AEG Applied Energy Group

PACIFICORP CONSERVATION POTENTIAL ASSESSMENT FOR 2019-2038

Volume 3: Class 1 and 3 DSM Analysis

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Report prepared for:
PACIFICORP

Energy Solutions. Delivered.

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1

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 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 behavioral demand response. 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 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 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 Third Party Contracts 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 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 section, we describe these analysis steps in more detail.

1. Market Characterization
    a. Segment the market into customer classes for purposes of the Class 1 and Class 3 DSM analyses
    b. 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
    a. Participation rates
    b. Peak demand impacts
    c. 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 1-1 summarizes the overall market segmentation approach for the study.

Table 1-1 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 estimated peak load forecast for the study timeframe. This is done at the PacifiCorp system level, and also by jurisdiction. We used PacifiCorp's peak demand data to develop the jurisdictional contribution to the estimated coincident peak values. These represent a state's projected demand at the time of PacifiCorp system peak for both summer and winter.

Figure 1-1 shows the jurisdictional contribution to the estimated system coincident summer peak, developed based on load forecast data provided by PacifiCorp. In the base year of analysis, 2016, system peak load for the summer (a typical July weekday at 3:00 pm) is 10,020 MW at the grid or generator level. Utah contributes 47% of summer system peak, followed by Oregon at 25%, Wyoming at 12%, Washington 8%, and Idaho 7%, with California at 1%. Over the study period, summer coincident peak load is expected to grow by an average of 0.63% annually.

Figure 1-1 Jurisdictional Contribution to Estimated System Coincident Peak Forecast by State (Summer)

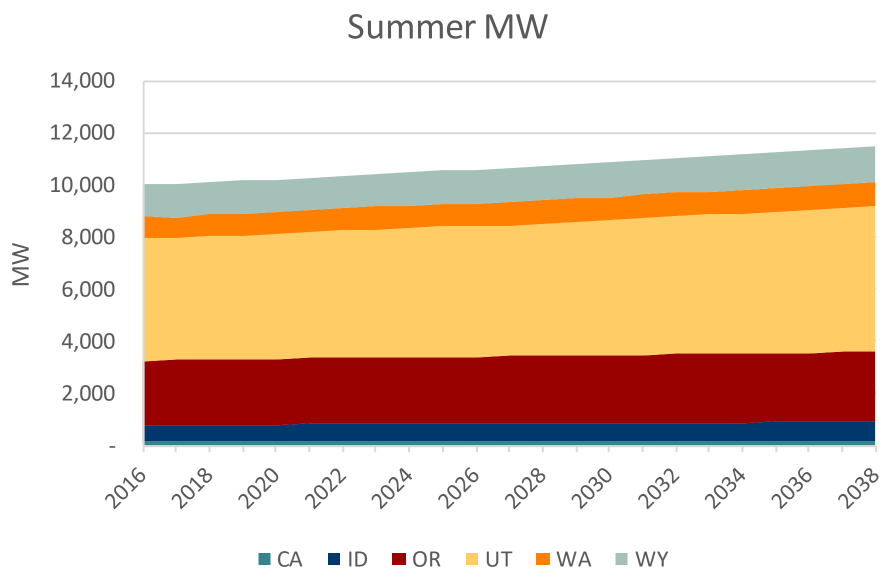
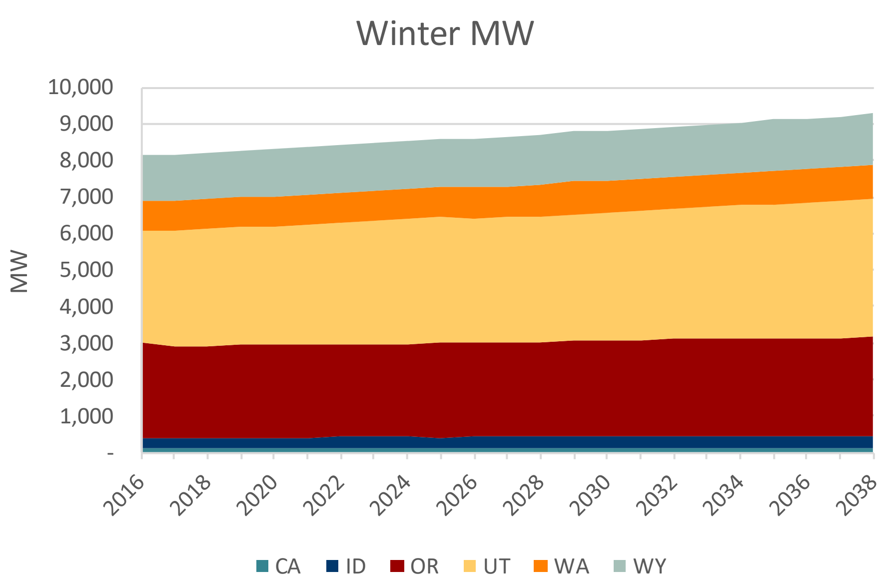


Figure 1-2 shows the jurisdictional contribution to the estimated system coincident winter peak forecast, developed based on load forecast data provided by PacifiCorp. In the base year of analysis, 2016, system peak load for the winter (a typical December weekday at 6:00 pm) is 8,170 MW at the grid or generator level. The winter system peak is about 18% lower than the summer peak. Utah contributes 38% of winter system peak, followed by Oregon at 32%, Wyoming at 15%, Washington 10%, and Idaho 3%, with California at 2%. Over the study period, winter coincident peak load is expected to grow by an average of 0.59% annually.

Figure 1-2 Jurisdictional Contribution to Estimated 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 1-2 lists the Class 1 DSM options considered in the study, followed by a brief discussion of the options selected. As shown below, this study includes one new Class 1 option that was not considered in the previous study, Ancillary Services. In addition, the study extends the Smart Thermostat offering to small and medium C&I customers.

Table 1-2 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	Yes
Smart Thermostats DLC	Residential, Small C&I Medium C&I	Internet-enabled control of thermostat set points	No	Yes, Residential only
Smart Appliances DLC	Residential	Internet-enabled control of operational cycles of white goods appliances	No	Yes
DLC of Room Air Conditioners	Residential	Direct load control switch installed on customer's equipment	No	Yes
Irrigation Load Control	Irrigation	Automated pump controllers	Yes, in ID and UT	Yes
Thermal Energy Storage	Small and Medium C&I	Peak shifting of space cooling loads using stored ice	No	Yes
Third Party Contracts	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	Yes
Ancillary Services	Residential, C&I	Automated control of various building management systems or end-uses through one of the mechanisms already described	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 is 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 PacifiCorp program managers. A detailed description of the basis for developing these assumptions is provided in the Appendix Volume 5 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 device, which cycles the unit on and off during an event. The Utah program currently realizes approximately 112[1] MW of load reduction potential from participating residential and C&I customers.[2] In our analysis of the Utah air conditioner load control program, we assume a continuation of the current program configuration (control of central air conditioners and heat pumps only) while looking at the incremental potential for expansion. For other jurisdictions, where such programs are yet to be established, the program offering is expanded to include 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 1-3 presents DLC offering basics.

Table 1-3 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[3]
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)

[1] Represent estimated Cool Keeper program impacts as of December 31, 2017.

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

[3] Rocky Mountain Power's current CAC DLC program is available for 100 hours, however, in general all 100 hours are not called. We assumed a total of 50 hours for this analysis.

Table 1-4 and Table 1-5 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 residential Cool Keeper program, we assume program ramp-up and participant recruitment would begin in 2021. This is to account for the necessary time to secure regulatory approvals, engage a vendor, and launch the offerings (if selected by the 2019 IRP), In Utah, the existing program is assumed to ramp up as soon as is practical if selected by the 2019 IRP, to recruit new participants for the 2019 cooling season.

Table 1-4 Residential DLC Program: Planning Assumptions

Data Item	Unit	Value
		Participation Assumptions[4]
Residential customer participation	Steady-state Participation (as % of eligible customers)	*Cooling:* 16% for UT, 5% for all other states *Water Heating:* 23% for UT, 15% for all other states *Space Heating*: 20% for all *Smart Thermostats*: 13% for UT, 25% for all other *Smart Appliances:* 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 for all states *EV Charging:* 0.28 for all states
Residential customer per participant impact – Winter Peak	Average kW reduction per participant @ meter	*Smart Thermostats:* CA: 0.53, ID: 0.54, OR: 0.54, UT: 0.21, WA: 1.01, WY: 0.39 *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 for all states *EV Charging:* 0.28 for all states

[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.

Data Item	Unit	Value
Cost Assumptions[6]		
Annual Program Administration Cost	$/year (split between Res & C&I)	*Central Cooling & Space Heating:* $300,000 each *Water Heating:* costs carried by the Central Cooling program[7] *Smart thermostats, Smart Appliances, EV Charging:* $75,000 each *Room AC:* costs carried by the Central Cooling program
Annual Marketing and Recruitment Costs	$/new participant	$50-60 per each residential program
Equipment capital and installation cost	$/new participant	*CAC, RAC, Space Heating:* $215 each *Water Heating:* $315 *Smart thermostat:* Bring-your-own[8] *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[9] (average number of CAC units per participant = 1.06)

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

[7] Water heating programs is assumed to be an add-on to the Central Cooling programs and therefore would not exist as an independent program.

[8] 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.

[9] In Utah Rocky Mountain Power was proposed to increase the incentive by 50%.

Table 1-5 C&I DLC Program: Planning Assumptions

Data Item	Unit	Value
Participation Assumptions[10]		
C&I customer participation	Steady-state Participation (as % of eligible customers)	*CAC:* Small and Medium C&I: 1.5%, Other States: 3% *Water Heating:* UT: Small C&I: 2.9%, Medium C&I: 3.9%, Other States: 3% *Space Heating*: 3%
Program ramp up period	Years	Five
Impact Assumptions[11]		
C&I customer per participant impact for **cooling**	Average kW reduction per participant @ meter	Small C&I: CA: 1, ID: 1.2, OR: 1.1, UT: 1.2, WA: 1.3, WY: 1.3 Medium C&I: All States: 15.2
C&I customer per participant impact for **water heating**		1.5, same for each class and state.
C&I customer per participant impact for **space heating**		CA: 1.8, ID: 4.4, OR: 3.0, UT: 1.7, WA: 3.7, WY: 4.5

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

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

Data Item	Unit	Value
		Cost Assumptions[12]
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[13], $128 for medium C&I *Water Heating:* $24

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 1-6 presents Ice Energy Storage program basics.

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

[13] Rocky Mountain Power currently offers an incentive of $40 and has a filing pending to increase the incentive by 50%.

Table 1-6 Ice Energy Storage Program: Planning Assumptions

Data Item	Unit	Value
Participation Assumptions[14]		
C&I customer participation	Steady-state Participation (as % of eligible customers)	UT: Small and Medium C&I- 0.8% Other States: 1.5%
Program ramp up period	Years	Five
Impact Assumptions[15]		
C&I customer per participant impact for cooling	Average kW reduction per participant @ meter	5.00
Cost Assumptions[16]		
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.

Third Party Contracts

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 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 may be 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

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

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

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

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.[17] 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 2021 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 1-7 presents key participation, impact and cost assumptions for the Third Party Contracts.

Table 1-7 Third Party Contracts Program: Planning Assumptions

Data Item	Unit	Value
Participation Assumptions[18]		
Large C&I customer participation (applicable to all 6 states)	Steady-state Participation (as % of eligible customers)	22.1%
Extra-large C&I customer participation (applicable to all 6 states)		20.9%
Program ramp up period	Years	3
Impact Assumptions[19]		
Per-participant load reduction	% of participant's load	21%
Cost Assumptions[20]		
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

Irrigation Load Control

This program option targets irrigation loads by shutting off or otherwise controlling irrigation pumps during peak periods. PacifiCorp currently operates Irrigation Load Control programs in Idaho and Utah, with realized load reductions of approximately 168 MW and 21 MW, respectively[21]. This program is currently being administered by a third party in each jurisdiction. In our analysis, we assume the continuation of the current program offering in Idaho and Utah and estimate the potential and associated costs for new program offerings in the other states.

[17] 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

[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 and kWh impacts at site.

[21] These represent realized load reductions as of December 31, 2017

In 2016, PacifiCorp launched a pilot program in Oregon targeting 3 MW of irrigation load reduction, but, given the limited duration of the pilot, 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.

Table 1-8 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 1-8 Irrigation Load Control Program: Planning Assumptions

Data Item	Unit	Value
	Participation Assumptions[22]	
Irrigation load participation	Steady-state Participation (as % of eligible load)	CA: 15%, ID: 48%, OR: 15%, UT: 27.1%, WA: 15%, WY: 15%
Program ramp up period	Years	5
	Impact Assumptions[23]	
Per participant load reduction	% of participant's load	100%
	Cost Assumptions[24]	
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;

Ancillary Services

Ancillary Services refer to functions that help grid operators maintain a reliable electricity system. Ancillary services maintain the proper flow and direction of electricity, address imbalances between supply and demand, and help the system recover after a power system event. In systems with significant variable renewable energy penetration, additional ancillary services may be required to manage increased variability and uncertainty.

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

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

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

Table 1-9 Ancillary Services: Planning Assumptions

Data Item	Unit	Value
	Participation Assumptions[25]	
Irrigation load participation	Steady-state Participation (as % of eligible load)	All States: 15%
Program ramp up period	Years	5
	Impact Assumptions[26]	
Per participant load reduction	Average kW reduction per participant @ meter	0.11
	Cost Assumptions[27]	
Program Development Cost	$/kW-year	$300,000
Annual Program Administration Cost	$/year	$257,250 ($150,000 for full time employee (FTE))

Class 1 DSM Options Considered, but Qualitatively Screened Out

In addition to the Class 1 DSM options included in the study, we considered additional options, but later qualitatively screened them out of the potential analysis. The excluded option and the rationale for ultimately not including it is below.

- 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.

Class 3 DSM Resources

Class 3 DSM resources considered in our analysis include the following dynamic pricing options: Time-of-Use (TOU) Rates, Critical Peak Pricing (CPP), Real-Time Pricing (RTP), TOU Demand (TOU Demand) Rates, TOU Rates specifically for electric vehicle owners, and Behavioral Demand Response (BDR).[28]

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 Volume 5, 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 report for more details on the “opt-out” case.

We assume that dynamic 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

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

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

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

[28] Impacts from existing inclining block rate (IBR) or TOU participants were assumed to be embedded in the baseline load. Impacts from this study are incremental to any existing embedded impacts and represent new participation on one of the options listed above.

dynamic pricing options, this study assumes that PacifiCorp makes a staggered deployment of AMI in Oregon by 2020, Idaho by 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 dynamic pricing options are based on the previous 2015 potential assessment, which included an 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 who are 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 Volume 5 of 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 2015 potential assessment included a detailed assessment of these impacts, but the inputs and variables have not materially changed in the past two years, so the analysis was not updated for this study. See Volume 3, Section 3 of the prior potential assessment for the results and findings.

For this study, 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 1-10 lists the Class 3 DSM pricing products analyzed for residential customers in this study. For forward-looking potential estimation purposes over the 2019-2038 timeframe, TOU, TOU Demand rates, and CPP rates are considered for residential customers. A residential RTP rate is not considered in the analysis. RTP rates face implementation challenges for residential customers; as 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, such as TOU and CPP.

BDR is structured like traditional demand response interventions, but it does not rely on enabling technologies nor does it offer financial incentives to participants. Participants are notified of an event and simply asked to reduce their consumption during the event window. Generally, notification occurs the day prior to the event and are deployed utilizing a phone call, email, or text message. The next day, customers may receive post-event feedback that includes personalized results and encouragement.

For this analysis, we assumed the BDR program would be offered as part of a Home Energy Reports program in a typical opt-out scenario. The low participation case represents a more conservative deployment, likely targeting participants with the highest potential, while the high participation case represents a more aggressive deployment, targeting as many customers as is feasible while maintaining a viable control group. Thus, the impacts of the high case were reduced by half to reflect a combination of high and low energy users. In Table 1-10 below we present the dynamic pricing and behavioral program options that we considered in this study. The table also includes a brief description of the approach and identifies whether PacifiCorp currently offers the program, and if it was part of the previous study.

Table 1-10 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	Yes
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	Yes
Time-Of-Use 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
TOU 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 usage and demand off-peak.	Yes. Limited pilot in UT	Yes
Critical Peak Pricing Rate	Assess impacts associated with a CPP rate offering to all residential customers. Impacts are estimated with both opt-in and opt-out provisions.[29]	Yes. Limited pilot in UT	Yes
Behavioral Demand Response	Voluntary demand reductions in response to behavioral messaging. Example programs exist in CA and other states. Requires AMI technology.	No	No

Table 1-11 below presents residential Class 3 program basic assumptions.

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

Table 1-11 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 OR and summer monthly demand charge of $14.51/kW in UT, with corresponding decrease in volumetric energy rate such that rate is revenue neutral on average[30] CPP: 6:1 on-peak/off-peak price ratio

Residential Class 3 Customer Participation Assumptions

Table 1-12 presents participation assumptions for residential customers in pricing options with a voluntary, opt-in offering. In 2019-2020, we assume impacts are realized only from existing TOU rates (i.e. no incremental potential), whereas new rates are offered beginning in 2021 to allow time for rate design and regulatory approvals. The assumed program start date varies by state based on AMI deployment assumptions mentioned above.

Participation levels to reach a steady state 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 participation assumptions are presented in Volume 5 of this report.

[30] 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 1-12 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%	2021
Time of Use	28%	2025	*n/a since already an existing rate*	2015	28%	2021
Time of Use w/ EV	28%	2025	*0%*	2021	28%	2021
TOU Demand Rate	14%	2025	14%	2021	14%	2021
TOU Demand Rate w/ EV	14%	2025	14%	2021	14%	2021
Behavioral DR	20%	2021	20%	2021	20%	2021

Residential Class 3 Customer Impact Assumptions

Residential impact assumptions for Class 3 DSM pricing options are based on AEG's comprehensive database of time-varying pricing pilots that have been conducted across the U.S. and internationally over the past decade. These pilots have tested over 200 different time-varying rate offerings for residential customers.

Table 1-13 presents impact assumptions for residential customers in time varying rates. The peak-to-off-peak price ratio is the key driver of demand response among participants in time-varying rates. A higher 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. 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.

Note also that the impacts during summer months tend to be larger than during winter months. The primary driver of this difference is that, in our experience, customers tend to be less sensitive to heat, than they are to the cold. That is to say, that they are more willing to be warmer than usual for a few hours, than they are to be colder than usual therefor resulting in a higher summer response and lower winter response.

Impact assumptions are presented in Table 1-13 and are based on these ratios and rate designs.

Table 1-13 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%	2.9%
Opt-in	Residential	All	Time-Of-Use with EVs	9.8%	9.9%
Opt-in	Residential	All	Critical Peak Pricing	12.5%	6.3%
Opt-in	Residential	OR, WA, CA	TOU Demand Rate	3.3%	1.7%
Opt-in	Residential	UT, ID, WY	TOU Demand Rate	8.0%	0.0%*
Opt-in	Residential	All	TOU Demand with EVs	9.8%	9.9%
Opt-in	Residential	All	Behavioral DR	2.0%	1.0%

** 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 1-14 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 Volume 3 of the previous, 2017 potential assessment, and no substantive changes to their implementation have occurred in the interim. For potential estimation purposes over the 2019-2038 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.[31]

[31] 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 1-14 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

Table 1-15 presents TOU, CPP, and RTP program basics for non-residential customers.

Table 1-15 Non-residential TOU, CPP and RTP Program Basics

Program Element	Assumption
Eligible Customer Classes	TOU: All C&I customer classes, Irrigation customers CPP: All C&I customer classes, Irrigation customers RTP: Large and Extra-large C&I customers
Controlled end uses	Any
Applicable Hours	TOU: Six hours on-peak period each summer 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 1-16 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 as mentioned above; except in the case of large and extra-large customers that already have interval meters for existing mandatory or voluntary rate options.

Participation levels are assumed to reach a steady-state five years after the introduction of a new product. As described earlier in this study, 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 participation assumptions is presented in Volume 5 of this report.

Table 1-16 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%	2021
	Large and Extra-large	18%	2021	18%	2021	18%	2021
	Irrigation	18%	2025	18%	2021	18%	2021
Time of Use	Small, Med, & Large	13%	2025	13%	2021	13%	2021
	Extra-large	*0% or n/a since already an existing rate*		13%	2021	*0% or n/a since already an existing rate*	
	Irrigation	13%	2025	13%	2021	13%	2021
Real time Pricing	Large	3%	2021	3%	2021	3%	2021
	Extra-large	5%	2021	5%	2021	5%	2021

Non-Residential Class 3 Customer Impact Assumptions

Table 1-17 shows the load impact assumptions (represented as "% of peak load reduction") for dynamic pricing options offered to non-residential customers. The industry, in general, has conducted fewer price elasticity studies for small and medium C&I customers than residential customers; for these segments, we relied on price elasticity estimates from a dynamic pricing pilot in California[32]. Due to the lack of national data, 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 1-17 are based on a 2:1 TOU on-to-off peak price ratio and a 6:1 CPP on-to-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 capabilities, therefore their response would not be driven by behaviors as a residential customer.

[32] "Impact Evaluation of the California Statewide Pricing Pilot" Final Report, prepared by Charles River Associates, March 2005

Table 1-17 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%	0.1%
	Critical Peak Pricing	0.6%	0.3%
Medium C&I	Time-Of-Use	2.6%	1.3%
	Critical Peak Pricing	7.3%	3.7%
Large C&I	Time-Of-Use	3.1%	1.6%
	Critical Peak Pricing	8.4%	4.2%
	Real Time Pricing	8.4%	4.2%
Extra-large C&I	Time-Of-Use	3.1%	1.6%
	Critical Peak Pricing	8.4%	4.2%
	Real Time Pricing	8.4%	4.2%
Irrigation	Time-Of-Use	4.7%	0.0%
	Critical Peak Pricing	13.0%	0.0%

Class 3 Customer Cost Assumptions

Table 1-18 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 Volume 5 of this report.

Table 1-18 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 with EVRTP 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 with EV Residential, Small and Medium C&I, Irrigation: $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 this study, we considered several options that were qualitatively screened out of the potential analysis. A listing of these options and the rationale for 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 Volume 3 of the previous, 2017 potential assessment, and no substantive changes to their implementation have occurred in the interim. 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 ended 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 PacifiCorp 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. Therefore, it is a theoretical maximum potential for a particular DSM option.

In this 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 because it would simply represent an estimate of the achievable MW if all eligible participants participated in a single option, i.e. if all customers participated in TOU, or CPP. The potential estimation for Class 3 resources considers two more realistic participation cases, "opt-in" and "opt-out" types of dynamic pricing options. 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 as 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 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 PacifiCorp's IRP. 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 this 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 6.91%[33] to calculate net present value (NPV) costs. An inflation rate of 2.30%[34] was applied only to administrative program costs. Other costs, such as equipment and installation 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 1-19, have been included in all levelized cost and potential figures.

Table 1-19 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%

[33] Consistent with PacifiCorp's 2019 Integrated Resource Plan.

[34] Consistent with the 2017 Demand Side Resource Potential Assessment.

Table 1-20 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 industry assumption. For Third Party Contracts 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, industry experience suggests a useful life of 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 appropriately capture all costs that would occur over PacifiCorp's 20-year IRP planning horizon, including equipment replacement and periodic implementation costs.

Table 1-20 Program Life Assumptions

Program Option	Lifetime (Years)
Direct Load Control of all considered end-uses	10
Irrigation Load Control	5
Ice Energy Storage	20
Third Party Contracts	3
Pricing options	10

As part of this study the calculation of the levelized costs was adjusted to conform to the California Public Utility Commission's (CPUC) cost-benefit analysis protocols[35] for all Pacific Power states including California, Oregon, Washington, and Wyoming. Utah and Idaho use traditional methods cost-benefit analysis methodology. The CPUC protocols include recommendations on:

- Participant Costs
- Avoided Capacity Value
- T&D Capacity Value
- Capital Amortization Period
- Load Impacts
- A Factor Adjustment to the Avoided Generation Capacity Value
- C Factor Adjustment to the Avoided Generation Capacity Value

For our analysis, because we are only concerned with actual program costs, and not avoided or T&D capacity values, we made adjustments to the participant costs only. CPUC recommendations around load impacts and amortization periods are left largely to the discretion of the Load Serving Entity (LSE).

The CPUC protocols address participant costs as being equal to the sum of Transaction Costs and the Value of Service Lost. However, given that those two costs are extremely difficult to quantify, other costs

[35] More information on the protocols can be found here: http://www.cpuc.ca.gov/general.aspx?id=7023

are often used as a proxy. In the past, Participant Costs have been presumed to be equal to Participant Benefits, which are defined as the cost of customer incentives and bill reductions, minus any customer capital costs. However, this is clearly inaccurate, since it is more likely that customers participate in programs because the benefits exceed the costs.[36] Given that we know that incentives likely exceed the true cost to the customer we have discounted the benefit of the incentive to the customer by 25% and counts only 75% of the incentive payment as a cost in the levelized cost calculation.

[36] See definition of participant costs in 2016 DR Cost Effectiveness Protocols here: http://www.cpuc.ca.gov/general.aspx?id=7023

2

CLASS 1 AND 3 DSM POTENTIAL RESULTS

This section presents potential analysis results for the Class 1 and 3 DSM options based on the assumptions and methodologies outlined in Volume 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 similar pilots and full-scale deployments from other utility programs.

Furthermore, this volume presents results for a voluntary, "opt-in" offering of time-varying rates. In Volume 5 of this report, we 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 volume 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 volume 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 Volume 5 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 new eligible customers. In our analysis we assumed new program offerings would be available for implementation beginning in 2021 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 2-1 and Table 2-2 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.

Key observations from our analysis results are:

- Total Class 1 DSM market potential more than doubles in 20 years from 2019-2038. Savings potential from Class 1 DSM resources are estimated to grow from 279 MW in 2019 to 930 MW in 2038, translating into 8.1% of projected system peak demand in 2038. Savings from existing programs account for about one-third of the total potential from Class 1 DSM options in 2038.
- In 2019, 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.[37] Incremental potential for these existing programs, above current impacts, is assumed to begin in 2021 to allow time for additional participant recruitment if selected by the 2019 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 three to five years, depending on the program. As a result of these assumptions, savings potential identified in this study begins to grow substantially starting in 2020.

- Control of residential and small and medium C&I cooling end uses using either DLC or smart thermostats provides the highest total potential of the Class 1 products. There is a total of 156 MW of reduction from DLC and 153 MW of reduction from smart thermostats for a total of 309 MW in 2038. It should be noted that about 65% of the total DLC related savings is from PacifiCorp's existing Cool Keeper program in Utah. An additional 54 MW of potential in 2038 is associated with a modest expansion of the Utah program, and new DLC programs launching in the PacifiCorp's remaining five states.
- Irrigation Load Control has the highest total potential of any single 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 86% of the 2038 savings potential for Irrigation Load Control is derived from these two states. The additional savings potential is primarily associated with new program deployments in the remaining four states.
- Third Party Contracts has the highest remaining market potential of all Class 1 DSM options; 168 MW of market potential in 2038. This CPA analysis includes an estimate of winter peak demand reduction potential. Total winter potential reaches 486 MW in 2038, 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 157 MW and 100 MW in 2038, respectively.

[37] 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 2-1 Class 1 DSM Total and Incremental Market Potential by Option (Summer Peak MW)

Sector	Total Potential Impacts in 2038	Impacts from Existing Options	Incremental Potential Impacts in 2038
Residential DLC Central AC	156.4	102.0	54.4
Residential DLC Space Heating	-	-	-
Residential DLC Water Heating	33.6	-	33.6
Residential DLC Smart Thermostats	153.2	-	153.2
Residential DLC Smart Appliances	15.0	-	15.0
Residential DLC Room AC	6.5	-	6.5
Residential DLC EV Charging	6.7	-	6.7
Residential Ancillary Services	1.6	-	1.6
C&I DLC Central AC	18.2	-	18.2
C&I DLC Space Heating	-	-	-
C&I DLC Water Heating	5.2	-	5.2
C&I DLC Smart Thermostats	98.8	-	98.8
C&I Third Party Contracts	168.3	-	168.3
C&I Ancillary Services	30.0	-	30.0
C&I Ice Energy Storage	7.6	-	7.6
DLC Irrigation	228.9	169.7	59.2
Total All Sectors	**930.2**	**271.7**	**658.5**
Potential (% of Projected 2038 system peak)	**8.1%**	**2.4%**	**5.7%**

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

Sector	Total Potential Impacts in 2038	Impacts from Existing Options	Incremental Potential Impacts in 2038
Residential DLC Central AC	-	-	-
Residential DLC Space Heating	156.8	-	156.8
Residential DLC Water Heating	33.6	-	33.6
Residential DLC Smart Thermostats	100.1	-	100.1
Residential DLC Smart Appliances	15.0	-	15.0
Residential DLC Room AC	-	-	-
Residential DLC EV Charging	6.7	-	6.7
Residential Ancillary Services	-	-	-
C&I DLC Central AC	-	-	-
C&I DLC Space Heating	8.5	-	8.5
C&I DLC Water Heating	5.2	-	5.2
C&I DLC Smart Thermostats	26.5	-	26.5
C&I Third Party Contracts	133.9	-	133.9
C&I Ancillary Services	-	-	-
C&I Ice Energy Storage	-	-	-
DLC Irrigation	-	-	-
Total All Sectors	**486.4**	**-**	**486.4**
Potential (% of Projected 2038 system peak)	**4.2%**	**0.0%**	**4.2%**

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

Class 1 DSM Market Potential Results by Option and State

Table 2-3 shows total Class 1 DSM potential results in 2038 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 68% of the savings potential in 2038 is derived from these two states. Note, as shown above, approximately 55% 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 Third Party Contracts.
- Oregon has the third largest potential savings, derived primarily from C&I Third Party Contracts and residential DLC programs, which have roughly equal potential.
- Wyoming has the fourth highest potential, with the majority of the savings derived from C&I Third Party Contracts 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 2-3 Class 1 DSM Total Market Potential by Option and State in 2038 (Summer Peak MW)

Program	CA	ID	OR	UT	WA	WY	Total
Residential DLC Central AC	0.3	0.8	4.9	147.2	1.9	1.3	**156.4**
Residential DLC Space Heating	-	-	-	-	-	-	-
Residential DLC Water Heating	0.7	1.2	11.0	15.2	4.2	1.3	**33.6**
Residential DLC Smart Thermostats	3.8	5.8	36.5	87.2	9.3	10.5	**153.2**
Residential DLC Smart Appliances	0.3	0.6	4.2	8.1	0.9	1.0	**15.0**
Residential DLC Room AC	0.2	0.4	1.5	3.0	0.7	0.8	**6.5**
Residential DLC EV Charging	0.1	0.2	1.3	4.8	0.3	0.1	**6.7**
Residential Ancillary Services	0.0	0.0	0.3	1.1	0.1	0.0	**1.6**
C&I DLC Central AC	0.5	0.9	6.7	5.9	1.8	2.3	**18.2**
C&I DLC Space Heating	-	-	-	-	-	-	-
C&I DLC Water Heating	0.1	0.4	2.1	1.4	0.4	0.7	**5.2**
C&I DLC Smart Thermostats	2.1	3.0	25.7	51.1	7.5	9.4	**98.8**
C&I Third Party Contracts	1.1	1.9	37.7	76.7	10.9	40.1	**168.3**
C&I Ancillary Services	0.5	0.7	7.9	15.9	1.9	3.2	**30.0**
C&I Ice Energy Storage	0.2	0.5	2.9	2.4	0.7	1.0	**7.6**
DLC Irrigation	4.6	177.3	13.9	23.0	8.3	1.8	**228.9**
Total	**14.5**	**193.8**	**156.6**	**443.0**	**48.8**	**73.5**	**930.2**

Table 2-4 presents the Class 1 DSM potential results in 2038 by option for each state in the winter peak season. Winter peak savings are about 53% of those projected for the summer peak season. Key observations are:

- In the residential sector, space heating dominates the winter savings potential, contributing 157 MW in 2038. The DLC Smart Thermostat program follows second with 100 MW of winter peak savings.
- For C&I, the highest contributing program is Third Party Contracts with 145 MW.

Table 2-4 Class 1 DSM Total Market Potential by Option and State in 2038 (Winter Peak MW)

Program	CA	ID	OR	UT	WA	WY	Total
Residential DLC Central AC	-	-	-	-	-	-	-
Residential DLC Space Heating	4.2	9.9	64.7	41.6	24.7	11.7	156.8
Residential DLC Water Heating	0.7	1.2	11.0	15.2	4.2	1.3	**33.6**
Residential DLC Smart Thermostats	3.0	6.9	46.0	18.5	17.8	7.8	**100.1**
Residential DLC Smart Appliances	0.3	0.6	4.2	8.1	0.9	1.0	**15.0**
Residential DLC Room AC	-	-	-	-	-	-	-
Residential DLC EV Charging	0.1	0.2	1.3	4.8	0.3	0.1	**6.7**
Residential Ancillary Services	-	-	-	-	-	-	-
C&I DLC Central AC	-	-	-	-	-	-	-
C&I DLC Space Heating	0.2	0.6	3.1	2.3	0.8	1.5	8.5
C&I DLC Water Heating	0.1	0.4	2.1	1.4	0.4	0.7	**5.2**
C&I DLC Smart Thermostats	0.8	2.0	11.9	3.5	5.2	3.2	**26.5**
C&I Third Party Contracts	0.7	1.4	32.8	51.3	10.2	37.5	**133.9**
C&I Ancillary Services	-	-	-	-	-	-	-
C&I Ice Energy Storage	-	-	-	-	-	-	-
DLC Irrigation	-	-	-	-	-	-	-
Total	**10.0**	**23.1**	**177.2**	**146.8**	**64.5**	**64.8**	**486.4**

Table 2-5 shows the incremental potential in 2038 by Class 1 DSM option and state. The C&I Third Party Contracts option in Utah has the highest contribution to incremental potential. Other options with significant contribution are the residential Smart Thermostat program in Utah and Oregon, C&I Third Party Contracts in Wyoming and Oregon, and C&I Smart Thermostat program in Oregon 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 2-5 Class 1 DSM Incremental Market Potential by Option and State in 2038 (Summer Peak MW)

Program	CA	ID	OR	UT	WA	WY	Total
Residential DLC Central AC	0.3	0.8	4.9	45.2	1.9	1.3	54.4
Residential DLC Space Heating	-	-	-	-	-	-	-
Residential DLC Water Heating	0.7	1.2	11.0	15.2	4.2	1.3	33.6
Residential DLC Smart Thermostats	3.8	5.8	36.5	87.2	9.3	10.5	153.2
Residential DLC Smart Appliances	0.3	0.6	4.2	8.1	0.9	1.0	15.0
Residential DLC Room AC	0.2	0.4	1.5	3.0	0.7	0.8	6.5
Residential DLC EV Charging	0.1	0.2	1.3	4.8	0.3	0.1	6.7
Residential Ancillary Services	0.0	0.0	0.3	1.1	0.1	0.0	1.6
C&I DLC Central AC	0.5	0.9	6.7	5.9	1.8	2.3	18.2
C&I DLC Space Heating	-	-	-	-	-	-	-
C&I DLC Water Heating	0.1	0.4	2.1	1.4	0.4	0.7	5.2
C&I DLC Smart Thermostats	2.1	3.0	25.7	51.1	7.5	9.4	98.8
C&I Third Party Contracts	1.1	1.9	37.7	76.7	10.9	40.1	168.3
C&I Ancillary Services	0.5	0.7	7.9	15.9	1.9	3.2	30.0
C&I Ice Energy Storage	4.6	26.8	13.9	3.7	8.3	1.8	59.2
DLC Irrigation	0.2	0.5	2.9	2.4	0.7	1.0	7.6
Total	**14.5**	**43.4**	**156.6**	**321.8**	**48.8**	**73.5**	**658.5**

Class 1 DSM Market Potential Results by Customer Class

Table 2-6 presents the total Class 1 DSM potential results broken down by customer class. The 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 40% of the total system-level potential in 2038. PacifiCorp's current residential program offerings are capturing 37.5% of the identified total potential in the residential sector.
- The irrigation sector has the second largest share of total potential, maintaining a 24.6% contribution in the overall Class 1 DSM potential. PacifiCorp's current irrigation DLC programs are already capturing 62.5% of the available potential in the irrigation sector.
- The C&I sector share increases steadily from 2019 onward, once Third Party Contracts 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. Small C&I customers constitute about 5% of the total Class 1 DSM savings potential.

Table 2-6 Class 1 DSM Total and Incremental Market Potential by Customer Class in 2038 (Summer Peak MW)

Customer Class	Total Potential	Impacts from Existing Options	Incremental Potential Impacts in 2038
Residential	373.0	102.0	271.0
Small C&I	49.1	-	49.1
Medium C&I	91.9	-	91.9
Large C&I	68.4	-	68.4
Extra-large C&I	118.7	-	118.7
Irrigation	228.9	169.7	59.2
Total	**930.2**	**271.7**	**658.5**

Table 2-7 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 are primarily operated in the summer, resulting in limited winter peak shaving program opportunity. Total and incremental savings are equal since there are no existing resources targeting winter peak savings.

Table 2-7 Class 1 DSM Total and Incremental Market Potential by Customer Class in 2038 (Winter Peak MW)

Customer Class	Total Potential	Impacts from Existing Options	Incremental Potential Impacts in 2038
Residential	312.2	-	312.2
Small C&I	34.7	-	34.7
Medium C&I	5.6	-	5.6
Large C&I	56.3	-	56.3
Extra-large C&I	77.6	-	77.6
Irrigation	-	-	-
Total	**486.4**	**-**	**486.4**

Class 1 DSM Market Potential Results by Customer Class and State in 2038

Table 2-8 and Table 2-9 show total Class 1 DSM potential by customer class in 2038 by state for summer and winter peak seasons. Key observations are:

- The residential and irrigation sectors dominate the potential in Utah and Idaho respectively. 91% of the total potential in Idaho comes from irrigation customers.
- In Wyoming, 49% of the potential is found in the extra-large C&I customer class through the Third Party Contracts option.
- In Oregon and Washington, the residential sector represents approximately 35% of the total identified potential. The next highest contribution is from extra-large C&I third party contract participants in Oregon and Irrigation in Washington, representing approximately 17% of the overall potential in each sector in the states.

- In California, in addition to the significant residential contribution, about one-third 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 Utah.

Table 2-8 Class 1 DSM Market Potential by Customer Class and State in 2038 (Summer Peak MW)

State	Res.	Small C&I	Med. C&I	Large C&I	Extra-large C&I	Irrigation	Total
CA	5.3	1.5	1.7	0.5	0.8	4.6	14.5
ID	9.1	2.9	2.2	1.0	1.2	177.3	193.8
OR	59.6	15.0	25.5	16.6	25.8	13.9	156.6
UT	266.6	19.5	47.0	38.4	48.6	23.0	443.0
WA	17.2	3.9	7.4	5.8	6.2	8.3	48.8
WY	15.1	6.3	8.1	6.0	36.2	1.8	73.5
Total	**373.0**	**49.1**	**91.9**	**68.4**	**118.7**	**228.9**	**930.2**

Table 2-9 Class 1 DSM Market Potential by Customer Class and State in 2038 (Winter Peak MW)

State	Res.	Small C&I	Med. C&I	Large C&I	Extra-large C&I	Irrigation	Total
CA	8.3	1.0	0.1	0.3	0.4	-	10.0
ID	18.8	2.8	0.2	0.5	0.9	-	23.1
OR	127.3	14.9	2.3	12.4	20.4	-	177.2
UT	88.2	5.9	1.3	31.7	19.6	-	146.8
WA	47.7	5.4	1.1	5.5	4.7	-	64.5
WY	21.9	4.7	0.6	5.9	31.6	-	64.8
Total	**312.2**	**34.7**	**5.6**	**56.3**	**77.6**	**-**	**486.4**

Class 1 DSM Levelized Costs

For each option, we estimated levelized costs over the entire study period of 2019–2038. Table 2-10 and Table 2-11 show levelized costs and 2038 market potential by option and state, for summer impacts and winter impacts respectively. As mentioned in the previous section, an assessment of the levelized cost per summer peak kW is conducted independently of an assessment of cost per winter peak kW. We provide PacifiCorp with both summer and winter levelized costs to enable flexibility during the IRP process. We focus our discussion of findings on levelized cost per summer peak kW since this is still PacifiCorp's primary system peak season and controlling system constraint. Results are aggregated at the state level.

- Irrigation Load Control, which is the largest existing Class 1 DSM program, has one of the lower levelized cost. Costs are lower in states such as Idaho and Utah due to the 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, Washington, 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, which can add on programs to leverage the administrative and delivery infrastructures. 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 which reduces program costs because the program would not have to offset the costs of equipment. For these reasons, many DLC options and customer classes show relatively low levelized costs. Additional differences by state for the assumed per-unit kW impact are shown in Table 1-4.
- The highest levelized costs are associated with Ancillary Services, 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.
- Third Party Contracts for C&I customers have 167 MW of potential system wide, with costs around $100 per summer kW reduced.

Table 2-10 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	$111	$151	$157	$108	$133	$136	**156.4**
Res DLC Space Heating							**-**
Res DLC Water Heating	$84	$85	$85	$87	$86	$86	**33.6**
Res DLC Smart Thermostats	$97	$138	$150	$66	$122	$122	**153.2**
Res DLC Smart Appliances	$248	$246	$254	$255	$253	$247	**15.0**
Res DLC Room AC	$236	$250	$397	$229	$320	$180	**6.5**
Res DLC EV Charging	$819	$738	$807	$729	$805	$886	**6.7**
Res Ancillary Services	$647	$485	$612	$454	$607	$749	**1.6**
C&I DLC Central AC[38]	$77	$84	$71	$70	$65	$71	**18.2**
C&I DLC Space Heating							**-**
C&I DLC Water Heating	$52	$34	$34	$73	$34	$35	**5.2**
C&I DLC Smart Thermostats	$29	$32	$24	$19	$20	$23	**98.8**
C&I Third Party Contracts	$97	$98	$98	$101	$102	$102	**168.3**
C&I Ancillary Services	$67	$54	$55	$34	$53	$35	**30.0**
C&I Ice Energy Storage	$171	$179	$174	$182	$174	$177	**7.6**
DLC Irrigation	$81	$59	$83	$61	$83	$84	**228.9**

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

Table 2-11 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							-
Res DLC Space Heating	$54	$42	$49	$43	$41	$46	**156.8**
Res DLC Water Heating	$84	$85	$85	$87	$86	$86	**33.6**
Res DLC Smart Thermostats	$121	$117	$119	$313	$64	$164	**100.1**
Res DLC Smart Appliances	$248	$246	$254	$255	$253	$247	**15.0**
Res DLC Room AC							-
Res DLC EV Charging	$819	$738	$807	$729	$805	$886	**6.7**
Res Ancillary Services							-
C&I DLC Central AC							-
C&I DLC Space Heating	$65	$29	$45	$83	$39	$31	**8.5**
C&I DLC Water Heating	$52	$34	$34	$73	$34	$35	**5.2**
C&I DLC Smart Thermostats	$79	$49	$52	$281	$28	$69	**26.5**
C&I Third Party Contracts	$156	$137	$113	$155	$110	$110	**133.9**
C&I Ancillary Services							-
C&I Ice Energy Storage							-
DLC Irrigation							-

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 Oregon, 2021 in Idaho, and 2025 in California, Washington, Utah, and Wyoming.

Table 2-12 shows the total potential from Class 3 DSM options in 2038. The total, therefore, reflects the effects of existing Class 3 resources and 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 2038 for the opt-in pricing options.

Key observations from our analysis are:

- The total summer potential from Class 3 DSM resources reaches 353 MW in 2038, which translates into 3.1% of PacifiCorp's projected system peak demand in 2038.
- We assume that the Residential TOU rate in Idaho is offered from 2019 onward. Savings from new TOU rates, RTP, and CPP are realized from 2021 onward, based on when AMI is available in each state as mentioned above. The savings from pricing options ramp up in their early years following an "S-shaped" diffusion curve, growing from 15 MW in 2021 to 171 MW in 2026, when all the pricing

programs are assumed to be available. Eventually, savings levels reach a steady state at 3% of projected system peak.

- In general, CPP has the highest contribution of the various Class 3 options because higher on-to-off peak price ratios combined with an "event" type structure typically encourage participants to shift more energy than a typical TOU or demand rate.
- All the residential pricing options are large contributors to Class 3 DSM potential in 2038. Residential CPP savings are the largest, followed by TOU Demand Rate, and traditional TOU, comprising 11% to 26% of the total Class 3 potential.
- For C&I customers, CPP is significantly higher than other pricing options, with potential in 2038 at 77 MW. Savings opportunities from RTP and TOU are considerably lower in 2028 at only 13.7 MW and 10.5 MW respectively.
- For irrigation customers, CPP rates have more than three times the savings potential in 2038 as compared to TOU rates.

Table 2-12 Class 3 DSM Total Potential in 2038 (Summer Peak)

Class 3 DSM Options	Total Incremental Potential (MW)	Potential (as % of projected summer peak)
Residential TOU Demand Rate	37.3	0.3%
Residential TOU Demand Rate with EV	7.9	0.1%
Residential TOU	66.1	0.6%
Residential TOU with EV	15.4	0.1%
Residential CPP	89.8	0.8%
Residential Behavioral DR	17.1	0.1%
C&I TOU	10.5	0.1%
C&I CPP	76.8	0.7%
C&I RTP	13.7	0.1%
Irrigation TOU	3.7	0.0%
Irrigation CPP	14.3	0.1%
Total Class 3 DSM Potential	**352.5**	**3.1%**

Potential results for Class 3 DSM winter peak pricing options are presented in Table 2-13. Winter peak potential is about 39% 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 2-13 Class 3 DSM Total Potential in 2038 (Winter Peak)

Class 3 DSM Options	Total Incremental Potential (MW)	Potential (as % of projected summer peak)
Residential TOU Demand Rate	4.6	0.0%
Residential TOU Demand Rate with EV	3.9	0.0%
Residential TOU	31.0	0.3%
Residential TOU with EV	7.7	0.1%
Residential CPP	42.4	0.4%
Residential Behavioral DR	8.6	0.1%
C&I TOU	4.4	0.0%
C&I CPP	30.1	0.3%
C&I RTP	5.3	0.0%
Irrigation TOU	0.0	0.0%
Irrigation CPP	0.0	0.0%
Total Class 3 DSM Potential	**137.9**	**1.2%**

Class 3 DSM Total Potential in 2038 by Option and State

Table 2-14 and Table 2-15 present the total Class 3 DSM potential results broken down by state in 2038. 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, particularly large sized industrial customers.
- In Idaho, roughly 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 2-14 Class 3 DSM Total Market Potential by Option and State in 2038 (Summer Peak MW)

Program	CA	ID	OR	UT	WA	WY	Total
Residential TOU Demand Rate	0.3	0.9	4.8	26.9	1.9	2.4	**37.3**
Residential TOU Demand Rate with EV	0.1	0.2	1.5	5.6	0.3	0.1	**7.9**
Residential TOU	0.9	0.0	16.7	38.4	6.6	3.5	**66.1**
Residential TOU with EV	0.2	0.0	3.0	11.3	0.6	0.2	**15.4**
Residential CPP	1.2	1.8	22.3	51.1	8.8	4.6	**89.8**
Residential Behavioral DR	0.3	0.7	4.8	9.2	1.0	1.1	**17.1**
C&I TOU	0.1	0.3	2.5	5.6	1.1	1.0	**10.5**
C&I CPP	0.6	1.0	17.4	36.1	6.1	15.7	**76.8**
C&I RTP	0.1	0.1	3.0	6.0	0.8	3.6	**13.7**
Irrigation TOU	0.2	2.0	0.6	0.5	0.3	0.1	**3.7**
Irrigation CPP	0.7	7.9	2.2	1.8	1.3	0.3	**14.3**
Total	**4.5**	**15.1**	**78.9**	**192.5**	**28.9**	**32.6**	**352.5**

Table 2-15 Class 3 DSM Total Market Potential by Option and State in 2038 (Winter Peak MW)

Program	CA	ID	OR	UT	WA	WY	Total
Residential TOU Demand Rate	0.2	-	3.2	-	1.2	-	**4.6**
Residential TOU Demand Rate with EV	0.0	0.1	0.8	2.8	0.2	0.1	**3.9**
Residential TOU	0.7	-	11.1	12.6	4.1	2.4	**31.0**
Residential TOU with EV	0.1	-	1.5	5.6	0.3	0.1	**7.7**
Residential CPP	0.9	1.2	14.8	16.8	5.4	3.2	**42.4**
Residential Behavioral DR	0.2	0.4	2.4	4.6	0.5	0.6	**8.6**
C&I TOU	0.0	0.1	1.0	2.3	0.5	0.5	**4.4**
C&I CPP	0.2	0.3	7.4	12.0	2.7	7.4	**30.1**
C&I RTP	0.0	0.1	1.3	1.8	0.4	1.7	**5.3**
Irrigation TOU	-	-	-	-	-	-	**-**
Irrigation CPP	-	-	-	-	-	-	**-**
Total	**2.4**	**2.1**	**43.6**	**58.6**	**15.2**	**16.0**	**137.9**

Class 3 DSM Total Potential in 2038 by Customer Class and State

Table 2-16 and Table 2-17 shows 2038 total pricing potential results broken down 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 the 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 potential across all states, while small C&I customers have minimal contribution to potential. For Idaho, more than half of the potential is likely to be realized from irrigation customers.

Table 2-16 Class 3 DSM Total Market Potential by Customer Class and State in 2038 (Summer Peak MW)

State	Res	Small C&I	Med. C&I	Large C&I	Extra-large C&I	Irrigation	Total
CA	2.8	<0.1	0.3	0.2	0.3	0.9	**4.5**
ID	3.7	0.1	0.5	0.4	0.5	10.0	**15.1**
OR	53.2	0.5	5.3	7.1	10.0	2.8	**78.9**
UT	142.6	0.5	12.3	16.0	18.8	2.3	**192.5**
WA	19.2	0.1	3.0	2.4	2.5	1.6	**28.9**
WY	12.0	0.1	2.2	2.6	15.3	0.4	**32.6**
Total	**233.6**	**1.3**	**23.4**	**28.8**	**47.5**	**17.9**	**352.5**

Table 2-17 Class 3 DSM Total Market Potential by Customer Class and State in 2038 (Winter Peak MW)

State	Res	Small C&I	Med. C&I	Large C&I	Extra-large C&I	Irrigation	Total
CA	2.1	<0.1	0.1	0.1	0.1	-	2.4
ID	1.6	<0.1	0.1	0.1	0.2	-	2.1
OR	33.9	0.2	2.1	2.9	4.5	-	43.6
UT	42.5	0.1	4.2	7.4	4.4	-	58.6
WA	11.6	<0.1	1.2	1.3	1.0	-	15.2
WY	6.4	0.1	1.0	1.4	7.0	-	16.0
Total	**98.2**	**0.5**	**8.8**	**13.2**	**17.3**	**-**	**137.9**

Class 3 DSM Incremental Potential by Option

The total potential shown below assumes that no migration away from PacifiCorp's existing Class 3 options, such as the voluntary TOU rates. As a result, the incremental potential from Class 3 DSM is estimated to change slightly, resulting in 342 MW of potential demand reductions by 2038, compared to the total market potential of 353 MW reported in Table 2-16 above. This is broken out by program option and state in Table 2-18. 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 are embedded in the baseline, such as mandatory residential IBR and mandatory extra-large C&I TOU, and are detailed in Volume 3, Section 3 of PacifiCorp's 2017 potential assessment report.

Table 2-18 Class 3 DSM Incremental Potential by Option and State in 2038 (Summer Peak MW)[39]

Program	CA	ID	OR	UT	WA	WY	Total
Residential TOU Demand Rate	0.25	0.95	4.85	26.94	1.91	2.44	**37.34**
Residential TOU Demand Rate w EV	0.09	0.22	1.52	5.63	0.32	0.12	**7.90**
Residential TOU	0.86	-	16.61	38.35	6.60	3.48	**65.90**
Residential TOU w EV	0.17	-	3.04	11.27	0.63	0.24	**15.35**
Residential CPP	1.15	1.80	22.30	51.12	8.78	4.63	**89.78**
Residential Behavioral DR	0.32	0.72	4.77	9.23	0.99	1.12	**17.15**
C&I TOU	0.01	0.24	-	-	-	-	**0.25**
C&I CPP	0.59	1.05	17.40	36.06	6.09	15.66	**76.84**
C&I RTP	0.08	0.14	3.00	5.96	0.83	3.64	**13.66**
Irrigation TOU	0.19	2.05	0.55	0.32	0.34	0.07	**3.51**
Irrigation CPP	0.73	7.91	2.19	1.84	1.30	0.29	**14.25**
Total	**4.45**	**15.08**	**76.23**	**186.72**	**27.79**	**31.69**	**341.94**

Class 3 DSM Levelized Costs

For each Class 3 DSM option, we estimated levelized costs over the study period of 2019–2038. The levelized costs for pricing options take into account costs associated with developing and administering the rates, including costs for customer education and outreach. Our analysis does not include costs associated with AMI deployment and communication networks or software. Costs also do not include reductions in revenue or customer incentives associated with participation in Class 3 DSM options. Any potential Class 3 proposals will need to carefully consider potential cost shifting. Costs are levelized over a 20-year lifetime to align with the IRP planning horizon. Detailed cost assumptions are presented in Volume 5 of the report.

Table 2-19 shows the levelized costs and associated 2038 incremental potential estimates for each option by state for the summer peak. Table 2-20 shows the results for the winter peak season. Key findings are:

- As Class 3 resources the impacts are by definition less reliable than Class 1 impacts because of the voluntary nature of the underlying customer actions. Also, dynamic pricing options and rate programs

[39] 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.

are relatively inexpensive to implement because they do not consider the cost of AMI or customer equipment costs and have substantial peak savings potential once AMI is deployed.

- Residential CPP, with the highest savings potential of 89 MW in 2038, with costs ranging from $20 to $46/kW-year depending on the jurisdiction.
- Potential for C&I CPP is estimated at 76 MW, with costs ranging from $3 to $14/kW-year depending on the jurisdiction.
- Pricing options for irrigation are the most cost effective given the comparatively large per-customer impacts. Levelized costs for irrigation pricing options range between $2 and $9/kW-year.

Table 2-19 Class 3 DSM Levelized Costs and Incremental Potential in 2038 (Summer Peak)

Option	CA	ID	OR	UT	WA	WY	Total Potential MW in Year 20
Res TOU Demand Rate	$81	$33	$57	$22	$48	$27	**37.3**
Res TOU Demand Rate w EV	$163	$90	$158	$55	$139	$199	**7.9**
Res TOU	$23	-	$16	$15	$14	$19	**66.1**
Res TOU w EV	$89	-	$86	$37	$77	$113	**15.4**
Res CPP	$42	$46	$27	$29	$20	$37	**89.8**
Res Behavioral DR	$72	$72	$73	$74	$73	$74	**17.1**
C&I TOU	$18	$10	$10	$7	$8	$8	**10.5**
C&I CPP	$16	$14	$7	$5	$6	$3	**76.8**
C&I RTP	$34	$16	$36	$15	$36	$15	**13.7**
Irrigation TOU	$8	$4	$7	$5	$9	$6	**3.7**
Irrigation CPP	$6	$2	$6	$5	$8	$6	**14.3**

Table 2-20 Class 3 DSM Levelized Costs and Incremental Potential in 2038 (Winter Peak)

Option	CA	ID	OR	UT	WA	WY	Total Potential MW in Year 20
Res TOU Demand Rate	$99	-	$85	-	$78	-	**4.6**
Res TOU Demand Rate with EV	$325	$180	$316	$110	$278	$398	**3.9**
Res TOU	$28	-	$24	$47	$22	$27	**31.0**
Res TOU with EV	$178	-	$172	$74	$155	$226	**7.7**
Res CPP	$52	$71	$40	$87	$32	$53	**42.4**
Res Behavioral DR	$144	$144	$146	$147	$147	$147	**8.6**
C&I TOU	$54	$30	$25	$16	$18	$15	**4.4**
C&I CPP	$49	$43	$17	$16	$14	$7	**30.1**
C&I RTP	$109	$42	$83	$51	$80	$31	**5.3**
Irrigation TOU	-	-	-	-	-	-	**-**
Irrigation CPP	-	-	-	-	-	-	**-**

3

COMPARISON WITH PREVIOUS DSM POTENTIAL ASSESSMENT

This section 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 February of 2017.[40] 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 3-1 presents a high-level comparison of the system-wide potential by Class 1 and 3 DSM option. Key observations are:

- The current study shows a slightly lower potential than the previous study with a total incremental potential of 1,325 MW in this study and a total of 1,419 MW in the previous study. This is primarily due to updated assumptions based on larger scale pilots for some Class 3 programs. These include lower participation in the TOU Demand Rate program to reflect more realistic customer adoption rate, and lower participation and impacts in the EV programs to reflect saturation of electric vehicles in the region.
- There have been baseline customer changes relative to the prior study. For example, peak load forecasts show higher growth in all states except Utah, Wyoming and to a lesser degree California. Projected Wyoming load growth in the oil & gas industry has flattened given the economic outlook for the sector.
- Compared to the prior study, a significant portion of the residential DLC Central AC opportunity was shifted to the Smart Thermostat option.
- The 20-year incremental potential for Class 1 DSM in the current study is 659 MW, which is roughly 17% larger than the 20-year Class 1 DSM potential estimate in the 2017 assessment of 562 MW.
    - Newly included program options drive a large portion of this increase: DLC Smart Thermostats and Ancillary Services in the C&I sector.
    - Conversely, there was a decrease in DLC programs for EVs and thermal storage given new information about program implementation, customer growth assumptions, saturation of applicable equipment, and estimated participation rates which are detailed further in the following tables.
    - Potential for DLC Irrigation and Third Party Contracts is similar between the two studies.
- The Class 3 DSM potential estimate in the current study is lower than the 2017 study, due largely to the revisions to the participation assumptions for TOU Demand Rates. The current study estimates

[40] "PacifiCorp Demand-Side Resource Potential Assessment for 2017-2036." Completed and published by Applied Energy Group Feb 14, 2017. Available at: http://www.pacificorp.com/es/dsm.html

342 MW of incremental Class 3 DSM potential in 2038 compared to 438 MW in 2036 from the previous study.

- Residential pricing potential in the current study is estimated at 233 MW in the final year, versus 321 MW in the previous assessment. This difference is driven by the lower participation of the TOU Demand Rate and TOU Demand Rate with 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 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 90.8 MW in 2038 is close to the corresponding value of 98.4 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 3-1 Comparison of Class 1 and 3 DSM Potential with 2017 Assessment (Incremental Summer Potential, without Interactive Effects)

DSM Options	2017 Assessment 2036 Potential (MW)	Current Assessment 2038 Potential (MW)
Class 1 DSM		
Residential DLC Central AC	106.5	54.4
Residential DLC Space Heating	-	-
Residential DLC Water Heating	40.2	33.6
Residential DLC Smart Thermostats	85.2	153.2
Residential DLC Smart Appliances	14.7	15.0
Residential DLC Room AC	8.5	6.5
Residential DLC EV Charging	22.2	6.7
Residential Ancillary Services	-	1.6
C&I DLC Central AC	24.7	18.2
C&I DLC Space Heating	-	-
C&I DLC Water Heating	4.4	5.2
C&I DLC Smart Thermostats	-	98.8
C&I Third Party Contracts	182.9	168.3
C&I Ancillary Services	-	30.0
C&I Ice Energy Storage	15.3	7.6
DLC Irrigation	57.6	59.2
Total Class 1 DSM	**562.2**	**658.5**

DSM Options	2017 Assessment 2036 Potential (MW)	Current Assessment 2038 Potential (MW)
Class 3 DSM		
Residential Pricing		
Res TOU Demand Rate	81.8	37.3
Res TOU Demand Rate with EV	71.9	7.9
Res TOU	70.7	65.9
Res TOU with EV	-	15.4
Res CPP	96.3	89.8
Res Behavioral DR	-	17.1
Total Residential Pricing	**320.7**	**233.4**
C&I Pricing		
C&I TOU	0.3	0.3
C&I CPP	83.2	76.8
C&I RTP	14.9	13.7
Total C&I Pricing	**98.4**	**90.8**
Irrigation Pricing		
Irrigation TOU	3.8	3.5
Irrigation CPP	15.3	14.3
Total Irrigation Pricing	**19.1**	**17.8**
Total Class 3 DSM	**438.2**	**341.9**

Comparison of Class 1 Resource Options with Previous Assessment

Table 3-2 presents a comparison of Class 1 DSM potential estimates by option and state and discusses the primary drivers behind variance between this study and the previous study.

Table 3-2 Comparison of Class 1 DSM Potential with 2017 Assessment (Incremental Summer Potential, without Interactive Effects)

Class 1 DSM Options	State	2017 Assessment 2036 Incremental Market Potential (MW)	Current Assessment 2038 Incremental Market Potential (MW)	Primary Differences in Potential Estimates
Residential DLC-Cooling	CA	1.0	0.3	Lowered the participation in this program, assuming a higher focus on the Smart Thermostat program
	ID	2.4	0.8	
	OR	18.4	4.9	
	UT	74.4	45.2	
	WA	6.6	1.9	
	WY	3.7	1.3	
	Total	**97.1**	**54.4**	
Residential DLC- Water Heating	CA	0.8	0.7	Overall potential is similar to that from the previous study
	ID	1.4	1.2	
	OR	15.8	11.0	
	UT	15.3	15.2	
	WA	5.7	4.2	
	WY	1.4	1.3	
	Total	**40.2**	**33.6**	
Residential DLC Smart Thermostats	CA	1.0	3.8	Increased participation in this program in current assessment Assumed to be a Bring-Your-Own-Thermostat style program
	ID	2.4	5.8	
	OR	18.4	36.5	
	UT	53.1	87.2	
	WA	6.6	9.3	
	WY	3.7	10.5	
	Total	**85.2**	**153.2**	

Class 1 DSM Options	State	2017 Assessment 2036 Incremental Market Potential (MW)	Current Assessment 2038 Incremental Market Potential (MW)	Primary Differences in Potential Estimates
Residential DLC Smart Appliances	CA	0.1	0.3	Overall potential is similar to that from the previous study
	ID	0.6	0.6	
	OR	4.1	4.2	
	UT	7.8	8.1	
	WA	0.9	0.9	
	WY	1.0	1.0	
	Total	**14.0**	**15.0**	
Residential DLC Room AC	CA	0.2	0.2	Overall potential is similar to that from the previous study
	ID	0.5	0.4	
	OR	2.0	1.5	
	UT	3.9	3.0	
	WA	1.0	0.7	
	WY	1.0	0.8	
	Total	**8.5**	**6.5**	
Residential DLC Elec Vehicle Charging	CA	0.1	0.1	Lowered the peak impacts from previous study, from 0.92 kW to 0.28 kW per customer, based on updated research
	ID	0.4	0.2	
	OR	11.1	1.3	
	UT	9.9	4.8	
	WA	0.5	0.3	
	WY	0.2	0.1	
	Total	**22.2**	**6.7**	
Residential Ancillary Services	CA	-	0.0	New program to current assessment
	ID	-	0.0	
	OR	-	0.3	
	UT	-	1.1	
	WA	-	0.1	
	WY	-	0.0	
	Total	**-**	**1.6**	

Class 1 DSM Options	State	2017 Assessment 2036 Incremental Market Potential (MW)	Current Assessment 2038 Incremental Market Potential (MW)	Primary Differences in Potential Estimates
C&I DLC-Cooling	CA	0.7	0.5	Overall potential is similar to that from the previous study.
	ID	0.7	0.9	
	OR	5.2	6.7	
	UT	4.2	5.9	
	WA	1.8	1.8	
	WY	2.1	2.3	
	Total	**14.7**	**18.2**	
C&I DLC Water Heating	CA	0.2	0.1	Overall potential is similar to that from the previous study.
	ID	0.2	0.4	
	OR	1.8	2.1	
	UT	1.4	1.4	
	WA	0.4	0.4	
	WY	0.4	0.7	
	Total	**4.4**	**5.2**	
Third Party Contracts	CA	1.2	1.1	Collapsed the Curtailable Agreements from previous assessment to this current program Assumed to be third-party contracts
	ID	2.1	1.9	
	OR	38.0	37.7	
	UT	85.9	76.7	
	WA	9.9	10.9	
	WY	45.8	40.1	
	Total	**182.9**	**168.3**	
C&I Ancillary Services	CA	-	0.5	New program to this assessment
	ID	-	0.7	
	OR	-	7.9	
	UT	-	15.9	
	WA	-	1.9	
	WY	-	3.2	
	Total	**-**	**30.0**	

Class 1 DSM Options	State	2017 Assessment 2036 Incremental Market Potential (MW)	Current Assessment 2038 Incremental Market Potential (MW)	Primary Differences in Potential Estimates
Irrigation DLC	CA	5.3	4.6	Overall potential is similar to that from the previous study
	ID	22.3	26.8	
	OR	14.0	13.9	
	UT	6.3	3.7	
	WA	7.5	8.3	
	WY	2.1	1.8	
	Total	**57.6**	**59.2**	
Ice Energy Storage	CA	0.5	0.2	Lowered the peak impacts from previous study, from 5 kW to 1.7 kW per customer, based on updated research
	ID	0.9	0.5	
	OR	5.1	2.9	
	UT	5.7	2.4	
	WA	1.2	0.7	
	WY	1.8	1.0	
	Total	**15.3**	**7.6**	

Comparison of Class 3 Resource Options with Previous Assessment

Table 3-3 presents a comparison of Class 3 DSM potential estimates by option and state and discusses the primary drivers behind variance between this study and the previous.

Table 3-3 Comparison of Class 3 DSM Potential with 2017 Assessment (Incremental Summer Potential, without Interactive Effects)

Class 3 DSM Options	State	2017 Assessment 2036 Incremental Opt-in Potential (MW)	Current Assessment 2038 Incremental Opt-in Potential (MW)	Primary Differences in Potential Estimates
Residential TOU Demand Rate	CA	0.57	0.25	Lowered participation to reflect more realistic customer adoption rate, since Demand Rates are more complex than regular TOU rates
	ID	2.07	0.95	
	OR	9.78	4.85	
	UT	60.36	26.94	
	WA	3.48	1.91	
	WY	5.58	2.44	
	Total	**81.84**	**37.34**	
Residential TOU Demand Rate w/ EV	CA	0.13	0.09	Lowered participation to reflect the saturation of electric vehicles in the territory
	ID	1.76	0.22	
	OR	23.85	1.52	
	UT	44.11	5.63	
	WA	0.96	0.32	
	WY	1.04	0.12	
	Total	**71.86**	**7.90**	
Residential TOU	CA	0.99	0.86	Overall potential is similar to that from the previous study
	ID	-	-	
	OR	16.76	16.61	
	UT	42.96	38.35	
	WA	6.01	6.60	
	WY	3.97	3.48	
	Total	**70.69**	**65.90**	
Residential TOU w/ EV	CA	-	0.17	New program to current assessment
	ID	-	-	
	OR	-	3.04	
	UT	-	11.27	
	WA	-	0.63	
	WY	-	0.24	
	Total	**-**	**15.35**	

Class 3 DSM Options	State	2017 Assessment 2036 Incremental Opt-in Potential (MW)	Current Assessment 2038 Incremental Opt-in Potential (MW)	Primary Differences in Potential Estimates
Residential CPP	CA	1.31	1.15	Overall potential is similar to that from the previous study
	ID	1.96	1.80	
	OR	22.49	22.30	
	UT	57.26	51.12	
	WA	8.00	8.78	
	WY	5.29	4.63	
	Total	**96.32**	**89.78**	
Residential Behavioral DR	CA	-	0.32	New program to current assessment
	ID	-	0.72	
	OR	-	4.77	
	UT	-	9.23	
	WA	-	0.99	
	WY	-	1.12	
	Total	**-**	**17.15**	
C&I TOU	CA	0.02	0.01	Overall potential is similar to that from the previous study
	ID	0.27	0.24	
	OR	-	-	
	UT	-	-	
	WA	-	-	
	WY	-	-	
	Total	**0.29**	**0.25**	
C&I CPP	CA	0.68	0.59	Overall potential is similar to that from the previous study
	ID	1.14	1.05	
	OR	17.56	17.40	
	UT	40.39	36.06	
	WA	5.55	6.09	
	WY	17.89	15.66	
	Total	**83.19**	**76.84**	

Class 3 DSM Options	State	2017 Assessment 2036 Incremental Opt-in Potential (MW)	Current Assessment 2038 Incremental Opt-in Potential (MW)	Primary Differences in Potential Estimates
C&I RTP	CA	0.10	0.08	Overall potential is similar to that from the previous study
	ID	0.16	0.14	
	OR	3.03	3.00	
	UT	6.67	5.96	
	WA	0.76	0.83	
	WY	4.15	3.64	
	Total	**14.87**	**13.66**	
Irrigation TOU	CA	0.22	0.19	Overall potential is similar to that from the previous study
	ID	2.24	2.05	
	OR	0.55	0.55	
	UT	0.37	0.32	
	WA	0.31	0.34	
	WY	0.08	0.07	
	Total	**3.77**	**3.51**	
Irrigation CPP	CA	0.83	0.73	Overall potential is similar to that from the previous study
	ID	8.65	7.91	
	OR	2.21	2.19	
	UT	2.06	1.84	
	WA	1.18	1.30	
	WY	0.33	0.29	
	Total	**15.26**	**14.25**	

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