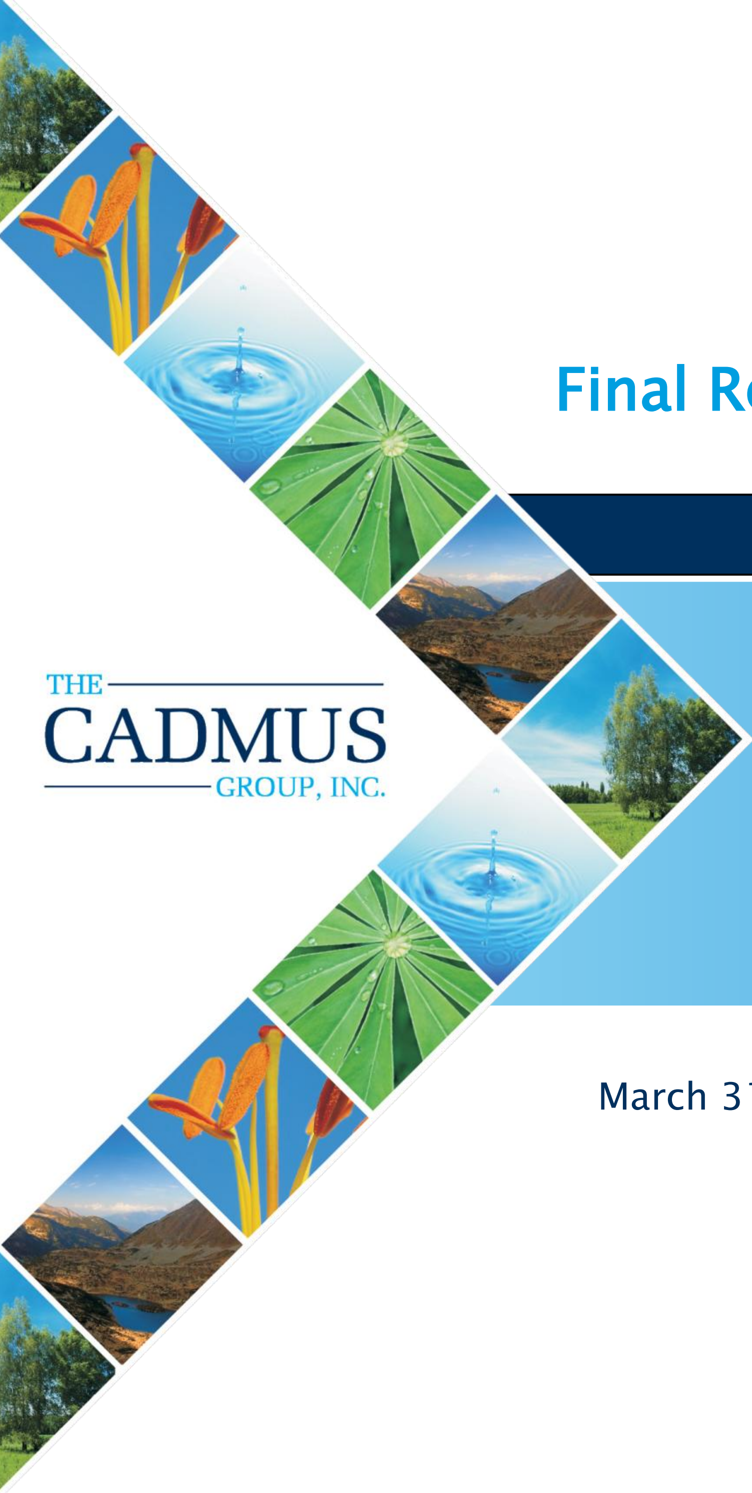

Final Report

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

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Definition of Terms

aMW	Average Megawatt
C&I	Commercial and Industrial
CBECS	Commercial Building Energy Consumption Survey
CHP	Combined Heat and Power
Council	Northwest Power and Conservation Council
CPP	Critical Peak Pricing
CPUC	California Public Utilities Commission
CSI	California Solar Initiative (program database)
DBB	Demand Buyback
DEER	Database of Energy Efficiency Resources
DLC	Direct Load Control
DSM	Demand-side Management
EIA	Energy Information Administration
ETO	Energy Trust of Oregon
EUIs	End-use Intensities
FC	Fuel Cell
GT	Gas Turbine
IRP	Integrated Resource Plan
LMOP	Landfill Methane Outreach Program (US EPA)
MT	Microturbine
NEEA	Northwest Energy Efficiency Alliance
PV	Photovoltaic
RE	Reciprocating Engine
RECS	Residential Energy Consumption Survey
RTF	Regional Technical Forum
RTP	Real-time Pricing
SCE	Southern California Edison
SGIP	Self-Generation Incentive Program (in California)
TES	Thermal Energy Storage
TOU	Time of use
UEC	Unit Energy Consumption

Acknowledgements

This study required compilation of a large amount of data from various sources, including several departments at PacifiCorp. It would be difficult to overstate the importance of the contributions PacifiCorp's staff made by to this effort. We thank all of them for their assistance.

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We thank Jeff Bumgarner, Director of Demand Side Management, and Don Jones, Jr., Senior Program Manager, , for their support. They offered invaluable insight and direction throughout the course of this study, while allowing us to exercise our independent judgment and to maintain our objectivity.

Executive Summary

Overview

PacifiCorp has provided a comprehensive set of demand-side management (DSM) programs to its customers since the 1970s. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. PacifiCorp is an innovator in energy efficiency, and has conceived and implemented programs such as Energy FinAnswer, which, in its class, is considered one of the best programs in North America.

Beginning in 1989, PacifiCorp developed biennial integrated resource plans (IRPs) to identify the optimal, least-cost mix of supply and demand-side options to meet its projected long-term resource requirements. This report summarizes the results of an independent study by The Cadmus Group Inc. to conduct a comprehensive, multi-sector assessment of the long-term potential for DSM resources in PacifiCorp's Pacific Power (Oregon,[1] Washington, and California) and Rocky Mountain Power (Idaho, Wyoming, and Utah) service territories. The study will support PacifiCorp's IRP process, state initiatives and further PacifiCorp's active pursuit of DSM resources.

This study's principal goal is to develop reliable estimates of the magnitude, timing, and cost of alternative DSM and supplemental resources, comprised of capacity-focused program options (defined throughout this report as Class 1 and Class 3 DSM resources), energy-efficiency products and services (defined as Class 2 DSM resources), and other "supplemental" resources such as solar and combined heat and power (CHP). This study is an update to PacifiCorp's comprehensive assessment of DSM and supplemental resources completed in 2007 (hereafter referred to as the 2007 Assessment).[2] A key difference between this study and the previous study is that no preliminary economic screen was performed for this study. As such, the results presented here include potential from resources with levelized costs up to several hundred dollars per kWh, and are not expected to all be economically viable for PacifiCorp to acquire. Economic selections and screening will be performed in conjunction with the development of the Company's IRP process and related analysis.

The study's main emphasis has been on resources with sufficient reliability characteristics, which are expected to be technically feasible (technical potential) and assumed achievable (achievable technical potential) during the 20-year planning horizon. Not all the achievable technical potential is cost-effective. For energy-efficiency resources (hereafter referred to as Class 2 DSM), the methods used to evaluate the technical and achievable technical potentials drew upon practices standard in the utility industry and used by other planning bodies within PacifiCorp's service territories, including the Northwest Power and Conservation Council (Council) in its assessment of regional energy-efficiency potential in the Northwest. Potential for capacity-focused resources (hereafter referred to as Class 1 and Class 3 DSM) and supplemental

[1] Since the ETO is responsible for the assessment and delivery of Class 2 DSM resources in Oregon, potential for these resources are exclusive of Oregon.

[2] "Assessment of Long-Term System-Wide Potential for Demand-Side and Other Supplemental Resources," Quantec, Summit Blue, Nexant, July 2007.

resources have been calculated using a similar methodology, with one exception. In this case, expected market acceptance rates based on customer surveys (Class 1 and Class 3 DSM) and prevailing trends in the U.S. (supplemental resources) were applied to technical potential to develop estimates of the achievable technical potential.

Summary of the Results

This study's results indicate a cumulative, system-wide, *technical* energy-focused potential of 1,408 average megawatts (aMW)[3] of electric energy savings over the 20-year planning horizon from 2011 to 2030 (Table ES-1). This technical potential for Class 2 DSM resources is nearly 25 percent higher than that found in the 2007 Assessment. The higher potentials originate from additional saving potentials in the residential and industrial sectors derived from new technologies such as ductless heat pumps, heat pump water heaters and industrial energy management, which were not either in the prior study or were treated as an emerging technology with significantly lower expected market saturation and feasibility. In addition, saturations of plug loads have increased appreciably since the prior study, with a corresponding increase in technical potential.

The technical potential energy savings impacts from supplemental resources are not included here as they were in the 2007 Assessment, as those values are significantly higher than the achievable technical potential, and thus misrepresent the totals. Approximately 1,334 aMW are assumed to be reasonably achievable once normal market and program delivery constraints are accounted for. Class 2 DSM (energy-efficiency) resources account for 87 percent (1,156 aMW), and supplemental resources (including on-site solar and CHP) account for the remaining 13 percent (178 aMW) of the achievable technical energy-efficiency potential. These results represent the savings measured at generation; therefore, they account for appropriate transmission and distribution losses.

Table ES-1. Energy-Focused Resource Potential (aMW in 2030): Technical and Achievable Technical by Resource and Service Territory

Resource Class/Service Territory	Technical Potential	Achievable Technical Potential
Rocky Mountain Power		
Class 2 DSM Resource	1,231	1,008
Supplemental Resource	NA	104
Pacific Power		
Class 2 DSM Resource*	177	148
Supplemental Resource	NA	74
PacifiCorp System	**1,408****	**1,334**

* Excludes Oregon.
** Class 2 DSM only
Note: Individual results may not sum to total due to rounding.

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

The coincident peak demand impacts from the identified resources are given in Table ES-2.[4] Note that these impacts do not factor in several of these products competing for the same markets and thus not being mutually exclusive. If all Class 2 DSM resources were implemented, they would reduce the load basis from which the Class 1 and 3 DSM impacts could be calculated. In addition, Class 1 and 3 DSM programs are not mutually exclusive; thus, the overall peak impact from demand-focused programs will be reduced if all interactions are accounted for. Again, the technical potential peak impact from supplemental resources is not included here, as those values are significantly higher than the achievable technical potential.

Table ES-2. Peak Demand Reduction Potential (MW in 2030): Technical and Achievable Technical by Resource and Service Territory

Resource Class/Service Territory	Technical Potential	Achievable Technical Potential
Rocky Mountain Power		
Class 1 DSM Resource	2,698	536
Class 2 DSM Resource	2,942	2,383
Class 3 DSM Resource	2,791	357
Supplemental Resource	NA	105
Pacific Power		
Class 1 DSM Resource	614	87
Class 2 DSM Resource*	318	267
Class 3 DSM Resource	699	157
Supplemental Resource	NA	69

* Excludes Oregon.

Because this study excludes an assessment of Oregon’s Class 2 DSM (energy-efficiency) potential, the report skews results towards Rocky Mountain Power service territories, which account for a disproportionately larger share of the total energy-focused resources (83 percent), and account for more than 87 percent of system peak demand reductions (Figure ES-1 and Figure ES-2). Oregon’s energy-efficiency potential has been captured in work conducted by the Energy Trust of Oregon, which provides these data to PacifiCorp for resource planning.

[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 are defined by program hours, and are not truly additive.

Figure ES-1. Achievable DSM Potential by Resource Type (MW and aMW 2030) (Rocky Mountain Power Territory)

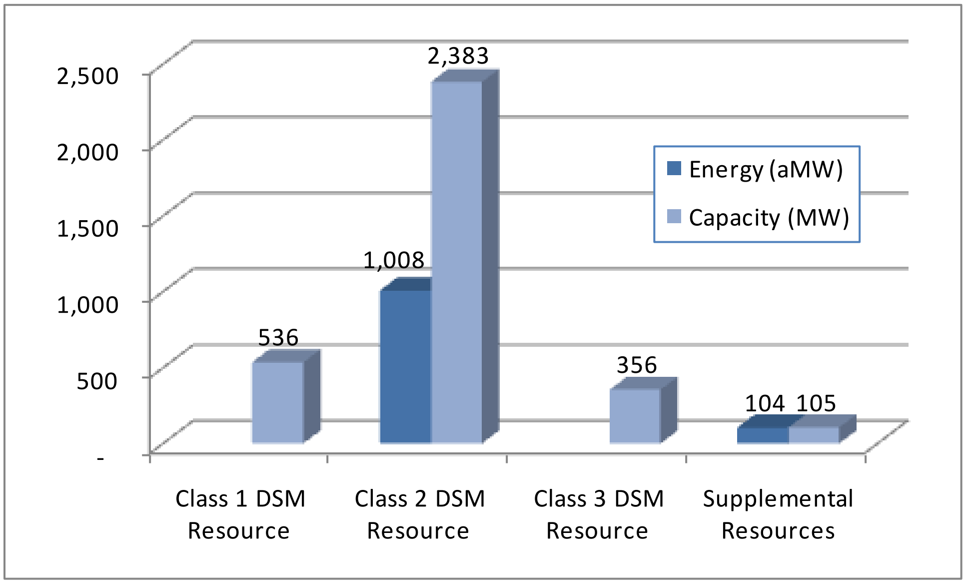
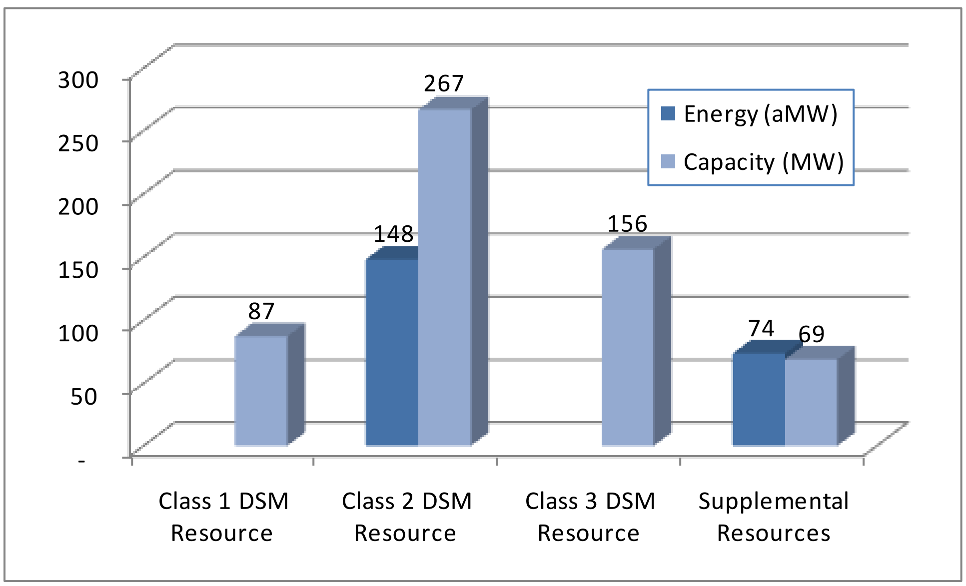


Figure ES-2. Achievable DSM Potential by Resource Type (2030) (Pacific Power Territory, Excluding Oregon for Class 2 DSM)



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

Demand-side resource options that focus on reducing capacity fall into the categories of "firm" (Class 1 DSM) and "non-firm" (Class 3 DSM) resources. Four capacity-focused options in Class 1 DSM—direct load control (DLC) of air conditioners and water heaters, irrigation load curtailment (irrigation DLC), thermal energy storage (TES), and commercial/industrial load curtailment (load curtailment)—and four options in Class 3 DSM—demand buyback (DBB), time-of-use (TOU) rates, critical peak pricing (CPP), and real-time pricing (RTP)—are analyzed in this study. The analyses results indicate the greatest opportunities for Class 1 DSM resources are likely to be in DLC of air conditioning equipment in the residential sector and irrigation DLC in the agricultural sector. In Class 3 DSM, irrigation TOU rates offer the largest possible contributor to peak load reduction opportunities because the rate design assumes implementation as a mandatory tariff (Table ES-3). This rate design was studied as a possible alternative product to the voluntary Class 1 DSM irrigation load management product and assumes regulators and interested parties would support mandatory participation with sufficiently high rates to enable realization of peak energy reduction potential.

The peak demand impacts reported in Table ES-3 do not include interactions between programs; for example, the pursuit of resources through a irrigation DLC program will reduce and possibly eliminate any potential for irrigation TOU program savings, and vice versa.

Cadmus estimates the combined impacts of Class 1 and 3 DSM (capacity-focused) resources, prior to an economic screening, will reduce PacifiCorp's 2030 peak capacity requirements by up to 4-5 percent (up to 9 percent without accounting for interactions among various DR products). These coincident peak impacts are an approximation, based on average impacts of individual programs during the system peak 40 hours, and assumes all technically achievable resources are pursued regardless of size. The results in Table ES-3 are inclusive of the quantity of reduction under contract for the irrigation DLC programs in Utah and Idaho and DLC of air conditioning (Cool Keeper) in Utah, but do not take into account interactive effects.

Table ES-3. Achievable Technical Class 1 and Class 3 (Capacity-focused) DSM Resource Potential by Customer Sector and Service Territory (MW in 2030)*

	Rocky Mountain Power	Pacific Power	PacifiCorp System	
	Achievable Technical Potential	Achievable Technical Potential	Achievable Technical Potential	Percent of 2030 Peak*
Class 1 DSM- "Firm"				
Agricultural	212	27	240	2%
Industrial	29	15	44	0%
Commercial	73	27	100	1%
Residential	221	18	239	2%
Class 3 DSM- "Non-Firm"				
Agricultural**	182	125	307	2%
Industrial	129	16	145	1%
Commercial	34	9	43	0%
Residential	11	7	18	0%

* Results are approximate; hours by program are unique and percent of peak is based on top 40 hours.

**This rate design is an alternative product to the voluntary Class 1 irrigation load management product and assumes regulators and interested parties would support mandatory participation with sufficiently high rates to enable realization of peak energy reduction potential.

Note: Individual results may not sum to total due to rounding.

Class 2 DSM (Energy-Efficiency) Resources

As shown above in Table ES-1, the system-wide technical potential for Class 2 DSM (energy-efficiency) resources is estimated at 1,408 aMW. An estimated 1,156 aMW (nearly 82 percent) of technical Class 2 DSM resources are assumed achievable (Table ES-4).

Table ES-4. Achievable Technical Class 2 (Energy-Efficiency) DSM Resource Potential by Customer Sector and Service Territory (aMW in 2030)

			PacifiCorp	
	Rocky Mountain Power	Pacific Power*	System	As Percent of 2030 Baseline Sector Sales*
Residential	463	51.4	514	29%
Commercial	339	21.9	361	15%
Industrial	258	6.7	265	9%
Irrigation	4.6	8.4	13.1	10%
Street Lighting	4.1	0.2	4.3	36%
Total	**1,064**	**88.6**	**1,156**	**16%**

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

The residential sector accounts for the largest share of achievable energy-efficiency savings at 514 aMW, followed by the commercial sector at 361 aMW. An additional 282 aMW of electricity savings are projected as available in the industrial, irrigation, and street lighting sectors. Discretionary resources (i.e., retrofit opportunities) account for 737 aMW (64 percent) of energy-efficiency savings 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.

Though this study's methodology for estimating Class 2 DSM (energy-efficiency) resources is consistent with the Council's, there are key differences. This study's timeframe and its geographic coverage differ from those in the Council's analysis of Northwest regional energy-efficiency potential. There are also marked differences among regional utilities with respect to their customer mix, past conservation activity, and load growth patterns. The study results are, therefore, only loosely comparable to those reported by the Council. In its *6th Northwest Regional Electric Power and Conservation Plan*, the Council estimated nearly 7,000 aMW of achievable technical conservation is expected regionally by the year 2029, which represents approximately 25 percent of the 2030 regional load. Using 2030 as the basis for calculations, the achievable technical Class 2 (energy-efficiency) resources identified in this study represent 16 percent of PacifiCorp's 20-year load (excluding Oregon), and are expected to displace 38 percent of the projected 20-year load growth in the five states addressed in this study, if all were cost-effective.

Supplemental Resources

In addition to Class 2 DSM (energy-efficiency) and Class 1 and 3 DSM (capacity-focused) resources, this study also examined the potential for other end-user focused resources not considered in PacifiCorp's standard definitions of Classes 1, 2, and 3 DSM. These resources, which may be loosely defined as "dispersed generation as alternative supply-side," are considered supplemental to DSM resources, and include energy-focused options such as CHP and on-site solar. The potential for solar-efficiency measures, which include solar water heaters and solar attic fans, do not account for interactions with Class 2 DSM resources (e.g., heat pump water heaters) or Class 1 and Class 3 DSM resources (DLC programs and pricing products). Total potential would be reduced if all resource types were pursued independently.

Table ES-5. Achievable Technical Supplemental Resource Potential by Technology and Service Territory (aMW in 2030)

Achievable Technical Potential	Rocky Mountain Power	Pacific Power	PacifiCorp System
Energy-Focused Resources (aMW)			
CHP: Non-Renewable	12	5	16
CHP: Renewable	78	52	130
Solar: PV	4	4	8
Solar: Efficiency Measures	10	13	23
Total Potential (aMW)	**104**	**74**	**178**

Note: Individual results may not sum to total due to rounding.

Resource Acquisition

Acquisition of all identified Class 2 DSM (energy-efficiency) resources may also require increasing participant incentives above the current level of approximately 50 percent of measure costs for most Class 2 DSM programs. The basis for the achievable technical potential in this study is based on historical assumptions used by the Council that 85 percent of all technical resources are achievable. However, based on information provided by customers during interviews we conducted during the 2007 Assessment, results of this analysis suggest participation in energy-efficiency programs is relatively inelastic with respect to incentive levels. Thus, a 50 percent increase in incentives (from 50 percent to 75 percent of the measure costs) may only lead to an increase of 11 percent in resource achievable technical potential. Moreover, although higher incentives do not affect the total resource costs, they do increase the cost burden borne by the utility and its customers, leading to higher rate impacts with sometimes concomitant customer equity ramifications.

Incentive amounts are one of the determinants of achievable technical potential; but they do not have an effect on economic potential or the estimated per-unit resource costs, since these are determined from a total resource cost (TRC) perspective, which focuses on full incremental costs of the DSM measure, regardless of who pays it—the utility or the customer participating in the DSM program. This applies in all state jurisdictions where PacifiCorp operates, except in Utah, where, according to the approved evaluation criteria, the utility cost test (UCT) is the primary basis for determining cost-effectiveness.

In this study, for the purpose of determining per-unit resource costs in Utah, it was assumed utility incentives will cover 100 percent of the incremental measure costs[5] to achieve the

[5] Incremental measure costs vary by resource type; i.e., discretionary or retrofit, where the incremental cost is equivalent to the full costs, and lost opportunity where the incremental cost is the difference between the least-efficiency and higher-efficiency alternatives.

assumed 85 percent achievable technical potential. This assumption is in line with the Council's perspective on achievable potential, which does not specifically consider how and from what source conservation resources are derived. Recent DSM potential studies in California have shown less than 50 percent of technical potential is likely to be achievable through utility programs under the most aggressive resource acquisition scenario, even when 100 percent of incremental measure costs are borne by the utility.[6]

By their nature, studies of resource potential rely on large amounts of data and a number of pivotal assumptions concerning the future in calculating technical and achievable technical potential. Uncertainties exist regarding future technological innovations and their market effects. For example, assessment of technical potential is inherently a static analysis, assuming "frozen" efficiencies for all baseline technologies. Advances in technologies that reduce the energy intensity of electrical equipment and appliances change the potential for various end-uses. Technological innovations that reduce costs, particularly in the area of on-site solar, may substantially improve the prospects for achievable technical potential for supplemental resources.

Studies of DSM potential provide a means for developing reasonable estimates of the magnitude, costs, and timing of DSM resources, and, as such, provide a necessary step in integrated resource planning. Resource potential studies also help inform the utility's DSM planning efforts. The objectives of resource potential assessment, however, differ from those of resource acquisition planning and program design, in that they do not provide specific guidance as to *how* and by *what means* the identified resource potential might be realized. For example, the potential for a portion of the equipment or building shell measures might be acquired through utility programs or through higher energy-efficiency codes and standards implemented through legislative action.

Although this study uses the best available knowledge, many uncertainties remain due to the length of the planning horizon. Therefore, these study findings should be considered indicative rather than conclusive. Over time, much of the data used in this study will be supplanted by improved data, and many of its assumptions will need to be reviewed and updated. PacifiCorp will need to adopt a measured approach in how data are utilized for firm resource planning purposes.

6 "California Energy Efficiency Potential Study," Volume 1, CALMAC Study ID: PGE0211.01, Prepared by Itron, May 2006.

1. Introduction

Background

PacifiCorp has provided a comprehensive set of demand-side management (DSM) programs to its customers since the 1970s. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. PacifiCorp continues to be an innovator in DSM.

In the early 1990s, PacifiCorp conceived and implemented the Energy FinAnswer program, which received awards from the U.S. Department of Energy, the State of Oregon, the City of Portland, and the American Institute of Architects for its creative design and on-bill financing. The program was designed so energy-efficiency investments were paid for through reductions in customers' bills, requiring no cash outlay by participants. This approach dramatically opened the energy-efficiency market in the commercial and industrial (C&I) sector.

In the early 2000s, PacifiCorp successfully responded to a highly volatile energy market with two innovative and successful demand reduction programs: the 20/20 Program provided a 20 percent reduction in the energy rate to customers able to reduce their energy use by 20 percent over their prior year's use; and the Power Forward Program, a State of Utah program co-funded by PacifiCorp, combined energy-saving tips with a public awareness mechanism.

Since 1989, PacifiCorp has developed biennial IRPs to identify the optimal, least-cost mix of resources to meet projections of its long-run resource requirements. The optimization process accounts for capital, energy, and ongoing operation costs as well as the risk profile of various resource alternatives, including traditional generation, renewable generation, energy efficiency, and capacity-focused resources.

Study Scope and Objectives

PacifiCorp commissioned this study to investigate amounts of Class 2 DSM (energy-efficiency) and Class 1 and 3 DSM (capacity-focused) potential remaining within its service territory from conventional capacity-focused program options, energy-efficiency products and services, and other supplemental resources, such as solar and CHP. Study results will inform the IRP process, and assist PacifiCorp in revising and improving designs of existing programs and in developing new programs. This study updates the 2007 Assessment of Long-Term System-Wide Potential for Demand-Side and Other Supplemental Resources,[7] hereafter referred to as the 2007 Assessment. That study was comprehensive in scope, and included building simulation modeling, conducting customer surveys, and completing other analyses that are used in the current study.

The principal goal of this study is to develop reliable estimates of the magnitude, timing, and costs of alternative DSM resources likely to be available to PacifiCorp over a 20-year planning horizon, beginning in 2011. The main emphasis of the study is on resources that may be realistically achievable during the planning horizon, market and other conditions warranting. The

[7] http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/Demand_Side_Management.pdf

results of this study will be incorporated into PacifiCorp's 2011 IRP and subsequent planning efforts.

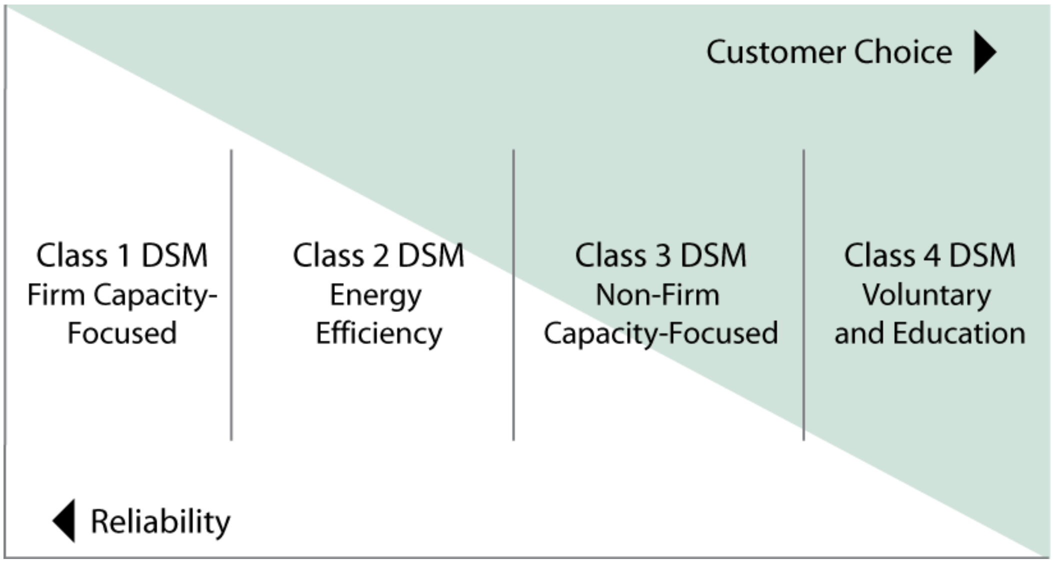
The study's scope encompasses multi-sector assessments of the long-term potential for DSM and other supplemental resources in PacifiCorp's Pacific Power (Oregon, Washington, and California) and Rocky Mountain Power (Idaho, Wyoming, and Utah) service territories. As the Energy Trust of Oregon (ETO) is responsible for identification and delivery of energy-efficiency resources in Oregon, the potential for these resources are exclusive to Oregon. ETO provides PacifiCorp an estimate of technically achievable energy-efficiency resources for its Oregon service territory, which are then incorporated in PacifiCorp's resource planning process.

The 2007 Assessment used PacifiCorp's classification of non-generation DSM options. According to this classification, DSM resources fall into four classes of resource opportunities that promote efficient electricity use through various intervention strategies aimed at changing the intensity (energy efficiency), level (load response), timing (price response and load shifting), or behavior (education and information) in energy use.

The four resource classes, described in detail below, may be evaluated and categorized by two main characteristics: reliability and customer choice. Class 1 DSM resources, particularly controlled capacity-focused programs, are considered the most reliable from a system planning perspective because 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 (DLC and energy efficiency, respectively) are involuntary in that, once the equipment and systems are in place, savings are expected to flow automatically. Class 3 and Class 4 DSM activities involve a greater range of customer choice and control (see Figure 1). Supplemental resources primarily comprise small-scale, dispersed generation on the facility side of the meter. Supplemental resources are generally less firm, either due to the uncertainties associated with their availability (solar) or to the extent customers control their operation (CHP).

The current study assessed resource potential from Class 1, 2, and 3 DSM resources as well as supplemental resources.

Figure 1. Reliability and Customer Choice Considerations in Demand-Side Management Resources



From a utility resource planning point of view as well as for analytic reasons, resources assessed in this study may be categorized as:

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

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

Capacity-focused (or demand-response) resources encompass both Class 1 and Class 3 DSM. These resources range from price-responsive loads that may shift to off-peak as the result of customers reacting to price signals to loads curtailed or interrupted by the utility, at its discretion, once customers have agreed to participate. Capacity-focused resources are relied upon, at varying levels of certainty, during system emergencies, periods of high market prices, or to help alleviate stress on distribution/transmission assets. The main difference between Class 1 and Class 3 DSM resources is their availability during periods of system peak (dispatchability) and reliability. Capacity-focused objectives may be met through a broad range of price-based (e.g., TOU and RTP) or incentive-based (e.g., DLC and DBB) program options. For this study, capacity-focused resources are defined based on PacifiCorp's characterization of two distinct classes of firm and non-firm resource options:

- ***Class 1 (Firm) DSM Resource***. This class of resources allows direct or scheduled interruptions, or cycling of electrical equipment and appliances, such as central air-conditioners, irrigation pumps, lighting, and process loads.
- ***Class 3 (Non-Firm) DSM Resources***. Resources in this class seek to achieve short-duration energy and capacity 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 and more traditional pricing products, such as TOU, RTP, or CPP programs.

Class 2 DSM (Energy-Efficiency) Resources

This group is comprised of technologies that reduce energy consumption at the end-use level, including high-efficiency equipment, and measures indirectly lowering energy use of equipment, such as shell improvements and controls. These resources are generally categorized as discretionary (retrofit in existing construction) or lost opportunity resources (equipment replacement and efficiency improvements in new construction). These resources can be captured through application of various market intervention mechanisms, such as equipment incentives, direct installation, audits, and information that leads to sustainable savings, or the advancement of codes and standards. The type and intensity of market intervention strategies, prevailing retail rates, and amounts of available capital in a given market or economy can affect the cost and amount of the Class 2 DSM resource captured.

Supplemental Resource Options

In this study, supplemental resources represent small-scale, dispersed power generation technologies that, although supply-side resources by nature, are sometimes considered an addition to conventional DSM resources. For the purposes of this assessment, two options are considered: 1) *Combined Heat and Power* (*CHP)* is the simultaneous generation of energy and heat, in which waste heat is captured and used for industrial process heating, space heating, and/or domestic hot water; and 2) *On-Site Solar* which is assumed to include small-scale photovoltaic (PV) and solar efficiency measures.

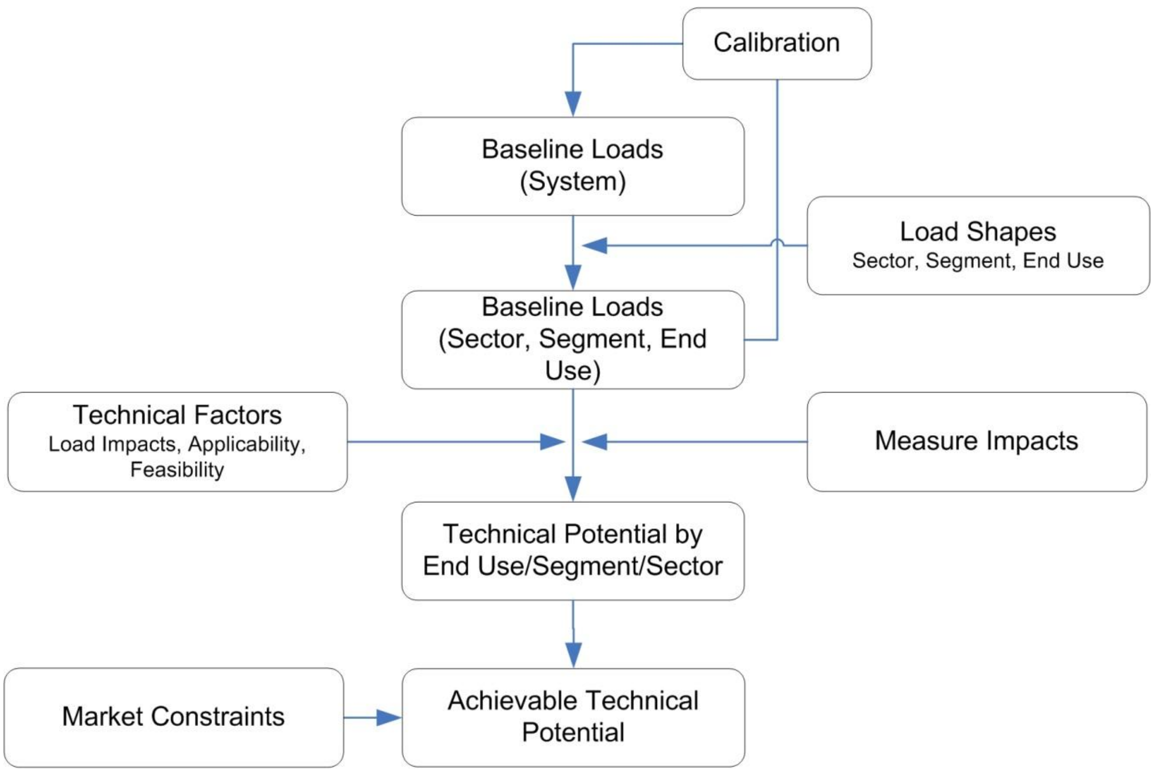
General Approach

The resources this study analyzed differ with respect to several salient attributes, such as the type of load impact (energy or capacity), and the availability, reliability, and applicability to various customer classes (e.g., commercial verses residential) and customer segments (e.g., office versus warehouse within the commercial class). While each DSM resource often requires fundamentally different approaches in program design, incentive structures, and delivery mechanisms for its deployment, the assessment is more similar than dissimilar, relying on a common conceptual framework, with similar analytic methodologies.

This general methodology used can be best described as a combination “top-down/bottom-up” approach. As illustrated in Figure 2, the top-down component begins with the most current load forecast, and decomposes it into its constituent customer sector, customer segment, and end-use components. The bottom-up component considers the potential technical impacts of various demand-side and supplemental resource technologies, measures, and practices on each end use. The impacts are then estimated based on engineering calculations, taking into account fuel shares, current market saturations, technical feasibility, and costs. These unique impacts are aggregated to produce estimates of resource potential at the end-use, customer sector, and service territory levels. In many ways, the approach is analogous to generating two alternative load forecasts at the end-use level (one with and one without DSM and supplemental resources), and calculating resource potential as the difference between the two forecasts.

Estimation of the technical potential in this study was based on best-practice research methods and analytic techniques that have become standard in the utility industry. These techniques are consistent with the conceptual approach and methodology used by other planning entities within PacifiCorp's service area, including the Council, in developing regional energy-efficiency potential. Estimates of achievable potential in this study for Class 2 DSM resources were derived using assumptions regarding technologies, expected market saturation, and ramp rates generally consistent with those in the 6th Northwest Regional Power Plan. The estimate of achievable potential for Class 1 and 3 DSM and supplemental resources was based on comparisons of programmatic achievements around the country.

Figure 2. General Methodology for Assessment of Demand-Side Resource Potential



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. In this analysis, naturally occurring conservation is accounted for in several ways.

First, the potential associated with certain energy-efficiency measures assumes a natural rate of adoption. For example, the savings associated with ENERGY STAR appliances account for current trends in customer adoption. Second, current codes and standards are applied in the consumption characteristics of new construction. Finally, the assessment accounts for gradual increases in efficiency as older equipment in existing buildings are retired and replaced by units meeting current standards. However, this assessment does not forecast changes to codes and standards; rather, it treats them at a "frozen" efficiency level.

Technical potential assumes all available DSM measures and supplemental resource options may be implemented, regardless of their costs or market barriers. For Class 2 DSM resources, technical potential is divided into two classes: discretionary (retrofit) and lost-opportunity (new construction or replacement on burnout). It is important to recognize the notion of technical potential is less relevant to resources such as Class 1 and 3 DSM resources and supplemental resources, as most end-use loads may be subject to interruption or displacement from a strictly technical point of view.

Achievable technical potential is the portion of technical potential that might reasonably be achievable in the course of the planning horizon, given market barriers that may impede customer participation in utility programs. Assumed achievable potential levels principally are meant to serve as planning guidelines and to inform the IRP process.

Knowledge of alternative resource options and reliable information on the long-run resource potential of achievable technology prove necessary for sound, utility IRP. The principal goal in resource potential studies is to develop reasonably reliable estimates of the magnitude, costs, and timing of alternative resources likely to be available over the course of the planning horizon. They are intended as a means of identifying and assessing resource potential likely to be available in a specific market over a defined time period; they are not meant to 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.

Resource potential studies are complex undertakings, requiring analysis of large amounts of technical and market data; they rely on a number of pivotal assumptions concerning the technical and achievable technical potential. For example, assessment of *technical* potential assumes “frozen” efficiency levels for all baseline technologies in place today. Clearly, the customer’s willingness to participate in demand-side programs largely depends on their energy costs, the incentive amounts offered by the utility, and their economic circumstance, with a greater likelihood of customer participation in programs where higher retail electricity costs are present with comprehensive and appropriate program incentives.

Therefore, it is important study findings be considered indicative, rather than conclusive. Inevitably, much of this study’s data will have to be updated, and many of its underlying assumptions will need to be revisited periodically.

Resource Interactions

The study’s methodology explicitly accounts for technical interactions occurring *within* a resource class (that is, among various program options and end-use measures). In addition, interaction between resource classes such as Class 1 and 3 DSM programs will result in lower savings than if calculated individually.

Several interactions have also been accounted for within the Class 2 DSM analysis. First, a “stacking effect” occurs when *complementary* retrofit measures, such as wall, ceiling, and floor insulation, are applied to a single end use. Since measure savings are always calculated in terms of reductions in end-use consumption, installation of one measure reduces the savings potential of measures installed subsequently.

A similar effect occurs when equipment and non-equipment (retrofit) measures within the 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 are captured first, replacement of existing equipment with high-efficiency equipment can be expected to have a smaller impact on end-use consumption than if the replacement had taken place first. Clearly, the order of measures depends on practical considerations of program design and implementation. For this study, it is assumed retrofit measures with the lowest levelized cost would be implemented first, and retrofit measures will always precede equipment replacement.

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

Interactions also occur between two or more classes of resources. The most obvious are the effects of energy efficiency on capacity-focused potential as implementation of energy-efficiency measures lowers peak demand, thus reducing the technical potential for Class 1 and 3 DSM resources. These interactions are not explicitly quantified in this study, but are recognized to occur.

Incorporation of Upcoming Codes and Standards

While Cadmus' analysis does not attempt to predict how energy codes and standards may change, it does incorporate the impacts of enacted legislation, even if the legislation will not go into effect for several years. The most notable, recent efficiency regulation is the Energy Independence and Security Act of 2007 (EISA), which set new standards for general service lighting, motors, and other end use equipment. It is particularly important to capture the effects of this legislation because residential lighting has played a large role in PacifiCorp's energy-efficiency programs over the past several years.

EISA requires general service lighting becomes roughly 30 percent more efficient than current incandescent technology, with standards phased in by wattage from 2012 to 2014. In addition to the 2012 phase-in, EISA contains a provision that requires still higher efficacy, beginning in 2020. As shown in Table 1, while the new residential lighting standards had the largest effect on potential, several other standards were explicitly accounted for in the current study, but not included in the 2007 Assessment.

Table 1. Enacted or Pending Standards

Equipment Type	Sector	Effective Date
Dishwasher	Residential	January 1, 2010
Dishwashers (Residential Type)	Commercial	January 1, 2010
EISA Commercial Lighting - Phase in	Commercial	July 1, 2010
EISA Residential Lighting - Phase in	Residential	January 1, 2012
EISA Motors (1 – 200 hp)	Commercial/ Industrial	December 17, 2010
Electric Storage Water Heater	Residential	April 16, 2015
Electric Storage Water Heater (Residential Type)	Commercial	April 16, 2015
Glass Door Refrigerators/Freezers	Commercial	January 1, 2010
Ice Makers	Commercial	January 1, 2010
Packaged Air Conditioners and Heat Pumps (≥65 kBtu/h)	Commercial	January 1, 2010
Solid Door Refrigerators/Freezers	Commercial	January 1, 2010
Walk-In Coolers and Walk-In Freezers	Commercial	January 1, 2009

In addition, we incorporated each state's energy code, as adopted by the state's legislature. Table 2 shows the state codes.

Table 2. State Energy Code

State	Energy Code Used
Washington	2009 State Code
Idaho	2009 IECC
Utah	2009/2006 IECC (commercial/residential)
California	2009 IECC[8]
Wyoming	2009 IECC[9]

IECC = International Energy Conservation Code

Organization of the Report

This report is organized in two volumes. The present document (Volume I) is organized into six sections. The next four sections following this introduction are devoted to an analysis of various resource options, namely:

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

Each section begins with a description of the scope of the analysis; presents a summary of the resource potential; provides a discussion of methodologies; and presents detailed results. Supplemental technical information, assumptions, data, and other relevant details are presented electronically in Volume II as appendices.

[8] California has its own state-level code; however, given its similarities with the 2009 IECC, the 2009 IECC was used in this study.

[9] Wyoming does not have a statewide energy code; 2009 IECC was used as a proxy.

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

Scope of Analysis

Demand-side resources with a focus on reducing capacity needs are often called demand response or load management programs. These programs are designed to help: reduce peak demand during system emergencies or extreme market prices; promote improved system reliability; and, in some cases, may lead to deferment of investments in the delivery and generation infrastructure.

These benefits occur by the program providing incentives to customers to curtail loads during utility-specified events (programs include DLC of air conditioners and irrigation pumps and DBB programs), or may occur by the use of pricing structures to induce participants to shift load away from peak periods (TOU rates, CPP, and RTP programs). For this study, capacity-focused resources have been defined by PacifiCorp's characterization of two distinct classes of firm and non-firm resource options.

Class 1 (Firm) DSM Resources. This class of capacity-focused program options 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, lighting, 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. Because of their relatively high reliability, resources of this nature are generally considered "firm" resources from a planning perspective. We analyzed four general program options for this study:

- *DLC* programs allow PacifiCorp to remotely interrupt or cycle electrical equipment and appliances at the customer's facility. In this study, we analyzed DLC program potential for small commercial and residential central electric cooling and electric water heating.
- *Irrigation DLC* allows PacifiCorp to directly control irrigation pumps through two-way control systems. Load curtailments require 24 hour advance notice.
- *TES* programs for the purpose of this study are designed to reduce demand associated with cooling during on-peak periods. Ice is made during off-peak periods (unoccupied times at night) using the existing cooling system; this ice is saved and used to cool the building during peak demand periods. This mitigates customer high demand and energy charges during on-peak periods. This type of program is targeted at large commercial customers with rooftop cooling units, and is run in conjunction with a TOU rate.
- *Load Curtailment* programs target larger commercial and industrial customers who have discretionary loads and/or on-site standby generation assets that can be called upon by the utility as needed. These customers enter into curtailment agreements with the utility or utility-hired aggregator, and are provided financial incentives for their participation and willingness to provide resources when needed. In most cases, mandatory participation is required once the customer enrolls in the program. Our analysis of these programs assumes customers with average monthly loads greater than 100 kW are targeted.

Class 3 (Non-Firm) DSM Resources. In this resource class, incentives either are in the form of event-by-event payments or time-differentiated rate structures. These program options are less reliable than those in Class 1 DSM because: they are not "dispatchable" by the utility; program participation per event is voluntary and variable; savings result from behavioral actions rather than technological changes (as in the case of Class 2 DSM), and program contributions typically cannot be measured until after the fact. Class 3 DSM resources include time-varying prices and DBB programs. Incentives are provided to participants either as a special tariff (time-varying prices) or per-event payments (DBB). We analyzed four specific program options in this resource class:

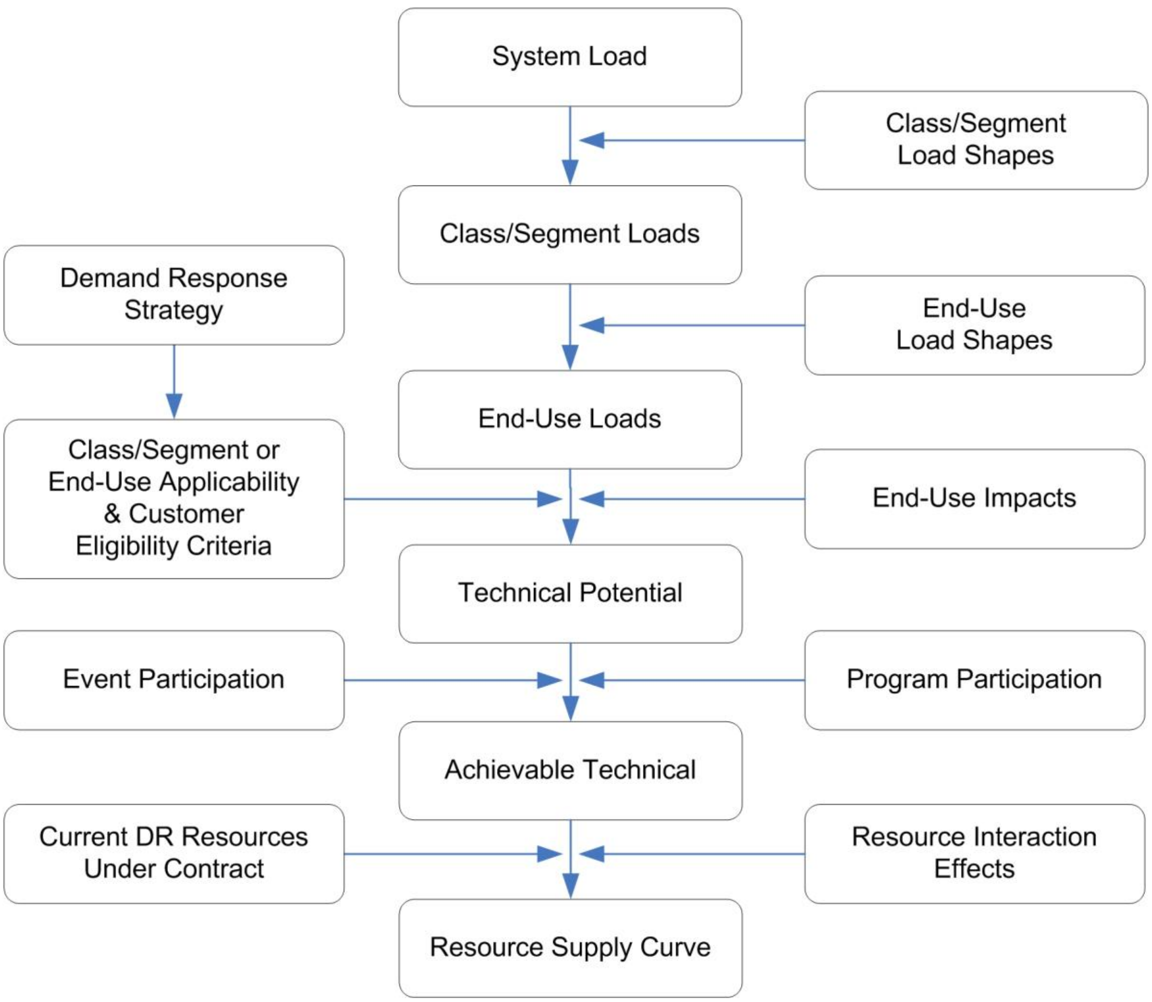
- *DBB* programs (such as PacifiCorp's Energy Exchange Program) refer to arrangements where the utility offers payments to customers for voluntarily reducing their demand when requested by the utility. The buyback amount generally depends on market prices published by the utility ahead of the event, coupled with the customer's ability to curtail use during the hours load is requested. The reduction level achieved is verified using an agreed-upon baseline usage level specific to the participating customer. As with the load curtailment program, this program targets C&I customers with loads greater than 100 kW.
- *TOU* programs are generally based on two- or three-tiered, time-differentiated tariff structures that charge fixed prices for usage during different blocks of time (typically on- and off-peak prices by season). TOU rates are designed to more closely reflect the marginal cost of generating and delivering power. Cadmus analyzed the potential for using TOU rates in the residential and agricultural sectors (the agricultural TOU was modeled as an alternative to the irrigation DLC program); C&I TOU rates are typically considered a standard tariff and not a capacity-focused program option.
- *CPP*, or extreme-day pricing, refers to programs aiming to reduce system demand by encouraging customers to reduce their loads for a limited number of hours during the year. During such events, customers have the option to curtail their usage or pay substantially higher-than-standard retail rates. As with load curtailment programs, this type of program targets C&I customers with loads greater than 100 kW.
- *RTP* is a tariff structure for customers to pay electric rates tied to market prices. Prices are typically posted by the utility, based on day-ahead hourly prices. RTP price structures are most suitable for large C&I customers with flexible schedules that can be adjusted on short notice. This analysis assumes an RTP tariff would target large C&I customers (greater than 100 kW).

As this study updates the 2007 Assessment, program options listed under Class 1 and Class 3 DSM resources are based largely on the 2007 Assessment and the products reviewed for that assessment. A review of new demand response literature and programs was completed, and updates were made to each program, as appropriate. The irrigation TOU program was added to this study to assess its viability as an alternative to the existing irrigation DLC program. These program options, design specifications, and assumptions underlying the analysis are described in more detail later in this section.

Assessment Methodology

The methodology used for estimating Class 1 and 3 DSM resource potentials was based on a combined top-down and bottom-up approach. As shown schematically in Figure 3, the approach began with utility system loads, which we disaggregated into sector, segment, and applicable end uses. For each Class 1 and 3 program (or program component), we calculated potential technical impacts for all applicable end uses. The end-use load impacts were aggregated to obtain estimates of technical potentials. Market factors, such as probabilities of programs and event participation, were then applied to technical potentials to obtain estimates of achievable technical potentials. The methodology for calculating technical and achievable technical potentials is described in greater detail below.

Figure 3. Schematic Overview of Class 1 and 3 DSM Resources Assessment Methodology



Estimating Technical Potential

Class 1 and 3 DSM resource technical potentials, first estimated at the end-use level, are aggregated to market segment, sector, and system levels. This approach was implemented through the following steps:

1. **Define customer sectors, market segments, and applicable end uses**. The first step in the process of estimating the load basis was to define customer sectors, customer segments, and applicable end uses, similarly to the energy-efficiency study. System loads were disaggregated into four sectors: residential, commercial, industrial, and agricultural. Each sector was broken down further by state, sector (Table 3), and end use (including computers, cooking, cooling, clothes dryers, freezers, heating, heat pumps, HVAC, lighting, office equipment, plug load, pool pumps, refrigeration, space heat, hot water heating, and the sum of all end uses).

Table 3. Capacity-Focused Analysis of Customer Sectors and Segments

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

2. **Screen customer segments and end uses for eligibility**. This step involved screening end uses for applicability of specific Class 1 and 3 DSM resource strategies. For example, hot water loads in hospitals were excluded.

3. **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.

4. **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 the 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 the strategy:

$$TP_p = \sum TP_{pes}$$

and

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

where,

LE_{ps} (load eligibility) represents the percentage of customer sector (s) loads 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.

Estimating Achievable Technical Potential

Achievable technical potential is a subset of technical potential that accounts for the customers' ability and willingness to participate in capacity-focused programs, subject to their unique business or household priorities, operating requirements, and economic (price) considerations. Estimates of achievable technical potential were derived by adjusting the technical potential of two factors: expected rates of program participation and expected rates of event participation. Achievable technical potential for the program option (ATP_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:

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

For each capacity-focused program (except the irrigation TOU program, which is assumed to be mandatory), projected program sign-up rates for all customer segments were informed by secondary research detailed in the program assumptions as well as on PacifiCorp's past program experience. Because of variations in program structures, their incentive levels, and customer mix, information on program participation in many cases was not transferable to PacifiCorp's service territory. Therefore, a survey of C&I customers, conducted during the 2007 Assessment, was used as a basis for determining the achievable technical potential for various capacity-focused options for C&I customers.

Estimating Costs and Supply Curves

Capacity-focused programs vary significantly with respect to both the type and level of costs. Applicable resource acquisition costs for capacity-focused strategies generally fall into two categories: 1) fixed direct expenses, such as infrastructure, administration, and data acquisition; and 2) variable costs, such as incentive payments to participants. The levelized cost ($/kW-year) of each program option is calculated over the 20-year period using cost estimates of upfront program development, installed technology, incentives, ongoing maintenance, administration, and communications. Finally, estimates of achievable technical potential are combined with per-unit resource costs to produce resource supply curves.

Resource Potential

Table 4 shows the estimated resource potential for Class 1 and 3 DSM resources during the top hours of the summer for each program.[10] Table 5 and Table 6 show the estimated potential by sector (residential, commercial, industrial, and agricultural) for each of the two territories. Estimated resource potential for Class 1 and 3 DSM resources Technical potential is highest in

[10] Pacific Power's peak occurs in the winter; thus, we assumed residential TOU programs will run in winter. All other programs, regardless of territory, were assumed to run during summer.

the residential and agricultural sector due to the opportunity for an air conditioning load control program and an irrigation load control program. The resource potential in the commercial sector includes load curtailment and TES. Coincident peak impacts are based on average impacts of individual programs during peak hours defined by the program, and are thus not truly additive.

Table 4. Technical and Achievable Technical Potential (MW in 2030) by Program

Resource Class	Program	Rocky Mountain Power		Pacific Power	
		Technical Potential	Achievable Potential	Technical Potential	Achievable Potential
Class 1	DLC Air Conditioning and Water Heat	746	222	184	19
	Irrigation Load Control	279	212	174	27
	Thermal Energy Storage	215	6	23	1
	Load Curtailment	1,458	95	233	40
	Total	**2,698**	**536**	**614**	**87**
Class 3	Demand Buyback	675	40	107	6
	Residential TOU	145	11	112	7
	Irrigation TOU	260	182	179	125
	Critical Peak Pricing	1,036	100	194	17
	Real Time Pricing	675	23	107	2
	Total	**2,791**	**357**	**699**	**157**

For the Rocky Mountain Power service territory, the Class 1 DSM achievable potential of 536 MW was driven by the irrigation DLC program (agricultural sector) and DLC of air conditioning and water heating (residential and small commercial sectors). These results include the quantity of curtailment currently contracted under Rocky Mountain Power's irrigation DLC programs and DLC of air conditioning (the Utah Cool Keeper program). The Cool Keeper Program is expected to achieve 123 MW of savings in 2011. The irrigation DLC program is expected to achieve 35 MW and 150 MW of realized load reduction savings in Utah and Idaho, respectively. Therefore, the remaining potential for PacifiCorp to achieve by 2030 is 228 MW. No expected intra-class interactions would result in a reduction of potential for the Class 1 resources.[11]

Table 5. Class 1 DSM: Rocky Mountain Power Territory Technical and Achievable Technical Potential (MW in 2030)

Sector	Technical Potential	Achievable Technical Potential
Agricultural	279	212
Industrial	839	29
Commercial	876	73
Residential	704	221
Total	**2,698**	**536**

Note: Individual results may not sum to total due to rounding.

[11] As participation in the thermal energy storage program is minimal, it is assumed no interaction would occur between this offering and the curtailment program.

The Pacific Power service territory, which has substantially less load than the Rocky Mountain Power territory, also has lower overall Class 1 DSM achievable potential, at 87 MW (Table 6). Contributing to the lower potential are fewer cooling days during the summer, lower saturation of cooling equipment (affecting the DLC AC program), and smaller irrigation pumps (affecting the irrigation DLC program). The potential assessments for both the agricultural and commercial sectors combined totals an estimated 69 MW of savings, which are achieved through three of the program options. Currently, PacifiCorp does not run Class 1-specific, capacity-focused programs in the Pacific Power service territory, and the four programs assessed here (AC DLC, irrigation DLC, TES, and load curtailment) will need to be deemed economically feasible prior to pursuing the 87 MW of possible resource opportunity by 2030.

Table 6. Class 1 DSM: Pacific Power Territory Technical and Achievable Technical Potential (MW in 2030)

Sector	Technical Potential	Achievable Technical Potential
Agricultural	174	27
Industrial	68	15
Commercial	224	27
Residential	148	18
Total	**614**	**87**

Note: Individual results may not sum to total due to rounding.

With respect to Class 3 DSM resources, the highest technical potential is in the agricultural sector of the Rocky Mountain Power's service territory. This change from our 2007 Assessment, where the industrial segment had the greatest opportunity for load reduction, is due to an assumption change that assessed the Irrigation TOU as if it were a mandatory program. Overall, the achievable technical potential in the Rocky Mountain Power territory is 357 MW. If intra-class interactions are included, the commercial and industrial sectors achievable technical potential would fall by about one-half. Within Class 3, no programs compete for the agricultural or residential sectors.

Table 7. Class 3 DSM: Rocky Mountain Power Territory Technical and Achievable Technical Potential (MW in 2030)

Sector	Technical Potential	Achievable Technical Potential
Agricultural	260	182
Industrial	1,619	129
Commercial	785	34
Residential	128	11
Total	**2,791**	**357**

Note: Individual results may not sum to total due to rounding.

In the Pacific Power service territory, the technical potential for Class 3 is lower than for Rocky Mountain Power, mainly due to the territory's overall smaller size, particularly in the industrial sector and differences in customer mix. Achievable technical potential shows the most opportunity in the commercial sector, with the total achievable potential of 157 MW much larger than the 21 MW reported in our 2007 Assessment, due to the addition of the mandatory treatment of the irrigation TOU program. If including intra-class interactions, the commercial and industrial sectors' achievable technical potential would fall by about one-half. Class 3 has no competing programs for the agricultural or residential sectors.

Table 8. Class 3 DSM: Pacific Power Territory Technical and Achievable Technical Potential (MW in 2030)

Sector	Technical Potential	Achievable Technical Potential
Agricultural	179	125
Industrial	209	16
Commercial	234	9
Residential*	77	7
Total	**699**	**157**

* Pacific Power's peak occurs in the winter; thus we assumed the Residential TOU Program would run in the winter.
Individual results may not sum to total due to rounding.

Resource Costs and Supply Curves

Capacity-focused program options vary significantly in their types of cost and amounts. Applicable resource acquisition costs generally fall into two categories: 1) fixed program expenses, such as infrastructure, administration, maintenance, and data acquisition; and 2) variable costs. Variable costs have two categories: those varying by the number of customers (e.g., hardware costs) and those varying by kW reduction (primarily incentives).

Where possible, cost estimates were developed for each program option, based on comparable programs. In certain cases, this specificity level was difficult to establish, as many utilities do not track or report program costs. For example, development of a new demand response program can be a significant cost for a utility, requiring enrollment, call centers, program management, load research, development of evaluation protocols, changes to billing systems, and marketing. Background research on utilities across the country provided cost estimates ranging from zero to $2 million. In 2002, PacifiCorp paid $317,000 in non-hardware expenses to begin TOU programs. In California, program development costs have been significantly higher. Therefore, this analysis assumes a basic program development cost of $400,000. Marketing is another example with widely varying costs, from about $25 per customer to over $5,000, based on interviews with program managers. This analysis conservatively assumed $25 for each new residential participant and $500 for each commercial or industrial participant.

In developing estimates of per-unit costs, program expenses were allocated annually over the expected program life cycle (20 years), and then discounted by a real cost of capital (7.1 percent) to estimate the total discounted cost. The ratio of this value and the average annual kW reduction produced the levelized per-kW cost for each resource. Additionally, attrition rates were used to account for program turnover due to changes in electric service (i.e., housing stock turnover) and program drop-outs. The basic assumption for this analysis was 5 percent, based on historic experiences of Rocky Mountain Power. Attrition required reinvestment of new customer costs, including technology, installation, and marketing. In addition, the analysis assumed a measure life for the installed technology, and, in most cases, the costs were adjusted upward by 5 to 15 percent to account for administrative expenses.

Table 9 displays per-unit ($/kW-year) costs for each service territory for the estimated achievable technical potential. For Class 1 DSM resources, the irrigation DLC program is estimated to be the least expensive option, with levelized costs of $54/kW-year and $74/kW-year for Rocky Mountain Power and Pacific Power service territories, respectively. Per-unit resource costs for the load curtailment program assume $82/kW-year for both territories, as the program is priced by a third-party aggregator. The DLC AC program has a levelized cost of $116/kW-year and $143/kW-year for Rocky Mountain Power and Pacific Power service territories, respectively. The addition of the water heating component to the DLC AC program adds $88/kW-year to the cost of the program in each territory, bringing the overall cost to run a combine DLC AC and water heat program to $204-year/kW for Rocky Mountain Power and $231/kW-year for Pacific Power, TES in the commercial sector is the highest-cost resource, owing mainly to the significant investment requirements in enabling technologies.

Table 9. Class 1 DSM: Levelized Costs and Achievable Technical Potential (MW in 2030)

Levelized Cost	DLC AC	DLC Water Heat	Irrigation DLC	TES	Load Curtailment
Rocky Mountain Power					
Achievable Technical Potential (MW)	217.2	4.6	212.5	6.4	95.2
Levelized Cost	$115.89	$87.74	$53.85	$253.28	$81.55
Pacific Power					
Achievable Technical Potential (MW)	14.1	5.2	27.3	0.7	40.1
Levelized Cost	$143.21	$87.74	$73.70	$253.28	$81.55

We constructed service territory supply curves from quantities of estimated achievable technical resource potential and per-unit costs of each resource option. The capacity-focused supply curves, shown in Figure 4 and Figure 5, represent the quantity of each resource (cumulative MW) that can be achieved at or below the cost at any point. Cumulative MW was created by summing the achievable technical potential along the horizontal axis sequentially, in the order of their levelized costs. The supply curves for Rocky Mountain Power and Pacific Power are relatively similar, with the only differences caused by the higher $/kW cost for the residential DLC and irrigation DLC programs.

Figure 4. Class 1 DSM: Rocky Mountain Power Territory Supply Curve (Cumulative MW in 2030)

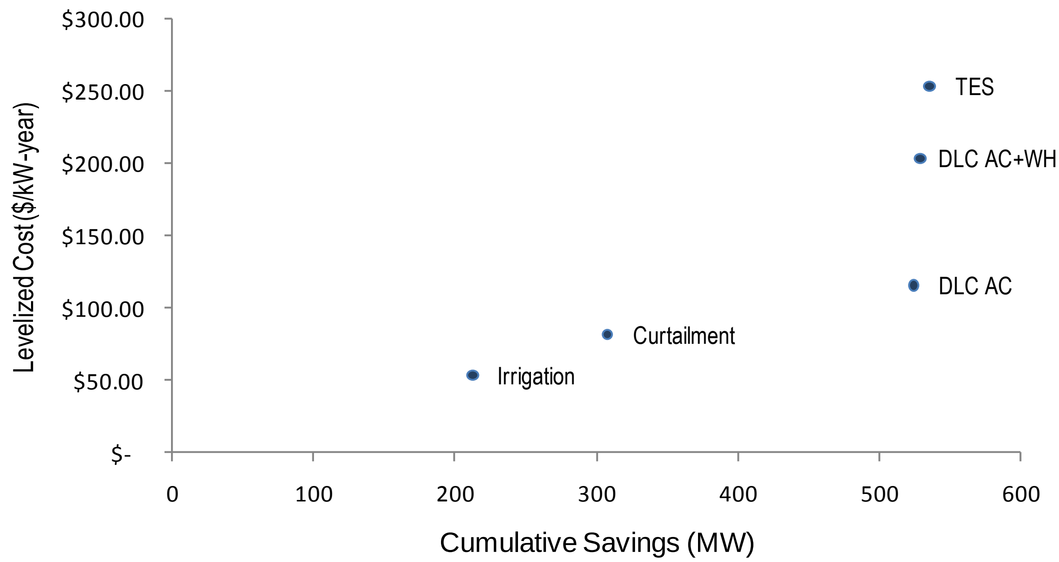
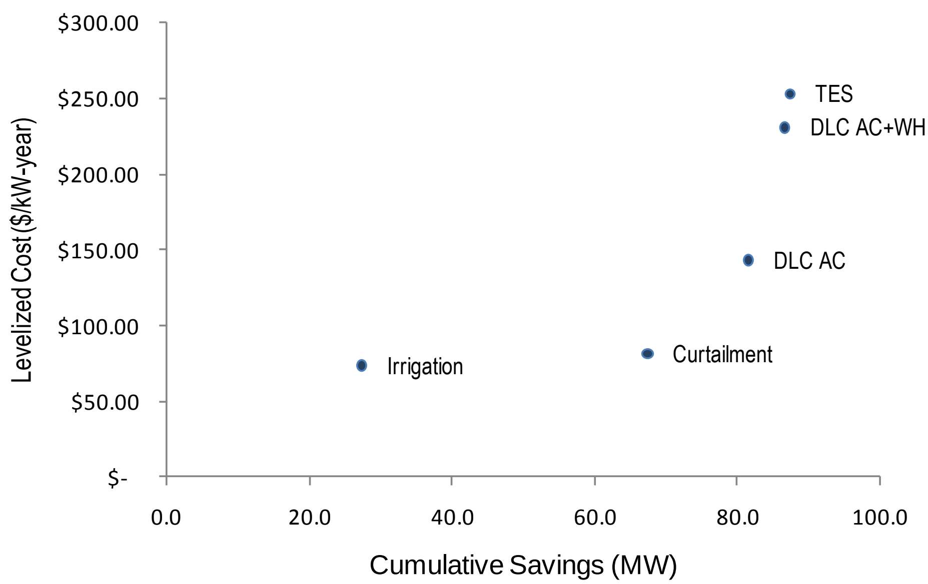


Figure 5. Class 1 DSM: Pacific Power Territory Supply Curve (Cumulative MW in 2030)



For Class 3 DSM resources, pricing programs for C&I customers and agricultural customers were estimated to be the least expensive. Irrigation TOU ($5/kW-year Rocky Mountain Power, $9/kW-year Pacific Power), RTP ($6/kW-year Rocky Mountain Power, $8/kW-year Pacific Power), and commercial CPP ($13/kW-year for both Rocky Mountain Power and Pacific Power) are relatively inexpensive, as there are no incentives paid. Additionally, these programs are targeted at larger C&I customers (greater than 100kW); so the average load reduction is potentially significant. DBB is also an inexpensive resource acquisition option, at $18/kW-year for both territories.

The residential TOU program is comparatively expensive due to the relatively small load reductions compared to installed technology (meters) as well as ongoing program maintenance costs (communications and administration).

Table 10. Class 3 DSM: Levelized Costs and Achievable Technical Potential (MW in 2030)

Levelized Cost	DBB	Residential TOU	Irrigation TOU	CPP	RTP
Rocky Mountain Power					
Achievable Technical Potential (MW)	40.3	11.5	181.7	100.1	22.9
Levelized Cost	$17.83	$166.76	$5.00	$12.92	$5.85
Pacific Power					
Achievable Technical Potential (MW)	6.3	6.9	125.3	16.7	1.8
Levelized Cost	$18.44	$173.83	$9.41	$12.92	$8.18

Figure 6. Class 3 DSM: Rocky Mountain Power Territory Supply Curve (Cumulative MW in 2030)

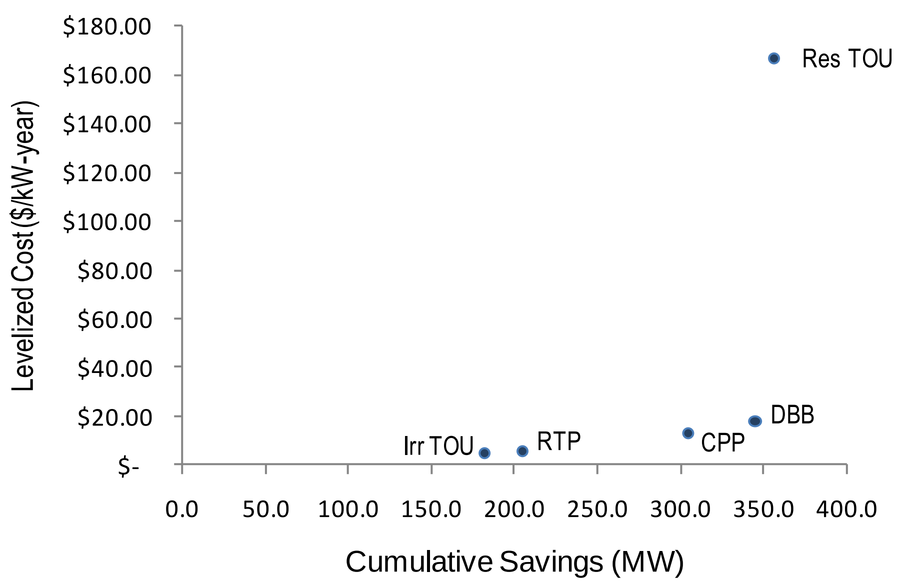
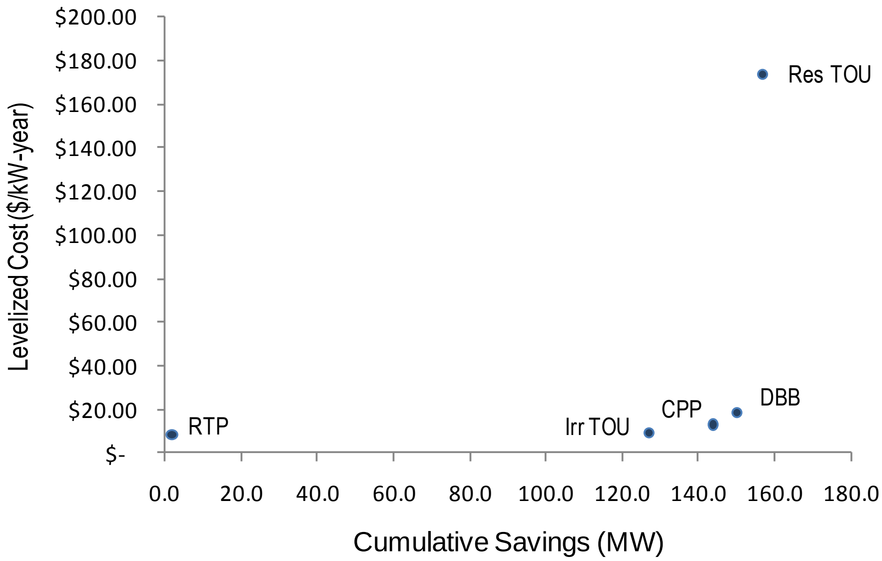


Figure 7. Class 3 DSM: Pacific Power Territory Supply Curve (Cumulative MW in 2030)



Class 1 DSM Resource Results by Program Option

Residential Direct Load Control

DLC programs are designed to interrupt specific end-use loads at customer facilities through utility-directed control. When deemed necessary, the utility is authorized to cycle or shut off participating appliances or equipment for a limited number of hours on a limited number of occasions. Customers generally do not have to pay for the equipment or installation of control systems, and are given incentives usually paid through credits on their utility bills. For this type of program, receiver systems are installed on the customer equipment to enable communications from the utility and to execute controls. DLC programs are generally mandatory once a customer elects to participate; however, some degree of voluntary participation is an option for some programs.[12]

Currently, PacifiCorp has approximately 123 MW of load curtailment under contract from its Utah Cool Keeper Program. Like many other national programs, it is targeted at the residential and small commercial customer classes (with less that 7.5 tons of cooling),[13] and only central cooling systems (including heat pumps) are eligible. On average, PacifiCorp has called events totaling to about 50 hours of curtailment per year, which is consistent with most utility programs researched. The combination of these factors resulted in the estimate of technical potential: 746 MW (Rocky Mountain Power) and 184 MW (Pacific Power). This estimate is inclusive of the quantity of potential currently under contract.

12 Typically, penalties are associated with non-compliance or opt-outs.

13 To assess the characteristics of customers in PacifiCorp's information system database with cooling systems less than 7.5 tons, those with a maximum demand of less than 30 kW during the summer were assumed to be eligible.

Table 11 shows technical and achievable technical potential results for the Rocky Mountain Power and Pacific Power territories, by customer class. As designed, the DLC programs also target water heaters for participants with electric water heating. Due to high cooling loads, the largest potential for air conditioning is in the Rocky Mountain Power territory, with 222 MW (2.2 percent of 2030 territory peak). In the Pacific Power territory, an additional 19 MW of potential (<1 percent of 2030 territory peak) is available. Water heating accounts for roughly 5 MW of the potential in the East and another 5 MW in the West.

Table 11. DLC Air Conditioning and Water Heat: Technical and Achievable Technical Potential (MW in 2030)

	Rocky Mountain Power			Pacific Power		
Sector	Technical Potential	Achievable Technical Potential	Achievable Technical as % of 2030 Peak	Technical Potential	Achievable Technical Potential	Achievable Technical as % of 2030 Peak
Agricultural	0.0	0.0	0.00%	0.0	0.0	0.00%
Industrial	0.0	0.0	0.00%	0.0	0.0	0.00%
Commercial	41.9	1.2	0.01%	35.8	0.8	0.02%
Residential	703.9	220.6	2.22%	148.0	18.5	0.52%
Total	**745.8**	**221.8**	**2.23%**	**183.8**	**19.3**	**0.54%**

Figure 8 displays state-specific results, with the residential sector in all states dominating the potential with 240 MW by 2030. Table 12 shows the levelized cost for a DLC program. Oregon and California, because of smaller loads and differing climactic conditions, result in lower demand reductions per switch, and have higher costs per kW saved. The program's water heating component is shown as an additional $/kW cost.

Figure 8. DLC Air Conditioning and Water Heat: Achievable Technical Potential by State (MW in 2030)

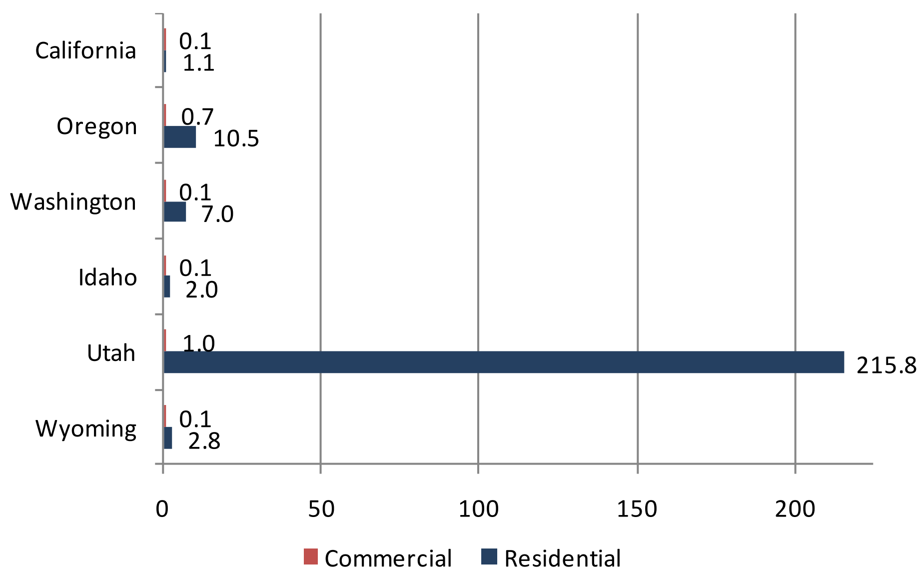


Table 12. DLC Air Conditioning and Water Heat: Levelized Cost by State ($/kW)

Territory	State	Achievable Potential (MW)	Levelized Cost – DLC AC($/kW)	Levelized Cost – DLC Water Heat ($/kW)
Pacific Power	California	1.1	$158.77	$87.74
	Oregon	11.2	$158.77	$87.74
	Washington	7.0	$115.89	$87.74
	Subtotal	**19.3**	**$143.21**	**$87.74**
Rocky Mountain Power	Idaho	2.1	$115.89	$87.74
	Utah	216.8	$115.89	$87.74
	Wyoming	2.9	$115.89	$87.74
	Subtotal	**221.8**	**$115.89**	**$87.74**
	Total	**241.1**	**$118.08**	**$87.74**

Detailed assumptions are shown in Table 13 and Table 14 for the program's air conditioning component, and in Table 15 and Table 16 for the program's water heat component.

Table 13. Residential DLC AC: Program Basics

Program Name	DLC - RES - AC
Customer Sectors Eligible	All residential and small commercial market segments
End Uses Eligible for Program	Central cooling, excludes heat pumps
Customer Size Requirements, if any	Residential and small commercial with cooling less than 7.5 tons (proxy of max demand <30 kW)
Summer Load Basis	Top 50 hours
Winter Load Basis	No winter

Table 14. Residential DLC AC: Inputs and Sources Not Varying by State or Sector*

Inputs	Value	Sources or Assumptions
Annual Attrition	5%	Rocky Mountain Power at 5% change of electrical service with a program life of 10 years.
Annual Utility Administrative Costs (%)	$300,000	Assumes two FTE to run the program system wide.
Technology Cost (per new participant)	$60 per switch plus $80 for installation labor	Based on vendor bids, research, and informal communication with vendors.
Marketing Cost (per new participant)	$25	Assumes 1/2 hour of staff time, valued at $50/hour. Based on research of vendor bids and informal communications with vendors.

Inputs	Value	Sources or Assumptions
Annual Vendor Costs (%)	15%	Based on research of vendor bids and informal communication with vendors. 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 half of the costs experienced by the PacifiCorp Idaho Irrigation system, which utilizes a two-way system.
Incentives (annual costs per participant)	$20	Residential Utah Cool Keeper Program incentive amount of $20, consistent with other programs across the country; commercial Utah Cool Keeper Program incentive of $40 per customer year, consistent with other national programs.
$/kW Costs	Varies by state	Savings per switch varies by state due to differing loads and climactic conditions. Utah saves approximately 1 kW per switch, as reported in the Cool Keeper Program Impact Evaluation. Idaho, Wyoming, and Washington's per unit energy consumptions are consistent with Utah, and are assumed to save 1 kW per switch. Oregon and California's average savings per switch is .7 kW, based on the per unit energy consumption coincident with system peak. Costs were reported on a per switch basis, and then adjusted by each state's saving per switch.
Load Class Eligibility	80% Utah; 50% all other states	The ability to control AC units is constrained by the proximity to the location of the paging signal. Load basis varies by the geographic makeup of each state's service territory, with rural service areas having a lower load basis than urban service areas.
Technical Potential	50%	Assumes all central AC units can be retrofit, and that the program employs a 50% cycling strategy.

Inputs	Value	Sources or Assumptions
Program Participation	Residential varies by state; 3% commercial	The average participation rate for national programs is between 15% and 20% of all residential customers, which translates into 20% to 30% of eligible customers (those with central air conditioning, which is the load basis for this program). For example, Rocky Mountain Power runs an air conditioning DLC program (Cool Keeper) in Utah, which currently has 15% of residential customers, but about 25% of eligible customers in the program (those with central cooling). Therefore, this analysis assumes there is potential to sign up 30% of eligible customers (an additional 5% beyond currently achieved levels) in Utah and 20%-25% in other states (to be consistent with other national program achievements and the 2009 FERC study), but only 3% of small commercial customers, based on the experience of PacifiCorp and other national utilities and supported by C&I surveys.
Event Participation	94%	The historic participation in the Utah Cool Keeper Program is based on homeowners removing units and operational breakdowns (2.5%-5.8%). This figure is consistent with Xcel Energy, MidAm, and EON. Lower rates were experienced by SMUD and PSE&G (80%).

*See Volume II, Appendix A for inputs and sources varying by state or sector.

Table 15. Residential DLC Water Heat: Program Basics

Program Name	DLC - RES - Water Heat
Customer Sectors Eligible	All residential market segments.
End Uses Eligible for Program	Electric hot water heating, excludes heat pump water heaters.
Customer Size Requirements, if any	Residential customers and with cooling less than 7.5 tons (proxy of max demand <30 kW). Program is run in conjunction with the DLC AC program.
Summer Load Basis	Top 50 hours.
Winter Load Basis	No winter.

Table 16. Residential DLC Water Heat: Inputs and Sources Not Varying by State or Sector*

Inputs	Value	Sources or Assumptions
Annual Attrition	5%	Rocky Mountain Power 5% change in electrical service.
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)	$12.50	Assumes 1/4 hour of staff time valued at $50/hour. Based on research of vendor bids and informal communication with vendors.
Annual Vendor Administrative Costs (%)	5%	Based on research of vendor bids and informal communication with vendors.
Communication (annual costs per participant)	$0	Communication is covered by the DLC AC program.
Incentives (annual costs per participant)	$20	Residential Utah Cool Keeper Program incentive amount of $20, consistent with other programs across the country; commercial Utah Cool Keeper Program incentive of $40 per customer year, consistent with other national programs. All incentive costs are included in the $/kW assumption.

Inputs	Value	Sources or Assumptions
$/kW Costs	$87.74	Assumes an average annual impact of .7 kW per switch consistent with PGE Direct Load Control Pilot for Electric Water Heat (2003). Since water heating loads in the residential sector tend to have low weather sensitivity, this annual average figure is appropriate for a summer program.
Load Class Eligibility	80% Utah; 50% all other states	The ability to control water heaters is constrained by the proximity to the location of the paging signal. Load basis varies by the geographic makeup of each state's service territory, with rural service areas having a lower load basis than urban services areas.
Technical Potential as % of Load Basis	100%	Assumes all customer electric hot water units can be retrofitted. A cycling strategy was not employed.
Program Participation (%)	Varies by state	Water heating program participation is assumed to be the same rate of program sign-up as the DLC AC program, but accounts for the saturation of electric hot water heating for customers with central AC. It is calculated as % of customers with electric hot water and central cooling / % of customers with electric hot water heating) * central AC participation rate.
Event Participation (%)	97%	Historic event participation in the Utah Cool Keeper Program is based on homeowners removing units and operational breakdowns (2.5%-5.8%). Because participants and contractors are less likely to remove units on water heaters, event participation is based on the upper bound.

*See Volume II, Appendix A for inputs and sources varying by state or sector.

Irrigation Load Control

A program targeting irrigation is an ideal option to reduce summer peak due to irrigation pumping coinciding with mid-afternoon summer peaks. PacifiCorp's Irrigation Load Control Program in Idaho and Utah includes a scheduled component where customers subscribe in advance for specific days and numbers of hours their irrigation systems will be turned off, as well as a dispatchable component where, like the residential DLC program, events will be called and irrigation pumps controlled for a four-hour period. Under the current program, PacifiCorp can achieve 35 MW of savings in Utah and 150 MW of savings in Idaho. Although a scheduled program option is still in place, most participants have transitioned to the dispatchable program option; therefore, the irrigation DLC program is designed to be 100 percent dispatchable, with no participants, on a predetermined schedule.

Table 17 shows an achievable technical potential estimate of 27 MW for Pacific Power (<1 percent of 2030 territory peak). For Rocky Mountain Power, 211 MW is available, which includes the 185 MW of expected 2011 achievements (2.1 percent of 2030 territory peak).

Table 17. Irrigation Load Control: Technical and Achievable Technical Potential (MW in 2030)

Sector	Rocky Mountain Power			Pacific Power		
	Technical Potential	Achievable Technical Potential	Achievable Technical as % of 2030 Peak	Technical Potential	Achievable Technical Potential	Achievable Technical as % of 2030 Peak
Agricultural	279.2	212.5	2.14%	173.8	27.3	0.77%
Industrial	0.0	0.0	0.00%	0.0	0.0	0.00%
Commercial	0.0	0.0	0.00%	0.0	0.0	0.00%
Residential	0.0	0.0	0.00%	0.0	0.0	0.00%
Total	**279.2**	**212.5**	**2.14%**	**173.8**	**27.3**	**0.77%**

Due to load distribution, the majority of potential is expected to come from Idaho (174 MW). Despite the presence of agricultural customers in Oregon, smaller pumps typically used in this region run for fewer hours, and can only achieve 13MW (Figure 9). Additionally, the program's maturity in Idaho, concentration of agricultural pumping loads and larger pump sizes results in lower program costs, compared to other states (Table 18).

Figure 9. Irrigation Load Control: Achievable Technical Potential by State (MW in 2030)

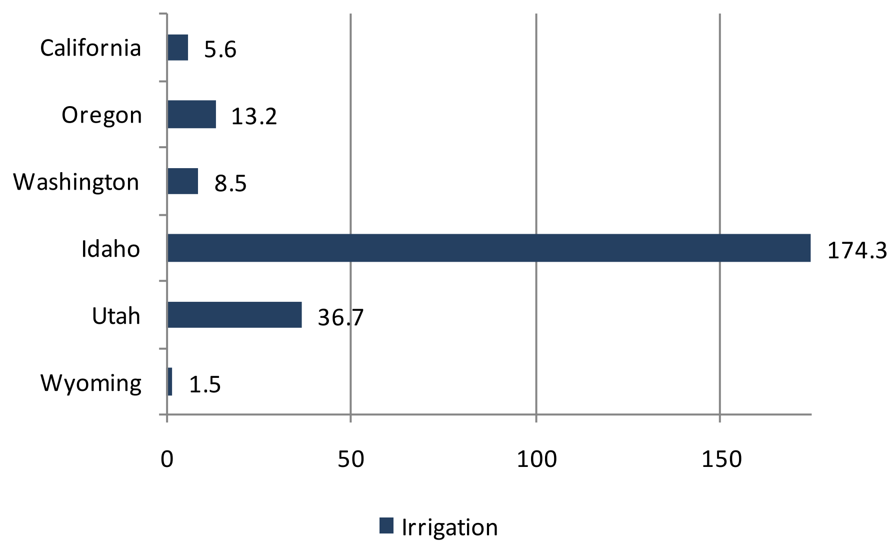


Table 18. Irrigation Load Control: Levelized Cost by State ($/kW)

Territory	State	Achievable Potential (MW)	Levelized Cost ($/kW)
Pacific Power	California	5.6	$73.70
	Oregon	13.2	$73.70
	Washington	8.5	$73.70
	Subtotal	**27.3**	**$73.70**
Rocky Mountain Power	Idaho	174.3	$49.50
	Utah	36.7	$73.70
	Wyoming	1.5	$73.70
	Subtotal	**212.5**	**$53.85**
	Total	**239.8**	**$56.11**

Detailed assumptions for the irrigation load control program are shown in Table 19 and Table 20.

Table 19. Irrigation Load Control: Program Basics

Program Name	Irrigation
Customer Sectors Eligible	Irrigation only
End Uses Eligible for Program	Irrigation pumping
Customer Size Requirements, if any	All irrigation customers
Summer Load Basis	Top 50 hours
Winter Load Basis	No Winter

Table 20. Irrigation Load Control: Inputs and Sources not Varying by State or Sector*

Inputs	Value	Sources or Assumptions
Annual Administrative Costs (%)	10%	An additional administrative cost is added to current PacifiCorp $/kW program costs.
Technology Cost (per new participant)	N/A	All costs are included in the $/kW assumption.
Marketing Cost (per new participant)	N/A	All costs are included in the $/kW assumption.
Incentives (annual costs per participating kW)	N/A	All costs are included in the $/kW assumption. Idaho Power currently pays $32/kW; Rocky Mountain Power pays $28/kW in Utah and $30/kW in Idaho.
Overhead: First Costs	N/A	All costs are included in the $/kW assumption.
$/kW Costs	Varies by state	Costs are based on the $/kW cost for the 2009 irrigation load control programs in Utah and Idaho. Climactic conditions and crop variety in other states are similar to those in Utah; therefore, the Utah $/kW cost was applied to all states except Idaho. Program costs are similar to those for Idaho Power, which are currently $64/kW.
Technical Potential as % of Load Basis	90%	End-use distribution shows 90% of load goes to pumping, while 10% goes to other end uses. Assumes all pumps can be controlled.
Program Participation (%)	Varies by state	PacifiCorp has participation rates of 85% in Idaho and 50% in Utah. Utah participation is expected to increase to 80% as the program matures. Idaho Power currently has about 30% of load under control, which is comparable to estimated participation in Washington and Wyoming. Both California and Oregon have smaller pumps and different pumping configurations, and are expected to have lower participation.

Inputs	Value	Sources or Assumptions
Event Participation (%)	92%	Event participation equals the number of customers, on average, who choose to participate in an event. We calculated event participation by taking the average number of opt-outs from PacifiCorp's 2009 Irrigation Load Control Program in Idaho and dividing it by the number of participating customers.

*See Volume II, Appendix A for inputs and sources varying by state or sector.

Thermal Energy Storage

For C&I customers, it is possible for cooling TES systems, which produce ice during off-peak periods, be used to cool buildings during pre-specified, on-peak periods. For this analysis, a TES program was designed to run for 480 peak hours in the summer (six hours each day) in conjunction with a TOU rate.

Few investor-owned utilities currently offer TES programs to their customers. Therefore, information regarding the program assumptions was based on previous research and discussions with a major manufacturer of TES equipment. TES systems require rooftop cooling units, typically found on large commercial sites. Thus, the analysis assumed only those commercial sector customers with greater than 100kW in total site demand would be eligible for participation, and the technical feasibility of participation was reduced to account for only customers with direct exchange cooling units. Program participation is assumed to be quite low (3 percent of eligible load), based on the experiences of Xcel Energy and Southern California Edison (SCE).

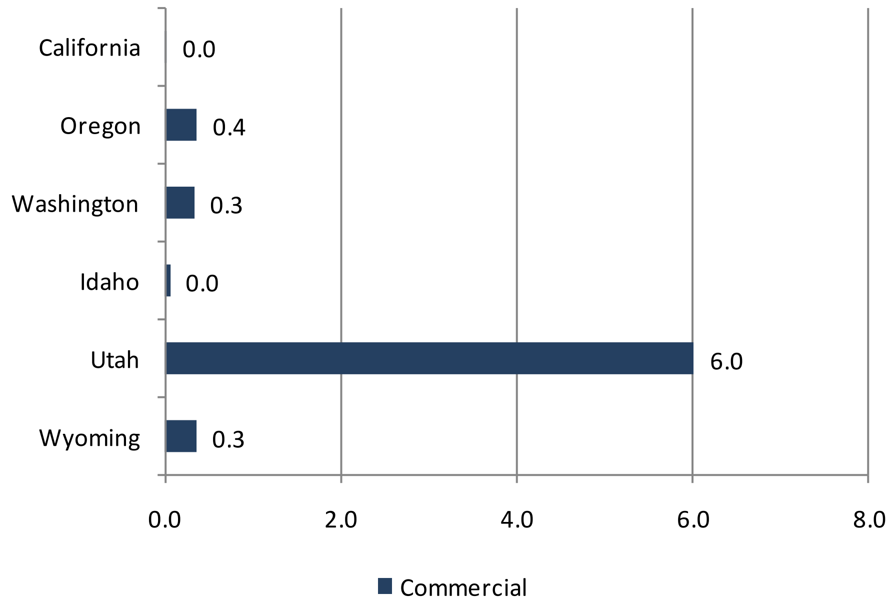
Table 21 displays results for a TES program in the Rocky Mountain Power and Pacific Power territories. Technically, the Rocky Mountain Power territory has 216 MW of potential, but, due to low participation rates, it is likely only 6.4 MW will be available (representing less than 0.1 percent of the 2030 territory peak). Similarly, the Pacific Power territory has 24 MW of potential, but only 0.7 MW of achievable technical potential.

Table 21. Thermal Energy Storage: Technical and Achievable Technical Potential (MW in 2030)

Sector	Rocky Mountain Power			Pacific Power		
	Technical Potential	Achievable Technical Potential	Achievable Technical as % of 2030 Peak	Technical Potential	Achievable Technical Potential	Achievable Technical as % of 2030 Peak
Agricultural	0.0	0.0	0.00%	0.0	0.0	0.00%
Industrial	0.0	0.0	0.00%	0.0	0.0	0.00%
Commercial	215.5	6.4	0.07%	23.5	0.7	0.02%
Residential	0.0	0.0	0.00%	0.0	0.0	0.00%
Total	**215.5**	**6.4**	**0.07%**	**23.5**	**0.7**	**0.02%**

Figure 10 shows achievable potential by state, with the majority of the potential in Utah.

Figure 10. Thermal Energy Storage: Achievable Technical Potential by State (MW in 2030)



TES is a technology-intensive option, as units must be retrofitted to produce and store ice for on-peak cooling. Costs are typically $2,200 per kW. As a third-party contractor handles site acquisition, installation, and project management, no additional administrative costs have been added to the per kW cost.

Table 22. Thermal Energy Storage: Levelized Cost by State ($/kW)

Territory	State	Achievable Potential (MW)	Levelized Cost ($/kW)
Pacific Power	California	0.0	$253.28
	Oregon	0.4	$253.28
	Washington	0.3	$253.28
	Subtotal	**0.7**	**$253.28**
Rocky Mountain Power	Idaho	0.0	$253.28
	Utah	6.0	$253.28
	Wyoming	0.3	$253.28
	Subtotal	**6.4**	**$253.28**
	Total	**7.1**	**$253.28**

Detailed assumptions for a TES program are shown in Table 23 and Table 24.

Table 23. Thermal Energy Storage: Program Basics

Program Name	Thermal Energy Storage
Customer Sectors Eligible	All large commercial market segments
End Uses Eligible for Program	Electric cooling loads
Customer Size Requirements, if any	All commercial customers with load >100kW
Summer Load Basis	Top 480 peak hours
Winter Load Basis	No winter

Table 24. Thermal Energy Storage: Inputs and Sources not Varying by State or Sector*

Inputs	Value	Sources or Assumptions
Annual Administrative Costs (%)	0%	Administrative functions are performed by a third-party vendor.
$/kW Costs	$2,200	Cost quoted by Ice Energy. Includes equipment, project management, and site acquisition. Applied as a first-time cost, based on total project size. Price can vary by geography. Contract is valid for 25 years and includes a full warranty. Cost per kW was calculated assuming a 20-year program life.
Maintenance Cost	2%	Ice Energy charges $325/unit/year, which translates to approximately 2% of total costs.
Technical Potential (%)	Varies by state and sector	Based on the saturation of DX cooling by commercial market sector and the maximum possible reduction in each facility's load.
Program Participation (%)	3%	The assumed participation rate is based on the experience of Austin Energy, which currently offers a $300/kW incentive. Given the high cost of this program, participation is expected to be minimal; especially in the small commercial sector. Moreover, from the utility's point of view, this program is less attractive than other Class 1 options.
Event Participation (%)	99%	Highly reliable scheduling of pre-cooling.

*See Volume II, Appendix A for inputs and sources varying by state or sector.

Load Curtailment

Load curtailment programs refer to contractual arrangements between utilities and their C&I customers, who agree to curtail or interrupt their operations, in whole or part, for a predetermined period when requested by the utility. In most cases, mandatory participation or liquidated damage agreements are required once the customer enrolls in the program; however, the number of curtailment requests, both in total and on a daily basis, is limited by the terms of each contract.

Customers generally are not paid for individual events, but are compensated through a fixed monthly amount per kW of pledged curtailable load or through a rate discount. Typically, contracts require customers to curtail their connected load either by a set percentage (e.g., 15 to 20 percent) or a predetermined level (e.g., 100 kW). These types of programs often involve long-term contracts and have penalties for non-compliance, which range from simply dropping the customer from the program to more punitive actions, such as requiring the customer to repay the utility for the committed (but not curtailed) energy at market rates.

In this study, we assumed C&I customers with a monthly demand of at least 100 kW would be eligible for such a program. Technical potential was estimated by customer segment, based on detailed engineering audits of the demand response potential of C&I customers in California, which provided the best data available in the region, and were appropriate for use in PacifiCorp's territory due to similarities in equipment, such as compressor and HVAC systems. Currently, PacifiCorp has a rate structure for its largest industrial accounts that allows curtailment during utility events, but this analysis does not include the load of these "special accounts," and, therefore, does not include their impact. However, customers who are able to use stand by generation as a load management strategy are included in the analysis.

We used the results of the PacifiCorp C&I customer survey, conducted for the 2007 Assessment, to estimate program participation. Customers indicated they were receptive to this program option, likely due to the incentive, which would be paid regardless of curtailment events. The concerns customers expressed about the program were related to specific business constraints that made participation difficult. Participation ranged from 0 percent for segments such as health, lodging, and petroleum manufacturing, to 20 to 25 percent for restaurants, schools, and offices. We adjusted participation rates for Oregon, since the original survey results were conservative for this region.

The Rocky Mountain Power territory has 95 MW of achievable technical potential in the C&I sector, totaling slightly less than 1 percent of the territory's 2030 peak (Table 25). The Pacific Power territory has 40 MW of achievable technical potential, and represents around 1.1 percent of Pacific Power territory's 2030 peak load. The technical potential and achievable potential in both territories is significantly higher than that listed in our 2007 Assessment, due to the inclusion of backup generators.

Table 25. Load Curtailment: Technical and Achievable Technical Potential (MW in 2030)

Sector	Rocky Mountain Power			Pacific Power		
	Technical Potential	Achievable Technical Potential	Achievable Technical as % of 2030 Peak	Technical Potential	Achievable Technical Potential	Achievable Technical as % of 2030 Peak
Agricultural	0.0	0.0	0.00%	0.0	0.0	0.00%
Industrial	839.0	29.4	0.31%	68.3	14.9	0.42%
Commercial	618.7	65.8	0.68%	164.9	25.2	0.71%
Residential	0.0	0.0	0.00%	0.0	0.0	0.00%
Total	**1457.7**	**95.2**	**0.99%**	**233.2**	**40.1**	**1.13%**

Figure 11 shows the majority of potential derives from Utah; Wyoming has a significant quantity of industrial load potential, including chemical manufacturing, mining, and "miscellaneous" manufacturing.

Figure 11. Load Curtailment: Achievable Technical Potential by State (MW in 2030)

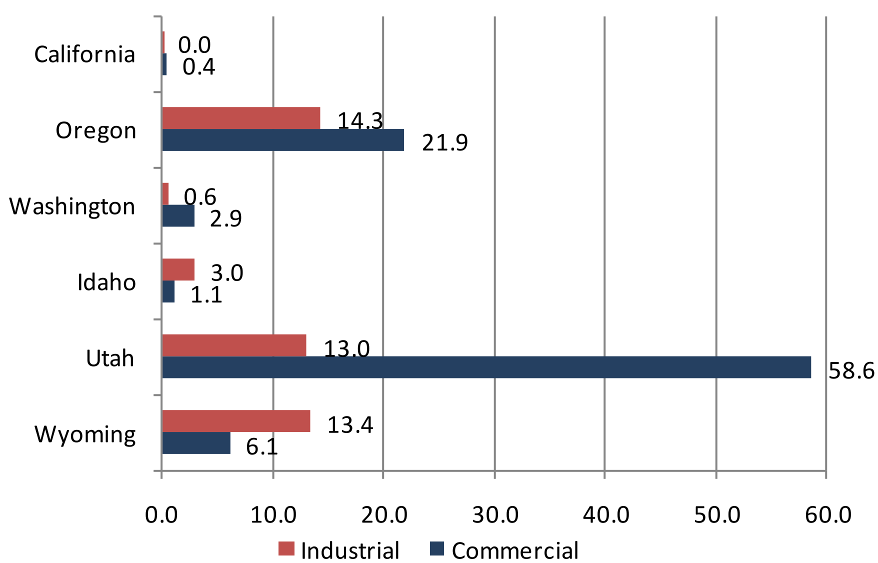


Table 26 shows levelized costs and achievable potential by state. Since the program will be implemented by a third-party aggregator, $/kW costs have been based on contractor bids. An additional administrative cost, to be incurred by PacifiCorp, has been added the aggregator's bid.

Table 26. Load Curtailment: Levelized Cost by State ($/kW)

Territory	State	Achievable Potential (MW)	Levelized Cost ($/kW)
Pacific Power	California	0.5	$81.55
	Oregon	36.2	$81.55
	Washington	3.4	$81.55
	Subtotal	**40.1**	**$81.55**
Rocky Mountain Power	Idaho	4.1	$81.55
	Utah	71.6	$81.55
	Wyoming	19.5	$81.55
	Subtotal	**95.2**	**$81.55**
	Total	**135.3**	**$81.55**

Detailed assumptions for a load curtailment program are shown in Table 27 and Table 28.

Table 27. Load Curtailment: Program Basics

Program Name	Load Curtailment
Customer Sectors Eligible	All industrial and commercial market segments
End Uses Eligible for Program	Total load of all end uses
Customer Size Requirements, if any	Customers >100kW
All Seasons Load Basis	Top 87 hours

Table 28. Load Curtailment: Inputs Consistent Across Market Segments*

Inputs	Value	Sources or Assumptions
Annual Administrative Costs (%)	$200,000	Assumes 1-1/3 FTE to run the program system wide.
Technology Cost (per new participant)	N/A	All costs are included in third-party aggregator bid.
Marketing Cost (per new participant)	N/A	All costs are included in third-party aggregator bid.
Incentives (annual costs per participating kW)	N/A	All costs are included in third-party aggregator bid.
Overhead: First Costs	N/A	All costs are included in third-party aggregator bid.
$/kW Costs	$81.55	Assumes an $80/kW average third-party aggregator bid plus the administrative adder.
Technical Potential as % of Load Basis	Varies by sector	Based on detailed engineering audits of demand response potential of C&I customers throughout California by Nexant, with third-party verification of results. Findings are amalgamated by sector and end use category and supported by senior engineering analysis.
Program Participation (%)	Varies by sector	Survey results assuming other program offerings.
Event Participation (%)	95%	Based on informal conversations with a third-party aggregator.

*See Volume II, Appendix A for inputs and sources varying by state or sector.

Class 3 DSM Resource Results by Program Option

Demand Buyback

Under DBB, the utility offers payments to customers for reducing their demand when requested by the utility. Under these programs, the customer remains on a standard rate, but is presented with options to bid or propose load reductions in response to utility requests. The buyback amount generally depends on market prices published by the utility ahead of the curtailment event, and the reduction level is verified against an agreed-upon baseline usage level.

DBB is a mechanism enabling consumers to actively participate in electricity trading by offering to undertake changes in their normal consumption patterns. Participation requires the customer to be flexible in their normal electricity demand profile, install the necessary control and monitoring technology to execute the bids, and demonstrate bid delivery. One of several Internet-based programs is generally used to disseminate information on buyback rates to potential customers, who can then take the appropriate actions to manage their peak loads during requested events. The program option in this analysis targets the largest C&I customers (>100kW), consistent with national programs. Unlike curtailment programs, customers have the option to curtail power requirements on an event-by-event basis. Incentives are paid to participants for energy reduced during each event, based primarily on the difference between market prices and utility rates.

To estimate potential, detailed C&I audits from California were used to determine the technically available portion of the load basis. Program participation, varying by sector, is based on the results of the customer survey conducted for the 2007 Assessment. Zero achievable technical potential is estimated for health, lodging, and petroleum manufacturing, based on survey responses.

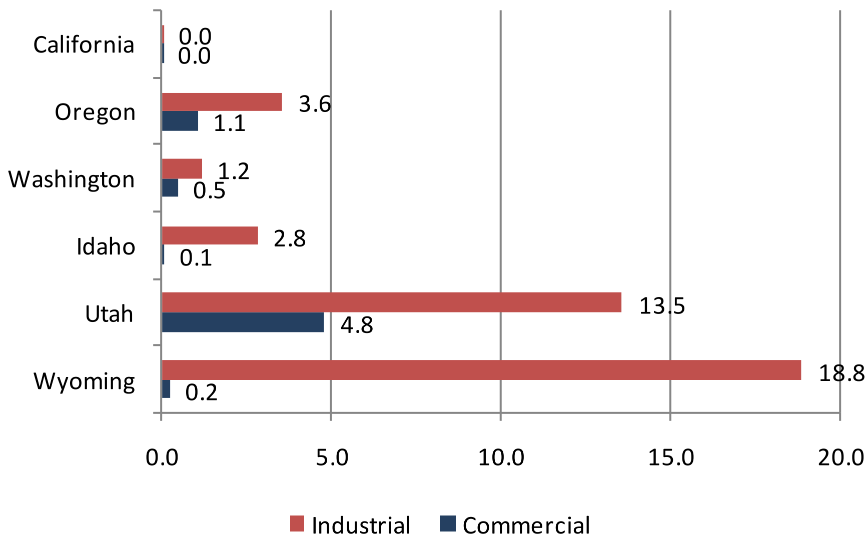
One of the most important and difficult DBB factors to estimate is the quantity of load curtailment that can be expected during any individual event. Cadmus relied on the 2007 Assessment's event participation assumption of 36 percent, which was twice the 2006 Energy Exchange event participation of 18 percent (representing the portion of participating load curtailed for the average event). Table 29 shows that in the Rocky Mountain Power territory, an average of 40 MW (less than 0.5 percent of territory peak) can be expected during any one event, although it is expected some individual events may produce more load reduction. In the Pacific Power territory, 107 MW of technical potential results in an average of 6 MW (less than 0.2 percent of territory peak) expected during any one event.

Table 29. Demand Buyback: Technical and Achievable Technical Potential (MW in 2030)

	Rocky Mountain Power			Pacific Power		
Sector	Technical Potential	Achievable Technical Potential	Achievable Technical as % of 2030 Peak	Technical Potential	Achievable Technical Potential	Achievable Technical as % of 2030 Peak
Agricultural	0.0	0.0	0.00%	0.0	0.0	0.00%
Industrial	519.8	35.2	0.37%	66.3	4.8	0.13%
Commercial	155.3	5.1	0.05%	40.9	1.5	0.04%
Residential	0.0	0.0	0.00%	0.0	0.0	0.00%
Total	**675.1**	**40.3**	**0.42%**	**107.2**	**6.3**	**0.18%**

Due to large industrial loads, Wyoming and Utah have significant potential for this program (Figure 12), where potential is driven by chemical manufacturing, mining, and other non-classified manufacturing.

Figure 12. Demand Buyback: Achievable Technical potential by State (MW in 2030)



Because participants are paid based on market energy rates, this program's cost is relatively low. Table 30 shows the resulting $18/kW-year in both the Rocky Mountain Power and Pacific Power territories. New customer costs include hardware ($1,400 for communications, connectivity, and any necessary metering), marketing ($500), and program development ($400,000). New participant costs must be reinvested due to 5 percent annual attrition rates (based on electrical service only) and a hardware life of 20 years. Incentives are converted from the cost per MWh to cost per kW based on historic Energy Exchange Program costs from 2000 to 2006, resulting in $10 per kW,[14] with an average of $100/MWh in energy payments.

[14] Based on data available after completion of our 2007 Assessment, the 2006 Energy Exchange Program's average per unit cost was $18/kW and $130/MWh. Therefore, the resulting levelized calculated cost of this program option may be understated.

Table 30. Demand Buyback: Levelized Cost by State ($/kW)

Territory	State	Achievable Potential (MW)	Levelized Cost ($/kW)
Pacific Power	California	0.1	$18.44
	Oregon	4.6	$18.44
	Washington	1.6	$18.44
	Subtotal	**6.3**	**$18.44**
Rocky Mountain Power	Idaho	2.9	$17.83
	Utah	18.3	$17.83
	Wyoming	19.1	$17.83
	Subtotal	**40.3**	**$17.83**
	Total	**46.6**	**$17.91**

Detailed assumptions for a DBB program are shown in Table 31 and Table 32.

Table 31. Demand Buyback: Program Basics

Program Name	Demand Buyback
Customer Sectors Eligible	All C&I market segments
End Uses Eligible for Program	Total load of all end uses
Customer Size Requirements, if any	Customers >100kW
All Seasons Load Basis	Top 87 hours

Table 32. Demand Buyback: Inputs and Sources not Varying by State or Sector*

Inputs	Value	Sources or Assumptions
Annual Administrative Costs (%)	15%	Assumes an administrative adder of 15%.
Technology Cost (per new participant)	$1,400	Technology costs include communications, connectivity, and meters, if necessary, based on California spending of $32M for 23,000 large C&I hardware after energy crisis.
Marketing Cost (per new participant)	$500	Assumes $500 per customer for marketing.
Incentives (annual costs per participating kW)	$10	Estimate of $10 per kW from 2000-2002 Demand Exchange Program based on average market prices of $100/MWh.
Overhead: First Costs	$400,000	Standard program development assumption, including necessary internal labor, research, and IT/billing system changes.
Technical Potential as % of Load Basis	Varies by sector	Based on detailed engineering audits of demand response potential of C&I customers throughout California by Nexant, with third-party verification of results.
Program Participation (%)	Varies by sector	Participation rates are based on self-reported findings of the commercial and industrial customer surveys conducted for the 2007 Assessment.
Event Participation (%)	36%	Event participation based on 2006 PacifiCorp results of average of 12 MW per event (18% event participation), with average price paid of $130/MWh—assuming increased focus on program could double event participation.

*See Volume II, Appendix A for inputs and sources varying by state or sector.

Residential Time-of-Use Rates

We obtained information on TOU rates was obtained from the 2007 Assessment, which relied on tariffs from 60 U.S. utilities, promotional materials used by utilities offering new TOU (or TOU with CPP) programs during the past five years, and several interviews with utility staff members.[15] TOU rates have been offered by U.S. utilities since at least the 1970s, but the historic impacts have been quite low. In fact, PacifiCorp ran a TOU pilot from 2002 to 2004, which had extremely low program sign-up (940 residential customers at the end of 2004, with an average of 25 percent annual attrition), despite an intensive marketing effort.

The TOU rates developed in recent years typically differ from those of the past in several important ways:

- First, most new TOU rates contain three price tiers, as opposed to the two-tier rates common in many long-standing TOU programs. This allows utilities to set high prices during their highest peak periods and offer exceptionally low off-peak prices overnight, when the cost is at its lowest and supply is plentiful. The majority of hours are assigned a “mid-peak” price that is typically a slightly discounted version of the standard rate.
- Another change is the duration of the peak period is typically shorter than it has been in the past—this analysis assumes the peak period last for six hours a day.
- Finally, the price differentials between peak and off-peak prices tends to be greater than in the past to encourage load shifting away from the peak period. For long-standing TOU rates, this differential averaged about 7.6 cents/kWh, whereas newer programs tend to have a differential of greater than 10 cents/kWh.

TOU rates are assumed to be available only to the residential customer segments, and the potential is based on the total load rather than individual end uses. The technically feasible portion of the load basis expected to be reduced during peak hours is 5 percent, based on results from California[16] and Puget Sound Energy. The average participation rate of the top 10 highest-enrolled TOU programs in the country[17] is 16 percent; yet these programs do not represent the experience of all national programs, many of which have participation rates of <1 percent. If a robust marketing effort is made in conjunction with a TOU rate design that is more than double PacifiCorp’s current TOU differential, the expected participation rate is assumed to be 10 percent.

Table 33 shows 145 MW of technical potential and 11.5 MW of achievable technical potential in the Rocky Mountain Power territory, which occurs during the summer peak. In the Pacific Power

[15] Includes Gulf Power, Alabama Power, Ameren, Pacific Gas and Electric, SCE, San Diego Gas and Electric, and Teco Energy. Interviews with utility staff included Arizona Public Service, Salt River Project, and Florida Power and Light.

[16] Charles River Associates, “Impact Evaluation of the California Statewide Pricing Pilot, Final Report,” March 16, 2005. See also Piette, Mary Ann and David S. Watson “Participation through Automation: Fully Automated Critical Peak Pricing in Commercial Buildings,” 2006, Lawrence Berkeley National Laboratory. Also see Linkugel, Eric, Proceedings of the 2006 ACEEE Summer Study on Energy Efficiency in Buildings, Pacific Grove, CA, August 2006.

[17] FERC, 2006 and R. Gunn, “North American Demand Response Survey Results” (Association of Energy Services Professionals, Phoenix, AZ, February 2006).

territory, where the program will run during the winter, there is 112 MW of technical potential and 7 MW of market, representing less than 0.5 percent of the 2030 territory winter peak.

Table 33. Residential TOU: Technical and Achievable Technical Potential (MW in 2030)

Sector	Rocky Mountain Power			Pacific Power		
	Technical Potential	Achievable Technical Potential	Achievable Technical as % of 2030 Peak	Technical Potential	Achievable Technical Potential	Achievable Technical as % of 2030 Peak
Agricultural	0.0	0.0	0.00%	0.0	0.0	0.00%
Industrial	0.0	0.0	0.00%	0.0	0.0	0.00%
Commercial	17.8	0.0	0.00%	35.0	0.0	0.00%
Residential	127.5	11.5	0.13%	76.6	6.9	0.22%
Total	**145.4**	**11.5**	**0.13%**	**111.6**	**6.9**	**0.22%**

Figure 13 shows Utah has the most potential, with 10 MW, followed by Oregon with about 5 MW. As previously noted, these potentials do not account for the interactive effects of competing capacity programs, such as Utah's air conditioner DLC program and water heater DLC activity, but rather look at each program independently, as such the potential saving are not additive. In addition, the Utah resource potential is assumed to be available in the summer, whereas the potential in Oregon is available in winter.

Figure 13. Residential TOU: Achievable Technical Potential by State (MW in 2030)

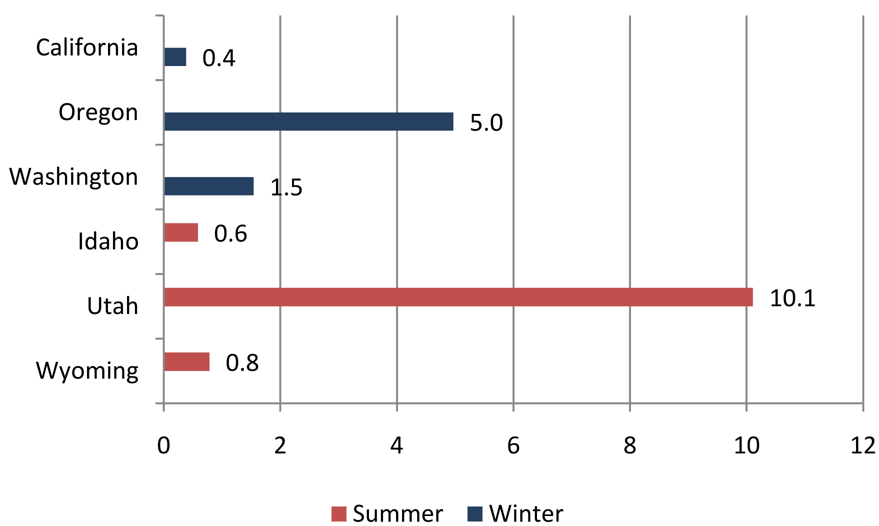


Table 34 displays the per-unit costs, using the assumptions of $400,000 in program development (based on a 2002 Portland General Electric program and PacifiCorp's TOU rate program development costs) and $125 in new participant costs ($100 per meter and $25 for marketing). Detailed assumptions for the residential TOU program are shown in Table 35 and Table 36.

Table 34. Residential TOU: Levelized Cost by State ($/kW)

Territory	State	Achievable Potential (MW)	Levelized Cost ($/kW)
Pacific Power	California	0.4	$173.83
	Oregon	5.0	$173.83
	Washington	1.5	$173.83
	Subtotal	**6.9**	**$173.83**
Rocky Mountain Power	Idaho	0.6	$166.76
	Utah	10.1	$166.76
	Wyoming	0.8	$166.76
	Subtotal	**11.5**	**$166.76**
	Total	**18.4**	**$169.41**

Table 35: Residential TOU: Program Basics

Program Name	TOU Rates
Customer Sectors Eligible	All residential market segments
End Uses Eligible for Program	Total load of all end uses
Customer Size Requirements, if any	Residential
Summer Load Basis	Top 480 peak hours (east states only)
Winter Load Basis	Top 600 peak hours (west states only)

Table 36. Residential TOU: Inputs and Sources not Varying by State or Sector*

Inputs	Value	Sources or Assumptions
Annual Administrative Costs (%)	15%	Assumes an administrative adder of 15%.
Technology Cost (per new participant)	$100	Incremental cost of a TOU meter, APS, and FERC 2006.
Marketing Cost (per new participant)	$25	APS reported incremental costs of $20-$30 per new participant, including marketing costs and support.
Incentives (annual costs per participant)	$0	Bill savings may accrue for some customers, equating to lost revenues for the utility. This analysis assumes revenue neutrality for the utility.
Overhead: First Costs	$400,000	Standard program development assumption, including necessary internal labor, research, and IT/billing system changes.
Technical Potential as % of Load Basis	5%	California residential pricing programs results from CA SPP, fixed TOU show 5% average peak demand reduced (Charles River Associates, 2005). Results from Puget Sound Energy's cancelled TOU program are similar.
Program Participation (%)	10%	APS has the highest TOU enrollment of any utility in the country, with nearly 400,000 participants or 45 percent of residential customers (Chuck Miessner, APS, 2007; FERC report of 2006). The participation rates of the top 10 highest-enrolled TOU programs in the country averages 16% (excluding the mandatory rates by PS Oklahoma. Yet, these programs do not represent the experience of all national programs; many TOU programs around the country have participation rates of <1% (but many of these are legacy programs not being promoted). Even among the top 10 highest enrollment programs (according to FERC), half have single digit participation rates. If a reasonable effort is made, a participation rate of 10% can be expected.
Event Participation (%)	90%	Assumes some participants will not be able to shift their consumption to off-peak hours.

*See Volume II, Appendix A for inputs and sources varying by state or sector.

Irrigation Time-of-Use Rates

A TOU program for irrigation customers is included in this analysis as an alternative to the DLC irrigation program. A TOU program for irrigation customers would function similarly to the residential TOU program, where rates are tiered to reflect high prices during the highest peak periods. However, for the purpose of this study the irrigation TOU program is designed to be mandatory, and all customers with irrigation loads would be switched to the TOU rate.

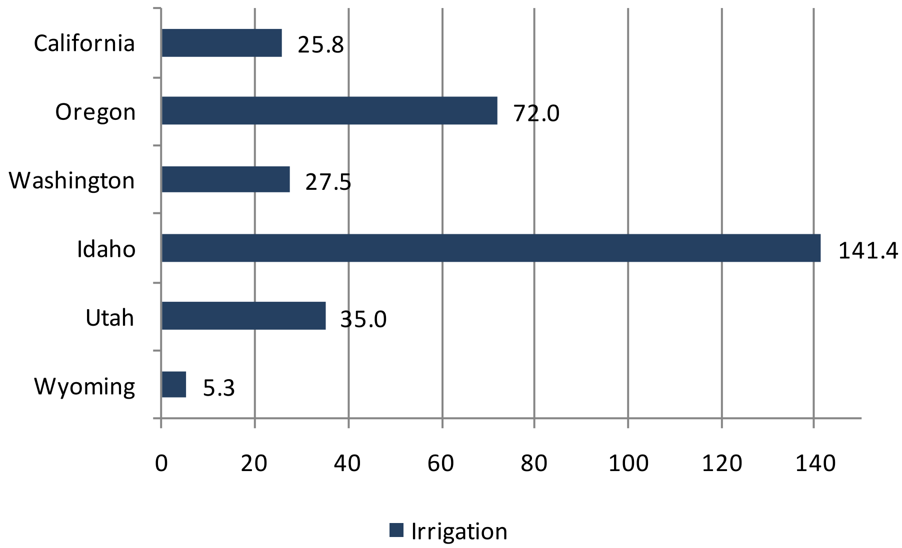
Currently, Nebraska Public Power offers a voluntary TOU program for its agricultural customers. This voluntary program, which utilizes an on-peak rate of nearly eight times the off-peak rate, is very successful, with an 83 percent program participation rate. Idaho Power recently implemented a TOU pilot program for its customers with irrigation load. The rate differential between on-peak and off-peak was closer to 1.5 times, resulting in minimal load reductions by participants during on-peak hours. This assessment assumed PacifiCorp will employ a rate structure similar to Nebraska Public Power, although differences in crops and climactic conditions will yield a slightly lower participation rate, which was captured through the event participation assumption.

Table 37 shows an achievable technical potential estimate of 125.3 MW for Pacific Power (3.8 percent of 2030 territory peak), which is significantly higher than the irrigation load control program potential, which is optional for customers. For Rocky Mountain Power, 182 MW is available (2 percent of 2030 territory peak). Due to load distribution, the majority of potential is expected to come from Idaho (141 MW; Figure 14).

Table 37. Irrigation TOU: Technical and Achievable Technical Potential (MW in 2030)

	Rocky Mountain Power			Pacific Power		
Sector	Technical Potential	Achievable Technical Potential	Achievable Technical as % of 2030 Peak	Technical Potential	Achievable Technical Potential	Achievable Technical as % of 2030 Peak
Agricultural	259.6	181.7	2.01%	179.0	125.3	3.77%
Industrial	0.0	0.0	0.00%	0.0	0.0	0.00%
Commercial	0.0	0.0	0.00%	0.0	0.0	0.00%
Residential	0.0	0.0	0.00%	0.0	0.0	0.00%
Total	**259.6**	**181.7**	**2.01%**	**179.0**	**125.3**	**3.77%**

Figure 14. Irrigation TOU: Achievable Technical Potential by State (MW in 2030)



The cost of an irrigation TOU program is relatively low due to minimal ongoing costs and 100 percent program participation (Table 38).

Table 38. Irrigation TOU: Levelized Cost by State ($/kW)

Territory	State	Achievable Potential (MW)	Levelized Cost ($/kW)
Pacific Power	California	25.8	$9.41
	Oregon	72.0	$9.41
	Washington	27.5	$9.41
	Subtotal	**125.3**	**$9.41**
Rocky Mountain Power	Idaho	141.4	$3.75
	Utah	35.0	$9.41
	Wyoming	5.3	$9.41
	Subtotal	**181.7**	**$7.52**
	Total	**307.0**	**$6.02**

Detailed assumptions for an irrigation TOU program are shown in Table 39 and Table 40.

Table 39. Irrigation TOU: Program Basics

Program Name	Irrigation
Customer Sectors Eligible	Irrigation only
End Uses Eligible for Program	Irrigation pumping
Customer Size Requirements, if any	All irrigation customers
Summer Load Basis	Top 480 peak hours
Winter Load Basis	No Winter

Table 40. Irrigation TOU: Inputs and Sources not Varying by State or Sector*

Inputs	Value	Sources or Assumptions
Annual Administrative Costs (%)	$75,000	Assumes 1/2 FTE for the program. For all tariff-based programs, this study assumes revenue neutrality.
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)	$0	No marketing costs associated with a mandatory program.
Overhead: First Costs	$400,000	Standard program development assumption, including necessary internal labor, research, and IT/billing system changes.
Technical Potential as % of Load Basis	100%	All load can be shifted.
Program Participation (%)	100%	Assumes all irrigators will participate in a mandatory program.
Event Participation (%)	70%	Event participation is based on an assumed 8-1 price differential between on-peak and off-peak rates. This is consistent with Nebraska Public Power, which has an on-peak rate of 7.7 times the off-peak rate and an 83% program participation rate. Event participation was adjusted down from Nebraska Public Power's rate because of climactic and crop differences. A less dramatic price differential will yield lower event participation. Idaho Power's TOU pilot, which employed an on-peak rate 1.5 times greater than the off-peak rate, spurred minimal changes in usage. Additionally, a price elasticity study conducted by Lawrence Berkley National Laboratory (2004) shows a 10% change in the on-peak/off-peak price ratio results in a 1.4% change in the on-peak/off-peak ratio of electricity consumption.

*See Volume II, Appendix A for inputs and sources varying by state or sector.

Critical Peak Pricing

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. However, the peak price is determined in advance, providing customers with some degree of certainty about participation costs. The basic rate structure is a TOU tariff, where the rate has fixed prices for usage during different blocks of time (typically on-, off-, and mid-peak prices by season). During CPP events, the normal peak price under a TOU rate structure is replaced with a much higher price, generally set to reflect the utility's avoided supply cost during peak periods.

CPP rates only take effect a limited number of times during the year. In times of emergency or high market prices, the utility can invoke a critical peak event, where customers are notified, and rates become much higher than normal, encouraging customers to shed or shift load. Most CPP programs provide advanced notice along with event criteria, such as a threshold for forecast weather temperatures, to help customers plan their operations. One of the features of a CPP program that may appeal to customers is the absence of a mandatory curtailment requirement.

The benefit of a CPP rate over a standard TOU rate is an extreme price signal can be sent to customers for a limited number of events. Utilities have found demand reductions during these events are typically greater than during TOU peak periods for several reasons: 1) customers under CPP rates are often equipped with automated controls triggered by a signal from the utility; 2) the higher CPP rate serves as an incentive for customers to shift load away during the CPP event period; and 3) the relative rarity of CPP events may encourage short-term behavioral changes, resulting in reduced consumption during the events.

Since the CPP rate only applies on select days, it raises a number of questions about when a utility can call an event, for how long, and how often. The rules governing utility dispatch of CPP events varies widely by utility and by program, with some utilities reserving the right to call an event at any time, while others must provide notice one day prior to the event. This analysis assumes approximately 10 four-hour events will be called during summer, for a total of 40 event hours.

There have been very few C&I CPP programs for medium-to-large customers; therefore, this analysis relies on the 2007 Assessment's estimates for technical potential and participation rates. Technically feasible potential is based on engineering audit assumptions, which are consistent with CPP studies, showing an average of 8 percent savings.[18] Event participation of 56 percent is based on the 2006 California C&I Pilot,[19] and accounts for the higher rate of opt-outs expected for commercial customers. Program participation was based on the survey of PacifiCorp customers.

Table 41 shows over 1,000 MW of technical potential in the Rocky Mountain Power territory, with 100 MW of achievable technical potential (representing 1 percent of 2030 territory peak). The Pacific Power territory has 194 MW of technical potential and 17 MW of achievable technical potential. The majority of achievable technical potential is in the industrial sector, dominated by Utah and Wyoming loads.

Table 41. CPP: Technical and Achievable Technical Potential (MW in 2030)

	Rocky Mountain Power			Pacific Power		
Sector	Technical Potential	Achievable Technical Potential	Achievable Technical as % of 2030 Peak	Technical Potential	Achievable Technical Potential	Achievable Technical as % of 2030 Peak
Agricultural	0.0	0.0	0.00%	0.0	0.0	0.00%
Industrial	579.4	73.6	0.74%	76.7	10.3	0.29%
Commercial	456.6	26.5	0.27%	117.0	6.4	0.18%
Residential	0.0	0.0	0.00%	0.0	0.0	0.00%
Total	**1,036.0**	**100.1**	**1.01%**	**193.8**	**16.7**	**0.47%**

18 LBNL Fully Automated CPP study, 2006.

19 Hopper, Nicole and Charles Goldman. The Summer of 2006: A Milestone in the Ongoing Maturation of Demand Response. 2007.

Figure 15. CPP-C&I: Achievable Technical Potential by State (MW in 2030)

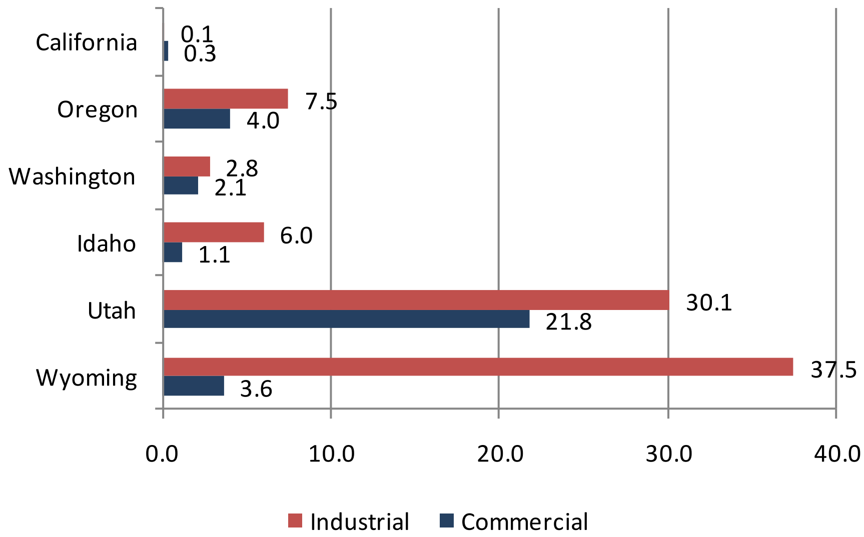


Table 42 displays the achievable technical potential and levelized costs by state. The costs include $500 per new participant for marketing. It is assumed all participating customers will have meters installed through the TOU rate structure; so no additional technology costs are associated with the program.

Table 42. CPP: Levelized Cost by State ($/kW)

Territory	State	Achievable Potential (MW)	Levelized Cost ($/kW)
Pacific Power	California	0.4	$12.92
	Oregon	11.5	$12.92
	Washington	4.8	$12.92
	Subtotal	**16.7**	**$12.92**
Rocky Mountain Power	Idaho	7.1	$12.92
	Utah	51.9	$12.92
	Wyoming	41.1	$12.92
	Subtotal	**100.1**	**$12.92**
	Total	**116.8**	**$12.92**

Detailed assumptions for the CPP program are shown in Table 43 and Table 44.

Table 43. CPP: Program Basics

Program Name	Critical Peak Pricing – C&I
Customer Sectors Eligible	All C&I market segments
End Uses Eligible for Program	Total load of all end uses
Customer Size Requirements, if any	C&I greater than 100 kW
Summer Load Basis	Top 40 hours

Table 44. CPP: Inputs and Sources not Varying by State or Sector*

Inputs	Value	Sources or Assumptions
Annual Administrative Costs (%)	$75,000	Assumes ½ FTE to run the program system wide.
Technology Cost (per new participant)	$0	Meters are already installed through the TOU program.
Marketing Cost (per new participant)	$500	Assumes 10 hours of effort by staff valued at $50/hour.
Incentives (annual costs per participant)	n/a	There are no customer incentives, but the utility may not design the rate to be revenue neutral, which could prove to be a cost in terms of lost revenues.
Overhead: First Costs	$400,000	Standard Program Development Assumption, including necessary internal labor, research, and IT/billing system changes.
Technical Potential as % of Load Basis	Varies by sector	Based on detailed engineering audits of demand response potential of C&I customers throughout California by Nexant, with third-party verification of results. Studies of CPP results show that 8% was saved on average (LBNL Fully Automated CPP study, 2006), which is comparable to taking this technical potential and the event participation combined.
Program Participation (%)	Varies by sector	Participation rates are based on self-reported findings of the commercial and industrial customer surveys conducted for the 2007 Assessment.
Event Participation (%)	56%	Based on 2006 California C&I results for CPP Pilot.

*See Volume II, Appendix A, for inputs and sources varying by state or sector.

Real-Time Pricing

Under RTP programs, electricity prices vary each hour according to the expected marginal cost of supply, and are typically established one day ahead of the time the prices are in effect. Where CPP utilizes pre-set pricing, RTP utilizes electricity wholesale prices, which change throughout the day. Programs vary from day-ahead to hour-ahead notifications. Notification occurs via the Internet or technology-enabled devices (Internet- or radio-based devices).

One important thing to note in C&I RTP programs is that, while a few programs have been very successful, it can be difficult to attract participants. A survey conducted by Lawrence Berkeley National Laboratory of 42 voluntary C&I RTP programs found just three programs had more than 100 customers enrolled in 2003, which accounted for the majority of all nonresidential RTP participants identified in the survey. [20] For example, half of the programs in the study had fewer than 10 customers enrolled, and one-third had no participants.

The program modeled in this analysis required a minimum threshold of 100 kW. Again, the technically feasible potential was based on engineering audit assumptions. Program participation is voluntary and was based on the survey of PacifiCorp customers, 2 percent of which were interested in an RTP program, which is consistent with the findings above.

Table 45 shows 675 MW of technical potential for the Rocky Mountain Power territory, with 23 MW of achievable technical potential.[21] The Pacific Power territory has 107 MW of technical

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[20] Barbose, Galen et al., A Survey of Utility Experience with Real Time Pricing, LBNL, December 2004. See also: Neenan Associates, "Customer Adaptation to RTP as Standard Offer Electric Service: A Case Study of Niagara Mohawk's Large Customer RTP Tariff," LBNL 2004.

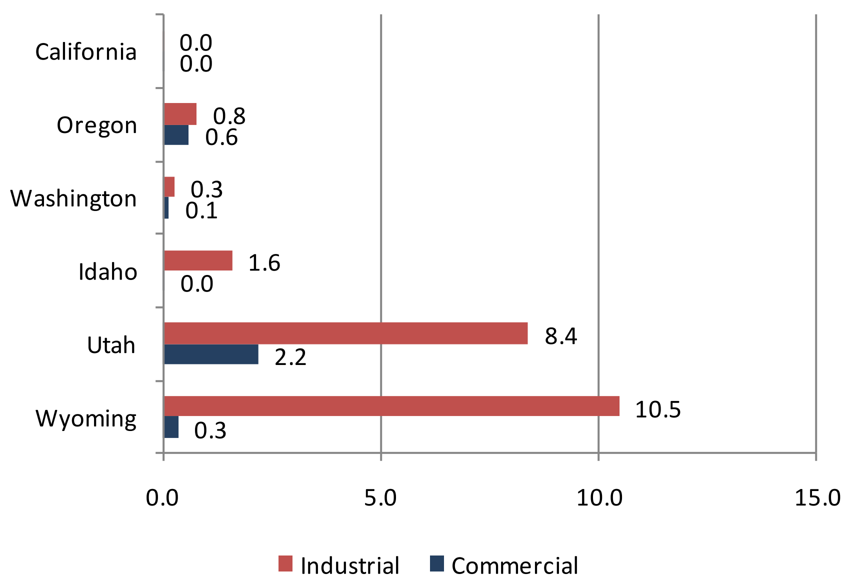
[21] Technical potential for RTP is less than the technical potential for CPP because of differences in load class eligibility. See Volume II Appendix A for detailed assumptions.

potential and 1.8 MW of achievable technical potential. The majority of achievable technical potential is in the industrial sector, dominated by Utah and Wyoming loads, as shown in Figure 16.

Table 45. RTP: Technical and Achievable Technical Potential (MW in 2030)

Sector	Rocky Mountain Power			Pacific Power		
	Technical Potential	Achievable Technical Potential	Achievable Technical as % of 2030 Peak	Technical Potential	Achievable Technical Potential	Achievable Technical as % of 2030 Peak
Agricultural	0.0	0.0	0.00%	0.0	0.0	0.00%
Industrial	519.8	20.4	0.21%	66.3	1.0	0.03%
Commercial	155.3	2.5	0.03%	40.9	0.7	0.02%
Residential	0.0	0.0	0.00%	0.0	0.0	0.00%
Total	**675.1**	**22.9**	**0.24%**	**107.2**	**1.8**	**0.05%**

Figure 16. RTP: Achievable Technical Potential by State (MW in 2030)



RTP is one of the lowest-cost resources due to the high expected impacts and relatively low costs for the required technologies (Table 46). The expected achievable technical potential costs $6/kW-year for Rocky Mountain Power and $8/kW-year in for Pacific Power. The cost components include $1,900 for each new participant ($1,400 hardware and $500 marketing) and $400,000 in program development costs.

Table 47 and Table 48 present detailed assumptions for a CPP program.

Table 46. RTP: Levelized Cost by State ($/kW)

Territory	State	Achievable Potential (MW)	Levelized Cost ($/kW)
Pacific Power	California	0.0	$8.18
	Oregon	1.4	$8.18
	Washington	0.4	$8.18
	Subtotal	**1.8**	**$8.18**
Rocky Mountain Power	Idaho	1.6	$5.85
	Utah	10.5	$5.85
	Wyoming	10.8	$5.85
	Subtotal	**22.9**	**$5.85**
	Total	**24.7**	**$7.02**

Table 47. RTP: Program Basics

Program Name	Real-Time Pricing Com
Customer Sectors Eligible	C&I market segments
End Uses Eligible for Program	Total load of all end uses
Customer Size Requirements, if any	C&I greater than 100 kW
All Seasons Load Basis	Top 87 hours

Table 48. RTP: Inputs and Sources not Varying by State or Sector*

Inputs	Value	Sources or Assumptions
Annual Administrative Costs (%)	15%	Assumes an administrative adder of 15%.
Technology Cost (per new participant)	$1,400	Technology costs include communications, connectivity, and meters, if necessary, based on California spending of $32M for 23,000 large C&I hardware after energy crisis.
Marketing Cost (per new participant)	$500	Assumes 10 hours of effort by staff valued at $50/hour.
Incentives (annual costs per participant)	N/A	There are no customer incentives, but the utility may not design the rate to be revenue neutral, which could entail a cost in terms of lost revenues.
Overhead: First Costs	$400,000	Standard program development assumption, including necessary internal labor, research, and IT/billing system changes.
Technical Potential as % of Load Basis	Varies by sector	Based on detailed engineering audits of demand response potential of C&I customers throughout California by Nexant, with third-party verification of results. Studies of CPP results show 8% was saved on average (LBNL Fully Automated CPP study, 2006), which is comparable to taking this technical potential and the event participation combined.
Program Participation (%)	Varies by sector	Participation rates are based on self-reported findings of the commercial and industrial customer surveys conducted for the 2007 Assessment.
Event Participation (%)	100%	NA

*See Volume II, Appendix A for inputs and sources varying by state or sector.

3. Class 2 DSM (Energy-Efficiency) Resources

Scope of Analysis

The main focus in assessing Class 2 DSM (energy-efficiency) resources was to provide updated estimates of savings available in PacifiCorp's service territory (Rocky Mountain Power and Pacific Power, excluding Oregon) over a 20-year planning horizon (2011 to 2030). Separate assessments of technical and achievable technical potential for residential, commercial, industrial, irrigation, and street lighting sectors were conducted for California, Idaho, Utah, Washington, and Wyoming.[22] Within each state's sector-level assessment, the study further distinguished by customer segments or facility types and their respective applicable end uses. Six residential segments (existing and new construction for single-family, multifamily, and manufactured homes), 24 commercial segments (12 building types within the existing and new construction), 14 industrial segments (existing construction only), and one segment for both irrigation and street lighting were analyzed.

The study included a comprehensive set of energy-efficiency measures. The analysis began by assessing the technical potential of 341 *unique* energy-efficiency measures (Table 49). The number of unique measures in the commercial and residential sectors is nearly double used in the 2007 Assessment, and the street lighting sector was not included in the prior study. Considering all permutations of these measures across all customer sectors, customer segments, and states, customized data were compiled and analyzed for over 18,000 measures. A complete list of energy-efficiency measures analyzed is provided in Volume II, Appendix B.

Table 49. Energy-Efficiency Measure Counts (Base-Case Scenario)

Sector	Measure Counts
Commercial	133 unique 11,576 permutations across segments
Residential	126 unique 4,671 permutations across segments
Industrial	67 unique 1,733 permutations across segments
Irrigation	3 unique 15 permutations across segments
Street Lighting	12 unique 60 permutations across segments

The remainder of this section is divided into three parts. Resource potential for energy efficiency by state and sector are presented, followed by a detailed description of the methodology for estimating the technical and achievable technical energy-efficiency potential. The section concludes with more detailed results and an assessment of the potential under alternative economic and market acceptance scenarios.

22 Energy efficiency in Oregon is delivered by the ETO, which completed its own assessment in 2010.

Resource Potential

Table 50 and Table 52 show 2030 baseline sales and potential by sector and state, respectively. As shown, the study results indicate 1,408 aMW of technically feasible electric energy-efficiency potential by 2030, the end of the 20-year planning horizon. Across all sectors and states, 1,156 aMW (82 percent of the technical potential) are estimated to be achievable. If acquired, the identified achievable potential amounts to 16 percent of the forecast load in 2030 and 40 percent of the projected load growth from 2011 to 2030 in PacifiCorp's system, excluding Oregon. Across the system, identified achievable potential represents about 58 aMW of saving per year, equating to approximately 1.0 percent of the system load annually.[23] Savings as a percentage of baseline sales vary by sector and state, as shown in Table 50 and Table 52.

Estimates of peak capacity impacts are derived by spreading annual potential by state, sector, segment, and end use over hourly load shapes to estimate hourly demand savings. The peak impacts reported below represent the average demand savings in the top 40 hours of system load. Peak impacts vary by sector and state, as shown in Table 51 and Table 53.

These savings are based on forecasts of future consumption, absent any PacifiCorp program activities. While consumption forecasts account for the past savings PacifiCorp has acquired, the estimated potential identified is inclusive of (not in addition to) current or forecasted program savings.

Table 50. Technical and Achievable Technical Energy-Efficiency Potential (aMW in 2030) by Sector

Sector	Baseline Sales (aMW)	Technical Potential (aMW)	Achievable Technical Potential (aMW)	Achievable Technical as % of Baseline Sales
Residential	1,787	617	514	29%
Commercial	2,367	424	361	15%
Industrial	2,929	346	265	9%
Irrigation	130	15	13	10%
Street Lighting	12	5	4	36%
Total	**7,225**	**1,408**	**1,156**	**16%**

Note: Results may not sum to total due to rounding

[23] Actual savings will vary by year, as a portion of the achievable technical potential comes from new construction, and the timing of acquisition will be dictated by sector-specific anticipated growth patterns.

Table 51. Technical and Achievable Technical Energy-Efficiency Potential (MW in 2030) by Sector

Sector	Technical Potential (MW)	Achievable Technical Potential (MW)	Achievable Technical as % of 2030 System Peak
Residential	2,043	1,651	12.4%
Commercial	763	649	4.9%
Industrial	399	305	2.3%
Irrigation	48	41	0.3%
Street Lighting	6	5	0.0%
Total	**3,259**	**2,651**	**20%**

Note: Results may not sum to total due to rounding

Table 52. Technical and Achievable Technical Energy-Efficiency Potential (aMW in 2030) by State

Territory	State	Baseline Sales (aMW)	Technical Potential (aMW)	Achievable Technical Potential (aMW)	Achievable Technical as % of Baseline Sales
Pacific Power	California	132	31	26	20%
	Washington	564	146	122	22%
	Subtotal	**696**	**177**	**148**	**21%**
Rocky Mountain Power	Idaho	356	74	63	18%
	Utah	4,013	897	737	18%
	Wyoming	2,161	259	208	10%
	Subtotal	**6,529**	**1,231**	**1,008**	**15%**
	Total	7,225	1,408	1,156	16%

* Levelized cost is based on total resource cost for all states except Utah, where it is based on a Utility Cost Test
Note: Results may not sum to total due to rounding

Table 53. Technical and Achievable Technical Energy-Efficiency Potential (MW in 2030) by State

Territory	State	Technical Potential (MW)	Achievable Technical Potential (MW)	Achievable Technical as % of 2030 System Peak
Pacific Power	California	49	41	0.3%
	Washington	269	226	1.7%
	Subtotal	**318**	**267**	**2.0%**
Rocky Mountain Power	Idaho	123	104	0.8%
	Utah	2,488	2,013	15.0%
	Wyoming	330	267	2.0%
	Subtotal	**2818**	**2280**	**17.8%**
	Total	**3,259**	**2,651**	**19.9%**

Note: Results may not sum to total due to rounding

Table 54 shows the technical and achievable technical potential by sector and resource type, which refers to whether the resources are discretionary or represent lost opportunities. Discretionary resources are opportunities existing in current building stock (retrofit opportunities in existing construction), while lost opportunities are reliant on equipment burnout and new construction. Estimates indicate the largest savings share in the industrial and irrigation sectors are comprised of discretionary resources since these sectors are governed less by codes and standard and more by common market practices, which include regular rebuilding and refurbishment and existing equipment stock. These practices, in combination with the nature of available data, make it difficult to definitively isolate the lost opportunity share of savings. Therefore, all savings in these sectors are classified as discretionary.[24] Overall, discretionary resources represent 64 percent (737 aMW) of achievable potential, as shown in Table 54.

Table 54. Technical and Achievable Technical Energy-Efficiency Potential (aMW in 2030) by Sector and Resource Type

Sector	Technical Potential		Achievable Technical Potential	
	Discretionary	Lost Opportunity	Discretionary	Lost Opportunity
Residential	232	386	196	318
Commercial	305	119	259	101
Industrial	346	- - -	265	- - -
Irrigation	15	- - -	13	- - -
Street Lighting	5	- - -	4	- - -
Total	**903**	**505**	**737**	**419**

Note: Results may not sum to total due to rounding

The distinction between discretionary and lost opportunity resources becomes important in the timing of resource availability and acquisition planning. Lost opportunity resources are timing-driven: when a piece of equipment fails, an opportunity occurs to install a high-efficiency model in its place. If standard equipment is installed, and without early replacement, the high-efficiency equipment would not be installed until the new equipment reaches the end of its normal life cycle. The same is true for new construction, where resource acquisition opportunities become available only when a home or building is built. Discretionary resources are not subject to the same timing constraints. For this study, assumed measure acquisitions are ramped over the planning horizon depending on market availability.[25]

In addition, given that each state within PacifiCorp's territory has unique market characteristics, the acquisition schedule will vary by state. For example, PacifiCorp has been running DSM programs in Utah and Washington for several years, and thus has a well-developed delivery infrastructure and high customer awareness. In Wyoming, however, programs are only starting to be rolled out; so the ramp-up time for full acquisition will be slower. California and Idaho markets fall between the middle of those extremes. Figure 17 shows market ramp rates, where

[24] In the residential and commercial assessments, lost opportunities are tied to specific forecasts for new construction and tied to decay patterns for specific types of end-use equipment (chillers, water heaters, etc.). In the industrial sector, these two elements do not have sufficient market data to allow delineation of lost opportunities, though many exist.

[25] Measure ramp rates are generally the same as those used in the 6th Plan.

Utah and Washington are considered "aggressive," Idaho and California are "normal," and Wyoming is "slow." Figure 18 shows the realization of resources for each sector, in total.

Figure 17. Market Acquisition Rate

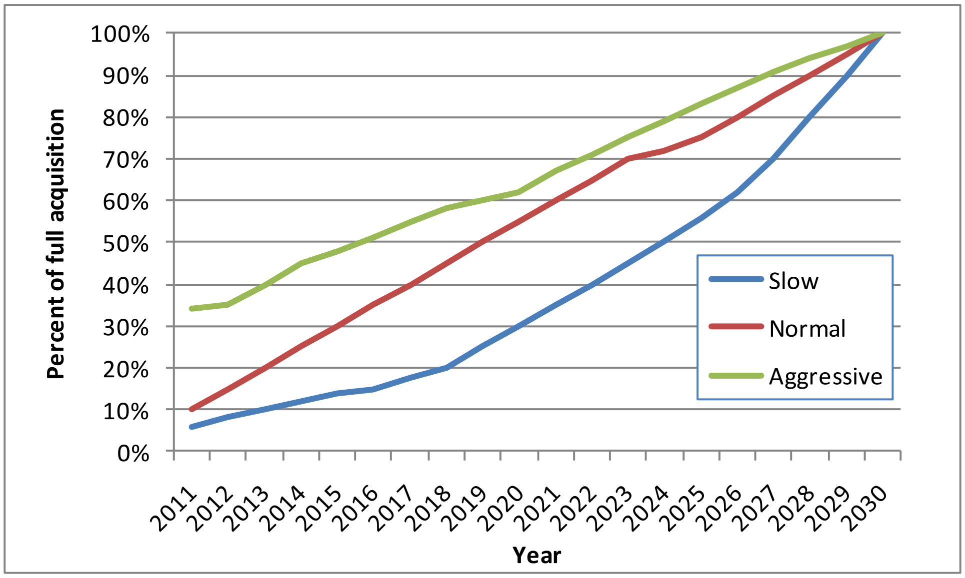
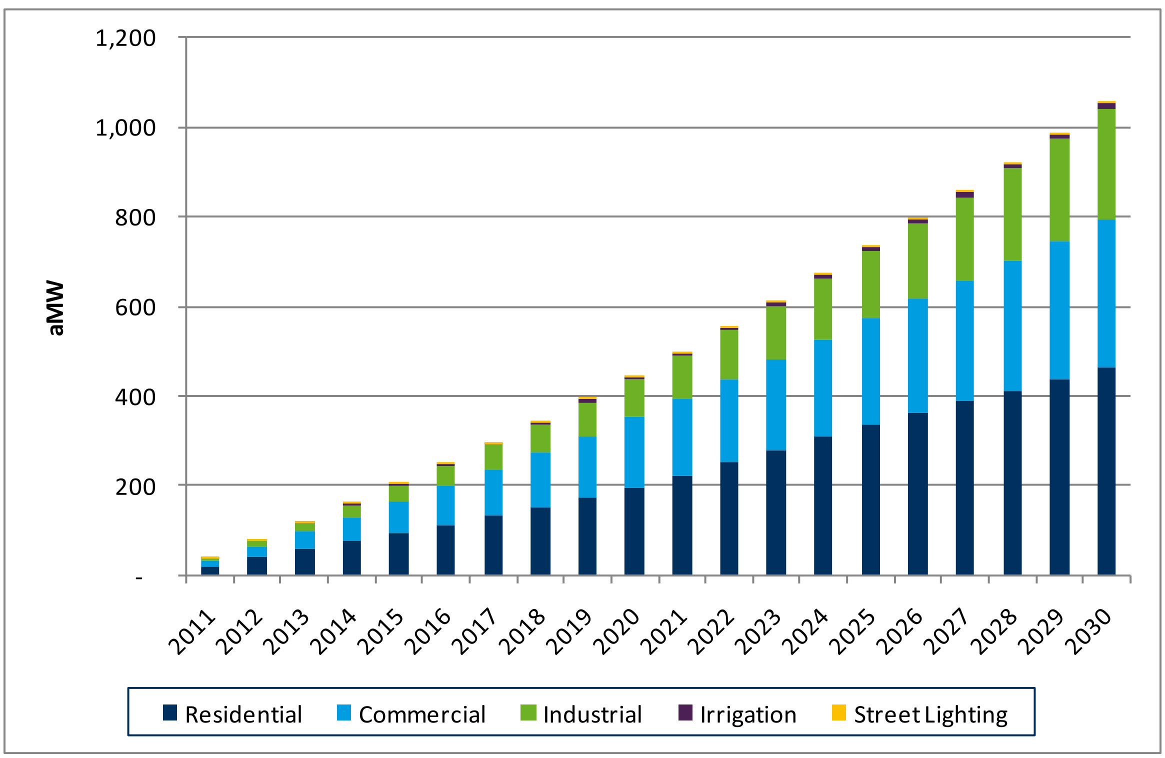


Figure 18. Acquisition Schedule for Achievable Savings by Year and Sector



Assessment Methodology

Overview

Determination of energy-efficiency potential is based on a sequential analysis of various energy-efficiency measures in terms of technical feasibility (technical potential) and expected market acceptance considering normal barriers that may impede measure implementation (achievable technical potential). The assessment is carried out in two main steps:

- ***Baseline forecasts:*** Determine 20-year future energy consumption by segment and end use, which is calibrated to PacifiCorp's system load forecasts in each state. The baseline forecast reflects efficiency characteristics of current codes and standards, which are assumed to be fixed (frozen efficiency) over the forecast horizon.

- ***Estimation of alternative forecasts of technical and achievable technical potential:*** Estimate technical and achievable technical potential based on alternative forecasts reflecting technical impacts of specific energy-efficiency measures and market constraints, respectively. The difference between the baseline and each alternative forecast represents the energy-efficiency potential associated with that particular type of potential.

These steps are represented conceptually in Figure 19, which shows a hypothetical baseline forecast, along with three alternative forecasts associated with technical and achievable technical potential.[26] These alternative forecasts represent consumption under different sets of assumptions and the difference between the baseline and each alternative forecasts represents their respective potential savings. For example, the technical potential forecast represents total consumption after incorporation of all measures, consistent with the definition above. The results are intuitive, with total consumption in the technical potential forecast much lower than the baseline (which also indicates the greatest amount of potential). As their respective benefit-cost and market acceptance constraints are added, forecasts for achievable technical scenarios come closer to the baseline, and their resulting potential savings decrease.

This approach has two advantages. First, savings estimates are driven by a baseline calibrated to PacifiCorp's sales forecasts, and thus remain consistent with IRP. The sales forecast serves as a reality check and helps control for possible errors. Other approaches may simply generate the total potential by summing the estimated impacts of individual measures, which can result in estimates of total savings that represent an unrealistically high percentage of baseline sales. The second advantage is the approach maintains consistency among all assumptions underlying the baseline and alternative (technical and achievable technical) forecasts. In the alternative forecasts, relevant inputs at the end-use level are changed to reflect the impact of energy-efficiency measures. Because the estimated savings represent the difference between the baseline and alternative forecasts, they can be directly attributed to specific changes made to analysis inputs.

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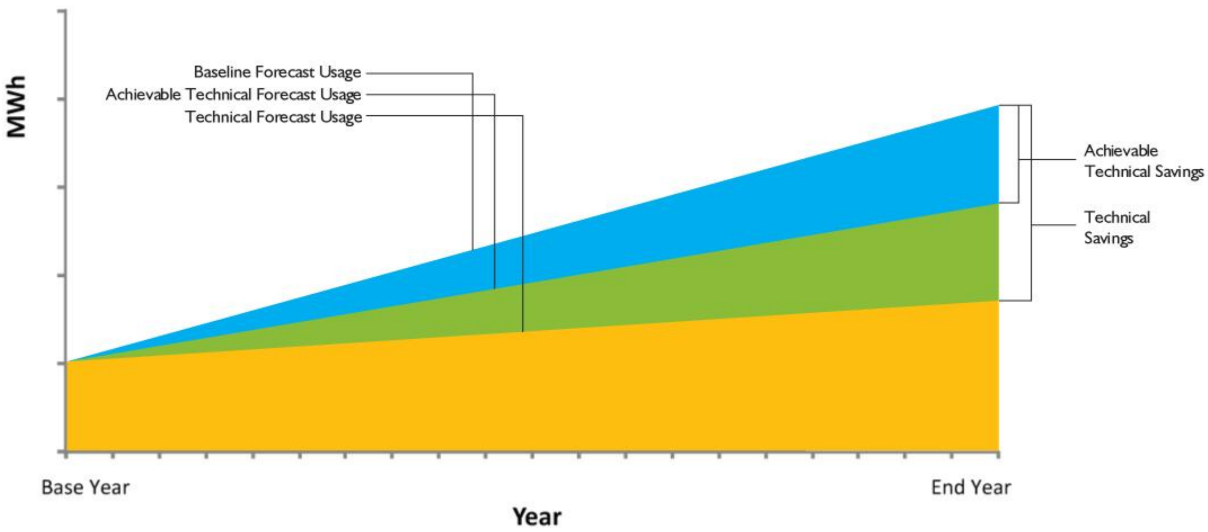
[26] The baseline and alternative forecasts shown in Figure 19 are purely for example purposes, and do not represent actual data underlying this assessment.

Figure 19. Example Representation of Alternative Forecast Approach to Estimation of Energy-Efficiency Potential



Data Sources

The full assessment of Class 2 DSM resource potential required compilation of a large set of measure-specific technical, economic, and market data from secondary sources, and through primary research. The main data sources used in this study included:

- ***PacifiCorp***. 2010 load forecasts, historic energy-efficiency activities, current customer counts and forecasts, and the 2006 Energy Decisions Survey. Table 55 shows a complete list of data elements provided by PacifiCorp.

Table 55. Class 2 DSM PacifiCorp Data Sources

Data Element	Key Variables	Use in This Study
2009 sales and customer counts	Number of customers and total sales by state and customer segment.	Base year customers and sales for calibration in end-use model.
2010 load forecasts by rate class	Sales and customer forecasts by state and customer segment, excluding all DSM activity.	End-use model calibration, new customers as drivers in end-use model development.
Historic program activities/achievements	Program participation and historic program achievements.	Measure saturations, validation of measure characterizations (savings, costs).
2006 Residential Energy Decision 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.
2006 Commercial Energy Decision Survey	Building characteristics, equipment saturations, and fuel shares.	Building type breakouts, square footage per dwelling, measure applicability factors, development of building simulation prototypes, forecast calibration.

- ***Building Simulations***. The estimates of normal consumption and load profiles for the majority of end uses in the residential and commercial sectors were developed for the 2007 Assessment using the eQuest (commercial), and Energy-10 (residential) building simulation models were used again for this study. Separate models were created for each state, customer segment, and construction vintage.

- ***Pacific Northwest Sources***. Several Northwest entities provided data critical to this study, including the Council, the Regional Technical Forum (RTF), and the Northwest Energy Efficiency Alliance (NEEA). These included technical information on measure savings, costs, and lives, hourly end-use load shapes (to supplement buildings simulations, described above), and commercial building and energy characteristics. Details are provided in Table 56.

Table 56. Class 2 DSM Pacific Northwest Data Sources

Pacific Northwest Data Source	Key Variables	Use in This Study
Council 6th Power Plan	Measure data, energy-efficiency potential 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 residential, commercial, and industrial sectors.
RTF Website	Measure data.	Measure savings, costs, and lives.

- ***California Energy Commission***. This study used information available in the 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 consisted primarily of available information from the 2007 Assessment, past energy-efficiency market studies, energy-efficiency potential studies, and evaluations of energy-efficiency programs in the Northwest and elsewhere in the country. The primary information sources for the industrial section were the U.S. Department of Energy, Energy Information Administration (EIA) Office of Industrial Technologies, and NEEA's Industrial Efficiency Alliance initiative.

Baseline Forecasts

PacifiCorp's state-level econometric forecasts form the basis for assessing energy-efficiency potential. Prior to estimating potential, state-level load forecasts were disaggregated by: customer sector (residential, commercial, and industrial—including irrigation); customer segment (business, dwelling, and 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 was to determine the appropriate customer segments within each state and sector. These designations were based on categories available in some of the key data sources used in this study, primarily PacifiCorp's load forecasts and the 2006 Energy Decisions Survey. Next, appropriate end uses are mapped to relevant customer segments in each state.[27] Table 57 through Table 59 show the full set of customer segments and

27 Note all segments are not applicable to all states. For example, the large office segment is not relevant in the California service territory, which is entirely rural. Similarly, not all end uses within a sector are necessarily relevant in every customer segment (e.g., cooking may not be relevant in the warehouse segment of the commercial sector).

end uses for each sector analyzed for this study. A comprehensive list of the state- and sector-specific segments and end uses is available in Volume II, Appendix C.

Table 57. Residential Sector Dwelling Types and End Uses

Residential Customer Segments	Electric End Uses
Manufactured	Computer
Multifamily	Cooking Oven
Single Family	Cooking Range
	Cool Central
	Cool Room
	Dehumidifier
	Dryer
	DVD
	Freezer
	Heat Central
	Heat Pump
	Heat Room
	Home Audio System
	Lighting Exterior
	Lighting Interior Specialty
	Lighting Interior Standard
	Microwave
	Monitor
	Plug Load Other
	Pool Pump
	Refrigerator
	Set Top Box
	TV
	TV Big Screen
	Ventilation and Circulation
	Water Heat

Table 58. Commercial Sector Customer Segments and End Uses

Commercial Customer Segments	Electric End Uses
Grocery	Computers
Health	Cooking
Large Office	Cooling Chillers
Large Retail	Cooling DX Evaporative Cooler
Lodging	Cooling Room
Miscellaneous	Heat Pump
Restaurant	HVAC Auxiliary
School	Lighting Exterior
Small Office	Lighting Interior
Small Retail	Other Office Equipment
Warehouse	Other Plug Load
Controlled Atmosphere Warehouse	Refrigeration
	Space Heat
	Water Heat

Table 59. Industrial Sector and End Uses

Industrial Customer Segments (NAICS)	Electric End Uses
Chemical Mfg	Fans
Electronic Mfg	HVAC
Food Mfg	Indirect Boiler
Industrial Machinery	Lighting
Lumber Wood Products	Motors Other
Miscellaneous Mfg	Other
Paper Mfg	Process Air Compressor
Petroleum Mfg	Process Cool
Primary Metal Mfg	Process Electro Chemical
Stone Clay Glass Products	Process Heat
Transportation Equipment Mfg	Process Other
Mining	Process Refrigeration
Irrigation	Pumps
Wastewater	
Water	

Once the appropriate customer segments and end uses were determined for each sector, we produced the baseline end-use forecasts, based on the integration of current and forecasted customer counts with key market and equipment usage data. For commercial and residential sectors, the total baseline annual consumption for each end use in each customer segment was calculated as shown below:

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

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 = the units per account in customer segment *i* (UPA_i is generally the average square feet per customer in commercial segments and is 1.0 in residential dwellings, which are assessed at the whole-home level)[28]

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

FSH_{ij} = the share associated with electricity in end use *j* of customer segment *i*

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

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

Total annual consumption in each sector was then determined as the sum of *EUSEij* across the end uses and customer segments. The key to ensuring accuracy of the baseline forecasts is the calibration of the end-use model estimates of total consumption to actual sales from 2009. This calibration to base year sales includes making appropriate adjustments to data where necessary to conform to known information about customer counts, appliance and equipment saturations, and fuel shares from a variety of sources. For example, the saturations of electric dryers, televisions, set-top boxes, and personal computer and related electronics all increased over the planning horizon.

Consistent with other potential studies and commensurate with industrial end-use consumption data, which vary widely in quality, the industrial sector's allocation of loads to end uses in various segments (NAICS) was based on data available from the U.S. Department of Energy's EIA.[29] For the irrigation sector, the total load in each state is well established and consists almost entirely of pumping; so no allocation of load to other end uses or processes was necessary.

Summaries of baseline forecasts for each state and sector are provided in Volume II, Appendix C.

Derivation of End-Use Consumption Estimates

Estimates of end-use energy consumption (EUI_{ije}) are one of the most important components in the development of the baseline forecast. In the residential sector, these estimates were based on the unit energy consumption (UEC), which represents the annual kWh consumption associated with the end use at the building level (in some cases, the end use represents the specific type of equipment, such as a central air conditioner or heat pump). For the commercial sector, the consumption estimates are treated as end-use intensities (EUIs), which represent annual kWh consumption per square foot of structure. The accuracy of these estimates is critical; they must account for weather and other factors described below that drive differences between various states and segments. For the industrial sector, end-use energy consumption represents the total annual facility consumption by end use, as allocated by the secondary data described above. In

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[28] It is important to note the average square footage by home type has been input into the building simulations developed in the 2007 Assessment, so weather and home size differences between states are reflected in the results.

[29] U.S. DOE, EIA, Manufacturing Energy Consumption Survey (2006).

the case of irrigation energy consumption, total use and end use are the same (i.e., pumping and the forecasted sales in each state do not require further allocation).

In the residential and commercial sectors, we derived the majority of end-use consumption estimates from building simulation models (eQuest and Energy-10 for commercial and residential segments, respectively)[30] to account for key regional differences, including weather, state codes, building size, and shell characteristics. For non-weather-sensitive end uses that cannot be modeled within a building simulations framework (e.g., residential refrigerators), we used the consumption estimates from ENERGY STAR, the EIA's Residential Energy Consumption Survey (RECS), and the Commercial Buildings Energy Consumption Survey. Most key drivers in developing the simulation models (operating schedules, setback temperatures, and building size) were developed from data in PacifiCorp's Energy Decisions Survey.[31] Summaries of the estimates for end-use consumption for residential (UECs), commercial (EUIs), and industrial (end-use percentages) are provided in Volume II, Appendix C.

Estimating Technical Potential

After developing the baseline forecasts, we estimated the technical potential. Because technical potential is based on creating an alternative forecast[32] that reflects installation of all possible measures, the selection of appropriate Class 2 DSM resources to include in this study was a central concern. For the residential and commercial sectors, we began the study with a broad range of energy-efficiency measures for possible inclusion. These measures were screened to include only measures commonly available, based on well-understood technology, and applicable to PacifiCorp's buildings and end uses. Examples of these measures were included in the Council 6th Power Plan or have been assessed by the RTF. The industrial sector measures were based on the Council's 6th Power Plan and other general categories of process improvements.[33]

Table 60, Table 61, and Table 62 outline the types of energy-efficiency measures we assessed in the residential, commercial, and industrial sectors, respectively. Equipment measures are those replacing end-use equipment (e.g., high-efficiency central air conditioners), while non-equipment measures are those reducing end-use consumption without replacing end-use equipment (e.g., insulation). A complete list of all measures, with descriptions, is provided in Volume II, Appendix B.

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30 For details on eQuest and Energy-10, see http://www.doe2.com and http://www.sbicouncil.org/store/e10.php, respectively.

31 Extensive effort was made to validate and cross-check the results from the Energy Decisions Surveys with data from other sources, including RECS, CBECS, and other available studies.

32 The alternative forecast actually consists of four separate forecasts to allow delineation between existing and new construction and equipment and non-equipment measures. These distinctions are explained later in this section.

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

Table 60. Residential Energy-Efficiency Measures

End Use	Measure Types
Heating and Cooling	*Non-Equipment*: air-to-air heat exchangers; canned lighting air tight sealing; ceiling fan; concrete and specialty framing; cool roof and green roof; ceiling, wall (2x4, 2x6) and floor insulation; insulated exterior doors and weatherstripping; duct locating in conditioned spaces, sealing, leak proof fittings, and insulation; equipment tune-up; efficient windows; whole-house fan; infiltration control; new home thermal shell with low infiltration and heat recovery; thermostat; solar attic fan; smart siting; radiant barrier; HVAC unit proper sizing. *Equipment*: high-efficiency heat pump; ground source heat pump; high-efficiency central AC; ENERGY STAR room AC; evaporative cooler; ECM/VFD motor; heat pump conversion.
Lighting	*Non-Equipment*: daylighting controls; occupancy sensor; time clock. *Equipment*: CFLs; LEDs.
Water Heating	*Non-Equipment*: hot water pipe insulation; faucet aerators; low-flow showerheads; water heater blanket and temperature setback; ENERGY STAR dishwashers and clothes washers; drain water heat recovery. *Equipment*: high-efficiency storage and heat pump water heaters.
Appliances	*Non-Equipment*: removal of old (inefficient) appliances (refrigerator and freezer). *Equipment*: ENERGY STAR freezers and refrigerators; high-efficiency microwave, cooking oven, and dryer.
Plug Load	*Non-Equipment*: 1-watt standby power; power strip with occupancy sensor; ENERGY STAR battery chargers, copiers, and printers. *Equipment:* ENERGY STAR computers, monitors, TVs, and set top box.
Other	*Non-Equipment*: pool pump timer. *Equipment*: pool pump.

Table 61. Commercial Energy-Efficiency Measures

End Use	Measure Types
HVAC	*Non-Equipment*: ceiling, wall, and floor insulation; duct sealing, leak proof fittings, and insulation; programmable thermostats; windows; equipment tune-up; automated ventilation control; pre-cooling; DDC system optimization; fan motor; constant air to VAV conversion; economizers; exhaust air to ventilation air heat recovery; recommissioning; chilled water/condenser water settings-optimization; chilled water piping loop w/ VSD control; cooling tower approach temperature; cooling tower (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. *Equipment*: high-efficiency heat pumps; high-efficiency chillers and DX packages, ground source heat pump; evaporative cooler.
Lighting	*Non-Equipment*: reduce power density; daylighting, continuous dimming, and stepped dimming controls; occupancy sensors; efficient refrigeration lighting and exit signs; time clock; exterior building lighting; surface and covered parking lighting; cold cathode and white LED lighting.
Water Heating	*Non-Equipment*: hot water pipe insulation; temperature setback; high-efficiency chemical, residential, and commercial dishwashing systems; demand controlled circulating systems; low-flow showerheads, spray heads, and faucet aerators; commercial- and residential-sized clothes washers; water cooled refrigeration with heat recovery. *Equipment*: high-efficiency water heater; heat pump water heater.
Refrigeration	*Non-Equipment*: VSD compressors; demand control defrost; commissioning; strip curtains; floating condenser heads; anti-sweat controls; glass and solid door refrigerator/freezer; ECM motors; case replacement; display case night cover; standalone to multiplex compressor; refrigeration retrofit and tune-up.
Other	*Non-Equipment:* combination and convection oven; cooking hood controls; optimized variable volume lab hood; power supply transformer/converter; power strip with occupancy sensor; high-efficiency ice maker, griddle, and deep fat fryer; ENERGY STAR steam cooker, hot food holding cabinet, battery charging system, copier, fax, monitor, printer, scanner, water cooler, refrigerator, and vending machine; high-efficiency motor and motor rewind; network PC power management and server virtualization; removal of inefficient appliance; low-pressure distribution complex. *Equipment*: ENERGY STAR computer.

Table 62. Industrial Energy-Efficiency Measures

Electric Measure Types*
Air Compressor Improvements
Building Improvements
Chillers
Clean Room Improvements
Efficiency Centrifugal Fan
Electric Chip Fab Improvements
Equipment Upgrades
Fan System Optimization
General Process Improvements
High-Efficiency Motors
Improved Controls
Lighting Improvements
Material Handling
Motor Management Plan
Motor Rewinds
Process Heat O&M
Properly Sized Fans
Pump Equipment Upgrade
Pump Improvements
Recommissioning
Refrigeration Retrofit
Refrigeration Tune-up
Switch From Belt Drive to Direct Drive
Synchronous Belts
Transformers
Whole Plant Improvements
Irrigation System Improvements
Scientific Irrigation Scheduling
Street Lighting LED Upgrades

*More than one-third of the potential in HVAC is associated with clean rooms in chemical and electronics manufacturing.

Once various measures were properly characterized in terms of savings and costs, we calculated technical potential by subtracting the alternative forecast from the baseline, which yielded savings by all dimensions included in the segmentation design (vintage, segment, etc.). The procedure involved three analytic steps, as follows.

Determine Measure Impacts

The starting point in assessing technical potential is to estimate measure-level impacts. It begins by compiling and analyzing data on the following measure characteristics:

- ***Measure savings***: The energy savings associated with a measure as a percentage of the total end-use consumption. Sources include engineering calculations, energy simulation modeling, Council’s 6th Power Plan, secondary data sources (case studies), and the California DEER database.

- ***Measure costs***: The per-unit cost (either full or incremental, depending on the application) associated with installation of the measure. Sources include the DEER database, Council's 6th Power Plan, RS Means, merchant Websites (Home Depot, Trane, etc.), and other secondary sources.
- ***O&M costs***: Annual operation and maintenance costs for a measure. These may be positive or negative as compared to the baseline.
- ***Measure life***: The expected lifetime of the measure. Sources include the DEER database, Council's 6th Power Plan, other potential studies, or DSM program evaluations.
- ***Measure applicability***: A general term encompassing a number of factors, including the technical feasibility of installation and the current or naturally occurring saturation of the measure, as well as factors to allocate savings associated with competing.
- ***Non-energy benefits***: Additional benefits attributable to a measure, such as water savings. These non-energy benefits are subtracted from the total resource cost of the measure when calculating the cost of conserved energy.

In estimating potential savings of equipment measures, it is assumed the measure's baseline efficiency would shift from its current level to prevailing codes upon burnout. Thus, it is assumed the average baseline efficiencies for this class of measures would improve over time as existing, sub-code equipment are replaced at the end of their normal, useful lives. The potential also assumes energy-efficient measures installed will be replaced by a similar efficiency level upon burnout. The difference between the baseline EUI and the technical potential EUI represent the savings.

The main feature of this approach is it accounts for the gradual decline in baseline usage as equipment decays and is replaced by units complying with current code. Moreover, by comparing average baseline usage with the constant efficiency scenario, the effects of naturally occurring conservation are also accounted for. The technical potential savings are estimated as the difference between the technical potential and the baseline, which would not be the case with a constant EUI. This demonstrates how this approach accurately estimates total potential, and accurately accounts for naturally occurring potential. Note, however, that the approach does not include any increased efficiency requirements embodied in *potential* changes to codes and standards (that is, the baseline assumes a "frozen efficiency"). Codes and standards, with compliance dates falling within the planning horizon, are incorporated in this study, as described in the Introduction.

The approach for non-equipment (or "retrofit") measures is more complicated because it requires assessing the collective impacts of a variety of measures with interactive effects. For each segment and end-use combination, the analysis objective is to estimate the cumulative effect of the bundle of eligible measures, and incorporate those impacts into the end-use model as a percentage adjustment to the baseline end-use consumption. In other words, the objective of the approach is to estimate the percentage of reduction in end-use consumption that could be saved in a "typical"[34] structure (multifamily dwelling, small office, etc.) by installing all available measures.

This approach starts by characterizing individual measure savings in terms of the percentage of their end-use consumption rather than their absolute energy savings. For each individual, non-equipment measure, savings are estimated using the following basic relationship:

$$SAVE_{ijm} = EUI_{ije} * PCTSAV_{ijem} * APP_{ijem}$$

where:

$SAVE_{ijm}$ = annual energy savings for measure *m* for end use *j* in customer segment *i*

EUI_{ije} = calibrated annual end-use energy consumption for the equipment *e* for end use *j* and customer segment *i*

$PCTSAV_{ijem}$ = the percentage savings of measure *m* relative to base usage for the equipment configuration *ije*, taking into account interactions among measures such as lighting and HVAC, calibrated to annual end-use energy consumption

APP_{ijem} = measure applicability, a fraction that represents a combination of the technical feasibility, existing measure saturation, end-use interaction, and any adjustments to account for competing measures

As described later in this section, it is appropriate to view a measure's savings in terms of what it saves as a percentage of baseline end-use consumption, given its overall applicability. In the case of wall insulation that saved 10 percent of space heating consumption, if the overall applicability was only 50 percent, the final percentage of the end use saved would be five percent. This value represents the percentage of baseline consumption the measure would save in an average home.

However, as noted, the study deals almost exclusively with cases where multiple measures affect a single end use. To avoid overestimating total savings, the assessment of cumulative impacts accounts for interactions among the various measures—a treatment called "measure stacking." The primary means to account for stacking effects is to establish a rolling, reduced baseline, applied iteratively as measures in the stack are assessed. This is shown in the equations below, where measures 1, 2, and 3 are applied to the same end use:

$$SAVE_{ij1} = EUI_{ij\,e} * PCTSAV_{ije1} * APP_{ije1}$$

$$SAVE_{ij2} = (EUI_{ije} - SAVE_{ij1}) * PCTSAV_{ije2} * APP_{ije2}$$

$$SAVE_{ij3} = (EUI_{ije} - SAVE_{ij1} - SAVE_{ij2}) * PCTSAV_{ije3} * APP_{ije3}$$

[34] This aspect of the approach requires careful determination of what a "typical" structure represents. For example, the average structure might have only a fraction of a measure installed; so it becomes necessary to think of the average single-family home (for instance) as having only 20 percent of a high-efficiency window already installed. Many structure attributes—size, measures installed, number of stories—were based on data we collected through the Energy Decisions Survey. See Volume II, Appendix F of the 2007 Assessment for details on building prototypes used.

After iterating through all measures in a bundle, the final percentage of end-use consumption reduced is the sum of the individual measures' stacked savings, divided by the original baseline consumption.

Finally, this approach requires clarification as there are actually two different savings types associated with a measure. The first is standalone savings (savings a measure would provide when installed entirely on its own). The second is stacked savings (savings attributable to a measure when assessed in conjunction with other measures and accounting for various factors that affect applicability). The former represents savings associated with a single, actual installation; the latter represents average savings a measure would achieve when installed across all homes.

Achievable Technical Potential

Achievable technical potential is defined as the portion of technical potential expected to be reasonably achievable in the course of the planning horizon. The quantity of energy-efficiency potential realistically achievable depends on several factors, including 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.[35] These barriers tend to vary, depending on customer sector, local energy market conditions, and other, hard-to-quantify factors. However, the central tenet used in assessing achievable potential is it is ultimately a function of the customers' willingness and ability to participate in utility programs, which is best ascertained through direct elicitation from potential participants.

Methods for estimating achievable potential vary across potential assessment efforts. Two dominant approaches appear to be most widely utilized:

1. The first, used in the assessment of energy-efficiency potential in California, is based on a hypothesized relationship between incentive levels and market penetration of energy-efficiency programs.
2. The second approach generally relies on a fixed percentage of the economic potential based on past experience of similar programs. For example, in the Northwest, the Council has historically assumed that, by the end of the 20-year assessment horizon, 85 percent of the technical potential would be achievable, including savings attributable to changes in codes and standards. This study utilizes the Council's 85 percent achievable portion.[36]

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[35] Consumers' apparent unwillingness to invest in energy efficiency has been attributed to the existence of certain energy-efficiency market barriers. A rich literature exists concerning what has become known as the "market barriers to energy efficiency" debate. The market barriers identified in the energy-efficiency literature fall into five broad classes of market imperfections thought to inhibit investments in energy efficiency: (1) misplaced or split incentives; (2) high front costs and lack of access to financing; (3) 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 an ample discussion of these barriers, see: William H. Golove and Joseph H. Eto, "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, March 1996.

[36] The 85 percent achievable potential applies to nearly all measures; however, adjustments were made to a few measures (such as industrial system optimization measures) where a lower achievable percentage is assumed.

Because ramp rates are incorporated for all measures and market region (see Figure 17 and Figure 18), the total achievable technical potential is, in fact, slightly less than a full 85 percent of the technical potential. Although by the end of the assessment horizon, the achievable technical potential is assumed to be 85 percent of the technical potential, these ramp rates result in a lower achievable fraction for lost-opportunity measures, which are phased-in during the assessment period. In other words, in early years when only, for example, 60 percent of the technical potential is assumed achievable, the remaining potential from lost-opportunity measures turning over in that year will never be achieved. The resulting achievable potential is approximately 82 percent of the technical potential.

The estimated achievable potential is meant to serve principally as a planning guideline. Acquiring these levels of demand-side resources depends on actual market acceptance of various demand-side technologies and measures, which depend in part on removing barriers, not all of which are completely in the utility's control. Depending on actual experiences with various programs in the future, PacifiCorp may consider alternative delivery methods, such as existing market transformation efforts and promotion of codes and standards, to capture portions of these resources. This is 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. However, as acceptance increases so would demand for energy-efficient products and services, which would likely lead to lower costs, obviating the need for incentives and, ultimately, preparing for a transition to codes and standards.

Class 2 DSM Detailed Resource Potential

Residential Sector

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

Based on resources included in this assessment, achievable potential in the residential sector is expected to be 514 aMW over 20 years, corresponding to a 29 percent reduction (ranging from 25 percent to 30 percent by state) of 2030 residential consumption (Table 63). Utah accounts for 69 percent (355 aMW) of these savings. Overall, savings amount to around 25.7 aMW per year, or an annual reduction in baseline residential sector sales around 1.7 percent.

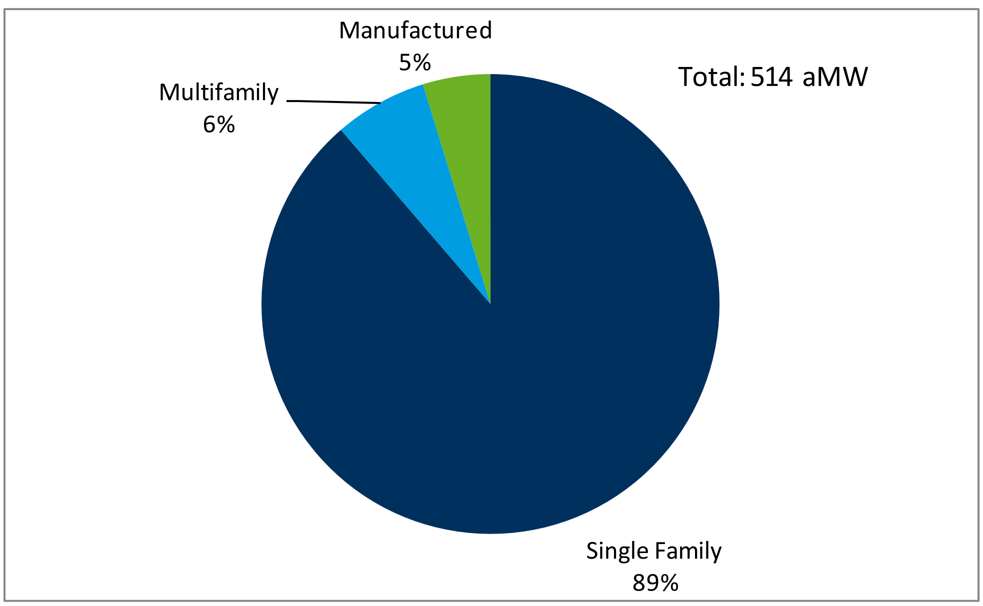
Table 63. Residential Sector Energy-Efficiency Potential by State (aMW in 2030)

Territory	State	2030 Baseline Sales	Technical Potential	Achievable Technical Potential	Achievable As Percent of Baseline Sales	Resource Cost Levelized $/kWh*
Pacific Power	California	60	18	15	25%	$0.22
	Washington	238	80	68	28%	$0.24
	Subtotal	**298**	**98**	**83**	**27%**	
Rocky Mountain Power	Idaho	146	43	36	25%	$0.19
	Utah	1,181	429	355	30%	$0.24
	Wyoming	162	47	40	25%	$0.30
	Subtotal	**1,489**	**519**	**431**	**27%**	
	Total	**1,787**	**617**	**514**	**29%**	

* Levelized cost is based on total resource cost for all states except Utah, where it is based on utility cost.
Note: Results may not sum to total due to rounding.

As shown in Figure 20, single-family homes represent 89 percent (456 aMW) of the total achievable residential potential, followed by multifamily (33.6 aMW) and manufactured homes (24.4 aMW). The main driver of these results is each home type's proportion of baseline sales, but other factors, such as heating fuel sources, play an important role in determining potential. For example, multifamily homes typically have more electric heating than other home types, which increases their relative share of potential. On the other hand, the lower use per customer for multifamily units serves to decrease 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. All specific factors affecting results are included in the state- and segment-specific data, provided in Volume II, Appendix C.

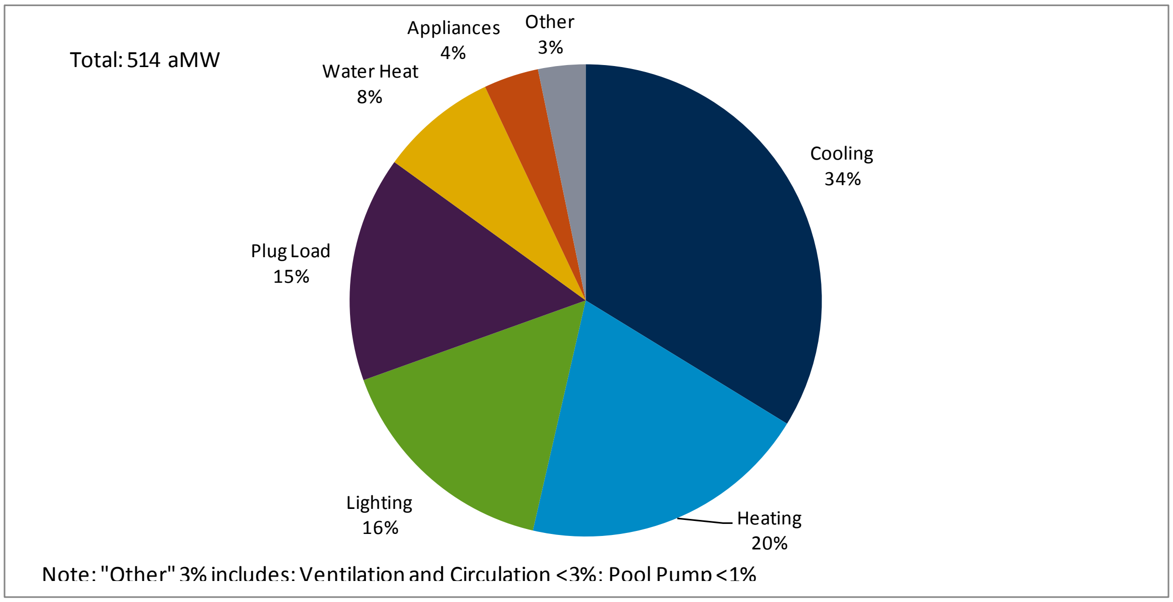
Figure 20. Residential Sector Achievable Technical Potential by Segment



Savings in HVAC systems account for more than half (54 percent) of total achievable technical potential by end use (Figure 21), where space heating (central and room) accounts for 20 percent and cooling accounts for 34 percent. Lighting accounts for 16 percent of the potential, driven by CFLs in the first few years,[37] with additional potential followed by plug loads, water heating, refrigerators and freezers (included in appliances and almost exclusively associated with recycling), and other appliances (see Table 64).

These results reflect Utah's large share of the total sales (56 percent). While the assumptions driving the lighting and appliance savings tend to be consistent throughout the territory, other end uses are affected by customer demographics, which vary widely between states, such as saturation of specific end uses. For example, the vast majority of the cooling component depicted in Figure 21 comes from Utah. The detailed results—which show savings by individual states and home types and provided in Volume II, Appendix C—reflect the differences in equipment saturations, shares for electricity, and proportions of baseline sales associated with different home types.

Figure 21. Residential Sector Achievable Technical Potential by End Use



[37] After 2014, provisions of the 2007 Energy Independence and Security Act (EISA 2007) will take effect, increasing the efficacy of standard light bulbs.

Table 64. Residential Sector Energy-Efficiency Potential by End Use (aMW in 2030)

End Use	Baseline Sales	Technical Potential	Achievable Technical Potential
Computer	36	10	8
Cooking Oven	21	3	3
Cooking Range	18	- - -	- - -
Cool Central	316	192	154
Cool Room	12	4	3
Dehumidifier	1	- - -	- - -
Dryer	92	6	5
DVD	27	- - -	- - -
Freezer	67	5	4
Heat Central	160	78	67
Heat Pump	48	20	17
Heat Room	124	42	35
Home Audio System	11	- - -	- - -
Lighting Exterior	25	7	6
Lighting Interior Specialty	59	15	13
Lighting Interior Standard	115	75	64
Microwave	29	1	1
Monitor	14	5	5
Plug Load Other	141	20	17
Pool Pump	4	2	1
Refrigerator	122	8	7
Set Top Box	27	15	13
TV	106	43	36
Ventilation and Circulation	83	18	15
Water Heat	130	48	41
Total	**1,787**	**617**	**514**

Commercial Sector

The commercial sector offers the largest source of opportunities for electric energy-efficiency improvements. This study's results indicate a total of 361 aMW of achievable technical potential in the commercial sector, over 20 years. Similarly to the residential sector, this potential is dominated by Utah (72 percent of achievable potential) and its particular customer demographics. Table 65 lists the commercial sector potential by state.

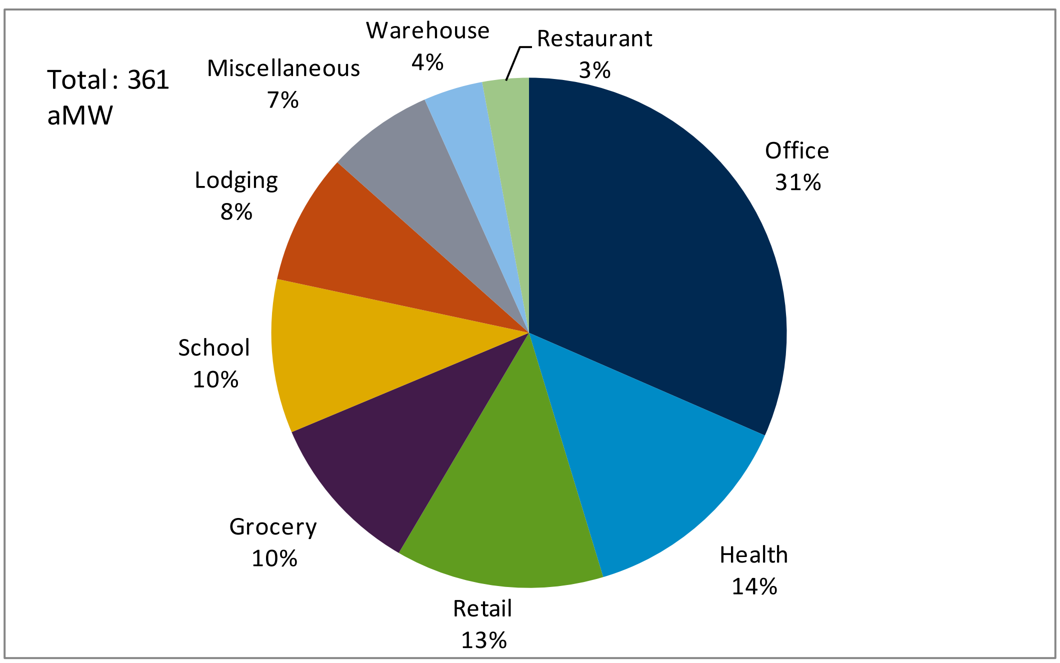
Table 65. Commercial Sector Energy-Efficiency Potential by State (aMW in 2030)

Territory	State	Baseline Sales	Technical Potential	Achievable Technical Potential	Achievable as Percent of Baseline Sales	Resource Cost Levelized $/kWh*
Pacific Power	California	55	10	9	16%	$0.13
	Washington	194	42	35	18%	$0.12
	Subtotal	**249**	**52**	**44**	**17%**	
Rocky Mountain Power	Idaho	92	15	13	14%	$0.14
	Utah	1,743	304	258	15%	$0.12
	Wyoming	284	53	45	16%	$0.12
	Subtotal	**2119**	**372**	**316**	**15%**	
	Total	**2,367**	**424**	**361**	**15%**	

* Levelized cost is based on total resource cost for all states except Utah, where it is based on utility cost.
Note: Results may not sum to total due to rounding.

As shown in Figure 22, offices and health facilities represent the largest shares (31 percent and 14 percent, respectively) of savings potential in the commercial sector. Considerable savings opportunities are expected in the commercial sector's retail (13 percent), school (10 percent), and grocery (10 percent) segments. Moderate savings amounts are expected to be available in lodging facilities, warehouses, restaurants, and miscellaneous buildings types (such as churches, assembly halls, and fitness centers). As discussed, Utah's largely urban customer population, with a substantial proportion of small and large office segments, is the main driver behind these results. Detailed information regarding the commercial sector potential achievable within each state is provided in Volume II, Appendix C.

Figure 22. Commercial Sector Achievable Technical Potential by Segment



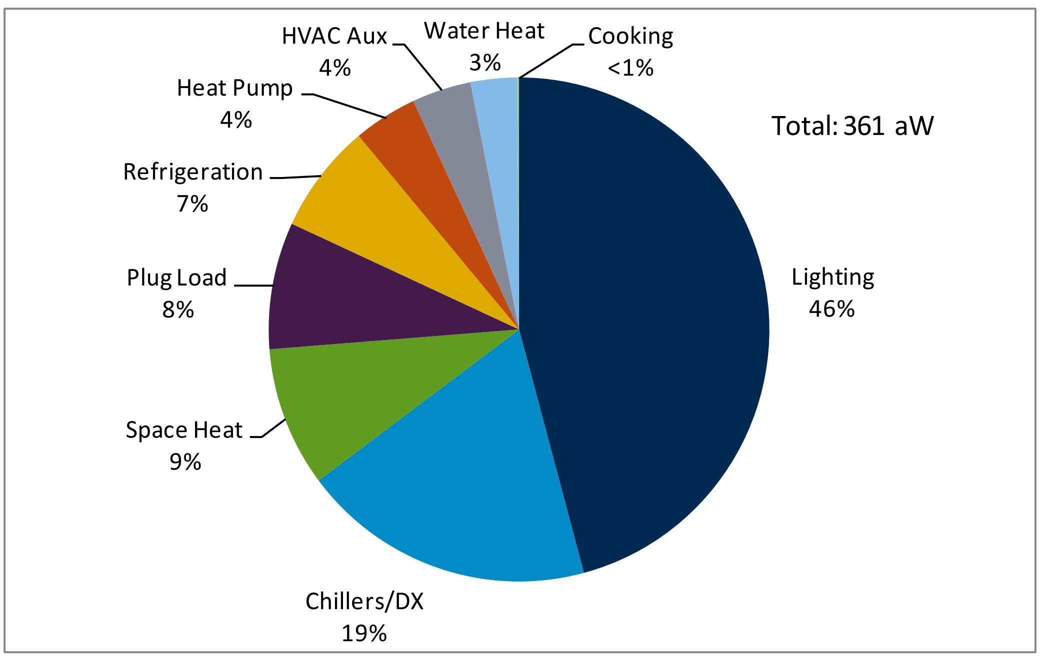
Lighting efficiency represents the largest portion of achievable potential in the commercial sector (46 percent), followed by cooling (19 percent) and heating (9 percent), as shown in Table 66 and Figure 23. These results reflect the pending federal standard, effectively eliminating T12 bulbs. Though current code lighting power density levels are being used, there is an increasing trend in commercial codes towards lower power density; the most appropriate means of acquisition for this resource might be through codes and standards.

Table 66. Commercial Sector Energy-Efficiency Potential by End Use (aMW in 2030)

End Use	Baseline Sales	Technical Potential	Achievable Technical Potential
Computers	56	15	13
Cooking	6	1	0
Cooling Chillers	24	13	11
Cooling DX Evaporative Cooler	133	65	55
Cooling Room	8	3	2
Heat Pump	43	17	15
HVAC Auxiliary	499	16	14
Lighting Exterior	145	31	27
Lighting Interior	936	163	139
Other Office Equipment	55	3	2
Other Plug Load	162	17	15
Refrigeration	172	30	25
Space Heat	97	38	32
Water Heat	32	13	11
Total	**2,367**	**424**	**361**

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

Figure 23. Commercial Sector Achievable Technical Potential by End Use



Industrial Sector

Technical and achievable technical energy-efficiency potential was estimated for major end uses within 14 major industrial sectors in PacifiCorp's service territory. These customer sectors correspond to the load forecast as close as practically possible. Achievable technical energy-efficiency potential in the industrial sector is estimated at 265 aMW, representing approximately 9 percent of the total industrial load in 2030. Miscellaneous manufacturing represents the largest percentage (28 percent) of achievable potential (Table 67 and Figure 24).

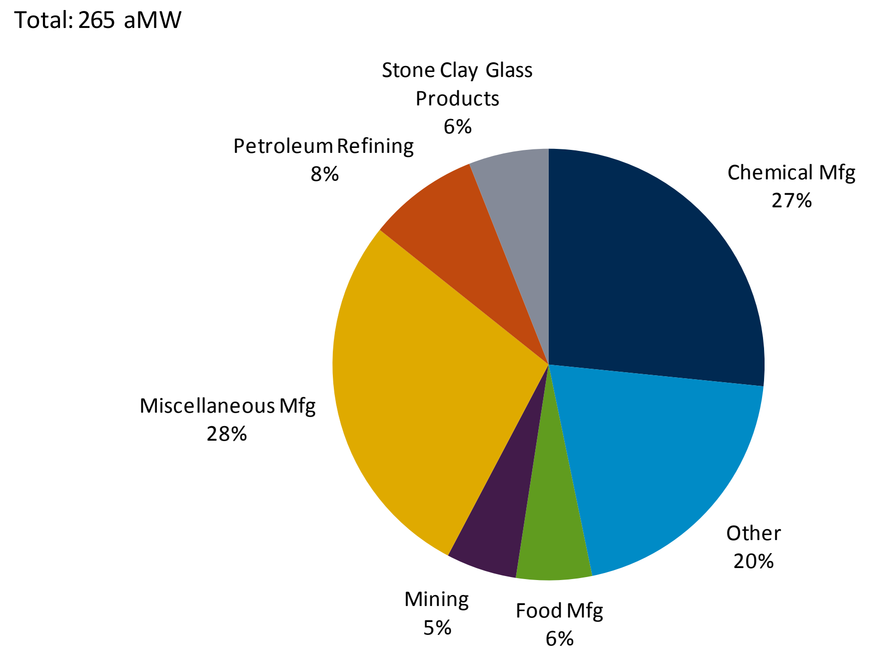
Table 67. Industrial Sector Energy-Efficiency Potential by State (aMW in 2030)

Territory	State	Baseline Sales	Technical Potential	Achievable Technical Potential	Achievable as Percent of Baseline Sales	Resource Cost Levelized $/kWh*
Pacific Power	California	4	1	1	17%	$0.01
	Washington	110	21	17	15%	$0.03
	Subtotal	**114**	**22**	**18**	**16%**	
Rocky Mountain Power	Idaho	46	8	6	13%	$0.02
	Utah	1,057	158	119	11%	$0.02
	Wyoming	1,712	158	122	7%	$0.02
	Subtotal	**2,815**	**324**	**247**	**10%**	
	Total	**2,929**	**346**	**265**	**9%**	

* Levelized cost is based on total resource cost for all states except Utah, where it is based on utility cost.
Note: Results may not sum to total due to rounding.

In examining these 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 nearly all residential and commercial customer segments were present in every state, some facility types in the industrial sector applied to as few as one state. The machinery and equipment manufacturing potential, for example, is exclusive to Utah. State- and industry-specific results are provided in Volume II, Appendix C.

Figure 24. Industrial Sector Achievable Technical Potential by Segment



Note: "Other" includes Primary Metal Mfg: 4%; Transportation Equiptment Mfg 4%; Electronic Equipment Mfg: 3.3%; Industrial Machinery: 2.8%; Paper Mfg: 2.8%; Water: 1.4%; Wastewater: 1%; Lumber Wood Products: <1%.

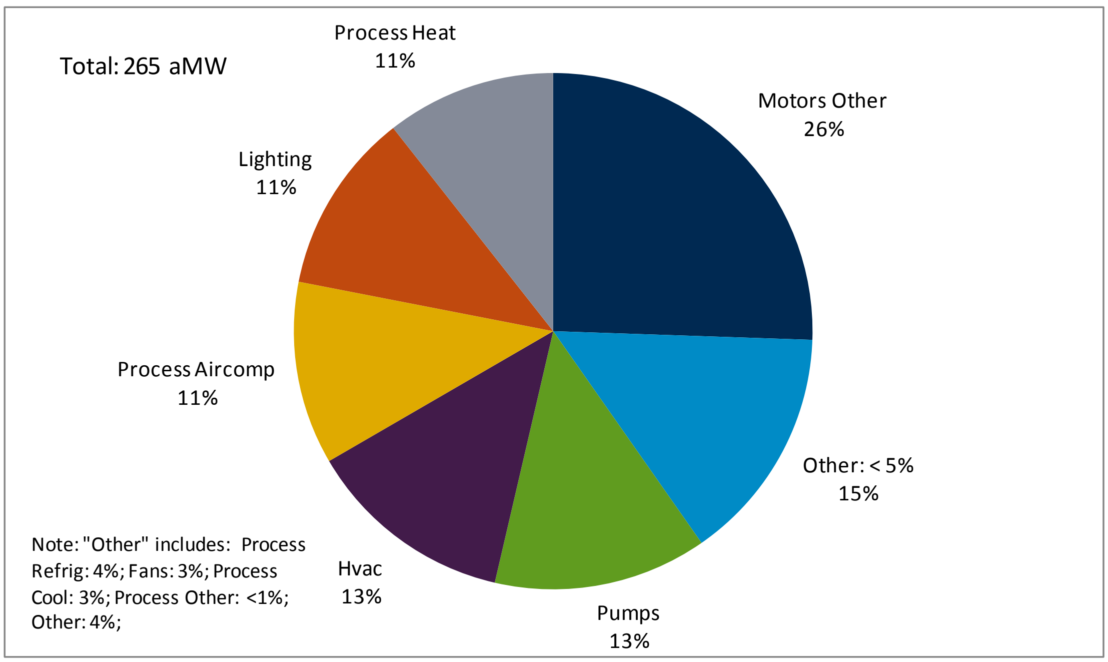
The majority of savings in the industrial sector (50 percent) are attributable to efficiency gains in motor upgrades, air compression, pumping, air distribution, and other motors, which include motors in mining applications. Because many motors used in mining do not fit into traditional industrial motor categories, they have been classified into "Motors - Other"—representing a large slice of potential (68 aMW). Remaining potential splits between HVAC[38] and other building improvements, process improvements, and lighting (Figure 25 and Table 68).

38 A substantial portion of industrial HVAC savings come from clean room applications.

Table 68. Industrial Sector Energy-Efficiency Potential by End Use (aMW in 2030)

End Use	Baseline Sales	Technical Potential	Achievable Technical Potential
Fans	126	12	9
HVAC	203	40	34
Indirect Boiler	57	- - -	- - -
Lighting	152	35	30
Motors - Other	1,208	82	68
Other	67	18	11
Process			
Air Compressors	192	45	30
Cooling	130	10	9
Electro-Chemical	134	- - -	- - -
Heat	165	44	28
Other Processes	207	0	0
Refrigeration	63	15	10
Pumps	223	45	35
Total	**2,929**	**346**	**265**

Figure 25. Industrial Sector Achievable Technical Potential by End Use



Irrigation Sector

Although irrigation potential is small compared to other industries, it is estimated 6 percent of 2030 usage could be achievable, with more than half the savings in Idaho. Electricity consumption in the irrigation sector primarily consists of motors used for pumping, with a much smaller portion going to miscellaneous, non-pumping end uses. As a result, all irrigation potential consists of measures that improve pumping efficiency, including pump upgrades, motor upgrades, and efficient nozzles. Cumulative aMW savings in 2030 associated with these measures are presented in Table 69.

Table 69. Irrigation Sector Energy-Efficiency Potential by State (aMW in 2030)

Territory	State	Baseline Sales	Technical Potential	Achievable Technical Potential	Achievable as Percent of Baseline Sales	Resource Cost Levelized $/kWh*
Pacific Power	California	12.8	1.5	1.3	10%	-$0.07
	Washington	19.8	2.3	2	10%	-$0.07
	Subtotal	**32.6**	**3.8**	**3.3**	**10%**	
Rocky Mountain Power	Idaho	71.3	8.4	7.2	10%	-$0.07
	Utah	23.6	2.8	2.4	10%	$0.11
	Wyoming	2.7	0.3	0.3	10%	-$0.07
	Subtotal	**97.6**	**11.5**	**9.9**	**10%**	
Total		**130.1**	**15.4**	**13.1**	**10%**	

* Levelized cost is based on total resource cost for all states except Utah, where it is based on utility cost.
Note: Results may not sum to total due to rounding.

Irrigation savings originate mainly from reduced pump motor energy use, which may be achieved from reduced pressure, reduced flow,[39] or both. Identified savings therefore may be achieved by alternative measures, such as nozzles upgrades. The magnitude of savings is also directly related to pump lift (total dynamic head), which varies across different service territories. This factor is a critical consideration for delivering cost-effective programs in this sector, which are likely more effective in jurisdictions such as Idaho, where deep wells tend to be more common sources for irrigation water.

Street Lighting

The achievable technical potential from upgrading high-pressure sodium street lighting fixtures to LEDs is approximately 4.3 aMW.[40] Approximately one-third of the sales could be reduced by this conversion. It should be noted many communities are currently upgrading their traffic and street lights to LED fixtures, using funding available through the American Reinvestment and Recovery Act; thus, not all this potential will likely need to be realized through utility investment. Street lighting potential was not included in the 2007 Assessment.

39 This includes scientific irrigation scheduling, which saves energy by minimizing the amount of irrigation required.

40 The aggregate potential is divided approximately equally between customer- and company-owned equipment; state level splits vary.

Table 70. Street Lighting Sector Energy-Efficiency Potential by State (aMW in 2030)

Territory	State	Baseline Sales	Technical Potential	Achievable Technical Potential	Achievable as Percent of Baseline Sales
Pacific Power	California	0.3	0.1	0.1	36%
	Washington	1.3	0.5	0.5	36%
	Subtotal	**1.6**	**0.6**	**0.6**	**36%**
Rocky Mountain Power	Idaho	0.3	0.1	0.1	36%
	Utah	8.7	3.6	3.1	36%
	Wyoming	1.4	0.6	0.5	36%
	Subtotal	**10.4**	**4.3**	**3.7**	**36%**
	Total	**11.9**	**5**	**4.3**	**36%**

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

4. Supplemental Resources

Scope of Analysis

In addition to traditional capacity-focused and energy-efficiency resources, this report includes an analysis of other resources not considered in the standard definitions of PacifiCorp's demand-side resource classes 1, 2, or 3. These resources, which may be loosely defined as "dispersed generation," are considered "supplemental" to this study's initial scope, and include the following:

- ***CHP*** units generate electricity and utilize waste heat for space or water heating requirements. They can be used in buildings that have a fairly coincident thermal and electric load, or buildings where combustible biomass or biogas is produced. CHP units have been traditionally installed in hospitals, schools, and manufacturing facilities, but they can be used across nearly all segments with an average annual energy load greater than about 30 kW. CHP is broadly divided into subcategories based on the fuel used. Non-renewable CHP runs on natural gas, while renewable CHP runs on a biologically derived fuel (biomass or biogas).

- ***On-site solar*** encompasses both electricity generation and energy-efficiency measures that use solar energy. Three solar-related resources included were: on-site solar electric generation or rooftop PVs, and two solar efficiency measures, solar water heaters and solar attic fans.

Assessment Methodology

The following, overall methodology was used to calculate the potential:

1. Separately calculate technical potential for each of the resource categories, using the following key data inputs:
    a. *CHP*: PacifiCorp's C&I customer database for "typical" building energy loads and service territory (Rocky Mountain Power and Pacific Power) demographics.
    b. *Rooftop PV*: customer counts and square footage assumptions.
    c. *Solar Efficiency Measures*: technical feasibility factors, similar to Class 2 DSM resources.
2. Calculate costs of various technologies given literature values, available databases, other states' programs, and, for CHP, a fuel price.
3. Determine achievable potential for each resource class, based on other programmatic successes.

Technical Potential

Technical potential from the supplemental resources is estimated to be 6,605 aMW in 2030, shown by territory and resource in Table 71.

For CHP, the total potential from non-renewable and renewable units is 1,849 aMW, representing 28 percent of 2030 energy-focused potential. On-site solar provides 4,756 aMW, primarily via rooftop PV, while the solar efficiency measures account for nearly 28 aMW.[41] It should be recognized the technical potential for supplemental resources are significantly higher than what can be achieved, largely since upfront costs are quite considerable. This is discussed further below.

Table 71. Supplemental Resources Technical Potential by Region and Resource Category (aMW in 2030)

Technical Potential	Rocky Mountain Power	Pacific Power	PacifiCorp System
CHP: Non-Renewable	851	251	1,102
CHP: Renewable	449	297	747
On-Site Solar: PVs	3,231	1,497	4,729
On-Site Solar: Efficiency Measures	12	16	28
Total	**4,544**	**2,061**	**6,605**

Achievable Technical Potential

Achievable technical potential for all supplemental resources is listed in Table 72 by region. As compared to technical potential (Table 71), this potential is significantly less due to low awareness of technologies and other permitting, siting, and/or interconnection concerns.

Table 72. Achievable Technical Potential for Supplemental Resources by Territory (aMW in 2030)

	Rocky Mountain Power	Pacific Power	PacifiCorp System
CHP: Non-Renewable	12	5	16
CHP: Renewable	78	52	130
On-Site Solar: PVs	4	4	8
On-Site Solar: Efficiency Measures	10	13	23
Total	**104**	**74**	**178**

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

Figure 26 outlines the assumed resource acquisition rates of all supplemental resource potential.

For CHP, the ramp rate in the initial 10 years is based on the amount of CHP installed from 2007 through 2010.[42] Beginning in 2021, the performance degradation of previous systems installed is greater than the amount of new capacity installed, which causes the decline in achievable technical potential from 2021 through 2030 for renewable and non-renewable CHP.

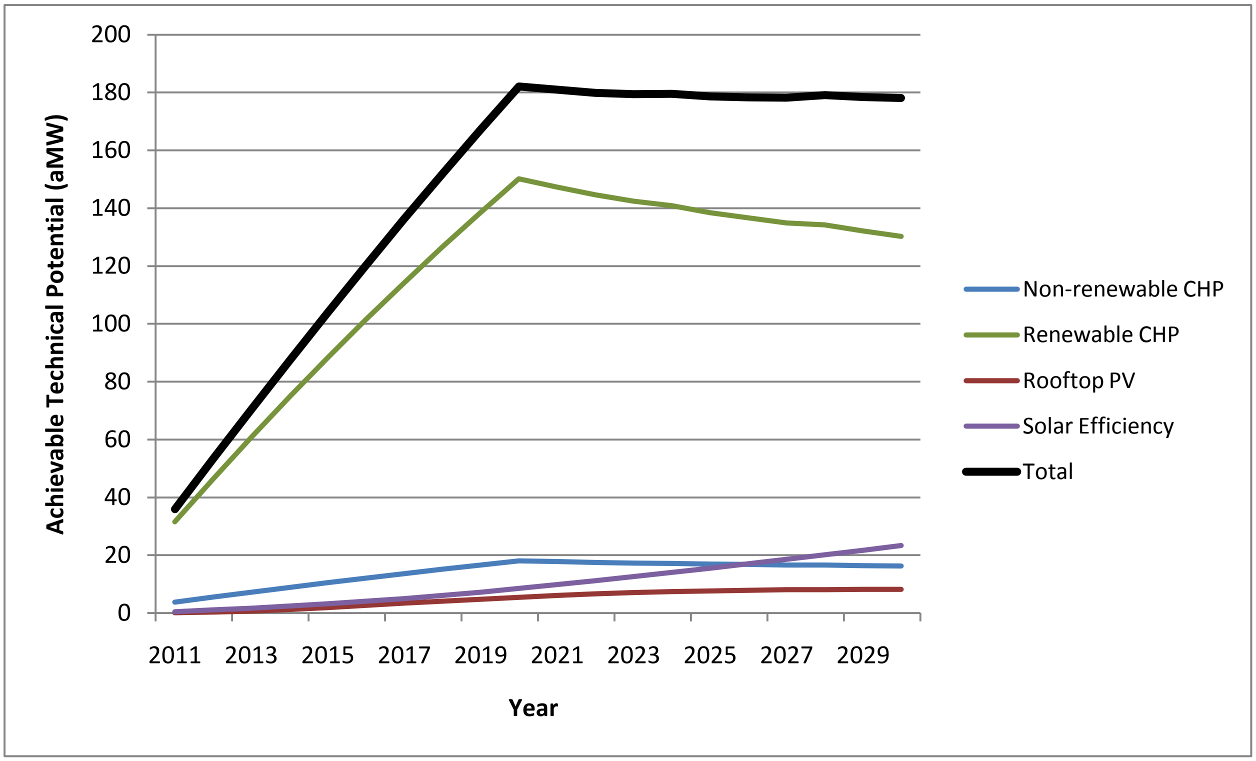
For solar resources, particularly PV, existing state programs across the country have had relatively slow growth for the first four years, with an increase in the fifth year, followed by

[41] It should be noted the technical potential for the solar efficiency measures accounts for the share of customers with electric end uses. For example, in Utah the large majority of domestic hot water heating is fueled by natural gas.

[42] A comparison of EEA data in 2007 to data in 2010 showed approximately 77 MW of CHP was installed in PacifiCorp's service territory during those three years.

continued and steady growth.[43] Since Oregon and Utah have PV programs,[44] they influence the market penetration curve, accelerating the overall growth rate. Other states within the PacifiCorp system currently without programs would likely see a slower growth rate.

Figure 26. Acquisition Schedule for Supplemental Resources by Resource Category



Combined Heat and Power Results

CHP encompasses all technologies generating both electricity and heat on-site at a customer's facility. Generally, power generated through these technologies is expected to contribute to the utility's base load resources, rather than peak load requirements. CHP has traditionally been installed in hospitals, schools, and manufacturing facilities, but can be used in any facility with a fairly coincident electric and thermal load and an average annual energy load greater than about 30 kW. CHP is broadly divided into non-renewable and renewable subcategories, based on the type of fuel used.

CHP includes a standard electrical generator, but the business total energy needs are reduced by capturing the generator's waste heat and using it for other processes. For example, a typical spark-ignition engine has an electrical efficiency of about only 30 percent.[45] The "lost" energy

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43 We analyzed data from New Jersey, Connecticut, California, and Oregon, and no data exist for more than 10 years of program history.

44 In Oregon, solar programs are through the ETO; in Utah, Rocky Mountain Power just finished a pilot PV program and is implementing a full-scale program.

45 "CPUC Self-Generation Incentive Program Eighth-Year Impact Evaluation," Itron, Inc. 2009.

can be captured by the CHP unit and used for heating space or water, achieving an overall efficiency of up to 80 percent. Thus, savings become available by offsetting boiler usage in addition to generating electricity.

The three primary generator technologies available in the market are: 1) reciprocating engines (REs; either spark-ignition or compression-ignition); 2) turbines (gas or steam for larger capacity [>1 MW] or microturbines [MTs] for smaller capacity [<1 MW]); and 3) fuel cells (FCs), primarily those using phosphoric acid or molten carbonate as the electrolyte, although other types of FCs are now becoming commercially viable.[46]

CHP is divided into two broad categories, depending on the fuel source. The fuel used for CHP can be from a renewable source (biomass or biogas) or a non-renewable source (natural gas). The same generators described above can be used with either fuel type.

Renewable Generation. In this study, renewable CHP includes all generation using a biomass-based fuel: anaerobic digesters and industrial biomass. Anaerobic digesters create methane gas (biogas fuel) by breaking down liquid or solid biological waste. The captured waste heat of the CHP unit is, in part, used to maintain the high temperature required by the digesters.

Industrial biomass, on the other hand, includes the waste products from industries, such as lumber mills or pulp and paper manufacturing, which are combusted in place of natural gas or other fuels. For solid industrial biomass, the heat produced from combustion is often used to run a steam turbine.[47]

Anaerobic digesters are coupled with smaller-scale generators, such as REs, MTs, or FCs, while industrial biomass is generally large scale, using generators such as steam or gas turbines (GTs) with a capacity greater than 1 MW.

Biomass fuels from the agricultural sector (e.g., crop waste, such as bagasse from sugar, rice hulls, and rice straw) are not considered in this study. Due to high moisture content and varying ability, crop residues are not a viable fuel alternative for most CHP applications.[48] In addition, the prime energy-producing crops (sugar cane and rice) are largely not present in PacifiCorp's service territory.

Non-Renewable Generation. Non-renewable generation includes all technologies that require burning a fossil fuel (such as natural gas or diesel) in a generator to produce electricity. In this study, only natural gas is considered because it is readily available and environmentally cleaner burning than diesel.

This study only considers on-site CHP generation primarily used for a building's energy and heat needs. Large "central-station" CHP generation facilities that operate to sell the majority (or all) of their power to the grid are outside the scope of this work. It should be recognized, however, that those types of plants can provide a large amount of potential, already modeled in the PacifiCorp IRP process. For example, in Oregon, such facilities currently generate over 1,000 MW.

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[46] Note not all types of FCs available operate at a high enough temperature to be applicable for a CHP-configuration. Only those types that are viable are considered here.

[47] This is commonly referred to as *cogeneration*.

[48] "Combined Heat & Power Market for Opportunity Fuels," Resource Dynamics Corp, 2004.

Background Data

The primary data source for installed cost of CHP technologies is the California Self-Generation Incentive Program (SGIP).[49] This program, funded by the major investor-owned utilities of California, provided varying levels of incentives for individual customers to install various distributed generation technologies, including CHP, with a maximum capacity of 5 MW through 2008. This program began in 2001 and has a publicly-available database of all installations, including generation technology, capacity, fuel, and total cost. Though the incentives for CHP are no longer available, the program evaluation still reports results for CHP systems, as participants were required to provide data and feedback on their systems for five years.

For the CHP assessment, nameplate capacity is based on the weighted average of units installed through California's SGIP for both non-renewable generation and anaerobic digesters. Typical nameplate capacities for industrial biomass vary widely; a 4,800 kW unit was used as a proxy based on a study for the ETO.[50] It should be noted larger capacity units (20 MW) can be installed. These values are summarized in Table 73, along with the net fuel heat rate, measure life, capacity factors, and performance degradation rates for the different generators. Heat rates and capacity factors are from the 2008 SGIP Impact Evaluation Report.[51] The measure life data were obtained from other literature.[52] These values are assumed equivalent across PacifiCorp's service territory.

Table 73. CHP Prototypical Generating Units

Technology	Nameplate Capacity (kW)	Fuel Heat Rate (MMBTU/MWh)	Measure Life (years)	Capacity Factor	Performance Degradation (percent/year)
CHP: Non-Renewable					
Reciprocating Engine	475	8	20	0.5	3%
Microturbine	120	8	15	0.5	3%
Fuel Cell	500	6.1	10	0.8	1%
Gas Turbine	2,960	6.3	20	0.8	1%
CHP: Renewable					
Anaerobic Digesters	428	N/A	15	0.5	3%
Industrial Biomass	4,800	N/A	20	0.9	3%

Note: no heat rate is given for the renewable generation technologies; since the fuel is produced on site, the heat rate is not relevant.

Costs of these prototypical generating units were determined from the SGIP database or, for industrial biomass, literature values.[52] The installed costs include planning and feasibility, engineering and design, permitting, generator equipment costs, waste heat recovery costs, construction and installation, interconnection, and service contracts. The SGIP database costs

49 http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/

50 "Sizing and Characterizing the Market for Oregon Biopower Projects," prepared for ETO, by CH2MHill, 2005.

51 "CPUC Self-Generation Incentive Program Eighth-Year Impact Evaluation," Itron, Inc. 2009.

52 "Gas-Fired Distributed Energy Resource Technology Characterization," National Renewable Energy Laboratory, NREL-TP-620-34783, 2003.

were reduced by 17 percent to remove the included sales tax (7 percent) as well a 10 percent reduction based on the higher costs typical of the California market.[53]

It should be noted, for generators used with anaerobic digesters, any of the three CHP technologies could be used; thus, costs can vary widely. In this analysis, a weighted average cost of the technologies, based on adoption proportions in California, is assumed. These costs are reported in Table 74, which also includes the assumed annual installed cost reduction, based on technology improvements and adoption of streamlined siting and interconnection requirements. These reductions will reduce or negate the effects of inflation (an annual increase of 1.9 percent). We assumed administration costs to be 14 percent of the total program costs, which increase with inflation. Fuel costs were calculated from the heat rates and vary by state, using the 2010 Forward Price Curve data for site-specific natural gas prices plus transportation and tariff adders.[54] Fuel costs in the table average across all states, and represent 2010 natural gas prices. Specifics on state-by-state fuel costs are outlined in Volume II, Appendix D. Together, these data allow a full life-cycle cost analysis of the resource.

Table 74. Costs for Assessed Technologies (2010$)

Technology	Installed Cost* ($/kW)	Installed Cost Reduction (percent/yr)	Annual O&M Costs ($/kW)	Annual Fuel Cost ($/kW)
Reciprocating Engine	1,738	1%	57	256
Microturbine	2,400	3%	54	256
Fuel Cell	4,238	5%	35	312
Gas Turbine	1,623	1%	57	322
Anaerobic Digesters	3,045	3%	53	0
Industrial Biomass	1,620	0.5%	32	0

*After the federal rebate was taken into account. Federal rebate amounts can be found at http://www.epa.gov/chp/incentives/

CHP Technical Potential

The technical potential for CHP assumes all technologies will be adopted in all available customer sites to meet their average annual electric demand, regardless of cost or other market barriers. This assumption applies to all C&I building types, large industrial biomass-producing facilities, and sites that may use anaerobic digesters. These three sectors, however, need to be treated separately. We used PacifiCorp's 2006 customer database to derive technical potential, ramped up from the first-year load. Details on resources used are available in Volume II, Appendix D. The technical potential by resource category and state is listed in Table 75.

Renewable: Anaerobic Digesters. The best candidates for anaerobic digesters include animal farms (dairy or swine), landfills, and wastewater treatment facilities. For farms, the amount of biogas that can be generated is directly related to the number and type of animals on site. Based on typical collection systems, a study by the EPA assumes one cow generates 2.5 kWh/day and one pig generates 0.25 kWh/day.[55] Given size constraints, it is likely only dairy farms with more than 500 head of cattle or 2,000 head of swine will install a generator. We calculated overall

[53] RS Means Building Construction Cost Data, 2007.

[54] Provided by PacifiCorp.

[55] "Market Opportunities for Biogas Recovery," EPA-430-8-06-004, http://www.epa.gov/agstar

potential based on the number and average size of farms across the states (by zip code) in PacifiCorp's service territory.[56,57]

Wastewater treatment facilities are similar to farms in that populations served by a particular facility will determine expected generation output. A study by the Federal Energy Management Program assumes 10,000 people will generate approximately 1 million gallons of waste per day (1 MGD). Each 1 MGD of waste can produce about 35 kW of energy; and generally 3 MGD is the minimum waste flow before an anaerobic digester will be installed.[58] Thus, only population centers with 30,000 people or more are considered for wastewater generation.

Finally, for landfills, the U.S. EPA Landfill Methane Outreach Program (LMOP) encourages implementation of generators. As part of this program, a database of participating and candidate landfills, based on waste-in-place and throughput, is available by state (with zip code resolution).

Renewable: Industrial Biomass. The industrial biomass potential is based on customers with an average annual electric load greater than 1 aMW in four key biomass-producing industries: lumber, food, pulp and paper, and chemical manufacturing. We used the PacifiCorp customer database to determine the overall load associated with these industries. For buildings with a load between 1 aMW and 5 aMW, we assumed an average load of 2.5 aMW; for those with a larger than 5 aMW annual load, we used the actual customer load listed in the customer database. All industrial biomass facilities within this size range are considered CHP eligible.

Non-Renewable Generation. For all other C&I facilities (excluding renewable-generation facilities), the only constraint on the technical potential is the applicability of a CHP unit within a particular building. For a building to be eligible for CHP, two key conditions must exist: 1) the ratio of thermal to electric loads should be within 0.5 to 2.5 (the range in which most CHP technologies operate), with a high coincidence between these two loads; and 2) the overall loads should be fairly constant throughout the year.

We obtained the overall percentage of buildings by market sector that are CHP eligible, based on this ratio and the load requirements, from Energy Insights™. Energy Insights has determined these consumption parameters from secondary sources, including the EIA Commercial Building Energy Consumption Survey (CBECS), the Manufacturing Energy Consumption Survey as well as market summaries developed by their own surveys, the Gas Technology Institute, and the American Gas Association. Using the PacifiCorp customer database provided for the 2007 study, the number of CHP-eligible establishments within a load bundle, (e.g., 200 akW–499 akW, or 500 akW–999 akW average annual electric load) together with an average load based on bundle size, was used to calculate the potential in aMW. For buildings with an annual load larger than 5 aMW, we used the actual customer load listed in the customer database.

56 http://www.nass.usda.gov/Census_of_Agriculture/index.asp

57 "Sizing and Characterizing the Market for Oregon Biopower Projects," CH2MHill for ETO, 2005.

58 http://www1.eere.energy.gov/femp/pdfs/bamf_wastewater.pdf

Table 75. CHP Technical Potential by State and Resource Category (aMW in 2030)

Resource	Pacific Power				Rocky Mountain Power				Total
	CA	OR	WA	Subtotal	ID	UT	WY	Subtotal	
Anaerobic Digesters	3	30	13	46	25	41	5	71	117
Industrial Biomass	7	196	49	252	167	104	108	379	630
Non-Renewable	6	182	63	251	11	557	283	851	1102
Total	**15**	**408**	**125**	**548**	**203**	**702**	**396**	**1301**	**1,849**

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

CHP Achievable Technical Potential

The achievable technical potential is based on adoption rates within other programs (primarily SGIP in California). This analysis was fairly independent of the technical potential, but gives reasonable results, based on adoption rates through other programs. In addition, a survey of PacifiCorp customers from 2007 provides territory-specific information. Lastly, a comparison of the 2010 EEA, CHP, and LMOP data with the 2007 data showed 67 MW of CHP and 10 MW of renewable-fueled CHP had been installed within PacifiCorp's service territory over the past three years.

2007 Survey Results

Although achievable technical potential is primarily based on adoption within the California market, the 2007 PacifiCorp survey results give some insight into the applicability in PacifiCorp's service territory. Full descriptions of survey results in Volume II, Appendix A, of the 2007 Assessment, are described briefly here. In general, there was a low level of knowledge—only 21 percent of surveyed customers were familiar with CHP systems. However, of those familiar, 28 percent (or 6 percent of the total sample) believed their company would be interested in installing a CHP unit in the future. This 6 percent of total surveyed customers represents 7.6 percent of the total load of surveyed customers. As such, without a rigorous education campaign, PacifiCorp could potentially achieve 7 percent of technical potential, purely based on current interest levels.

Renewable: Anaerobic Digesters. The availability of potential sites for anaerobic digesters (farms, landfills, and wastewater treatment facilities) is area-specific; therefore, the adoption rate from other states' programs may not be representative for PacifiCorp territories. Instead, potential was based on a similar adoption percentage of the technical potential (1 percent in the first 10 years of program implementation) as the non-renewable CHP. All anaerobic digesters are installed in the commercial sector, and the achievable potential is about 1 aMW in 2030.

Renewable: Industrial Biomass. The projected growth in U.S. electricity generation from industrial biomass[59] was used as the basis for growth in generation by biomass within PacifiCorp's industrial sector. The PacifiCorp industrial biomass growth was normalized by the

59 From EIA 2007 Annual Energy Outlook.

ratio of the PacifiCorp industrial electrical load to the U.S. industrial load. The state-by-state breakdown is based on the distribution of the technical potential from the four key biomass-producing industries (lumber, food, pulp and paper, and chemical manufacturing) with greater than 1 aMW of annual energy load. As the name indicates, all penetration is in the industrial sector, and is estimated at about 129 aMW in 2030.

Non-Renewable Generation. The achievable technical potential for non-renewable CHP is based upon California's success implementing CHP installations within SGIP and the amount of CHP installed from 2007 to 2010. The results of SGIP were used as an expected generation outcome for PacifiCorp, normalized by the PacifiCorp load compared to the load of the participating SGIP utilities. The SGIP provided rebates for non-renewable CHP for six years and provided incentives that cover approximately 50 percent of the system cost. With slow initial growth for program implementation and greater expected barriers (e.g., longer payback periods, potentially less statewide support, insufficient interconnection standards, etc.), this generation is targeted for PacifiCorp after 10 years of program implementation. The four primary generator technologies (REs, MTs, FCs, and GTs) were all included in SGIP, and treated distinctly in this analysis. It is assumed across all non-renewable CHP that 65 percent will go toward the commercial sector, and 35 percent will be installed in the industrial sector, with no residential sector penetration, as residential CHP technologies are still nascent. The overall achievable technical potential is 16 aMW for non-renewable CHP.

Resource Potential

The analysis results indicate a cumulative achievable technical potential of 146 aMW from all CHP technologies by 2030 (Table 76). As with all other resources, this potential is scaled up to include state- and sector-specific line-loss adders.[60] The largest potential is from industrial biomass (129 aMW) and non-renewable RE applications (11 aMW). An additional 2 aMW is expected to be available through installation of GTs. Table 77 provides the state-by-state breakout, based on the state's proportion of the technical potential.

Table 76. Achievable Technical Potential for CHP (aMW in 2030)

Sector	Industrial Biomass	Anaerobic Digesters	Non-Renewable				Total
			Recip. Engine	GT	Micro-turbine	FC	
Industrial	128.3	0.0	3.9	0.7	0.5	0.6	134.1
Commercial	0.0	0.9	7.2	1.3	1.0	1.1	11.6
Total	**128.3**	**0.9**	**11.0**	**2.1**	**1.5**	**1.7**	**145.6**
% of 2030 System Sales	2.24%	0.02%	0.19%	0.04%	0.03%	0.03%	2.54%

60 From PacifiCorp 2007 Electric Operations Loss Study.

Table 77. Achievable Technical Potential for CHP by State and Technology (aMW in 2030)

Territory	State	Industrial Biomass	Anaerobic Digesters	Non-Renewable				Total
				Recip Engine	GT	Micro-turbine	FC	
Pacific Power	California	1.4	0	0	0	0	0	1.5
	Oregon	40	0.2	2.3	0.4	0.3	0.4	43.6
	Washington	10.1	0.1	0.7	0.1	0.1	0.1	11.2
	Subtotal	51.5	0.3	3	0.5	0.4	0.5	56.2
Rocky Mountain Power	Idaho	34.9	0.2	1	0.2	0.1	0.2	36.6
	Utah	21.1	0.3	4.6	0.9	0.6	0.7	28.2
	Wyoming	21.7	0	2.4	0.4	0.3	0.4	25.2
	Subtotal	77.7	0.5	8	1.5	1	1.3	90
Total		**129.2**	**0.8**	**11**	**2**	**1.4**	**1.8**	**146.2**

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

Levelized Cost

Levelized costs ($/kWh) are given in Table 78 for each technology, calculated using costs given in Table 74, the levelized fuel price,[61] and a nominal discount rate of 7.4 percent. Levelized costs, based on both total resource cost and utility costs, are reported.

Table 78. Levelized Costs for CHP Technologies

Sector	Industrial Biomass	Anaerobic Digesters	Non-Renewable			
			Recip. Engine	GT	Micro-turbine	FC
TRC Levelized Cost ($/kWh)	$0.03	$0.10	$0.12	$0.08	$0.14	$0.15
Utility Levelized Cost ($/kWh)*	$0.01	$0.06	$0.03	$0.01	$0.03	$0.08

* Levelized cost is based on total resource cost for all states except Utah, where it is based on utility cost.

On-Site Solar Results

On-site solar encompasses both energy-efficiency measures using solar energy and solar-electricity generation (rooftop PV). Two solar efficiency measures are analyzed: solar water heaters and solar attic fans, both of which affect a specific end use. Rooftop PV, on the other hand, generates electricity for general building consumption. As on-site solar resources are used to offset annual energy usage, they are considered (like CHP) to be an energy-focused resource.

Solar Efficiency Measures

The principle analysis objective of solar efficiency potential is to obtain reasonable and reliable estimates of long-term opportunities, based on an end-use modeling approach. Solar efficiency resource potential for electricity were analyzed for six residential segments: existing and new construction of single-family, multifamily, and manufactured homes. Solar water heaters potential was also analyzed for commercial segments within each state using more than

[61] The average fuel price over all states was used for Table 76. For the state-by-state analysis, the actual state's fuel price was used.

9,000 kWh per year to heat water. These segments included: lodging, large office, schools, large retail, restaurants, and health.

Solar Water Heaters. Solar water heaters or solar thermal collectors are typically connected to domestic hot water systems for a home or business. This technology helps offset energy required to heat a domestic hot water system. Commonly, these systems are set up so the solar water heater preheats water before it enters the supplemental or conventional water heater. Solar water heaters almost always require some type of supplemental system during cloudy weather and increased demand.

Solar Attic Fan. A solar attic fan is a device used to ventilate attic space for cooling by means of a PV-powered fan. The fan typically operates when the sun shines, using a 10-20 Watt PV module to power a DC motor. The fan cools the attic space, thereby reducing energy required to air condition the living space during hot summer days. Depending on the model, the solar fan exhausts air at 800 to 1,200 CFM.[62] For best results, residences should have soffits or gable vents to allow the fan to generate adequate air flow through the attic space.

Rooftop PV

Rooftop PV systems are weather-dependent, and rely on the sun to generate electricity. This study focuses on renewable-electricity generation potential from rooftop residential and commercial buildings. Typically, PV generation only offsets a portion of the baseline loads and, in most cases, is considered a secondary source of a building’s energy needs. PV electrical generation above the building load is fed into the grid. This depends heavily on the PV system size, and generally occurs for residential and commercial customers when the building is not occupied.

In this study, the three primary PV technologies considered are: 1) mono-crystalline (single crystalline cell); 2) poly-crystalline (multi-crystalline cell); and 3) amorphous thin-film. These three technologies currently dominate the solar market.[63] Efficiencies of these technologies, improving annually, are taken into account in this study. Large PV generation facilities that operate to sell the majority (or all) of their power to the grid and emerging PV technologies are not included in this study.

On-Site Solar Background Data

The primary and secondary resources for installed cost of all on-site solar options are derived from the PacifiCorp’s PV pilot program in Utah (the Solar Incentive Program), the State of Utah’s tax incentive program, the California Public Utilities Commission (CPUC) California Solar Initiative (CSI) program database, the ETO, the U.S. Department of Energy, and other on-line sources. Table 79 shows installed costs and O&M costs per kW as well as the measure life for all three solar technologies.

For residential solar water heaters, the average system size is approximately 4 kW. The average retrofit system cost in Oregon in 2010 (provided by the ETO) is $8,342, and the average retrofit

62 Source: ToolBase Services c/o NAHB Research Center – www.toolbase.org

63 EIA, based on PV cell and module shipments by type, 2005.

system cost in California from 2007–2009 was $6,822.[64] For this analysis, an average cost of $7,500 was used for retrofit systems, and new construction systems were assumed to cost 20 percent less. Commercial and multifamily system sizes are dependent on the segment and state. Retrofit systems were reported to cost $75 to $115 per square foot collector area, with new construction systems costing 20 percent less.[64] Installed costs and O&M costs in Table 79 reflect a weighted average across the commercial, multifamily, and residential sectors.

A typical 10 Watt solar attic fan costs around $540 to install. Our analysis of costs for other programs' PV installations results in average installation costs in 2010 of $8 per Watt for residential systems[65] and $7.50 per Watt for commercial systems[66] (as assumed in this analysis). Remaining consistent with assumptions from PacifiCorp's PV pilot program in Utah, the operational and maintenance (O&M) costs include one inverter replacement over the system's life.[67] We assumed the measure life for a PV system to be 30 years.[68]

These costs are summarized in Table 79. Consistent with other resources, PacifiCorp's administration cost is assumed to be 14 percent of the total program cost. The administrative adder increases with inflation (1.9 percent), but it is assumed capital costs are nominally constant (therefore, decreasing in real terms), based on historical trends.

Table 79. On-Site Solar Technology Costs and Measure Lives

Technology	Installed Costs ($/kW)*	O&M Costs ($/kW)	Measure Life (years)
Solar Water Heating	$1,313	$11	20
Solar Attic Fan	$16,613 $540 per unit	- - -	10
Solar PV	$5,366	$24	30

*After the federal tax incentive.

On-Site Solar Technical Potential

As methodologies differ for calculating potential between solar efficiency measures and solar generation (PV), they are discussed separately.

Solar Efficiency Measures. The technical potential of solar efficiency measures is based on the Class 2 DSM end-use modeling approach, discussed in Chapter 3, which basically developed a

64 http://energycenter.org/index.php/incentive-programs/solar-water-heating/swhpp-documents/cat_view/55-rebate-programs/172-csi-thermal-program/321-cpuc-documents

65 The average residential system was assumed to be 3 kW, based on the average system size in the Utah State Energy Program. The average system cost for 2 to 5 kW systems that applied to the Utah Solar Energy Program in 2010 was $7.98 per Watt.

66 The average commercial system was assumed to be 20 kW, based on the average size in the Utah State Energy Program. The average system cost for 10 to 30 kW systems that applied to the Utah Solar Energy Program in 2010 was $9.20; however, the average system cost for the same size range in the CSI program was $6.60. Because larger systems generally cost less per Watt than smaller systems, $7.50 was used in the analysis.

67 Current typical module warranties are for 10 to 15 years. Solarbuzz reported inverter costs in July 2010 as $0.715 per Watt. http://www.solarbuzz.com/Inverterprices.htm

68 Current typical module warranties are for 25 years; so a 30-year system life was used. Additionally, the National Renewable Energy Laboratory's Solar Advisor Model assumes a 30-year system life.

baseline end-use forecast and an alternative forecast with energy efficiency. The difference between the two forecasts determines the technical potential. The alternative end-use forecast includes assumptions of the technical feasibility of both solar water heaters and solar attic fans, accounting for orientation and shading restrictions, installation constraints, and compatibility factors. Technical feasibility factors for solar water heaters and solar attic fans are 15 percent and 25 percent, respectively.

Rooftop PV. Analysis of this technical potential is based only on rooftop applications. This provides a conservative estimate as other applications, such as ground or pole mounted PV, awnings, and car ports are not considered. This estimate of the technical potential considers the physical limitations due to roof area, shading, orientation, and expected building growth. Each input will be described in detail below, with details available in Volume II, Appendix D.

Existing Stock and Forecasting. Available square footage of roof area is based on PacifiCorp's existing stock and the Energy Decisions Survey. The load forecast is used to estimate growth in the building stock.

PV Commercial Assumptions. The following assumptions are comparable to and consistent with other studies:

- Commercial buildings install their systems at a 30° tilt.
- Thirty percent of all roofs are unavailable (20 percent due to obstructions and equipment, 10 percent space lost due shading from the equipment).
- Urban structures have an additional 10 percent reduction in available space due to shading by other surrounding buildings; the urban/rural split is designated by zip code.
- All building types are equally distributed across all zip codes within a state.

These factors together determined a weighted total available roof space for each state.

PV Residential Assumptions. The following assumptions are based on field experience and remain consistent with other studies:

- Single-family and manufactured households install their systems at a 37° tilt.
- Multifamily buildings install their systems at a 30° tilt.
- Twenty-five percent of roofs are south facing.
- Eighty-one percent of the roof area is unavailable due to shading.
- Rural homes have an additional reduction in shading from the increase of surrounding trees; the urban/rural split is designated by zip code.
- All building types are equally distributed across all zip codes.

These factors together determined a weighted total available roof space for each state.

PV Power Density Assumptions. PV cell technology evolves over time, and efficiency continually improves. According to the U.S. DOE, cell efficiency is projected to improve at an average rate of roughly 2.1 percent a year across all three classes of technologies. This assumption is comparable with other studies. Conversely, there is a performance degradation of approximately 1 percent efficiency per year. Both these assumptions were included in this analysis.

This analysis also takes into account market shares of competing solar cell technologies: mono-crystalline, poly-crystalline, and amorphous ‘thin-film,’ from which a weighted average was calculated to determine an overall efficiency. In addition, it is important to account for the space between modules needed for racking materials and installation requirements for the entire array, increasing the overall footprint. To adjust for this, the power density (W/sq.ft.) is reduced by 25 percent to give the total system array efficiency. This result is applied to the projected increase in cell efficiency to determine the power density annually.

The system power density, multiplied by the useable square footage for each building type, results in the total nameplate capacity (kW), or the total DC kW installed.

PV Watts Performance Calculator. The PV Watts performance calculator, developed by the National Renewable Energy Laboratory, was used to determine the capacity factor for each state. The amount of solar insolation determines the performance potential for each region. Weather stations were chosen equivalent to those used in the 2007 Assessment. The main assumption from PV Watts is the DC to AC de-rate factor of 84 percent. All commercial and multifamily buildings are fixed with a 30° array tilt, while single-family and manufactured homes are fixed at a 37° tilt. The end result produced capacity factors for each state, as shown in Table 80.

Table 80. Solar Annual Capacity Factors by State

	Pacific Power			Rocky Mountain Power		
	California	Oregon	Washington	Idaho	Utah	Wyoming
Capacity Factors	0.16	0.16	0.16	0.17	0.18	0.19

The technical potential for on-site solar is 4,754 aMW, primarily from rooftop PV, where the solar-efficiency measures component is 25 aMW. Table 81 shows technical potential by state in the year 2030. It should be noted, for the solar efficiency measures, the technical potential takes into account only electric-related end uses. For example, in the case of solar water heaters, each state has different fuel shares associated with water heating (natural gas or electric). This drives the potential down in some states, such as Utah, where the large majority of domestic hot water heating is by natural gas. In the case of solar attic fans, the only end use affected is central air conditioning. Utah has the largest residential population and cooling load requirement, resulting in the highest technical potential.

Table 81. On-Site Solar Technical Potential by State (aMW in 2030)

Resource	Pacific Power				Rocky Mountain Power				Total
	CA	OR	WA	Subtotal	ID	UT	WY	Subtotal	
Solar PV	64.4	1,172.8	259.9	1497.1	170.5	2,664.1	396.8	3231.4	4,728.6
Solar Water Heater	1.3	10.3	3.7	15.3	2	6.7	1.9	10.6	25.9
Solar Attic Fans	0	0.4	0.1	0.5	0	1.1	0	1.1	1.6
Total	**65.8**	**1,183.5**	**263.7**	**1512.9**	**172.6**	**2,671.9**	**398.8**	**3243.1**	**4,756.2**

Note: Results may not sum to total due to rounding

On-Site Solar Achievable Technical Potential

Solar Efficiency Measures. The achievable technical potential for solar water heaters and solar attic fans was determined similarly to the Class 2 Measures, where a ramp rate was selected. For these two technologies, the Emerging Technology Slow rate was used, which was the slowest rate that can be selected in the model.

Rooftop PV. The achievable technical potential for PV was based upon solar programs from around the country. The same sources from the 2007 Assessment were used to determine the adoption rate of implementing PV installations within their region, as the solar programs present in PacifiCorp's service territory are still young. These sources included: New Jersey's Clean Energy Program™; the Connecticut Clean Energy Fund; the ETO; Florida Energy Office's Solar Energy Systems Incentives Program; Massachusetts Technology Collaborative's Small Renewables Initiative; and California Energy Commission's Renewable Energy Program with San Diego Gas & Electric.[69]

The success of a program is, in part, dependent on current incentives available. Incentives can be provided by one or more of the following: federal tax incentives, state tax incentives, utility buy-downs, production-based incentives, and other rebates. Volume II, Appendix D lists several state programs from around the country offering PV incentives.[70] Incentives have become critical in promoting and creating a successful PV program. Depending on the type and size of an incentive, it can affect the adoption rate. In most instances, the total incentive is roughly 50 percent of the installed cost for the residential market and 75 percent for the commercial sector. The achievable technical potential was based on existing programs implementing these levels of incentives, and was calculated from their adoption rates. The resulting achievable technical potential is less than 1 percent (average of 0.17 percent) of the technical potential.

The resulting achievable technical potential percentage is not appropriate to apply to all states evenly, since each has varying degrees of acceptance and political climate. Across PacifiCorp's territory, each state's adoption rate depends heavily on the existence of current programs, "green" culture, understanding of technology and meteorological considerations as well as other economic factors. With all of these considerations, Oregon and Utah have the highest likelihood of succeeding in high adoption rates, while Idaho and Wyoming are less likely to achieve high adoption rates over the next 10 years.

For all solar technologies, the achievable technical potential is 23 aMW, with most potential (13.3 aMW) from solar water heaters. The state-by-state breakout, based on the state's proportion of the technical potential, is shown in Table 82.

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69 "Technical Potential for Rooftop Photovoltaic in the San Diego Region," by Scott Anders of the Energy Policy Initiatives Center, University of San Diego School of Law, and Tom Bialek of San Diego Gas & Electric, 2005.

70 Database of State Incentives for Renewables and Energy Efficiency; www.dsireusa.org.

Table 82. On-Site Solar Achievable Technical Potential by State (aMW in 2030)

	Pacific Power				Rocky Mountain Power				Total
	CA	OR	WA	Subtotal	ID	UT	WY	Subtotal	
Solar PVs	0.08	3.37	0.34	3.79	0.18	3.85	0.43	4.46	8.24
Solar Water Heater	1.14	8.7	3.15	12.99	1.71	5.66	1.64	9.01	22
Solar Attic Fans	0.01	0.37	0.07	0.45	0.01	0.91	0.02	0.94	1.4
Total	**1.23**	**12.44**	**3.55**	**17.23**	**1.9**	**10.42**	**2.09**	**14.41**	**31.64**

Levelized Costs

The levelized costs for on-site solar measures are listed in Table 83. The TRC levelized costs vary from state to state because of differences in solar resource availability in each state. Utah requires the Utility Cost Test; so the utility levelized cost is reported for Utah, but was not calculated for the other states.

Table 83. On-Site Solar Levelized Costs ($/kWh) by State*

	Pacific Power			Rocky Mountain Power		
	California	Oregon	Washington	Idaho	Utah	Wyoming
Solar PVs	$0.37	$0.37	$0.37	$0.35	$0.14	$0.31
Solar Water Heater	$0.27	$0.23	$0.27	$0.25	$0.13	$0.23
Solar Attic Fan	$1.73	$1.73	$1.72	$1.62	$0.22	$1.43

* Levelized cost is based on total resource cost for all states except Utah, where it is based on utility cost.