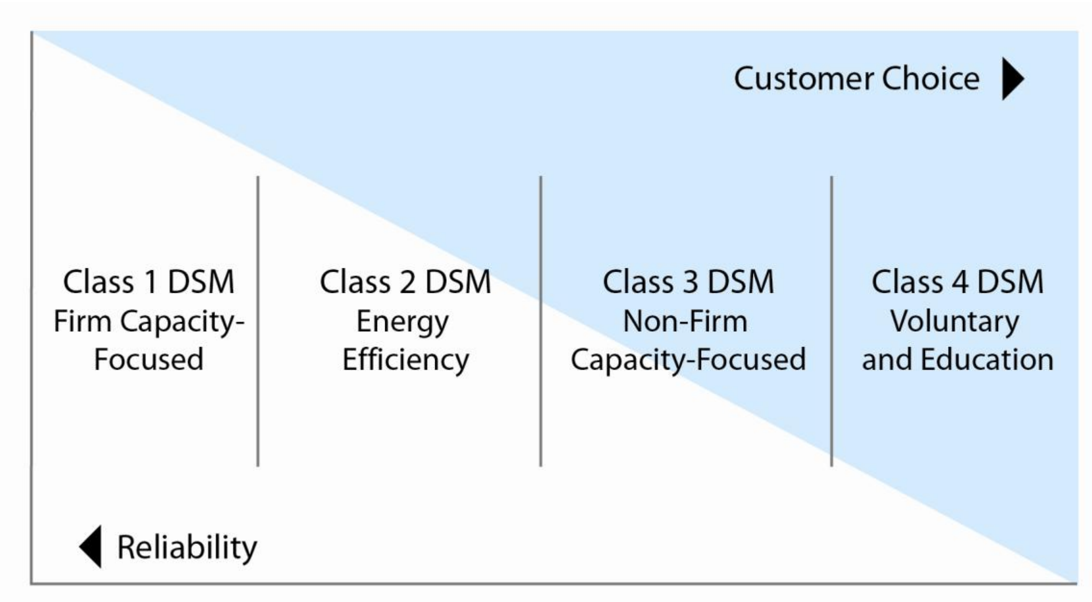
This study primarily seeks to develop reliable estimates of the magnitude, timing, and costs of DSM resources likely available to PacifiCorp over a 20-year planning horizon, beginning in 2013. The study focuses on resources realistically achievable during the planning horizon, given normal market dynamics that may hinder acquisition of these resources. Study results will be incorporated into PacifiCorp's 2013 IRP and subsequent planning efforts and into its DSM program design efforts.

For resource planning purposes, PacifiCorp classifies DSM resources into four categories, differentiated by two primary characteristics: reliability and customer choice (see Figure 1). These resources are captured through programmatic efforts promoting efficient electricity use through various intervention strategies, aimed at changing: energy use peak levels (load curtailment), timing (price response and load shifting), energy intensity (energy efficiency), or behaviors (education and information).

From a system-planning perspective, Class 1 DSM (firm) resources (particularly controlled capacity-focused programs) can be considered the most reliable, as these can be dispatched by the utility. In contrast, behavioral changes, resulting from voluntary educational programs included in Class 4 DSM, tend to be the least reliable. With respect to customer choice, Class 1 DSM and Class 2 DSM (energy-efficiency) resources should be considered involuntary in that, once equipment and systems have been put in place, savings can be expected to flow. Class 3 and Class 4 DSM activities involve greater customer choice and control.

Supplemental resources, consisting mainly of small-scale, dispersed generation[6] on the facility side of the meter, tend to be less firm, either due to uncertainties associated with their availability (solar) or to the extent customers control their operation (CHP).

Figure 1. Reliability and Customer Choice Considerations in DSM Resources



PacifiCorp commissioned this study to reassess the potential for Class 1 and 3 DSM (capacity-focused), Class 2 DSM (energy-efficiency), and other supplemental resources within its service territory. Study results will inform the IRP process and assist PacifiCorp in revising designs of existing programs and in developing new programs. The study did not include assessments of Class 4 DSM resources.

This study, the third comprehensive assessment commissioned by PacifiCorp, builds upon prior assessments, which were completed in 2007 and 2011. The study updates the 2011 *Assessment of Long-Term System-Wide Potential for Demand-Side and Other Supplemental Resources*[7] (the 2011 Assessment). The study also refers to the prior study, the 2007 Assessment.

The study's scope encompasses multisector assessments of long-term potential for DSM and other supplemental resources in PacifiCorp's Pacific Power (California, Oregon, and Washington) and Rocky Mountain Power (Idaho, Utah, and Wyoming) service territories. All results presented in the report represent savings at generation; that is, savings at the customer meter have been grossed up to account for line losses.

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[6] Often, the terms "distributed" or "dispersed" generation are used interchangeably. This study refers to "dispersed" generation to describe decentralized power generation at customer facilities. "Distributed" generation generally refers to generating units owned and operated by the utility.

[7] http://www.pacificorp.com/es/dsm.html

The Energy Trust of Oregon (Energy Trust), however, takes responsibility for identifying and delivering energy-efficiency resources in Oregon; thus the study does not assess Class 2 DSM potential for Oregon. The state's Class 2 DSM potential, included in PacifiCorp's 2013 IRP, will be based on the Energy Trust's *2012 Resource Assessment Update*.[8] Appendix C-5 includes a comparison of measures assessed in the Cadmus team's and Energy Trust's assessments.

Class 1 and Class 3 DSM (Capacity-Focused) Resources

Capacity-focused (or demand-response) resources encompass Class 1 and Class 3 DSM. Class 1 and Class 3 DSM resources principally can be differentiated in terms of their reliability during periods of system peak or during emergencies (dispatchability). For this study, capacity-focused resources have been defined based on PacifiCorp's characterization of two distinct classes of firm (dispatchable) and non-firm (non-dispatchable) resource options:

- ***Class 1 (Firm Capacity-Focused) DSM Resource.*** This resource class allows controlled or scheduled interruptions, or cycling, of electrical equipment and appliances, such as central air conditioners and irrigation pumps. Examples include PacifiCorp's Cool Keeper residential and small commercial air conditioner direct load control (DLC) program in Utah and irrigation load control programs in Utah and Idaho. While program participation is voluntary, once participating, event participation becomes mandatory.
- ***Class 3 (Non-Firm Capacity Focused) DSM Resources.*** This resource class seeks to achieve peak demand savings from actions taken by customers voluntarily, based on a financial incentive or time-specific price signal. Program options in this class include demand buyback (PacifiCorp's Energy Exchange tariffs) and more traditional pricing products, such as TOU (currently offered to various customer segments in all PacifiCorp's states) and critical-peak pricing (CPP) programs. Both program participation and event participation are voluntary.

Class 2 DSM (Energy-Efficiency) Resources

This resource class consists of technologies and measures, such as high-efficiency equipment and appliances, building shell improvements, and controls, that reduce energy consumption at the end-use level. Such resources may further be categorized as discretionary (retrofits in existing construction) or lost opportunities (equipment replacement and efficiency improvements in new construction). Class 2 DSM resources can be acquired through various market intervention mechanisms, such as: equipment incentives; direct installation; process and activity optimization leading to sustained changes in energy use; or advancement of codes and standards. The type and intensity of market intervention strategies, prevailing retail rates, and availability of capital in a given market can affect the amount and cost of Class 2 DSM resources. Once installed, savings are assumed to persist (remain firm) over the 20-year study period (customers will reinvest in "equal to" or greater efficiency at the end of the measure's useful life).

[8] http://energytrust.org/library/reports/121114_2012_ResourceAssessment.pdf

Supplemental Resources

For this study, supplemental resources represent small-scale,[9] dispersed power generation technologies. This assessment considered two options:

1. *CHP*, as the simultaneous generation of energy and heat, with waste heat captured and used within a steam turbine or for industrial process heating, space heating, and/or domestic hot water. CHP generation technologies include: reciprocating engines, microturbines, fuel cells, gas turbines, and steam turbines.
2. *On-Site Solar*, which includes small-scale photovoltaics (PV) and SWHs.[10]

The Cadmus team estimated technical and market potentials for these resources. The technical potential, as with other resource types, results as a measure of total savings, assuming all resources are installed in all technically feasible applications. Market potential, on the other hand, is an estimate of what will likely be installed, given market constraints, and is based on historical activity within PacifiCorp's territory.

Resource Interactions

In assessments involving diverse DSM resources (such as the present one), one must acknowledge technical interactions occurring both *within* a resource class (i.e., among various program options and end-use measures) and between them (i.e., interactions between similarly focused resource classes, such as Class 1 and 3 DSM). These effects must be carefully considered to avoid double-counting available potential. This study explicitly estimates intra-class and resource type (energy or capacity) interactions, but it does not account for interactions between energy-focused and capacity-focused resources.

Interactions within Class 2 DSM

Several interactions have been accounted for in the Class 2 DSM analysis. First, a "stacking effect" occurs when *complementary* retrofit measures—such as wall, ceiling, and floor insulation—apply to a single end use. As measure savings are always calculated in terms of reductions in end-use consumption, installation of one measure reduces the savings potential of subsequently installed measures. That is, the combined effect of installing two measures affecting the same end use tends to be less than the sum of their individual impacts.

A similar effect occurs when equipment and non-equipment (retrofit) measures within Class 2 DSM compete for the same end-use resource, such as space conditioning (e.g., a high-efficiency central air conditioner and high-efficiency windows). As with the stacking effect, if non-equipment measures can be captured first, replacement of existing equipment with high-efficiency equipment can be expected to have smaller impacts on end-use consumption than if replacement had taken place first.

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9 Resources with nameplate capacities of less than 10 MW generally are considered "small scale."

10 The 2011 Assessment included solar attic fans, which this study excluded due to the very high costs per kWh.

The analysis also accounts for technical interactions among measures, such as lighting retrofits and weather-sensitive loads; depending on the season, heat loss from efficient lighting may increase (in winter) or decrease (in summer) HVAC power consumption.

Interactions Between Class 1 and 3 DSM Resources

For PacifiCorp's IRP modeling (resource supply curve construction), the Cadmus team accounted for interactions within and between Class 1 and Class 3 DSM resources. The numbers in this report represent the full potential, without interactions; Appendix A-5 provides the potential estimates with interactions. Resources were prioritized within each customer sector by the firmness of the resource and then by cost. The following logic allowed potential adjustments to account for these interactions:

- ***Residential:*** The Cadmus team assumed participation in the DLC air conditioning and water heating programs would take precedence over TOU rates. Customers already enrolled in the DLC program would not opt out to participate in the TOU program.
- ***Small Commercial:*** As small commercial only had one product, the study did not consider interactive effects.
- ***Large Commercial and Industrial:*** The Cadmus team assumed all available potential would likely be captured by the nonresidential load curtailment program and no remaining potential would be available for Demand Buyback (DBB) or CPP where load curtailment is offered.
- ***Irrigation:*** The Cadmus team's analysis indicated current programs in Idaho and Utah have exhausted the market potential in this sector for those states; therefore, no potential remains for the TOU program. For the remainder of the states, the Cadmus team adjusted TOU program participation to account for interactions with the irrigation DLC opportunities.

Interactions Between Energy-Focused and Capacity-Focused Resources

Interactions also exist between Class 2 and Class 1 and 3 DSM resources as well as with supplemental resources. Primarily, because implementation of energy-efficiency or supplemental resources measures lowers peak demand, it reduces technical and market potential for Class 1 and 3 DSM resources. Though an important factor to recognize, this study did not attempt to quantify such interactions due to uncertainties regarding resources likely to be found economic and pursued.

Incorporating Recent or Pending Codes and Standards

While the Cadmus team's analysis does not predict how energy codes and standards may change over time, the study incorporates estimates of enacted legislation's impacts, even if the legislation will not take effect for several years. The most notable, recent efficiency regulation has been the Energy Independence and Security Act of 2007 (EISA), which set new standards for general service lighting, motors, and other end-use equipment. Capturing effects from this legislation has been particularly important, as residential lighting has played a large role in

PacifiCorp's energy-efficiency programs over the past several years. In addition to enacted federal legislation, several states in PacifiCorp's service territory have updated and revised their state energy codes. Table 1 provides a list of the efficiency standards explicitly accounted for in the development of the current study.

Table 1. Enacted or Pending Standards

Equipment Type	Sector	Year Effective*
Appliances		
Clothes Washer (1.76 MEF top loading, 2.2 MEF front loading)	Commercial/Residential	2016
Clothes Washer (2.0 MEF top loading)	Commercial/Residential	2018
Commercial Refrigeration Equipment - (Semivertical and Vertical Cases)	Commercial	2012
Cooking Oven	Residential	2012
Dehumidifier	Residential	2013
Dishwasher (307 kWh/year)	Commercial/Residential	2014
Dryer	Residential	2015
Freezer	Commercial/Residential	2015
Ice Maker	Commercial	2013
Refrigerator	Commercial/Residential	2015
Vending Machines	Commercial	2012
Motors		
Small Electric Motors	Commercial/Industrial	2015
Water Heaters		
Water Heater > 55 gallons (EF ≥ 2.0, varying by size)	Commercial/Residential	2015
Water Heater ≤ 55 gallons (e.g. EF = 0.948 for 40 gallon)	Commercial/Residential	2015
HVAC		
Central Air Conditioner (SEER 14)	Residential – California only	2015
Heat Pump - Air Source (14 SEER/ 8.2 HSPF)	Residential	2015
Room Air Conditioner (10.9 CEER)	Residential	2015
Lighting		
Lighting General Service Fluorescent Lamp – EISA	Commercial/Industrial	2012
Lighting General Service Lamp - EISA	Commercial/Industrial/Residential	2013, 2014**
Lighting General Service Lamp - EISA Backstop Provision	Commercial/Industrial/Residential	2020**
Lighting Specialty Lamp - EISA Incandescent Reflector Lamps	Residential	2012

*Standards taking effect mid-year are assumed to begin on January 1 of the following year.
** California standards take effect one year prior to federal standards.

To capture impacts of upcoming equipment standards in estimating Class 2 DSM resource potential, the Cadmus team incorporated these standards into the baseline forecast. Table 2 shows estimated impacts of changes in equipment efficiency standards on forecasted baseline residential and commercial loads in 2032, respectively.[11] Overall, new equipment standards lead to decreases in 2032 baseline sales of 7.4% and 1.3% in the residential and commercial sectors, respectively. A large portion of the difference in residential resulted from the impact of EISA standards on lighting.[12]

Table 2. Impact of Efficiency Standards on Baseline Forecast in 2032

Sector	State	2032 Forecast Without Standards (aMW)	2032 Forecast With Standards (aMW)*	Effect of Standards (Percent Reduction in 2032 Forecasted Sales)
Residential	California	49	46	5.7%
	Idaho	113	106	5.8%
	Utah	896	820	8.5%
	Washington	204	196	4.1%
	Wyoming	136	127	6.7%
	Subtotal	**1,398**	**1,295**	**7.4%**
Commercial	California	33	33	1.4%
	Idaho	62	61	1.1%
	Utah	1,076	1,062	1.3%
	Washington	164	162	0.9%
	Wyoming	205	202	1.4%
	Subtotal	**1,540**	**1,520**	**1.3%**
	Total	**2,938**	**2,815**	**4.2%**

* Used as baseline for Class 2 DSM potentials analysis

End-use consumption for new construction buildings accounted for state building codes, but it did not incorporate future changes to codes over the planning horizon.[13] No attempt was made to quantify impacts of recently updated building codes due to the difficulty in determining an appropriate baseline from which to claim savings. Table 3 provides energy codes in place at the time of this study.

11 The study did not quantify the impacts of standards in the industrial sector, as these were anticipated to be small.

12 Screw base lighting makes up a much larger share of total sales in the residential sector compared to commercial, which explains why lighting standards have a larger impact on residential sales.

13 State energy codes typically update on a three-year cycle, but this study did not attempt to predict future code changes.

Table 3. State Energy Codes

State	Energy Code Used	
	Residential	Nonresidential
Washington[14]	Energy Code 2009 Edition, Chapter 51-11 WAC	Energy Code 2009 Edition, Chapter 51-11 WAC
Idaho	2009 IECC	2009 IECC
Utah	2006 IECC	2009 IECC with references to ASHRAE 90.1-2007
California[15]	2008 Building Energy Efficiency Standards, Title 24	2008 Building Energy Efficiency Standards, Title 24
Wyoming	2003 IECC*	2003 IECC*

IECC = International Energy Conservation Code.
* As Wyoming does not have a statewide residential energy code, 2003 IECC (Zone 16) was used as a proxy.

Cross-Resource Assumptions

Several assumptions applied to all resources: discount rate, inflation rate, and line losses. Consistent with PacifiCorp's 2013 IRP assumptions, this study used a nominal discount rate of 6.88%, with an inflation rate of 1.9%. Table 4 provides line losses.

Table 4. Line Loss Assumptions by State

Sector	Washington	Idaho	California	Wyoming	Utah	Oregon
Residential	9.7%	11.5%	11.4%	9.5%	9.3%	10.0%
Commercial	9.5%	10.7%	11.1%	8.9%	8.7%	9.6%
Industrial	8.2%	4.9%	9.9%	5.6%	5.4%	7.1%
Irrigation	9.7%	11.4%	11.4%	9.3%	9.2%	9.9%
Street Lighting	9.7%	11.5%	11.4%	9.%	9.3%	10%

All baselines and potentials presented in this report include these line losses and thus represent sales and savings at the generator.

Report Organization

This report is divided into two volumes, with the present document (Volume I) organized into five sections. The three sections following the Executive Summary and Introduction sections address analyses of various resource options, primarily:

- Class 1 and Class 3 DSM (capacity-focused) resources;
- Class 2 DSM (energy-efficiency) resources; and
- Supplemental resources.

The DSM resource sections begin by describing the scope of the analysis, followed by a discussion of methodologies, then summarize the resource potential, and finish with detailed

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14 Washington State Energy Code 2009 Edition: http://apps.leg.wa.gov/wac/default.aspx?cite=51-11

15 California's 2008 Code of Regulations Title 24: http://www.energy.ca.gov/2008publications/CEC-400-2008-001/CEC-400-2008-001-CMF.PDF

results. The supplemental resource chapter takes a somewhat different form to account for the wide variation in resources considered. Volume II of this report presents additional technical information, assumptions, data, and other relevant details for both DSM and supplemental resources.

CLASS 1 AND CLASS 3 DSM (CAPACITY-FOCUSED) RESOURCES

Scope of Analysis

This DSM resource class consists of products and programmatic options designed to:

- Help reduce peak demand during system emergencies or periods of extreme market prices;
- Promote improved system reliability; and
- In some cases, balance variable-load resources, particularly wind energy.

Benefits from Class 1 and 3 DSM resources accrue by providing incentives for customers to curtail loads during utility-specified events (e.g., DLC and DBB) or by offering pricing structures to induce participants to shift load away from peak periods (e.g., TOU and CPP programs). This study defined capacity-focused resources using PacifiCorp's characterization of two distinct classes of firm (Class 1 DSM) and non-firm (Class 3 DSM) resource options.

Class 1 (Firm Capacity-Focused) DSM Resources. This class of capacity-focused resources offers the most reliable resource to the utility. Strategies in this category allow for total or partial interruption of electric loads for equipment and appliances, such as central air conditioners, irrigation pumps, and process loads. Load interruptions may be achieved through direct control by the utility (or a third-party under contract to the utility), on a scheduled basis, or through coordination with energy-management systems at the end-user's facility. From a planning perspective, Class 1 resources generally are considered "firm" as the utility's control over the resources gives them a relatively high level of reliability.

This study analyzed three primary program options identified by system opportunity:

- *Residential and small commercial DLC* programs allow PacifiCorp to remotely interrupt or cycle electrical equipment and appliances at the customer's facility. This study analyzed DLC program potential for residential and small commercial central electric cooling and electric water heating.
- *Irrigation DLC* allows PacifiCorp to directly control irrigation pumps during periods of high demand.
- *Nonresidential Load Curtailment* programs target larger commercial and industrial (C&I) customers with shiftable loads and/or on-site standby generation assets that can be called upon by the utility, as needed. These customers, entering into curtailment agreements with the utility or an aggregator, receive financial incentives for their participation and willingness to provide resources when needed.

Class 3 (Non-Firm Capacity-Focused) DSM Resources. These program options prove less reliable than those in Class 1 DSM as they are not "dispatchable" by the utility. Event participation is voluntary, thus variable, and impacts cannot be ascertained until after the fact.

Class 3 DSM resources include time-varying prices and the DBB program. Participants receive incentives either through rates (time-varying prices) or per-event payments (DBB). This study analyzed three specific program options in this DSM resource class:

- *TOU and Time-of-Day (TOD)* programs generally operate based on two- or three-tiered, time-differentiated tariff structures, which charge fixed prices for usage during different blocks of time (typically on- and off-peak prices by season). TOU rate design seeks to more closely reflect marginal costs of generating and delivering power. The Cadmus team analyzed the potential for using TOU rates in the residential and irrigation sectors; in most cases, C&I time-variant rates have already been in place within the company's service area; hence, the study did not further assess additional incremental opportunities.
- *CPP*, or extreme time-of-day pricing, refers to programs seeking to reduce system demand by encouraging customers to reduce loads for a limited number of hours during the year. During such events, customers may curtail their usage or pay substantially higher-than-standard retail rates. This program targets large C&I customers as an additional component to existing TOU rate structures.
- *DBB or Demand Bidding* programs (such as PacifiCorp's Energy Exchange Program) are arrangements where a utility offers payments to customers for voluntarily reducing their demand when requested by the utility. Bid amounts generally depend on market prices, published by the utility ahead of the event, coupled with the customer's ability to curtail use during the hours requested. Reduction levels achieved can be verified using an agreed-upon baseline usage level, specific to the participating customer. This program targets large C&I customers.

The 2007 and 2011 Assessments analyzed two additional resources: real-time pricing (RTP) and thermal energy storage (TES). The current study did not conduct additional analyses of these resource options for two reasons:

- RTP is considered a competing, less common, alternative to other price-based options, such as CPP, and thus is not expected to incrementally contribute to overall potential.
- Preliminary research indicated that there has been little or no change in TES technologies since the 2011 Assessment, and the option continues to be a high-cost resource.[16]

Assessment Methodology

General Approach

The study based its methodology for estimating Class 1 and 3 DSM resource potentials on a hybrid top-down and bottom-up approach. The approach began with utility system loads, disaggregated into sector, segment, and applicable end uses. For each Class 1 and 3 DSM program (or program component) studied, potential impacts were first assessed at the end-use level. End-use load impacts were then aggregated to obtain estimates of technical potentials. Market factors, such as likely program and event participation levels, could then be applied to

[16] The 2011 Assessment found TES costs to be over $250/kW per year.

technical potentials to obtain estimates of market potentials. General analytic steps involved in estimating market potential (excepting the residential and small commercial DLC program) follow below.

1. **Define customer sectors, market segments, and applicable end uses**. The first step in estimating the load basis was to define customer sectors, customer segments, and applicable end uses, similar to the energy-efficiency study (described in the next section). System loads were disaggregated into four sectors: residential, commercial, industrial, and irrigation. Each sector was further broken down by state, market segment (see Table 5), and end use (such as cooking, cooling, heating, heat pumps, HVAC, lighting, plug load, refrigeration, space heat, and hot water heating).[17]

Table 5. Capacity-Focused Analysis of Customer Sectors and Segments

Residential	Commercial	Industrial	Irrigation
Single-Family	Grocery	Agriculture (non-irrigation)	Irrigation
Manufactured	Health	Chemical Manufacturing	
Multifamily	Large Office	Electronic Equipment Manufacturing	
	Large Retail	Food Manufacturing	
	Lodging	Industrial Machinery	
	Miscellaneous	Lumber Wood Products	
	Restaurant	Mining	
	School	Miscellaneous Manufacturing	
	Small Office	Paper Manufacturing	
	Small Retail	Petroleum Refining	
	Warehouse	Primary Metal Manufacturing	
		Stone Clay Glass Products	
		Transportation Equipment Manufacturing	
		Wastewater	
		Water	

2. **Compile utility-specific sector/end-use loads.** Reliable estimates of Class 1 and 3 DSM resource potentials depend on the correct characterization of sector, segment, and end-use loads. Load profiles were developed for each end use, and contributions to system peak of each end use was determined based on end-use load shapes.

3. **Screen customer segments for eligibility.** This step involved screening customer segments for applicability of specific Class 1 and 3 DSM resource strategies. For example, only customers with maximum monthly demand of at least 1,000 kW were assumed eligible for the critical-peak pricing program.

[17] End-use segmentation was based on the Class 2 DSM analysis. As the scope of the Class 2 DSM assessment did not include Oregon, Cadmus used California's end-use segmentation, adjusted for Oregon's equipment saturation, as a proxy. Equipment saturation data derived from PacifiCorp's Energy Decisions Surveys in Oregon. Oregon-specific data was used for segmentation within each sector.

4. **Estimate impacts of current programs.** Class 1 load impacts were derived from PacifiCorp's evaluation reports. Class 3 impacts were estimated by analyzing likely effects on electricity consumption from changes in rate structure, obtained from secondary sources, described below.

5. **Estimate technical potential**. Technical potential for each Class 1 and 3 DSM resource program is 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) represents 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) is 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.

6. **Estimate market potential**. Market potential accounts 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 who will participate in a demand response event—applicable to programs such as the irrigation DLC program, where customers can opt out of events). 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:

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

For each capacity-focused program, projected sign-up rates for all customer segments were informed by secondary research, described in the program assumptions, as well as on PacifiCorp's past program experience.[18]

[18] Appendix A-1 provides a list of secondary sources used in this analysis.

Projected potential for Class 1 DSM products included PacifiCorp's current program offerings, as the load forecast did not account for these programs' impacts. Existing Class 3 DSM offering impacts, however, reflected in the load forecast; therefore, market potential results in this report should be considered incremental to those PacifiCorp currently has under contract. The next section details the methodology for estimating impacts of existing Class 3 DSM offerings.

7. **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. Administrative costs for all programs were based on the assumption that a fully loaded FTE costs $150,000 per year ($72/hour). For nonresidential load curtailment and DBB programs, costs were calculated at the system (rather than state) level, assuming events would be called system-wide. Remaining programs, on the other hand, were assumed to be implemented at the state level.

DLC

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

1. Number of customers.
2. Expected per unit (kW) impacts.
3. Equipment saturation rate.
4. Expected participation.

Derivation of Per-Unit Impacts

Despite the large number of DLC programs currently in operation, and the relatively large number of evaluation studies of these programs, estimates of end-use impacts tend to vary a great deal. DLC impacts depend on a number of program design parameters, such as: typical equipment size/capacity, cycling strategy, event time and duration, local climate, and measurement and verification protocols. A recent ESource survey of 22 DLC air conditioning programs found average per-unit load impacts ranging from 0.75 kW (Alliant Energy) to over 1.5 kW (Commonwealth Edison).[19]

PacifiCorp already operates a large DLC program in its Utah service area. Measurement of program impacts has shown an average reduction of 1 kW per unit. Indexing per-unit impacts to Utah allowed estimation of per-unit impacts for other PacifiCorp service jurisdictions using the following procedure.

As PacifiCorp system peaks correlate highly to Utah weather, the average temperature for a representative location in each state was calculated for Utah's 50 hottest hours, based on TMY3

[19] E Source. *Hot or Not? DLC Program Benchmarking*. Focus Report EDRP-F-41.

(typical meteorological year) hourly data. Manual J, the protocol used to size air conditioning equipment, was used to derive equipment design temperatures (the top 1%) for each state and equipment capacities derived from the Simple Energy Enthalpy Model (SEEM) runs completed for the Class 2 DSM analysis. The study adjusted the 1 kW impact per switch used in Utah by the ratio of system peak to design temperature and air conditioner capacity; per switch kW impacts for the other five states were estimated. Appendix A-3 provides a summary of assumptions and savings per switch by state.

Equipment Saturation Rates

Equipment saturation represents the percentage of customers who were eligible for participation in the program (i.e., to participate in the air conditioning DLC program, a customer had to have a central air conditioner or heat pump). PacifiCorp's most recent Energy Decisions Surveys provided information on equipment saturation levels in each jurisdiction.[20]

Expected Participation

The study based expected program participation rates on PacifiCorp's experience, utility reports, and national sources, particularly *A National Assessment of Demand Response Potential* and its updated results for states in the Western Area Coordinating Council (WECC).[21] Table 17 provides details on DLC program participation rates.

Current Programs and Product Offerings

Class 1 DSM

PacifiCorp currently offers Class 1 DSM programs in both Utah and Idaho. The Cool Keeper Program, in Utah, serves as one of the country's most successful residential and small commercial DLC Air Conditioning (DLC AC) programs, with up to 121 MW under management (temperature dependent). The Irrigation Load Control Program, offered in both Utah and Idaho, also has seen very successful participation levels in both states. Currently, PacifiCorp has up to 171 MW and 38 MW (realized load at dispatch) in Idaho and Utah, respectively. As discussed in the methodology section, the market potential assessment results for the DLC programs include current program impacts identified in this study.

Class 3 DSM

PacifiCorp currently offers several rate structures to help manage customer usage. These include: inverted block structures for residential customers and TOU structures for residential and C&I customers.[22] As these programs' impacts have been captured in PacifiCorp's actual and

[20] The most recent Energy Decisions Survey were conducted in 2006 with residential customers and 2007 with commercial customers.

[21] See *A National Assessment of Demand Response Potential*, Staff Report, Federal Energy Regulatory Commission, June 2009. See Also *WECC 20-Year Demand Response Forecast*, Prepared by the Brattle Group for Lawrence Berkeley National Laboratory, June 2012.

[22] Program offerings vary by state. In some cases, participation is mandatory.

forecasted sales, identified potential resulting from analyses of Class 3 DSM products is incremental to that achieved through existing rate structures.

Residential inverted block structures increase the rate ($/kWh) for energy as usage increases. These rates are mandatory for all residential customers in all six of PacifiCorp's states. The pricing structure varies by jurisdiction, with increasing prices starting at 400 kWh per month in Utah to 1,000 kWh per month in Oregon. Utah has a second price threshold, starting at 1,000 kWh per month, while California's incremental tier varies by season, county, and whether the customer uses electric heat.

The incremental price of each usage tier also varies by jurisdiction. In California, the highest block price is approximately 14% higher than the base price, while, in Wyoming, the highest block price is more than 100% higher than the base price. Other jurisdictions' top block prices range from 22% to 56% higher than the base price. Combining the incremental price difference and the amount of consumption in the top tier drives the overall impact of the block rate structure on usage.

Residential TOU rates have predominately seen subscriptions in Idaho, with limited participation in Oregon and Utah. TOU rates vary by season in Oregon and Idaho. In Utah, TOU rates apply only in summer months.

C&I TOU rates combine voluntary and mandatory rates, depending on the jurisdiction and the customer's size, as defined by maximum monthly demand. Rates also vary in complexity. Some rates vary by time of use, while others add a demand surcharge for on-peak use. Rates also vary by season.

Methodology

Rate impacts on usage can be estimated using price elasticity. Price elasticity measures either the reduction in use due to a price increase (own-price elasticity) or a shift in usage from peak to off-peak usage, due to different prices at different periods (cross-price elasticity). Existing literature estimating price elasticities has drawn from TOU programs with a relatively short on-peak period, generally four to six hours. PacifiCorp's on-peak period tends to be much longer, up to 15 to 16 hours for many schedules, from early morning to late evening. The on-peak period in rate design impacts participants' opportunities to shift usage to off-peak periods. As on-peak periods reviewed in the current literature typically average shorter than PacifiCorp's current design, elasticity estimated by the studies will likely overestimate impacts of PacifiCorp's programs. Further, as elasticity estimates vary between studies, and can change over time due to technology shifts and economic conditions, a range of potential impacts follows.

For this analysis, the Cadmus team relied on several recent energy price elasticity research papers. The 2006 National Renewable Energy Laboratory (NREL) study *Regional Differences in the Price-Elasticity of Demand for Energy* examined own-price elasticity across various regions of the United States. In 2008, the Brattle Group prepared a study for the Edison Electric Institute (EEI): *Quantifying the Benefits Of Dynamic Pricing In the Mass Market*. In 2012, Freeman, Sullivan & Co. evaluated PG&E's TOU rates for nonresidential customers. These latter two studies calculated the elasticity of substitution between on-peak and off-peak usage.

For estimating residential impacts, the Cadmus team relied on conventional economic theory, which states consumption tends to fall as price rises. The NREL paper measured the effect of rising prices on consumption. If the percentage change in consumption falls below the percentage change in price, the good consumed is considered inelastic. Energy consumption typically falls into this category, at least in the short run. In the long run, consumers may shift technologies, such as changing their heating fuels, which can lead to an elastic response wherein consumption falls by an amount greater than the percentage change in price.

The NREL study found a small relationship between consumption and price. That is, demand remains relatively inelastic with respect to price. Further, the study found, in the past 20 years, this relationship has not changed significantly; analyses performed in the 1980s showed approximately the same results. These findings might imply consumers have few available options in response to changes in energy prices, and demand responds little to changes in price. The study used data from 1979 through 2004 and acknowledged that energy prices declined (in real dollars) during this period, which may have resulted in a tendency to reduce the elasticity impact of price increases.

As the NREL study found regional differences in elasticity, the study applied NREL regional high and low, own-price, long-run elasticity findings of -0.101 to -0.407 for the Pacific region to PacifiCorp's Pacific Power jurisdictions and from -0.172 to -0.362 for the Mountain region to PacifiCorp's Rocky Mountain Power jurisdictions.[23] Although relatively minor differences emerged, the more negative lower bound for the Mountain region elasticity reflected a slightly higher expected response to price-based programs.

The Brattle Group study sought to broadly measure impacts of TOU, real-time pricing, and critical-peak pricing as a guide to deployment of advanced metering infrastructure (AMI) technologies. It found a residential TOU elasticity of substitution of 0.079 to 0.090. Notably, the study analyzed a TOU program, with an educational component and the potential for a critical peak event. Other studies have shown responses to critical-peak pricing greater than responses for TOU-only programs.

The Freeman, Sullivan & Co. report focused on small to medium nonresidential customers on PG&E's TOU rate. The study sought to estimate TOU rate impacts on usage; it also reviewed current literature on TOU elasticities of substitution, finding a range for nonresidential impacts of 0 to 0.21. Elasticities of substitution measure the usage amount shifted from one good to a substituted good due to price. In analyzing TOU rates, off-peak usage substitutes for on-peak usage.

The Freeman, Sullivan & Co. report also analyzed PG&E's rates for voluntary participation of small nonresidential and agricultural pumping TOU customers. While the study cautioned it was

23 An elasticity value indicates the percentage change in consumption resulting from a percentage change in price. For example, an own-price elasticity value of -0.10 indicates a 100% increase in price results in a 10% decrease in consumption (100% * -0.10). A substitution elasticity of 0.10 indicates a 100% relative price difference between options (on-peak and off-peak) results in a 10% shift from the higher price option to the lower price option.

hampered by a lack of pre-enrollment data and control groups constructed after the fact, the findings remained consistent with the literature; elasticities ranged from 0.09 to 0.32 for agricultural usage and from 0.10 to 0.24 for small commercial.

This analysis used a range from 0.03, observed for health care facilities, to 0.17 observed for manufacturing as the elasticity of substitution for nonresidential, non-agricultural rates, and 0.09 to 0.32 as the elasticity of substitution for agricultural pumping.

Estimated Load Impacts

Table 6 presents results of residential TOU and block rate analysis, with TOU impacts estimated using the cross-price elasticity applied to on-peak usage. The block rate impacts were estimated by applying the own-price elasticity estimate to the percentage price differential between the base block rate and the higher block rate, multiplied by usage in the higher block.[24] In instances where multiple inclining blocks or seasonal rates occurred, the elasticity estimate was applied to usage in each block or season individually. As discussed in the methodology section, market potential assessment results for Class 3 DSM programs are incremental to current program impacts, as shown below.

Coincident MW impact is derived from estimated MWh impacts of residential TOU and inclining block rates, using the same whole-house hourly load shapes and peak coincidence factors used in the rest of the Class 1 and 3 DSM potential analysis. Results suggested existing inverted block and TOU rates lowered on-peak usage from 1.6% to 4.0% on average across PacifiCorp's six jurisdictions, resulting in 47 MW to 125 MW of reduced demand during system peak periods.

Based on the methodology, Idaho proved to be the jurisdiction with the highest percentage of usage on-peak, exhibiting the highest elasticity response for TOU rates. Jurisdictions with the largest differential between base price and incremental block price or lower block cutoffs exhibited the largest percentage load reduction. For example, Wyoming's higher-priced tier begins at 500 kWh, priced more than 100% higher than the base tier. Similarly, Washington's higher-priced tier begins at 600 kWh, priced 58% higher than the base tier. At the other end of the spectrum, Oregon, California, and Utah have highest-priced tiers beginning at 1,000 kWh, with relatively lower differentials.

[24] Usage includes line losses.

Table 6. Estimated Impacts of Existing Residential Class 3 DSM Resources

Description	State	Participating Customers*	Enrolled Loads (MWh) **	MWh Shifted or Saved Due to Rate		Coincident Peak kW Impact		Percent of Estimated Baseline Consumption Shifted or Saved	
				Low	High	Low	High	Low	High
TOU (optional)	Utah	335	262	12	14	3	3	4.5%	5.1%
	Oregon	1,281	3,898	311	355	58	66	7.4%	8.3%
	Idaho	14,290	130,294	16,849	19,195	1,896	2,160	11.5%	12.8%
	Subtotal	**15,906**	**134,454**	**17,172**	**19,564**	**1,957**	**2,229**	**11.3%**	**12.7%**
Inverted rate pricing (mandatory)	Utah	706,948	7,314,347	61,289	128,992	12,940	27,235	0.8%	1.7%
	Wyoming	110,089	1,181,202	114,093	240,127	17,054	35,893	8.8%	16.9%
	Oregon	474,810	6,025,556	18,518	74,622	3,420	13,780	0.3%	1.2%
	Washington	104,004	1,789,050	57,658	232,347	10,647	42,905	3.1%	11.5%
	California	35,681	440,299	2,243	9,037	252	1,015	0.5%	2.0%
	Idaho	43,198	487,948	9,755	20,532	1,098	2,311	2.0%	4.0%
	Subtotal	**1,474,720**	**17,238,402**	**263,557**	**705,657**	**45,411**	**123,138**	**1.5%**	**3.9%**
Total	**System**	**1,490,636**	**17,372,855**	**280,730**	**725,221**	**47,367**	**125,367**	**1.6%**	**4.0%**

* As of December 31, 2011

** Residual on-peak portions of TOU loads and actual Inverted Rate Pricing loads after impacts of respective pricing structures, calendar year 2011.

Table 7 presents the results of the nonresidential TOU rate analysis. Impacts were estimated by multiplying the substitution elasticity estimate by the percentage difference between the on-peak and off-peak rates and by the on-peak load yielding a gross estimate of the loads shifted. This estimate was further adjusted by the percentage of the TOU rate that was variable. The on-peak proportion of load and variable portion of the TOU rate was determined using billing determinants provided by PacifiCorp.

As in the residential sector, the coincident MW impact was calculated from the estimated MWh impacts, using the peak coincidence factors used in the rest of the Class 1 and 3 DSM potential analysis. Our analysis suggests 2.0% to 10.2% of the eligible MWh was reduced due to the TOU rates, resulting in a reduction between 25 MW and 140 MW in coincident peak demand.

Table 7. Estimated Impacts of Existing Commercial and Industrial Class 3 DSM Resources

Rate Class	Schedule (M-Mandatory, V-Voluntary)	Participating Customers*	Enrolled Loads (MWh) **	MWh Shifted or Reduced Due to Rate		Coincident kW Impact		Percent of Estimated Baseline Consumption Shifted or Saved	
				Low	High	Low	High	Low	High
General Service - Large, ≥ 1,000 kW	Washington (Sch.47T) - M	1	1,403	9	51	2	10	0.6%	3.5%
General Service - Large, ≥ 1,000 kW	Washington (Sch,48T) - M	59	141,345	955	5,409	192	1,088	0.7%	3.7%
General Service - Large >= 500 kW	California (Sch. AT48) - M	19	55,429	161	910	23	131	0.3%	1.6%
General Service - Distribution Voltage, < 15,000 kW (35A = farm)	Idaho (Sch. 35/35A) - V	3	62	1	5	0	1	1.3%	7.1%
General Service – Large, Partial Requirements, ≥ 1,000 kW	Wyoming (Sch.33) -M	9	324,737	1,063	6,024	214	1,212	0.3%	1.8%
General Service – Large, >= 1,000 kW	Wyoming (Sch.46) - M	81	328,746	1,972	11,176	397	2,249	0.6%	3.3%
General Service – Large, Transmission Delivery, ≥ 1,000 kW	Wyoming (Sch.48T) - M	26	592,518	4,288	24,299	863	4,889	0.7%	3.9%
General Service - < 1,000 kW	Utah (Sch. 6A) - V	2,195	163,251	7,559	42,832	1,085	6,149	4.4%	20.8%
General Service - < 1,000 kW	Utah (Sch. 6B) - V	2,195	137,737	2,663	15,089	382	2,166	1.9%	9.9%
General Service - Large, ≥ 1,000 kW	Utah (Sch. 8) - M	274	881,718	25,507	144,539	5,132	29,083	2.8%	14.1%
General Service - High Voltage	Utah (Sch. 9 / 9A) - M	158	1,734,206	60,338	341,915	12,141	68,798	3.4%	16.5%
Agricultural Pumping	Utah (Sch. 10/ TOD [1]option) - V	251	13,960	3,289	11,695	969	3,444	19.1%	45.6%
Back-Up, Maintenance, and Supplementary Power	Utah (Sch. 31) - M	4	38,146	1,153	6,532	232	1,314	2.9%	14.6%
General Service - Small Nonresidential	Oregon (Sch. 23 / 210) - V	274	1,278	175	990	25	142	12.0%	43.7%
Agricultural Pumping	Oregon (Sch. 41 / 210) - V	58	431	54	190	16	56	11.0%	30.6%
General Service - Large, ≥ 1,000 kW	Oregon (Sch. 47) - M	5	95,765	959	5,432	193	1,093	1.0%	5.4%
General Service - Large, ≥ 1,000 kW	Oregon (Sch. 48) - M	211	1,748,675	16,087	91,161	3,237	18,343	0.9%	5.0%
Total		**5,823**	**6,259,407**	**126,230**	**708,249**	**25,102**	**140,169**	**2.0%**	**10.2%**

* As of December 31, 2011

** Residual on-peak portion of TOU loads after impacts of TOU pricing, calendar year 2011.

Table 8 summarizes the estimated impact of existing residential and commercial TOU and block rates. The estimate is presented as a range due to the variability in the underlying assumptions, including the own-price and cross-price elasticities and the coincidence factor. These impacts are embedded in current customer usage and range from a low estimate of 72 MW to a high estimate of 266 MW. As discussed in the methodology section, results of the market potential assessment for the Class 3 programs are incremental to the current program impacts, as shown below.

Table 8. Summary of Impacts of Existing Class 3 DSM Resources

Description	Enrolled Loads (MWh) *	MWh Shifted or Reduced Due to Rate		Coincident kW Impact		Percent of Estimated Baseline Consumption Shifted or Saved	
		Low	High	Low	High	Low	High
Residential	17,372,855	280,730	725,221	47,367	125,367	1.6%	4.0%
C&I	6,245,016	122,888	696,364	24,118	136,669	1.9%	10.0%
Irrigation	14,391	3,343	11,885	984	3,500	18.8%	45.2%
Total	**23,632,263**	**406,960**	**1,433,470**	**72,470**	**265,536**	**1.7%**	**5.7%**

* Residual on-peak portion of TOU loads and actual Inverted Rate Pricing loads, after the impacts of the respective pricing structures, calendar year 2011.

Class 1 and 3 Resource Potential

Table 9 shows the estimated market potential (at the generator) during system peak hours for each of the Class 1 and 3 DSM programs. Table 10 shows the estimated potential by sector (residential, commercial, industrial, and irrigation) for each of the two territories and the entire system. Class 1 DSM products include current program impacts, while Class 3 products are incremental opportunities above PacifiCorp's current offerings.

Based on PacifiCorp's peak demand forecast in 2032, the Rocky Mountain Power service territory will account for approximately 70% of the system peak demand. Thus, the Pacific Power service territory has a substantially lower market potential (136 MW) than the Rocky Mountain Power service territory (533 MW). Additional factors contributing to the lower potential in the Pacific Power service territory include: lower temperatures during system peak; lower saturations of cooling equipment (affecting the DLC AC program); and smaller irrigation pumps (affecting the irrigation DLC program).

Table 9. Class 1 and 3 DSM Market Potential (MW in 2032) by Program*

Resource Class	Program	Market Potential		
		Rocky Mountain Power	Pacific Power	PacifiCorp System
Class 1 DSM	DLC Air Conditioning	144	28	172
	DLC Water Heating	8	14	22
	Irrigation Load Control	210	11	221
	Load Curtailment	125	64	189
	Subtotal	**488**	**116**	**604**
Class 3 DSM	Demand Buyback	14	5	19
	Residential TOU	19	7	25
	Irrigation TOU	11	7	18
	CPP	2	1	3
	Subtotal	**45**	**20**	**66**
Class 1 and Class 3 DSM	**Total**	**533**	**137**	**670**

* Hours vary by program and may not reflect actual available reductions during system peak.

The residential and irrigation sectors exhibit the highest estimated market potential for Class 1 and 3 DSM resources. The majority of this potential, however, already is under contract through PacifiCorp's Cool Keeper (Utah) and Irrigation Load Control (Idaho and Utah) programs (121 MW and 209 MW, respectively). The nonresidential load curtailment program, which applies to both the C&I sectors, has the most remaining potential (189 MW) of any Class 1 DSM resource. As coincident peak impacts are based on average impacts of individual programs during peak hours, as defined by the program, the Class 1 and Class 3 DSM program potentials are not truly additive.

Table 10. Market Potential (MW in 2032) by Sector*

Resource Class	Program	Market Potential		
		Rocky Mountain Power	Pacific Power	PacifiCorp System
Class 1 DSM	Residential	151	41	192
	Small Commercial	1	1	2
	Large Commercial	55	42	97
	Irrigation	210	11	221
	Industrial	70	22	92
	Subtotal	**488**	**116**	**604**
Class 3 DSM	Residential	19	7	25
	Small Commercial	-	-	-
	Large Commercial	5	4	8
	Irrigation	11	7	18
	Industrial	12	2	14
	Subtotal	**45**	**20**	**66**
Class 1 and Class 3 DSM	**Total**	**533**	**137**	**670**

* Hours vary by program and may not reflect actual available reductions during system peak.

Resource Costs and Supply Curves

Resource acquisition costs fall into several categories, including:

- Infrastructure
- Administration
- Maintenance
- Data acquisition
- Hardware costs
- Marketing expenses
- Incentives[25]

Estimates for each type of expense category within each program were developed using PacifiCorp's program data and experience and using secondary sources, such as reports on similar programs offered by other utilities.[26] In developing estimates of levelized costs, program expenses were allocated annually over the expected program life cycle and then discounted by PacifiCorp's cost of capital (6.88%).[27] The ratio of this value and the discounted kW reduction produced the levelized per-kW cost for each resource in each state.

Table 11 and Table 12 display the Class 1 DSM market potential and per-unit ($/kW-year) costs for each program in each state. The irrigation DLC program is expected to be the least expensive program option, with levelized costs ranging from $51/kW-year to $64/kW-year. Per-unit resource costs for the nonresidential load curtailment program are estimated at $69/kW-year for both service territories (as events are assumed to be called on a system-wide basis). The residential DLC AC program exhibits levelized costs ranging from $72/kW-year in Utah to $164/kW-year in Idaho. The assumed per-switch kW impact drives this variation in cost, with these impacts highest in Utah (1 kW) and the lowest in Idaho (0.43 kW).[28] Both the small commercial and water heating DLC programs would rely on the existence of the residential DLC program; therefore, program costs must be considered in addition to residential DLC costs.

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25 As incentives for Class 1 and Class 3 DSM are treated as resource acquisition costs (rather than transfer payments), they are included in the levelized cost calculations.

26 A single full-time equivalent (FTE) employee was assumed to cost $150,000 per year. All costs based on a specific number of FTE or set amount of staff time were calculated using this assumption.

27 Class 1 resources were assumed to have a 10-year program life, based on the average length of implementation contracts, while Class 3 resources were assumed to have a 20-year program life, based on the expected useful life of an interval meter.

28 See Appendix A-3 for details.

Table 11. Class 1 DSM: Market Potential by State (MW in 2032)

State	DLC AC - Residential	DLC Water Heat - Residential	DLC AC - Small Commercial	DLC Water Heat - Small Commercial	Irrigation DLC	Nonresidential Load Curtailment	Total
Pacific Power							
California	1	0.5	0.03	0.02	4	2	8
Oregon	18	10	1	0.2	3	46	78
Washington	8	3	0.1	0.04	4	16	31
Subtotal	**27**	**13**	**1**	**0.3**	**11**	**64**	**116**
Rocky Mountain Power							
Idaho	1	0.3	0.03	0.01	172	9	183
Utah	139	7	1	0.1	38	91	276
Wyoming	3	1	0.2	0.02	0	25	29
Subtotal	**143**	**8**	**1**	**0.1**	**210**	**125**	**488**
Total	**170**	**21**	**2**	**0.4**	**221**	**189**	**604**

Table 12. Class 1 DSM: Levelized Costs by State ($/kW-year)

State	DLC AC - Residential	DLC Water Heat - Residential	DLC AC - Small Commercial	DLC Water Heat - Small Commercial	Irrigation DLC	Nonresidential Load Curtailment
Pacific Power						
California	$94	$63	$75	$63	$64	$69
Oregon	$123	$64	$99	$64	$61	$69
Washington	$94	$64	$75	$64	$64	$69
Subtotal*	**$114**	**$64**	**$93**	**$64**	**$63**	**$69**
Rocky Mountain Power						
Idaho	$164	$63	$131	$63	$51	$69
Utah	$72	$64	$57	$64	$51	$69
Wyoming	$85	$64	$68	$64	$64	$69
Subtotal*	**$72**	**$64**	**$61**	**$64**	**$51**	**$69**
Total*	**$79**	**$64**	**$73**	**$64**	**$52**	**$69**

* Subtotals and totals are weighted by market potential.

For Class 3 DSM resources, programs for C&I and irrigation customers are estimated to be less expensive than for residential customers. Due to the eligibility criteria, customers participating in C&I programs already would have interval meters in place, while residential customers would need to have interval meters installed, thereby incurring an additional cost to the residential programs. Critical-peak pricing (ranging from $9/kW-year in Oregon and Utah to $96/kW-year in California) is the least expensive pricing program, as it does not require incentives or meter costs. Irrigation TOU is slightly more expensive (ranging from $20/kW-year in Idaho to $97/kW-year in Washington and Wyoming), as interval meters must be installed for all new participants. Demand Buyback, at $26/kW-year for all states (assuming events would be called system-wide), also offers a relatively low-cost option.

The residential TOU program costs more due to the small load reductions compared to the installed technology (meters) and to ongoing program maintenance costs (communications and administration).

Table 13. Class 3 DSM: Market Potential by State (MW in 2032)

State	Residential TOU	Irrigation TOU	DBB	CPP	Total
Pacific Power					
California	0.3	2	0.1	0.03	2
Oregon	4	4	4	1	13
Washington	2	2	1	0.2	5
Subtotal	**7**	**7**	**5**	**1**	**20**
Rocky Mountain Power					
Idaho	-	9	0.4	0.1	10
Utah	17	1	9	1	28
Wyoming	2	0.3	4	1	7
Subtotal	**19**	**11**	**14**	**2**	**45**
Total	**25**	**18**	**19**	**3**	**66**

Table 14. Class 3 DSM: Levelized Costs by State ($/kW-year)

State	Residential TOU	Irrigation TOU	DBB	CPP
Pacific Power				
California	$347	$40	$26	$96
Oregon	$286	$62	$26	$9
Washington	$117	$97	$26	$25
Subtotal*	**$231**	**$66**	**$26**	**$14**
Rocky Mountain Power				
Idaho	N/A	$20	$26	$38
Utah	$124	$58	$26	$9
Wyoming	$195	$97	$26	$10
Subtotal*	**$130**	**$25**	**$26**	**$11**
Total*	**$157**	**$41**	**$26**	**$12**

* Subtotals and totals are weighted by market potential.

Appendix A-2 provides supply curves for Class 1 and Class 3 DSM, which represent the quantity of each resource (cumulative MW) that can be achieved at or below the estimated per-unit cost at any point.

Class 1 DSM Resource Results by Program Option

Residential and Small Commercial DLC

The DLC resource assessed in this study would allow PacifiCorp to manage cooling and water heating loads during peak periods. Customers enrolling in the program have a switch installed on their cooling equipment (either a central air conditioner or a heat pump); this cycles the unit on and off during a program event. Utility staff call events, which may last up to four hours. The utility compensates participating customers with an incentive; both residential and small commercial customers may qualify for the program.

Currently, PacifiCorp has approximately 121 MW of load under contract from its Cool Keeper air conditioner Program in Utah. Based on the Cadmus team's research on similar programs offered by other utilities, PacifiCorp may have saturated the existing market; additional potential may derive from load growth over the 20-year period and not from an increase in the participation rate. The Cadmus team estimates a total of 143 MW of potential in the Rocky Mountain Power territory, including that currently under contract in Utah, and 27 MW in the Pacific Power territory.

Table 15 displays state-specific total and incremental market potentials (total potential less impacts of current programs, where offered). As shown, Utah has the largest amount of potential in 2032. Overall, the small commercial sector offers limited savings, though costs will likely be lower than in the residential sector due to small commercial customers, with larger cooling units, realizing 25% higher per-switch impacts.

Table 15. Residential and Small Commercial DLC Air Conditioning: Market Potential (MW in 2032) and Levelized Cost by State ($/kW-yr)

Territory	State	Residential				Small Commercial			
		Total Market Potential (MW)	Existing Program Impact (MW)	Incremental Market Potential (MW)	Levelized Cost ($/kW-yr)*	Total Market Potential (MW)	Under Contract (MW)	Incremental Market Potential (MW)	Levelized Cost ($/kW-yr)*
Pacific Power	California	0.9	-	0.9	$94	0.0	-	0.0	$75
	Oregon	18.4	-	18.4	$123	0.5	-	0.5	$99
	Washington	7.9	-	7.9	$94	0.1	-	0.1	$75
	Subtotal	**27.2**	**-**	**27.2**	**$114**	**0.7**	**-**	**0.7**	**$93**
Rocky Mountain Power	Idaho	0.8	-	0.8	$164	0.0	-	0.0	$131
	Utah	138.9	120.0	18.9	$72	0.9	0.7	0.2	$57
	Wyoming	3.4	-	3.4	$85	0.2	-	0.2	$68
	Subtotal	**143.1**	**120.0**	**23.1**	**$72**	**1.1**	**0.7**	**0.4**	**$61**
	Total	**170**	**120**	**50**	**$79**	**1.7**	**0.7**	**1.1**	**$73**

* Subtotals and totals are weighted by market potential.

Table 16 and Table 17 present detailed assumptions about program costs, participation rates, and other variables used in the analysis.

Table 16. Residential and Small Commercial DLC Air Conditioning: Program Basics

Program Element	Assumption
Customer sectors eligible	All residential and small commercial market segments.
End uses eligible for program	Central cooling, including heat pumps.
Customer size requirements	Residential and small commercial customers
Applicable hours	Top 50 summer system hours

Table 17. Residential and Small Commercial DLC Air Conditioning: Planning Assumptions

Inputs	Value	Source(s) or Rationale
Annual attrition	7%	Based on actual program experience; provided by Rocky Mountain Power.
Annual utility administrative costs	$300,000	Assumes two FTE to run the program system-wide.
Technology cost (per new participant)	$60 per switch, and $80 for installation labor	Based on vendor bids, research, and informal communication with vendors.
Marketing cost (per new participant)	$36	Assumes 1/2 hour of staff time.
Annual vendor costs (%)	15%	Vendor administration of the program is expected to be 15% of all the utility's non-administrative costs (technology, marketing, communication, incentives). This assumption is based on research of vendor bids and informal communication with vendors. The cost includes maintenance, administrative labor, and dispatch software.
Communication (annual costs per participant)	$7	Accounts for monthly per-customer communications of a one-way transmission system. Assumed to be one-half of the costs experienced by the PacifiCorp Idaho Irrigation system, which utilizes a two-way system.
Incentives (annual costs per participant)	$20	The Utah Cool Keeper Program incentive amount of $20 is consistent with other programs across the country.
Savings per switch	Varies by state and sector	Savings per switch vary by state due to differing loads and climatic conditions. Utah saves approximately 1 kW per switch, as reported in the 2011 Cool Keeper Program Impact Evaluation. Other states are indexed to Utah, adjusted by design temperatures during the top 50 hours. Assumes commercial customers save 25% more per switch due to larger units. Savings per residential switch by state can be found in Appendix A-3.
Program participation	Residential: 26% UT, 12.5% CA, ID OR, WA, WY Small Commercial: 3.5% all states	Participation is assumed to be 12.5% of all eligible customers for all states except Utah, which is expected to have a 26% participation rate among eligible customers (The Brattle Group, WECC 20-year Demand Response Forecast 2012). Findings from ESource and FERC support this, with participation found to be generally between 5% and 25% of total customers, before adjusting for eligibility. Participation for small commercial customers is assumed to be 3.5% for all states, as supported by ESource findings, which show program participation ranging from 1.4% to 28%.
Event participation	100%	Event participation is assumed at 100%, as it is captured in average per unit impacts.

The study analyzed a water heating component as an addition to the DLC AC program. Though this option is available to residential and small commercial customers, customers must have air conditioners enrolled in the program and have electric water heat to qualify for participation. In conjunction with the DLC AC program, this option would add an estimated 8 MW and 14 MW of market potential in Rocky Mountain Power's and Pacific Power's service territories, respectively, as shown in Table 18.

Utah and Oregon offer the highest potential due to their large customer bases, compared to the other four states. The levelized cost remains the same across the residential and small commercial customer classes, given each DLC switch saves an assumed 0.5 kW, regardless of the customer class or state. Reported levelized costs remain relatively low, as the air conditioning component bears much of the DLC program costs. Levelized costs for a standalone water heating DLC program would be considerably higher.

Table 18. Residential and Small Commercial DLC Water Heating: Levelized Cost by State ($/kW)

Territory	State	Residential		Small Commercial	
		Total Market Potential (MW)	Levelized Cost ($/kW-yr)*	Total Market Potential (MW)	Levelized Cost ($/kW-yr)*
Pacific Power	California	0.5	$63	0.02	$63
	Oregon	9.6	$64	0.21	$64
	Washington	3.4	$64	0.04	$64
	Subtotal	**13.5**	**$64**	**0.27**	**$64**
Rocky Mountain Power	Idaho	0.3	$63	0.01	$63
	Utah	6.9	$64	0.08	$64
	Wyoming	0.5	$64	0.02	$64
	Subtotal	**7.8**	**$64**	**0.11**	**$64**
	Total	**21.2**	**$64**	**0.38**	**$64**

*Subtotals and totals are weighted by market potential.

Table 19 and Table 20 show detailed assumptions about programs costs, participation rates, and other variables.

Table 19. Residential and Small Commercial DLC Water Heating: Program Basics

Program Element	Assumption
Customer sectors eligible	All residential and small commercial market segments.
End uses eligible for program	Electric hot water heating, excluding heat pump water heaters. Program runs in conjunction with the DLC AC program.
Customer size requirements	Residential and small commercial customers.
Applicable hours	Top 50 summer system hours.

Table 20. Residential and Small Commercial DLC Water Heat Planning Assumptions

Inputs	Value	Source(s) or Rationale
Annual attrition	7%	Based on actual program experience; provided by Rocky Mountain Power for AC DLC.
Annual utility administrative costs	$0	FTE costs are covered by the DLC AC program.
Technology cost (per new participant)	$60 per switch plus $40 for installation labor	An additional control for each water heater is consistent with best practices; 50% additional labor is required for installation.
Marketing cost (per new participant)	$9	Assumes 1/8 hour of staff time.
Annual vendor administrative costs (%)	5%	Vendor administration of the program is expected at 5% of all non-utility administrative costs. This assumption derives from research of vendor bids and informal communications with vendors. The cost includes maintenance, administrative labor, and dispatch software.
Communication (annual costs per participant)	$0	Communication is covered by the DLC AC program.
Incentives (annual costs per participant)	$10	Consistent with other programs offered across the country (e.g., Kentucky's Touchstone Energy Cooperatives provides an additional $10 credit for water heat).
Savings per switch	0.5 kW	Assumes an average annual impact of 0.5 kW per switch, based on BPA evaluation of the summer WH DLC pilot.
Program participation (%)	Residential: 26% UT, 12.5% CA, ID OR, WA, WY Small Commercial: 3.5% all states	Water heating program participation is assumed at the same rate of program sign-up for the DLC AC program, but accounts for saturations of electric hot water heating for customers with central AC. It is calculated as the product of the percent of customers with electric water heating and central cooling and the AC DLC participation rate. Saturations of electric hot water heating can be found in Appendix A-3.
Event participation	100%	Event participation is assumed to be 100% as it is captured in the average per-unit impacts.

Irrigation Load Control

PacifiCorp's Irrigation Load Control programs in Idaho and Utah include a scheduled component, where customers subscribe in advance for specific days and numbers of hours their irrigation systems may be turned off, along with a dispatchable component, such as the residential DLC program, where irrigation pumps are controlled for a four-hour period during each event. Under the current program, PacifiCorp can achieve 38 MW of savings in Utah and 171 MW of savings in Idaho. Although a scheduled program option remains in place, most participants have transitioned to the dispatchable program option; therefore, for estimating potential, the irrigation DLC program is considered to be 100% dispatchable, without participants on a predetermined schedule.

Table 21 shows a market potential estimate of 11 MW for Pacific Power. For Rocky Mountain Power, 210 MW is considered achievable (this estimate includes 209 MW available through the current programs). As the program has extremely high participation rates, and recent recruitment efforts in Idaho and Utah have not produced additional participation, the additional potential identified in these states would derive from new customers who have been acquired over the 20-year period. Given its high irrigation load, the majority of the market potential (78%) appears available from Idaho. Despite agriculture in other states, smaller pumps are typically used and the shorter irrigation seasons offer much lower potential. Additionally, compared to other states, the program's maturity in Idaho and Utah, the concentration of agricultural pumping loads, and larger pump sizes result in lower program costs (on a per-kW basis).

Table 21. Irrigation Load Control: Market Potential (MW in 2032) and Levelized Cost by State ($/kW-yr)

Territory	State	Total Market Potential (MW)	Under Contract (MW)	Incremental Market Potential (MW)	Levelized Cost ($/kW-yr) *
Pacific Power	California	4.5	-	4.5	$64
	Oregon	2.8	-	2.8	$61
	Washington	3.8	-	3.8	$64
	Subtotal	**11.1**	**-**	**11.1**	**$63**
Rocky Mountain Power	Idaho	172.0	171	1.0	$51
	Utah	38.2	38	0.2	$51
	Wyoming	0.2	-	0.2	$64
	Subtotal	**210.4**	**209**	**1.4**	**$51**
	Total	**222**	**209**	**12.5**	**$52**

* Subtotals and totals are weighted by market potential.

Table 22 and Table 23 provides detailed assumptions for the Irrigation Load Control program.

Table 22. Irrigation Load Control: Program Basics

Program Name	Irrigation DLC
Customer sectors eligible	Irrigation customers.
End uses eligible for program	Irrigation pumps.
Customer size requirements	All customers with at least 25 horsepower irrigation pump (92% of sales CA, 100% of sales ID, 78% of sales OR, 100% of sales UT, 75% of sales WA, 82% of sales WY).
Applicable hours	Top 50 summer system hours.

Table 23. Irrigation Load Control: Planning Assumptions

Inputs	Value	Source(s) or Rationale
Incentive costs	$23/kW	Assumption based on PacifiCorp's experience and a review of similar programs
Delivery costs	$10 ID, $10 UT $16 OR, $18 CA, $18 WA, $18 WY	Delivery costs include all administration and communications for the program. Costs are based on PacifiCorp's current experience and on the geographical makeup of each state. States with higher concentrations of irrigation sites have lower delivery costs.
Load class eligibility	50% CA, 100% ID, 25% OR, 100% UT, 50% WA, 25% WY	Cooler temperatures, heavy rainfall, easy access to surface water and variations in crop types cause a lower level of load class eligibility for Oregon, Wyoming, California, and Washington. Additionally, irrigators are more geographically dispersed in Oregon and Wyoming, making program delivery more difficult.
Program participation (%)	25% CA, 78% ID, 15% OR, 78% UT, 25% WA, 15% WY	Given the high share of load already under contract, the Cadmus team assumes Utah and Idaho have hit maximum participation levels. A more conservative participation estimate of 25%, in line with the 30% achieved by Idaho Power, was assumed for Washington and California. Both Wyoming and Oregon have smaller pumps, different pumping configurations, better access to surface water, and are expected to have lower participation rates.
Event participation (%)	94%	Event participation equals the number of customers, on average, choosing to participate in an event. Event participation was calculated by dividing the average number of opt-outs from PacifiCorp's 2010 Irrigation Load Control Program in Idaho by the number of participating customers.

Nonresidential Load Curtailment

Load curtailment programs consist of contractual arrangements between a utility (or a contractor working on its behalf) and its C&I customers, which agree to curtail or interrupt their operations, in whole or part, for a predetermined period, when requested by the utility. This study assumed C&I customers with a maximum monthly demand of at least 150 kW would qualify for such a program. Currently, PacifiCorp has a rate structure in place for its largest industrial accounts that allows curtailment during utility events; this analysis excludes such "special contract" arrangements. However, customers with installed standby generation capability are considered eligible for this program.

Rocky Mountain Power's service territory has an estimated 125 MW of nonresidential curtailment market potential, with an additional 64 MW in Pacific Power's service territory. Both territories have higher market potential than that estimated in the 2011 Assessment due to higher assumed program participation rates (consistent with current national trends for similar programs administered by third-party curtailment aggregators and service providers). Table 24 shows levelized costs and market potential by state. As the study assumed the program would be implemented system-wide, the system-level $/kW-year has been applied to all states.

Table 24. Nonresidential Load Curtailment: Market Potential (MW in 2032) and Levelized Cost by State ($/kW-yr)

Territory	State	Market Potential (MW)	Levelized Cost ($/kW-yr) *
Pacific Power	California	2	$69
	Oregon	46	$69
	Washington	16	$69
	Subtotal	**64**	**$69**
Rocky Mountain Power	Idaho	9	$69
	Utah	91	$69
	Wyoming	25	$69
	Subtotal	**125**	**$69**
	Total	**189**	**$69**

* Subtotals and totals are weighted by market potential.

Table 25 and Table 26 show detailed assumptions for the Nonresidential Load Curtailment program.

Table 25. Nonresidential Load Curtailment: Program Basics

Program Element	Assumption
Customer sectors eligible	All industrial and commercial market segments.
End uses eligible for program	All.
Customer size requirements	150 kW or greater.
Applicable hours	Top 60 system hours.*

*A 30-hour option focusing on a narrower system peak was considered for IRP modeling. Because this curtailment would last fewer hours, the incentive per peak kW subscribed would be reduced, translating to a reduction in levelized cost of roughly 5% compared to the 60-hour option.

Table 26. Load Curtailment: Planning Assumptions

Inputs	Value	Source(s) or Rationale
Annual administrative costs	$225,000	Assumes 1.5 FTE to run the program system-wide.
Technology cost (per new participant)	$0	Assumes customers meeting the eligibility requirements for the program will already have interval meters in place.
Marketing cost (per participant)	$576/year (first year costs) $576/year (ongoing costs)	Assumes 8 hours of effort by staff for initial marketing and an additional 8 hours each year for ongoing customer service.
Incentives (annual costs per participating kW)	$60/kW	Based on a review of several programs, including PG&E's Business Energy Coalition Program of $50/kW, MidAmerican of $41.6/kW, and CenterPoint Energy of$40/kW.
Overhead: first costs	$150,000	Assumes 1 FTE to start up the program.
Technical potential as % of load basis	30%	Customers shed 26.9% to 34% of load for day-of and day-ahead events, respectively (2010 and 2011 Statewide Aggregator Demand Response Programs: Final Report, Christensen Associates).
Program participation (%)	Ranges from 10%-30%	Programs across the country experience participation rates from 4.5% (MidAmerican Energy) to 30% (Georgia Power and Indiana Michigan Power Company). See Appendix A-4 for participation by state.
Event participation (%)	95%	Event participation in PJM and MidAmerican programs ranged from 90% to 95%.

Class 3 DSM Resource Results by Program Option

Residential Time-of-Use Rates

Currently, PacifiCorp offers residential TOU rates in Oregon, Utah, and Idaho. As with other Class 3 DSM products assessed in this study, the market potential the Cadmus team estimated is incremental to the impacts of the existing rates. Approximately 25% of residential customers in Idaho are currently on the TOU rate. As the Cadmus team did not find other utilities with participation at these levels, the study assumed maximum participation has been reached. The Cadmus team estimated a total of 19 MW of incremental market potential in the Rocky Mountain Power territory and 7 MW of incremental market potential in the Pacific Power territory. Table 27 displays the market potential and levelized per-unit costs by state. Costs higher than in the 2011 Assessment reflect increases in PacifiCorp's meter hardware and installation costs.

Table 27. Residential TOU: Market Potential (MW in 2032) and Levelized Cost by State ($/kW-yr)

Territory	State	Market Potential (MW)	Levelized Cost ($/kW-yr) *
Pacific Power	California	0.3	$347
	Oregon	4.3	$286
	Washington	2.3	$117
	Subtotal	**6.9**	**$231**
Rocky Mountain Power	Idaho	-	$0
	Utah	17.0	$124
	Wyoming	1.6	$195
	Subtotal	**18.6**	**$130**
	Total	**25.5**	**$157**

* Subtotals and totals are weighted by market potential.

Table 28 and Table 29 show detailed assumptions for the Residential TOU program.

Table 28. Residential TOU: Program Basics

Program Element	Assumption
Customer sectors eligible	All residential market segments.
End uses eligible for program	All.*
Customer size requirements	None.
Applicable hours	Six hours on-peak period each summer weekday.
Rate structure	Assumes a two-tier rate structure, with the peak rate 3 times greater than the off-peak rate.

* The TOU rate structure likely will not affect the consumption of some end uses (e.g., refrigerators). "Technical Potential as % of Load Basis" accounts for this.

Table 29. Residential TOU: Planning Assumptions

Inputs	Value	Source(s) or Rationale
Annual administrative costs	$15,000	Assumes the program will require 1/10 FTE for annual administration.
Technology cost (per new participant)	$426	Meter costs for PacifiCorp are $133, with $293 additional installation cost.
Marketing cost (per new participant)	$36/year (first year costs) $3.6/year (ongoing costs)	Assumes 1/2 hour of staff time per year. An additional 1/20 hour per year is assumed for ongoing marketing and customer support.
Overhead: first costs	$150,000	Assumes 1 FTE to design and launch the program.
Technical potential as % of load basis	9% for OR and CA and 16% for WY, UT, ID, WA	PG&E's residential pricing program shows about 16% average peak demand reduction in summer months for customers in warmer climates and 9% for those in cooler climates (Freeman, Sullivan & Co., 2011 and 2012). Additionally, a 2005 evaluation of Pacific Power's TOU program in Oregon shows an average reduction of 8% in the summer months (Quantec LLC, *Analysis of the Load Impacts and Economic Benefits of the TOU Rate Option*).
Incremental program participation (%)	0% in Idaho, 5% in all other states	Even among the top 10 IOU programs with the highest enrollment (according to FERC), more than one-half have single-digit participation rates. A 5% participation rate can be expected if a reasonable effort is made. This market penetration rate is assumed to be incremental to current participation in states where TOU tariffs remain in effect, except Idaho, where no additional participation is expected (as previously discussed regarding the current Idaho program).
Event participation (%)	100%	Event participation is captured in the average load impact.

Irrigation TOU Rates

An irrigation sector TOU program is assumed to function similarly to the residential TOU program, where rates have been tiered to reflect high prices during system peak periods. The potential presented in this report is incremental to the impacts of PacifiCorp's existing irrigation TOU rates in Oregon and Utah. This analysis assumes the program would be voluntary, in contrast to the mandatory structure analyzed in the 2011 Assessment.

Table 30 shows an estimated market potential of 11 MW in the Rocky Mountain Power service territory, with an additional 7 MW in the Pacific Power territory. Though most identified potential occurs in Idaho, these numbers notably do not account for interactions with the irrigation DLC program. As discussed in Section 1, this potential decreases significantly when considered in conjunction with an irrigation DLC program. Idaho also has the lowest implementation costs, with costs highest in Washington and Wyoming, driven by estimated per-customer impacts.

Table 30. Irrigation TOU: Market Potential (MW in 2032) and Levelized Cost by State ($/kW-yr)

Territory	State	Market Potential (MW)	Levelized Cost ($/kW-yr) *
Pacific Power	California	1.7	$40
	Oregon	3.8	$62
	Washington	1.8	$97
	Subtotal	**7.3**	**$66**
Rocky Mountain Power	Idaho	9.5	$20
	Utah	0.7	$58
	Wyoming	0.3	$97
	Subtotal	**10.5**	**$25**
	Total	**17.8**	**$41**

* Subtotals and totals are weighted by market potential.

Table 31 and Table 35 show detailed assumptions for an irrigation TOU program.

Table 31. Irrigation TOU: Program Basics

Program Element	Assumption
Customer sectors eligible	Irrigation customers.
End uses eligible for program	Irrigation pumping.
Customer size requirements	None.
Applicable hours	120 hours: assumes two on-peak hours each weekday, June to August.

Table 32. Irrigation TOU: Planning Assumptions

Inputs	Value	Source(s) or Rationale
Annual administrative costs	$15,000	Assumes 1/10 FTE to run the program system-wide.
Technology cost (per new participant)	$1,000	Technology costs assume $1,000 per new participant for meter and installation costs.
Marketing cost (per new participant)	$720/year (first year costs) $72/year (ongoing costs)	Assumes 10 hours of effort by staff per new participant. An additional hour per year is assumed for ongoing marketing and customer support.
Overhead: first costs	$150,000	Assumes 1 FTE to design and launch the program.
Technical potential as % of load basis	30%	Idaho Power achieved 11% and 7% in 2001 and 2002 through an Irrigation TOU Pilot program. The on-peak rate was $0.05/kWh, and the off peak rate was $0.014/kWh, and peak hours ranged from 1:00 pm to 9:00 pm. It is assumed, with the shortened on-peak window of 2 hours, customers will be able to shift a higher percentage of load.

Inputs	Value	Source(s) or Rationale
Program participation (%)	13.5% CA, ID, WA, WY 12.5% OR, 4.5% UT	The current participation levels in several of PacifiCorp's voluntary nonresidential Class 3 rates range from 0.37% to 9% participation, with 9% of Utah customers participating in an Irrigation TOU program. It is assumed PacifiCorp would be able to increase participation with a revised program design, using a more dramatic peak-to-off-peak rate differential. Participation rates shown are incremental to current participation in states with an existing irrigation TOU rate.
Event participation (%)	100%	Event participation is captured in the average load impact.

Nonresidential CPP

Under a CPP program, customers receive a discount on their normal retail rates during non-critical-peak periods in exchange for paying premium prices during critical-peak events. As the peak price has been determined in advance, however, customers receive some degree of certainty regarding participation costs. The basic rate structure is a TOU tariff, with the rate using 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 would be replaced with a much higher price, generally set to reflect the utility's avoided supply cost during peak periods.

The Cadmus team estimates 2 MW market potential in the Rocky Mountain Power territory, with an additional 1 MW of market potential in the Pacific Power territory The majority of market potential occurs in the industrial sector, dominated by Utah, Wyoming, and Oregon loads.

CPP costs remain relatively low, ranging from $9/kW-year in Oregon and Utah to $96/kW-year in California, as shown in Table 33. Given the program assumption of a minimum 1,000 kW, no metering costs are included, as customers of this size already would have an interval meter. Additionally, pricing programs do not require incentive payments and have minimal administrative costs. As with irrigation TOU, cost variations result from the amount of load that can be reduced by a single customer (as marketing costs are tied to participants and not to the load reduced) as well as from costs associated with starting up the program (assumed to be the same in each state, regardless of participation).

Table 33. Nonresidential CPP: Market Potential (MW in 2032) and Levelized Cost by State ($/kW-yr)

Territory	State	Market (MW)	Levelized Cost ($/kW-yr) *
Pacific Power	California	0.03	$96
	Oregon	0.91	$9
	Washington	0.15	$25
	Subtotal	**1.09**	**$14**
Rocky Mountain Power	Idaho	0.08	$38
	Utah	1.39	$9
	Wyoming	0.90	$10
	Subtotal	**2.37**	**$11**
	Total	**3.46**	**$12**

* Subtotals and totals are weighted by market potential.

Table 34 and Table 35 show details on cost assumptions for the Nonresidential CPP program.

Table 34. Nonresidential CPP: Program Basics

Program Element	Assumption
Customer sectors eligible	All C&I market segments.
End uses eligible for program	Total load of all end uses.
Customer size requirements	C&I customers with maximum monthly demand greater than 1,000 kW.
Applicable hours	Top 40 system hours, assuming 10 four-hour events.

Table 35. Nonresidential CPP: Planning Assumptions

Inputs	Value	Source(s) or Rationale
Annual administrative costs	$15,000	Assumes the program will require 1/10 FTE for annual administration.
Technology cost (per new participant)	$0	Assumes customers meeting the program eligibility requirements will already have interval meters in place.
Marketing cost (per participant)	$720/year (first year costs) $72/year (ongoing costs)	Assumes 10 hours of effort by staff, valued at $72/hour. An additional hour per year is assumed for ongoing marketing and customer support.
Overhead: first costs	$150,000	Assumes 1 FTE, 1/2 for Rocky Mountain Power and 1/2 for Pacific Power, to design and launch the program.
Technical potential as % of load basis	5.0%	In the 2010 California Statewide Nonresidential CPP Evaluation, program impacts ranged from 2.8% to 5.26% of load for SCE, SDG&E and PG&E. In 2011, load impacts ranged by utility: PG&E averaged 5.9%, SCE averaged 5.7% and SDG&E averaged 5.8%.
Program participation (%)	4.0% CA, 2.4% ID, 2.7% OR, 2.1% UT, 4.5% WA, 2.4% WY	CPP programs typically have low participation rates. California, for example. experienced a 1.1% participation rate across the state, accounting for 2.9% of peak load enrolled. Individual utility participation ranged from 0.1% for SCE to 3.5% for PGG&E in 2005.* PG&E's on-peak energy rates during High-Price Periods and Moderate-Price Periods are five times and three times higher, respectively, than on-peak energy rates during non-event days. SCE's High-Price Periods and Moderate-Price Periods are about 9.3 times and 3.3 times higher, respectively, than on-peak rates during non-event days. (Quantum Consulting 2005 Evaluation of Nonresidential Day-Ahead and Reliability Demand Response Programs). Values are expected to vary across states, depending on their customer mix. For example, certain industries (such as mining in Wyoming) are less likely to participate.
Event participation (%)	100%	As technical potential includes customers who did and did not submit bids, there is a default event participation rate of 100%.

*Cadmus relied on data from the 2005 California CPP programs because the programs offered then were similar in design to PacifiCorp (opt-in), whereas currently, California only offers opt-out programs to its commercial and industrial customers.

Demand Buyback

Under DBB, the utility offers payments to large C&I customers for reducing their demand when requested by the utility. The customer remains on a standard rate but has the option to voluntarily bid or propose load reductions in response to the utility's request. The bid amount generally depends on market prices posted by the utility ahead of the curtailment event, and the reduction level is verified against an agreed-upon baseline usage level. PacifiCorp's existing Energy Exchange is a typical DBB program.

Market electricity prices tend to be the main participation drivers in this program. PacifiCorp's Energy Exchange program has seen minimal participation in recent years, primarily due to electricity prices (and therefore posted prices to participating customers) having been too low to spur participation. As shown in Table 36, results from this assessment indicate 14 MW could be achieved during an event in the Rocky Mountain Power territory. In the Pacific Power territory, 5 MW of potential will likely be achievable during any one event. As described below, these potentials assume future market prices would warrant PacifiCorp making higher per-kW payments than seen recently in the Energy Exchange. Despite minimal participation in recent years, PacifiCorp could rely on existing program infrastructures to reduce costs to $26/kW-year, making DBB a relatively low-cost option.

Table 36. Demand Buyback: Market Potential (MW in 2032) and Levelized Cost by State ($/kW-yr)

Territory	State	Market Potential (MW)	Levelized Cost ($/kW-yr) *
Pacific Power	California	0.1	$26
	Oregon	4.2	$26
	Washington	0.7	$26
	Subtotal	**5.1**	**$26**
Rocky Mountain Power	Idaho	0.4	$26
	Utah	9.2	$26
	Wyoming	4.2	$26
	Subtotal	**13.7**	**$26**
	Total	**18.8**	**$26**

* Subtotals and totals are weighted by market potential.

Table 37 and Table 38 show detailed assumptions for DBB.

Table 37. Demand Buyback: Program Basics

Program Element	Assumption
Customer sectors eligible	All C&I market segments.
End uses eligible for program	Total load of all end uses.
Customer size requirements	C&I customers with maximum monthly demand greater than 1,000 kW.
Applicable hours	Top 50 system hours.

Table 38. Demand Buyback: Planning Assumptions

Inputs	Value	Source(s) or Rationale
Annual administrative costs	$75,000	Assumes 1/2 FTE to run the program system-wide.
Technology cost (per new participant)	$0	Assumes customers who meet the program eligibility requirements will already have interval meters in place.
Marketing cost (per new participant)	$720/year (first year costs) $72/year (ongoing costs)	Assumes 10 hours of effort by staff, with an additional hour per year assumed for ongoing marketing and customer support.
Incentives (annual costs per participating kW)	$20	Assumes $0.40 per kWh for 50 hours of interruption. This figure is slightly lower than the $0.50 per kWh paid by California utilities.
Overhead: first costs	$75,000	Assumes 1/2 FTE, 1/4 for Rocky Mountain Power, and 1/4 for Pacific Power, to expand current program offerings.
Technical potential as % of load basis	7%	The average total load shed during events, accounting for customers who did and did not submit a bid (event participation), was 7% for PG&E and 7.6% for SCE (*2011 Statewide Demand Bidding Programs for Nonresidential Customers:* Report, Christensen Associates).
Program participation (%)	13% CA, 8% ID, 9% OR, 10% UT, 15% WA, 8% WY	Participation rates are based on SCE's participation 2011 rate of 10.8%. Values are expected to vary across states, depending on the customer mix in each. For example, certain industries (such as mining in Wyoming) are less likely to participate.
Event participation (%)	100%	As technical potential includes customers who did and did not submit bids, a default event participation rate of 100% was assumed.

CLASS 2 DSM (ENERGY-EFFICIENCY) RESOURCES

Scope of Analysis

Assessing Class 2 DSM (energy-efficiency) resources primarily focused on updating estimates of available potential in PacifiCorp's service territory (Rocky Mountain Power and Pacific Power, excluding Oregon) over a 20-year planning horizon (2013 to 2032). This study separately examined technical and achievable technical potential for residential, commercial, industrial, irrigation, and street lighting sectors in California, Idaho, Utah, Washington, and Wyoming.[29]

Within each state's sector-level assessment, the study further distinguished customer segments or facility types, and their respective applicable end uses. The analysis addressed:

- Six residential segments (existing and new construction for single-family, multifamily, and manufactured homes);
- Twenty-four commercial segments (12 building types within existing and new construction);
- Fourteen industrial segments (existing construction only);
- Four street lighting segments (new and existing customer-owned and company-owned for existing fixtures)[30]; and
- One segment for irrigation.

Table 39, Table 40, and Table 41 show the full set of customer segments and end uses for each sector analyzed in this study. Volume II, Appendix C, provides a comprehensive list of state- and sector-specific segments and end uses.

29 The Energy Trust of Oregon, which delivers energy efficiency in Oregon, completed an assessment of potential in PacifiCorp's Oregon service territory in 2012: http://energytrust.org/library/reports/121114_2012_ResourceAssessment.pdf.

30 New construction was not modeled in Utah or Wyoming due to lack of forecasted load growth

Table 39. Residential Sector Dwelling Types and End Uses

Residential Customer Segments	End Uses
Manufactured	Computer
Multifamily	Cooking oven
Single-family	Cooking range
	Copier
	Dehumidifier
	Dryer
	DVD
	Freezer
	Heat pump
	Home audio system
	Lighting interior specialty
	Lighting standard (interior and exterior)
	Microwave
	Monitor
	Multifunction device
	Other
	Plug load other
	Pool pump
	Printer
	Refrigerator
	Set top box
	Space cooling - central
	Space cooling - room
	Space heating - central
	Space heating - room
	TV
	Ventilation and circulation
	Water heating <= 55 gal
	Water heating > 55 gal

Table 40. Commercial Sector Customer Segments and End Uses

Commercial Customer Segments	End Uses
Grocery	Computer
Health	Cooking
Office—large	Fax
Office—small	Flat screen monitors
Lodging	Freezers
Miscellaneous	Heat pump
Restaurant	Lighting exterior
School	Lighting interior fluorescent
Retail—large	Lighting interior HID
Retail—small	Lighting interior other
Warehouse	Lighting interior screw base
Warehouse – controlled atmosphere	Other
	Other plug load
	Photo copiers
	Printers
	Refrigeration
	Refrigerators
	Servers
	Space cooling - chillers
	Space cooling - DX evap
	Space cooling - room
	Space heat
	Vending machines
	Ventilation and circulation
	Water heat <= 55 gal
	Water heat > 55 gal

Table 41. Industrial Sector Customer Segments and End Uses

Industrial Customer Segments (NAICS)	Electric End Uses
Agriculture	HVAC
Chemical manufacturing	Indirect boiler
Electronic manufacturing	Lighting
Food manufacturing	Process electro chemical
Industrial machinery	Process heat
Lumber wood products	Process other
Miscellaneous manufacturing	Process cool
Paper manufacturing	Fans
Petroleum manufacturing	Pumps
Stone clay glass products	Process aircomp
Transportation equipment manufacturing	Process refrig
Mining	Motors other
Metal manufacturing	Other
Wastewater	
Water	

The study included examining a comprehensive set of energy-efficiency measures, incorporating measures assessed by the Council in its 6th Power Plan, the RTF, and the Energy Trust of Oregon, as well as those within the Cadmus team's library of measures. Analysis began by assessing the technical potential of hundreds of unique energy-efficiency measures (actual quantities are shown in Table 42). Considering all permutations of these measures across states, customer sectors, customer segments, end uses, and construction vintages required compiling and analyzing customized data for over 19,000 measure permutations. Volume II, Appendix B, provides a complete list of energy-efficiency measures analyzed in all states.

Table 42. Class 2 DSM Measure Counts*

Sector	Measure Counts	Measure Permutations
Residential	131	3,262
Commercial	145	12,284
Industrial	93	3,640
Irrigation	3	15
Street lighting	4	64
Total	**376**	**19,265**

* Measure counts and permutations represent only measures with potential energy-efficiency savings. Appendix C-2 includes the comprehensive list of energy-efficiency measures considered in this study.

The remainder of this section is divided into four parts:

- A detailed description of the methodology used for estimating the technical and achievable technical Class 2 DSM potential;
- Class 2 DSM resource potential, by state and sector;

- Detailed Class 2 DSM resource potential for each sector, by segment and end use; and
- A comparison of these results with the 2011 Assessment.

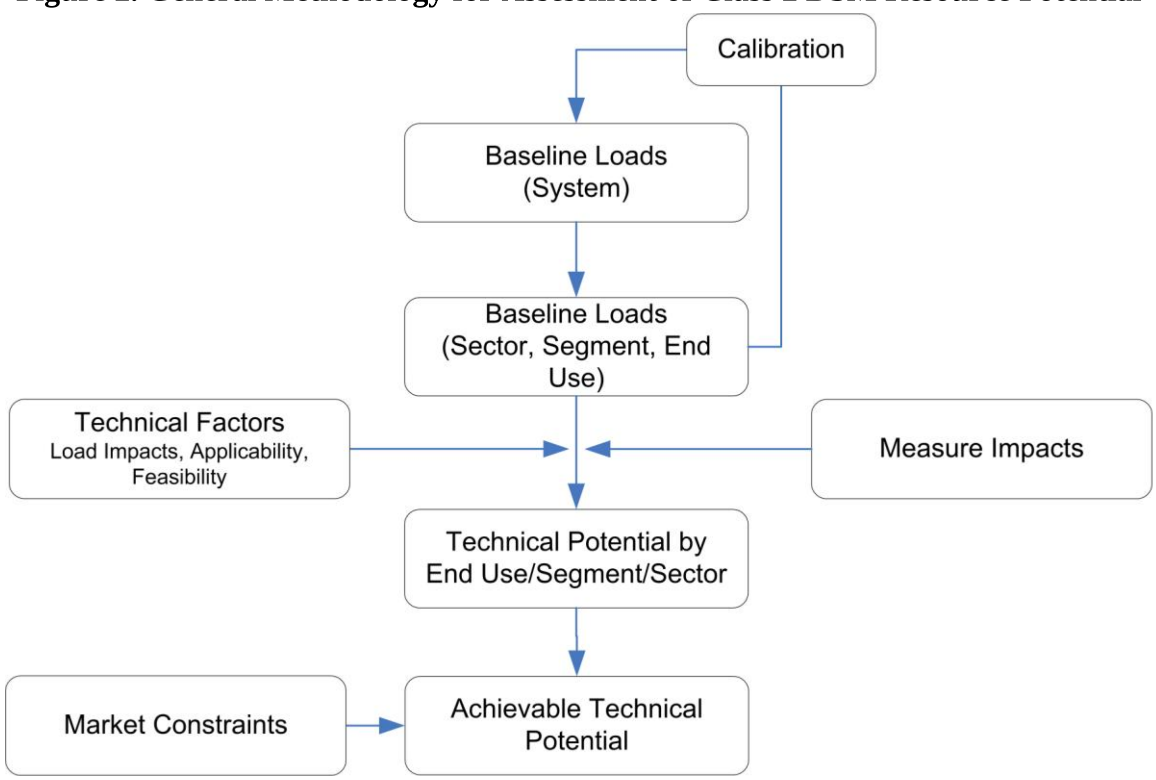
Assessment Methodology

General Approach

The Cadmus team's general methodology can be best described as a combined "top-down/bottom-up" approach. As shown in Figure 2, the top-down component began with the most current load forecast, adjusting for building codes, equipment efficiency standards, and market trends not accounted for in that forecast, then decomposing this into its constituent customer sector, customer segment, and end-use components. The bottom-up component considered potential technical impacts of various Class 2 DSM measures and practices on each end use. Impacts could then be estimated, based on engineering calculations and accounting for fuel shares, current market saturations, technical feasibility, and costs.

In this chapter, these unique, measure-level impacts have been aggregated to produce resource potential estimates at the end use, customer sector, state, and service territory levels. Summaries of resource potential, by state, sector, and end use can be found in Appendix C-4.

Figure 2. General Methodology for Assessment of Class 2 DSM Resource Potential



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 energy-efficiency 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.
- 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 Class 2 DSM 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 Class 2 DSM 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 within PacifiCorp's service area, such as those of the Council in developing regional energy-efficiency potential, and remained consistent with methods used in PacifiCorp's 2007 and 2011 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, as identified levels of achievable technical potential principally serve as planning guidelines and to inform the IRP process. The Ramp Rate section of this chapter further describes the amount of technical potential considered achievable on an annual basis beginning in 2013.

Developing sound utility IRPs requires knowledge of alternative resource options and reliable information on the long-run resource potential of achievable technologies. 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.

Overview

Estimating Class 2 DSM potential draws on a sequential analysis of various energy-efficiency measures in terms of technical feasibility (technical potential) and expected market acceptance, considering normal barriers possibly impeding measure implementation (achievable technical potential). The assessment utilized 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, 2012, to PacifiCorp's sector load forecasts in each state. It then removed PacifiCorp's special accounts to ensure a forecast appropriate for Class 2 DSM activity.[31] As described above, the baseline forecasts shown in this report include the Cadmus team's estimated impacts of naturally occurring potential.[32]
- ***Estimation of alternative forecasts of technical potential:*** Estimating technical potential, based on alternative forecasts, that reflect technical impacts of specific energy-efficiency 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 PacifiCorp's base year (2012) sales. Although subsequent baseline years may differ from PacifiCorp's load forecast, comparisons to PacifiCorp'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-efficiency measures. As estimated savings represented the difference between the baseline and alternative forecasts, they could be directly attributed to specific changes made to analysis inputs.

Data Sources

Full assessment of Class 2 DSM resource potential required compiling large amounts of measure-specific technical, economic, and market data from secondary sources and primary research. Main data sources used in this study included:

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[31] These accounts have significant loads and work with key account managers to manage these loads.

[32] The Cadmus team's baseline forecast accounted for codes and standards not embedded in PacifiCorp's load forecast. In addition, the baseline drew upon end-use saturations, which generally align with those in PacifiCorp's load forecast, though some end-use saturations may differ after accounting for future Class 2 DSM activity or because Cadmus used other, more recent data sources in the baseline. Due to these adjustments, 2032 baseline sales presented in this report may not match PacifiCorp's official load forecast.

- ***PacifiCorp:*** 2012 sales forecasts, historic and projected energy-efficiency activities, current customer counts and forecasts, and the recent Energy Decisions Survey. Table 43 shows a complete list of data elements provided by PacifiCorp.

Table 43. PacifiCorp Data Sources Used in Class 2 DSM Analysis

Data Element	Key Variables	Use in This Study
2011 sales and customer counts	Numbers of customers and total sales by state and customer segment.	Data used for customers and sales for calibration in the end-use model.
2012 sales and customer forecasts	Sales and customer forecasts by state and customer sector, excluding projected DSM activity.	Informs end-use model base case forecast, with new customers serving as drivers in end-use model development.
Historic and projected Class 2 DSM program achievements	Program participation, number of measures installed, and savings.	Measure saturations; validation of measure characterizations (savings, costs).
2006 Residential Energy Decisions Survey	Dwelling characteristics, equipment saturations, and fuel shares.	Dwelling type breakouts; square footage per dwelling; applicability factors; incomplete factors; development of building simulation prototypes' forecast calibration.
2005 and 2007 Commercial Energy Decisions Surveys	Building characteristics, equipment saturations, and fuel shares.	Building type breakouts; square footage per dwelling; measure applicability factors; development of building simulation prototypes; forecast calibration.
2011 FinAnswer® Express Market Characterization Studies	Measure data.	Measure savings; costs and useful life assumptions.
2009–2010 Program Evaluation Reports	Savings estimates.	The savings estimates for measures were based on recent evaluation studies, as available.

- ***Building Simulations:*** This study relied on normal consumption and load profile estimates for the majority of end uses in commercial segments, as developed for the 2007 Assessment using the eQuest building simulation models. Energy intensities have been adjusted to account for pertinent codes and standards adopted since the 2007 Assessment. The current assessment required development of new building simulations (using SEEM) for the residential sector, with separate models created for each state, customer segment, and construction vintage.[33]

- ***Pacific Northwest Sources:*** Several Northwest entities provided data critical to this study, including the Council and the RTF. Data included technical information on measure savings, costs, and useful lives; hourly end-use load shapes (to supplement buildings simulations, as described above); and commercial building physical and energy consumption characteristics. Table 44 provides further details.

[33] For details on eQuest and SEEM (v.94), see (respectively): http://www.doe2.com and http://www.nwcouncil.org/energy/rtf/measures/support/SEEM/Default.asp.

Table 44. Class 2 DSM Pacific Northwest Data Sources

Pacific Northwest Data Source	Key Variables	Use in This Study
Council 6th Power Plan	Measure data estimates.	Measure savings, costs, and lives; cross-check of potential estimates.
Council Hourly Electric Load Model	Hourly load shapes.	Hourly end-use load shapes for the residential, commercial, and industrial sectors.
RTF Website	Measure data.	Measure savings, costs, and lives.

- ***California Energy Commission (CEC):*** This study used information available in the 2005 and 2008 Database of Energy Efficiency Resources (DEER) to validate many assumptions and data collected on energy-efficiency measure costs and savings.
- ***Ancillary Sources:*** Other data sources primarily consisted of available information from the 2007 and 2011 Assessments; past energy-efficiency market studies; energy-efficiency potential studies; and evaluations of energy-efficiency programs offered throughout the country. In addition to the previously cited PacifiCorp Market Characterization Studies and the Council's 6th Power Plan, data sources included the U.S. Department of Energy Industrial Assessment Centers Database and reports from the Northwest Energy Efficiency Alliance (NEEA) on its Industrial Efficiency Alliance Initiative and Emerging Technologies and Behaviors for Energy Efficient Industrial Refrigeration.

Baseline Forecasts

PacifiCorp's state- and sector-level sales and customer forecasts provided the basis for assessing energy-efficiency potential. Prior to estimating potential, the study disaggregated state- and sector-level load forecasts by customer segment (business, dwelling, or facility types), building vintage (existing structures and new construction), and end uses (all applicable end uses in each customer sector and segment).

The first step in developing the baseline forecasts determined the appropriate customer segments within each state and sector. Designations drew upon categories available in some key data sources used in the study, primarily PacifiCorp's 2011 customer database and the recent Energy Decisions Survey, followed by mapping appropriate end uses to relevant customer segments in each state.[34]

Once appropriate customer segments and end uses had been determined for each sector, the study produced the baseline end-use forecasts, based on integration of current and forecasted customer counts with key market and equipment usage data. For the commercial and residential sectors, calculating total baseline annual consumption for each end use in each customer segment used the following equation:

[34] Not all segments were modeled in all states. For example, the large office segment did not prove relevant in the entirely rural California service territory. Similarly, not all end-uses within a sector necessarily proved relevant in every customer segment (e.g., cooking typically is not present in the commercial sector's warehouse segment).

$$EUSE_{ij} = \Sigma_e\ ACCTS_i * UPA_i * SAT_{ij} * FSH_{ij} * ESH_{ije} * EUI_{ije}$$

where:

$EUSE_{ij}$ = total energy consumption for end use *j* in customer segment *i*

$ACCTS_i$ = the number of accounts/customers in customer segment *i*

UPA_i = units per account in customer segment *i* (UPA_i generally the average square feet per customer in commercial segments, and 1.0 in residential dwellings, assessed at the whole-home level)[35]

SAT_{ij} = the share of customers in customer segment *i* with end use *j*

FSH_{ij} = the share of end use *j* of customer segment *i* served by electricity

ESH_{ije} = the market share of efficiency level *e* in equipment for customer segment and end use *ij*

EUI_{ije} = end-use intensity: energy consumption per unit (per square foot for commercial) for the electric equipment configuration *ije*

For each sector, total annual consumption could be determined as the sum of *EUSEij* across the end uses and customer segments. Ensuring accuracy of the baseline forecasts depended on the calibration of end-use model estimates of total consumption to PacifiCorp's forecasted sales from 2012.

Consistent with other potential studies, and commensurate with industrial end-use consumption data (which varied widely in quality), allocating the industrial sector's loads to end uses in various segments drew on data available from the U.S. Department of Energy's Energy Information Administration (EIA).[36] For the irrigation sector, the total load in each state has been well established, consisting almost entirely of pumping, with a small amount of energy in system controls and motor drives for wheel-based systems. Street lighting loads were allocated based on PacifiCorp data on company versus customer ownership and on the number and type of fixtures present in each state.

Volume II, Appendix C, provides summaries of baseline forecasts for each state and sector.

Derivation of End-Use Consumption Estimates

Estimates of end-use energy consumption by segment, end use, and efficiency level (EUI_{ije}) provide one of the most important components in developing a baseline forecast. In the residential sector, the study based estimates on unit energy consumption (UEC), representing annual energy consumption associated with an end use (represented by a specific type of equipment, such as a central air conditioner or heat pump).

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[35] The average square footage by home type was entered into building simulations used in the SEEM models; therefore, the results reflected weather and home size differences between states.

[36] U.S. Department of Energy (DOE), EIA. 2006. *Manufacturing Energy Consumption Survey*.

For the commercial sector, the study treated consumption estimates as end-use intensities (EUIs), representing annual energy consumption per square foot served. Accuracy of these estimates proved critical, as they had to account for weather and other factors, described below, that drive differences between various states and segments.

For the industrial sector, end-use energy consumption represented total annual industry consumption by end use, as allocated by the secondary data, described above. In irrigation energy consumption, nearly all usage was allocated to the pumping end use, and a small amount was allocated to "other."[37] Street lighting was allocated entirely to lighting and was segmented to company- or customer-owned fixtures.

The study derived many end-use consumption estimates from building simulation models (eQuest and SEEM for commercial and residential segments, respectively) to account for key regional differences, including weather, state codes, building sizes, and shell characteristics. For non-weather-sensitive end uses that could not be modeled within a building simulation framework (e.g., residential refrigerators), the study used consumption estimates from ENERGY STAR; the EIA's Residential Energy Consumption Survey (RECS) and the Commercial Buildings Energy Consumption Survey (CBECS); the 2007 Commercial Building Stock Assessment (CBSA)[38] completed by NEEA; and the 2006 California Commercial End-Use Survey.[39]

Most key drivers used in developing commercial simulation models (operating schedules, setback temperatures, and building sizes) drew upon data in PacifiCorp's Energy Decisions Survey.[40] The study based residential simulation models on the RTF's SEEM models for its energy-efficiency measures. To create a simulation, SEEM used a number of input parameters, including those for occupancy, equipment, ducts, envelope, foundations, and infiltration. The Cadmus team updated the SEEM models specifically for PacifiCorp's service territory. Volume II, Appendix C, summarizes end-use consumption estimates for residential (UECs), commercial (EUIs), and industrial (end-use percentages).

Energy-Efficiency Measures

As technical potential drew upon an alternative forecast, reflecting installation of all technically feasible measures, selecting appropriate Class 2 DSM resources to include in this study posed a central concern. To alleviate the concern and arrive at the most robust set of appropriate measures, for the residential and commercial sectors the study began with a broad range of energy-efficiency measures for possible inclusion, screened to include only measures commonly available, based on well-understood technologies, and applicable to PacifiCorp's buildings and end uses. Many of these measures are included in the Council's 6th Power Plan and/or assessed

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37 Non-pumping end uses include system controls and motor drives for wheel-based systems.

38 http://neea.org/resource-center/regional-data-resources/commercial-building-stock-assessment

39 http://www.energy.ca.gov/ceus/

40 Extensive efforts sought to validate and cross-check results from the Energy Decisions Survey with data from other sources, including CBECS, CBSA, and other available studies.

by the RTF. The industrial sector measures drew upon the Council's 6th Power Plan and on other general categories of process improvements.[41]

Table 45, Table 46, and Table 47 outline types of energy-efficiency measures assessed in the residential, commercial, and industrial sectors, respectively. Equipment measures replace end-use equipment (e.g., high-efficiency central air conditioners), while non-equipment measures reduce end-use consumption without replacing end-use equipment (e.g., insulation). Volume II, Appendix B, provides a complete list of all measures, including descriptions.

Table 45. Residential Energy-Efficiency Measures Types

End Use	Measure Types
Heating and cooling	*Non-Equipment*: air-to-air heat exchangers; insulating concrete form and structural insulated panel construction; cool roof and green roof; ceiling, wall (2x4, 2x6), floor and slab insulation; insulated exterior doors and weatherstripping; duct sealing and insulation; HVAC unit quality installation and tune-up; efficient windows; whole-house fan; infiltration control; new home thermal shell with low infiltration; multi-zone thermostat; radiant barrier. *Equipment*: high-efficiency heat pump; ground source heat pump; high-efficiency central AC; ENERGY STAR room AC; ductless heat pump; evaporative cooler; heat pump conversion.
Ventilation and circulation	*Equipment*: ECM motor.
Lighting	*Non-Equipment*: daylighting control; occupancy sensor; time clock. *Equipment*: compact fluorescent lamps (CFL); light emitting diodes (LED).
Water heating	*Non-Equipment*: hot water pipe insulation; faucet aerators; low-flow showerheads; ENERGY STAR dishwasher and clothes washer; drain water heat recovery. *Equipment*: high-efficiency storage and heat pump water heaters.
Appliances	*Non-Equipment*: removal of standalone freezers and secondary refrigerators. *Equipment*: ENERGY STAR freezers and refrigerators; high-efficiency cooking ovens, ranges, and dryers.
Plug load	*Non-Equipment*: smart strip; ENERGY STAR battery charger. *Equipment:* ENERGY STAR computer, monitor, TV, set top box, dehumidifier, DVD player, home audio system, multifunction device, copier, and printer; high-efficiency microwave.
Pool pump	*Equipment*: pool pump.

[41] Industrial improvements derived from a variety of practices and specific measures, such as those defined in the DOE's Industrial Assessment Centers Database: http://www.iac.rutgers.edu/database/

Table 46. Commercial Energy-Efficiency Measures Types

End Use	Measure Types
HVAC	*Non-Equipment*: ceiling, wall, and floor insulation; duct repair, sealing, and insulation; windows; equipment tune-up; automated ventilation control; pre-cooling; direct digital control system optimization; constant air to variable-air volume (VAV) conversion; high-efficiency VAV box; economizers; exhaust air to ventilation air heat recovery and variable frequency drive (VFD) control; re-commissioning; exhaust hood makeup air; chilled water/condenser water settings-optimization; chilled water piping loop with VSD control; cooling tower approach temperature; two-speed and variable-speed fan; pipe insulation for chillers; cool and green roof; natural ventilation; infiltration reduction; new construction Integrated Building Design; window film; hotel key card control; high-efficiency motor, motor rewind and VFD; low-pressure distribution complex; cooking hood controls; optimized variable volume lab hood. *Equipment*: high-efficiency heat pumps; high-efficiency chillers, packaged terminal AC units, and DX packages; ground source heat pump; evaporative cooler.
Lighting	*Non-Equipment*: daylighting, continuous and stepped dimming controls; bi-level control; occupancy sensors; efficient refrigeration lighting and exit signs; time clock; exterior building lighting; surface and covered parking lighting; solid state LED white lighting; new construction integrated building design. *Equipment*: high-efficiency fluorescent, induction, metal halide, CFL, LED, and lighting packages
Water heating	*Non-Equipment*: hot water pipe insulation; high-efficiency chemical, residential, and commercial dishwashing systems; demand controlled circulating systems; low-flow showerheads, spray heads, and faucet aerators; ultrasonic faucet control; commercial- and residential-sized clothes washers; water cooled refrigeration with heat recovery; drain water heat recovery water heater. *Equipment*: high-efficiency water heater; heat pump water heater.
Refrigeration	*Non-Equipment*: compressor and rooftop unit supply fan VFD; demand control defrost; strip curtains; floating condenser head pressure control; anti-sweat controls; glass and solid door refrigerator/freezer; walk-in and case electronically commutated motors (ECM) and controllers; case replacement; display case night cover and motion sensor; standalone to multiplex compressor; commissioning or re-commissioning; visi cooler; vertical and semi-vertical no doors refrigeration.
Appliances	*Non-Equipment:* appliance recycling. *Equipment*: ENERGY STAR freezers and refrigerators.
Plug load	*Non-Equipment:* network PC power management and server virtualization; power supply transformer/converter; smart strip; high-efficiency ice maker; ENERGY STAR battery charging system, scanner, and water cooler. *Equipment:* ENERGY STAR computer, monitor, fax, copier, printer, and vending machine; high-efficiency server.
Cooking	*Non-Equipment:* High-efficiency combination and convection oven, fryer, griddle; ENERGY STAR hot food holding cabinet and steam cooker.

Table 47. Industrial Energy-Efficiency Measures Types

Measure Types
Agricultural process improvements
Air compressor improvements
Building improvements
Circulating fans
Clean room improvements
Cold storage retrofit/tune-up
Compressor improvements
Electric chip fabrication improvements
Facility energy managements/recommissioning
Fan system improvements
General process improvements
High-efficiency motors
HVAC equipment improvements
Improved controls
Lighting controls
Lighting equipment improvements
Motor rewinds
Process heat operations and maintenance
Properly sized fans
Pump improvements
Refrigeration improvements
Switch from belt drive to direct drive
Synchronous belts
Transformers
Variable speed drives
Ventilation system improvements

In addition, street lighting and irrigation sectors both have efficiency measures. Street lighting measures replace existing high-pressure sodium or mercury vapor lighting with LEDs. Irrigation measures include scientific irrigation scheduling (SIS), high-efficiency motors, and other system improvements.

Measure Impacts

Assessing technical potential began by estimating measure-level impacts, which required compiling and analyzing data on the following characteristics for each measure:

- ***Measure savings*:** Energy savings associated with a measure, as a percentage of total end-use consumption. Sources included: standard engineering algorithms, energy simulation modeling, the Council's 6th Power Plan, RTF, PacifiCorp's 2011 FinAnswer® Express market characterization studies, secondary data sources (case studies), and the California DEER database.

- ***Measure life*:** The measure's expected useful life. Sources included: the DEER database, the Council's 6th Power Plan, other potential studies, and DSM program evaluations.

- ***Measure applicability*:** A general term encompassing a number of factors, including the technical feasibility of installation, the measure's current or naturally occurring saturation, and sharing of energy savings with competing measures. Sources include Council's 6th Power Plan, RTF, and the DEER database.
- ***Measure costs*:** Per-unit costs (either full or incremental, depending on the application) associated with measure installation. Sources included the Council's 6th Power Plan, RTF, RS Means, the DEER database, merchant Websites (e.g., Home Depot, Trane), and other secondary sources.
- ***Operations and maintenance (O&M) costs*:** A measure's annual operation and maintenance costs. These may be positive or negative, compared to the baseline, and are subtracted from the measure's net present value cost when calculating its cost of conserved energy. This study only included O&M costs for Washington and Idaho.
- ***Non-energy benefits*:** Additional benefits attributable to a measure, such as water savings, and accounted for in the measure's net present value cost when calculating its cost of conserved energy. This study only included non-energy benefits for Washington and Idaho.
- ***Secondary energy benefits*:** Additional energy benefits attributable to a measure, such as natural gas savings,[42] subtracted from the measure's net present value cost when calculating costs of conserved energy (also only included for Washington and Idaho).
- ***Conservation Credit*:** The 10% regional conservation credit used in the 6th Power Plan is not included in the levelized costs presented in this report. PacifiCorp will apply the credit for Class 2 DSM resources in Washington in the IRP modeling process.[43]

About Technical Potential

Technical potential represents total energy available to be saved from all measures, adjusting only for applicability. For example, high wall insulation levels can be placed in a certain percentage of homes, a certain share of which may already have such insulation in place. Consequently, technical potential only includes technically feasible homes without measures in place.

Another important aspect in assessing technical potential is, wherever possible, to assume installation of the highest-efficiency equipment. For example, this study examined CFL and LED general service lighting in residential applications and, in assessing technical potential, assumed that, as equipment fails or new homes are built, customers will install LED lighting wherever technically feasible regardless of cost. CFLs would be assumed installed in sockets ineligible for LEDs, where applicable. Competing non-equipment measures have been treated the same way, assuming installation of the highest-saving measures where technically feasible.

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[42] The study conducted analysis at an end-use level. For example, for a measure applied to an air conditioning end-use, these benefits included the value of heating energy saved across electric and natural gas heating fuels.

[43] PacifiCorp will also apply a 10% conservation credit to Class 2 DSM savings in Oregon for IRP modeling.

In estimating technical potential, one cannot merely sum up savings from individual measure installations, as significant interactive effects can result from the 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 upgrades 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 accounted for such interactions by "stacking" interactive measures—iteratively reducing baseline consumption as measures were installed, thus lowering savings from subsequent measures.

While 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 assumed the realization 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 annual incremental and cumulative potential was estimated by state, sector, segment, construction vintage, end use, and measure.

About Achievable Technical Potential

Achievable technical potential can be defined as the portion of technical potential expected to be reasonably achievable in the course of a planning horizon. The quantity of energy-efficiency potential realistically achievable depends on several factors, including the customers' willingness to participate in energy-efficiency programs (partially a function of incentive levels), retail energy rates, and a host of market barriers historically impeding adoption of energy-efficiency measures and practices by consumers.[44] These barriers tend to vary, depending on the customer sector, local energy market conditions, and other, hard-to-quantify factors. Assessing achievable

[44] Consumers' apparent unwillingness to invest in energy efficiency has been attributed to certain energy-efficiency market barriers. A rich body of literature exists concerning the "market barriers to energy efficiency." In one such study, market barriers identified fell into five broad classes of market imperfections, thought to inhibit energy-efficiency investments: (1) misplaced or split incentives; (2) high upfront costs, and a lack of access to capital; (3) a lack of information, and uncertainty concerning the benefits, costs, and risks of energy-efficiency investments; (4) investment decisions guided by convention and custom: and (5) time and "hassle" factors. For a discussion of these barriers, see: William H. Golove and Joseph H. Eto. March 1996. "Market Barriers to Energy Efficiency: A Critical Reappraisal of the Rationale for Public Policies to Promote Energy." Lawrence Berkeley National Laboratory, University of California, Berkeley, California. LBL-38059.

technical potential, however, adopts a central tenet that assumes it is ultimately a function of the customers' willingness and ability to adopt energy-efficiency measures; this information can be best ascertained through direct elicitations from potential participants.

Though methods for estimating achievable technical potential vary across potential assessment efforts, two dominant approaches appear to be most widely utilized:

1. The first approach assumes a hypothesized relationship between incentive levels and market penetration of energy-efficiency programs. This achievable potential generally can be defined as that achieved solely through utility incentive programs, and often it is based on an incentive level at 50% of the incremental cost.
2. The second approach generally relies on a fixed percentage of the technical potential, which is based on past experiences with similar programs. In the Northwest, for example, the Council has historically assumed that, by the end of the 20-year assessment horizon, 85% of the technical potential could be achieved, including savings from utility programs, market transformation, and changes in codes and standards.

Consistent with the Council, this study used option two, assuming up to 85% of technical potential could be acquired over the 20-year planning horizon. In addition to applying a fixed percentage, this assessment incorporated ramp rates to estimate annual achievable technical potential. As discussed below, two layers of ramp rates have been incorporated for all measures and market regions.

Estimated achievable technical potential principally serves as a planning guideline. Acquiring such DSM resource levels depends on actual market acceptance of various technologies and measures, which partly depend on removing barriers (not all of which a utility can control).

In addition to utility-sponsored programs, alternative delivery methods, such as existing market transformation efforts and codes and standards promotion, can be used to capture portions of these resources, depending on actual experiences with various programs. This proves particularly relevant in the context of long-term Class 2 DSM resource acquisition plans, where incentives might be necessary in earlier years to motivate acceptance and installations. As acceptance increases, so would demand for energy-efficient products and services, likely leading to lower costs, and thereby obviating the need for incentives and (ultimately) preparing for transitions to codes and standards.

Measure Ramp Rates

The study applied measure ramp rates to lost opportunity and discretionary resources, though interpretation and application of these rates differed for each class (as described below). Measure ramp rates generally matched those used in the Council's 6th Power Plan, although the study incorporated additional considerations for Class 2 DSM measure acquisition:

- The first year of the 6th Power Plan ramp rates (2010) aligned with the study's first year (2013).
- For measures not specified in the 6th Power Plan, the study assigned a ramp rate considered appropriate for that technology (i.e., the same ramp rate as a similar measure in 6th Power Plan).

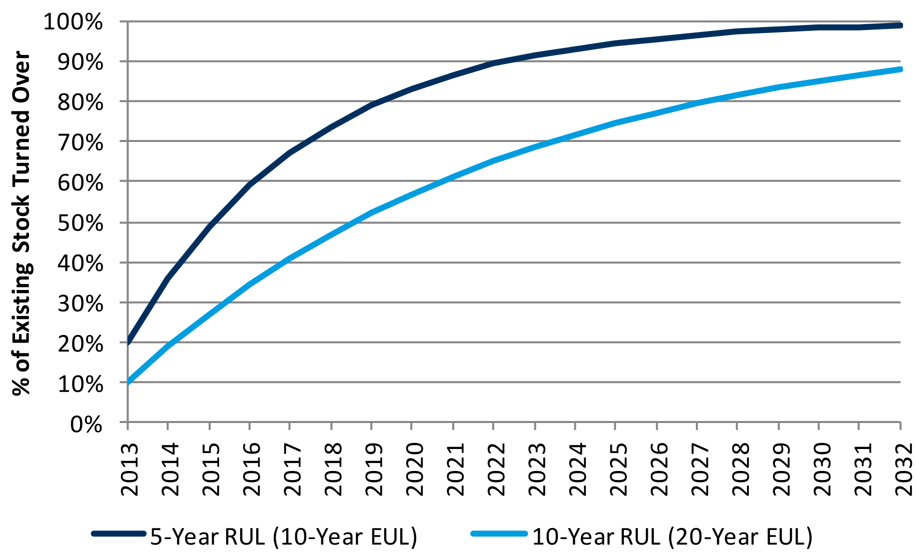
- General service CFLs required use of a custom ramp rate, with the study's CFL penetration estimate in 2013 aligning with PacifiCorp's 2012 activity, market trends, and forecasted 2013 activity.

Lost Opportunity Resources

Quantifying achievable technical potential for lost opportunity resources in each year required determining amounts technically available through new construction and natural equipment turnover. New construction rates drew directly from PacifiCorp's customer forecast. The study developed equipment turnover rates by dividing units in each year by the measure life. For example, if 100 units initially had a 10-year life, one-tenth of units (10) would be replaced. In the following year, 90 units would remain, and one-tenth of these (9) would be replaced, and so on over the study's course.

As the mix of existing equipment stock ages, the remaining useful life (RUL) would be, on average, one-half of the effective useful life (EUL).[45] The fraction of equipment turning over each year would be a function of this RUL; thus, the technical potential for lost opportunity measures would have an annual shape before application of any ramp rates, as shown in Figure 3. The same concept applied to new construction, where resource acquisition opportunities only become available during home or building construction. In addition to showing an annual shape, Figure 3 demonstrates amounts of equipment turning over during the study period as a RUL function: the shorter the RUL, the higher the percentage of equipment assumed to turn over.

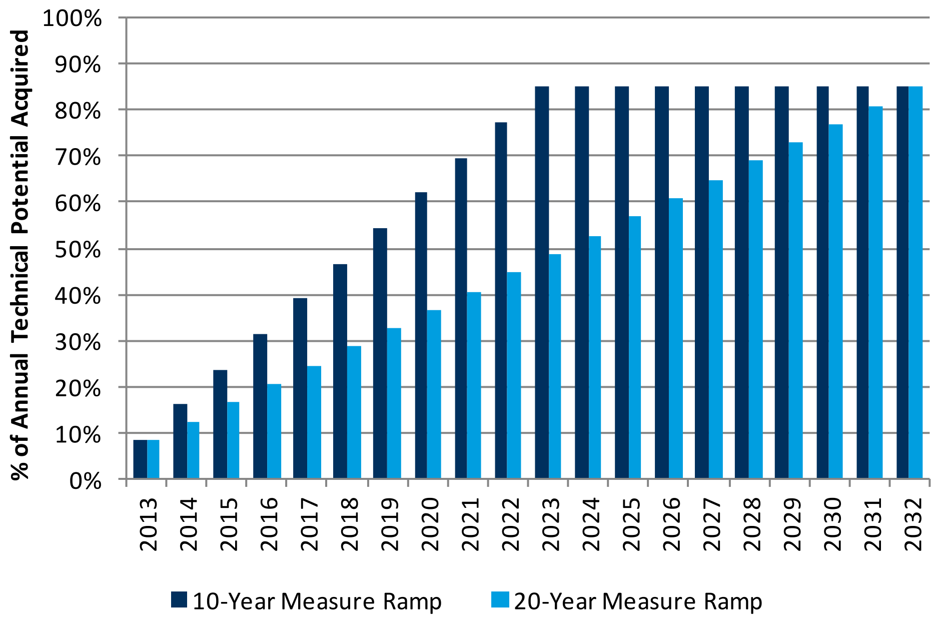
Figure 3. Existing Equipment Turnover for Varying RULs



45 EULs represented median lifetimes, defined as the year that one-half of measures installed remained in place and operable and one-half did not, as defined by the RTF: http://www.nwcouncil.org/energy/rtf/subcommittees/measurelife/RTF%20Measure%20Useful%20Life%20Guidelines%20Final%202012%200515.pdf

In addition to natural timing constraints imposed by equipment turnover and new construction rates, the Cadmus team applied measure ramp rates to reflect other resource acquisition limitations over the study horizon, such as market availability. These measure ramp rates had a maximum value of 85%, reflecting the Council's assumption that, on average across all measures, up to 85% of technical potential could be achieved over a 20-year planning horizon. As illustrated by Figure 4, a measure that ramps up over 10 years would reach full market maturity (85% of annual technical potential) by the end of that period, whereas another measure might take 20 years to reach full maturity.

Figure 4. Examples of Lost Opportunity Measure Ramp Rates



To calculate annual achievable technical potential for each lost opportunity measure, the study multiplied technical resource availability and measure ramping effects together, consistent with the Council's methodology. Particularly in the early years of the study horizon, a gap occurs between assumed acquisition and the 85% maximum achievability. Thus, these "lost" resources can be assumed not available until the measure's EUL elapses. Therefore, depending on EUL and measure ramp rate assumptions, some potential may be pushed beyond the study's 20th year, and total lost opportunity achievable technical potential may be less than 85% of technical potential.

Figure 5 shows such a case for a measure with a five-year RUL/10-year EUL. The spike in achievable technical potential starting in year 2023 (after the measure's EUL) resulted from acquisition of opportunities missed at the beginning of the study period.

Figure 5. Example of Combined Effects of Technical Resource Availability and Measure Ramping Based on 10-Year EUL

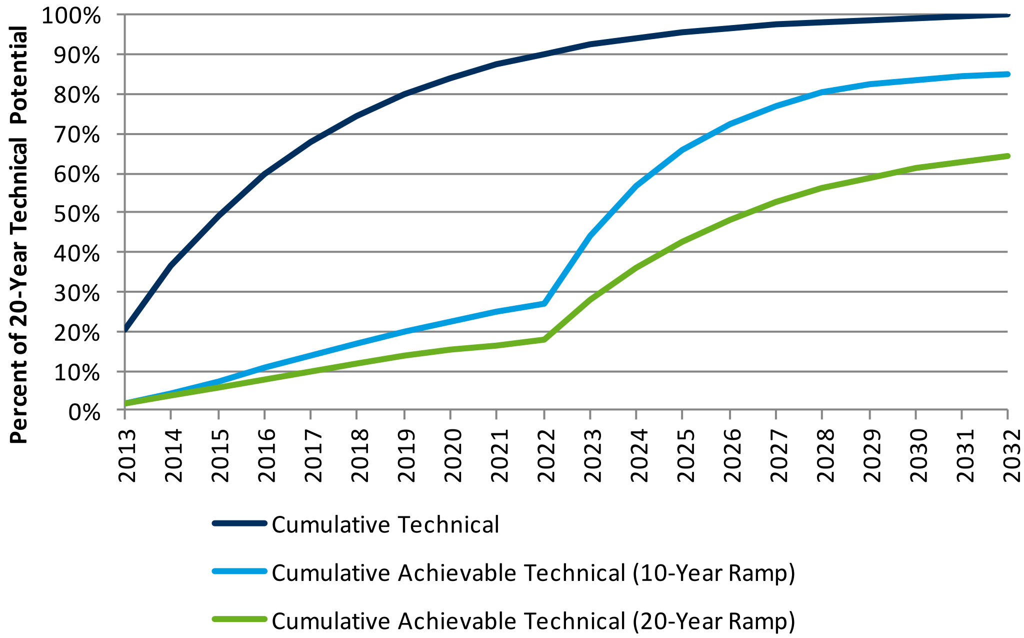


Table 48, below, illustrates this method, based on the same five-year RUL/10-year EUL measure on a 10-year ramp rate (the light blue line in Figure 5), assuming 1,000 inefficient units are in place in 2012. In the first 10 years (2013 through 2022), lost opportunities accumulate as the measure ramp-up rate caps availability of high-efficiency equipment. Starting in 2023 (the 11th year), opportunities lost 10 years prior become available again. Table 48 also shows that this EUL and measure ramp rate combination results in 85% of technical potential achieved by the study period's close.

As described, amounts of achievable technical potential are a function of the EUL and measure ramp rate. The same 10-year EUL measure, on a slower 20-year ramp rate, would achieve less of its 20-year technical potential (also shown in Figure 5). Across all lost opportunity measures included in this study, approximately 72% of technical potential appears achievable over the 20-year study period, a finding consistent with the Council's assumption that less than 85% of lost opportunity resources can be achieved.[46]

[46] *A Retrospective Look at the Northwest Power and Conservation Council's Conservation Planning Assumptions*. April 2007. http://www.nwcouncil.org/library/2007/2007-13.htm

Table 48. Example of Lost Opportunity Treatment: 10-Year EUL Measure on a 10-Year Ramp Rate

Year	Incremental Stock Equipment Turnover (Units)	Cumulative Stock Equipment Turnover (Units)	Measure Ramp Rate	Installed High Efficiency Units	Missed Opportunities for Acquisition in Later Years (Units)	Missed Opportunities Acquired (Units)	Cumulative Units Installed	Cumulative Percent of Technical Achieved
2013	200	200	9%	17	180	0	17	9%
2014	160	360	16%	26	130	0	43	12%
2015	128	488	24%	30	92	0	73	15%
2016	102	590	31%	32	65	0	106	18%
2017	82	672	39%	32	44	0	138	20%
2018	66	738	47%	31	29	0	168	23%
2019	52	790	54%	29	19	0	197	25%
2020	42	832	62%	26	11	0	223	27%
2021	34	866	70%	23	6	0	246	28%
2022	27	893	77%	21	2	0	267	30%
2023	21	914	85%	18	0	153	438	48%
2024	17	931	85%	15	0	110	563	60%
2025	14	945	85%	12	0	78	653	69%
2026	11	956	85%	9	0	55	717	75%
2027	9	965	85%	7	0	38	762	79%
2028	7	972	85%	6	0	25	793	82%
2029	6	977	85%	5	0	16	814	83%
2030	5	982	85%	4	0	10	828	84%
2031	4	986	85%	3	0	5	836	85%
2032	3	988	85%	2	0	2	840	85%

Note: Units represent those installed annually. Columns may not add to totals due to rounding.

Discretionary Resources

Discretionary resources differ from lost opportunity resources due to their acquisition availability at any point within the study horizon. From a theoretical perspective, this suggests all achievable technical potential for discretionary resources could be acquired in the study's first year, though, from a practical perspective, this outcome is realistically impossible to achieve due to infrastructure and budgetary constraints and to customer considerations.

Further, due to interactive effects between discretionary and lost opportunity resources, immediate acquisition would distort the potential for lost opportunity resources. For example, if one assumes all homes would be weatherized in the first year of a program, potentially available high-efficiency HVAC equipment would decrease significantly (i.e., a high-efficiency heat pump would save less energy in a fully weatherized home).

Consequently, the study addressed discretionary resources in two steps:

1. Developing a 20-year estimate of discretionary resource technical potential, assuming technically feasible measure installations would occur equally (at 5% of the total

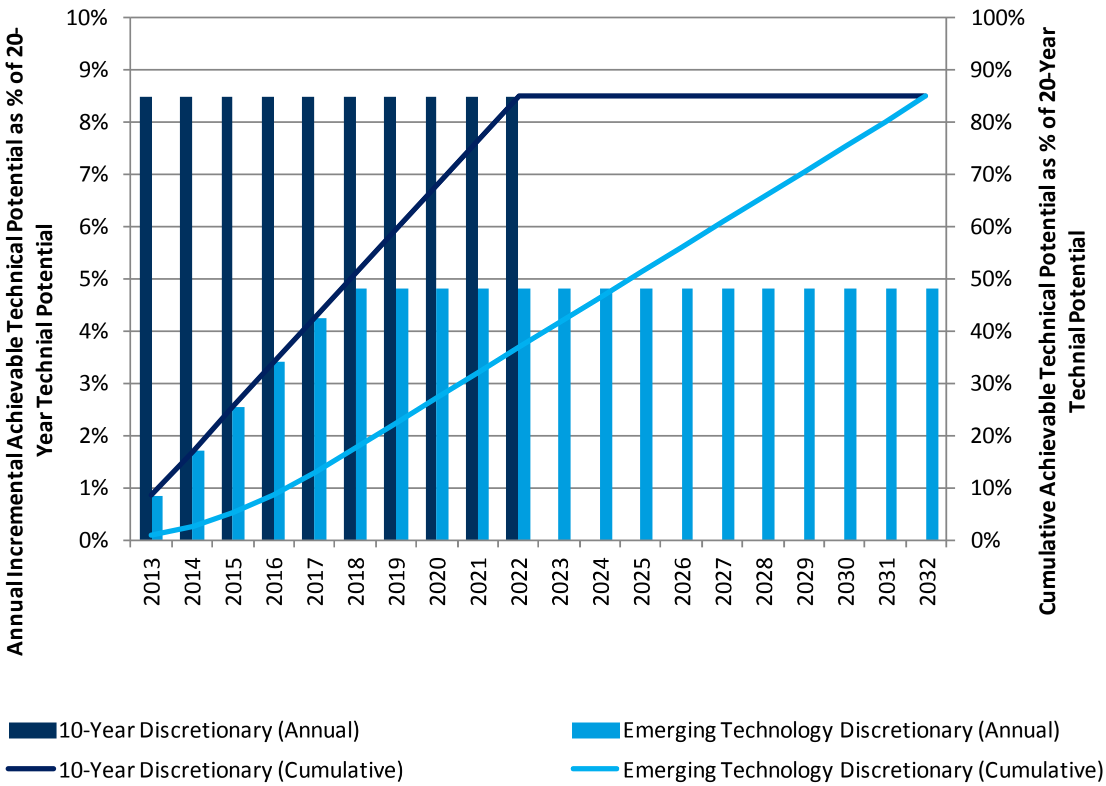
available) for each year of the study, and avoiding distortion of interactions between discretionary and lost opportunity resources, as described above.

2. Overlaying a measure ramp rate to specify the timing of achievable discretionary resource potential, thus transforming a 20-year cumulative technical value into annual, incremental, achievable values.

The discretionary measure ramp rates specify only the timing of resource acquisition and do not affect the portion of the 20-year technical potential achieved over the study period.

Figure 6 shows incremental (bars) and cumulative (lines) acquisitions for two different discretionary ramp rates. A measure on the 10-year discretionary ramp rate reaches full maturity (85% of its total technical potential) in 10 years, with market penetration increasing in equal increments each year. A measure on the emerging technology discretionary ramp rate would take longer to reach full maturity (also 85% of total technical potential), but ultimately it would arrive at the same cumulative savings as the measure on the 10-year ramp rate.

Figure 6. Examples of Discretionary Measure Ramp Rates



In this study, discretionary measures accounted for 70% of total technical potential and achieved 85% of that technical potential over the 20-year horizon. Lost opportunity measures accounted for the remaining 30% of total technical potential and achieved 65% of that technical potential over 20 years (as described above). Overall, the study estimates 79% of total technical potential (discretionary and lost opportunity) can be achieved over the study horizon.

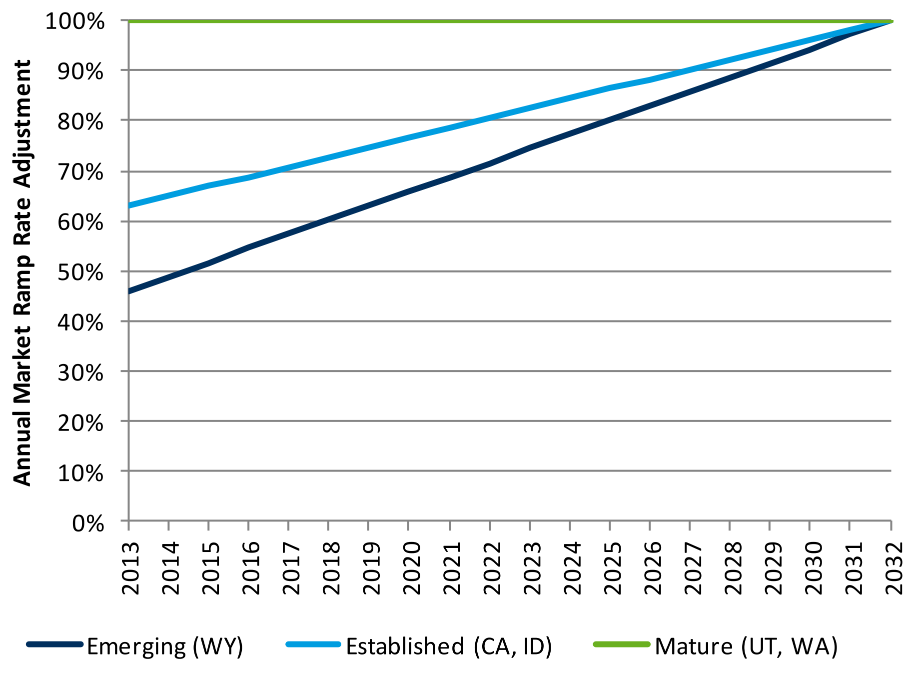
Market Ramp Rates

After addressing technical and general market constraints, the study applied state-specific market ramp rates to reflect the unique market characteristics of each state within PacifiCorp's service territory that were not captured by the more generic measure-specific ramp rates, as previously described.

For example, robust Class 2 DSM programs have been offered in Utah and Washington for many years and thus have well-developed delivery infrastructures and high customer awareness in these states. In Wyoming, with newer Class 2 DSM programs, the study assumes the ramp-up time for full acquisition will be slower. California and Idaho markets fall between these extremes factoring in the company's smaller and more rural service areas in these states and the impact on market factors.

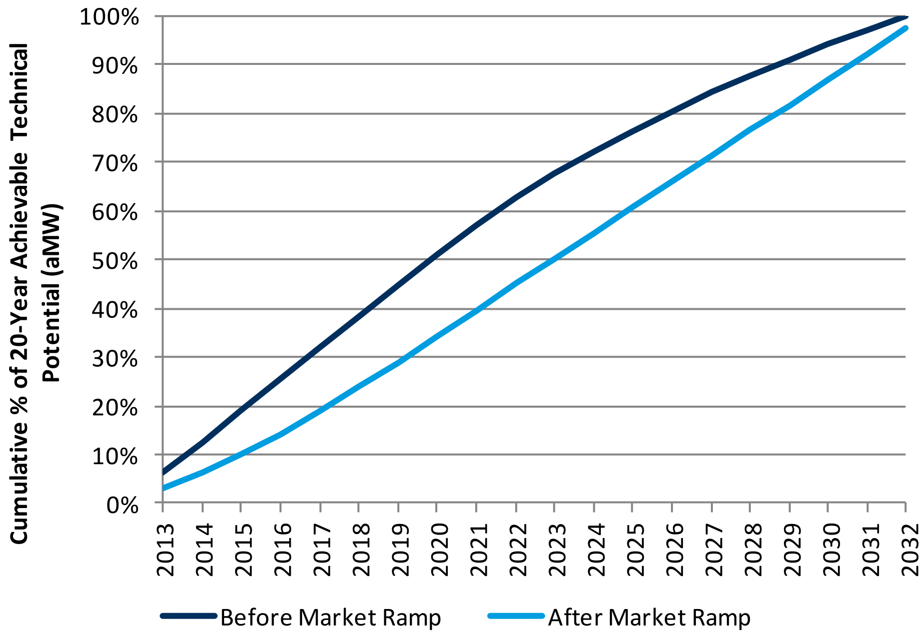
To accurately reflect acquisition trends in each state, the Cadmus team designed market ramp rates to set identified 2013 achievable technical potential, reflecting a continued growth in market activity over PacifiCorp's forecasted 2012 Class 2 DSM acquisitions in each state. Figure 7 illustrates these market ramp rates, with Utah and Washington unadjusted for market constraints (i.e., assumed to be at full program maturity), Idaho and California as "established" markets, and Wyoming as an "emerging" market.

Figure 7. Market Ramp Rates by State



Overlaying these market ramp rates on the measure ramp rates provided a final estimate of annual achievable technical potential in each state. For discretionary opportunities, slower acquisition pushes some resources out to later years, but the 20-year achievable technical potential remains the same. However, due to timing constraints of lost opportunities, failure to acquire these resources in early years may push opportunities beyond the 20-year study period, depending on the EUL. As shown in Figure 8, applying the "emerging" market ramp rate in Wyoming only leads to a 2% reduction in 20-year achievable technical potential.

Figure 8. Example of Market Ramp Rate Impacts for Wyoming



About Levelized Costs of Conserved Energy

In addition to achievable technical potential, the levelized cost of conserved energy (levelized cost) had to be determined to characterize each measure in the Class 2 DSM supply curves. Where possible, the study aligned its approach for calculating levelized costs for each measure to the Council's levelized-cost methodology, while recognizing differences in cost-effectiveness screening in each state within PacifiCorp's service territory.[47] Table 49 summarizes components of levelized cost in each PacifiCorp state assessed in this study.

Table 49. Levelized Cost Components by State

Component	State				
	Washington	Idaho	California	Wyoming	Utah
Initial capital cost	Included				Utility incentive
Reinstallation cost	Included				Not included*
Annual incremental O&M	Included		Not included		
Secondary energy impacts	Included		Not included		
Non-energy impacts	Included		Not included		
Administrative costs	20% of incremental cost				

* Assumes the customer will reinstall the measure upon burnout without utility intervention.

47 Failure to align costs used for IRP optimization with methods used to assess program cost-effectiveness could lead to an inability to deliver selected quantities in a cost-effective manner in a given jurisdiction.

Utah's levelized cost was assessed on a Utility Cost Test (UCT) basis, while the other states are evaluated on a Total Resource Cost (TRC) basis. To maintain consistency with the Council, RTF and accepted regulatory practices, secondary benefits, non-energy impacts, and incremental O&M have been included for Washington and Idaho. In California and Wyoming, only capital costs (initial and reinstallation) and administrative costs have been included. For Washington resources, the Council's 10% conservation credit will apply during the IRP modeling process, and this credit has not been included in the levelized costs presented in this report.

The approach to calculating a measure's levelized cost of conserved energy aligned with that of the Council's, considering the costs required to sustain savings over a 20-year study horizon, including reinstallation costs (except in Utah) for measures with useful lives less than 20 years. If a measure's useful life extended beyond the end of the 20-year study, the Cadmus team incorporated an end effect, treating the measure's levelized cost over its useful life as an annual reinstallation cost for the remainder of the 20-year period.[48] For example, Figure 9 shows the timing of initial and reinstallation costs for a measure with an eight-year lifetime, in context with the 20-year study. As a measure's lifetime in this study ends after the study horizon, the final four years (Year 17 through Year 20) have been treated differently, levelizing measure costs over its eight-year life and treating these as annual reinstallation costs.

Figure 9. 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			

For PacifiCorp's Utah service territory, the study adopted the utility's share of initial capital costs (i.e., an incentive amount) in the levelized cost calculation. The following assumptions regarding incentive amounts applied for Utah:

- Specific program measure (e.g., evaporative coolers and appliance recycling) incentives aligned with the current program design.
- Zero and negative incremental cost measures used incentives based on their assumed kWh savings, and on PacifiCorp's average, first-year, cost per kWh saved of $0.02/kWh.
- Company-owned street lighting incentives were set to 100% of incremental measure costs.

48 This method applied both to measures with a useful life greater than 20 years and those with useful lives extending beyond the 20th year at the time of reinstallation.

- Incentives for all other measures represented 70% of the incremental measure cost, based on a high (but realistic) incentive level required to achieve 85% of the technical potential.[49]

For Utah, the study did not include reinstallation costs, given the assumption that the utility only provided incentives for first measure installations. That is, customers will reinstall the measure without utility intervention, and savings persist throughout the planning period, though the cost is incurred only during the first installation.

To determine an appropriate assumption for administrative costs, the Cadmus team reviewed eight electric utilities' recent (2010 and 2011) annual reports, comparing non-incentive expenditures on Class 2 DSM programs with reported measure costs.[50] The review included only utilities with sufficient information to determine incremental costs, and properly interpreting the data required some professional judgment. The study excluded third-party administrators, as administrative costs may differ from utility-sponsored programs.

To most closely align with Class 2 DSM resources, the Cadmus team removed demand response, education, and renewable energy programs from the analysis (subject to availability of granular data). Across these utilities, the Cadmus team found average administrative costs as 22.8% of measure incremental costs. Removing one outlier with a 45% administrative percent led to a 19.9% average.[51] Consequently, the Cadmus team used a 20% administrative cost assumption for this assessment (a formulation consistent with the Council's assumed 20% administrative adder in the 6th Power Plan).

Summary of Resource Potentials

Table 50 and Table 52 show 2032 baseline sales and cumulative potential by sector and state, respectively. Study results indicate 819 aMW of technically feasible, energy-efficiency potential by 2032, the end of the 20-year planning horizon, with an estimated 648 aMW (79% of the technical potential) achievable across all sectors and states (or 12% of forecasted baseline sales in 2032). As a percentage of baseline sales, savings vary by sector and state, as shown in Table 50 and Table 52. These results account for line losses and represent savings at the generator. In addition, these values represent cumulative energy savings.

The cumulative energy savings differs from the sum of incremental savings due to the phase-in of energy standards. For example, although the potential includes CFLs in early years, these CFLs have zero cumulative potential by the 20th year due to EISA provisions. In other words, the baseline accounts for higher-efficiency standards, and—based on the effective life by the end of the planning period—all bulbs will be replaced by CFLs by following this standard.

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49 Incremental measure costs vary by resource type (i.e., discretionary or retrofit), with incremental costs equaling full costs for discretionary resources, and for lost opportunities, the incremental cost is the difference between the standard-efficiency and higher-efficiency alternatives.

50 Utilities included (with state): Alliant Energy (IA); Avista (WA); Avista (ID); National Grid (MA); NSTAR (MA); PSE (WA); Xcel Energy (CO); and Xcel Energy (MN).

51 Appendix B-2 provides a list of utility administrative expenditures and incremental costs, estimated from the annual reports.

The study estimated demand impacts by spreading annual potential by state, sector, segment, and end use over hourly load shapes. Peak impacts, reported below, represent average demand savings in the top 40 hours of system demand (occurring in summer). Peak impacts vary by sector and state, as shown in Table 51 and Table 53.

These savings draw upon forecasts of future consumption, absent PacifiCorp Class 2 DSM program activities. While these consumption forecasts accounted for past PacifiCorp Class 2 DSM resource acquisition, the identified estimated potential is inclusive of (not in addition to) forecasted program savings. As discussed, the 2032 forecasted baseline sales presented in this report may differ from PacifiCorp's official sales forecast.

Table 50. Baseline Sales, Technical and Achievable Technical Class 2 DSM Potential (Cumulative aMW in 2032) by Sector

Sector	Baseline Sales (aMW)	Technical Potential (aMW)	Technical as a Percent of Baseline Sales	Achievable Technical Potential (aMW)	Achievable Technical as a Percent of Baseline Sales
Residential	1,295	274	21%	190	15%
Commercial	1,522	282	19%	234	15%
Industrial	2,352	243	10%	207	9%
Irrigation	129	16	12%	13	10%
Street lighting	13	4	35%	4	30%
Total	**5,311**	**819**	**15%**	**648**	**12%**

Note: Results may not sum to totals due to rounding.

Table 51. Technical and Achievable Technical Class 2 DSM Potential (Cumulative Coincident Peak MW in 2032) by Sector

Sector	Technical Potential (MW)	Achievable Technical Potential (MW)
Residential	706	545
Commercial	493	407
Industrial	291	247
Irrigation	49	42
Street lighting	0.6	0.5
Total	**1,540**	**1,241**

Note: Results may not sum to totals due to rounding.

Table 52. Baseline Sales, Technical and Achievable Technical Class 2 DSM Potential (Cumulative aMW in 2032) by State

Territory	State	Baseline Sales (aMW)	Technical Potential (aMW)	Achievable Technical Potential (aMW)	Achievable Technical as Percent of Baseline Sales
Pacific Power	California	96	18	14	15%
	Washington	487	94	75	15%
	Subtotal	**582**	**112**	**88**	**15%**
Rocky Mountain Power	Idaho	268	47	34	13%
	Utah	3,002	491	389	13%
	Wyoming	1,459	169	136	9%
	Subtotal	**4,729**	**707**	**560**	**12%**
	Total	**5,311**	**819**	**648**	**12%**

Note: Results may not sum to totals due to rounding.

Table 53. Technical and Achievable Technical Class 2 DSM Potential (Cumulative Coincident Peak MW in 2032) by State

Territory	State	Technical Potential (MW)	Achievable Technical Potential (MW)
Pacific Power	California	28	23
	Washington	172	140
	Subtotal	**200**	**163**
Rocky Mountain Power	Idaho	77	61
	Utah	1,042	839
	Wyoming	221	178
	Subtotal	**1,339**	**1,078**
	Total	**1,540**	**1,241**

Note: Results may not sum to totals due to rounding.

Table 54 shows technical and achievable technical potential by sector and resource type, referring to whether resources can be considered discretionary or represent lost opportunities. Discretionary resource opportunities exist in current building stock (retrofit opportunities in existing construction), while lost opportunities rely on equipment burnout and new construction.

For the industrial and irrigation sectors, the study modeled all measures as discretionary resources. While in practice, natural equipment turnover and new construction will drive some opportunities, the majority of savings will likely be acquired during regular rebuilding and refurbishment of existing equipment stocks. In combination with the nature of available data, these practices pose difficulties in definitively isolating lost opportunity shares of savings. Therefore, all savings in these sectors have been classified as discretionary, an approach consistent with the Council.[52] Caveats aside, study results estimate discretionary resources

52 Residential and commercial assessments tied lost opportunities to specific forecasts for new construction and to decay patterns for specific types of end-use equipment (e.g., chillers and water heaters). In the industrial sector, the two elements have insufficient market data to allow delineation of lost opportunities (though many exist).

represent 75% (488 aMW out of 648 aMW) of cumulative achievable technical potential in 2032, as shown in Table 54.

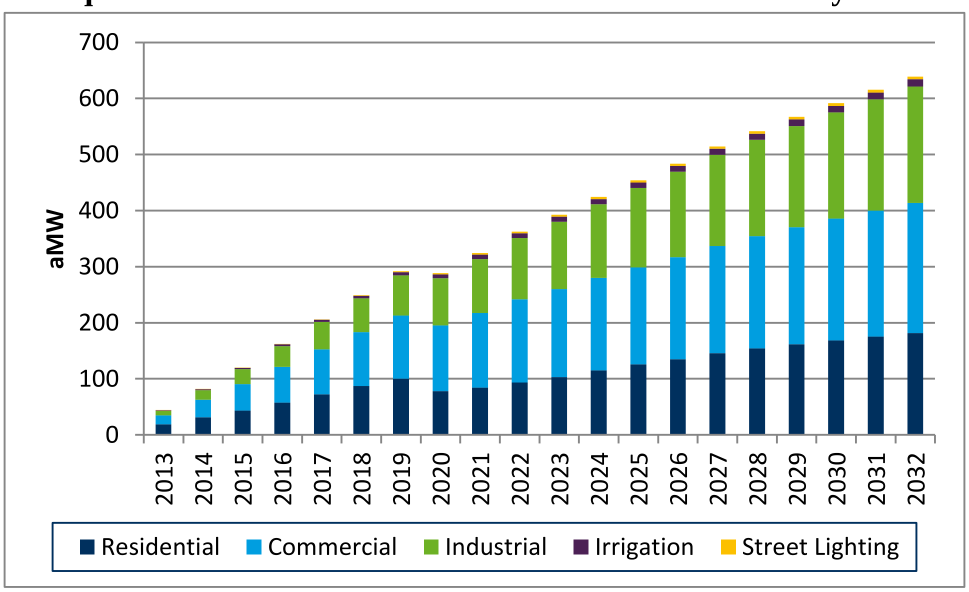
Table 54. Technical and Achievable Technical Class 2 DSM Potential (Cumulative aMW in 2032) by Sector and Resource Type

Sector	Technical Potential		Achievable Technical Potential	
	Discretionary	Lost Opportunity	Discretionary	Lost Opportunity
Residential	113	160	96	94
Commercial	202	80	172	62
Industrial	243	0	207	0
Irrigation	16	0	13	0
Street Lighting	0	4	0	4
Total	**574**	**245**	**488**	**160**

Note: Results may not sum to totals due to rounding.

Figure 10 provides a graphical representation of the cumulative achievable technical potential by sector in each study year, incorporating measure and market ramp rates, as discussed previously. The 2020 dip in potential represents the effect of the EISA-backstop provision; i.e., all general service incandescent lighting will have to meet minimum efficacy standards of 45 lumens per watt starting in 2020. In the baseline forecast, due to the comparatively short life of incandescent lighting and an assumption that CFLs become the *de facto* standard by 2020 (because they are the lowest cost option that currently meets the 45 lumens per watt), it is assumed that all incandescents are replaced with CFLs by 2020. These impacts are captured in Cadmus' baseline forecast; therefore, there is assumed to be no impact after 2019 from previously installed CFLs that would lead to a drop in cumulative potential even though there is new incremental potential.

Figure 10. Acquisition Schedule for Achievable Technical Potential by Year and Sector



Class 2 DSM Detailed Resource Potential

Residential Sector

Residential customers in PacifiCorp's service territory account for about one-quarter of forecasted 2032 baseline retail sales. Single-family, manufactured, and multifamily dwellings comprising this sector present a variety of potential savings sources, including equipment efficiency upgrades (e.g., heat pumps, air conditioning), improvements to building shells (e.g., insulation, windows, air sealing), and increases in lighting efficiency.

Based on resources included in this assessment, the Cadmus team estimated residential sector, cumulative, achievable technical potential of 190 aMW over 20 years, corresponding to a 15% reduction (ranging from 13% to 17%, by state) in forecasted 2032 baseline residential consumption (as shown in Table 55). Utah, which represents 63% of forecasted 2032 residential baseline sales, accounts for 62% (112 aMW) of this identified achievable technical potential.

Table 55. Residential Sector Class 2 DSM Potential by State (aMW in 2032)

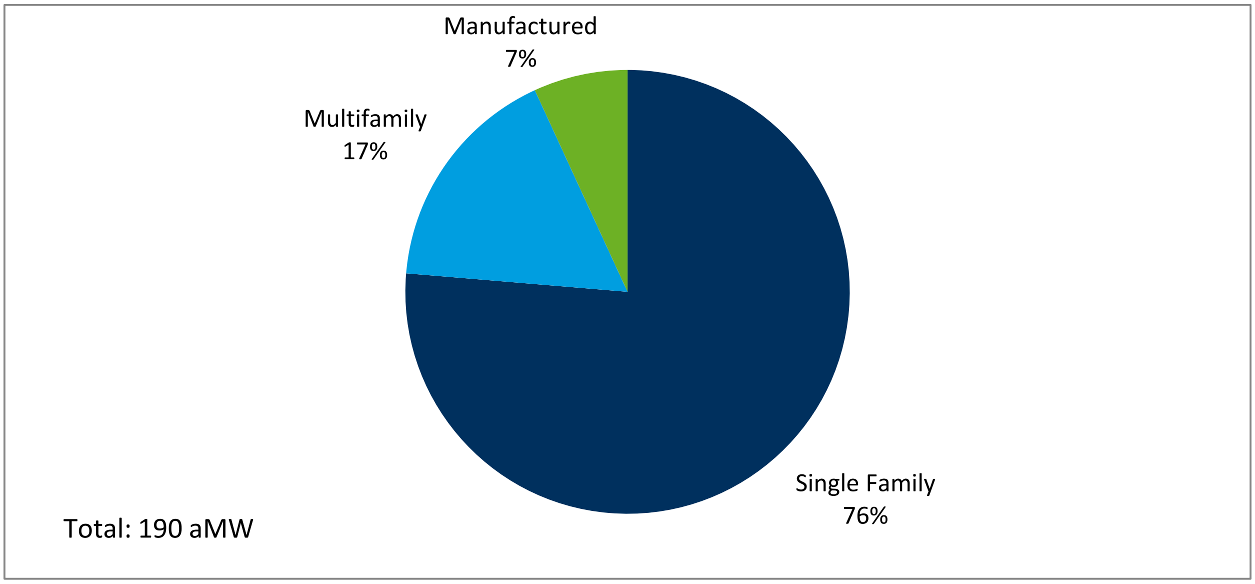
Territory	State	2032 Baseline Sales	Technical Potential	Achievable Technical Potential	Achievable Technical As Percent of Baseline Sales
Pacific Power	California	46	9	7	14%
	Washington	196	44	33	17%
	Subtotal	**242**	**54**	**39**	**16%**
Rocky Mountain Power	Idaho	106	25	16	15%
	Utah	820	169	118	14%
	Wyoming	127	26	17	13%
	Subtotal	**1,053**	**220**	**151**	**14%**
	Total	**1,295**	**274**	**190**	**15%**

Note: Results may not sum to totals due to rounding.

As shown in Figure 11, single-family homes represent 76% (145 aMW) of total achievable technical residential potential, followed by multifamily (32 aMW) and manufactured homes (13 aMW). Each home type's proportion of baseline sales primarily drives these results, but other factors, such as heating fuel sources, play an important role in determining potential.

For example, multifamily homes more commonly use electricity for space heating than do single-family homes, increasing their relative shares of space heating potential. Alternatively, lower use per customer for multifamily units decreases this potential, as some measures may not be cost-effective at lower consumption levels. Other factors include varying equipment saturation levels by state, home type, and weather, as reflected in heating and cooling loads. Specific factors affecting results have been included in the state- and segment-specific data, provided in Volume II, Appendix C.

Figure 11. Residential Sector Class 2 DSM Achievable Technical Potential by Segment (Cumulative in 2032)



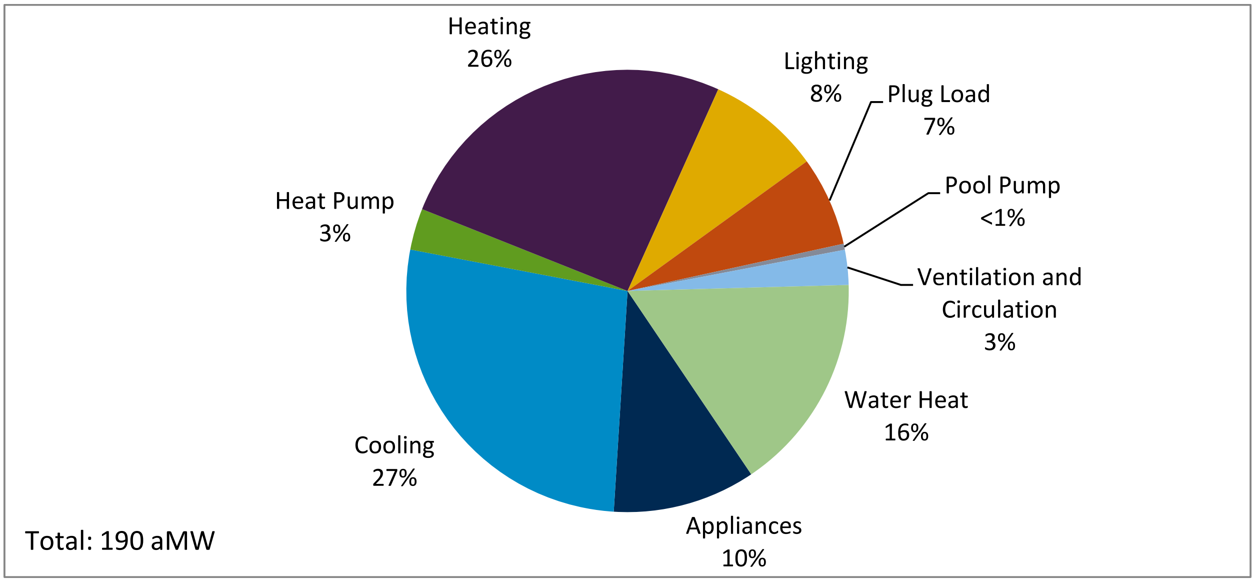
HVAC system savings account for over one-half (59%) of total achievable technical potential by end use (as shown in Table 56 and Figure 12), where space heating (central and room) accounts for 26%, cooling accounts for 27%, heat pumps account for 3%, and an additional 3% comes from ventilation and circulation. While significant opportunities exist in residential lighting during the early years examined by this study, this end use accounts for only 8% of cumulative achievable technical potential by 2032, driven down by impacts of the 2020 EISA backstop provision. Additional potential includes plug loads, water heating, refrigerators and freezers (included in appliances, and almost exclusively associated with recycling), and other appliances.

These results reflect Utah's large share of forecasted residential sales (62%). While assumptions driving lighting and appliance savings tend to remain consistent throughout the territory, other end uses can be affected by customer demographics (such as saturations of specific end uses), which can vary widely between states. For example, 84% of cooling savings shown in Table 56 and Figure 12 occurs in Utah. Detailed results showing achievable technical potential for individual states and home types, provided in Volume II, Appendix C, reflect differences in equipment saturations, shares for electricity, and baseline sales.

Table 56. Residential Sector Class 2 DSM Potential by End Use (Cumulative aMW in 2032)

End Use	Baseline Sales	Technical Potential	Achievable Technical Potential	Achievable Technical as Percent of Baseline Sales	Achievable Technical as Percent of Total
Computer	33	2	2	5%	1%
Cooking oven	11	0.2	0.1	1%	0%
Cooking range	5	0.0	0.0	0%	0%
Cool central	207	62	50	24%	26%
Cool room	9	1	1	11%	1%
Copier	2	0.0	0.0	2%	0%
DVD	4	0.4	0.4	10%	0%
Dehumidifier	1	0.1	0.1	6%	0%
Dryer	95	1	1	1%	1%
Freezer	30	8	7	23%	4%
Heat central	151	45	26	17%	13%
Heat pump	27	8	6	22%	3%
Heat room	150	36	23	15%	12%
Home audio system	11	1	1	7%	1%
Lighting interior specialty	23	16	14	60%	7%
Lighting standard	82	7	2	2%	1%
Microwave	20	3	2	10%	1%
Monitor	7	0.2	0.2	2%	0%
Multifunction device	0.0	0.0	0.0	0%	0%
Other	29	0.0	0.0	0%	0%
Plug load other	77	3	2	3%	1%
Pool pump	2	1	1	45%	1%
Printer	21	1	1	4%	1%
Refrigerator	70	21	12	17%	6%
Set top box	13	3	3	20%	2%
TV	46	2	2	4%	1%
Ventilation and circulation	66	13	5	7%	3%
Water heat GT 55 gal	9	4	4	42%	2%
Water heat LE 55 gal	93	33	27	29%	14%
Total	**1,295**	**274**	**190**	**15%**	**100%**

Figure 12. Residential Sector Class 2 DSM Achievable Technical Potential by End Use in 2032



Commercial Sector

For the commercial sector, results indicate 234 aMW of cumulative achievable technical potential over 20 years. As in the residential sector, Utah dominates this potential (70%) due to its large share (70%) of forecasted baseline sales. Table 57 lists commercial sector potential by state.

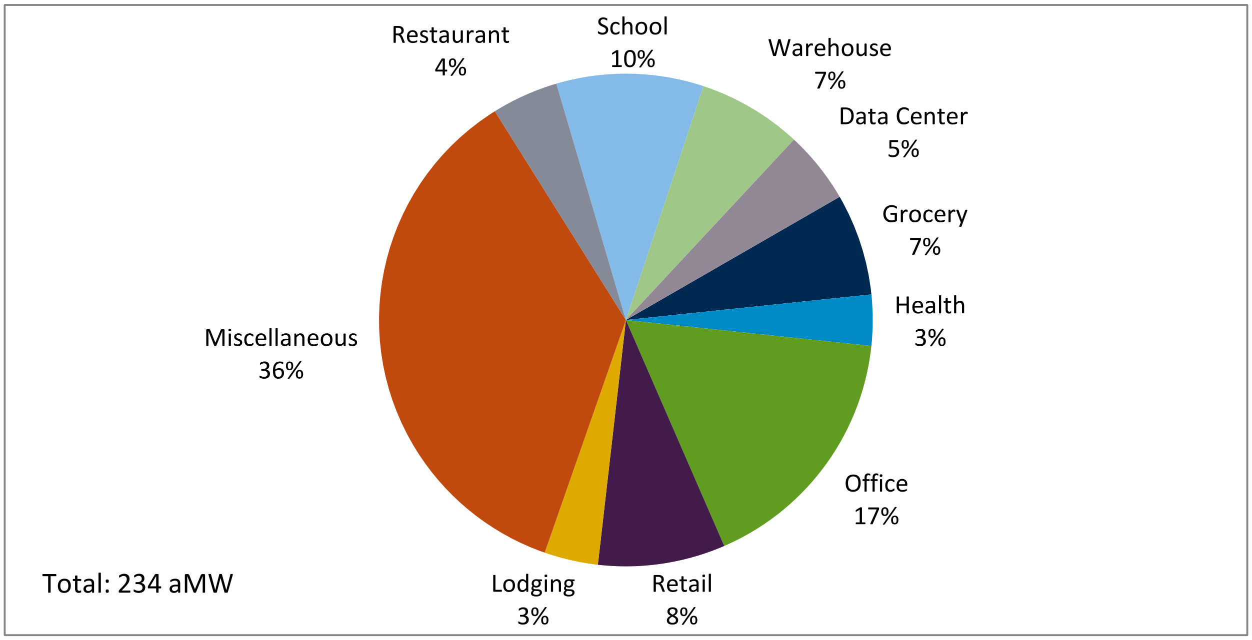
Table 57. Commercial Sector Class 2 DSM Potential by State (Cumulative aMW in 2032)

Territory	State	Baseline Sales	Technical Potential	Achievable Technical Potential	Achievable Technical as Percent of Baseline Sales
Pacific Power	California	33	6	5	17%
	Washington	162	34	28	18%
	Subtotal	**195**	**40**	**34**	**18%**
Rocky Mountain Power	Idaho	61	11	9	15%
	Utah	1,064	196	163	15%
	Wyoming	202	36	29	15%
	Subtotal	**1,328**	**242**	**200**	**15%**
	Total	**1,522**	**282**	**234**	**16%**

Note: Results may not sum to totals due to rounding.

As shown in Figure 13, "miscellaneous" buildings represent the largest share of cumulative, achievable, technical potential in the commercial sector (36%). These buildings either are unclassified within PacifiCorp's Customer Information System or are classified to a segment outside the named segments (e.g., firehouses). Considerable savings opportunities also emerged in the commercial sector's office (17%), school (10%), and retail (8%) segments. Lower levels of achievable technical potential appeared in lodging facilities, warehouses, restaurants, grocery stores, health care facilities, and data centers. Volume II, Appendix C, provides detailed information regarding achievable technical potential within each state.

Figure 13. Commercial Sector Class 2 DSM Achievable Technical Potential by Segment in 2032



Lighting efficiency (including interior and exterior applications) represents the largest portion of achievable technical potential in the commercial sector (37%), followed by cooling (16%) and ventilation and circulation (13%), as shown in Table 58 and Figure 14. These results reflect the pending federal standard, effectively outlawing most T-12 lamps.

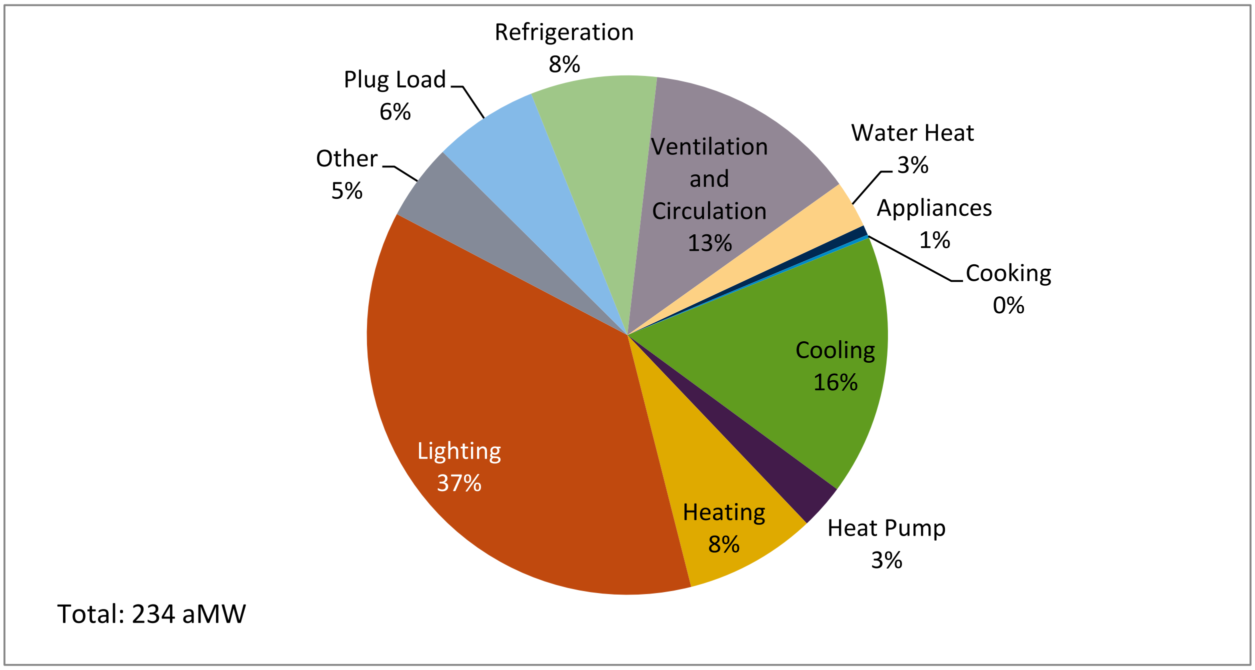
Table 58. Commercial Sector Class 2 DSM Potential by End Use (Cumulative aMW in 2032)

End Use	Baseline Sales	Technical Potential	Achievable Technical Potential	Achievable Technical as Percent of Baseline Sales	Achievable Technical as Percent of Total
Computers	32	6	5	16%	2%
Cooking	4	1	0.5	13%	0%
Cooling chillers	10	4	4	34%	2%
Cooling DX evap	99	40	34	34%	14%
Cooling room	2	1	1	24%	0%
Fax	2	1	1	39%	0%
Flat screen monitors	7	0.2	0.1	2%	0%
Freezers	1	0.1	0.1	12%	0%
Heat pump	24	8	7	28%	3%
Lighting exterior	126	38	32	26%	14%
Lighting interior fluorescent	324	39	33	10%	14%

End Use	Baseline Sales	Technical Potential	Achievable Technical Potential	Achievable Technical as Percent of Baseline Sales	Achievable Technical as Percent of Total
Lighting interior HID	78	8	7	9%	3%
Lighting interior Other	86	14	12	14%	5%
Lighting interior screw base	42	4	2	4%	1%
Other	40	13	11	28%	5%
Other plug load	94	7	6	6%	3%
Photo copiers	8	0.1	0.1	1%	0%
Printers	6	0.2	0.2	3%	0%
Refrigeration	87	22	18	21%	8%
Refrigerators	7	2	1	21%	0%
Servers	6	1	1	19%	0%
Space heat	78	23	19	25%	8%
Vending machines	13	3	2	16%	1%
Ventilation and Circulation	327	38	31	10%	13%
Water heat GT 55 gal	1	0.2	0.2	18%	0%
Water heat LE 55 gal	20	8	7	33%	3%
Total	**1,522**	**282**	**234**	**15%**	**100%**

Note: Results may not sum to totals due to rounding; "other" includes servers, fans, and HVAC in data centers.

Figure 14. Commercial Sector Class 2 DSM Achievable Technical Potential by End Use in 2032



Industrial Sector

The study assessed technical and achievable energy-efficiency potential for major end uses within 14 major industrial segments in PacifiCorp's service territory. These customer segments were based on SIC[53] allocations in PacifiCorp's customer database. The assessment estimated 207 aMW of industrial achievable technical potential, representing approximately 9% of forecasted 2032 industrial baseline sales.

Table 59. Industrial Sector Class 2 DSM Potential by State (Cumulative aMW in 2032)

Territory	State	Baseline Sales	Technical Potential	Achievable Technical Potential	Achievable as Percent of Baseline Sales
Pacific Power	California	4	1	0.4	10%
	Washington	108	13	11	10%
	Subtotal	**112**	**14**	**12**	**10%**
Rocky Mountain Power	Idaho	29	3	2	8%
	Utah	1,084	121	103	9%
	Wyoming	1,127	106	90	8%
	Subtotal	**2,240**	**229**	**195**	**9%**
Total		**2,352**	**243**	**207**	**9%**

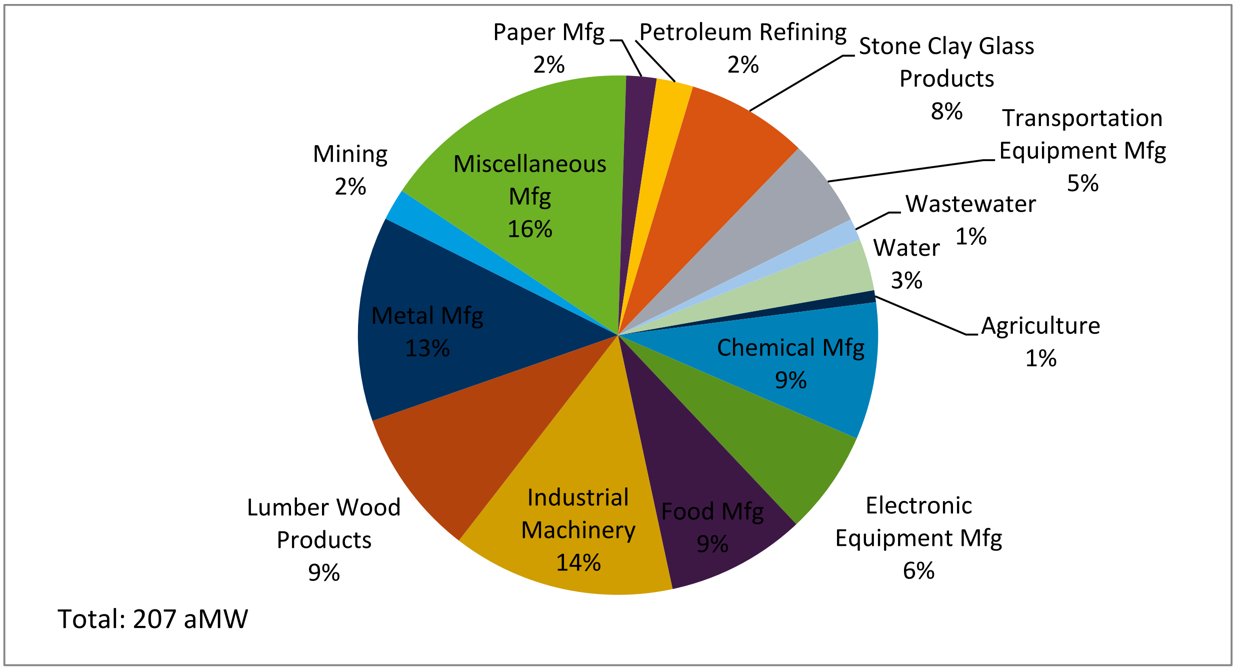
Note: Results may not sum to totals due to rounding.

In examining aggregate results for the industrial sector, some caution should be used in associating summary potential information for a particular facility type to individual states. While every state included nearly all residential and commercial customer segments, some industrial sector facility types applied only to a single state. Utah, for example, is the only state to indicate machinery and equipment manufacturing potential. Volume II, Appendix C, provides state- and industry-specific results.

Miscellaneous manufacturing represents the largest percentage of achievable technical potential (16%), as shown in Figure 15. This includes all manufacturing that is unclassified or falls outside other named segments, such as apparel or leather manufacturing. Industrial machinery represents the segment with the next largest portion of potential.

[53] SIC, the Standard Industrial Classification system, is used to identify the industry of a given customer.

Figure 15. Industrial Sector Class 2 DSM Achievable Technical Potential by Segment in (Cumulative in 2032)



The majority of industrial sector savings (60%) can be attributed to efficiency gains in air compressors, pumping, air distribution, and other motors (including mining applications). As many motors used in mining do not fit into traditional industrial motor categories, they have been classified as "Motors—Other" and represent a significant slice of potential (27 aMW). Lighting and process heating present the two end uses with the most savings, each accounting for 20% of achievable technical potential. Remaining potential splits between HVAC[54] and other building improvements, process improvements, and lighting (as shown in Figure 16 and Table 60).

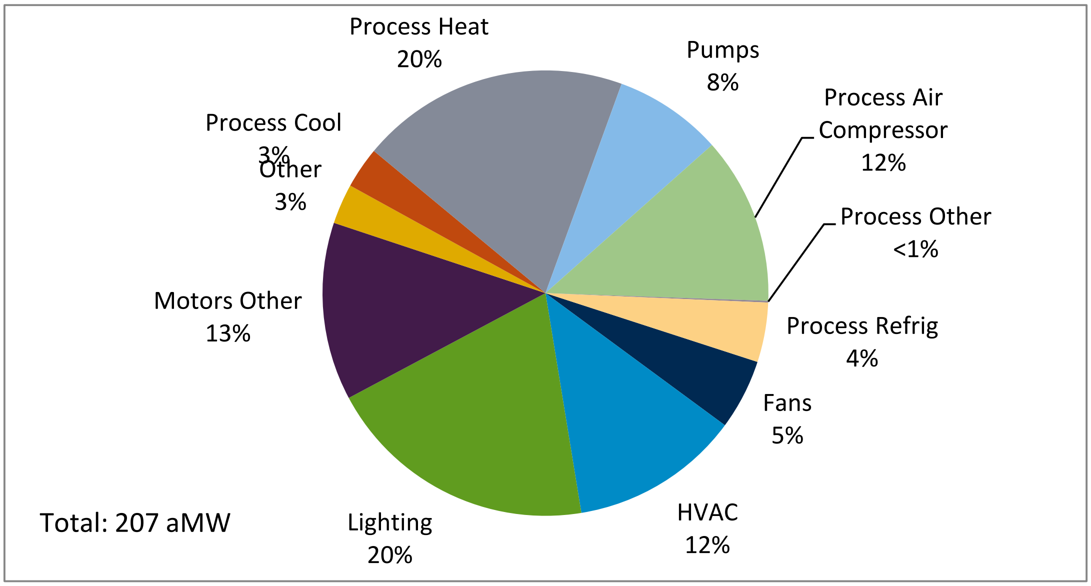
Table 60. Industrial Sector Class 2 DSM Potential by End Use (Cumulative aMW in 2032)

End Use	Baseline Sales	Technical Potential	Achievable Technical Potential	Achievable Technical as Percent of Baseline Sales	Achievable Technical as Percent of Total
Fans	141	12	11	7%	5%
HVAC	220	30	25	12%	12%
Lighting	158	48	41	26%	20%
Motors - other	674	31	27	4%	13%
Other	111	7	6	5%	3%
Process cooling	118	7	6	5%	3%
Process heating	235	47	40	17%	20%
Pumps	241	19	16	7%	8%
Indirect boiler	33	0	0	0%	0%

54 A substantial portion of industrial HVAC savings derive from clean room applications.

End Use	Baseline Sales	Technical Potential	Achievable Technical Potential	Achievable Technical as Percent of Baseline Sales	Achievable Technical as Percent of Total
Process air compressors	152	30	25	16%	12%
Process electro-chemical	130	0.0	0.0	0%	0%
Process other	73	0.3	0.3	0%	0%
Process refrigeration	64	11	9	14%	4%
Total	**2,352**	**243**	**207**	**9%**	**100%**

Figure 16. Industrial Sector Class 2 DSM Achievable Technical Potential by End Use (Cumulative in 2032)



Irrigation Sector

Although irrigation potential remains small compared to other sectors, the study estimated achievable technical potential represents 10% of 2032 baseline sales, with more than one-half of this potential in Idaho. Irrigation sector electricity consumption primarily consists of motors used for pumping, with a much smaller portion used for miscellaneous, non-pumping end uses.[55] Consequently, all irrigation potential derives from measures improving pumping efficiency, including high-efficiency motors, irrigation system improvements, and SIS.
Table 61 shows cumulative potential in 2032 associated with these measures.

55 Non-pumping end uses include system controls and motor drives for wheel-based systems.

Table 61. Irrigation Sector Class 2 DSM Potential by State (Cumulative aMW in 2032)

Territory	State	Baseline Sales	Technical Potential	Achievable Technical Potential	Achievable as Percent of Baseline Sales
Pacific Power	California	12	2	1	10%
	Washington	20	2	2	10%
	Subtotal	**32**	**4**	**3**	**10%**
Rocky Mountain Power	Idaho	71	9	7	10%
	Utah	24	3	2	10%
	Wyoming	3	0.3	0.3	10%
	Subtotal	**97**	**12**	**10**	**10%**
	Total	**129**	**16**	**13**	**10%**

Note: Results may not sum to totals due to rounding.

Irrigation savings mainly originate from reduced pump motor energy use, which may be achieved from reduced pressure, reduced flow,[56] or both. The savings magnitude also directly relates to pump lift (total dynamic head), which varies across different service territories. This proves a critical consideration in delivering cost-effective programs in this sector, which will likely become more viable in jurisdictions such as Idaho where deep wells tend to be more commonly used for irrigation water.

Street Lighting

Upgrading high-pressure, sodium, street lighting fixtures to LEDs offers approximately 3.7 aMW in achievable technical potential by 2032, representing a reduction in forecasted baseline sales of approximately 30%, as shown in Table 62.

Table 62. Street Lighting Sector Class 2 DSM Potential by State (Cumulative aMW in 2032)

Territory	State	Baseline Sales	Technical Potential	Achievable Technical Potential	Achievable as Percent of Baseline Sales
Pacific Power	California	0.3	0.1	0.1	31%
	Washington	0.9	0.3	0.3	30%
	Subtotal	**1.2**	**0.4**	**0.4**	**30%**
Rocky Mountain Power	Idaho	0.5	0.2	0.2	33%
	Utah	9.7	3.3	2.8	29%
	Wyoming	1.3	0.5	0.4	31%
	Subtotal	**11.5**	**4.0**	**3.4**	**30%**
	Total	**13**	**4.4**	**3.7**	**30%**

Note: Results may not sum to totals due to rounding.

Across all states, customer-owned fixtures account for 68% of achievable technical street lighting potential in 2032. Company-owned fixtures capture the remaining 32% of achievable technical potential. Table 63 shows achievable technical potential for company- and customer-owned fixtures, by state.

56 This includes scientific irrigation scheduling, which saves energy by minimizing irrigation requirements.

Table 63. Street Lighting Sector Class 2 DSM Achievable Technical Potential by State and Fixture Ownership (Cumulative aMW 2032)

Territory	State	Baseline Sales		Achievable Technical Potential	
		Company-Owned	Customer-Owned	Company-Owned	Customer-Owned
Pacific Power	California	0.1	0.2	0.0	0.1
	Washington	0.4	0.5	0.1	0.1
	Subtotal	**0.5**	**0.7**	**0.1**	**0.2**
Rocky Mountain Power	Idaho	0.0	0.5	0.0	0.2
	Utah	2.3	7.3	0.7	2.2
	Wyoming	1.2	0.1	0.4	0.0
	Subtotal	**3.5**	**7.9**	**1.0**	**2.3**
	Total	**4.0**	**8.6**	**1.2**	**2.6**

Note: Results may not sum to totals due to rounding.

Comparison of Results with the 2011 Assessment

As noted, this assessment builds upon a study completed in 2011, including the following updates to the Class 2 DSM analysis:

- Accounting for newly enacted building codes and equipment efficiency standards, even if they have not yet taken effect;
- Adjusting for PacifiCorp's actual and projected DSM program accomplishments from 2010 through 2012;
- Incorporating adjustments to measure savings, based on recent evaluation results, including data available from the Regional Technical Forum (RTF);
- Applying 2011 customer information to determine segmentation; and
- Utilizing 2012 sales and customer forecasts.

Together, these changes decreased total achievable technical 20-year potential from 1,156 aMW to 648 aMW, a system-wide decrease of 44%.

Much of this decrease resulted from changes in long-term forecasted baseline sales. Compared to the 2011 Assessment, the assessment's forecasted 20-year sales have decreased by 25%. Sales in Pacific Power's territory (Washington and California) decreased by 12%, compared to Rocky Mountain Power's territory (Idaho, Utah, and Wyoming), which decreased by 27%. The commercial sector saw the most significant decrease in projected sales, at 36%. Residential loads decreased by 28%, and industrial decreased by 16% (with minimal load changes occurring for street lighting and irrigation).

Part of this decrease, as described in the Introduction section of this study, resulted from incorporation of pending equipment efficiency standards. In addition, baseline sales were impacted by naturally occurring potential, including turnover of existing equipment to prevailing or pending standards on burnout as well as on the continuing adoption of high-efficiency units.[57] For example, baseline sales for residential plug load equipment in the 20th year dropped from the prior study by about 40% (142 aMW), largely due to this study projecting continuing high ENERGY STAR market shares.[58]

Table 64 compares, by sector, achievable technical potential (in aMW and as a percentage of sales) between the two assessments. This comparison includes potential in the 20th year (2030 for the 2011 Assessment and 2032 for the current assessment).

Table 64. Comparing Class 2 DSM Achievable Technical Potential in 2011 and Current Assessments

Sector	Achievable Technical Potential (Year-20 Cumulative aMW)		Achievable as a Percent of Year- 20 Baseline Sales	
	2011 Assessment	Current Assessment	2011 Assessment	Current Assessment
Residential	514	190	29%	15%
Commercial	361	234	15%	15%
Industrial	265	207	9%	9%
Irrigation	13	13	10%	10%
Street lighting	4	4	36%	30%
Total	**1,156**	**648**	**16%**	**12%**

Savings assumptions served as one driver of this decrease in potential. As shown in Volume II, Appendix C, measure savings were updated to reflect new data, including the residential SEEM models and recent RTF measure savings workbooks. The 2011 assessment primarily relied on workbooks used in the 6th Power Plan. In Washington, most measures were updated based on recent RTF work. RTF updates primarily reflect recent evaluation work as well as ongoing reviews of savings assumptions.

Accounting for this sales change, nonresidential potential (as a percent of sales) did not change significantly from the 2011 Assessment. For the commercial, industrial, and irrigation sectors, both studies estimated cumulative achievable technical potential of 15%, 9%, and 10% of year-20 baseline sales, respectively. Street lighting potential changed from 36% to 30% of sales, due to availability of updated data on existing stock.

While potential, in percentage terms, remained the same at the sector level for commercial, industrial, and irrigation, differences occurred between the two studies at the end-use level. For example, this study thoroughly reviewed and updated measures comprising interior lighting potential; these were based on more recent lighting fixture data, a methodology to estimate post-installation lumen requirements,[59] new building codes, and the 2012 lighting standard. Table 65

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57 These high saturations will likely continue without PacifiCorp program intervention.

58 Includes television, DVD players, computer monitors, computers, set top boxes, and other plug loads; from: http://www.energystar.gov/index.cfm?c=partners.unit_shipment_data_archives

59 The 2011 Assessment determined potential by assuming a reduction in lighting power density while holding total lumens constant. The current study allows lumens to vary by up to 10% of pre-levels.

provides differences in the two studies at a rolled-up, end-use level for the commercial sector, including some key drivers for these differences.

In the residential sector, however, cumulative achievable technical potential as a percentage of year-20 baseline sales decreased from 29% to 15%, driven by many factors—most significantly updates to assumed market shares of ENERGY STAR appliances and office equipment, including dehumidifiers, computers, monitors, televisions, set top boxes, and printers. Using the most recent ENERGY STAR market share reports at the time of this study, the potential attributed to this equipment dropped by more than two-thirds.

Another notable change emerged in using SEEM models to estimate UECs and savings for HVAC and shell measures. The prior study used Energy-10 models, whereas the RTF used SEEM models to estimate savings for shell and other measures. For all HVAC end uses, the SEEM models reduced savings relative to the prior study.[60] Table 66 presents additional details on differences between the two studies in the residential sector, at the end-use level.

[60] Other factors, such as measure saturations, efficiency standards, and measure efficiency levels also contributed to changes in the HVAC potential, but SEEM models alone would drive the savings down.

Table 65. Comparison of 2011 and Current Assessment Commercial Class 2 DSM Achievable Technical by End Use Group (Cumulative aMW in Year 20)

End Use Group	Baseline Sales		Achievable Technical Potential		Change in Potential		Key Drivers of Differences
	2011	Current	2011	Current	aMW	Percent	
Residential-style appliances	0	8	0	1	1	N/A	Refrigerator and freezer recycling included in the current study.
Data centers	N/A	40	0	11	11	N/A	Data centers not included in the previous study.
Space Heating and Cooling	305	213	115	65	-50	-43%	Review of applicability assumptions and savings estimates.
Lighting (interior and exterior)	1,081	656	166	86	-80	-48%	Updated methodology.
Office equipment	273	149	30	12	-18	-59%	Higher ENERGY STAR market shares led to lower baseline sales. Savings shifted from achievable technical to naturally occurring.
Cooking and vending machines	6	17	0	3	3	N/A	Vending machines not included in the previous study.
Refrigeration	172	87	25	18	-7	-28%	Reallocation of sector sales by segment, based on the latest PacifiCorp customer database, indicated lower total sales in segments using refrigeration.
Servers (excludes data centers)	N/A	6	N/A	1	1	N/A	Not included in the prior study.
Ventilation and Circulation	499	327	14	31	17	121%	An additional measure (motors VFD) accounted for most of the difference in potential change; Year-20 sales dropped due to constant EUI assumption in current study.
Water heat (includes clothes washers and dishwashers)	32	21	11	7	-4	-35%	No significant change in potential as a percent of sales. Sales dropped due to new efficiency standards.
Total	**2,367**	**1,524**	**361**	**234**	**-126**	**-35%**	

* Numbers may not sum to totals due to rounding.

Table 66. Comparison of 2011 and Current Assessment Residential Class 2 DSM Achievable Technical by End Use Group (Cumulative aMW in Year 20)

End- Use Group	Baseline Sales		Achievable Technical Potential		Change in Potential		Key Drivers of Differences
	2011	Current	2011	Current	aMW	Percent	
Appliances (refrigerator, freezer, dryer)	281	195	16	20	4	25%	Updated efficiency standards for refrigerators and freezers. The 2011 Assessment assumed an end to appliance recycling in Year 5; current study maintains this throughout the study horizon.
Cooking (range and oven)	39	16	3	0.1	-3	-97%	Updated efficiency standards.
Space heating and cooling	660	544	276	106	-170	-62%	Updated efficiency standard for heat pumps, updated savings based on SEEM models, and updated technical feasibility for evaporative coolers for each state.
Lighting (standard and specialty)	199	105	83	16	67	-81%	Revised methodology to account for EISA, new assumptions on per home usage.
Office equipment	210	126	62	9	-53	-86%	Increase in ENERGY STAR market share projections.
Pool pump	4	2	1	1	0	0%	Savings updated based on new usage data; Year-20 sales dropped due to constant UEC assumption in current study.
Plug load (microwave, home audio, dehumidifier, other)	182	138	18	5	-13	-72%	Updated efficiency standards for dehumidifier; increased ENERGY STAR market share in baseline forecast.
Ventilation and circulation	83	66	15	5	-10	-67%	Removal of the VFD motor measure in current study due to technical feasibility constraints.
Water heat (includes clothes washers and dishwashers)	130	102	41	31	-10	-24%	Updated efficiency standard for water heaters and appliances.
Total	**1,787**	**1,294**	**514**	**190**	**-322**	**-63%**	

* Numbers may not sum to totals due to rounding.

SUPPLEMENTAL RESOURCES

Scope of Analysis

As in the 2007 and 2011 Assessments, the term "supplemental resources" referred to renewable and non-renewable customer-sited generation. While these resources may not reduce a building's energy consumption or peak demand, they provide benefits to the electric grid by reducing energy amounts required from utility-owned resources. This study assessed the following such resources:

- CHP
- Solar PV
- SWH

Traditionally, such resources fall outside the standard classification of Class 2 DSM resources for two main reasons: either they reduce utility-provided electricity consumption at the building level (and not at end use, as applies to CHP and PV), or they rely on renewable resources (PV and SWH).

For each technology, this report includes methods and results for estimating technical potential, market potential, and levelized energy costs. Levelized costs presented have been based on the TRC test for all states and technologies, except for on-site solar resources in Utah, which use the UCT.

Methodology Overview

For supplemental resources, the definition of technical potential is similar to that used in the Class 2 DSM analysis, representing total electric generation (or savings, in the case of SWH) that could be offset if all resources were installed in all technically feasible applications. For example, the PV technical potential assumed every rooftop with favorable (i.e., southern) solar exposure would have a PV system installed. This largely unrealizable potential should be considered a theoretical construct.

The next potential level is market potential—analogous to achievable technical potential for Class 2 DSM resources. Market potential measures the likely penetration within PacifiCorp's service territory, given existing (or projected) market conditions. For supplemental resources, market potential is based on historic adoption of resources, accounting for state-to-state variations, as appropriate. For example, for PV, market potential ties to the presence or absence of utility rebates in each state.

For each technology, the Cadmus team calculated a levelized cost from a total resource or utility perspective, depending on the state and technology. Although variations in assumptions exist between technologies, overall TRC levelized costs included:

- The installation cost, less the federal investment tax credit (ITC) for systems installed before 2017, assuming the ITC expires as planned on December 31, 2016. State tax credits and utility incentives are not deducted from the installation cost, as although the

TRC test counts these as benefits to customers installing the systems, they are also included as costs to the state's taxpayers, resulting in a zero net effect.

- Utility costs other than incentives, interconnection for CHP, or program administrative costs for on-site solar.
- O&M costs assumed to occur annually, adjusted to the net present value.
- Fuel costs for CHP, using PacifiCorp projections for average annual natural gas costs, by service territory (Pacific Power and Rocky Mountain Power).[61]

For on-site solar resources in Utah, the study calculated levelized costs, reflecting the utility's cost of administering the program, including the following:

- Administration and marketing costs.
- Incentive amounts, assumed to be a percentage of installed costs after applying the federal tax credit[62] and accounting for projected trends in incremental costs. State tax credits do not affect the utility incentive amount.

For both perspectives, the Cadmus team used PacifiCorp's 6.88% nominal discount rate, along with a 1.9% inflation rate, to adjust future costs to present dollars. Costs were then divided by the system's energy production over its lifespan, obtaining the levelized cost of energy (LCOE). Energy production includes a line loss factor, varying by state and sector, as shown in Section 1 of this report. These line loss values represent avoided losses on the utility system, not energy loss from the customer-sited unit to the facility (which is assumed to be zero). Energy production over the system's life accounted for system performance degradation, as applicable.

CHP

Technologies Assessed

CHP systems generate electricity and utilize waste heat for thermal loads, such as space or water heating. They can be used in buildings with a fairly coincident thermal and electric load or in buildings producing combustible biomass or biogas, such as lumber mills or landfills.

Traditionally, CHP systems have been installed in hospitals, schools, and manufacturing facilities, but they can be used across nearly all C&I market segments with average monthly energy loads greater than about 30 kW. CHP broadly divides into subcategories, based on fuels used; nonrenewable CHP typically runs on natural gas, while renewable CHP runs on a biologically derived fuel (biomass or biogas).

[61] PacifiCorp provided annual gas rate projections (nominal $/MMBtu) for use in the levelized cost analysis.

[62] The incentive does not increase with expiration of the federal tax credit in 2016.

The Cadmus team analyzed the same nonrenewable CHP systems as in the 2011 Assessment:

- Reciprocating engines (RE)
- Microturbines (MT)
- Gas turbines (GT)
- Fuel cells (FC)

REs cover a wide size range, while GTs typically are large systems. FCs and MTs are newer technologies with higher capital costs, though FCs have the highest electrical conversion efficiency.

The renewable CHP assessment included the same technologies as the 2011 Assessment, analyzing industrial biomass systems and anaerobic digester biogas systems:

- Industrial biomass systems are utilized in industries such as lumber mills or pulp and paper manufacturing where site-generated waste products can be combusted in place of natural gas or other fuels. This analysis assumed the combustion process includes a CHP system (generally, steam turbines) to generate electricity on-site. Industrial biomass systems generally operate on large scales, with a capacity greater than 1 MW.
- Anaerobic digesters create methane gas (biogas fuel) by breaking down liquid or solid biological waste. Anaerobic digesters can be coupled with a variety of generators, including REs and MTs, and typically are installed at landfills, wastewater treatment facilities, (WWTFs), and livestock farms.

The study did not include waste heat-to-power (WHP) systems, as initial research identified the following challenges:

- The United States currently has very little WHP installed (33 sites, 557 MW, excluding landfill gas).
- WHP can only be applied in industries producing high-temperature heat (e.g., metal and chemical manufacturing).
- WHP presents significant technical barriers (e.g., space limitations, dispersed waste heat sources, and low volume/seasonal operations).

Although WHP offers potential energy savings, low market awareness and willingness to adopt this technology at this time, coupled with relatively significant technical barriers, suggest small market potential for these applications.

Data Sources

The Cadmus team reviewed many data sources to determine inputs most appropriate for CHP analysis. As shown in Table 67, U.S. Environmental Protection Agency (EPA) and U.S. Department of Energy (DOE) reports on CHP technologies provided many inputs, with other sources used for additional inputs, as appropriate.

Table 67. References for CHP Analysis

Source	Inputs	Website Link
Catalog of CHP Technologies, U.S. EPA	System Size, Installed Cost, Heat Rate, O&M Cost	www.epa.gov/chp/documents/catalog_chptech_full.pdf
Biomass Combined Heat and Power Catalog of Technologies, U.S. EPA	System Size, Heat Rate, O&M Cost, WWTF Data	www.epa.gov/chp/documents/biomass_chp_catalog.pdf
R.S. Means	State Cost Adjustment	N/A
Combined Heat and Power Partnership, U.S. EPA	Federal ITC	www.epa.gov/chp/incentives/
Gas-Fired Distributed Energy Resource Technology Characterizations, U.S. DOE	Measure Life	www.nrel.gov/docs/fy04osti/34783.pdf
California Self-Generation Incentive Program (SGIP) 10th Impact Evaluation Report	Capacity Factor	www.cpuc.ca.gov/PUC/energy/DistGen/sgip/
California SGIP Combined Heat and Power Performance Investigation	Performance Degradation	www.cpuc.ca.gov/PUC/energy/DistGen/sgip/
Market Opportunities for Biogas Recovery Systems at U.S. Livestock Facilities, U.S. EPA	Agricultural CHP Data	www.epa.gov/agstar/documents/biogas_recovery_systems_screenres.pdf
Agricultural Waste Management Field Handbook, USDA	Agricultural CHP Data	policy.nrcs.usda.gov/OpenNonWebContent.aspx?content=31475.wba
Census of Agriculture, USDA	Farm Data	www.agcensus.usda.gov/Publications/2007/Full_Report/Volume_1,_Chapter_1_State_Level/
Landfill Methane Outreach Program (LMOP), U.S. EPA	Landfill Gas Data	www.epa.gov/lmop/
Energy Insights	CHP Eligibility by Facility Type and Size	N/A
Combined Heat and Power Installation Database	Existing CHP Installations	www.eea-inc.com/chpdata/
PacifiCorp	2011 Customer Data, Current Installations, Interconnection Cost, Natural Gas Costs, Inflation Rate, Discount Rate, Line Losses	N/A

Inputs

The tables below summarize key inputs for each technology. Table 68, Table 69, Table 70, and Table 71 list assumptions for nonrenewable fuel systems by technology and size range. Table 72 and Table 73 list assumptions for renewable fuel systems by fuel and technology.

O&M costs represent typical maintenance costs and do not include fuel costs. The net heat rate, measured in Btu/kWh, equals the increased system fuel use (total fuel input to the CHP system minus the fuel normally used to generate the same thermal output) divided by the electricity output. In biogas systems, the analysis assumed waste heat fed back to the anaerobic digester for biogas generation; therefore, the total heat rate was used, rather than the net heat rate.

For biogas systems, the cost shown represents the generator cost. Additional expenses for building digesters have not been included, as this could be completed independently of the CHP system. Similarly for biomass systems, the study assumed boiler and fuel processing systems would already be in place at large industrial facilities; therefore, only CHP generator costs have been included.

Table 68. Inputs for Natural Gas Fuel Cells

Input	100–250 kW	250–750 kW	750–1,500 kW
National average installation cost ($/kW)	$6,310	$5,580	$5,250
Annual O&M cost ($/kWh)	$0.038	$0.035	$0.032
Net heat rate (Btu/kWh)	4,168	6,022	6,043
Annual performance degradation	5%		
Capacity factor	0.71		
Measure life (years)	10		
Federal ITC through 2016	30% of installed cost		

Table 69. Inputs for Natural Gas-Fired Gas Turbines

Input	<3,000 kW	≥3,000 kW
National average installation cost ($/kW)	$3,324	$1,314
Annual O&M cost ($/kWh)	$0.0111	$0.0074
Net heat rate (Btu/kWh)	7,013	5,839
Annual performance degradation	0%	
Capacity factor	0.81	
Measure life (years)	20	
Federal ITC through 2016	10% of installed cost	

Table 70. Inputs for Natural Gas-Fired Microturbines

Input	<50 kW	50–150 kW	>150 kW
National average installation cost ($/kW)	$2,970	$2,490	$2,440
Annual O&M cost ($/kWh)	$0.020	$0.0175	$0.016
Net heat rate (Btu/kWh)	7,313	5,796	6,882
Annual performance degradation	5%		
Capacity factor	0.49		
Measure life (years)	10		
Federal ITC through 2016	10% of installed cost		

Table 71. Inputs for Natural Gas-Fired Reciprocating Engines

Input	<200 kW	200–500 kW	500–2,000 kW	2,000–4,000 kW	>4,000 kW
National average installation cost ($/kW)	$2,210	$1,940	$1,640	$1,130	$1,130
Annual O&M cost ($/kWh)	$0.022	$0.016	$0.013	$0.010	$0.009
Net heat rate (Btu/kWh)	4,383	4,470	4,385	5,107	4,950
Annual performance degradation	6%				
Capacity factor	0.40				
Measure life (years)	20				
Federal ITC through 2016	10% of installed cost				

Table 72. Inputs for Industrial Biomass Steam Turbine Systems

Input	<2,000 kW	2,000–5,000 kW	>5,000 kW
National average installation cost ($/kW)	$1,117	$475	$429
Annual O&M cost ($/kWh)	$0.004		
Heat rate (Btu/kWh)	4,515	4,568	4,388
Annual performance degradation	1%		
Capacity factor	0.90		
Measure life (years)	25		
Federal ITC through 2016	10% of installed cost		

Table 73. Inputs for Biogas Systems

Input	FC	GT	MT	RE
National average installation cost ($/W)	$5,713	$2,319	$2,633	$1,610
Annual O&M cost ($/kWh)	$0.025	$0.0085	$0.014	$0.0165
Heat rate (Btu/kWh)	8,705	12,400	12,703	10,357
Annual performance degradation	5%	0%	5%	6%
Capacity factor	0.71	0.81	0.49	0.40
Measure life (years)	10	20	10	20
Federal ITC through 2016 (% of installed cost)	30%	10%	10%	10%

Installation costs shown in the above tables have been based on national averages. Analysis adjusted these values for each state, based on living costs in the part of state served by PacifiCorp. Table 74 shows these adjustment factors (with the cost in each state as a percentage of the national average cost).

Table 74. CHP Cost Adjustments by State

	CA	ID	OR	UT	WA	WY
Material	103%	100%	100%	81%	103%	99%
Labor	114%	65%	97%	69%	93%	49%
Total	**107%**	**88%**	**99%**	**77%**	**99%**	**82%**

Levelized Cost of Energy

The Cadmus team calculated the LCOE for each configuration shown above in each state and installation year (2013–2032). Table 75 shows results for units installed in 2013 (with details provided in Volume II, Appendix D-1).

Costs slightly increase for systems installed after 2016, when the federal tax credit expires. Levelized costs vary across states due to differences in cost-of-living adjustments, line losses, and natural gas rates. Energy production over the system's life accounts for system performance degradation.

The Cadmus team calculated levelized costs based on the TRC perspective for all states, for consistency with treatment of other generation resources in the IRP, as these systems are treated as Qualifying Facilities, as defined by The Public Utility Regulatory Policies Act of 1978.

Table 75. 2013 Levelized Cost by Configuration and State

Technology	Size Range	CA	ID	OR	UT	WA	WY
Fuel Cell	100–250 kW	$0.15	$0.15	$0.15	$0.15	$0.15	$0.15
	250–750 kW	$0.14	$0.14	$0.14	$0.14	$0.14	$0.14
	750–1,500 kW	$0.13	$0.13	$0.14	$0.14	$0.14	$0.14
Gas Turbine	<3,000 kW	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09
	>3,000 kW	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06
Microturbine	<50 kW	$0.13	$0.13	$0.14	$0.14	$0.14	$0.13
	50–150 kW	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11
	>150 kW	$0.11	$0.11	$0.11	$0.11	$0.12	$0.11
Reciprocating Engine	<200 kW	$0.10	$0.10	$0.10	$0.10	$0.10	$0.10
	200–500 kW	$0.08	$0.08	$0.09	$0.09	$0.09	$0.09
	500–2,000 kW	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08
	2,000–4,000 kW	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07
	>4,000 kW	$0.06	$0.07	$0.07	$0.07	$0.06	$0.06
Biomass—Steam Turbine	<2,000 kW	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02
	2,000-5,000 kW	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
	>5,000 kW	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Biogas	Fuel Cell	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09
	Gas Turbine	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11
	Microturbine	$0.05	$0.06	$0.06	$0.06	$0.05	$0.06
	Reciprocating Engine	$0.03	$0.04	$0.04	$0.04	$0.04	$0.04

Technical Potential

The Cadmus team calculated technical CHP potential based on the sources described above, including PacifiCorp customer data, and data on farms, landfills, and WWTFs within PacifiCorp's service territory, resulting in a total estimated 20-year system-wide technical potential of 4,301 MW, as measured at the generator. Table 76, below, details technical potential by technology and by rated system capacity (MW).

The study based average energy production on the capacity factors of systems described above. To avoid double-counting opportunities across technologies, the study divided total potential for each size range into different technologies, based on distributions of existing installations for states within PacifiCorp's territory. For example, for systems less than 500 kW, RTs, MTs, and FCs represented 77%, 19%, and 4% of installations, respectively. For all technologies, across all states, the technical potential for energy generation was estimated at 2,233 aMW (an average capacity factor of 0.52).

Table 76. CHP Technical Potential by State and Technology (Cumulative MW in 2032)

System Type	Technical Potential (MW)						
	CA	ID	OR	UT	WA	WY	System
Natural Gas Total	54	162	346	2,546	449	354	3,911
< 500 kW	31	82	156	1,053	212	158	1,693
500–999 kW	3	8	40	409	87	36	583
1–4.9 MW	20	45	108	818	151	110	1,252
5 MW+	0	26	42	264	0	49	382
Biomass Total	12	3	141	41	31	6	233
< 500 kW	1	2	22	11	5	1	43
500–999 kW	1	1	15	6	4	2	29
1–4.9 MW	10	0	71	16	13	3	113
5 MW+	0	0	32	8	8	0	48
Biogas Total	2	22	31	52	8	42	157
Landfill	0	0	1	8	5	3	17
Farm	2	22	29	44	3	39	139
WWTF	0	0	1	0	0	0	1
Total	**68**	**187**	**519**	**2,639**	**488**	**402**	**4,301**

Market Potential

The Cadmus team applied data on recent CHP system installations in PacifiCorp's service territory to determine market potential or likely installations in future years. The study based the assumed annual market penetration rate on the actual capacity installed, relative to estimated technical potential, and calculated by dividing the average annual capacity (MW) of CHP installed from 2008 through 2011 by the estimated technical potential for the 2008–2032 period.[63] Percentages of technical potential installed each year could then be applied to the estimated, 20-year technical potential to calculate market potential over the next 20 years, as shown in Table 77 and Table 78. The study estimated a cumulative 20-year market potential of 336 MW at the generator.

63 Technical potential for 2008–2032 was calculated by adding the actual installations from 2008–2011 (seven new installations with a total capacity of 50 MW) to the 20-year technical potential estimated in this study. As installation data were not yet available for 2012, Cadmus assumed the 2012 installation rate equaled the average of 2008–2011. The study calculated the market penetration rate as a single value across PacifiCorp's service area, due to the limited number of installations by state.

Table 77.CHP Market Potential by State (Cumulative in 2032)

Technology	CA	ID	OR	UT	WA	WY	Total
System Capacity (MW)	5.3	15	41	206	38	31	*336*
Number of Systems*	15	37	82	398	79	70	*681*
Total Energy (aMW)	3	7	24	101	18	15	*168*

* Number of systems does not include the reinstalled systems

Table 78. CHP Market Potential by Fuel (Cumulative in 2032)

Technology	Natural Gas	Industrial Biomass	Biogas	Total
System Capacity (MW)	305	18	12	*336*
Number of Systems*	632	22	28	*681*
Total Energy (aMW)	147	16	5	*168*

* Number of systems does not include the reinstalled systems

As the market potential was based on current installation rates, this study did not assume ramping. That is, each year's incremental potential was assumed to be one-twentieth of the total 20-year potential. For measures with an effective life of less than 20 years, the study assumed the measure would be reinstalled upon burnout.

Peak Impacts

CHP unit peak impacts were assumed the equivalent of system capacity. That is, all CHP systems could operate at their nameplate capacity during peak periods. This resulted in peak impacts of 336 MW.

Solar PV

Solar PV systems include a collection of solar modules, generally mounted on building roofs, with an inverter to convert available sunlight into electricity compatible with a building's standard electrical infrastructure. Widely applicable in the residential and nonresidential sectors, solar PV has been in use for several decades.

Technical Potential

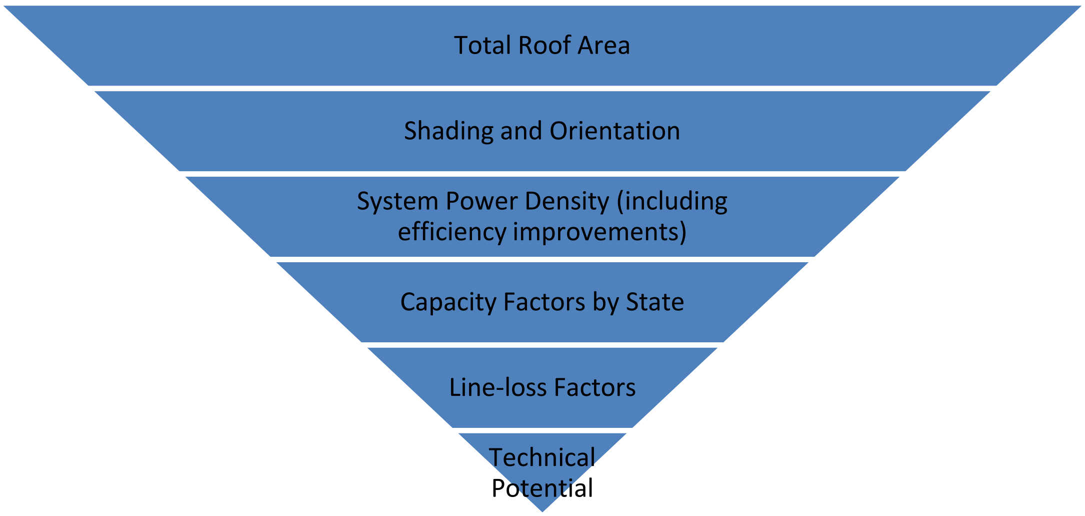
Methodology

Determining technical potential for solar PV in PacifiCorp's territory primarily involved estimating roof areas available for residential and nonresidential building stock over the study period, combined with relevant industry data, projections for system power density (installed kW per square foot), and capacity factor projections.

The study used building stock data gathered during PacifiCorp's Energy Decision Surveys, conducted in 2005 for commercial and in 2006 for residential, combined with 2011 customer data and relevant building characteristic assumptions, to identify the total roof area expected feasible for solar PV system installations. The Cadmus team then conducted a literature review of typical PV system power densities and expected efficiency improvements over the 20-year study period, which enabled calculation of expected system power density. Finally, the study applied the PVWatts tool, developed by NREL, to calculate residential and nonresidential capacity factor values for each state.

Figure 17 depicts high-level steps for determining technical potential for solar PV. Technical and market potential account for line losses, as shown in the Introduction section of this report, and all potential results are presented as values at the generator.

Figure 17. Calculation Steps for Technical Potential



Data Sources and Assumptions

As shown in Table 79, the Cadmus team used several sources to estimate technical potential in each state.

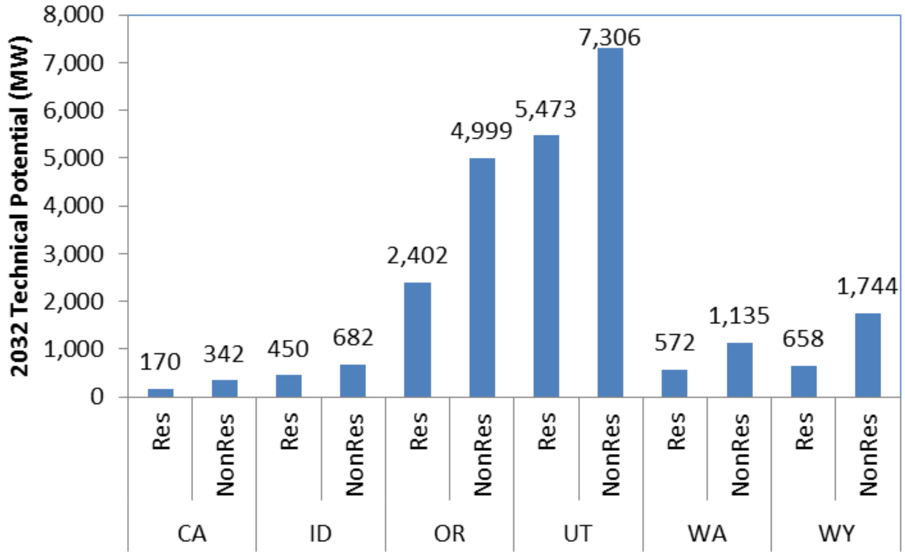
Table 79. Data Sources Used in Solar PV Technical Potential Calculations

Input	Source	Website Link
Available Roof Area by Building Type (Commercial)	PacifiCorp Energy Decisions Surveys (2005 and 2006)	N/A
Available Roof Area by Building Type (Residential)		N/A
Number of Customers by Building Type (Commercial)	PacifiCorp Customer Forecast Used in 2013 IRP and 2011 Customer Information System	N/A
Number of Customers by Building Type (Residential)		N/A
New Construction Rates by Building Type	PacifiCorp customer forecast Used in 2013 IRP	N/A
Portion of Roof Area Useable for Solar PV	Navigant Consulting, *PV Grid Connected Market Potential under a Cost Breakthrough Scenario*, 2004	http://www.ef.org/documents/EF-Final-Final2.pdf
Power Density of Solar PV	U.S. Department of Energy, *Photovoltaics - Energy for the New Millennium: The National Photovoltaics Program Plan 2000-2004*, DOE/GO-10099-940 (Washington, DC, January 2000)	Available upon request

Results

Figure 18 shows estimated 20-year technical potential for solar PV in each state within PacifiCorp's territory, indicating a combined technical potential of 9,725 MW for the residential sector, 16,208 MW for the nonresidential sector, and 25,933 MW overall.[64]

Figure 18. PacifiCorp Solar PV Technical Potential by State and Sector in 2032



Building stock within PacifiCorp's territory in each state largely drove state-specific technical potential. However, high technical potential alone did not drive market potential, as discussed in the following section.

Market Potential

Methodology

Assumed market penetration rates drew upon actual capacity installed, relative to estimated technical potential. The Cadmus team obtained installed capacity data from PacifiCorp for January 2010 through July 2012 net metering agreements in each state. In addition, PacifiCorp provided projections for the remainder of 2012. Table 80 details these data.

64 Unless otherwise noted, all capacity results reported refer to direct current (DC) capacity values.

Table 80. Installed Solar PV Capacity by State and Sector 2010–2012

		Installed Capacity (MW)		
State	**Sector**	**2010**	**2011**	**2012***
CA	Res	0.027	0.108	0.272
	NonRes	0.002	0.027	0.319
ID	Res	0.024	0.008	0.086
	NonRes	0.013	0.166	0.002
OR	Res	1.593	1.964	2.679
	NonRes	1.564	3.322	3.785
UT	Res	0.561	0.797	1.032
	NonRes	0.486	1.229	3.917
WA	Res	0.055	0.064	0.104
	NonRes	0	0.078	0.023
WY	Res	0.075	0.029	0.041
	NonRes	0.081	0.053	0.024
Total	**Res**	**2.335**	**2.97**	**4.214**
	NonRes	**2.146**	**4.875**	**8.07**

* Note: The 2012 installed capacity was based on actual data through July and projected data for August through December.

Each state received an annual market penetration rate, based on the presence (or lack thereof) of incentive programs in the state. Using data from Table 80, the Cadmus team calculated the average annual percentage of technical potential achieved in the states with long-term incentive programs (Oregon and California) and in the states without incentive programs (Washington, Idaho, and Wyoming). The Cadmus team averaged market potential in Oregon and California to estimate the long-term market penetration for Utah.

Although Utah had higher installation rates, relative to technical potential, than non-program states, Utah's incentive program remains in the pilot stage, and it likely does not accurately represent the long-term impacts of a mature and long-running incentive program. Therefore, using installation data to date for Utah could underrepresent long-term market penetration rates.

This methodology, which the study used for calculating market penetration, updated the methodology used in the 2011 Assessment, which based the market penetration rate on PV incentive programs throughout the United States with available installed capacity data. Very few states in PacifiCorp's territory had such data available at that time, and, in addition, most data were outdated. (In the Results section, Table 82 compares market penetration rates used in this study to those in the 2011 Assessment.)

Data Sources

To calculate annual and total market potential for the residential and nonresidential sectors in each state, the Cadmus team used a combination of reported actual capacity installed, by state and sector; technical potential, calculated as described above; and ramp rates. Table 81 lists these data sources.

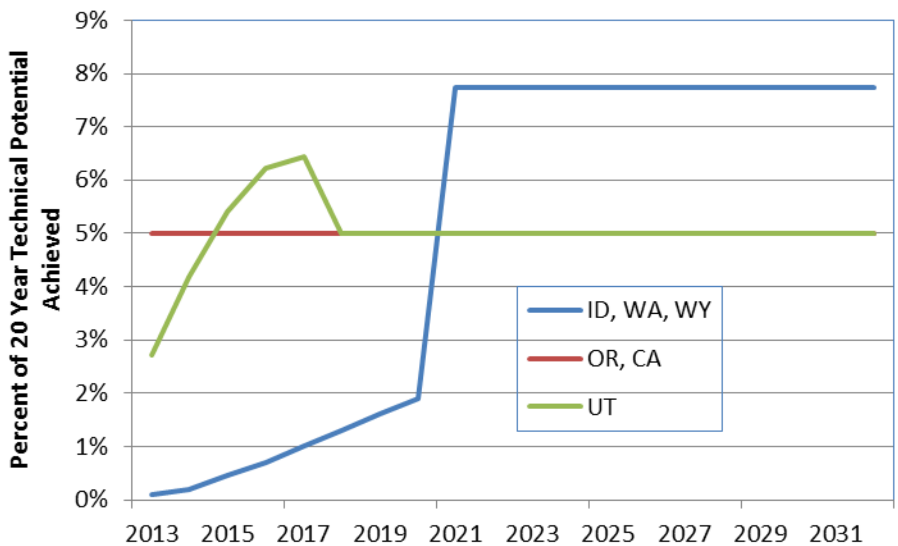
Table 81. Data Sources and Assumptions for Solar PV Market Potential

Input	Source	Website Link
Installed Capacity	Based on executed net metering agreements through July 2012 and projected through December 3012, provided by PacifiCorp.	N/A
Ramp Rate (for states without incentive programs: ID, WA, WY)	Lost Opportunity Emerging Technology Ramp Rate.	www.nwcouncil.org/energy/powerplan/6/default.htm
Ramp Rate (OR and CA)*	Assumed flat ramp rate of 5% per year, over 20 years, reflecting presence of an established incentive program.	N/A
Ramp Rate (UT only)	Assumes an initial five-year period to ramp up and maintain consistency with program filings.	N/A

*At PacifiCorp's direction, 2013–2017 market potentials for Utah were fixed to match program filings.

The study used ramp rates to adjust annual market potential numbers and to account for factors such as market momentum, supply chain initialization, and consumer education. Ramp rates, shown in Figure 19, did not impact 20-year total technical or market potentials, merely impacting the assumed rate of acquisition.

Figure 19. Solar PV Ramp Rates



Results

As shown in Table 82, this study's methodology resulted in increased estimated market penetration for states with existing incentive programs (Oregon, California, and Utah), compared to the 2011 assessment. The table's values represent the average percentage of the 20-year technical potential, acquired annually.

Table 82. Solar PV Annual Market Penetration Rates Used in the 2011 and 2013 IRPs

Existing Program?	State	2011 Assessment	Annual Market Penetration Rate	
			Residential	Nonresidential
No	WA	0.02%	0.02%	0.01%
	ID	0.01%		
	WY	0.01%		
Yes	OR	0.02%	0.14%	0.08%
	CA	0.02%		
	UT	0.02%		

Table 83 summarizes technical and market potential results for the residential and nonresidential sectors in each state. A total of 428 MW of installed capacity may be achieved system-wide by 2032. Table 84 provides the energy corresponding with these capacity potentials.

Table 83. Solar PV Technical and Market Potential (Cumulative MW in 2032)

State	Sector	20-year Technical Potential (MW)	20-year Market Potential (MW)
CA	Res	170	4.7
	NonRes	342	5.2
ID	Res	450	1.6
	NonRes	682	1.4
OR	Res	2,402	66
	NonRes	4,999	76
UT	Res	5,473	151
	NonRes	7,306	111
WA	Res	572	2.0
	NonRes	1,135	2.3
WY	Res	658	2.4
	NonRes	1,744	3.5
Total	**Res**	**9,725**	**228**
	NonRes	**16,208**	**199**

Table 84. Solar PV Technical and Market Penetration (Cumulative aMW in 2032)*

State	Sector	Technical Potential (aMW)	Market Potential (aMW)
CA	Res	23	0.7
	NonRes	46	0.7
ID	Res	65	0.3
	NonRes	97	0.2
OR	Res	322	9.5
	NonRes	669	11
UT	Res	816	24
	NonRes	1,079	17
WA	Res	76	0.3
	NonRes	149	0.3
WY	Res	106	0.4
	NonRes	275	0.6
Total	**Res**	**1,408**	**35**
	NonRes	**2,316**	**30**

* Note: values in this table include performance degradation losses for systems installed prior to 2032.

Peak Impacts

To estimate the peak impact of achievable solar PV potential, the Cadmus team combined the modeled hourly output profile of typical solar PV systems in each state and sector, as described previously, with the PacifiCorp peak 40 hours of annual demand. By matching these two curves, the Cadmus team calculated an average capacity factor applying to peak demand periods for solar PV in the residential and commercial sectors for each state. In general, every MWdc of installed PV results in approximately 400 kW of peak reduction, varying slightly by state and segment. Total peak reduction for PV is estimated at 177 MW.

Levelized Cost of Energy

Methodology

The LCOE, based on a single representative PV system for each sector, compares life-cycle costs to energy savings. The LCOE was calculated using the TRC perspective for all states except Utah (where, as noted, the UCT is the accepted perspective). The Cadmus team calculated levelized costs separately for residential customers (separated into single-family and multifamily buildings) and commercial customers (a category including health, lodging, large office, large retail, and school buildings).

The study adjusted installation and O&M costs in future years based on inflation and discount rates. The Cadmus team also collected data on cost trends, module efficiency improvements, and module performance degradation to estimate energy outputs of systems installed in future years and of systems as they age. The PVWatts model, developed by NREL, produced estimates of capacity factors for a typical system within each state, during the first year of operation.

Data Sources and Assumptions

The Cadmus team reviewed multiple data sources for the analysis, as shown in Table 85 (by inputs used in analysis). The table includes Website links to sources (if available). If reports or data cannot be found online, interested parties may contact the Cadmus team or PacifiCorp to request the information.

Table 85. Data Sources Used for the Solar PV LCOE Analysis

Input	Source	Website Link (Where Available)
Installed Cost	California Solar Initiative (CSI) Program Data, downloaded July 2012.	http://www.californiasolarstatistics.ca.gov/current_data_files/
Installed Cost	Utah Solar PV Incentive Pilot Program Data from 2011.	Provided by PacifiCorp.
Installed Cost	Utah State Energy Program 2011 data.	Provided by Utah State Energy Program.
Installed Cost	Energy Trust data.	Provided by the Energy Trust.
Inverter Costs	Solar Buzz Website.	http://www.solarbuzz.com/Inverterprices.htm
Annual Change in Installed Cost	Lawrence Berkeley National Laboratory. Tracking the Sun IV: The Installed Cost of Photovoltaics in the U.S. from 1998-2010. September 2011.	http://eetd.lbl.gov/ea/emp/re-pubs.html
O&M Cost	Arizona Renewable Energy Assessment by Black and Veatch; Comparative Costs of California Central Station Electricity Generation Technologies by the CEC with Aspen Environmental Group; and Renewable Energy Transmission Initiative for RETI	Provided by NREL in its 2007 comments.

Input	Source	Website Link (Where Available)
	Coordinating Committee.	
Tilt	Utah Solar PV Incentive Pilot Program Data for 2011.	Provided by PacifiCorp.
Azimuth	Utah Solar PV Incentive Pilot Program Data for 2011.	Provided by PacifiCorp.
Capacity Factor	PVWatts Solar Calculator.	http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/
Annual Change in Module Efficiency	"Solar Energy Technologies Program, Multi-Year Technical Plan 2003-2007 and beyond" U.S. DOE Energy Efficiency and Renewable Energy.	Can be provided by the Cadmus team upon request.
Average Size	Utah Solar PV Incentive Pilot Program Data for 2011.	Provided by PacifiCorp.
Average Size	Utah State Energy Program.	Provided by the Utah State Energy Program.
Average Size	Energy Trust data for 2011.	Provided by Energy Trust.
Performance Degradation	PVWatts default model assumption.	http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/derate.cgi
Measure Life	Assumptions used by NREL's System Advisor Model (SAM).	http://www.sam.nrel.gov
Federal Rebate	Database of State Incentives for Renewables and Efficiency.	http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US37F&re=1&ee=1
State Rebates	Database of State Incentives for Renewables and Efficiency.	http://www.dsireusa.org/

This analysis did not include interconnection costs. The cost to cover basic application reviews and meter replacements by the utility is estimated at less than 1% of total system costs, therefore having a minimal impact on cost-effectiveness.

Overview of Installed System Cost Data

The Cadmus team gathered and reviewed installed system cost data from four main sources:

1. The Utah Solar PV Incentive Pilot Program
2. The Utah State Energy Program
3. The California Solar Initiative (CSI)
4. Energy Trust of Oregon Program

Table 86 compares installed costs reported for these programs.

Table 86. Comparison of Installed Costs for Solar PV Systems in the U.S.

Size (kW) (CEC PTC AC)*	2011 Utah Pilot Systems (2012 $/W)	2011 Utah State Energy Program Systems (2012 $/W)**	2011 CSI Systems (2012 $/W)	2012 CSI Systems (2012 $/W)	Energy Trust (2012 $/W)***
< 5 kW	$6.57	$7.56	$7.94	$7.46	$7.70
5 to 10 kW	Sample size is too small	$6.84	$6.40	$5.91	n/a
10 to 30 kW	Sample size is too small	$8.14	$6.13	$5.20	$7.21

*The CEC Photovoltaics for Utility Scale Applications (PVUSA) Test Conditions (PTC) module size was used, with the inverter efficiency taken into account to convert direct current (DC) to alternating current (AC). PVUSA Test Conditions include: 1,000 watts of solar irradiance per square meter; 20 degrees Celsius air temperature; and wind speed of 1 meter per second at 10 meters above ground level. Standard test conditions (STC) include: 1,000 watts of solar irradiance per square meter; 25 degrees Celsius cell temperature; air mass equaling 1.5; and ASTM G173-03 standard spectrum. The PTC rating, lower than the STC rating, offers a more realistic measure of module output, as test conditions better reflect "real-world" solar and climatic conditions, compared to the STC rating.

**Values converted from cost per DC watt at STC to cost per AC watt at PTC, by assuming: 1.2 W STC-DC per 1.0 W CEC PTC-AC.

***The Energy Trust provided average system cost data for residential and nonresidential systems, with the < 5 kW system cost corresponding to residential systems (with an average size of 2.7 kW), and the 10 to 30 kW system cost corresponding to nonresidential systems (with an average size of 13.9 kW).

For Utah and CSI system costs, the Cadmus team used the year customers first applied for the program, assuming this the best proxy for the year the customer received a price quote. Analysis also eliminated CSI systems with third-party system owners, as it could not be determined whether these systems fell under a Power Purchase Agreement, which generally resulted in higher reported costs. The study removed sales tax from California costs to isolate PV equipment and installation costs. Data received from other sources already included this adjustment; therefore, no further sales tax-related adjustments were necessary.

Residential and Commercial Inputs to Levelized Cost Analysis

Solar PV system costs remain at historic lows and will likely continue to decrease. Due to large influxes of inexpensive PV modules over the past several years (primarily from China), costs have decreased more rapidly than suggested by longer-term trends. Pending tariff regulations from the Department of Commerce on Chinese-manufactured solar PV modules likely will play a role in leveling out recent declines in solar PV prices.

Whether present cost reduction rates will persist beyond the short term is unknown, and significant uncertainty exists regarding short-term price predictions. Consequently, the Cadmus team used long-term historical cost data, presented in the Lawrence Berkeley National Laboratory (LBNL) study referenced in Table 87, which represents a conservative predictor of future cost trends.

The following tables summarize inputs used for the analysis. Table 87 lists assumptions for residential single-family systems.

Table 87. Solar PV Residential Single-Family Assumptions

Input	Value	Reasoning
Average Size	3 kW	Average residential system size in the 2011 Utah Solar PV Incentive Pilot Program was 3.2 kW, as was the average residential system size in the Utah State Energy Program in 2011. The average size in the Energy Trust program in 2012 is 2.7 kW.
Measure Life (years)	30	The typical module manufacturer warranty period is 25 years. The NREL SAM assumes a 30-year life.
2013 Installation Cost ($/W)	$7.45	Average cost from programs reviewed.
Annual Change in Nominal Installation Cost	-4.6%	From the LBNL study, as the trend from 1998 to 2010; supported by lower costs in Germany and Japan, which should be achievable in the U.S. as the market grows. Though costs have seen a larger annual decline in recent years (per LBNL, as much as 22% from 2010 to 2011), it is not expected this will continue over 20 years.
O&M Cost (nominal cost for inverter replacement in year 15)	$2,133	Based on Solarbuzz inverter costs reported for March 2012 of $0.711/W. Assumes one inverter replacement over the 30-year life, which also falls within the range ($25–$100 per year), presented by NREL comments on the 2007 report.
Tilt (degrees)	32	Average residential system tilt in the Utah Solar PV Incentive Pilot Program from 2010–2011.
Azimuth	South	Average residential system azimuth in the Utah Solar PV Incentive Pilot Program from 2010–2011.
Inverter Efficiency	95%	Typical inverter efficiency.
Annual Change in Module Efficiency	2.1%	US DOE EERE report on Solar Energy Technologies Program Multi-Year Technical Plan; average across all three classes of technology (mono-crystalline, poly-crystalline, and amorphous thin-film).
Annual Performance Degradation	1%	PV Watts default derate value.
Capacity Factor	Depends on location	From PV Watts.

*Some assumptions also apply to calculations made for the technical and/or market potential.

Table 88 lists assumptions for multifamily, commercial, and industrial systems.

Table 88. Solar PV Multifamily, Commercial, and Industrial Assumptions

Input	Value	Reasoning
Average Size	20 kW	The average commercial system size in the 2011 Utah Solar PV Incentive Pilot Program was 19.1 kW. The average size in the 2011 Utah State Energy Program was 11.5 kW. It is assumed a full-scale incentive program would see more participants and larger systems.
Measure Life (years)	30	Typical module manufacturer warranty period is 25 years. The NREL SAM assumes a 30-year life.
2013 Installation Cost ($/W)	$6.67	Average cost from the programs reviewed.
Annual Change in Nominal Installation Cost	-4.6%	Found in the LBNL study as the trend from 1998 to 2010; supported by lower costs in Germany and Japan, which should be achievable in the U.S. as the market grows. Though costs have seen a larger annual decline in recent years (per LBNL, as much as 22% from 2010 to 2011), it is not expected this will continue over 20 years.
O&M Cost (nominal cost for inverter replacement in year 15)	$14,220	Based on Solarbuzz inverter costs reported for March 2012 of $0.711/W; assumes one inverter replacement over the 30-year life.
Tilt (degrees)	25	Average commercial system tilt in the Utah Solar PV Incentive Pilot Program from 2010–2011.
Azimuth	South	Average commercial system azimuth in the Utah Solar PV Incentive Pilot Program from 2010–2011.
Inverter Efficiency	95%	Typical inverter efficiency.
Annual Change in Module Efficiency	2.1%	U.S. DOE EERE report on Solar Energy Technologies Program Multi-Year Technical Plan; average across all three classes of technology (mono-crystalline, poly-crystalline, and amorphous thin-film).
Annual Performance Degradation	1%	PV Watts default derate value.
Capacity Factor	Depends on location	From PV Watts.

*Some assumptions also apply to calculations made for the technical and/or market potential.

Results

As shown in Table 89, LCOE likely will decrease over the next 20 years, with the notable exception of the federal ITC expiration at the end of 2016, causing LCOE to increase before resuming a downward trend through 2032. As discussed, the markedly lower LCOE for Utah results from use of the UCT, whereas the remainder of the states' LCOE use the TRC perspective.

Table 89. Solar PV Levelized Cost of Energy Summary Results and Capacity Factors

State	Sector	Levelized Cost*			Capacity Factor
		2013 ($/kWh)	2017** ($/kWh)	2032** ($/kWh)	
CA	Res	$0.30	$0.35	$0.18	0.16
	NonRes	$0.27	$0.32	$0.16	0.16
ID	Res	$0.28	$0.33	$0.17	0.17
	NonRes	$0.26	$0.30	$0.16	0.17
OR	Res	$0.30	$0.35	$0.18	0.16
	NonRes	$0.27	$0.32	$0.17	0.16
UT	Res	$0.07	$0.06	$0.03	0.17
	NonRes	$0.06	$0.05	$0.03	0.17
WA	Res	$0.30	$0.36	$0.18	0.16
	NonRes	$0.28	$0.33	$0.17	0.16
WY	Res	$0.25	$0.30	$0.15	0.19
	NonRes	$0.23	$0.27	$0.14	0.19

* Utah LCOE was calculated using the UCT, while other states use the TRC test.

**The Federal ITC will expire at the end of 2016. LCOE estimates for 2017 and 2032 assume the ITC will not be extended or renewed.

Solar Water Heating

SWH systems use sunlight to pre-heat domestic hot water tanks, reducing the need for electricity to heat water. Widely applicable in the residential and nonresidential sectors, SWHs have been in use for several decades.

Technical and Market Potential

Methodology

The Cadmus team calculated technical potential for SWH using the following steps:

1. The study calculated the total number of electric hot water heaters in each state and sector, based on survey data.
2. The estimated number of electric water heaters was reduced by the number of heat pump water heaters included in the 20-year Class 2 DSM achievable technical potential.
3. The number of eligible water heaters was then multiplied by the water heater UEC in each segment, calculated as part of the Class 2 DSM analysis.
4. A series of RETScreen models determined representative solar fraction values for each state and sector, representing the percentage of water heating consumption the unit could offset. These values were applied to the results of step three to arrive at the 20-year technical potential.

The Cadmus team assumed a 15% maximum market penetration for all segments, basing this market potential percentage on actual Energy Trust rebate data (for program years 2009 through

2011) and on technical potential calculated by Energy Trust. The Cadmus team used the same lost opportunity ramp rate as the Council to allocate the 20-year potential annually.[65]

Results

Table 90 shows the results of the Cadmus team's analysis and summarizes 20-year cumulative technical and market potential by state and sector, as measured at the generator.[66]

Table 90. SWH Technical and Market Potential by State and Sector (Cumulative aMW in 2032)

Sector	CA	ID	UT	WA	WY	Total*
Technical Potential						
Nonresidential	0.12	0.12	0.96	0.27	0.20	1.67
Residential	1.85	3.20	10.5	2.47	2.43	20.5
Total*	**1.97**	**3.32**	**11.4**	**2.74**	**2.63**	**22.1**
Market Potential						
Nonresidential	0.02	0.02	0.14	0.04	0.03	0.25
Residential	0.28	0.48	1.57	0.37	0.36	3.06
Total*	**0.30**	**0.50**	**1.71**	**0.41**	**0.39**	**3.31**

*Totals may vary slightly due to rounding.

Though the SHW industry generally does not discuss systems in terms of rated capacity (e.g., kilowatts), it can be useful to understand the general instantaneous output of a SHW system for assessing utility grid impacts and for comparison with other efficiency or renewable energy measures. In 2004, the International Energy Agency established a 0.7 $kW_{thermal}/m^2$ (0.065 kWthermal/ft^2) value as a benchmark for converting a gross collector area into an equivalent rated power value.[67]

Peak Impacts

Peak impacts derive from the water heating load shape and its coincidence factor during peak periods. In other words, the peak impact is calculated based on MW = aMW * CF, where CF represents the coincidence factor. The Pacific Power territory has a coincidence factor of 0.973, and Rocky Mountain Power territory has a factor of 0.971. Total peak reduction is estimated at 3.2 MW.

65 http://www.nwcouncil.org/energy/powerplan/6/default.htm The Council's potential did not include manufactured homes.

66 The Energy Trust estimates potential for SWH in PacifiCorp's Oregon service territory. Results can be found in Energy Trust's 2012 Resource Assessment Update: http://energytrust.org/library/reports/121114_2012_ResourceAssessment.pdf

67 Winn, Menicucci, and Vuppuluri. *Effective Power Ratings for Solar Hot Water Systems*. Available at: http://www.academia.edu/247830/EFFECTIVE_POWER_RATINGS_FOR_SOLAR_HOT_WATER_SYSTEMS

Levelized Cost of Energy

Methodology

The LCOE, based on a single representative SWH system for each state and sector, compares life-cycle costs to energy savings, calculated based on the TRC perspective for all states (except Utah, which uses the UCT). Applicable commercial segments were chosen based on average annual hot water heating electricity consumption of at least 9,000 kWh, as these facilities were more likely to have sufficient hot water heating loads to justify investments in SWH systems.

Sources

In early 2009, Itron released an Interim Evaluation report for the California Center for Sustainable Energy (CCSE) Solar Water Heating Pilot Program (SWHPP). This report compiled SWH information from numerous sources, including cost data from incentive programs in the United States and information from contractor interviews.[68]

For the SWH analysis, the Cadmus team reviewed the Itron report and other data sources, such as the ENERGY STAR Website and NREL. The Cadmus team also downloaded the most recent California Solar Thermal program data from the California Public Utilities Commission to update installed system costs for residential and nonresidential systems. The Cadmus team obtained information about average system costs for residential systems from the Energy Trust.

Resources for Calculations

The solar fraction—the percentage of energy used for heating water provided by the SWH—provided the data required to calculate energy savings. Solar fractions for each segment and location combination were developed using RETScreen International[69] and assumptions of gallons of hot water used per day and sector-specific load shapes. Numbers of collectors were adjusted until the solar fraction neared 70%, as systems typically are designed to reach a solar fraction of 40% to 80%.[70]

The utility incentive level was defined as 10% of the incremental cost, based on Energy Trust rebate information for program years 2009 to 2011. The Cadmus team's analysis applied this 10% rebate after the 30% federal rebate during program years 2013 to 2016. The Cadmus team's review of other states' SWH programs indicated incentives ranging from 10% to 20%; therefore, Energy Trust's incentive offers a reasonable—if slightly conservative—assumption for all states.

Overview of Installed System Cost Data

Table 91 compares installed costs for residential retrofit SWH systems in the United States. SWH systems, unlike some other water heater efficiency improvements, typically do not replace

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[68] The CCSE SWHPP Interim Report can be downloaded from: http://energycenter.org/uploads/CCSE_SWHPP_Interim_Report_Final.pdf

[69] Natural Resources Canada developed RETScreen International, which can be downloaded free of charge from: http://www.retscreen.net/

[70] NREL. The Technical Potential of Solar Water Heating to Reduce Fossil Fuel Use and Greenhouse Gas Emissions in the United States. March 2007, page 5. Accessed August 2, 2010, from http://www.nrel.gov/docs/fy07osti/41157.pdf.

a customer's existing hot water heater. Rather, most SWH systems supplement existing hot water heaters by pre-heating the cold water supply (e.g., well or municipal) before it enters an existing hot water heater.

Table 91. Comparison of Installed Costs for U.S. Residential Single-Family SWH Systems

Program	Average Residential System Cost (2012 $)	Typical System Type
California Solar Thermal Program 2012	$8,401*	Active glycol and drainback systems
Eugene Water and Electric Board 2008	$7,607	Active glycol and drainback systems
Energy Trust 2011-2012	$8,688	Active glycol and drainback systems

*Adjusted to remove sales tax.

The Cadmus team derived installation costs for nonresidential SWH projects from data reported by the California Solar Hot Water Program in 2012. The study assumed SWH system costs remain constant over time, with economies of scale due to increased market adoption balancing increasing material costs for SWH system components.

Residential, Multifamily, and Commercial Inputs

Table 92 lists inputs and assumptions used in the Cadmus team's analysis of residential systems.

Table 92. Solar Water Heating Residential Assumptions

Input	Value	Reasoning
Average Size (collector square feet)	48	Assumes two collectors, with the typical collector area of 40 to 60 square feet per home.
Measure Life (years)	20	Minimum collector lifetime from warranty claims in Hawaii. See SWHPP Interim Report Table 5-3; ENERGY STAR also lists a 20 year lifetime: http://www.energystar.gov/index.cfm?c=solar_wheat.pr_savings_benefits
Installed Cost for Retrofit Systems	$8,500	Average cost (rounded), reported by the CA Solar Thermal Program and the Energy Trust.
Assumed Rebate (% of incremental cost)	10%	The Energy Trust has offered a 10% rebate on average for the last several years.
Annual Change in Nominal Installed Cost	0%	Costs have increased steadily over the past six years, due to increases in material costs. The study assumes costs will stabilize over the next 20 years.
O&M Cost	$120 every three years; $40 per year (nominal)	Assumes customers have systems inspected every three to four years, and occasionally have heat transfer fluid flushed and replaced. (SWHPP Interim Evaluation Report Table 7-6). The Cadmus team assumes a three-year replacement cycle, at the conservative end of the given range.
Tilt (degrees)	32	Average residential system tilt in the Utah Solar PV Incentive Pilot Program from 2010–2011.
Azimuth	South	Average residential system azimuth in the Utah Solar PV Incentive Pilot Program.
Annual Change in Efficiency	0%	As solar thermal is a mature technology, improvements in efficiency are not expected.
Annual Performance Degradation	1%	Assumption used in the NREL SAM, which can be downloaded for free of charge from: https://www.nrel.gov/analysis/sam/
Solar Fraction	Varies by location	Modeled using RETScreen International.
Federal Tax Incentive (% of installed cost, no cap)	30%	The current federal tax incentive for renewable energy measures, set to expire on December 31, 2016.

Table 93 lists inputs and assumptions for the Cadmus team's analysis of commercial systems.

Table 93. Solar Water Heating Multifamily and Commercial Assumptions

Input	Value	Reasoning
Average Size	Varies by sector and location	Size calculated based on gallons of hot water used per day in each segment within each state.
Measure Life (years)	20	Minimum collector lifetime from warranty claims in Hawaii. See SWHPP Interim Report Table 5-3; ENERGY STAR also lists a 20-year lifetime: www.energystar.gov/index.cfm?c=solar_wheat.pr_savings_benefits
Installed Cost for Retrofit Systems ($/collector square foot)	$106	Average cost per square foot for commercial and multifamily systems in the California Solar Thermal program in 2012.
Assumed Rebate (% of incremental cost)	10%	The Energy Trust has offered a 10% rebate on average for the last several years.
Annual Change in Nominal Installed Cost	0%	The Cadmus team assumes costs will remain stable over the next 20 years.
Annual O&M Cost	10% of installation cost divided by 20 years	Assumes customers have systems inspected and glycol flushed and replaced periodically. (SWHPP Interim Evaluation Report Table 7-11)
Tilt (degrees)	25	Average commercial system tilt in the Utah Solar PV Incentive Pilot Program, from 2010–2011.
Azimuth	South	Average commercial system azimuth in the Utah Solar PV Incentive Pilot Program from 2010–2011.
Annual Change in Efficiency	0%	As solar thermal is a mature technology, improvements in efficiency are not expected.
Annual Performance Degradation	1%	Assumption used in the NREL SAM, which can be downloaded free of charge from: https://www.nrel.gov/analysis/sam/
Solar Fraction	Varies by location and sector	Modeled using RETScreen International.
Federal Tax Incentive (% of installed cost; no cap)	30%	The current federal tax incentive for renewable energy measures, set to expire on December 31, 2016.

Results

Table 94 shows levelized costs for SWH systems before and after expiration of the ITC, as calculated from the TRC perspective for all states except Utah (as based on the UCT). Incentive levels before and after the ITC expiration are held constant, assuming no additional utility funds will be provided to offset additional costs from 2017 onwards.

Table 94. SWH Levelized Cost of Energy Before and After the ITC Expiration

Sector	Levelized Cost of Energy ($/kWh)				
	CA	ID	UT*	WA	WY
2013-2016					
Nonresidential	$0.18	$0.16	$0.02	$0.18	$0.15
Residential	$0.45	$0.29	$0.04	$0.45	$0.36
2017-2032					
Nonresidential	$0.25	$0.22	$0.02	$0.26	$0.21
Residential	$0.63	$0.40	$0.04	$0.62	$0.50

* LCOE values for Utah calculated using the UCT; all other states use the TRC perspective.

Summary of Results

Technical Potential

Table 95 provides the technical potential for supplemental resources, by resource category territory.

Table 95. Supplemental Resources Technical Potential by Territory and Resource Category (Cumulative aMW in 2032)

Resource	Rocky Mountain Power	Pacific Power	PacifiCorp System
CHP	3,227	1,074	4,301
On-Site Solar: PVs	2,438	1,285	3,724
On-Site Solar: Water Heating*	17.4	4.7	22.1
Total	**5,682**	**2,364**	**8,047**

*Excludes Oregon

Note: Results may not sum to totals due to rounding.

Market Potential

Table 96 shows a market potential (or the amount of resources expected to be achievable over the 20-year planning horizon) of 202 aMW, broken down by resource category and territory.

Table 96. Market Potential for Supplemental Resources by Territory and Resource Category (Cumulative aMW in 2032)

Resource	Rocky Mountain Power	Pacific Power	PacifiCorp System
CHP	123	45	168
On-Site Solar: PVs	43	23	65
On-Site Solar: Water Heating*	2.6	0.7	3.3
Total	**168**	**68**	**236**

* Excludes Oregon

Note: Results may not sum to totals due to rounding.