PACIFICORP DEMAND-SIDE RESOURCE POTENTIAL ASSESSMENT FOR 2017-2036

VOLUME 3:
CLASS 1 & 3 DSM ANALYSIS

Prepared for:
PacifiCorp

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INTRODUCTION

In 2015, 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 2017–2036 to inform the development of PacifiCorp's 2017 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 of demand-side resources.

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 2017 IRP and subsequent DSM planning and program development efforts. This study serves as an update of similar studies completed in 2007, 2011, 2013, and 2015.[2]

DSM RESOURCE CLASSES

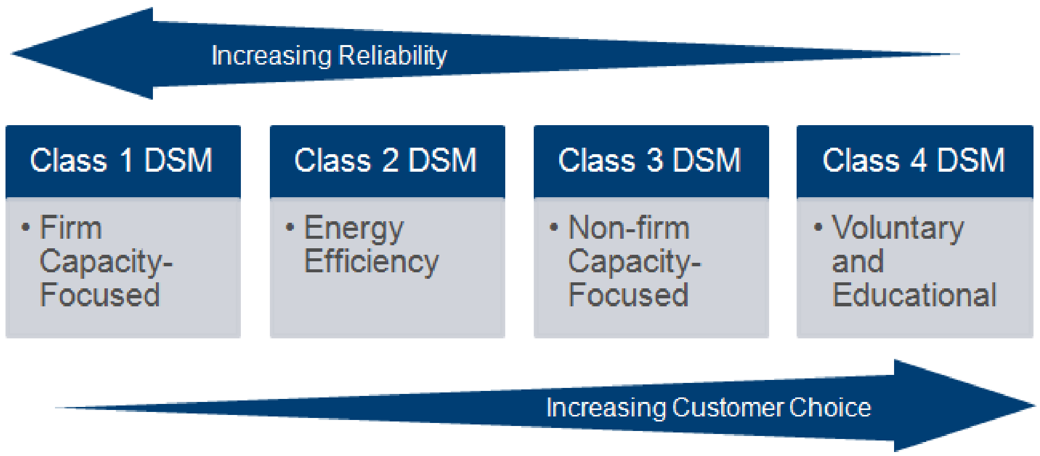
For resource planning purposes, PacifiCorp classifies DSM resources into four categories, differentiated by two primary characteristics: reliability and customer choice (see Figure 1-1). These resources are captured through programmatic efforts promoting efficient electricity use through various intervention 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 equipment. In contrast, 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, which provides Oregon energy-efficiency potential 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 due to uncertainties regarding resources likely to be found economic and pursued.

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

Table 1-1 provides a list of abbreviations and acronyms used in this report, 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 (NWPCC)
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 Cooling
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

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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 potential 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 a Class 1 DSM program, the timing and persistence of load reduction is involuntary on their part, within 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. 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 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. 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. 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. Another example from the Class 1 DSM resources is that multiple Direct Load Control (DLC) programs aim to reduce customers' cooling load. These different programs are allocated based on equipment availability such as Central A/C vs Room A/C, and furthermore allocated based on assumed adoption of smart thermostats vs DLC switches.

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. Whereas the 2015 potential study only assessed capacity-focused resources at the time of the overall system peak, which occurs in the summer, this study also includes an assessment of resources targeted at the winter peak.

Figure 2-1 shows the system coincident summer peak forecast values by state, developed based on load forecast data provided by PacifiCorp. In the base year of analysis, 2015, system peak load for the summer (a typical July weekday at 3:00 pm) is 9,935 MW at the grid or generator level. Utah contributes 48% of summer system peak, followed by Oregon at 25%, Wyoming at 13%, WA 8%, and ID 5%. The smallest contributor is CA at 2%

Figure 2-1 System Coincident Peak Forecast by State (Summer)

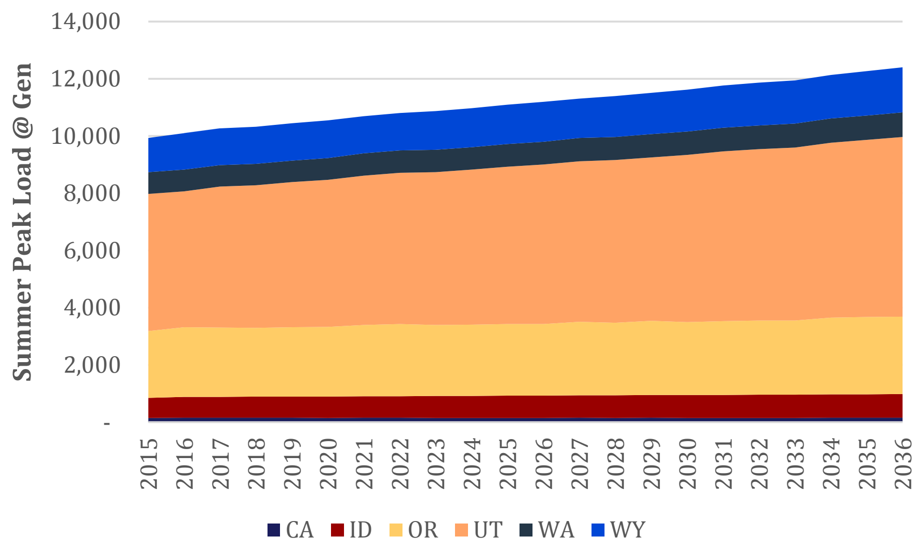
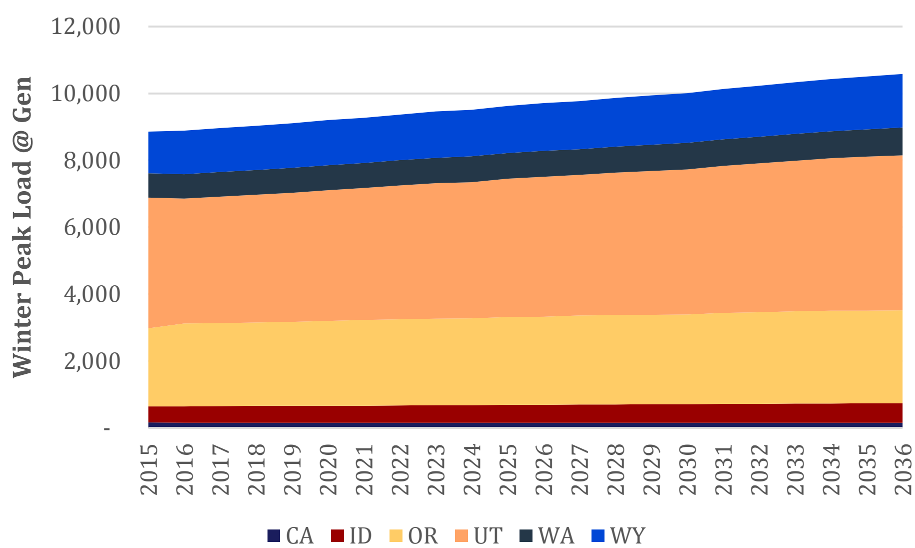


Figure 2-2 shows the system coincident winter peak forecast values by state, developed based on load forecast data provided by PacifiCorp. In the base year of analysis, 2015, system peak load for the winter (a typical December weekday at 6:00 pm) is 8,857 MW at the grid or generator level. The winter system peak is about 11% lower than the summer peak.

Figure 2-2 System Coincident Peak Forecast by State (Winter)



Definition of Class 1 and 3 DSM Options

The next step in the analysis is to characterize the Class 1 and 3 DSM products for the analysis. We considered the characteristics and applicability of a comprehensive list of options available in the DSM marketplace today as well as those projected into the 20-year study time horizon. We included for quantitative analysis those options which have been deployed at scale such that reliable estimates exist for cost, lifetime, and performance. Each selected product is described briefly below, as well as a description and rationale for any product that was considered but ultimately screened out because of insufficient data applicability.

Class 1 DSM Resources

Table 2-2 lists the Class 1 DSM options considered in the study, followed by a brief discussion of the options selected. As shown, this study includes several Class 1 options that were not considered in the previous study. The primary reasons for this are the new assessment of winter peak impacts in addition to summer as well as maturing technologies such as smart thermostats, ice energy storage, and electric vehicle chargers.

Table 2-2 Class 1 DSM Products Assessed in the Study

Class 1 DSM Option	Eligible Customer Classes	Mechanism	Currently Offered by PacifiCorp?	Considered in Previous CPA?
Direct Load Control (DLC) of central air conditioners	Residential, Small C&I, Medium C&I	Direct load control switch installed on customer's equipment	Yes, AC offered in UT	Yes
DLC of domestic hot water heaters (DHW)	Residential, Small C&I, Medium C&I	Direct load control switch installed on customer's equipment	No	Yes
DLC of Space Heating	Residential, Small C&I, Medium C&I	DLC switch installed on customer's equipment	No	No
Smart Thermostats DLC	Residential	Internet-enabled control of thermostat set points	No	No
Smart Appliances DLC	Residential	Internet-enabled control of operational cycles of white goods appliances	No	No
DLC of Room Air Conditioners	Residential	Direct load control switch installed on customer's equipment	No	No
Irrigation Load Control	Irrigation	Automated pump controllers	Yes, in ID and UT	Yes
Ice Energy Storage	Small and Medium C&I	Peak shifting of space cooling loads using stored ice	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
Electric Vehicle DLC Smart Chargers	Residential	Automated, level 2 EV chargers that postpone or curtail charging during peak hours.	No	No

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, under the name "Cool Keeper", 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 realizes about 115 MW of load reduction potential from participating residential and C&I customers.[3] 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) while looking at incremental potential for expansion. For other jurisdictions, where such programs are yet to be established, the program offering is expanded to include several DLC options for both residential and C&I customer. For residential customers, we consider DLC for space cooling, space heating, water heating, smart thermostats, smart appliances, and smart electric vehicle chargers. For small and medium C&I customers, we consider DLC for space cooling, space heating, and water heating. Table 2-3 presents DLC offering basics.

Table 2-3 Residential and C&I DLC Program Basics

Controlled end uses	Eligible Customer Classes	Applicable Hours
Cooling equipment, including Central Air Conditioners and Heat Pumps	Residential, Small C&I, Medium C&I	Top 50 summer system hours
Electric Water Heating	Residential, Small C&I, Medium C&I	Top 50 summer system hours, and top 50 winter system hours
Space Heating	Residential, Small C&I, Medium C&I	Top 50 winter system hours
Room AC	Residential	Top 50 summer system hours
Smart Thermostats	Residential	Top 50 summer system hours, and top 50 winter system hours
Smart Appliances	Residential	6 hours at peak every summer weekday (528 total) and every winter weekday (also 528 total)
Electric Vehicle Charging	Residential	6 hours at peak every summer weekday (528 total) and every winter weekday (also 528 total)

Table 2-4 and Table 2-5 present 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 five-year period, and then slows over the second half. For all programs and states other than the existing Utah programs, we assume program ramp-up and participant recruitment would begin in 2019. This is to account for the necessary time to secure regulatory approvals, engage a vendor, and launch the offerings (if selected by the 2017 IRP), In Utah, the existing program is assumed to ramp up beginning in 2018 if selected by the 2017 IRP, to allow time to recruit new participants.

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

Table 2-4 Residential DLC Program: Planning Assumptions

Data Item	Unit	Value
Participation Assumptions[4]		
Residential customer participation	Steady-state Participation (as % of eligible customers)	*Cooling & Water* Heating – 23% for UT, 15% for all other states *Space Heating* – 20% for all *Smart Thermostats* – 7% for UT, 15% for all other *Smart App* – 5% for all *EV charging* – 25% for all
Program ramp up period	Years	Five, Three years for UT Water heating
Impact Assumptions[5]		
Residential customer per participant impact - Summer Peak	Average kW reduction per participant @ meter	*Cooling & Smart Thermostats* – CA- 0.66, ID- 0.46, OR- 0.43, UT- 0.97, WA- 0.53, WY- 0.53 *Water Heating* – 0.58 for all states Room AC – CA- 0.23, ID- 0.21, OR- 0.14, UT- 0.23, WA- 0.17, WY- 0.30 *Smart Appliances* – -0.14 *EV Charging* – 0.92
Residential customer per participant impact – Winter Peak	Average kW reduction per participant @ meter	*Smart Thermostats* – CA- 1.25, ID- 1.10, OR- 1.11, UT- 0.35, WA- 1.10, WY- 0.89 *Water Heating* – 0.58 for all states *Space Heating* – CA- 1.11, ID- 1.75, OR- 1.20, UT- 1.38, WA- 1.47, WY- 1.78 *Smart Appliances* – -0.14 *EV Charging* – 0.92
Cost Assumptions[6]		
Annual Program Administration Cost	\$/year (split between Res & C&I)	Central Cooling & Space Heating – \$300,000 each Water Heating – costs assumed in Central Cooling program Smart thermostats, Smart Appliances, EV Charging – \$75,000 each Room AC – costs assumed in Central Cooling program
Annual Marketing and Recruitment Costs	\$/new participant	\$50-60 for residential for each program
Equipment capital and installation cost	\$/new participant	CAC, RAC, Space Heating – \$215 each Water Heating - \$315 Smart thermostat – Bring-your-own[7] Smart Appliances – \$300 EV Charging – \$1,200
Annual O&M cost	\$/participant/year	\$11, except for Smart thermostat - \$20
Per participant annual incentive	\$/participant/year	Water Heating - \$2 per month year round, \$24 annually All others - \$20 annual per participating unit (avg number of CAC units per participant = 1.06)

[4] Detailed documentation of participation assumptions is presented in Volume 5, Section A of the report.

[5] Detailed documentation of impact assumptions is presented in Volume 5, Section B of the report.

[6] Detailed documentation of cost assumptions is presented in Volume 5, Section C of the report.

[7] Assumes that participating customers already own a compatible thermostat. A program design that pays for all or a portion of thermostat cost would have additional costs.

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

Data Item	Unit	Value
Participation Assumptions[8]		
C&I customer participation	Steady-state Participation (as % of eligible customers)	*CAC* – <u>For UT:</u> *Small C&I - 2.3%, Medium C&I – 3.4%,* <u>Other States</u> *3%* *Water Heating* – <u>For UT:</u> Small C&I- 2.9%, Medium C&I- 3.9%, <u>Other States</u> 3% *Space Heating* – 3%
Program ramp up period	Years	Five, One year for UT
Impact Assumptions[9]		
C&I customer per participant impact for **cooling**	Average kW reduction per participant @ meter	<u>Small C&I</u> CA- 1.7, ID- 1.2, OR- 1.1, UT- 2.5, WA- 1.3, WY- 1.3 <u>Medium C&I</u> 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**	Average kW reduction per participant @ meter	1.46 – 1.47, same for each class.
C&I customer per participant impact for **space heating**	Average kW reduction per participant @ meter	CA- 2.82, ID- 4.41, OR- 3.02, UT- 3.50, WA- 3.72, WY- 4.51
Cost Assumptions[10]		
Annual Program Administration Cost	$/year (split between Res & C&I)	*CAC & Space Heating* – $300,000 each *Water Heating* – costs attached to CAC *Smart Thermostats Smart Appliances, EV Charging* – $75,000 each *Room AC* – program is add-on or extension of CAC program and uses its infrastructure
Annual Marketing and Recruitment Costs	$/new participant	$63-75 for small C&I, $75-90 for medium C&I
Equipment capital and installation cost for AC switch	$/new participant	*CAC & Space Heating* – $387 each for small C&I, $1,120 each for medium C&I *Water heating* – $315
Annual O&M cost	$/participant/year	$19 for small C&I, $60 for medium C&I
Per participant annual incentive (AC)	$/participant/year	*CAC & Space Heating each* $38 for small C&I, $128 for medium C&I *Water Heating* $24

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

Ice Energy Storage

Ice Energy Storage, a type of thermal energy storage, is an emerging technology that is being explored in many peak-shifting applications across the country. This technology involves cooling and freezing water in a storage container so that the energy can be used at a later time for space cooling. More specifically, the freezing water takes advantage of the large amount of latent energy associated with the phase change between ice and liquid water, which will absorb or release a large amount of thermal energy while maintaining a constant temperature at the freezing (or melting) point. An ice energy storage unit turns water into ice during off-peak times when price and demand for electricity is low, typically night time. During the day, at peak times, the stored ice is melted to meet all or some of the building's cooling requirements, allowing air conditioners to operate at reduced loads.

Ice energy storage has capital costs in the range of $100 to $500 per installed kW with a typical lifetime of 10-30 years depending on the storage cycles and operating conditions.

Ice energy storage is primarily being used in non-residential buildings and applications, as modeled in this analysis, but may see expansion in the future to encompass smaller, residential systems as well as emerging grid services for peak shaving and renewable integration. Table 2-6 presents Ice Energy Storage program basics.

Table 2-6 Ice Energy Storage Program: Planning Assumptions

Data Item	Unit	Value
Participation Assumptions[11]		
C&I customer participation	Steady-state Participation (as % of eligible customers)	For UT – Small C&I- 1.2%, Medium C&I- 1.7%, Other States 1.5%
Program ramp up period	Years	Five
Impact Assumptions[12]		
C&I customer per participant impact for cooling	Average kW reduction per participant @ meter	5.00
Cost Assumptions[13]		
Annual Program Administration Cost	$/year (split between Res & C&I)	$75,000
Annual Marketing and Recruitment Costs	$/new participant	$75-90 for medium C&I
Equipment capital and installation cost for AC switch	$/new participant	$10,000
Annual O&M cost	$/participant/year	No O&M
Per participant annual incentive (AC)	$/participant/year	No annual incentive. As an initial incentive, the program purchases & installs unit.

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 predefined 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

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

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 the Environmental Protection Agency's RICE/NESHAP regulations that are likely to constrain operation of certain backup generators installed before 2006.[14] A participation rate deflator is applied to factor in lowered participation levels on account of these regulations.

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 2019 to allow for vendor selection, contracting and regulatory approvals. These assumptions are described in Volume 5 of the report under Curtailment Program participation rate development. Table 2-7 presents key participation, impact and cost assumptions for the Curtailable Agreements.

Table 2-7 Curtailable Agreements Program: Planning Assumptions

Data Item	Unit	Value
Participation Assumptions[15]		
Large C&I customer participation (applicable to all 6 states)	Steady-state Participation (as % of eligible customers)	21.1%
Extra-large C&I customer participation (applicable to all 6 states)		20.9%
Program ramp up period	Years	3
Impact Assumptions[16]		
Per-participant load reduction	% of participant's load	21%
Cost Assumptions[17]		
Program Delivery Cost (administered by third party)	$/kW-year	Would be included in 3rd Party Costs, within Utility Admin Costs below
Internal utility administration cost	$/kW-year	$70.7
Payment for energy reduction during event hours	$/kWh	$0.11

[14] 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

[15] Detailed documentation of participation assumptions is presented in Volume 5, Section A of the report.

[16] Detailed documentation of impact assumptions is presented in Volume 5, Section B of the report.

[17] 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.

Irrigation Load Control

This program option targets irrigation loads by shutting off or scheduling 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 each jurisdiction. 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.

In 2016, PacifiCorp launched a pilot program in Oregon targeting 3 MW of irrigation load reduction, but we do not count this as existing potential for the purposes of this analysis, so it is still available to future full-scale deployments in the potential assessment

Eligible customer load comes from irrigation customers with at least 25 horsepower irrigation pumps, which is the vast majority of class load: 92% of load in CA, 100% in ID, 78% in OR, 100% in UT, 75% in WA, and 82% in WY. The irrigation pumps are able to be controlled and curtailed for the top 52 summer system hours.

Table 2-8 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 2019 to allow for vendor selection, contracting and regulatory approvals.

Table 2-8 Irrigation Load Control Program: Planning Assumptions

Data Item	Unit	Value
Participation Assumptions[18]		
Irrigation load participation	Steady-state Participation (as % of eligible load)	CA- 15%; ID- 52.5%; OR-15%; UT- 30%; WA-15%; WY- 15%;
Program ramp up period	Years	5
Impact Assumptions[19]		
Per participant load reduction	% of participant’s load	100%
Cost Assumptions[20]		
Program Development Cost	$/kW-year	No startup costs; Framework already exists for current programs
Internal utility administration cost *(administered by third party)*	$/kW-year	$52 for ID and UT; $68 for remaining states;

Class 1 DSM Options Considered, but Qualitatively Screened Out

In addition to the Class 1 DSM options included in the study, we considered 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.

[18] Detailed documentation of participation assumptions is presented in Volume 5, Section A of the report.

[19] Detailed documentation of impact assumptions is presented in Volume 5, Section B of the report.

[20] Detailed documentation of cost assumptions is presented in Volume 5, Section C of the report. Cost assumptions are based on kW impacts at site.

- **Battery Energy Storage.** This program provides the ability to shift peak loads using stored electrochemical energy. There are many utilities looking into customer-sited pilots, and cost and performance are projected to improve in the coming years, but at this time estimates of cost, lifetime, and performance of full-scale efforts are not sufficient and reliable enough to quantify as a resource at the level of reliability required for IRP planning.
- **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 as well. 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 and other programs. 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.[21]

CLASS 3 DSM RESOURCES

Class 3 DSM resources considered in our analysis include the following pricing options: Time-of-Use (TOU) rates, Critical Peak Pricing (CPP), Real-Time Pricing (RTP), TOU Demand Rates, and TOU Demand Rates specifically for electric vehicle owners.

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 which assumes a scenario where all customers are placed on the dynamic pricing options by default, and then given an opt-out provision. Please see Volume 5 of the appendix for more details on the "opt-out" case.

We assume that these pricing options require an Advanced Metering Infrastructure (AMI) to enable two-way communication between the customer and utility for notification and billing purposes, except in cases where existing Class 3 rates and infrastructure have already been established. PacifiCorp does not currently have comprehensive AMI in any of its service territories, so in order to assess the potential for dynamic pricing options, this study assumes that PacifiCorp makes a staggered deployment of AMI in Oregon in 2020, Idaho in 2021, and all other territories in 2025. New Class 3 options are therefore modeled beginning in those years. 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. 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 Volume 5 Appendix to this report.

Note that PacifiCorp is already implementing several Class 3 DSM resources as existing rate options. For the purposes of this potential analysis, the impacts from these initiatives are generally assumed to be embedded in the baseline and not a part of the new savings potential. The prior potential

[21] 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

assessment included a detailed assessment of these impacts, but the inputs and variables have not changed materially in the past two years, so it was deemed unnecessary to repeat at this time. See Volume 3, Chapter 3 of the prior potential assessment for the results and findings. In summary, all residential customers in all states are on a mandatory inclining block rate (IBR) unless they have volunteered to participate in a TOU rate, mostly in Idaho but with small uptake in Oregon and Utah. All Extra Large C&I customers are on a mandatory TOU Demand Rate, except those in Idaho. All other C&I customers are split among various flat, TOU, demand, or other rates and contracts.

The Class 3 DSM options that *are* 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.

Class 3 Options for Residential Customers

Table 2-9 lists the Class 3 DSM pricing products analyzed for residential customers in the study. We estimated embedded impacts for the existing Inclining Block Rates (IBRs)[22] and TOU rates currently being offered by PacifiCorp as a parallel analysis in Chapter 3 of the previous, 2015 potential assessment, and no substantive changes to their implementation have occurred in the interim, so please see that report for details. For forward-looking potential estimation purposes over the 2017-2036 timeframe, time-of-use (TOU), TOU with demand charges (TOU Demand), and critical peak pricing (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 the simpler, alternative rates included in the analysis.

Table 2-9 Class 3 Options for Residential Customers

Class 3 DSM Option	Analysis Approach	Whether Current PacifiCorp Offering	Considered in Previous CPA?
Time of Use Demand Rate	Rate that includes a billing component based on a customer's peak demand in a given month. The "TOU" element means that this billing demand would be measured during a peak period of time. This rate structure has traditionally been used with C&I customers, but better reflects the grid's evolving underlying cost structure and is being considered here for residential application.	No	No
Time-of-Use Demand Rate for Electric Vehicle Owners	This rate has the same structure as the TOU Demand Rate listed above, but reflects the group of customers who would participate while owning and charging an electric vehicle. These participants would in effect have an "enabling technology" in the form of their EV that would enable them to shift larger amounts of usage and demand off-peak.	No	No
Time-Of-Use (TOU) Rate	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.[23]	No	Yes

[22] 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.

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

Table 2-10 below presents residential Class 3 program basics.

Table 2-10 Class 3 Residential Program Basics

Program Element	Assumption
Eligible Customer Classes	All residential customers are eligible for TOU, TOU Demand, and CPP rates. TOU Demand with EVs is only applicable for households with an electric vehicle
Controlled end uses	Any end use, although some are more likely than others to be affected. For example, customers may modulate their use of air conditioners, dishwashers, or clothes wasters, but are not likely to unplug their refrigerators.
Applicable Hours	TOU and TOU Demand Rates: 6 hours at peak every summer weekday (528 total) and every winter weekday (also 528 total) CPP: Top 60 summer system hours
Rate structure	TOU: 2:1 on-peak/off-peak price ratio TOU Demand Rates: monthly demand charge of $5.59/kW in Oregon and summer monthly demand charge of $14.51/kW in Utah, with corresponding decrease in volumetric energy rate such that rate is revenue neutral on average[24] CPP: 6:1 on-peak/off-peak price ratio

Residential Class 3 Customer Participation Assumptions

Table 2-11 presents participation assumptions for residential customers in pricing options with a voluntary, opt-in offering. Our analysis considered the simultaneous offering of multiple new rate options as part of a "rates portfolio". In 2017-2018, we assume impacts are realized only from existing TOU rates (i.e. no incremental potential), whereas new rates are offered beginning in 2019 to allow time for rate design and regulatory approvals. Assumed program start date varies by state based on AMI deployment assumptions.

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. Participation rates are specified in terms of a percentage of the eligible customer base. Detailed documentation of the basis for developing participation assumptions is presented in Volume 5 of this report.

[24] Detailed TOU Demand Rate analysis is developed for Utah and Oregon only, and the resulting customer behavioral impacts and price-responsiveness is applied as a reasonable proxy to PacifiCorp's other, nearby service territories. Relative impacts for Utah are therefore assumed to be the same in Idaho and Wyoming, while relative impacts for Oregon are assumed to be the same in Washington and California.

Table 2-11 Class 3 Participation Assumptions for Residential Customers (with Opt-in Offer)

	CA, UT, WA, WY		ID		OR	
	Steady State Participation Rate	**Program Start Date**	**Steady State Participation Rate**	**Program Start Date**	**Steady State Participation Rate**	**Program Start Date**
Critical Peak Pricing	17%	2025	17%	2021	17%	2020
Time of Use	28%	2025	*n/a since already an existing rate*	2015	28%	2020
TOU Demand Rate	28%	2025	28%	2021	28%	2020
TOU Demand Rate w/ EV	84%	2025	84%	2021	84%	2020

Residential Class 3 Customer Impact Assumptions

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.[25] These pilots have tested over 200 different time-varying rate offerings for residential customers.

Table 2-12 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 cost during peak means a stronger price signal and greater bill savings and demand reduction opportunities for participants. 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 and time-varying rates are relatively uncommon.

Similarly for CPP, the price ratio assumed for this analysis is 6:1, which is also a more moderate level among other national CPP rates. The price of the demand charge in the TOU Demand rate was provided by PacifiCorp. The level of the demand charge in Oregon is roughly in the middle of the range of residential demand charges observed elsewhere.[26] The demand charge in Utah is high in the range, only because it is constrained to summer months rather than applied year-round. In the analysis, the demand charges are levelized on a per-kWh basis across the peak hours of the TOU to produce a peak-to-off-peak price ratio that is comparable to that of the other rate designs.

Impact assumptions are presented in Table 2-12, and are based on these ratios and rate designs.

[25] For a discussion of select pilots in the database, see Ahmad Faruqui and Sanem Sergici, "Arcturus: International Evidence on Dynamic Pricing," *The Electricity Journal*, August/September 2013.

[26] For a summary of residential demand charges currently being offered by utilities, see Ryan Hledik, "Rediscovering Residential Demand Charges," *The Electricity Journal*, August/September 2014.

Table 2-12 Class 3 Impact Assumptions for Residential Customers

Type of Offer	Customer Class	State	Option	Per Customer Summer Peak Demand Reduction (%)	Per Customer Winter Peak Demand Reduction (%)
Opt-in	Residential	All	Time-Of-Use	5.7%	5.7%
Opt-in	Residential	All	Critical Peak Pricing	12.5%	12.5%
Opt-in	Residential	OR, WA, CA	TOU Demand Rate	3.3%	3.3%
Opt-in	Residential	UT, ID, WY	TOU Demand Rate	8.0%	0.0%*
Opt-in	Residential	OR, WA, CA	TOU Demand with EVs	9.8%	9.9%
Opt-in	Residential	UT, ID, WY	TOU Demand with EVs	20.3%	0.0%*

** Note that TOU Demand Rates designed for Eastern States are focused on summer peak reductions and exclude winter peak savings and associated rate design elements.*

Class 3 Options for Non-Residential Customers

Table 2-13 lists the relevant Class 3 DSM pricing options considered in the study for non-residential customers. Note again that we have estimated impacts for PacifiCorp's existing TOU rates as a parallel analysis in Chapter 3 of the previous, 2015 potential assessment, and no substantive changes to their implementation have occurred in the interim, so please see that report for details. For potential estimation purposes over the 2017-2036 timeframe, only TOU, CPP, and RTP rates are considered for commercial and industrial customers. For irrigation customers, only TOU and CPP rates are considered, as RTP is not considered appropriate for irrigation customers.[27]

Table 2-13 Class 3 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 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.	No	Yes, only for extra-large C&I
Real Time Pricing (RTP) Rate	Large and 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	Yes
Irrigation Time-Of-Use (TOU) Rate	Irrigation	For states without existing irrigation TOU rates (CA, ID, WA, WY), study analyzes impacts associated with new TOU rates.	Offered in California, Oregon and Utah	Yes

[27] 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.

Table 2-14 presents TOU, CPP, and RTP program basics for non-residential customers.

Table 2-14 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 and winter weekday (summer only in UT) Irrigation TOU: 120 hours- assumes two on-peak hours each weekday, June to August CPP: Top 60 system hours for each summer and winter peak season (summer only in UT)
Rate structure	TOU: 2:1 on-peak/off-peak price ratio CPP: 6:1 on-peak/off-peak price ratio

Non-Residential Class 3 Customer Participation Assumptions

Table 2-15 presents participation assumptions for non-residential customers in pricing options with a voluntary, opt-in offering. Participation assumptions are based on a portfolio of rate offerings which include TOU, CPP, and RTP. New rates are assumed available the year that AMI is assumed to be fully deployed in a given territory; except in the case of large and extra-large customers that already have interval meters for existing mandatory or voluntary rate options.

Changes in participation to reach a steady state after a new product introduction are assumed to take place over a five-year timeframe. As described earlier in this report, ramp up to steady-state participation follows an "S-shaped" diffusion curve. Participation rates are specified in terms of a percentage of the eligible customer base. Detailed documentation of the basis for developing participation assumptions is presented in Volume 5 of this report.

Table 2-15 Class 3 Participation Assumptions for Non-Residential Customers (with Opt-in Offer)

		CA, UT, WA, WY		ID		OR	
		Steady State Participation Rate	Program Start Date	Steady State Participation Rate	Program Start Date	Steady State Participation Rate	Program Start Date
Critical Peak Pricing	Small and Medium	18%	2025	18%	2021	18%	2020
	Large and Extra Large	18%	2019	18%	2019	18%	2019
	Irrigation	18%	2025	18%	2021	18%	2020
Time of Use	Small, Medium, & Large	13%	2025	13%	2021	13%	2020
	Extra Large	*0% or n/a since already an existing rate*		13%	2019	*0% or n/a since already an existing rate*	
	Irrigation	13%	2025	13%	2021	13%	2020
Real time Pricing	Large	3%	2019	3%	2019	3%	2019
	Extra Large	5%	2019	5%	2019	5%	2019

Non-Residential Class 3 Customer Impact Assumptions

Table 2-16 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 than 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 2-16 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.

Table 2-16 Class 3 Load Impact Assumptions for Non-Residential Customers

Customer Class	Option	Per Customer Summer Peak Demand Reduction (%)	Per Customer Winter Peak Demand Reduction (%)
Small C&I	Time-Of-Use	0.2%	0.2%
Small C&I	Critical Peak Pricing	0.6%	0.6%
Medium C&I	Time-Of-Use	2.6%	2.6%
Medium C&I	Critical Peak Pricing	7.3%	7.3%
Large C&I	Time-Of-Use	3.1%	3.1%
Large C&I	Critical Peak Pricing	8.4%	8.4%
Large C&I	Real Time Pricing	8.4%	8.4%
Extra Large C&I	Time-Of-Use	3.1%	3.1%
Extra Large C&I	Critical Peak Pricing	8.4%	8.4%
Extra Large C&I	Real Time Pricing	8.4%	8.4%
Irrigation	Time-Of-Use	4.7%	4.7%
Irrigation	Critical Peak Pricing	13.0%	13.0%

Class 3 Cost Assumptions

Table 2-17 presents 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 technology costs. Costs for Class 3 pricing options do not include any incremental AMI or metering costs that may be required. Detailed documentation of cost assumptions is presented in the Volume 5 Appendix of this report.

Table 2-17 Class 3 Cost Assumptions

Cost Item	Unit	Value
Development Cost	$/program	$150,000 (1 full-time employee equivalent, or FTE) for TOU & CPP each; $75,000 (0.5 FTE) for TOU Demand Rate, TOU Demand Rate w/ EV, RTP each;
Annual Program Administration Cost	$/year	$75,000 (0.5 FTE) for each pricing program
Annual Marketing and Recruitment Costs	$/new participant	All sectors $10 for TOU; Residential $20 for TOU Demand Rate & TOU Demand Rate w/ EV; Residential, Small and Medium C&I, Irrig- $50 for CPP; Large C&I- $200 CPP & RTP; Extra-large C&I: $400 CPP & RTP
Enabling technology costs	$/participant or $/kW	Assumed zero costs to program

Class 3 DSM Options Considered, but Qualitatively Screened Out

In addition to the Class 3 DSM options included in the study, we considered several 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.

- **Existing Class 3 Options -** PacifiCorp currently offers IBR and TOU rates for several customer classes across its service territories. We estimated the embedded impacts for these rates as a parallel analysis in Chapter 3 of the previous, 2015 potential assessment, and no substantive changes to their implementation have occurred in the interim, so please see that report for details. These impacts are embedded in the baseline forecast and do not represent incremental potential available for selection by the IRP.
- **Demand Buyback / Energy Exchange –** This was a program offered by PacifiCorp where customers would enact their customized, voluntary curtailment plan in response for a market-based economic incentive with no penalties for non-performance. This program was included in the previous study, but was omitted from the current study as the program has been cancelled in all states. The associated savings potential is captured in the Curtailment Agreements offering.
- **TOU Demand Rate for Electric Vehicles with DLC Smart Chargers –** This rate has the same structure as the TOU Demand Rate for electric vehicle households analyzed above, but would focus specifically on combining it with the enabling technology of a smart charger that would automate the delay of charging during peak hours. Having both a rate and a smart charger would theoretically lead to larger per-customer reductions than either option alone, but would also result in a correspondingly higher total cost. Investigating each option separately provides better information regarding optionality from a resource planning perspective, but their combination may be an option for PacifiCorp to investigate further at a future date.

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 is a theoretical construct assuming 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 in this report. 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 research studies conducted in the United States 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 demand reductions provides the levelized cost per kilowatt for each Class 1 and 3 DSM resource in each state, for direct comparison with supply-side alternatives in integrated resource planning. 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. An assessment of the levelized cost per summer peak kW is conducted independently of an assessment of the cost per winter peak kW. In other words, there is no allocation of costs between seasons and each figure in this report represents the full program cost applied to the seasonal peak impact. 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 6.57% to calculate net present value (NPV) costs. An inflation rate of 2.30% 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 2-18, have been included in all levelized cost and potential figures.

Table 2-18 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 2-19 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 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 assumed to be 10 years. For the Ice Energy Storage program, a lifetime of 20 years is assumed to align with the lifetime of the associated HVAC equipment. 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 is conducted as appropriate for the full 20-year period that is contemplated by PacifiCorp’s IRP.

Table 2-19 Program Life Assumptions

Program Option	Lifetime (Years)
Direct Load Control	10
Irrigation Load Control	5
Ice Energy Storage	20
Curtailable Agreements	3
Pricing options	10

3

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 provided 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 Volume 5 of this report. Within the Class 1 resources, some customers are eligible for multiple competing Class 1 options (e.g., DLC Cooling and DLC Smart Thermostats). This is also true for the Class 3 options. To account for this, our analysis made assumptions within each resource class about the choices that 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 resource option, customer class, and state. The discussion of results in this chapter centers on potential impacts in 2036. 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 resource 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 potential starts with a strong resource base already in place, and increases rapidly in the early years as new programs are assumed to become available. After this, participation more or less reaches a steady state such that savings potential grows only with the growth of eligible customers. In our analysis we assumed new program offerings would be available for implementation beginning in 2019 to allow for vendor selection, contracting and regulatory approvals. Typically, programs take three to five years to be fully deployed and reach steady-state participation levels.

Table 3-1 shows total and incremental savings potential in 2036 for all Class 1 DSM resources during summer peak periods. 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.

Table 3-2 shows the same information for winter peak savings potential.

Key observations from our analysis results are:

- Total Class 1 DSM market potential more than doubles in 20 years from 2017-2036. Savings potential from Class 1 DSM resources are estimated to grow from 305 MW in 2017 to 857 MW in 2036, translating into 6.91% of projected system peak demand in 2036. Savings from existing programs account for about one third of the total potential from Class 1 DSM options in 2036.
- In 2017, potential is derived only from PacifiCorp’s existing Class 1 DSM programs; a residential and small C&I air conditioning load control programs in Utah, as well as irrigation load control

programs in Idaho and Utah.[28] Incremental potential for these existing programs, above current impacts, is assumed to begin in 2018 to allow time for additional participant recruitment if selected by the 2017 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 2018.

- 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 88% of the 2036 savings potential for Irrigation Load Control is derived from these two states. Additional savings potential is primarily associated with new program deployments in the remaining four states.
- Total savings potential from the residential DLC option targeting cooling equipment is the next highest contributor and is estimated to reach 206 MW in 2036. However, about half of the total savings is from PacifiCorp's existing Cool Keeper program in Utah. An additional 75 MW of potential in 2036 is associated with a modest expansion of the Utah program, and new DLC program launches in the Company's remaining five states.
- Curtailable Agreements has the highest remaining market potential of all Class 1 DSM options; 183 MW of market potential in 2036.
- New savings potential, as compared to the previous CPA, is driven by several new program options included in this current analysis. These programs include: DLC Smart Thermostats, DLC Smart Appliances, DLC Room Air Conditioning, DLC Electric Vehicle Chargers, and DLC Space Heating.
- This CPA analysis, unlike the prior CPA, includes an estimate of winter peak demand reduction potential. Total winter potential reaches 525 MW in 2036, which is substantially lower than summer savings potential. The largest contributors to winter potential are the DLC Space Heating and DLC Smart Thermostats programs, with potential reaching 190 MW and 94 MW in 2036, respectively.

[28] In May of 2016, PacifiCorp received regulatory approval to operate an irrigation load control pilot in its Oregon service territory. As the pilot program is small, time-bound, and the potential analysis was already materially complete at this point, the impacts of this pilot are not considered "existing" in this study.

Table 3-1 Class 1 DSM Total and Incremental Market Potential by Option (Summer Peak MW)

Class 1 DSM Options	Total Potential Impacts in 2036	Impacts from Existing Options	Incremental Potential Impacts in 2036
Residential DLC Central AC	206.5	100.0	106.5
Residential DLC Space Heating	0.0	0.0	0.0
Residential DLC Water Heating	40.2	0.0	40.2
Residential DLC Smart Thermostats	85.2	0.0	85.2
Residential DLC Smart Appliances	14.7	0.0	14.7
Residential DLC Room AC	8.5	0.0	8.5
Residential DLC EV Chargers	22.2	0.0	22.2
C&I DLC Central AC	29.7	15.0	14.7
C&I DLC Space Heating	0.0	0.0	0.0
C&I DLC Water Heating	4.4	0.0	4.4
DLC Irrigation	247.6	190.0[29]	57.6
Ice Energy Storage	15.3	0.0	15.3
Curtailment Agreements	182.9	0.0	182.9
Total (MW)	**857.3**	**305.0**	**552.3**
Potential (% of projected 2036 system peak)	**6.9%**	**2.5%**	**4.5%**

Table 3-2 Class 1 DSM Total and Incremental Market Potential by Option (Winter Peak MW)

Class 1 DSM Options	Total Potential Impacts in 2036	Impacts from Existing Options	Incremental Potential Impacts in 2036
Residential DLC Central AC	0.0	0.0	0.0
Residential DLC Space Heating	190.4	0.0	190.4
Residential DLC Water Heating	40.2	0.0	40.2
Residential DLC Smart Thermostats	94.1	0.0	94.1
Residential DLC Smart Appliances	14.7	0.0	14.7
Residential DLC Room AC	0.0	0.0	0.0
Residential DLC EV Chargers	22.2	0.0	22.2
C&I DLC Central AC	0.0	0.0	0.0
C&I DLC Space Heating	7.9	0.0	7.9
C&I DLC Water Heating	4.4	0.0	4.4
DLC Irrigation	0.0	0.0	0.0
Ice Energy Storage	0.0	0.0	0.0
Curtailment Agreements	151.5	0.0	151.5
Total (MW)	**525.5**	**0.0**	**525.5**
Potential (% of projected 2036 system peak)	**5.0%**	**0.0%**	**5.0%**

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

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

Class 1 DSM Market Potential Results by Option and State

Table 3-3 shows total Class 1 DSM potential results in 2036 by option for each state in the summer peak season. 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 70% of the savings potential in 2036 is derived from these two states. Note, as shown above, 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 largest potential savings, derived primarily from C&I Curtailable Agreements and residential DLC programs, which show roughly equal potential.
- Wyoming has the fourth highest potential, with the 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 3-3 Class 1 DSM Total Market Potential by Option and State in 2036 (Summer Peak MW)

Program	CA	ID	OR	UT	WA	WY	Total
Residential DLC Central AC	1.0	2.4	18.4	174.4	6.6	3.7	**206.5**
Residential DLC Space Heating	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	***n/a***
Residential DLC Water Heating	0.8	1.4	15.8	15.3	5.7	1.4	**40.2**
Residential DLC Smart T-Stats	1.0	2.4	18.4	53.1	6.6	3.7	**85.2**
Residential DLC Smart Appliances	0.3	0.6	4.2	7.8	0.9	1.0	**14.7**
Residential DLC Room AC	0.2	0.5	2.0	3.9	1.0	1.0	**8.5**
Residential DLC EV Chargers	0.1	0.4	11.1	9.9	0.5	0.2	**22.2**
C&I DLC Central AC	0.7	0.7	5.2	19.2	1.80	2.1	**29.7**
C&I DLC Space Heating	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	***n/a***
C&I DLC Water Heating	0.2	0.2	1.8	1.4	0.4	0.4	**4.4**
DLC Irrigation	5.3	192.3	14.0	26.3	7.5	2.1	**247.6**
Ice Energy Storage	0.5	0.9	5.1	5.8	1.2	1.8	**15.3**
Curtailment Agreements	1.2	2.1	38.0	85.9	9.9	45.8	**182.9**
Total	**11.2**	**203.9**	**134.1**	**402.9**	**42.1**	**63.2**	**857.3**

Table 3-4 presents the Class 1 DSM potential results in 2036 by option for each state in the winter peak season. Winter peak savings are about 60% of those projected for the summer peak season. Key observations are:

- In the residential sector, space heating dominates the winter savings potential, contributing 190 MW in 2036. The DLC Smart Thermostat program follows second with 94 MW of winter peak savings.
- For C&I, the highest contributing program is Curtailment Agreements with 151 MW.

Table 3-4 Class 1 DSM Total Market Potential by Option and State in 2036 (Winter Peak MW)

Program	CA	ID	OR	UT	WA	WY	Total
Residential DLC Central AC	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	***n/a***
Residential DLC Space Heating	4.1	10.4	82.6	55.9	25.9	11.5	**190.4**
Residential DLC Water Heating	0.8	1.4	15.8	15.3	5.7	1.4	**40.2**
Residential DLC Smart T-Stats	1.9	5.7	47.6	19.0	13.7	6.2	**94.1**
Residential DLC Smart Appliances	0.3	0.6	4.2	7.8	0.9	1.0	**14.7**
Residential DLC Room AC	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	***n/a***
Residential DLC EV Chargers	0.1	0.4	11.1	9.9	0.5	0.2	**22.2**
C&I DLC Central AC	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	***n/a***
C&I DLC Space Heating	0.3	0.4	2.8	2.7	0.8	0.8	**7.9**
C&I DLC Water Heating	0.2	0.2	1.8	1.4	0.5	0.4	**4.4**
DLC Irrigation	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	***n/a***
Ice Energy Storage	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	***n/a***
Curtailment Agreements	0.9	2.5	33.7	62.7	9.1	42.6	**151.5**
Total	**8.4**	**21.6**	**199.6**	**174.7**	**57.0**	**64.1**	**525.5**

Table 3-5 shows the incremental potential in 2036 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. For the winter peak season, there is no distinction between total and incremental potential results because there are no existing programs targeted at the winter peak season.

Table 3-5 Class 1 DSM Incremental Market Potential by Option and State in 2036 (Summer Peak MW)

Program	CA	ID	OR	UT	WA	WY	Total
Residential DLC Central AC	0.98	2.38	18.40	74.43	6.63	3.71	**106.53**
Residential DLC Space Heating	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	***n/a***
Residential DLC Water Heating	0.75	1.36	15.77	15.26	5.66	1.41	**40.21**
Residential DLC Smart T-Stats	0.98	2.38	18.40	53.09	6.63	3.71	**85.19**
Residential DLC Smart Appliances	0.28	0.62	4.16	7.80	0.86	0.97	**14.69**
Residential DLC Room AC	0.24	0.49	1.99	3.87	0.97	0.97	**8.53**
Residential DLC EV Chargers	0.06	0.40	11.12	9.93	0.45	0.23	**22.19**
C&I DLC Central AC	0.67	0.70	5.23	4.22	1.79	2.12	**14.73**
C&I DLC Space Heating	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	***n/a***
C&I DLC Water Heating	0.20	0.24	1.80	1.35	0.44	0.41	**4.44**
DLC Irrigation	5.29	22.33	14.03	6.31	7.53	2.08	**57.58**
Ice Energy Storage	0.52	0.89	5.10	5.76	1.23	1.80	**15.28**
Curtailment Agreements	1.21	2.07	38.03	85.92	9.94	45.77	**182.94**
Total	**11.19**	**33.86**	**134.05**	**267.93**	**42.11**	**63.18**	**552.31**

Class 1 DSM Market Potential Results by Customer Class

Table 3-6 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 residential sector is the largest contributor to total potential, with approximately 43% of the total potential in 2036. PacifiCorp's current residential program offerings are capturing 26% of the identified total potential.
- The irrigation sector has the second largest share of total potential, maintaining a 29% contribution in the overall Class 1 DSM potential. PacifiCorp's current irrigation DLC programs are already capturing 77% of the available potential.
- The C&I sector share increases steadily from 2017 onward, once Curtailable Agreements are assumed to be in place, and becomes roughly equal to irrigation sector 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 6% of the total Class 1 DSM savings potential.

Table 3-6 Class 1 DSM Total and Incremental Market Potential by Customer Class in 2036 (Summer Peak MW)

Customer Class	Total Potential	Impacts from Existing Options	Incremental Potential Impacts in 2036
Residential	377.3	100.0	277.3
Small C&I	24.8	3.8	21.0
Medium C&I	24.6	11.2	13.4
Large C&I	66.3	*n/a*	66.3
Extra Large C&I	116.6	*n/a*	116.6
Irrigation	247.6	190.0	57.6
Total	**857.3**	**305.0**	**552.3**

Table 3-7 presents the same Class 1 DSM potential breakdown by customer class for winter peak demand savings. Major trends by sector mirror those described above for summer peak savings except for the fact that irrigation operations essentially shut down in the winter such that peak shaving programs for this sector are not relevant. Again, total and incremental savings are equal here since there are no existing resources targeting winter peak savings.

Table 3-7 Class 1 DSM Total and Incremental Market Potential by Customer Class in 2036 (Winter Peak MW)

Customer Class	Total Potential	Impacts from Existing Options	Incremental Potential Impacts in 2036
Residential	361.7	*n/a*	361.7
Small C&I	10.5	*n/a*	10.5
Medium C&I	1.8	*n/a*	1.8
Large C&I	64.4	*n/a*	64.4
Extra Large C&I	87.1	*n/a*	87.1
Irrigation	-	*n/a*	-
Total	**525.5**	***n/a***	**525.5**

Class 1 DSM Market Potential Results by Customer Class and State in 2036

Table 3-8 and Table 3-9 show total Class 1 DSM potential by customer class in 2036 with the additional dimension of a state-by-state breakdown for summer and winter peak seasons. Key observations here are:

- The residential and irrigation sectors dominate the potential in Utah and Idaho respectively. 94% of the total potential in Idaho comes from irrigation customers.
- In Wyoming, 62% 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 50% of the total identified potential. The next highest contribution is from extra-large C&I curtailment participants in Oregon and Irrigation in Washington, representing approximately 15-20% of the overall potential in each sector in the states.
- In California, just under half of the Class 1 potential is found in the irrigation customer class.
- In the winter peak season, the highest potential also comes from the residential sector, mainly from Oregon and UT.

Table 3-8 Class 1 DSM Market Potential by Customer Class and State in 2036 (Summer Peak MW)

State	Res.	Small C&I	Med. C&I	Large C&I	Extra Large C&I	Irrigation	Total
CA	3.3	1.0	0.4	0.5	0.7	5.3	**11.2**
ID	7.6	1.4	0.4	1.0	1.1	192.3	**203.9**
OR	69.8	7.9	4.2	15.3	22.7	14.0	**134.0**
UT	264.4	9.8	16.5	38.4	47.5	26.3	**402.9**
WA	21.2	1.9	1.5	4.8	5.2	7.5	**42.1**
WY	11.0	2.8	1.5	6.3	39.5	2.1	**63.2**
Total	**377.3**	**24.8**	**24.6**	**66.3**	**116.6**	**247.6**	**857.3**

Table 3-9 Class 1 DSM Market Potential by Customer Class and State in 2036 (Winter Peak MW)

State	Res.	Small C&I	Med. C&I	Large C&I	Extra Large C&I	Irrigation	Total
CA	7.1	0.5	0.0	0.4	0.5	*n/a*	**8.4**
ID	18.5	0.6	0.0	0.9	1.6	*n/a*	**21.6**
OR	161.3	4.0	0.6	12.8	21.0	*n/a*	**199.6**
UT	107.9	3.3	0.8	38.7	24.0	*n/a*	**174.7**
WA	46.6	1.1	0.2	4.9	4.2	*n/a*	**57.0**
WY	20.3	1.1	0.1	6.8	35.9	*n/a*	**64.1**
Total	**361.7**	**10.5**	**1.8**	**64.4**	**87.1**	***n/a***	**525.5**

Class 1 DSM Levelized Costs

For each option, we estimated levelized costs over the entire study period of 2017–2036. Table 3-10 and Table 3-11 show levelized costs and 2036 market potential by option and state, for summer impacts and winter impacts respectively. As mentioned in the previous chapter, an assessment of the levelized cost per summer peak kW is conducted independently of an assessment of cost per winter peak kW. In other words, there is no allocation of costs between seasons and each figure in this report represents the full program cost applied to the seasonal peak impact. We focus our discussion of findings on levelized cost per summer peak kW since this is still PacifiCorp's primary planning objective and controlling system constraint. Results are aggregated at the operating company level and for the overall PacifiCorp system.

- Irrigation Load Control, which is the largest existing Class 1 DSM program, also has one of the lower levelized cost. 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 various end uses in residential and commercial customer premises, can vary greatly based on region, climate, equipment saturation, and customer/unit size. For example, warmer temperatures, higher cooling saturation and relatively larger unit load reductions makes the DLC Central AC option more attractive in Utah as compared to the other states. There are also substantive economies of scale from existing programs like this that accrue to add-on programs that can leverage the administrative and delivery infrastructures built by the existing, core programs. For example, DLC Water Heating has substantially lower delivery costs since it is assumed to leverage the infrastructure of co-delivered DLC Central AC programs. Lastly, it is worth reiterating that smart thermostat initiatives in this analysis assume a "bring your own" model where customers furnish qualifying units on their own such that equipment costs are not program costs. These are reasons why many DLC options and customer classes show relatively low levelized costs. Also see the differences by state in the assumed per-unit kW impact, as shown in Table 2-4.
- The highest levelized costs are associated with Residential DLC Smart Appliances, DLC Smart EV Charging, and Ice Energy Storage. This is because these are emerging technologies with relatively high equipment costs. DLC Room AC is also quite expensive from a levelized cost perspective, due to its relatively small per-unit impacts.
- Curtailable Agreements for C&I customers, with 182 MW of potential system wide, costs around $90 per summer kW reduced.

Table 3-10 Class 1 DSM Levelized Costs and Incremental Potential @ Generator (Summer Peak)

Option	CA	ID	OR	UT	WA	WY	Total Potential MW in Year 20
Res DLC Central AC	$87	$127	$135	$43[30]	$110	$111	**206.53**
Res DLC Space Heating	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	***n/a***
Res DLC Water Heating	$93	$95	$95	$94	$94	$95	**40.21**
Res DLC Smart Thermostats	$65	$92	$100	$45	$81	$82	**85.19**
Res DLC Smart Appliances	$256	$269	$263	$278	$261	$266	**14.69**
Res DLC Room AC	$238	$264	$404	$244	$323	$185	**8.53**
Res DLC EV Chargers	$236	$245	$242	$251	$241	$245	**22.19**
C&I DLC Central AC[31]	$38	$59	$51	$13	$38	$44	**29.73**
C&I DLC Space Heating	n/a	n/a	n/a	n/a	n/a	n/a	**n/a**
C&I DLC Water Heating	$36	$37	$37	$37	$37	$37	**4.44**
DLC Irrigation	$80	$58	$81	$60	$81	$82	**247.58**
Ice Energy Storage	$199	$210	$205	$217	$206	$206	**15.28**
Curtailment Agreements	$85	$108	$87	$90	$89	$91	**182.94**

Table 3-11 Class 1 DSM Levelized Costs and Incremental Potential @ Generator (Winter Peak)

Option	CA	ID	OR	UT	WA	WY	Total Potential MW in Year 20
Res DLC Central AC	n/a	n/a	n/a	n/a	n/a	n/a	**n/a**
Res DLC Space Heating	$52	$35	$49	$43	$40	$34	**190.4**
Res DLC Water Heating	$93	$95	$95	$94	$94	$95	**40.2**
Res DLC Smart Thermostats	$34	$39	$39	$124	$39	$49	**94.1**
Res DLC Smart Appliances	$256	$269	$263	$278	$261	$266	**14.7**
Res DLC Room AC	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	***n/a***
Res DLC EV Chargers	$236	$245	$242	$251	$241	$245	**22.2**
C&I DLC Central AC	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	***n/a***
C&I DLC Space Heating	$43	$28	$44	$42	$38	$30	**7.9**
C&I DLC Water Heating	$36	$37	$37	$37	$37	$37	**4.4**
DLC Irrigation	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	***n/a***
Ice Energy Storage	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	***n/a***
Curtailment Agreements	$123	$92	$97	$121	$96	$97	**151.4**

[30] Note this cost represents the average per-unit cost of existing and new impacts and may not represent the marginal or incremental cost of acquiring new participation.

[31] Note that C&I direct load control costs assume economies of scale from aligning with residential program and leveraging shareable resources.

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. In general, the Class 3 options are assumed to be offered only after AMI has been deployed by 2020 in OR, 2021 in ID, and 2025 in CA, WA, UT, and WY.

Table 3-12 shows the total, absolute potential from Class 3 DSM options as they would be configured in 2036. 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 2036. Results are presented for the opt-in case for pricing options. Opt-out case results are discussed in Volume 5 of the report.

Key observations from our analysis are:

- The total summer potential from Class 3 DSM resources reaches 449.4 MW in 2036, which translate into 3.6% of PacifiCorp's projected system peak demand in 2036.
- We assume that the Residential TOU rate in Idaho is offered from 2017 onward. Savings from new TOU rates, RTP, and CPP are realized from 2020 onward, based on when AMI is available in each state. The savings from pricing options ramp up in their early years following an "S-shaped" diffusion curve, growing from 20 MW in 2020 to 173 MW in 2025, when all of the pricing programs have started. Eventually, savings levels reach a steady state at 3.62% of projected system peak.
- All of the Residential pricing options are large contributors to Class 3 DSM potential in 2036. Residential CPP savings are the largest, followed by TOU Demand Rate, TOU Demand Rate for electric vehicle owners, and traditional TOU, each comprising 15 to 20% of the total Class 3 potential.
- For C&I customers, CPP is significantly higher than other pricing options, with potential in 2036 at 83 MW. Savings opportunities from RTP and CPP are considerably lower at only 14.9 MW and 11.3 MW in 2036 respectively.
- For irrigation customers, CPP rates have more than twice the savings potential in 2036 as compared to TOU rates.

Table 3-12 Class 3 DSM Total Potential in 2036 (Summer Peak)

Class 3 DSM Options	Total Potential (MW)	Potential (as % of projected summer peak)
Residential TOU Demand Rate	81.8	0.66%
Residential TOU Demand Rate w EV	71.9	0.58%
Residential TOU	70.9	0.57%
Residential CPP	96.3	0.78%
C&I TOU	11.3	0.09%
C&I CPP	83.2	0.67%
C&I RTP	14.9	0.12%
Irrigation TOU	4.0	0.03%
Irrigation CPP	15.3	0.12%
Total Class 3 DSM Potential	**449.4**	**3.6%**

Potential results for Class 3 DSM winter peak pricing options are presented in Table 3-13. Winter peak potential is about 35% less than summer peak potential. This is due to the lower system load in the winter, as well as smaller per-unit impacts from winter options.

Table 3-13 Class 3 DSM Total Potential in 2036 (Winter Peak)

Class 3 DSM Options	Total Potential (MW)	Potential (as % of projected winter peak)
Residential TOU Demand Rate	18.5	0.17%
Residential TOU Demand Rate w EV	25.2	0.24%
Residential TOU	68.3	0.65%
Residential CPP	95.2	0.90%
C&I TOU	10.0	0.09%
C&I CPP	67.9	0.64%
C&I RTP	11.9	0.11%
Irrigation TOU	0.0	0.00%
Irrigation CPP	0.1	0.00%
Total Class 3 DSM Potential	**297.2**	**2.8%**

Class 3 DSM Total Potential in 2036 by Option and State

Table 3-14 and Table 3-15 presents the total Class 3 DSM potential results broken down by state in 2036. 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. The three C&I pricing options combined have roughly equal potential to residential CPP.
- Oregon has the second highest potential, after Utah. Residential pricing (TOU, TOU Demand Rate w/EV, 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, just about half of the savings opportunities from pricing options are in the irrigation sector.
- In Washington and California, the residential sector constitutes nearly half the total savings potential from pricing options.
- As similar trend continues in the winter peak season, with Oregon and Washington contributing the most potential due to the residential rate programs and C&I CPP.

Table 3-14 Class 3 DSM Total Market Potential by Option and State in 2036 (Summer Peak MW)

Program	CA	ID	OR	UT	WA	WY	Total
Residential TOU Demand Rate	0.6	2.1	9.8	60.4	3.5	5.6	**81.8**
Residential TOU Demand Rate w EV	0.1	1.8	23.9	44.1	1.0	1.0	**71.9**
Residential TOU	1.0	-	16.9	43.0	6.0	4.0	**70.9**
Residential CPP	1.3	2.0	22.5	57.3	8.0	5.3	**96.3**
C&I TOU	0.1	0.3	2.5	6.3	1.0	1.1	**11.3**
C&I CPP	0.7	1.1	17.6	40.4	5.6	17.9	**83.2**
C&I RTP	0.1	0.2	3.1	6.7	0.8	4.2	**14.9**
Irrigation TOU	0.2	2.2	0.6	0.5	0.3	0.1	**4.0**
Irrigation CPP	0.8	8.7	2.2	2.1	1.2	0.3	**15.3**
Total	**4.9**	**18.3**	**98.9**	**260.7**	**27.2**	**39.4**	**449.4**

Table 3-15 Class 3 DSM Total Market Potential by Option and State in 2036 (Winter Peak MW)

Program	CA	ID	OR	UT	WA	WY	Total
Residential TOU Demand Rate	1.0	-	13.3	-	4.1	-	**18.5**
Residential TOU Demand Rate w EV	0.1	-	24.1	-	1.0	-	**25.2**
Residential TOU	1.8	-	22.9	30.8	7.2	5.54	**68.3**
Residential CPP	2.4	4.2	30.5	41.1	9.6	7.38	**95.2**
C&I TOU	0.1	0.3	2.1	5.5	0.9	1.10	**10.0**
C&I CPP	0.5	1.3	15.3	29.4	4.9	16.70	**67.9**
C&I RTP	0.1	0.2	2.7	4.4	0.7	3.83	**11.9**
Irrigation TOU	0.0	0.0	0.0	0.0	0.0	0.00	**0.0**
Irrigation CPP	0.0	0.0	0.0	0.0	0.0	0.00	**0.1**
Total	**6.1**	**6.0**	**110.8**	**111.2**	**28.5**	**34.56**	**297.2**

Class 3 DSM Total Potential in 2036 by Customer Class and StateTable 3-16Table 3-16 and

Table 3-17 shows summer 2036 total pricing potential results broken down slightly differently, this time by customer class and state for summer and winter peaks. Key observations are:

- Residential customers in Utah and Oregon represent substantial savings opportunities. For most states, approximately half of the potential is derived from residential customers, except for Idaho which displays a significantly lower share due to large irrigation loads.
- Among C&I customer classes, extra-large C&I customers provide highest savings opportunities in 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 3-16 Class 3 DSM Total Market Potential by Customer Class and State in 2036 (Summer Peak MW)

State	Res	Small C&I	Med. C&I	Large C&I	Extra Large C&I	Irrigation	Total
CA	3.0	0.0	0.3	0.2	0.3	1.0	**4.9**
ID	5.8	0.1	0.5	0.5	0.6	10.9	**18.3**
OR	73.0	0.5	5.3	7.1	10.1	2.8	**98.9**
UT	204.7	0.5	13.7	18.0	21.1	2.6	**260.7**
WA	18.5	0.1	2.7	2.2	2.3	1.5	**27.2**
WY	15.9	0.2	2.5	3.0	17.5	0.4	**39.4**
Total	**320.9**	**1.3**	**25.1**	**31.0**	**51.9**	**19.2**	**449.4**

Table 3-17 Class 3 DSM Total Market Potential by Customer Class and State in 2036 (Summer Peak MW)

State	Res	Small C&I	Med. C&I	Large C&I	Extra Large C&I	Irrigation	Total
CA	5.4	0.0	0.2	0.2	0.2	0.0	6.1
ID	4.2	0.1	0.5	0.4	0.9	0.0	6.0
OR	90.7	0.4	4.4	6.0	9.3	0.0	110.8
UT	71.9	0.3	10.2	18.1	10.7	0.0	111.2
WA	22.0	0.0	2.2	2.3	1.9	0.0	28.5
WY	12.9	0.2	2.4	3.2	15.9	0.0	34.6
Total	**207.1**	**1.1**	**19.9**	**30.1**	**38.8**	**0.2**	**297.2**

Class 3 DSM Incremental Potential by Option

The total potential shown above assumes that no migration away from the Company's existing Class 3 options, such as the voluntary TOU rates. Incremental potential from Class 3 DSM is estimated to change slightly when this occurs, resulting in 438 MW of potential demand reductions by 2036. This is broken out by program option and state in Table 3-18. Most trends and findings are the same except for minor adjustments made to net out those existing TOU rates. Major contributors to the incremental potential are still residential and C&I CPP rates in Utah and Oregon, C&I CPP rates in Wyoming, and residential TOU and TOU Demand Rate rates in Utah.

As mentioned previously, impacts from the existing Class 3 DSM resources that are embedded in the baseline, such as mandatory residential IBR and mandatory extra-large C&I TOU, are detailed in Volume 3, Chapter 3 of PacifiCorp's previous potential assessment report.

Table 3-18 Class 3 DSM Incremental Potential by Option and State in 2036 (Summer Peak MW)[32]

Program	CA	ID	OR	UT	WA	WY	Total
Residential TOU Demand Rate	0.57	2.07	9.78	60.36	3.48	5.58	**81.84**
Residential TOU Demand Rate w EV	0.13	1.76	23.85	44.11	0.96	1.04	**71.86**
Residential TOU	0.99	0*	16.76	42.96	6.01	3.97	**70.69**
Residential CPP	1.31	1.96	22.49	57.26	8.00	5.29	**96.32**
C&I TOU	0.02	0.27	0*	0*	0*	0*	**0.29**
C&I CPP	0.68	1.14	17.56	40.39	5.55	17.89	**83.19**
C&I RTP	0.10	0.16	3.03	6.67	0.76	4.15	**14.87**
Irrigation TOU	0.22	2.24	0.55	0.37	0.31	0.08	**3.77**
Irrigation CPP	0.83	8.65	2.21	2.06	1.18	0.33	**15.26**
Total	**4.84**	**18.25**	**96.23**	**254.19**	**26.25**	**38.33**	**438.10**

Class 3 DSM Levelized Costs

For each Class 3 DSM option, we estimated levelized costs over the study period of 2017–2036. 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, no options were burdened with AMI deployment and communication network related costs. Costs are

[32] In cases marked with an asterisk, 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 relative to existing program participation or a less aggressive rate pricing structure as compared 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 other rates. For calculation of the total incremental potential, these negative values have been adjusted to zero.

levelized over a 20-year lifetime to align with the IRP time horizon. Detailed cost assumptions are presented in Volume 5 of the report.

Table 3-19 shows the levelized costs and associated 2036 incremental potential estimates for each option by state for the summer peak. Table 3-20 shows the results for the winter peak season. Key findings are:

- Dynamic pricing and rate programs are relatively inexpensive to implement without considering the cost of AMI, and have substantial peak savings potential once AMI is deployed. There are also no explicit customer equipment costs. As Class 3 resources, however, the impacts are by definition less reliable than Class 1 impacts because of the voluntary nature of the underlying customer actions.
- Residential CPP, with the highest savings potential of 96 MW in 2036, cost from $22 to $44/kW-year depending on the jurisdiction.
- Potential for C&I CPP is estimated at 83 MW at a low range of cost between $3 and $14/kW-year depending on the jurisdiction.
- Pricing options for irrigation customers can also be administered for a levelized cost between $2 and $6/kW-year.

Table 3-19 Class 3 DSM Levelized Costs and Incremental Potential in 2036 (Summer Peak)

Option	CA	ID	OR	UT	WA	WY	Total Potential MW in Year 20
Res TOU Demand Rate	$64	$29	$40	$19	$34	$25	**81.84**
Res TOU Demand Rate w EV	$19	$10	$16	$11	$18	$11	**71.86**
Res TOU	$20		$13	$14	$11	$18	**70.87**
Res CPP	$41	$44	$25	$28	$22	$38	**96.32**
C&I TOU	$16	$8	$7	$7	$7	$8	**11.25**
C&I CPP	$14	$12	$6	$5	$5	$3	**83.19**
C&I RTP	$9	$9	$10	$10	$10	$10	**14.87**
Irrigation TOU	$5	$3	$5	$5	$7	$6	**3.95**
Irrigation CPP	$5	$2	$5	$5	$8	$6	**15.26**

Table 3-20 Class 3 DSM Levelized Costs and Incremental Potential in 2036 (Winter Peak)

Option	CA	ID	OR	UT	WA	WY	Total Potential MW in Year 20
Res TOU Demand Rate	$35		$29		$28		**18.48**
Res TOU Demand Rate w EV	$18		$16		$18		**25.20**
Res TOU	$11		$9	$19	$9	$13	**68.30**
Res CPP	$23	$21	$18	$38	$18	$27	**95.16**
C&I TOU	$22	$8	$8	$7	$7	$8	**10.02**
C&I CPP	$19	$11	$6	$7	$6	$3	**67.94**
C&I RTP	$14	$7	$11	$16	$11	$11	**11.91**
Irrigation TOU	-	-	-	-	-	-	-
Irrigation CPP	-	-	-	-	-	-	-

4

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 January of 2015.[33] As the previous study only assessed impacts during summer peak periods, a comparison of winter peak impacts is not available.

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 4-1 presents a high level comparison of the system-wide potential by Class 1 and 3 DSM option. Key observations are:

- The current study shows substantially larger potential, primarily due to the availability of new program options to the analysis. The most significant new potential comes from smart thermostat DLC programs and from electric vehicle related programs in OR and UT.
- There have also been variations due to geography and baseline changes since the prior study. For example, peak load forecasts show higher growth in all states except UT and WY. Projected WY load growth in the oil & gas industry has flattened substantially.
- The 20-year incremental potential for Class 1 DSM in the current study is 552 MW, which is roughly one third larger than the 20-year Class 1 DSM potential estimate in the 2015 assessment of 373 MW.
    - Again, newly included program options drive a large portion of this increase: DLC Smart Thermostat, DLC Smart Appliances, DLC Room AC, DLC EV Charging, and Ice Energy Storage.
    - There is also an increase in Cooling DLC, given new information about program implementation, customer growth assumptions, saturation of applicable equipment, and estimated participation rates which are detailed further in the following sections. An increase in Water Heating DLC potential is driven primarily by higher impact assumptions on a per-unit basis from the Northwest Power and Conservation Council's Seventh Power Plan.
    - Potential for DLC Irrigation and Curtailable Agreements is similar between the two studies.
- The Class 3 DSM potential estimate in the current study is also higher than the 2015 study, again due largely to the addition of new rate options, namely TOU Demand Rates. The current study estimates 438 MW of incremental Class 3 DSM potential in 2036, which compares to 260 MW in 2034 from the previous study.
    - Residential pricing potential in the current study is estimated at 320 MW in the final year, vs. 138 MW in the previous assessment. This difference is driven by the addition of the TOU Demand Rate and TOU Demand Rate w/EV programs. Additionally, the previous study assumed a pullback or decrease in traditional TOU participation in the middle of the study in favor of higher adoption of other rate options such as CPP. The current study assumed more straightforward program ramping instead of predicting such an inflection point, so the current

[33] "PacifiCorp Demand-Side Resource Potential Assessment for 2015-2034." Completed and published by Applied Energy Group Jan 30, 2015. Available at: http://www.pacificorp.com/es/dsm.html

CPP potential is slightly lower than the previous study while the TOU potential is slightly higher.

- The C&I pricing potential in the current study of 98 MW in 2036 is close to the corresponding value of 90 MW from the previous study. Many of the assumptions around impacts and participation rates remained consistent between the two studies so changes in potential were relatively minor.

Table 4-1 Comparison of Class 1 and 3 DSM Potential with 2015 Assessment (Incremental Summer Potential, without Interactive Effects)

DSM Options	2015 Assessment 2034 Potential (MW)	Current Assessment 2036 Potential (MW)
Class 1 DSM		
Residential DLC- Cooling	97.1	106.5
Residential DLC- Water Heating	11.8	40.2
Residential DLC Space Heating	*not analyzed*	0.0
Residential DLC Smart Thermostats	*not analyzed*	85.2
Residential DLC Smart Appliances	*not analyzed*	14.7
Residential DLC Room AC	*not analyzed*	8.5
Residential DLC EV Chargers	*not analyzed*	22.2
C&I DLC- Cooling	13.9	24.7
C&I DLC- Water Heating	0.6	4.4
C&I DLC- Space Heating	*not analyzed*	0
Irrigation Load Control	64.5	57.6
Ice Energy Storage	*not analyzed*	15.3
Curtailable Agreements	185.1	182.9
Total Class 1 DSM	**373.1**	**552.3**
Class 3 DSM		
Residential Pricing		
Residential TOU	25.7	70.7
Residential CPP	112.6	96.3
Residential TOU Demand Rate	*not analyzed*	81.8
Residential TOU Demand Rate w EV	*not analyzed*	71.9
Total Residential Pricing	*138.3*	*320.7*
C&I Pricing		
C&I TOU	9.7	0.3
C&I CPP	70.0	83.2
C&I RTP	10.5	14.9
Total C&I Pricing	*90.2*	*98.4*
Irrigation Pricing		
Irrigation TOU	3.2	3.8
Irrigation CPP	9.7	15.3
Total Irrigation Pricing	*12.9*	*19*
Total Class 3 DSM	**260**	**438**

Comparison of Class 1 Resource Options with Previous Assessment

Table 4-2 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 4-2 Comparison of Class 1 DSM Potential with 2015 Assessment (Incremental Summer Potential, without Interactive Effects)

Class 1 DSM Options	State	2015 Assessment 2034 Incremental Market Potential (MW)	Current Assessment 2036 Incremental Market Potential (MW)	Primary Differences in Potential Estimates
Residential DLC-Cooling	CA	1.6	1.0	• Higher projected saturation growth of applicable cooling equipment in current study vs. 2015 study (applies to ID, UT, and WY). Saturation projections are slightly lower for CA and WA.
	ID	1.7	2.4	
	OR	18.4	18.4	
	UT	63.4[34]	74.4	
	WA	8.9	6.6	
	WY	3.1	3.7	
	Total	**97.1**	**106.5**	
Residential DLC-Water Heating	CA	0.55	0.8	• Higher impact per WH control switch in current study (0.58 kW in current study based on 7th Plan update vs. 0.26 kW from 2015 research and assessment) • Differences in WH saturation assumptions • Previous 2015 study assumed that DLC savings in Utah was based on the existing program offer only and that no new savings were derived through control of electric water heaters.
	ID	0.94	1.4	
	OR	6.57	15.8	
	UT	0.0	15.3	
	WA	2.23	5.7	
	WY	1.52	1.4	
	Total	**11.8**	**40.2**	
Residential DLC Smart Thermostats	CA		1.0	• New program to current assessment
	ID		2.4	
	OR		18.4	
	UT		53.1	
	WA		6.6	
	WY		3.7	
	Total		**85.2**	

[34] Both current and 2015 study considered a base of 100 MW of impact from existing program.

Class 1 DSM Options (*Continued*)	State	2015 Assessment	Current Assessment	Primary Differences in Potential Estimates
		2034 Incremental Market Potential (MW)	2036 Incremental Market Potential (MW)	
Residential DLC Smart Appliances	CA		0.1	• New program to current assessment
	ID		0.6	
	OR		4.1	
	UT		7.8	
	WA		0.9	
	WY		1.0	
	Total		14	
Residential DLC Room AC	CA		0.2	• New program to current assessment
	ID		0.5	
	OR		2.0	
	UT		3.9	
	WA		1.0	
	WY		1.0	
	Total		**8.5**	
Residential DLC Elec Vehicle Charging	CA		0.1	• New program to current assessment
	ID		0.4	
	OR		11.1	
	UT		9.9	
	WA		0.5	
	WY		0.2	
	Total		**22.2**	
C&I DLC-Cooling	CA	0.4	0.7	• Overall potential estimate in current study is close to that presented in 2015 assessment. • Generally higher saturation of cooling equipment estimated in current assessment, particularly CA and ID.
	ID	0.4	0.7	
	OR	5.7	5.2	
	UT	4.2[35]	4.2	
	WA	1.8	1.8	
	WY	1.4	2.1	
	Total	**13.9**	**14.7**	

[35] Both current and 2015 study considered 15 MW impact from existing program

Class 1 DSM Options (*Continued*)	State	2015 Assessment: 2034 Incremental Market Potential (MW)	Current Assessment: 2036 Incremental Market Potential (MW)	Primary Differences in Potential Estimates
C&I DLC Water Heating	CA	0.03	0.2	• Higher impact per WH control switch in current study (1.47 kW in current study vs. 0.33 kW in 2015 assessment) • Previous 2015 study assumed that DLC savings in Utah was based on the existing program offer only and that no new savings were derived through control of electric water heaters.
	ID	0.04	0.2	
	OR	0.41	1.8	
	UT	0.00	1.4	
	WA	0.09	0.4	
	WY	0.06	0.4	
	Total	**0.6**	**4.4**	
C&I Ice Energy Storage	CA	-	0.5	• New program to current assessment
	ID	-	0.9	
	OR	-	5.1	
	UT	-	5.7	
	WA	-	1.2	
	WY	-	1.8	
	Total	**-**	**15.3**	
Irrigation Load Control	CA	4.2	5.3	• Overall potential estimate in current study is close to that presented in 2015 assessment. • Higher peak load forecast for irrigation customers in OR, leading to a larger base from which to start. • Calibration to existing program conditions in current study results in slight decrease of remaining customer base for participation in more mature program markets of ID and UT.
	ID	26[36]	22.3	
	OR	8.7	14.0	
	UT	19[37]	6.3	
	WA	5.1	7.5	
	WY	1.5	2.1	
	Total	**59.5**	**57.6**	
Curtailable Agreement	CA	1.0	1.2	• Overall potential estimate in current study is close to that presented in 2015 assessment. • Summer peak load for large and extra-large customers is slightly lower in UT and higher in OR.
	ID	2.3	2.1	
	OR	32.9	38.0	
	UT	92.6	85.9	
	WA	9.5	9.9	
	WY	46.8	45.8	
	Total	**185.1**	**182.9**	

Comparison of Class 3 Resource Options with Previous Assessment

Table 4-3 presents a comparison of Class 3 DSM potential estimates by option and state and discusses the primary drivers behind variance between the two studies.

[36] Both current and 2015 study assume 170 MW of existing potential

[37] Both current and 2015 study assume 20 MW of existing potential

Table 4-3 Comparison of Class 3 DSM Potential with 2015 Assessment (Incremental Summer Potential, without Interactive Effects)

<table>
<tr><th rowspan="2">Class 3 DSM Options</th><th rowspan="2">State</th><th>2015 Assessment</th><th>Current Assessment</th><th rowspan="2">Primary Differences in Potential Estimates</th></tr>
<tr><th>2034 Incremental Opt-in Potential (MW)</th><th>2036 Incremental Opt-in Potential (MW)</th></tr>
<tr><td rowspan="7">Residential TOU</td><td>CA</td><td>0.3</td><td>0.9</td><td rowspan="7">• In ID, the existing TOU rate is not considered, shown here as zero
• The previous study assumed a pullback or decrease in traditional TOU participation in the middle of the study in favor of higher adoption of other rate options such as CPP. The current study assumed more straightforward program ramping instead of predicting such an inflection point, so the current CPP potential is slightly lower than the previous study while the TOU potential is slightly higher</td></tr>
<tr><td>ID</td><td>-</td><td>-</td></tr>
<tr><td>OR</td><td>6.1</td><td>16.8</td></tr>
<tr><td>UT</td><td>15.7</td><td>43.0</td></tr>
<tr><td>WA</td><td>1.8</td><td>6.0</td></tr>
<tr><td>WY</td><td>1.9</td><td>4.0</td></tr>
<tr><td>Total</td><td>25.7</td><td>70.7</td></tr>
<tr><td rowspan="7">C&I TOU</td><td>CA</td><td>0.3</td><td>0.02</td><td rowspan="7">• In both the current and prior assessments, the potential analysis assumes a redistribution of participants relative to existing program participation and in some cases a less aggressive rate pricing structure as compared to the existing rates. In certain edge cases this results in a negative incremental potential, which we have zeroed out. This occurred in UT and WY in the prior assessment, but also in OR and WA in the current assessment</td></tr>
<tr><td>ID</td><td>0.8</td><td>0.3</td></tr>
<tr><td>OR</td><td>7.1</td><td>-</td></tr>
<tr><td>UT</td><td>-</td><td>-</td></tr>
<tr><td>WA</td><td>1.5</td><td>-</td></tr>
<tr><td>WY</td><td>-</td><td>-</td></tr>
<tr><td>Total</td><td>9.7</td><td>0.3</td></tr>
<tr><td rowspan="7">Irrigation TOU</td><td>CA</td><td>0.2</td><td>0.2</td><td rowspan="7">• The potential estimates in the two studies are very similar.</td></tr>
<tr><td>ID</td><td>1.8</td><td>2.2</td></tr>
<tr><td>OR</td><td>0.5</td><td>0.6</td></tr>
<tr><td>UT</td><td>0.3</td><td>0.4</td></tr>
<tr><td>WA</td><td>0.3</td><td>0.3</td></tr>
<tr><td>WY</td><td>0.1</td><td>0.08</td></tr>
<tr><td>Total</td><td>3.2</td><td>3.8</td></tr>
</table>

Class 3 DSM Options (*Continued*)	State	2015 Assessment 2034 Incremental Opt-in Potential (MW)	Current Assessment 2036 Incremental Opt-in Potential (MW)	Primary Differences in Potential Estimates
Residential CPP	CA	1.4	1.3	• In the current assessment, the per-unit impact and participation rates for each state are lower than in the 2015 assessment. • The previous study assumed a pullback or decrease in traditional TOU participation in the middle of the study in favor of higher adoption of other rate options such as CPP. The current study assumed more straightforward program ramping instead of predicting such an inflection point, so the current CPP potential is slightly lower than the previous study while the TOU potential is slightly higher
	ID	2.8	2.0	
	OR	26.2	22.5	
	UT	66.3	57.3	
	WA	7.8	8.0	
	WY	8.1	5.3	
	Total	**112.6**	**96.3**	
C&I CPP	CA	0.5	0.7	• The participation rates and peak load forecasts in the current assessment are slightly higher.
	ID	1.1	1.1	
	OR	12.6	17.6	
	UT	36.2	40.4	
	WA	4.4	56	
	WY	15.2	17.9	
	Total	**70.0**	**83.2**	
Irrigation CPP	CA	0.6	0.8	• The participation rates in the current assessment are slightly higher. • The summer peak load in ID is also higher, driving a meaningful increase in potential savings.
	ID	5.1	8.7	
	OR	1.4	2.2	
	UT	1.5	2.1	
	WA	0.9	1.2	
	WY	0.2	0.3	
	Total	**9.7**	**15.3**	
C&I RTP	CA	0.1	0.1	• The participation rates and peak load forecasts in the current assessment are slightly higher.
	ID	0.1	0.2	
	OR	1.9	3.0	
	UT	5.2	6.7	
	WA	0.5	0.8	
	WY	2.7	4.2	
	Total	**10.5**	**14.9**	

Class 3 DSM Options (*Continued*)	State	2015 Assessment 2034 Incremental Opt-in Potential (MW)	Current Assessment 2036 Incremental Opt-in Potential (MW)	Primary Differences in Potential Estimates
Demand Buyback	CA	0.1	-	• Program eliminated from the current assessment
	ID	0.2	-	
	OR	3.1	-	
	UT	8.1	-	
	WA	0.8	-	
	WY	6.4	-	
	Total	**18.7**	-	
Residential TOU Demand Rate	CA	-	0.6	• New program to current assessment
	ID	-	2.1	
	OR	-	9.8	
	UT	-	60.4	
	WA	-	3.5	
	WY	-	5.6	
	Total	-	**81.8**	
Residential TOU Demand Rate w/ EV	CA	-	0.1	• New program to current assessment
	ID	-	1.8	
	OR	-	23.9	
	UT	-	44.1	
	WA	-	1.0	
	WY	-	1.0	
	Total	-	**71.9**	

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