PacifiCorp Demand-Side Resource Potential Assessment for 2015-2034

Volume 3: Class 1 and 3 DSM Analysis

Applied Energy Group
500 Ygnacio Valley Road
Suite 450
Walnut Creek, CA 94596
925.482.2000
www.appliedenergygroup.com

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PacifiCorp

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This report was prepared by:

Applied Energy Group
500 Ygnacio Valley Blvd., Suite 450
Walnut Creek, CA 94596

I. Rohmund, Project Director
D. Costenaro, Project Manager
D. Ghosh
C. Carrera

Subcontractor:

The Brattle Group
A. Faruqui
R. Hledik
W. Davis

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INTRODUCTION

In 2013, PacifiCorp commissioned Applied Energy Group, with subcontractor The Brattle Group, to conduct this Demand-Side Resource Potential Assessment. This study provides estimates of the potential for electric demand-side management (DSM) resources in PacifiCorp's six-state service territory,[1] including supply curves, for the 20-year planning horizon of 2015–2034 to inform the development of PacifiCorp's 2015 Integrated Resource Plan (IRP) and satisfy state-specific requirements associated with forecasting and DSM resource acquisition.

Since 1989, PacifiCorp has developed biennial Integrated Resource Plans (IRPs) to identify an optimal mix of resources that balance considerations of cost, risk, uncertainty, supply reliability/deliverability, and long-run public policy goals. The optimization process accounts for capital, energy, and ongoing operation costs as well as the risk profiles of various resource alternatives, including: traditional generation and market purchases, renewable generation, and DSM resources such as energy efficiency, and capacity-focused resources i.e. demand response and direct load control. Since the 2008 IRP, DSM resources have competed directly against supply-side options, allowing the IRP model to selectively choose the right mix of resources to meet the needs of PacifiCorp's customers while minimizing cost and risk. Thus, this study does not assess cost-effectiveness.

This study primarily seeks to develop reliable estimates of the magnitude, timing, and costs of DSM resources likely available to PacifiCorp over the 20-year planning horizon mentioned above. The study focuses on resources assumed achievable during the planning horizon, recognizing known market dynamics that may hinder resource acquisition. Study results will be incorporated into PacifiCorp's 2015 IRP and subsequent DSM planning and program development efforts. This study serves as an update of similar studies completed in 2007, 2011, and 2013.[2]

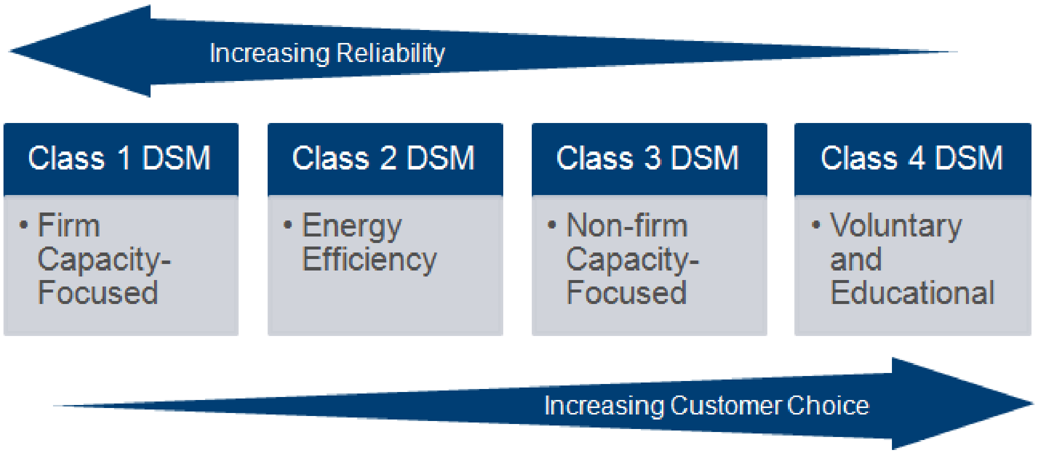
DSM Resource Classes

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

From a system-planning perspective, Class 1 and Class 2 DSM resources (particularly Class 1 direct load control programs) are considered the most reliable, as once a customer elects to participate in a Class 1 DSM program, the resource is under the utility's control and can be dispatched as needed. Similarly, when a customer invests in a home or business efficiency improvement, the savings are locked in as a result of the installation and will occur during normal operation of the end use. In contrast, behavioral savings, resulting from energy education and awareness actions included in Class 4 DSM, tend to be the least reliable, as savings will vary due to greater customer control and the need for customers to take specific and consistent actions to lower their usage during peak periods.

[1] Class 2 analysis for Oregon is excluded from this report because it is assessed statewide by the Energy Trust of Oregon.
[2] The previous potential studies can be found at: http://www.pacificorp.com/es/dsm.html

Figure 1-1 Characteristics of DSM Resource Classes



PacifiCorp commissioned this DSM resource potential assessment to inform the Company's biennial IRP planning process, to satisfy other state-specific DSM planning requirements, and to assist PacifiCorp in revising designs of existing DSM programs and in developing new programs. The study's scope encompasses multi-sector assessments of long-term potential for DSM resources in PacifiCorp's Pacific Power (California, Oregon, and Washington) and Rocky Mountain Power (Idaho, Utah, and Wyoming) service territories. This study excludes an assessment of Oregon's Class 2 DSM potential, as this potential has been captured in assessment work conducted by the Energy Trust of Oregon[3], which provides energy-efficiency potential in Oregon to PacifiCorp for resource planning purposes. This study does not include assessments of Class 4 DSM resources. Unless otherwise noted, all results presented in this report represent savings at generation; that is, savings at the customer meter have been grossed up to account for line losses.

Interactions Between Resources

This assessment includes multiple resources, actions, and interventions that would interact with each other if implemented in parallel. As explained in more detail later in this report, we take specific actions to account for these interactions to avoid double-counting the available potential. The interactive effects that we have analyzed occur within the major analysis sections; meaning that the interactions of energy efficiency resources are considered across all Class 2 DSM resources. Likewise, the analysis of capacity-focused Class 1 and 3 DSM resources explicitly considers interactions. It should be noted, however, that this study does not attempt to quantify potential interactions between energy-focused and capacity-focused resources. Though an important factor to recognize, this study did not attempt to quantify such interactions due to uncertainties regarding resources likely to be found economic and pursued.

[3] The Energy Trust of Oregon's 2014 Energy Efficiency Resource Assessment Report can be found here: http://energytrust.org/library/reports/Energy_Efficiency__Resource_Assessment_Report.pdf

Report Organization

This report is presented in five volumes as outlined below. This document is **Volume 3, Class 1 and 3 DSM Analysis**.

- Volume 1, Executive Summary
- Volume 2, Class 2 DSM Analysis
- Volume 3, Class 1 and 3 DSM Analysis
- Volume 4, Class 2 DSM Analysis APPENDIX
- Volume 5, Class 1 and 3 DSM Analysis APPENDIX

Abbreviations and Acronyms

Throughout the report we use many abbreviations and acronyms. Table 1-1 provides a list of them, along with an explanation.

Table 1-1 Explanation of Abbreviations and Acronyms

Acronym	Explanation
aMW	Average Megawatt, obtained by dividing Megawatt-hours by 8760
AMI	Advanced Metering Infrastructure
Auto-DR	Automated Demand Response
C&I	Commercial and Industrial
CAC	Central Air Conditioning
Council	Northwest Power and Conservation Council
CPP	Critical Peak Pricing
DHW	Domestic Hot Water
DEER	California's Database for Energy Efficient Resources
DSM	Demand-Side Management
DLC	Direct Load Control
EE	Energy Efficiency
EIA	Energy Information Administration
EUL	Effective Useful Life
EUI	Energy Usage Intensity
FERC	Federal Energy Regulatory Commission
HVAC	Heating Ventilation and Air Conditioning
IBR	Inclining Block Rate
IOU	Investor Owned Utility
NPV	Net Present Value
O&M	Operations and Maintenance
PCT	Programmable Communicating Thermostat
RTF	Regional Technical Forum
RTP	Real-time Pricing
TOU	Time-of-Use
TRC	Total Resource Cost
UCT	Utility Cost Test
UEC	Unit Energy Consumption
UES	Unit Energy Savings
WH	Water Heater

ANALYSIS APPROACH

Capacity-focused products are called upon to provide load reduction by shedding or shifting customer loads to help fill a temporary resource need and/or balance system loads during high use periods. For this potentials analysis, capacity-focused DSM resources have been defined based on PacifiCorp's characterization of two distinct classes; Class 1, or firm/dispatchable, and Class 3, or non-firm/non-dispatchable resources:

- **Class 1 DSM: Resources from fully dispatchable or scheduled firm capacity product offerings/programs-** Class 1 DSM programs are those for which capacity savings occur as a result of active Company control or advanced scheduling. Once customers agree to participate in Class 1 DSM program, the timing and persistence of the load reduction is involuntary on their part within the agreed upon limits and parameters of the program. In most cases, loads are shifted rather than avoided. Examples include residential and small commercial central air conditioner load control programs ("Cool Keeper") that are dispatchable in nature and irrigation load management and interruptible or curtailment programs (which may be dispatchable or scheduled firm, depending on the particular program design and/or event noticing requirements).
- **Class 3 DSM: Resources from price responsive energy and capacity product offerings/programs** – Class 3 DSM programs seek to achieve short-duration (hour by hour) energy and capacity savings from actions taken by customers voluntarily, based on a financial incentive or signal. Savings are measured at a customer-by-customer level (via metering and/or metering data analysis against baselines), and customers are compensated in accordance with a program's pricing parameters. As a result of their voluntary nature, savings are less predictable, making them less suitable to be relied upon as a firm planning resource, at least until such time that their size and customer behavior profile provide sufficient information for a reliable diversity result for modeling and planning purposes. Savings typically only endure for the duration of the incentive offering. Program examples include large customer energy bid programs ("Energy Exchange"), time-of-use pricing plans, critical peak pricing plans, and inverted block tariff designs. Although the impacts of such programs may not be explicitly considered in the resource planning process, current programs are captured in the historic loads that form the basis for the long-term load growth patterns and forecasts used in the development of the IRP

Definition of Potential

To assess the various levels of resource potential available in the PacifiCorp service territory, we investigated the following cases:

- **Class 1 DSM Technical Potential** - This case assumes 100% participation of eligible customers in all relevant Class 1 DSM programs included in the study. This case is a theoretical construct, and is only provided in the appendix for informational purposes. The main body of the report focuses on the remaining cases.
- **Class 1 DSM Market potential, with Class 3 Opt-in potential** - This case assumes achievable market participation rates for eligible customers in Class 1 DSM options. Dynamic pricing options under Class 3 DSM are assumed to be offered on a voluntary, opt-in basis, to eligible customers.
- **Class 1 DSM Market potential, with Class 3 Opt-out potential** - This assumes achievable market participation rates for eligible customers in Class 1 DSM options. Dynamic pricing options under Class 3 DSM are assumed to be offered on a default, opt-out basis to customers.

Treatment of Resource Interactions

As mentioned in the introduction, Class 1 and Class 3 DSM programs may rely on similar customer classes and end-use loads to realize impacts during peak periods. For example, C&I customers enrolled in the Curtailable Agreements program are unlikely to have sufficient load available to further reduce loads through a Critical Peak Pricing (CPP) program, given the likelihood of both programs targeting the same peak load hours.

To provide PacifiCorp with an accurate assessment of the impacts and economics of each individual resource option and to maintain consistency with past methodology for facilitated comparative analyses, this report focuses primarily on the program options on a standalone basis. The standalone analysis does not consider interactions between Class 1 and 3 DSM resources. <u>Therefore, the potential and cost of programs for Class 1 DSM presented in the main body of the report, are not additive to those for Class 3 DSM.</u> However, within the same resource class, the standalone analysis considers interactions among different program options that are, or may become, available. For example, for Class 3 DSM, the analysis assumes that if customers are offered a portfolio of rates, they would transition from Time Of Use (TOU) to CPP once a CPP product becomes available. For Class 1 DSM, there is no overlap in eligible customers among the options considered in our analysis, therefore the standalone analysis for Class 1 DSM represents potential for each individual resource on an independent basis.

Documentation and results of the analysis including interactions between Class 1 and 3 DSM resources are available in the appendix (Volume 5), where we discuss the program participation hierarchy used to stack impacts and define the interactions.

Overview of Analysis Steps

The major steps used to perform the Class 1 and 3 DSM resource potential assessment are listed below. Throughout the remainder of this chapter, we describe these analysis steps in more detail.

1. Market Characterization
    - Segment the market into customer classes for purposes of the Class 1 and Class 3 DSM analyses
    - Establish baseline peak demand and customer forecasts by state
2. Definition of relevant Class 1 and 3 DSM program options by customer class
3. Development of Program Assumptions
    - Participation rates
    - Peak demand impacts
    - Program costs
4. Estimation of Class 1 and 3 DSM potential
5. Calculation of levelized cost by program option and state

Market Characterization

Segmentation of Customers for Class 1 and 3 DSM Analysis

For this study, we segmented PacifiCorp's customers as follows:

- By state
- By sector: residential, commercial and industrial (C&I), and irrigation
- By customer class. C&I customers are further segmented into customer classes based on maximum demand, typically following utility rate schedules. A uniform segmentation approach is applied across all six states. Note that the breakpoint of 200 kW is included to

create a minimum threshold for customers that are typically recruited for third-party delivered capacity reduction programs. Extremely large customers, who are served through special contracts, are outside the scope of this analysis as they are currently providing load reduction through specialized agreements and are already accounted for in PacifiCorp's existing resource base.

Table 2-1 summarizes the overall market segmentation approach for the study.

Table 2-1 Analysis Segmentation

Market Dimension	Segmentation Variable	Description
Dimension 1	State	UT, OR, WY, WA, ID, CA
Dimension 2	Sector	Residential, Commercial and Industrial (C&I), and Irrigation
Dimension 3	Customer Class	Residential: all customers
		C&I: by maximum peak demand Small C&I: <=30 kW Medium C&I: >30 kW and <=200 kW Large C&I: >200 kW and <=1,000 kW Extra Large C&I: >1,000 kW
		Irrigation: all customers

System and Coincident Peak Forecasts by State

The next step in market characterization is to define the peak load forecast for the study timeframe. This is done at the PacifiCorp system level, and also by jurisdiction. The jurisdictional peak values represent a state's projected demand during the time of PacifiCorp system peak.

Figure 2-1 and Table 2-2 show the system coincident peak forecast values by state, developed based on load forecast data provided by PacifiCorp.

Figure 2-1 System Coincident Peak Forecast by State

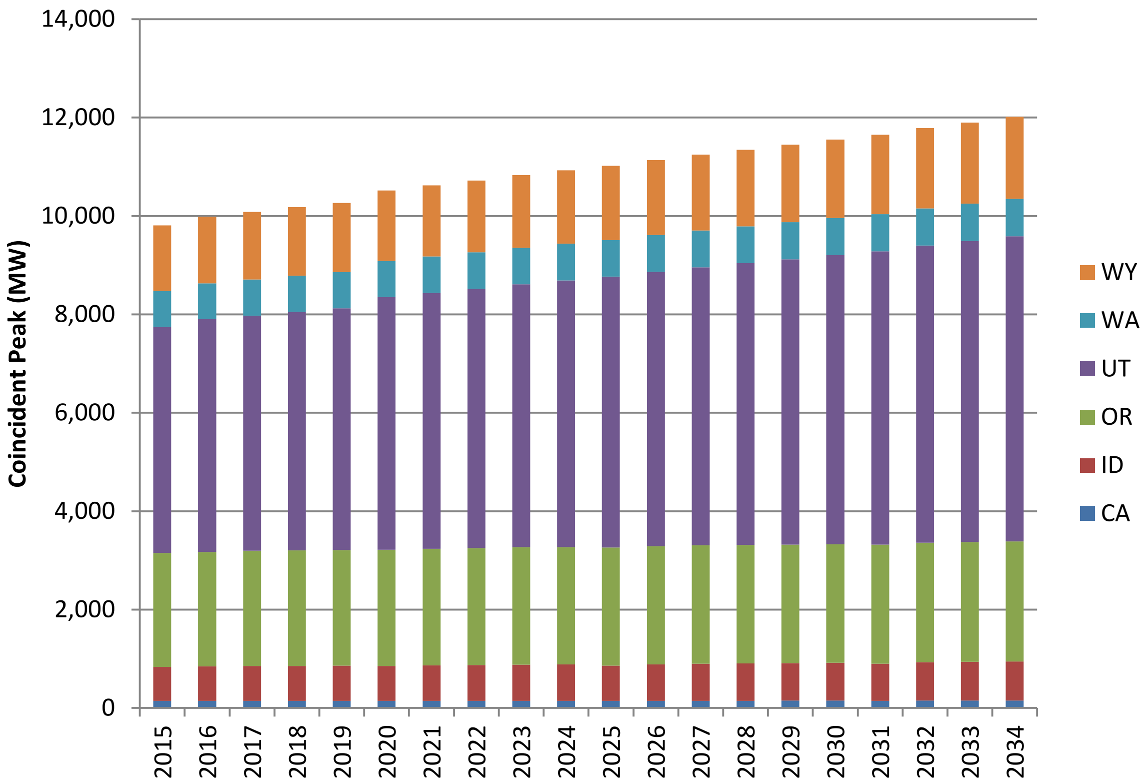


Table 2-2 System Coincident Peak Forecast by State (MW @ Generation)

State	2015	2020	2025	2030	2034	Avg. annual growth rate (2015-2034)
CA	146	146	146	151	153	0.2%
ID	688	710	719	768	793	0.7%
OR	2,320	2,363	2,397	2,412	2,442	0.3%
UT	4,594	5,132	5,503	5,873	6,200	1.6%
WA	731	739	746	753	759	0.2%
WY	1,333	1,427	1,508	1,595	1,668	1.2%
System	**9,812**	**10,516**	**11,020**	**11,552**	**12,014**	**1.1%**

Definition of Class 1 and 3 DSM Options

The next step in the analysis is to characterize the Class 1 and 3 DSM products considered in the analysis. Each product is described briefly below.

Class 1 DSM Resources

Table 2-3 lists the Class 1 DSM options considered in the study, followed by a brief discussion of the options selected.

Table 2-3 Class 1 DSM Products Included in the Study

Class 1 DSM Option	Eligible Customer Classes	Mechanism	Currently Offered by PacifiCorp?	Considered in Previous CPA?
Direct Load Control (DLC) of air conditioners (A/C) and domestic hot water heaters (DHW)	Residential , Small C&I	Direct load control switch installed on customer's equipment	Yes, AC offered in UT	Yes
	Medium C&I	Direct load control switch installed on customer's equipment	No	No
Curtailable Agreements	Large C&I, Extra-large C&I	Customers enact their customized, mandatory curtailment plan. Penalties apply for non-performance.	No	Yes
Irrigation Load Control	Irrigation	Automated pump controllers	Yes, in ID and UT	Yes

The description of options below includes a summary of the basic features of each program type and the key assumptions used for potential and levelized cost calculations. The development of these assumptions are based on findings from research and review of available information on the topic, including national program survey databases, evaluation studies, program reports, regulatory filings, and interviews with program managers. A detailed description of the basis for developing these assumptions is provided in the Volume 5 Appendix to this report.

Direct Load Control (DLC)

PacifiCorp currently administers a direct load control program, the "Cool Keeper" program, for residential and small commercial customers in Utah. The air conditioning unit at a customer premise is controlled using a two-way communicating direct load control device, which cycles the unit on and off during an event. The Utah program currently has 115 MW of load reduction potential from participating residential and C&I customers.[4]

In our analysis of the Utah air conditioner load control program we assume continuation of the current program configuration (control of central air conditioners and heat pumps only) when looking at the incremental potential for expansion. For other jurisdictions, where such programs are yet to be established, the program offering is expanded to include eligible electric water heaters in residential and small C&I customer premises with participating cooling equipment. For medium C&I customers, we assume control of cooling equipment only. Table 2-4 presents the DLC offering basics.

Table 2-4 Residential and C&I DLC Program Basics

Program Element	Assumption
Eligible Customer Classes	Residential, Small C&I, Medium C&I
Controlled end uses	Cooling equipment, including Central Air Conditioners and Heat Pumps Electric Water Heating (for all states, except Utah)
Applicable Hours	Top 50 summer system hours

[4] Current realizable load reduction potential information provided by PacifiCorp. These potential estimates are at the generator.

Table 2-5 presents key participation, impact and cost assumptions by customer class and state used to develop potential and levelized cost estimates. Due to longstanding market involvement and experience, DLC assumptions for Utah have been calibrated to existing program information. For all other states, DLC participation is assumed to ramp up following an “S-shaped” diffusion curve over a five year timeframe. The rate of participation growth accelerates over the first half of the 5-year period, and then slows over the second half. For all states other than Utah, to account for the necessary time to secure regulatory approvals, engage a vendor, and launch the offerings (if selected by the 2015 IRP), we assume program ramp-up and participant recruitment would begin in 2017. In Utah, the existing program is assumed to ramp up beginning in 2016 if selected by the 2015 IRP, to allow time to recruit new participants.”

Table 2-5 Residential and C&I DLC Program: Planning Assumptions

Data Item	Unit	Value
Participation Assumptions[5]		
Residential customer participation	Steady-state Participation (as % of eligible customers)	23% for UT, 15% for all other states;
C&I customer participation	Steady-state Participation (as % of eligible customers)	For UT: Small C&I- 2.9%, Medium C&I- 3.9% For other states: Small and Medium C&I- 3%
Program ramp up period	Years	Five
Impact Assumptions[6]		
Residential customer per participant impact for cooling	Average kW reduction per participant @ meter	CA- 0.66, ID- 0.46, OR- 0.43, UT- 0.97, WA- 0.53, WY- 0.53
Residential customer per participant impact for water heating		0.26 for all states
C&I customer per participant impact for cooling	Average kW reduction per participant @ meter	Small C&I CA- 1.7, ID- 1.2, OR- 1.1, UT- 2.5, WA- 1.3, WY- 1.3 Medium C&I CA- 18.8, ID- 13.2, OR- 12.3, UT- 27.8, WA- 15.2, WY- 15.2
C&I customer per participant impact for water heating		Small C&I- 0.33 for all states
Cost Assumptions[7]		
Annual Program Administration Cost	$/year	$300,000
Annual Marketing and Recruitment Costs	$/new participant	$50-60 for residential, $62-75 for small C&I, $75-90 for medium C&I
Equipment capital and installation cost for AC switch	$/new participant	$215 for residential, $360 for small C&I, $1,120 for medium C&I
Equipment capital and installation cost for WH switch	$/new participant	$300 for residential and small C&I
Annual O&M cost	$/participant/year	$11 for residential, $18 for small C&I, $56 for medium C&I
Per participant annual incentive (AC)	$/participant/year	$21 for residential, $38 for small C&I, $128 for medium C&I
Per participant annual incentive (WH)	$/participant/year	$8 for residential and small C&I

[5] Detailed documentation of participation assumptions is presented in Volume 5, Section A of the report.
[6] Detailed documentation of impact assumptions is presented in Volume 5, Section B of the report.
[7] Detailed documentation of cost assumptions is presented in Volume 5, Section C of the report.

Curtailable Agreements

Under this program option, it is assumed that participating customers will agree to reduce demand by a specific amount or curtail their consumption to a pre-specified level at the time of an event. In return, they receive a fixed incentive payment in the form of capacity credits or reservation payments (typically expressed as $/kW-month or $/kW-year). Customers are paid to be on call even though actual load curtailments may not occur. The amount of the capacity payment typically varies with the load commitment level. In addition to the fixed capacity payment, participants typically receive a payment for energy reduction during events. Because it is a firm, contractual arrangement for a specific level of load reduction, enrolled loads represent a firm resource and can be counted toward installed capacity requirements. Penalties are assessed for under-performance or non-performance. Events may be called on a day-of or day-ahead basis as conditions warrant.

This option is typically delivered by load aggregators, and is most attractive for customers with maximum demand greater than 200 kW and flexibility in their operations. Industry experience indicates that aggregation of customers with smaller sized loads is less attractive financially due to lower economies of scale. For the potentials analysis, we assume that this option will be offered to large and extra-large C&I customers on standard retail rates. . Customers with 24x7 operations, continuous processes, or with obligations to continue providing service (such as schools and hospitals) are not often good candidates for this option. The analysis assumes that customers with standby generators would be eligible to participate and takes into account implications of EPA's RICE/NESHAP regulations that are likely to constrain operation of certain backup generators installed before 2006.[8] A participation rate deflator is applied to factor in lowered participation levels on account of these regulations. These assumptions are described in Volume 5 of the report under Curtailment Program participation rate development. Table 2-6 presents Curtailable Agreements program basics.

Table 2-6 Curtailable Agreements Program Basics

Program Element	Assumption
Eligible Customer Classes	Large C&I, Extra Large C&I
Controlled end uses	Any, depending on the business type
Applicable Hours	Top 30 summer system hours

Table 2-7 presents key participation, impact and cost assumptions used for potential and levelized cost calculations. Detailed documentation of the basis for developing participation estimates, program impacts, and cost assumptions is presented in Volume 5 of this report. For the Curtailable Agreements option, which is typically delivered by third parties, participation is assumed to ramp up linearly over a three year timeframe. Since this is a new program, we assume program ramp-up and participant recruitment begins in 2017 to allow for vendor selection, contracting and regulatory approvals.

[8] The National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines ("RICE NESHAP") limits emissions of toxic air pollutants from stationary reciprocating internal combustion engines. More information available at- http://www.epa.gov/ttn/atw/icengines/docs/20130919complianceinfo.pdf

Table 2-7 Curtailable Agreements Program: Planning Assumptions

Data Item	Unit	Value
Participation Assumptions[9]		
Large C&I customer participation (applicable to all 6 states)	Steady-state Participation (as % of eligible customers)	22%
Extra-large C&I customer participation (applicable to all 6 states)		21%
Program ramp up period	Years	3
Impact Assumptions[10]		
Per-participant load reduction	% of participant's load	21%
Cost Assumptions[11]		
Program Delivery Cost (administered by third party)	$/kW-year	$70
Internal utility administration cost	$/kW-year	$0.70
Payment for energy reduction during event hours	$/kWh	$0.11

Irrigation Load Control

This program option targets irrigation loads by shutting off or scheduling off irrigation pumps during times of peak demand. PacifiCorp currently operates this program in Idaho and Utah, with actual load reductions of roughly 170 MW and 20 MW, respectively. This program is currently being administered by a third party in both jurisdictions. In our analysis, we assume continuation of the current program offering in Idaho and Utah, and estimate potential and associated costs for new program offerings in the other states.

Table 2-8 presents Irrigation Load Control program basics. Table 2-9 presents key participation, impact and cost assumptions used for potential and levelized cost calculations. The detailed documentation describing the basis for developing these assumptions is presented in Volume 5 of this report. For Idaho and Utah, assumptions have been calibrated to existing program information. For all other states, participation is assumed to ramp up following an "S-shaped" diffusion curve over a five year timeframe. Since this is a new program for all states other than Idaho and Utah, we assume program ramp-up and participant recruitment begins in 2017 to allow for vendor selection, contracting and regulatory approvals.

Table 2-8 Irrigation Load Control Program Basics

Program Element	Assumption
Eligible Customer Classes	Irrigation customers with at least 25hp irrigation pumps (92% of load in CA, 100% of load in ID, 78% of load in OR, 100% of load in UT, 75% of load in WA, 82% of load in WY).
Controlled end uses	Irrigation pumps
Applicable Hours	Top 52 summer system hours

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[9] Detailed documentation of participation assumptions is presented in Volume 5, Section A of the report.
[10] Detailed documentation of impact assumptions is presented in Volume 5, Section B of the report.
[11] Detailed documentation of cost assumptions is presented in Volume 5, Section C of the report. Cost assumptions are based on kW and kWh impacts at site.

Table 2-9 Irrigation Load Control Program: Planning Assumptions

Data Item	Unit	Value
Participation Assumptions[12]		
Irrigation load participation	Steady-state Participation (as % of eligible load)	CA- 15%; ID- 74%; OR-15%; UT- 52%; WA-15%; WY- 15%;
Program ramp up period	Years	5
Impact Assumptions[13]		
Per participant load reduction	% of participant's load	100%
Cost Assumptions[14]		
Program Delivery Cost (administered by third party)	$/kW-year	$47.5 for ID and UT; $61.75 for remaining states;
Internal utility administration cost	$/kW-year	$4.75 for ID and UT; $6.17 for remaining states;

Class 1 DSM Options Considered, but Qualitatively Screened Out

In addition to the three Class 1 DSM options included in the study, we considered three options that were qualitatively screened out of the potentials analysis. A listing of these options and the rationale for ultimately not including each is below.

- **Smart Appliance DLC**. A home area network of communicating white goods appliances is a relatively unproven and emerging technology at this time. Existing research on impacts by appliance type shows relatively low potential for load reduction. Additionally, the technology investment costs are likely to be prohibitively high in terms of communication infrastructure costs and device enablement.
- **DR providing ancillary services (Fast DR).** DR resources for providing ancillary services such as frequency regulation or spinning reserves need to be Auto-DR enabled and possess very fast response times, thereby entailing high infrastructure costs. They need to be available 24x7 with a high degree of reliability. Therefore, participation is challenging and likely to be low. Moreover, much of the available potential for this program option would likely come from customers with the appropriate technical infrastructure to enroll in the Curtailable Agreements program. Overall, this option is unlikely to be cost-effective under current system conditions. However, with increasing amounts of renewable resources coming online, the value of flexible resources like Fast DR to integrate and balance them may gain system value in future planning cycles.[15]
- **Thermal Energy Storage**. Thermal energy storage technologies are a relatively mature technology that is worthwhile in some niche applications and climates. PacifiCorp has assessed these systems in the past and found cost and applicability to be unfavorable in their service territory. The underlying technologies have not experienced significant improvements

[12] Detailed documentation of participation assumptions is presented in Volume 5, Section A of the report.
[13] Detailed documentation of impact assumptions is presented in Volume 5, Section B of the report.
[14] Detailed documentation of cost assumptions is presented in Volume 5, Section C of the report. Cost assumptions are based on kW impacts at site.
[15] For additional information, please refer to the study titled "The Role of Demand Response in Integrating Variable Energy Resources", prepared by EnerNOC for the Western Interstate Energy Board; December 2013. available at http://www.westgov.org/sptsc/documents/12-20-13SPSC_EnerNOC.pdf

or price changes in recent years, and AEG's research found they are still not coming into the mainstream.

Class 3 DSM Resources

Class 3 DSM resources include pricing options considered in our analysis and Demand Buyback. Pricing options included in our study are Time of Use (TOU) rates, Critical Peak Pricing (CPP), and Real Time Pricing (RTP).

The analysis in this report focuses on a case where voluntary, "opt-in" pricing options are offered to customers. The study also considers a case in the appendix to this report that assumes a scenario where all customers are placed on the dynamic pricing options by default, and then given an opt-out provision. Please see the appendix for more details on the "opt-out" case.

We assumed that two of these pricing options, CPP and RTP, require an Advanced Metering Infrastructure (AMI) to enable two-way communication between the customer and utility for notification and billing purposes. PacifiCorp does not currently have AMI in any of its service territories, however, to assess the potential for dynamic pricing this study assumes that all territories are AMI-enabled by the end of 2019. Therefore, CPP and RTP are modeled for the years 2020 and beyond. This analysis does not consider the independent business case for AMI, and therefore, no AMI deployment costs have been allocated to dynamic pricing options in the development of levelized costs in this study.

Participation assumptions for pricing options are based on The Brattle Group's extensive review of enrollment in full-scale, time-varying rates being offered in the United States and internationally, as well as findings of recent market research studies. With respect to full scale deployments, the review focused specifically on rate offerings that have been heavily marketed to customers and have achieved significant levels of enrollment. The enrollment estimates are based on data reported to FERC by utilities and competitive retail suppliers and other entities. To provide additional insight, the analysis included survey-based market research studies from other comparable utilities and transferrable jurisdictions designed to gauge customer interest in time-varying rates. The surveys are from a statistically valid sample of respondents representative of all considered customers. Adjustments are made to account for the natural tendency of respondents to overstate their interest. The detailed description of the methodology for developing these rates is provided in the Appendix to this report.

The Class 3 DSM options included in the study are briefly described below, first for residential customers and then for non-residential customers. We also present participation, impact, and cost assumptions used for potential and levelized cost calculations.

Pricing Options for Residential Customers

Table 2-10 lists the Class 3 DSM pricing products analyzed for residential customers in the study. We estimate embedded impacts for the existing Inclining Block Rates (IBRs)[16] and TOU rates currently being offered by PacifiCorp as a parallel analysis in Chapter 3. For forward-looking potential estimation purposes over the 2015-2034 timeframe, only TOU and CPP rates are considered for residential customers. A residential Real Time Pricing (RTP) rate is not considered in the analysis, as RTP rates face implementation challenges for residential customers; it is difficult for residential customers to understand and respond to these rates, and the majority of the benefits can be realized from simpler alternative rates already included in the analysis.

[16] Under Inclining Block Rates (IBRs), the price a customer faces increases as their monthly consumption increases. There are two or three tiers of prices in PacifiCorp's IBRs. These rates are only offered to residential customers.

Table 2-10 Pricing Options for Residential Customers

Class 3 DSM Option	Analysis Approach	Whether Current PacifiCorp Offering	Considered in Previous CPA?
Inclining Block Rate (IBR)	Assess only the embedded impacts of existing IBRs relative to a revenue-equivalent flat rate for all six jurisdictions.	Mandatory for residential customers in all states, except ID (where customers can choose a TOU that is not layered on top of an IBR)	Yes (only existing impacts, no incremental potential considered)
Time-Of-Use (TOU) Rate	In states with existing TOU rates (ID, UT, OR), assess whether modifications to existing rate structures (changes in peak to off peak price ratios, shifting peak time periods) would affect peak demand. Also estimate incremental impacts associated with existing TOU rates relative to flat rates for these states. In states without existing TOU rates (WA, WY, CA), analyze impacts associated with new TOU rates.	Optional TOU rates in ID, UT, and OR	Yes
Critical Peak Pricing (CPP) Rate	Assess impacts associated with a CPP rate offering to all residential customers. Impacts are estimated with both opt-in and opt-out provisions.[17]	No	No

Table 2-11 presents residential TOU and CPP program basics.

Table 2-11 Residential TOU and CPP Program Basics

Program Element	Assumption
Eligible Customer Classes	All residential customers are eligible for TOU and CPP rates
Controlled end uses	Any
Applicable Hours	TOU: Six hours on-peak period each summer weekday CPP: Top 60 summer system hours
Rate structure	TOU: 2:1 on-peak/off-peak price ratio CPP: 6:1 on-peak/off-peak price ratio

[17] We do not estimate impacts for rates with enabling technology due to higher costs associated with that option.

Residential Customer Participation Assumptions in Pricing Options

Table 2-12 presents participation assumptions for residential customers in pricing options with a voluntary, opt-in offering. Our analysis considered simultaneous offering of multiple new rate options as part of a "rates portfolio". In 2015 and 2016, we assume impacts are realized only from existing TOU rates (i.e. no incremental potential), whereas new TOU rates are offered beginning in 2017 to allow for vendor selection, contracting and regulatory approvals. CPP is offered beginning in 2020, after AMI is assumed to be fully deployed. Based on industry market research, when TOU and CPP are both offered simultaneously as opt-in options, customers have a higher preference for CPP as compared to TOU.[18] When CPP is the opt-out option, with TOU as an alternative opt-in option, enrollment rates in CPP are significantly higher.[19] The steady-state enrollment for TOU is assumed to be 10%. The steady-state enrollment level for CPP is assumed to be 20% under the opt-in offer.

Changes in participation levels to reach a steady state are assumed to take place over a 5-year timeframe once the new rates are offered. As described earlier, ramp up to steady-state participation follows an "S-shaped" diffusion curve. Detailed documentation of the basis for developing participation assumptions is presented in Volume 5 of this report.

Table 2-12 Participation Assumptions for Residential Customers in Time Varying Rates (with Opt-in Dynamic Pricing Offer)

Option by State	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024 to 2034
Time of Use (TOU) Rates										
CA, WA, WY	-	-	2.8%	8.4%	19.6%	26.2%	22.6%	15.4%	11.8%	10.0%
UT	0.05%	0.05%	2.8%	8.4%	19.6%	26.2%	22.6%	15.4%	11.8%	10.0%
ID	24.1%	24.1%	24.5%	25.3%	26.8%	26.2%	22.6%	15.4%	11.8%	10.0%
OR	0.3%	0.3%	3.0%	8.6%	19.7%	26.2%	22.6%	15.4%	11.8%	10.0%
Critical Peak Pricing (CPP) Rate										
All states	-	-	-	-	-	2.0%	6.0%	14.0%	18.0%	20.0%

Residential Customer Impact Assumptions in Pricing Options

Residential impact assumptions for Class 3 DSM pricing options are based on The Brattle Group's comprehensive database of time-varying pricing pilots that have been conducted across the U.S. and internationally over the past decade.[20] These pilots have tested over 200 different time-varying rate offerings for residential customers. Table 2-13 presents impact assumptions for residential customers in time varying rates. The peak-to-off-peak price ratio is the key driver of demand response among participants in time-varying rates. A higher price ratio means a stronger price signal and greater bill savings opportunities for participants – on average, participants provide larger peak demand reductions as a result. We surveyed the range of price ratios that have been offered in new time-varying rates over the past decade to establish reasonable assumptions for PacifiCorp. Within the range of values, we chose a moderate 2:1 TOU price ratio to be representative of similar rates that are delivered in regions like PacifiCorp's where energy prices are lower than the national average. Low prices are less frequently modified to create a large spread between the on-peak and off-peak rates, largely due to the fact that such changes for lower rates create the perception of a larger proportional rate shock to customers. Similarly

[18] Market research studies, that have examined the effects of a portfolio rate offering, show that when CPP and TOU are both offered simultaneously as opt-in options, between 1.5 and 3 customers prefer CPP for every customer that prefers TOU.

[19] Market research shows that 10 to 15 customers would remain enrolled in the CPP for every customer that chooses the TOU.

[20] For more information, see Ahmad Faruqui and Sanem Sergici, "Arcturus: International Evidence on Dynamic Pricing," *The Electricity Journal*, August/September 2013.

for CPP, the price ratio assumed for this analysis is 6:1, which is also a more moderate level among other national CPP rates. Impact assumptions presented in Table 2-13 are based on these ratios.[21]

Table 2-13 Impact Assumptions for Residential Customers in Pricing Options

Type of Offer	Customer Class	Option	Data Element	Reduction as % of Peak Load
Opt-in	Residential	Time-Of-Use	Per Customer Impact (%)	6.2%
Opt-in	Residential	Critical Peak Pricing	Per Customer Impact (%)	13.1%

Pricing Options for Non-Residential Customers

Table 2-14 lists the relevant Class 3 DSM pricing options considered in the study for non-residential customers. We have estimated impacts for the existing TOU rates currently being offered by PacifiCorp as a parallel analysis in Chapter 3. For potential estimation purposes over the 2015-2034 timeframe, only TOU, CPP and RTP rates are considered for C&I customers. For irrigation customers, only TOU and CPP rates are considered. RTP is not considered appropriate for irrigation customers.[22]

[21] This potential analysis only considers the CPP offering without enabling technology like a programmable communicating thermostat (PCT). Several residential pilots have shown that adding a PCT to residential CPP rates increases the impact (21.1% vs 13.1%), but our economic analysis found that levelized costs per unit of demand reduced were higher for CPP with enabling technology. Therefore, the CPP-only case was preferentially chosen for purposes of this analysis.

[22] Irrigation customers are likely to experience much lower levels of real time fluctuations in load as compared to C&I customers. In most cases, irrigation load remains flat during specific time periods. Loads are likely to vary by season and time of day, but hourly fluctuations may be practically non-existent. Therefore, RTP would not make sense for irrigation customers. Moreover, irrigation customers are not likely to have the ability or interest in managing their load on an hourly basis in response to real-time price fluctuations. Large industrial customers have the sophistication and financial incentive to do this, but agricultural customers don't have the right business model for RTP to be a viable proposition.

Table 2-14 Pricing Options for Non-Residential Customers

Class 3 DSM Option	Eligible Customer Classes	Analysis Approach	Current PacifiCorp offering?	Considered in Previous CPA?
Time-Of-Use (TOU) Rate	All C&I	For states and customer classes with existing TOU rates, assess whether modifications to existing rate structures (changes in peak to off-peak price ratios, shifting peak time periods) could potentially yield higher impacts. We also assess incremental impacts associated with existing TOU rates relative to flat rates. For states and customer classes without existing TOU rates, study analyzes impacts associated with new TOU rates.	Offered on voluntary or mandatory basis depending on state and customer class.	Yes
Critical Peak Pricing (CPP) Rate	All C&I, Irrigation	Assess impacts associated with a CPP rate offering to all C&I customers.[23]	No	Yes, only for extra-large C&I
Real Time Pricing (RTP) Rate	Extra-large C&I	Assess impacts associated with an RTP rate offering for extra-large C&I customers. Impacts are estimated with both opt-in and opt-out provisions.	No	No
Irrigation Time-Of-Use (TOU) Rate	Irrigation	For states with existing irrigation TOU rates (OR and UT), assess whether modifications to existing rate structures (changes in peak to off-peak price ratios, shifting peak time periods) could potentially yield higher impacts. We also assess incremental impacts associated with existing TOU rates relative to flat rates. For states without existing irrigation TOU rates (CA, ID, WA, WY), study analyzes impacts associated with new TOU rates.	Offered in Oregon and Utah	Yes
Demand Buyback	Extra-large C&I	Customer has the option to voluntarily reduce load by bidding in a certain amount of load reduction in response to the utility's request. The bid amount depends on the market prices posted by the utility before the event is called, typically on a day-ahead basis. Impact is estimated against an agreed upon baseline energy use.	Yes. However, participation has been minimal in recent years, due to relatively low market prices.	Yes

[23] We do not estimate impacts for rates with enabling technology due to higher levelized costs for the option that combines rates with enabling technology.

Table 2-15 presents TOU, CPP, and RTP program basics for non-residential customers.

Table 2-15 Non-residential TOU, CPP and RTP Program Basics

Program Element	Assumption
Eligible Customer Classes	TOU: All C&I customer classes, Irrigation customers CPP: All C&I customer classes, Irrigation customers RTP: Large and Extra-large C&I customers
Controlled end uses	Any
Applicable Hours	TOU: Six hours on-peak period each summer weekday Irrigation TOU: 120 hours- assumes two on-peak hours each weekday, June to August CPP: Top 40 system hours
Rate structure	TOU: 2:1 on-peak/off-peak price ratio CPP: 6:1 on-peak/off-peak price ratio

Non-Residential Customer Participation Assumptions in Pricing Options

Table 2-16 presents participation assumptions for non-residential customers in pricing options with a voluntary, opt-in offering. Participation assumptions are based on portfolio of rate offerings which include TOU, CPP, and RTP. Where TOU rates do not currently exist, new rates are assumed available beginning in 2017 to allow for vendor contracting and regulatory approval. CPP and RTP options are assumed available beginning in 2020, when AMI is assumed to be fully deployed. Before 2020, TOU is available on an opt-in basis to all customers except extra large customers, for whom it is the mandatory rate in all states other than Idaho.

Changes in participation to reach a steady state after a new product introduction are assumed to take place over a 5-year timeframe. As described earlier, ramp up to steady-state participation follows an “S-shaped” diffusion curve. Detailed documentation of the basis for developing participation assumptions is presented in Volume 5 of this report.

Table 2-16 Participation Assumptions for Non-Residential Customers in Time Varying Rates as Percent of Eligible Customers (with Opt-in Dynamic Pricing Offer)

Option by State	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024 to 2034
Small C&I TOU										
CA, ID, WA, WY	-	-	1.3%	3.9%	9.1%	12.2%	10.6%	7.4%	5.8%	5.0%
OR	0.4%	0.4%	1.7%	4.2%	9.2%	12.2%	10.6%	7.4%	5.8%	5.0%
UT	0.5%	0.5%	1.8%	4.3%	9.3%	12.2%	10.6%	7.4%	5.8%	5.0%
Medium C&I TOU										
CA, OR, WA, WY	-	-	1.3%	3.9%	9.1%	12.2%	10.6%	7.4%	5.8%	5.0%
ID	0.2%	0.2%	1.5%	4.0%	9.2%	12.2%	10.6%	7.4%	5.8%	5.0%
UT	12.6%	12.6%	12.6%	12.7%	12.9%	12.2%	10.6%	7.4%	5.8%	5.0%
Large C&I TOU										
CA	20.5%	20.5%	20.5%	20.5%	20.5%	19.2%	16.5%	11.1%	8.4%	7.0%
ID	3.6%	3.6%	4.6%	6.4%	10.2%	12.4%	11.2%	8.8%	7.6%	7.0%
OR, WY	-	-	1.3%	3.9%	9.1%	12.4%	11.2%	8.8%	7.6%	7.0%
UT	8.3%	8.3%	8.7%	9.7%	11.6%	12.4%	11.2%	8.8%	7.6%	7.0%
WA	4.2%	4.2%	5.1%	6.8%	10.4%	12.4%	11.2%	8.8%	7.6%	7.0%
Extra Large C&I TOU										
CA, OR, UT, WA, WY	100%	100%	100%	100%	100%	98.2%	94.6%	87.4%	83.8%	82.0%
ID	--	-	8.2%	24.6%	57.4%	82.0%	82.0%	82.0%	82.0%	82.0%
Irrigation TOU										
CA, ID, WA, WY	-	-	2.5%	7.5%	17.5%	24.0%	22.0%	18.0%	16.0%	15.0%
OR	1.5%	1.5%	3.8%	8.5%	17.9%	24.0%	22.0%	18.0%	16.0%	15.0%
UT	17.2%	17.2%	18.0%	19.5%	22.7%	24.0%	22.0%	18.0%	16.0%	15.0%
CPP for all C&I classes and Irrigation										
All states	-	-	-	-	-	1.5%	4.5%	10.5%	13.5%	15.0%
Large and Extra-Large C&I RTP										
All states	-	-	-	-	-	0.3%	0.9%	2.1%	2.7%	3.0%

Non-Residential Customer Impact Assumptions in Pricing Options

Table 2-17 shows the load impact assumptions (represented as "% of peak load reduction") for pricing options offered to non-residential customers.

The impacts for small and medium C&I customers are a less researched area as compared to that for residential customers; for these segments, we relied on price elasticity estimates from a dynamic pricing pilot in California. Impacts for larger customers are derived from experience with full-scale deployments in the northeastern U.S. In all cases, we account for a non-linear relationship between the price ratio in the time-varying rate and the customer's load reduction. The detailed description of the methodology for developing these rates is provided in Volume 5 of this report.

The price ratios for developing impact assumptions for non-residential customers are the same as those used for residential customers. Impact assumptions in Table 2-17 are based on a 2:1 TOU on-peak/off-peak price ratio and a 6:1 CPP on-peak/off-peak price ratio. However, unlike those for residential customers, impact assumptions for non-residential customers do not differ under opt-in and opt-out cases. Business customers are assumed to be driven more by their operational needs, with more sophisticated energy management capability, and their response would therefore not appreciably display this effect. Impact assumptions for dynamic pricing options (CPP and RTP) are developed for "rate only" and "rate with enabling technology" offers. Enabling technology for non-residential customers refers to Auto-DR and is not included with TOU because the peak period price signal is non-dispatchable.

Table 2-17 Load Impact Assumptions for Non-Residential Customers in Pricing Options

Customer Class	Option	Data Element	Reduction as % of Peak Load
Small C&I	Time-Of-Use	Per Customer Impact (%)	0.2%
Small C&I	Critical Peak Pricing	Impact w/ Enabling Tech (%)	12.5%
Small C&I	Critical Peak Pricing	Impact w/o Enabling Tech (%)	0.6%
Medium C&I	Time-Of-Use	Per Customer Impact (%)	2.6%
Medium C&I	Critical Peak Pricing	Impact w/ Enabling Tech (%)	11.7%
Medium C&I	Critical Peak Pricing	Impact w/o Enabling Tech (%)	7.3%
Large C&I	Time-Of-Use	Per Customer Impact (%)	3.1%
Large C&I	Critical Peak Pricing	Impact w/ Enabling Tech (%)	15.6%
Large C&I	Critical Peak Pricing	Impact w/o Enabling Tech (%)	8.4%
Large C&I	Real Time Pricing	Impact w/ Enabling Tech (%)	15.6%
Large C&I	Real Time Pricing	Impact w/o Enabling Tech (%)	8.4%
Extra Large C&I	Time-Of-Use	Per Customer Impact (%)	3.1%
Extra Large C&I	Critical Peak Pricing	Impact w/ Enabling Tech (%)	15.6%
Extra Large C&I	Critical Peak Pricing	Impact w/o Enabling Tech (%)	8.4%
Extra Large C&I	Real Time Pricing	Impact w/ Enabling Tech (%)	15.6%
Extra Large C&I	Real Time Pricing	Impact w/o Enabling Tech (%)	8.4%
Irrigation	Time-Of-Use	Per Customer Impact (%)	4.7%
Irrigation	Critical Peak Pricing	Impact w/o Enabling Tech (%)[24]	13.1%

Cost Assumptions for Pricing Options

Itemized cost assumptions include fixed and variable cost elements such as program development costs, annual administration costs, marketing and recruitment costs, and enabling

[24] There is no field level data on CPP offer with enabling technology for irrigation customers. Therefore, unit impacts could only be developed for a rate-only offering.

technology costs. Costs for pricing options do not include any incremental AMI or metering costs that may be required. Table 2-18 present cost assumptions for pricing options. Detailed documentation of cost assumptions is presented in Volume 5 of this report.

Table 2-18 Cost Assumptions for Pricing Options

Cost Item	Unit	Value
Development Cost	$/program	$150,000 (1 full-time employee equivalent, or FTE) for TOU and CPP each; $75,000 (0.5 FTE) for RTP;
Annual Program Administration Cost	$/year	$75,000 (0.5 FTE) for TOU; $150,000 (1 FTE) for CPP; $75,000 (0.5 FTE) for RTP;
Annual Marketing and Recruitment Costs	$/new participant	Residential, Small and Medium C&I, Irrigation- $50 for CPP; Large C&I- $200; Extra-large C&I: $400
Enabling technology costs	$/participant	Residential and Small C&I- $470; Medium C&I- $587.50;
Enabling technology costs	$/kW	Large and extra-large customers- $360

Demand Buyback

Under the Demand Buyback option, extra-large C&I customers have the option to voluntarily bid a certain amount of load reduction in response to PacifiCorp's request. The bid amount depends on market prices posted by the utility ahead of the curtailment event, and the reduction level is verified against an agreed-upon baseline usage level. PacifiCorp's existing Energy Exchange is a typical Demand Buyback program. Table 2-19 presents Demand Buyback program basics. Table 2-20 shows participation estimates, impact and cost assumptions used in the development of the potential assessment and levelized cost calculations. Details regarding the basis for developing these assumptions are presented in Volume 5 of the report.

Table 2-19 Demand Buyback Program Basics

Program Element	Assumption
Eligible Customer Classes	Extra-Large C&I Customers (greater than 1000 kW of demand)
Controlled end uses	Any
Applicable Hours	Top 50 system hours

Table 2-20 Demand Buyback Program: Planning Assumptions[25]

Data Item	Unit	Value
Participation Assumptions		
Program participation	Steady-state Participation (as % of eligible load)	11% for all states
Program ramp up period	Years	5
Impact Assumptions		
Per participant load reduction	% of enrolled load	6%
Cost Assumptions		
Annual Program Administration Cost	$/MW-year	$5,000
Marketing and Recruitment Costs	$/new participant	$200
Hourly credit rate	$/kWh	$0.40

Estimation of Class 1 and 3 DSM Potential

Once the market characterization is complete and the program assumptions are developed, the actual estimation of Class 1 and 3 DSM potential is performed, first for technical potential in the case of Class 1 resources and then for market potential for both Class 1 and 3 resources.

Estimation of Technical Potential

Technical potential assumes 100 percent participation of eligible customers in applicable DSM options. It is estimated by multiplying the unit load impact assumptions, described in the earlier section, by the entire eligible customer load in the relevant customer class. It assumes perfect market conditions in which all eligible customers participate in the applicable DSM option, without taking into consideration any barriers to participation. It is therefore a theoretical maximum potential for a particular DSM option.

In the current study, technical potential is defined for Class 1 DSM options only. The concept of technical potential is not considered to be applicable for Class 3 DSM. The potential estimation for Class 3 resources considers two participation cases- “opt-in” and “opt-out” types of offers for dynamic pricing. The bases for arriving at these participation assumptions are described in Volume 5 of this report.

Estimation of Market Potential

Market potential considers achievable participation rates in DSM options, taking into consideration real world market conditions. It accounts for customers’ ability and willingness to participate in capacity-focused programs, subject to their unique business or household priorities, operating requirements, and economic considerations.

For Class 1 DSM options, market potential is calculated by multiplying the technical potential by the participation assumptions described earlier. These participation assumptions are based on an extensive database of similar program offerings, offered nationwide by other utilities and system operators. Detailed documentation of assumptions is presented in Volume 5 of this report.

For Class 3 DSM options, the study estimates potential associated with “opt-in” and “opt-out” dynamic pricing rate offerings, which is akin to market potential for Class 1 DSM options. The participation assumptions are based on a review of full-scale rate deployments and market

[25] Detailed documentation of assumptions is presented in Volume 5 of the report.

research studies conducted in the U.S. and internationally. Detailed documentation of assumptions is presented in Volume 5 of this report.

Calculation of Levelized Cost

The annualized costs divided by the annualized kW reductions provides the levelized cost per kW for each Class 1 and 3 DSM resource in each state. The levelized cost ($/kW-year) calculations include costs for items such as program development and administration, customer marketing and recruitment, incentive payments, enabling technology, and O&M costs. Details regarding the basis for developing these assumptions are presented in Volume 5 of the DSM study report.

In developing estimates of levelized costs, program costs were allocated annually over the expected program life cycle and then discounted using PacifiCorp's weighted average cost of capital (WACC) of 6.61% to calculate net present value (NPV) costs. An inflation rate of 1.86% was applied only to administrative program costs. Other costs were assumed to experience technology improvements or economies of scale to offset the effects of inflation.

Unless otherwise specified, all energy impacts in this report are presented at the generator or system level, rather than at the customer meter. Therefore, electric delivery losses, as provided by PacifiCorp and presented in Table 2-21, have been included in all levelized cost and potential figures.

Table 2-21 Line Loss Factors

Sector	CA	ID	OR	UT	WA	WY
Residential	11.43%	11.47%	10.01%	9.32%	9.67%	9.51%
Small C&I	11.12%	10.51%	9.52%	8.56%	9.48%	8.54%
Medium C&I	11.05%	10.35%	9.44%	8.42%	9.42%	8.48%
Large C&I	10.82%	9.87%	9.05%	8.14%	9.26%	7.75%
Extra Large C&I	10.22%	7.63%	7.94%	6.48%	8.39%	5.78%
Irrigation	11.43%	11.45%	9.89%	9.24%	9.67%	9.28%

Table 2-22 shows the program lifecycle assumptions for Class 1 and 3 DSM resources that are used for annualizing or levelizing the numbers in the calculations. DLC options have a lifetime assumption of 10 years, which is associated with the lifespan of switching equipment and is a standard assumption in the industry. For Curtailable Agreements and Irrigation Load Control, program lifetime assumptions are 3 and 5 years respectively. Both these options are assumed to be delivered by third parties, which typically perform implementation and evaluation cycles of 3 to 5 years. For pricing programs, life is tied to the life of the meter, which is assumed to be 20 years. For Demand Buyback, program life is assumed to be 10 years. The above lifetime assumptions are used to correctly capture all costs that would occur over the 20-year planning horizon, including equipment replacement and periodic implementation costs. The ultimate levelized cost analysis, however, is conducted over the full 20-year period that is contemplated by PacifiCorp's IRP.

Table 2-22 DR Program Life Assumptions

DR Option	Lifetime (Years)
Direct Load Control	10
Irrigation Load Control	5
Curtailable Agreements	3
Pricing options	20
Demand Buyback	10

ASSESSMENT OF EXISTING CLASS 3 RATES

PacifiCorp is already implementing various programs within both the Class 1 and Class 3 DSM resource categories, the impacts of which are either explicitly treated as existing resources in the IRP (Class 1 DSM) or embedded in the load forecast (Class 3 DSM). Thus, to avoid overstating the remaining potential, it's critical to net existing impacts out of the total identified potential. The estimated impacts of these existing resources is stated and compared in the following chapter alongside the results of the total potential estimates; and the incremental potential is the difference between the total and existing potentials.

For event-based programs like Class 1 DSM resources, it is a comparatively straightforward matter to catalog the impacts that programs have achieved, as the impacts during an event are typically measured against a readily comparable non-event period as an implicit part of the program to qualify for grid credit or authorize financial incentives or penalties. Class 3 DSM pricing or rate-based resources pose a significant challenge, however, with respect to their measurability. The counterfactual case is more difficult to consider: what electricity consumption patterns would customers have maintained if the existing TOU and/or IBR rate structures were not in place? This requires a careful and detailed parallel analysis, and this chapter focuses specifically on how we estimated the embedded or current impacts of PacifiCorp's existing Class 3 DSM rate options.

Approach for Estimating Existing Class 3 Rate Impacts

The purpose of this analysis is to establish estimates of the load impacts that are associated with the current TOU and IBRs being offered by PacifiCorp. We estimate the likely impact of the existing rates on electricity consumption relative to a scenario where all rates are flat (constant cents per kWh).

In IBR, the price customers face, per unit of energy consumed, increases as their monthly consumption increases. PacifiCorp's IBRs are mandatory for all residential customers and consist of either two or three price tiers, depending on state.

Two types of TOU rates are considered- volumetric TOU and demand TOU. In the volumetric TOU rate, the volumetric rate (cents/kWh) is higher during peak period hours than during off-peak hours. In some cases, there is also a mid-peak pricing period. Volumetric TOU rates are offered to all customer classes in some jurisdictions. For demand TOU rates, the demand charge ($/kW-month) is multiplied by the customer's highest demand measured during the peak period. Demand TOU rates are only offered to non-residential customers.

Our estimates of these impacts are based on an extensive survey of customer price-responsiveness under a range of pricing plans, and on an assessment of the modeling frameworks that have been used to simulate these impacts in prior analyses.

We focus on the peak demand impact of the TOU rates, which provide a financial incentive to reduce peak demand, and on the sales impact of the IBR rates, which provide a financial incentive for overall energy conservation.

A six-step approach is used for estimating impacts from existing rates.

1. Characterize enrollment in current rates
2. Establish all-in estimates of existing rates
3. Simulate impacts of IBRs
4. Simulate impacts of volumetric TOU rates

5. Simulate impacts of demand TOU rates
6. Aggregate impacts to the system level

Each of these steps is briefly described below.

Characterize Enrollment in Current Rates

The first step is to characterize enrollment by customer class in existing IBRs and TOU rates. Table 3-1 presents enrollment data by existing rate and customer class for the six states, as of the end of 2012, the last complete year of actual data at the time the analysis was conducted.

Table 3-1 Current Enrollment in Existing Rates by Class and State (% of Total Customers)

Customer Class and State	IBR	TOU Volumetric	TOU Demand	Other[26]	Total
Residential Customers					
CA	100%	-	-	-	100%
ID	75.9%	24.1%	-	-	100%
OR	99.7%	0.3%	-	-	100%
UT	99.95%	0.05%	-	-	100%
WA	100%	-	-	-	100%
WY	100%	-	-	-	100%
Small C&I Customers					
CA	-	-	-	100%	100%
ID	-	-	-	100%	100%
OR	-	0.42%	-	99.58%	100%
UT	-	0.53%	0.02%	99.45%	100%
WA	-	-	-	100%	100%
WY	-	-	-	100%	100%
Medium C&I Customers					
CA	-	-	-	100%	100%
ID	-	-	0.17%	99.83%	100%
OR	-	0.01%	-	99.99%	100%
UT	-	12.28%	0.31%	87.41%	100%
WA	-	-	-	100%	100%
WY	-	-	-	100%	100%
Large C&I Customers					
CA	-	-	20.3%	79.7%	100%
ID	-	-	3.6%	96.4%	100%
OR	-	-	-	100%	100%
UT	-	5.6%	2.7%	91.7%	100%
WA	-	-	4.2%	95.8%	100%
WY	-	-	-	100%	100%
Extra Large C&I Customers					
CA	-	-	100%	-	100%
ID	-	-	-	-	100%
OR	-	-	100%	-	100%
UT	-	-	100%	-	100%
WA	-	-	100%	-	100%
WY	-	-	100%	-	100%
Irrigation Customers					
CA	-	-	-	1,836	100%
ID	-	-	-	4,820	100%
OR	-	0.74%	-	99.26%	100%
UT	-	8.6%	-	91.4%	100%
WA	-	-	-	100%	100%
WY	-	-	-	100%	100%

Establish All-in Estimates of Existing Rates

The next step in the impact assessment is to establish all-in estimates of existing rates. All-in rates are computed by converting each non-volumetric charge to a volumetric charge

[26] "Other" rates include flat volumetric rates with various non-time-specific demand charges, declining block rates, special contracts, and other variations.

(cents/kWh) using the class average customer's load, and then layering this converted charge on top of the existing volumetric charge. The resulting value is essentially total revenue from fixed and variable charges divided by retail kWh sales.

The underlying assumption is generally that customers do not respond to individual charges on their bill, but rather to the amount of the total bill, with some general awareness of the extent to which it varies by time of day or with monthly consumption. Results from the all-in estimates from existing rates are shown below.

All-in Residential IBRs

Table 3-2 summarizes the all-in IBRs. The price in the highest tier is never more than twice as higher as the price in the lowest tier.

Table 3-2 All-in Residential IBRs by State

State	Tier 1	Tier 2	Tier 3	Ratio (Highest Tier Rate/Tier 1 Rate)	Tier Cut-Off (kWh)
California	$0.10	$0.12	NA	1.2	~666 (Winter), ~495 (Summer)
Idaho (Summer)	$0.12	$0.15	NA	1.3	700
Idaho (Winter)	$0.09	$0.12	NA	1.3	1,000
Oregon	$0.10	$0.12	NA	1.2	1,000
Utah (Summer)	$0.10	$0.12	$0.15	1.6	400; 1,000
Utah (Winter)	$0.09	$0.10	NA	1.1	400
Washington	$0.06	$0.10	NA	1.5	600
Wyoming	$0.07	$0.13	NA	1.8	500

All-in Volumetric TOU Rates

Table 3-3 summarizes the all-in volumetric TOU rates by customer class and state. The peak to off peak price ratio ranges from 1.7-to-1 to 2.8-to-1, depending on the customer class and jurisdiction. In some jurisdictions, customers in a given class had multiple TOU options. The representative rate used for this analysis accounts for more than 95% of volumetric TOU customers in each class.

Table 3-3 All-in Volumetric TOU Rates by State

Customer Class	State	Peak Price ($/kWh)	Off-Peak Price ($/kWh)	Peak to Off-Peak Ratio
Residential	ID	$0.17	$0.07	2.3
	OR	$0.18	$0.11	1.7
	UT	$0.16	$0.09	1.8
Small C&I	OR	$0.18	$0.07	2.6
	UT	$0.17	$0.08	2.1
Medium C&I	OR	$0.17	$0.06	2.8
	UT	$0.14	$0.05	2.6
Large C&I	UT	$0.13	$0.05	2.7
Extra Large C&I	UT	$0.09	$0.04	2.2
Irrigation	OR	$0.18	$0.09	2.1
	UT	$0.26	$0.15	1.7

All-in Demand TOU Rates

For customers that have a demand charge component to their billing rate, i.e. some non-residential customers, the all-in demand TOU rates are summarized in Table 3-4 below. The demand charge varies significantly across jurisdictions. The "all-in price" is in addition to the peak demand charge.

In some jurisdictions, customers in a given class had multiple TOU options. In these cases, we created a composite TOU rate that was the enrollment-weighted average of the TOU options. The resulting representative rate used for this analysis accounts for more than 95% of the demand TOU customers in that class. Also, some demand TOU rates included a modest time-varying volumetric charge; for simplicity in the table below, the peak and off-peak prices were averaged to arrive at a single all-in price.

Table 3-4 All-in demand TOU Rates by State[27]

Customer Class	State	On-Peak Demand Charge ($/kW)	All-In Price ($/kWh)
Small C&I	UT	$15.72	$0.12
Medium C&I	ID	$16.45	$0.05
	UT	$16.34	$0.05
Large C&I	CA	$3.30	$0.05
	ID	$15.61	$0.05
	UT	$14.02	$0.05
	WA	$7.40	$0.06
Extra Large C&I	CA	$3.30	$0.05
	OR	$6.85	$0.05
	UT	$13.80	$0.05
	WA	$7.40	$0.05
	WY	$14.42	$0.01

Simulate Impacts of IBRs

The literature regarding impacts of IBRs on electricity consumption is relatively sparse, but we were able to identify four distinct modeling approaches that have been used - and published - in prior analyses. Two of these approaches played a role in approved utility regulatory filings and were determined by our team to be based on sound economic principles useful to this study for PacifiCorp. We label these two approaches the "Tier-Specific" approach and the "Marginal Tier" approach and have adopted them in our analysis to establish a range of potential impacts from PacifiCorp's existing IBR offering. These are briefly described below.

The "Tier-Specific" approach assumes that customers respond to the price in each tier. The price in each tier is compared to the price of a revenue neutral flat rate. Consumption in the first tier is assumed to be less price responsive than consumption in the second tier. The theory is that first-tier consumption is associated with necessary baseline energy use from appliances like refrigerators; outer tier consumption is associated with more discretionary end-uses. Based on a survey of price elasticities, we assume an elasticity of -0.13 for the first tier and -0.26 for the second (and third) tier. [28] Since the price in the first tier of the IBR is lower than the average rate and the price in the second tier is higher than the average rate, this methodology captures the

[27] In some jurisdictions, customers in a given class had multiple TOU options. The representative rate used for this analysis accounts for more than 95% of volumetric TOU customers in that class.

[28] Price elasticity represents the relationship between changes in price and changes in demand. For a price elasticity of -0.13, a 100% increase in price would result in a 13% decrease in consumption.

opposing influence of these two factors – namely that a lower first tier price encourages additional consumption while a higher second tier price encourages conservation.

The "Marginal Tier" approach assumes that customers only respond to the price in their marginal tier. The price of each customer's marginal tier is compared to the price of a revenue neutral flat rate. The theory is that customers only respond to the change in price in their highest respective tier (their marginal price). Based on the findings of the researchers who developed this methodology, we use an elasticity of 0 for the first tier and -0.10 for the second (and third) tier. That is, customers with all of their consumption in the first tier do not change their consumption, while customers with consumption in the second tier decrease their total consumption accordingly.

Our resulting estimates of residential IBR sales impacts using the two approaches are summarized in Table 3-5 below. Given a general lack of industry consensus around the "best" approach to use when simulating customer response to IBRs, we recommend that the results of the "Tier-specific" and "Marginal Tier" results be used to establish the range of possible impacts of PacifiCorp's existing rates. In general, we estimate a relatively small impact associated with the IBRs, ranging from less than 1 percent to as much as 2 percent of estimated consumption relative to a revenue-equivalent flat rate, depending on the jurisdiction and modeling framework being used.

Table 3-5 Estimated Impacts of Residential IBRs by State

State	Average Monthly Consumption (kWh/ customer)[29]	"Tier-Specific" Approach			"Marginal Tier" Approach		
		% Impact	Average Monthly Impact (kWh/ customer)[30]	Total Annual Impact (MWh)[31]	% Impact	Average Monthly Impact (kWh/ customer)[32]	Total Annual Impact (MWh)[33]
CA	912	0.4%	3.3	1,415	0.8%	7.2	3,064
ID	804[34]	0.4%	3.4	1,825	1.2%	9.3	4,936
OR	950	0.3%	3.0	17,150	0.7%	6.9	39,034
UT	771	0.3%	2.6	22,935	0.9%	6.7	58,411
WA	1,281	0.5%	6.6	8,285	1.4%	18.0	22,714
WY	797	0.3%	2.6	3,532	1.9%	15.5	20,707
All				**55,142**			**148,866**

Simulate Impacts of Energy-based or Volumetric TOU Rates

We simulate the volumetric TOU impacts using the survey of dynamic pricing pilots described in Chapter 2.[35] Participant peak demand reductions are a function of the peak-to-off-peak price ratio in the TOU rate, with a higher price ratio leading to larger peak reductions. The underlying assumption is that peak period demand is shifted to off-peak periods, rather than being eliminated, and hence no energy savings are estimated.[36] Details of our methodology are described in Volume 5 of this report.

[29] These per customer values are given at the meter.
[30] These per customer impact estimates are given at the meter.
[31] These aggregated impact values are given at the generator, arrived at by including line losses.
[32] These per customer impact estimates are given at the meter.
[33] These aggregated impact values are given at the generator, arrived at by including line losses.
[34] In Idaho, the average IBR customer's monthly consumption is significantly lower than that of the class average customer. This is because many of Idaho's large residential customers are enrolled in a TOU rate instead.
[35] Brattle's residential "Arc of Price Responsiveness" incorporates estimates of customer price responsiveness from over 160 different pricing tests conducted in North America and internationally over the past decade. The C&I Arcs vary by customer class and are based on pilots and full scale deployments in California and the Northeastern U.S.
[36] The assumption that there would not be significant energy savings is supported by the majority of the TOU pilots that have been conducted recently.

The average peak impacts for volumetric TOU participants are summarized in Table 3-6 below. It also shows the aggregate load reduction impacts at the generator by state.
Key findings are:

- Residential impacts range roughly between 6 and 7 percent.
- Small C&I impacts are small due to low price responsiveness of this segment.[37]
- Other C&I impacts range from 3 to 5 percent.
- Actual impacts may be lower due to very long peak period in some TOU rates.[38]

Table 3-6 Estimated Impacts of Energy-based or Volumetric TOU Rates by State

Customer Class	State	TOU Price Ratio	Average Peak Demand (kW/customer @ meter)	% Impact	Peak Impact (kW/customer @ meter)	Total Peak Impact (MW @ Generator)
Residential	ID	2.3	1.6	6.7%	0.1	1.69
	OR	1.7	1.7	5.6%	0.1	0.13
	UT	1.8	2.5	5.8%	0.1	0.05
Small C&I	OR	2.6	4.2	0.3%	0.0	0.004
	UT	2.1	4.4	0.2%	0.0	0.004
Medium C&I	OR	2.8	23.5	4.0%	1.0	0.001
	UT	2.6	46.1	3.7%	1.7	3.11
Large C&I	UT	2.7	252.9	4.6%	11.6	1.78
Extra Large C&I	UT	2.2	2,421.2	3.5%	84.3	0.45
Irrigation	OR	2.1	7.6	5.0%	0.4	0.02
	UT	1.7	18.4	3.3%	0.6	0.16
All	**All**					**7.4**

Simulate Impacts of Demand TOU Rates

We used a similar approach to estimate the impact of the demand TOU rates, although with a nuanced difference. We first convert the demand TOU to an equivalent volumetric TOU. This is done by dividing the $/kW-month demand charge by the number of peak hours in the month. The resulting volumetric (cents/kWh) charge is added to the energy price in the peak period to approximate an equivalent volumetric TOU rate. [39]
The average peak impacts for demand TOU participants are summarized in Table 3-7. Key findings are:

- Impacts vary widely due to significant variation in demand charges
- At the lower end, impacts are significantly less than 1 percent

[37] Dynamic pricing pilots have found that this customer segment is not price responsive unless equipped with technologies to automate load reductions. This is presumably because electricity is a relatively low share of the total cost of business for these customers, and they do not have sophisticated energy management systems that would facilitate significant price response.
[38] With longer peak periods, there are fewer lower priced, off-peak hours to which customers can shift consumption. This constraint, in turn, can lead to lower price responsiveness.
[39] While there has been very little research on the impacts of demand charges, a 1983 study for Wisconsin Public Service supports this approach in its conclusion that customer response to a system peak-coincident demand charge is similar to their response to an equivalent volumetric TOU rate. See Douglas Caves, Laurits Christensen, and Joseph Herriges, "Modelling Alternative Residential Peak-Load Electricity Rate Structures," *Journal of Econometrics*, August 1983.

- Generally, the impacts tend to be lower than those of the volumetric TOU due to lower equivalent price ratios

Table 3-7 Estimated Impacts of Demand TOU Rates by State

Customer Class	State	TOU Price Ratio	Average Peak Demand (kW/customer @ meter)	% Impact	Peak Impact (kW/customer @ meter)	Total Peak Impact (MW @ Generator)
Small C&I	UT	1.6	4.4	0.1%	0.01	0.000
Medium C&I	ID	2.0	51.2	2.6%	1.3	0.001
	UT	2.3	46.1	3.2%	1.5	0.069
Large C&I	CA	1.2	226.6	0.5%	1.1	0.010
	ID	2.0	259.5	3.0%	7.7	0.026
	UT	2.5	252.9	4.1%	10.3	0.755
	WA	1.4	184.0	1.2%	2.2	0.048
Extra Large C&I	CA	1.2	1,120.2	0.5%	6.1	0.075
	OR	1.4	1,417.3	1.3%	18.9	5.309
	UT	2.5	2,421.2	4.1%	98.2	36.025
	WA	1.5	2,502.7	1.5%	38.6	1.726
	WY	4.4	5,582.1	6.8%	378.8	46.231
All	**All**					**90.27**

Aggregate Impacts at the System Level

The final step is to combine the enrollment rates with the per-participant impacts to establish state-level impacts. We have done so in the following sections for IBR and TOU separately.

Summary of Impacts

Figure 3-1 shows the overall summary of IBR impacts as "% of jurisdictional sales." The absolute impact values for residential IBRs, by state, were presented earlier in Table 3-5.

Key observations are:

- The Tier Specific Method estimates that if the IBR was removed (i.e., converted to a flat rate), residential sales in the various jurisdictions would increase by between 0.04% and 0.21%.
- The Marginal Tier Method estimates that if the IBR was removed, residential sales in the jurisdictions would increase by 0.14% to 0.56%.
- Both methods are industry-accepted approaches to simulating the impact of IBRs. When considering the results of both approaches to represent the range of possible impacts of the existing rates, this indicates that the effect of the IBR causes an embedded reduction of energy consumption equivalent to a few tenths of a percent.

Figure 3-1 Residential IBR Impacts as % of Jurisdictional Sales

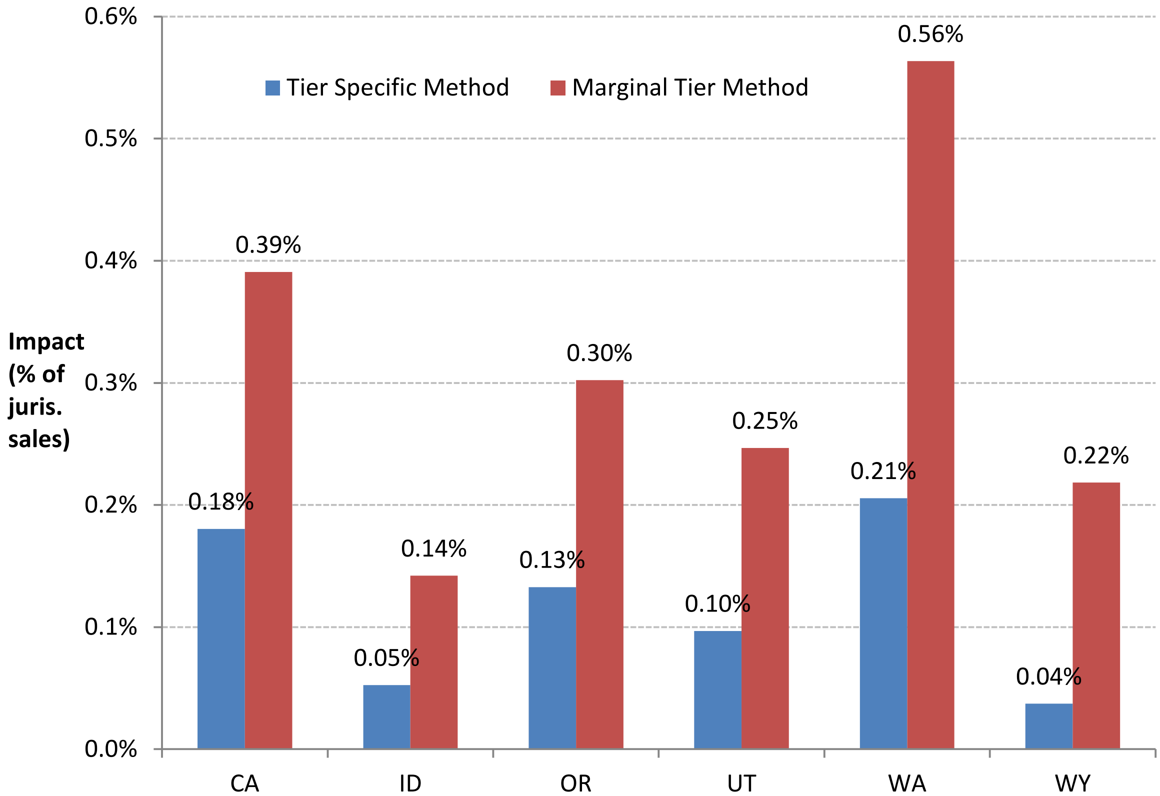


Table 3-8 shows the estimated impact from volumetric and demand TOU rates during the system peak, by state, for residential, C&I and irrigation customers. Figure 3-2 shows the overall summary of TOU impacts as '% of jurisdictional demand during the system peak'.

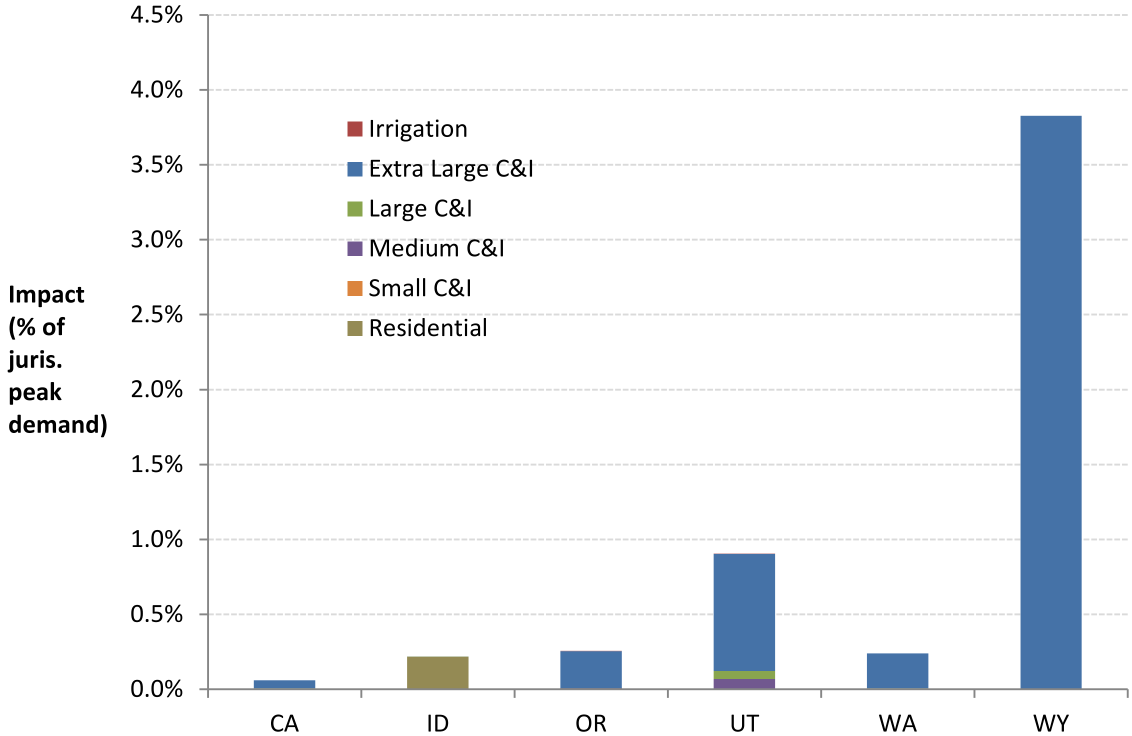
Key observations are:

- The largest reduction as a percent of the state jurisdiction peak is in Wyoming, where load is concentrated in the Extra Large C&I segment and the price ratio is over 4-to-1
- In terms of system peak, analysis results show that total reduction in system peak demand is roughly 1%, driven largely by Extra Large C&I TOU rates in Utah and Wyoming
- All TOU impacts are coincident with the system peak

Table 3-8 Estimated Impacts from Existing TOU Rates (MW @ Generator during System Peak)

Class 3 DSM Options	CA	ID	OR	UT	WA	WY	Total
Residential TOU	-	1.69	0.13	0.05	-	-	**1.9**
C&I TOU	0.09	0.03	5.31	42.19	1.77	46.23	**95.6**
Irrigation TOU	-	-	0.02	0.16	-	-	**0.2**
Total TOU	**0.09**	**1.72**	**5.46**	**42.4**	**1.77**	**46.23**	**97.7**

Figure 3-2 TOU Impacts as % of Jurisdictional Demand during System Peak[40]



[40] Idaho is the only state where TOU rates are not offered on a mandatory basis to Extra Large C&I customers. The C&I TOU impact in Idaho is 0.03 MW, whereas the residential TOU impact is much larger at 1.7 MW. Since non-residential impacts are much smaller when compared to residential TOU impacts, they do not show up in the figure.

CLASS 1 AND 3 DSM POTENTIAL RESULTS

This chapter presents potential analysis results for the Class 1 and 3 DSM options based on the assumptions and methodologies outlined in Chapter 2 of this report. The results are given on a standalone basis, meaning that no interactions are considered between Class 1 and 3 DSM resources. For results of the integrated analysis that considers interactive effects between the two resource classes, see Section G of Volume 5 of this report. Within the Class 1 DSM resource analysis, there are no overlapping programs that target the same customer segment or end-use load, so there are no interactions to account for (i.e., no chance of double counting the impact for the individual program options). Within the Class 3 DSM resource analysis, however, some of the same customers are eligible for multiple dynamic pricing options (TOU, CPP, and RTP). To account for this, our analysis made assumptions about the choices eligible customers would make if competing options were offered in parallel, based on observed customer preference in such pilots and full-scale deployments.

Furthermore, this chapter presents results for a voluntary, “opt-in” offering of time-varying rates. In the Appendix (Volume 5) of this report, we also provide results for Class 3 DSM potential results under a default, “opt-out” offering.

We present potential results both at an aggregate level, and also disaggregated by DSM option, customer class, and state. The discussion of results in this chapter centers around potential impacts in 2034. Potential is presented in terms of both the total estimated impact and the incremental impact beyond participation in PacifiCorp’s current offerings.

This chapter also presents levelized costs by state and DSM option. Class 1 DSM technical potential results, and Class 1 and 3 DSM integrated potential results are presented in Volume 5 of this report. As mentioned previously, the integrated analysis in the appendix is the only place in this report that considers interactive effects between the two resource classes. Therefore, the results presented in the main body of the report are not additive between the two resource classes.

Class 1 DSM Market Potential Results

Class 1 DSM Market Potential Results by Option

Class 1 DSM potential starts with a strong resource base already in place, and increases rapidly in the 2017-2022 timeframe as new programs are assumed to be available. After this, savings more or less reach a steady state. In our analysis we assumed new program offerings would be available for implementation beginning in 2017 to allow for vendor selection, contracting and regulatory approvals. Typically, programs take 3 to 5 years to be fully deployed and reach steady-state participation levels.

Table 4-1 shows total and incremental savings potential in 2034 for all Class 1 DSM resources. It also shows the approximate current impacts from existing program offerings. The incremental potential impacts are calculated by subtracting the impacts of existing Class 1 DSM offerings from the total potential estimates for those program options.

Key observations from our analysis results are:

- Total Class 1 DSM potential more than doubles in 20 years from 2015-2034. Savings potential from Class 1 DSM resources are estimated to grow from 310 MW in 2015 to 678 MW in 2034, translating into 5.6% of projected system peak demand in 2034. Savings from existing programs account for almost half of the total potential from Class 1 DSM options in 2034.

- In 2015 and 2016, potential is derived only from PacifiCorp's existing Class 1 DSM programs; a residential and small commercial and industrial air conditioning load control program in Utah, as well as irrigation load control programs in Idaho and Utah. Incremental potential for these existing programs, above current impacts, is assumed to begin in 2016 to allow time for additional participant recruitment if selected by the 2015 IRP. For planning purposes, this study assumes that if the IRP identifies a need for new Class 1 DSM resources, new programs could begin to be implemented within 18-24 months. The 18-24 month planning assumption is necessary to allow time for vendor selection, contracting and regulatory approvals. Following a new program's implementation, its savings potential is expected to be fully realized within 3-5 years, dependent on the resource option added. As a result of these assumptions, savings potential identified in this study begins to grow substantially starting in 2017.
- Irrigation Load Control has the highest total potential of any Class 1 DSM product. However, the high impacts are driven by the large existing base of controllable irrigation load in Idaho and Utah. More than 75% of the 2034 savings potential for Irrigation Load Control is derived from these two states. Additional savings potential is primarily associated with new program launches in the remaining four states.
- Curtailable Agreements has the highest remaining market potential of all Class 1 DSM options; 185 MW of market potential in 2034. For the purpose of this study Curtailable Agreements are assumed available for implementation beginning in 2017.
- Total savings potential from the residential DLC option, targeting cooling equipment, is estimated to reach 197 MW in 2034. However, more than half of the total savings is derived from PacifiCorp's existing Cool Keeper program in Utah. An additional 97 MW of potential in 2034 is associated with a modest expansion of the Utah program, and new DLC program launches in the Company's remaining five states.

Table 4-1 Class 1 DSM Total and Incremental Market Potential by Option (MW)

Class 1 DSM Options	Total Potential Impacts in 2034	Impacts from Existing Options	Incremental Potential Impacts in 2034
Residential DLC-Cooling	197.1	100	97.1
Residential DLC-Water Heating	11.8	-	11.8
C&I DLC- Cooling	28.9	15	13.9
C&I DLC- Water Heating	0.6	-	0.6
Irrigation Load Control	254.5	190[41]	64.5
Curtailable Agreements	185.1	-	185.1
Total (MW)	**678.1**	**305**	**373.1**
Potential (% of PacifiCorp 2034 system peak)	**5.6%**	**2.5%**	**3.1%**

Next, we present a breakdown of the total and incremental potential by option at the state level.

Class 1 DSM Market Potential Results by Option and State

Table 4-2 shows total Class 1 DSM potential results in 2034 by option for each state. This combines the effects of existing Class 1 DSM resources with new options that have incremental potential in future years. Key observations are:

- Utah and Idaho are the top contributors to Class 1 DSM potential. Approximately 80% of the savings potential in 2034 is derived from these two states. Note, as shown above,

[41] Of the total existing impacts for Irrigation Load Control, 170 MW are in Idaho and the remainder (20 MW) are in Utah.

approximately 60% of the total potential in these states is already captured through existing Class 1 DSM program offerings. While Idaho potential is derived primarily from Irrigation Load Control, Utah derives its potential mostly from residential DLC and C&I Curtailable Agreements.

- Oregon has the third highest potential savings, derived primarily from C&I Curtailable Agreements and residential DLC, which show roughly equal potential.
- Wyoming has the fourth highest potential, with majority of the savings derived from C&I Curtailable option. This is driven by the presence of a relatively large industrial customer base in the state.
- In California, more than half of the savings are derived from Irrigation Load Control.

Table 4-2 Class 1 DSM Total Market Potential by Option and State in 2034 (MW)

State	Res DLC-Cooling	Res DLC-WH	C&I DLC-Cooling	C&I DLC-WH	Irrigation Load Control	Curtailable Agreements	Total
CA	1.59	0.55	0.39	0.03	4.20	1.03	**7.8**
ID	1.67	0.94	0.44	0.04	195.94	2.31	**201.3**
OR	18.41	6.57	5.74	0.41	8.67	32.86	**72.7**
UT	163.43	-[42]	19.21	-	39.12	92.61	**314.4**
WA	8.90	2.23	1.77	0.09	5.12	9.47	**27.6**
WY	3.10	1.52	1.36	0.06	1.47	46.84	**54.4**
Total	**197.10**	**11.81**	**28.92**	**0.62**	**254.52**	**185.11**	**678.1**

Table 4-3 shows the incremental potential in 2034 by Class 1 DSM option and state. The C&I Curtailable Agreements option in Utah has the highest contribution to incremental potential. Other options with significant contribution are the residential DLC program in Utah and Oregon, C&I Curtailment Agreements in Wyoming and Oregon, and Irrigation Load Control program in Idaho and Utah. Incremental savings from the residential DLC program in Utah in the near term (2015-2020 timeframe) are primarily associated with a ramp-up in program participation rate and a projected increase in the saturation of central cooling equipment. Beyond 2020, it is assumed that growth in cooling saturation slows down and, even with continued marketing and recruitment, the participation rate would reach a steady-state. Therefore, the growth in potential beyond 2020 is driven solely by projected rates of new construction.

Table 4-3 Class 1 DSM Incremental Market Potential by Option and State in 2034 (MW)

State	Res DLC-Cooling	Res DLC-WH	C&I DLC-Cooling	C&I DLC-WH	Irrigation Load Control	Curtailable Agreements	Total
CA	1.59	0.55	0.39	0.03	4.20	1.03	**7.8**
ID	1.67	0.94	0.44	0.04	25.94	2.31	**31.3**
OR	18.41	6.57	5.74	0.41	8.67	32.86	**72.7**
UT	63.43	-	4.21	-	19.12	92.61	**179.4**
WA	8.90	2.23	1.77	0.09	5.12	9.47	**27.6**
WY	3.10	1.52	1.36	0.06	1.47	46.84	**54.4**
Total	**97.1**	**11.8**	**13.9**	**0.6**	**64.5**	**185.1**	**373.1**

[42] The current Cool Keeper program in Utah targets only eligible cooling equipment. The DLC savings potential in Utah are based on the existing program offer. Therefore, in Utah, DLC savings are derived through control of cooling equipment only and electric water heater control is not included. In all other states, where new DLC programs are assumed to be launched, savings are derived through control of both cooling and water heating equipment.

Class 1 DSM Market Potential Results by Customer Class

Table 4-4 presents the total Class 1 DSM potential results broken down in a slightly different way; by customer class. Again, this total potential combines the effects of existing Class 1 DSM resources with new options that have incremental potential in future years. Key observations are:

- The irrigation sector has the largest contribution to total potential, with approximately 40% of the total potential in 2034. PacifiCorp's current irrigation program offerings are capturing 75% of the identified irrigation potential, leaving the irrigation sector contributing 17% of the overall incremental potential.
- The residential sector has the second largest share of total potential, maintaining close to 30% contribution in the overall Class 1 DSM potential. PacifiCorp's current Utah residential DLC program is capturing 48% of the identified residential potential, leaving the residential sector contributing 29% of the overall incremental potential.
- The C&I sector share increases steadily from 2017 onward, once Curtailable Agreements are in place, and becomes roughly equal to residential contributions in later years. Large and extra-large customers make up the bulk of the C&I savings opportunities. Medium and small C&I customers constitute less than 5% of the total savings Class 1 DSM potential and 4% of the incremental potential after accounting for impacts of PacifiCorp's current programs.

Table 4-4 Class 1 DSM Total and Incremental Market Potential by Customer Class in 2034 (MW)

Customer Class	Total Potential	Impacts from Existing Options	Incremental Potential Impacts in 2034
Residential	208.9	100	108.9
Small C&I	9.2	3.8	5.4
Medium C&I	20.3	11.2	9.1
Large C&I	67.3	-	67.4
Extra Large C&I	117.8	-	117.8
Irrigation	254.5	190	64.5
Total	**678.1**	**305**	**373.1**

Class 1 DSM Market Potential Results by Customer Class and State in 2034

Table 4-5 shows total Class 1 DSM potential by customer class in 2034 with the additional dimension of a state-by-state breakdown. Key observations here are:

- The residential and irrigation sectors dominate the potential in Utah and Idaho respectively. More than 95% of the total potential in Idaho comes from irrigation customers.
- In Wyoming, almost 75% of the potential is found in the extra-large C&I customer class through the Curtailable Agreements option.
- In Oregon and Washington, the residential sector represents approximately 30-40% of the total identified potential. The next highest contribution is from extra-large C&I curtailment participants, representing approximately 20-25% of the overall potential in both states.
- In California, more than half of the Class 1 potential is found in the irrigation customer class.

Table 4-5 Class 1 DSM Market Potential by Customer Class and State in 2034 (MW)

State	Res.	Small C&I	Med. C&I	Large C&I	Extra Large C&I	Irrigation	Total
CA	2.14	0.22	0.21	0.44	0.58	4.20	**7.8**
ID	2.61	0.28	0.20	1.11	1.19	195.94	**201.3**
OR	24.99	2.55	3.59	13.30	19.55	8.67	**72.7**
UT	163.43	4.91	14.30	41.54	51.07	39.12	**314.4**
WA	11.12	0.64	1.22	4.53	4.94	5.12	**27.6**
WY	4.62	0.60	0.82	6.41	40.42	1.47	**54.3**
Total	**208.91**	**9.20**	**20.34**	**67.35**	**117.76**	**254.52**	**678.1**

Class 1 DSM Levelized Costs

For each option, we estimated levelized costs over the entire study period of 2015–2034. Table 4-6 shows levelized costs and 2034 market potential by option and state. Results are aggregated at the operating company level and for the overall PacifiCorp system.

- Irrigation Load Control, which is the largest Class 1 DSM program, also has the lowest levelized cost among Class 1 DSM options. Costs are lower in states such as Idaho and Utah with substantial irrigation potential. In the remaining four states, achieving savings through Irrigation Load Control is likely to be more difficult due to crop patterns, shorter irrigation seasons and smaller pump sizes. Consequently, associated costs are higher in California, Oregon, and Wyoming.
- Costs for DLC programs, targeting cooling and electric water heating in residential and commercial customer premises, can vary greatly based on temperature, cooling saturation, and unit size. Warmer temperatures, higher cooling saturation and relatively larger unit load reductions makes this option more attractive in Utah as compared to the other states. DLC cost in Utah is substantially lower than the estimated costs in other states. The primary driver of differences in cost by state is the assumed per-unit kW impact, as shown in Table 2-5.
- Curtailable Agreements for C&I customers, with 185 MW of potential system wide, costs around $77/kW-yr.

Table 4-6 Class 1 DSM Levelized Costs and Incremental Potential @ Generator

Area	Direct Load Control		Curtailable Agreements		Irrigation Load Control	
	Cost ($/kW-year)	2034 Potential (MW)	Cost ($/kW-year)	2034 Potential (MW)	Cost ($/kW-year)	2034 Potential (MW)
Pacific Power						
CA	$116	2.6	$74	1.0	$69	4.2
OR	$152	31.1	$76	32.9	$71	8.7
WA	$134	13.0	$76	9.5	$71	5.1
Subtotal		46.7		43.4		18.0
Rocky Mountain Power						
ID	$156	3.1	$76	2.3	$51	25.9
UT	$62	67.7	$77	92.6	$52	19.0
WY	$131	6.0	$78	46.8	$71	1.5
Subtotal		76.8		141.7		46.4
Total						
All PacifiCorp		123.5		185.1		64.4

Class 3 DSM Potential Results

For Class 3 DSM resources, potential results associated with pricing options represent a voluntary, “opt-in” type of offering for dynamic pricing programs. Pricing potential associated with an “opt-out” type of offering is presented in Volume 5 of this report. The dynamic pricing options of CPP and RTP are assumed to be offered only after AMI has been deployed in 2020. Unlike the TOU option, it is assumed that these rates require the AMI system for customer and back-office enablement. For this reason, CPP and RTP rates achieve steady-state participation levels after a five-year timeframe (2020-2025). Demand Buyback potential is treated separately because it is the only non-pricing or non-rate-based Class 3 DSM option. Its impacts are small relative to the pricing options.

Class 3 DSM Total Pricing Potential by Option

Table 4-7 shows the total, absolute potential from Class 3 DSM options as they would be configured in 2034. This combines the effects of existing Class 3 resources with new options that have incremental potential in future years. The potential is expressed here both in MW reductions and as a percentage of PacifiCorp’s projected system peak in 2034. Results are presented for the opt-in case for pricing options. Opt-out case results are discussed in Volume 5 of the report. The potential estimates presented in Table 4-8 include impacts from existing rates, which were presented earlier in Chapter 3.

Key observations from our analysis results are:

- The total potential from Class 3 DSM resources reaches 326 MW in 2034, which translate into 2.7% of PacifiCorp’s projected system peak demand in 2034.
- We assumed that TOU rates and Demand Buyback are offered from 2017 onward. Savings from CPP and RTP are realized from 2020 onward, after AMI has been deployed in all states. The savings from pricing options ramp up in their early years following an S-shaped diffusion curve, growing from 165 MW in 2020 to 280 MW in 2025. Eventually, savings levels reach a steady state at 2.5% of projected system peak.

- Residential CPP is the top contributor to Class 3 DSM potential in 2034. Residential CPP savings constitute more than one-third of the total Class 3 DSM potential, and is significantly higher as compared to residential TOU savings.
- For C&I customers, CPP and TOU options have roughly equal potential in 2034 at 70 MW each. Savings opportunities from RTP are considerably lower at only 10 MW in 2034.
- For irrigation customers, CPP rates have more than double savings potential in 2034 as compared to TOU rates.
- Demand Buyback savings potential reaches 19 MW in 2034, constituting only 0.2% of projected system peak in that year.

Table 4-7 Class 3 DSM Total Potential in 2034 (MW)

Class 3 DSM Options	Total Potential (MW)	Potential (as % of system peak)
Pricing Options		
Residential TOU	26.6	0.22%
Residential CPP	112.5	0.62%
C&I TOU	74.1	0.94%
C&I CPP	70.0	0.58%
C&I RTP	10.5	0.09%
Irrigation TOU	3.5	0.03%
Irrigation CPP	9.75	0.08%
Pricing Options Subtotal	***306.9***	***2.5%***
Demand Buyback	18.7	0.16%
Total Class 3 DSM Potential[43]	**325.6**	**2.7%**

Class 3 DSM Total Pricing Potential in 2034 by Option and State

Table 4-8 presents the total Class 3 DSM potential results broken down by state in 2034. Again, this combines the effects of existing Class 3 resources with new options that have incremental potential in future years. Key observations are:

- In Utah, residential CPP has the highest contribution to potential. C&I CPP and TOU combined have roughly equal potential as residential CPP.
- Oregon has the second highest potential, after Utah. Residential pricing (TOU and CPP) constitute more than half of the potential in Oregon.
- Wyoming ranks third in terms of potential contribution from pricing options. Most of the potential is derived from C&I customers in the state, particularly large sized industrial customers.
- In Idaho, more than half of the savings opportunities from pricing options are in the irrigation sector.

[43] The independent analysis results being presented for Demand Buyback do not consider interactions with other Class 3 DSM options. The integrated analysis in the appendix assumes that customers who are on TOU rates are eligible to participate in Demand Buyback, while CPP participants are excluded. The independent analysis here does not consider this interactive effect, and therefore Demand Buyback potential is not strictly additive with potential from pricing options.

- In Washington and California, the residential sector constitutes almost half the total savings potential from pricing options.
- For Demand Buyback, most of the savings opportunities lie with extra-large C&I customers in Utah and Wyoming.

Table 4-8 Class 3 DSM Total Potential by Option and State in 2034 (MW)

State	Res TOU	Res CPP	C&I TOU	C&I CPP	C&I RTP	Irrig. TOU	Irrig. CPP	Dem. Buyback	Total
CA	0.3	1.4	0.4	0.5	0.1	0.2	0.6	0.1	**3.5**
ID	0.7	2.8	0.8	1.1	0.1	1.8	5.1	0.2	**12.6**
OR	6.2	26.2	12.4	12.6	1.9	0.5	1.4	3.1	**64.3**
UT	15.7	66.3	33.0	36.2	5.2	0.5	1.5	8.1	**166.5**
WA	1.8	7.8	3.3	4.4	0.5	0.3	0.9	0.8	**19.9**
WY	1.9	8.1	24.1	15.2	2.7	0.1	0.2	6.4	**58.9**
Total	**26.6**	**112.5**	**74.1**	**70.0**	**10.5**	**3.5**	**9.7**	**18.7**	**325.6**

Class 3 DSM Total Potential in 2034 by Customer Class and State

Table 4-9 shows 2034 total pricing potential results broken down slightly differently, this time by customer class and state. Key observations are:

- Residential customers in Utah and Oregon provide substantial savings opportunities. For most states, approximately half of the potential is derived from residential customers, except for Idaho and Wyoming, which display a significantly lower share.
- Among C&I customer classes, extra-large C&I customers provide highest savings opportunities, especially in the states of Utah and Wyoming, where there is a larger base of high-demand customers.
- Medium and large C&I customers have moderate levels of contribution across all states, while small C&I customers have minimal contribution. For Idaho, more than half of the potential is likely to be realized from irrigation customers.

Table 4-9 Class 3 DSM Total Potential by Customer Class and State in 2034 (MW)

State	Res	Small C&I	Med. C&I	Large C&I	Extra Large C&I	Irrigation	Total
CA	1.7	0.0	0.2	0.2	0.6	0.8	**3.5**
ID	3.4	0.1	0.4	0.4	1.3	7.0	**12.6**
OR	32.4	0.3	3.4	5.0	21.3	1.9	**64.3**
UT	81.9	0.4	10.9	15.5	55.7	2.0	**166.5**
WA	9.6	0.0	1.9	1.7	5.4	1.2	**19.9**
WY	10.1	0.1	1.9	2.4	44.1	0.3	**58.9**
Total	**139.1**	**1.0**	**18.7**	**25.1**	**128.5**	**13.2**	**325.7**

Class 3 DSM Incremental Pricing Potential by Option

The total potential shown above includes the estimated impacts of the Company's existing TOU rates, as shown in Table 3-8. Incremental potential from Class 3 DSM (beyond the estimated impacts of the Company's current TOU rates) is estimated to be 260 MW by 2034, and is broken out by program option and state in Table 4-10. Major contributors to the incremental potential are residential and C&I CPP rates in Utah and Oregon, C&I CPP rates in Wyoming, and residential TOU rates in Utah.

Table 4-10 Class 3 DSM Incremental Potential by Option and State in 2034 (MW)

State	Res TOU	Res CPP	C&I TOU	C&I CPP	C&I RTP	Irrig. TOU	Irrig. CPP	Dem. Buyback	Total
CA	0.3	1.4	0.3	0.5	0.1	0.2	0.6	0.1	**3.5**
ID	0.0[44]	2.8	0.8	1.1	0.1	1.8	5.1	0.2	**11.9**
OR	6.1	26.2	7.1	12.6	1.9	0.5	1.4	3.1	**58.8**
UT	15.7	66.3	0.0[45]	36.2	5.2	0.3	1.5	8.1	**133.3**
WA	1.8	7.8	1.5	4.4	0.5	0.3	0.9	0.8	**18.0**
WY	1.9	8.1	0.0[46]	15.2	2.7	0.1	0.2	6.4	**34.6**
Total	**25.7**	**112.6**	**9.7**	**70.0**	**10.5**	**3.2**	**9.7**	**18.7**	**260.1**

Class 3 DSM Levelized Costs

For each Class 3 DSM option, we estimated levelized costs over the study period of 2015–2034. The levelized costs for pricing options take into account costs associated with developing and administering the rates, including costs for customer education and outreach. In our analysis, pricing options contingent on AMI deployment, CPP and RTP, were not burdened with any metering and communication network related costs. Costs are levelized over a 20-year lifetime, tied to the life of a meter. Detailed cost assumptions are presented in Volume 5 of the report.

Table 4-11 shows the levelized costs and associated 2034 incremental potential estimates for each option by state. Key findings are:

- Dynamic pricing programs are relatively inexpensive to implement without considering the cost of AMI, and have substantial potential once AMI is deployed.
- Residential CPP, with the highest savings potential of 112 MW in 2034, costs from $12.3 to $22.7/kW-year depending on the jurisdiction.
- Potential for C&I CPP is estimated at 70 MW at a low range of cost between $3.6 and $15.3/kW-year depending on the jurisdiction.
- Pricing options for irrigation customers can also be administered for a levelized cost between $1.8 and $6.5/kW-year.
- Demand Buyback savings of around 20 MW in 2034 can be delivered at levelized costs ranging from $23.8 to $24.6/kW-year depending on the jurisdiction.

[44] In this case, the incremental potential calculation resulted in a negative value, which has been adjusted to zero. A negative incremental potential indicates the potential analysis assumes a redistribution of participants or impacts relative to the existing rates. Our analysis also allows TOU participation to drop below current levels, when assuming that some of the existing TOU customers migrate to CPP. For calculation of the total incremental potential, these negative values have been adjusted to zero.
[45] *Ibid.*
[46] In the case of Wyoming, the existing TOU structure with a 4:1 peak to off-peak ratio is more aggressive than the 2:1 pricing structure considered in the potential study. Therefore, no incremental impacts are anticipated relative to what is already in place.

Table 4-11 Class 3 DSM Levelized Costs over 2015-2034 and Incremental Potential in 2034

Option	CA	ID	OR	UT	WA	WY	PacifiCorp
Residential TOU							
Cost ($/kW-year)	22.7	15.1	17.2	13.2	12.3	14.5	
Potential (MW)	0.3	0	6.1	15.7	1.8	1.9	**25.7**
Residential CPP							
Cost ($/kW-year)	31.0	33.8	24.6	19.2	17.0	19.4	
Potential (MW)	1.4	2.8	26.2	66.3	7.8	8.1	**112.6**
C&I TOU							
Cost ($/kW-year)	2.8	3.5	1.8	1.5	1.5	1.5	
Potential (MW)	0.3	0.8	7.1	0.0	1.5	0.0	**9.7**
C&I CPP							
Cost ($/kW-year)	15.3	11.9	8.1	4.8	5.8	3.6	
Potential (MW)	0.5	1.1	12.6	36.2	4.4	15.2	**70.0**
C&I RTP							
Cost ($/kW-year)	18.1	19.0	18.5	16.9	15.9	19.2	
Potential (MW)	0.1	0.1	1.9	5.2	0.5	2.7	**10.5**
Irrigation TOU							
Cost ($/kW-year)	3.5	1.8	4.9	2.4	5.0	4.3	
Potential (MW)	0.2	1.8	0.5	0.3	0.3	0.1	**3.2**
Irrigation CPP							
Cost ($/kW-year)	4.7	2.4	6.3	3.9	6.5	5.8	
Potential (MW)	0.6	5.1	1.4	1.5	0.9	0.2	**9.7**
Demand Buyback							
Cost ($/kW-year)	23.8	24.4	24.3	24.6	24.1	24.6	
Potential (MW)	0.1	0.2	3.1	8.1	0.8	6.4	**18.7**

COMPARISON WITH PREVIOUS DSM POTENTIAL ASSESSMENT

This chapter compares potential estimates for Class 1 and 3 DSM options in the current study to those presented in the previous potential assessment study published by PacifiCorp in March of 2013[47].

First, we present a side-by-side comparison of the 20-year incremental potential at the system level by DSM option for Class 1 and 3 DSM resources. These potential estimates do not consider interactions between the two resource classes. Next, we present a detailed comparison of the potential by option and by state, and indicate the primary reasons for differences in potential estimates between the two studies.

Table 5-1 presents a high level comparison of the system-wide potential by Class 1 and 3 DSM option. Key observations are:

- The 20-year incremental potential for Class 1 DSM in the current study is 368 MW, which is roughly one third larger than the 20-year potential estimate in the 2013 assessment.
  - The increase is primarily due to higher incremental potential estimates for DLC-Cooling and Irrigation Load Control, given new information about program implementation, customer growth assumptions, saturation of applicable equipment, and estimated participation rates that are detailed further in the following sections.
  - Potential for Curtailable Agreements is similar between the two studies.
- The Class 3 DSM potential estimate in the current study is also higher than the 2013 study, due largely to the consideration of new program options and rate designs in the current study. The current study estimates 260 MW of incremental Class 3 DSM potential in 2034, as compared to 66 MW in 2032 from the previous study.
  - Residential pricing potential in the current study is estimated at 138 MW in the final year, vs. 25 MW in the previous assessment. This difference is entirely driven by the fact that the previous assessment did not consider a Critical Peak Pricing (CPP) offering for residential customers. This option is enabled in the current study by the assumption that AMI will be in place in PacifiCorp's service territory by 2020. If AMI deployment does not occur, this would constitute a significant obstacle to attaining this potential at the cost identified in this study.
  - The C&I pricing potential in the current study of 90 MW in 2034 is also substantially larger than the corresponding value of 3.5 MW from the previous study. The previous study did not show any potential for two of the three options considered by the current study (TOU and RTP), and had varying assumptions surrounding the comparable CPP option as explained in Table 5-3 below.
  - The two studies provide almost identical potential estimates for the Demand Buyback program option.

[47] "Assessment of Long-Term System-Wide Potential for Demand-Side and Other Supplemental Resources, 2013-2032, Volume I and II; prepared by the Cadmus Group for PacifiCorp; March 2013".
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/DSM_Potential_Study/PacifiCorp_DSMPotential_FINAL_Vol%20I.pdf
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/DSM_Potential_Study/PacifiCorp_DSMPotential_Vol-II_Mar2013.pdf

Table 5-1 Comparison of Class 1 and 3 DSM Potential with 2013 Assessment (Incremental Potential, without Interactive Effects)

DSM Options	2013 Assessment	Current Assessment
	2032 Potential (MW)	2034 Potential (MW)
Class 1 DSM		
Residential DLC- Cooling	50.0	97.1
Residential DLC- Water Heating	21.2	11.8
C&I DLC- Cooling	1.1	13.9
C&I DLC- Water Heating	0.4	0.6
Irrigation Load Control	12.5	64.5
Curtailable Agreements	189.1	185.1
Total Class 1 DSM	**274**	**373.1**
Class 3 DSM		
Residential Pricing		
Residential TOU	25.5	25.7
Residential CPP	-	112.6
Total Residential Pricing	*25.5*	*138.3*
C&I Pricing		
C&I TOU	-	9.7
C&I CPP	3.5	70.0
C&I RTP	-	10.5
Total C&I Pricing	*3.5*	*90.2*
Irrigation Pricing		
Irrigation TOU	18	3.2
Irrigation CPP	-	9.7
Total Irrigation Pricing	*18*	*12.9*
Demand Buyback	18.8	18.7
Total Class 3 DSM	**66**	**260**

Comparison of Class 1 Resource Options with Previous Assessment

Table 5-2 presents a comparison of Class 1 DSM potential estimates by option and state and discusses the primary drivers behind variance between the two studies.

Table 5-2 Comparison of Class 1 DSM Potential Results (Incremental Potential, without Interactive Effects)

Class 1 DSM Option	State	2013 Assessment 2032 Incremental Market Potential (MW)	Current Assessment 2034 Incremental Market Potential (MW)	Primary Differences in Potential Estimates
Residential DLC- Cooling	CA	0.9	1.6	• Larger customer growth rate primarily in largest market: Utah. • Higher projected saturation growth of applicable cooling equipment in current study vs. 2013 study (applies to CA, ID, UT, and WA) • Higher participation assumptions in current study vs. 2013 study
	ID	0.8	1.7	
	OR	18.4	18.4	
	UT	18.9[48]	63.4[49]	
	WA	7.9	8.9	
	WY	3.4	3.1	
	Total	**50**	**97.1**	
Residential DLC- Water Heating	CA	0.5	0.55	• UT WH DLC potential not being considered in current study • Lower impact per WH control switch in current study (0.26 kW in current study vs. 0.56 kW in 2013 assessment) • Differences in WH saturation assumptions
	ID	0.3	0.94	
	OR	9.6	6.57	
	UT	6.9	0.0[50]	
	WA	3.4	2.23	
	WY	0.5	1.52	
	Total	**21.2**	**11.8**	
C&I DLC- Cooling	CA	0.03	0.4	• Larger targeted customer base in current study vs. 2013 study (2013 study targeted only small office and small retail customers, while current study targets a much broader market segment encompassing small and medium C&I customers) • Larger per- participant impacts in current study vs. impact assumptions in 2013 study
	ID	0.03	0.4	
	OR	0.5	5.7	
	UT	0.9[51]	4.2[52]	
	WA	0.1	1.8	
	WY	0.2	1.4	
	Total	**1.8**	**13.9**	

[48] 2013 assessment considered a base of 120 MW of impact from existing program.
[49] Current study considered a base of 100 MW of impact from existing program.
[50] The current Cool Keeper program in Utah targets only eligible cooling equipment. The DLC savings potential in Utah are based on the existing program offer. Therefore, in Utah, DLC savings are derived through control of cooling equipment only and electric water heater control is not included. In all other states, where new DLC programs are assumed to be launched, savings are derived through control of both cooling and water heating equipment.
[51] 2013 assessment considered 0.7 MW of impact from existing program
[52] Current study considered 15 MW impact from existing program

Class 1 DSM Option	State	2013 Assessment 2032 Incremental Market Potential (MW)	Current Assessment 2034 Incremental Market Potential (MW)	Primary Differences in Potential Estimates
C&I DLC Water Heating	CA	0.02	0.03	• Potential estimate in current study is higher primarily due to larger market size in current study as compared to 2013 assessment. • Current study targets small C&I customers for this option- the customer count for this segment is larger than the market segment targeted in the 2013 assessment, including small office and small retail customers.
	ID	0.01	0.04	
	OR	0.2	0.41	
	UT	0.1	0.0[53]	
	WA	0.04	0.09	
	WY	0.02	0.06	
	Total	**0.4**	**0.6**	
Irrigation Load Control	CA	4.5	4.2	• In Idaho, the peak coincident irrigation class load is larger than the 2013 assessment, leading to a larger base from which to start. • For Utah, the overall potential estimates between the two studies are very close. However, the 2013 study assumes 38 MW of existing capacity under contract whereas the current study assumes 25 MW of existing potential, leading to differences in incremental potential.
	ID	1.0[54]	26[55]	
	OR	2.8	8.7	
	UT	0.2[56]	19[57]	
	WA	3.8	5.1	
	WY	0.2	1.5	
	Total	**12.5**	**59.5**	
Curtailable Agreement	CA	1.8	1.0	• Overall potential estimate in current study is close to that presented in 2013 assessment. • Current study assumes lower per-participant impact at 21% as compared to 30% in 2013 assessment. • Current study assumes uniform 23% participation across all states, whereas previous study assumed participation rates in the 10%-30% range, varying by state.
	ID	9.4	2.3	
	OR	46.3	32.9	
	UT	91.4	92.6	
	WA	15.6	9.5	
	WY	24.6	46.8	
	Total	**189.1**	**185.1**	

[53] The current Cool Keeper program in Utah targets only eligible cooling equipment. The DLC savings potential in Utah are based on the existing program offer. Therefore, in Utah, DLC savings are derived through control of cooling equipment only and electric water heater control is not included. In all other states, where new DLC programs are assumed to be launched, savings are derived through control of both cooling and water heating equipment.

[54] Assumes 171 MW of capacity under contract

[55] Assumes 170 MW of existing potential

[56] Assumes 38 MW of capacity under contract

[57] Assumes 20 MW of existing potential

Comparison of Class 3 Resource Options with Previous Assessment

Table 5-3 presents a comparison of Class 3 DSM potential estimates by option and state and discusses the primary drivers behind variance between the two studies.

Table 5-3 Comparison of Class 3 DSM Potential Results with 2013 Assessment Results (Incremental Potential, without Interactive Effects)

Class 3 DSM Option	State	2013 Assessment 2032 Incremental Market Potential (MW)	Current Assessment 2034 Incremental Market Potential (MW)	Primary Differences in Potential Estimates
Residential TOU	CA	0.3	0.3	• Overall residential TOU estimates are very close between the two studies • Unit impact assumptions in the current study are slightly lower when compared to the 2013 study assumptions, while participation rate assumptions are slightly greater.
	ID	-	-	
	OR	4.3	6.1	
	UT	17.0	15.7	
	WA	2.3	1.8	
	WY	1.6	1.9	
	Total	**25.5**	**25.7**	
C&I TOU	CA	-	0.3	• The 2013 study estimated the impacts of the Company's existing C&I TOU rates, but did not assess incremental potential for these rates. Additional Class 3 DSM opportunities for C&I customers were considered in the Nonresidential CPP and Demand Buyback analysis.
	ID	-	0.8	
	OR	-	7.1	
	UT	-	-	
	WA	-	1.5	
	WY	-	-	
	Total	**-**	**9.7**	
Irrigation TOU	CA	1.7	0.2	• Irrigation TOU potential in the current study is smaller due to a revised per-customer impact assumption (5% now vs. 30% previously) informed by new information from regional and national implementation experience.
	ID	9.5	1.8	
	OR	3.8	0.5	
	UT	0.7	0.3	
	WA	1.8	0.3	
	WY	0.3	0.1	
	Total	**17.8**	**3.2**	

Class 3 DSM Option	State	2013 Assessment 2032 Incremental Market Potential (MW)	Current Assessment 2034 Incremental Market Potential (MW)	Primary Differences in Potential Estimates
Residential CPP	CA	-	1.4	• The 2013 study assumed no AMI would be available in the planning horizon therefore did not assess residential CPP potential • The current study assumes AMI would be available beginning in 2020 (opportunity and costs are therefore contingent on this assumption).
	ID	-	2.8	
	OR	-	26.2	
	UT	-	66.3	
	WA	-	7.8	
	WY	-	8.1	
	Total	**-**	**112.6**	
C&I CPP	CA	0.0	0.5	• The potential estimate in the current study is substantially higher, primarily due to higher participation from AMI-enabled customers. The 2013 study assumed no AMI would be available in the planning horizon, and therefore only modeled potential for the subset of customers that already have interval meters. • Per-participant impact assumed in current study is higher than the 2013 study.
	ID	0.1	1.1	
	OR	0.9	12.6	
	UT	1.4	36.2	
	WA	0.2	4.4	
	WY	0.9	15.2	
	Total	**3.5**	**70.0**	
Irrigation CPP	CA	-	0.6	• The 2013 study did not assess potential for irrigation CPP potential, as the study vendor saw DLC and TOU as more appropriate for this sector. • The combined impact of CPP and TOU in this study is 12.9 MW, as compared to the estimate of 17.8 MW for TOU only in the 2013 study.
	ID	-	5.1	
	OR	-	1.4	
	UT	-	1.5	
	WA	-	0.9	
	WY	-	0.2	
	Total	**-**	**9.7**	
C&I RTP	CA	-	0.1	• The 2013 study did not consider the RTP option for C&I customers as at the time of the analysis, the study vendor saw RTP as a competing, less common alternative to other price-based options available to these customers and unlikely to increase the total Class 3 DSM potential.
	ID	-	0.1	
	OR	-	1.9	
	UT	-	5.2	
	WA	-	0.5	
	WY	-	2.7	
	Total	**-**	**10.5**	
Demand Buyback	**CA**	0.1	0.1	• Overall, Demand Buyback potential estimates in the two studies are very similar.
	ID	0.4	0.2	
	OR	4.2	3.1	
	UT	9.2	8.1	
	WA	0.7	0.8	
	WY	4.2	6.4	
	Total	**18.8**	**18.7**	

About Applied Energy Group (AEG)

Founded in 1982, AEG is a multi-disciplinary technical, economic and management consulting firm that offers a comprehensive suite of demand-side management (DSM) services designed to address the evolving needs of utilities, government bodies, and grid operators worldwide. Hundreds of such clients have leveraged our people, our technology, and our proven processes to make their energy efficiency (EE), demand response (DR), and distributed generation (DG) initiatives a success. Clients trust AEG to work with them at every stage of the DSM program lifecycle – assessing market potential, designing effective programs, supporting the implementation of the programs, and evaluating program results.

The AEG team has decades of combined experience in the utility DSM industry. We provide expertise, insight and analysis to support a broad range of utility DSM activities, including: potential assessments; end-use forecasts; integrated resource planning; EE, DR, DG, and smart grid pilot and program design and administration; load research; technology assessments and demonstrations; project reviews; program evaluations; and regulatory support.

Our consulting engagements are managed and delivered by a seasoned, interdisciplinary team comprised of analysts, engineers, economists, business planners, project managers, market researchers, load research professionals, and statisticians. Clients view AEG's experts as trusted advisors, and we work together collaboratively to make any DSM initiative a success.

Applied Energy Group, Inc.
500 Ygnacio Valley Road, Suite 450
Walnut Creek, CA 94596

P: 510.982.3525
F: 925.284.3147