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Incorporating Demand Response into Western Interconnection Transmission Planning

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Incorporating Energy Efficiency into Western Interconnection Transmission Planning

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Table of Contents

List of Figures ... v

List of Tables ... v

Acronyms ... vii

Abstract ... ix

1. Introduction ... 1

2. WECC 10-Year Common Case ... 4
   - 2.1 Developing DR Resource Quantities ... 4
   - 2.2 Hourly Shaping of DR Resource Availability ... 10
   - 2.3 Simulated Dispatch of DR Resources ... 11
     - 2.3.1 Developing DR Resource Dispatch Characteristics ... 11
     - 2.3.2 Consideration of Alternative Approaches for DR Dispatch ... 13
     - 2.3.3 Demand Response Dispatch Tool ... 14

3. SPSC 10-Year High DSM Case ... 17
   - 3.1 Developing DR Quantities ... 17
     - 3.1.1 Updates to the FERC 2009 Study ... 18
     - 3.1.2 DR Resource Capacities for the SPSC 10-year High DSM Case ... 23
   - 3.2 Hourly Shaping of DR Resource ... 26
   - 3.3 Simulated Dispatch of DR Resources ... 26
     - 3.3.1 Developing DR Characteristics ... 27
     - 3.3.2 Demand Response Dispatch Tool ... 28

4. WECC 20-Year Reference Case ... 30
   - 4.1 Developing the Peak Demand Reductions in the WECC Reference Case ... 30
     - 4.1.1 Simulated Hourly Dispatch ... 30
     - 4.1.2 2022 Demand Reductions for the Four System Conditions ... 31
     - 4.1.3 Extrapolating Demand Reductions to 2032 ... 31
   - 4.2 Results ... 32

5. SPSC 20-Year High DSM Case ... 35
   - 5.1 Developing 2032 DR Potential Estimates ... 35
     - 5.1.1 Developing a High DR Scenario ... 35
     - 5.1.2 Balancing Authority DR Capacities ... 44
     - 5.1.3 Simulated Hourly Dispatch ... 45
   - 5.2 Results ... 46

6. Recommendations: Potential Improvements to Data, Methodology, and Process for Future TEPPC Study Cycles 50

References 52

Technical Appendices 53

List of Figures

Figure 1. WECC Balancing Authorities (circa 2011) 3
Figure 2: 2021 WECC BA adjusted non-firm load forecasts 7
Figure 3: WECC Common Case Non-Firm Load Forecast by BA 9
Figure 4: WECC Common Case DR Resources as Percent of 2021 Peak Demand 10
Figure 5: Example Hourly Shaping Factor for SCE on 2022 Peak Day 11
Figure 6: Simulated Dispatch Results for SCE Load Zone on Representative Day 15
Figure 7: Simulated Dispatch Results for WECC Common Case Non-Interruptible DR Programs 16
Figure 8: Summary of 2022 WECC-wide DR Potential 22
Figure 9: SPSC High DSM Case DR Resource Capacity by WECC BA and DR Program Type 25
Figure 10: SPSC High DSM Case DR Resource Capacities as a Percent of 2021 Annual Peak Demand 26
Figure 11: Simulated Dispatch Results for SPSC High DSM Case 29
Figure 12: 2032 WECC Reference Case Annual Peak Reduction from DR (Non-Coincident Peak Basis) 34
Figure 13: Assumed AMI Market Penetration in 2022 and 2032 37
Figure 14: The U.S. Census Divisions 38
Figure 15: Air-conditioning Market Saturation Projections 39
Figure 16: CAC Saturation in 2009 and 2032 39
Figure 17: Air-Conditioning DLC Participation Forecast 40
Figure 18: WECC High DR Resource Potential in 2022 and 2032 (as % of Peak Demand) 43
Figure 19: Forecast of State-Level DR Resources (as % of Peak Demand) 44
Figure 20: 2032 SPSC High DSM Case DR Resource Capacity by WECC BA and DR Program Type 45
Figure 21: 2032 SPSC High DSM Case WECC Reference Case Annual Peak Reduction from DR (Non-Coincident Peak Basis) 49

Figure A-1: 2022 High DSM Case FERC 2009 Study Allocation Methodology 55

List of Tables

Table 1: 2021 Non-Firm Load Forecast 5
Table 2: California IOU Program-Level Adjustments 8
Table 3: 2021WECC Common Case Non-Firm Load Forecast 9
Table 4: WECC Common Case Expected Dispatch Hours per Year 12
Table 5: Comparison of Major Assumptions in FERC 2009 Study 18
Table 6: FERC 2009 Study Data Updates 19
Table 7: FERC 2009 Study Assumption Updates 21
Table 8: State-by-State DR Potential Estimates Assumed in SPSC 10-Year High DSM Case (2022) 23
Table 9: Comparison of WECC Common Case and SPSC High DSM Case DR Resource Capacities by DR Program Type 25

Table 10: Comparison of WECC Common Case and SPSC High DSM Case Expected Dispatch Hour per Year 28
Table 11: 2032 WECC Reference Case System Condition Peak Demand Reductions 33
Table 12: 2022 and 2032 Dynamic Pricing Participation Rate Assumptions by State and Customer Class 42
Table 13: 20-Year SPSC High DSM Case DR Capacities by Program Type .... **Error! Bookmark not defined.**
Table 14: 2032 SPSC High DSM Case Quarterly Peak Demand Reductions 48

Table A-1: 2021 Common Case DR Capacities 53
Table A-2: 2022 SPSC High DSM Case DR Capacities 54
Table A-3: 2022 and 2032 WECC Reference Case Peak Demand Reductions 56
Table A-4: 10- and 20-year state-by-state summary of DR potential in High DSM Cases 57
Table A-5: 2032 SPSC High DSM Case Quarterly Peak Demand Reductions – 'Initial' and 'Flexible' Dispatch Approaches 59

Acronyms

AEO – Annual Energy Outlook
AESO – Alberta Electric System Operator
APS – Arizona Public Service Company
ARRA – American Recovery and Reinvestment Act
AVA – Avista Corporation
BA – Balancing authority
BCTC – BC Transmission Corporation
BIP – Base Interruptible Program
BPA – Bonneville Power Administration
CBP – Capacity Bidding Program
CFE – Comision Federal de Electricidad
CHPD – Public Utility District No. 1 of Chelan County
CISO – California Independent System Operator
CPP – critical peak pricing
CPUC – California Public Utilities Commission
DG – distributed generation
DLC – direct load control
DRDT – Demand Response Dispatch Tool
DOE – U. S. Department of Energy
DOPD – Public Utility District No. 1 of Douglas County
DR – demand response
DSM – Demand Side Management
EE – energy efficiency
EIA – Energy Information Administration
EISA – Energy Independence and Security Act
EPE – El Paso Electric Company
FAR_EAST – Idaho Power Company, Far East load zone
FERC – Federal Energy Regulatory Commission
GEP – Global Energy Partners
GCPD – Public Utility District No. 2 of Grant County
IID – Imperial Irrigation District
IOU – investor owned utility
IPCO – Idaho Power Company
IRP – Integrated Resource Plan
LBNL – Lawrence Berkeley National Laboratory
LDWP – Los Angeles Department of Water and Power
LMP – Locational Marginal Price
LRS – Loads & Resources Subcommittee
LTPP – Long Term Procurement Plan
MAGIC_VLY – Idaho Power Company, Magic Valley load zone
NEMS – National Energy Modeling System
NERC – North American Electric Reliability Corporation
NEVP – Nevada Power Company

NISO – Northern California Independent System Operator load zone
NPCC – Northwest Power and Conservation Council
NWMT – NorthWestern Energy
PACE_ID – PacifiCorp–Idaho
PACE_UT – PacifiCorp–Utah
PACE_WY – PacifiCorp–Wyoming
PACW – PacifiCorp–West
PGE – Pacific Gas & Electric
PGE_BAY – Pacific Gas & Electric, San Francisco Bay load zone
PGE_VLY – Pacific Gas & Electric, Central Valley load zone
PGN – Portland General Electric
PLS – Permanent Load Shift
PNM – Public Service Company of New Mexico
PSC – Public Service Company of Colorado
PSE – Puget Sound Energy
RTEP – Regional Transmission Expansion Planning
RTP – real time pricing
SCE – Southern California Edison
SCL – Seattle City Light
SDGE – San Diego Gas & Electric
SISO – Southern California Independent System Operator load zone
SMUD – Sacramento Municipal Utility District
SPP – Sierra Pacific Power Company
SPSC – State-Provincial Steering Committee
SRP – Salt River Project
TEP – Tucson Electric Power Company
TEPPC – Transmission Expansion Planning and Policy Committee
TIDC – Turlock Irrigation District
TPWR – Tacoma Power
TREAS_VLY – Idaho Power Company, Treasure Valley load zone
WACM – Western Area Power Administration, Colorado-Missouri Region
WALC – Western Area Power Administration, Lower Colorado Region
WAUW – Western Area Power Administration, Upper Great Plains West
WECC – Western Electricity Coordinating Council
WGA – Western Governors’ Association

Abstract

This report documents the demand response (DR)-related analyses developed by LBNL and its collaborators for the Western Electricity Coordinating Council (WECC) transmission planning studies conducted within the 2011 and 2012 study cycles and includes four distinct study cases: the 10-Year Reference Case (termed the WECC 10-Year Common Case), the 10-Year State-Provincial Steering Committee (SPSC) High DSM/DG Case, the 20-Year WECC Reference Case, and the 20-Year SPSC High DSM/DG Case.

For each study case, DR model inputs for each WECC load zone were developed for use within WECC's planning models. WECC non-firm load forecasts were validated and adjusted to provide DR resource capacities for the WECC Reference Cases. In developing estimates of DR potential for the SPSC High DSM/DG Cases, LBNL drew initially upon the 2009 FERC assessment of DR potential and then identified and adjusted key forecast assumptions that were expected to change during the 20-year time horizon (e.g., advanced metering infrastructure (AMI) market penetration, residential central air-conditioning (CAC) saturation, direct load control (DLC) participation rates, and dynamic pricing participation rates).

These DR resource capacities in each study case were then subjected to LBNL's simulated dispatch tool to create hourly load modifying profiles for each WECC load zone according to DR program constraints and availability factors. These hourly load modifying profiles of DR served as the main inputs to the 10-year WECC transmission planning studies on the potential contribution of DR resources. For the 20-year transmission planning studies, the hourly load modifying profiles were used as the basis for calculating demand reductions from DR resources under WECC-defined system conditions.

This report is targeted primarily for participants in WECC's transmission planning process, and is intended to serve as a reference document to inform future transmission planning efforts within the Western Interconnection. In addition, the methods described herein for modeling demand response impacts within WECC's recent transmission planning analyses may also have broader application, including to regional transmission planning organizations engaged in FERC Order 1000 compliance activities, individual utilities conducting integrated resource planning, and other interconnection-wide transmission planning efforts.

1. Introduction

The Western Electricity Coordinating Council (WECC) conducts transmission planning studies through its Transmission Expansion Planning and Policy Committee (TEPPC). In recent years, WECC's transmission planning process has been substantially expanded and enhanced with funding from the U. S. Department of Energy provided under the American Recovery and Reinvestment Act (ARRA) of 2009. This expanded effort, designated the *Regional Transmission Expansion Planning* (RTEP) project, entails the development of biennial 10- and 20-year transmission plans that serve to identify future transmission expansion needs and options for meeting those needs. The analysis conducted for each plan evaluates numerous stakeholder-driven "study cases" (i.e., scenarios) using production cost modeling and capacity expansion modeling tools. These study cases are selected through WECC's annual study request process, whereby stakeholder groups can recommend specific study cases for analysis during the annual study cycle. State regulators and energy agencies provide input to WECC's transmission planning analyses via (among other channels) the State-Provincial Steering Committee (SPSC), an entity formed by the Western Governors' Association (WGA), which participates in the annual study request process.

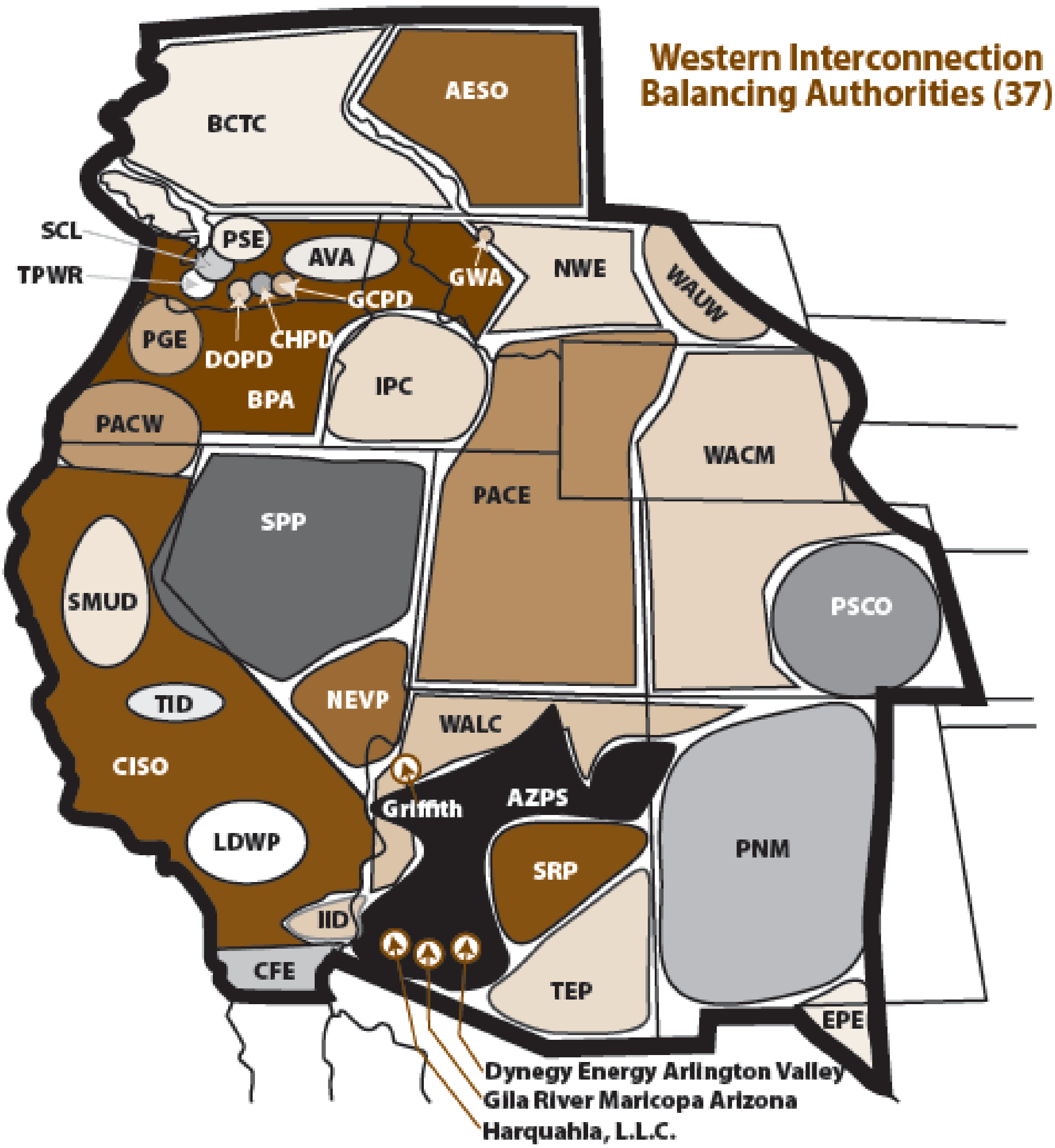
Lawrence Berkeley National Laboratory (LBNL) provides technical assistance to the SPSC and WECC with the development of demand-side management (DSM)-related assumptions and modeling inputs for WECC's transmission planning analyses. In this capacity, LBNL's work to-date has largely revolved around the implementation of specific SPSC study requests for both the 10-year and 20-year plans: in particular, requests for (a) "reference cases" that incorporate the expected impacts of current DSM-related policies and plans and (b) "High DSM" study cases that entail higher levels of DSM impacts than anticipated in the reference case. This activity has occurred under the auspices of the SPSC DSM Work Group, and participants in that group—including state regulatory and energy agency staff, utilities, and regional DSM experts—have vetted and provided input on key assumptions and methodologies. Critical review and input has also been provided by the TEPPC DSM Task Force, the TEPPC Data Work Group, and other key participant groups within the TEPPC process.

This report documents the DSM-related analyses developed by LBNL and its collaborators for WECC study cases conducted within the 2011 and 2012 study cycles. This includes four distinct study cases: the 10-Year Reference Case (termed the WECC 10-Year Common Case), the 10-Year SPSC High DSM/DG Case, the 20-Year WECC Reference Case, and the 20-Year SPSC High DSM/DG Case. Each of those study cases included assumptions and analyses for energy efficiency (EE), demand response (DR), and distributed generation (DG). This report focuses specifically on demand response; the EE and DG components of the study cases are addressed in separate reports (see Barbose et al., 2013). For each study case, model inputs were developed for each of the 39 individual load zones used within WECC's modeling tools; these load zones correspond roughly to the set of balancing authorities (BAs) shown in Figure 1, with the exceptions that several BAs (CISO and PACE) are decomposed into constituent load zones,[1] and five BAs are generation-only.[2]

[1] The CISO BA consists of four load zones (PGE_BAY, PGE_VLY, SCE, and SDGE), and the PACE BA consists of three load zones (PACE_ID, PACE_UT, and PACE_WY).
[2] The five generation-only BAs are identified with asterisks in the legend of Figure 1.

This report is targeted primarily for participants in WECC's transmission planning process, and is intended to serve as a reference document to inform future transmission planning efforts within the Western Interconnection. In addition, the methods described herein for modeling demand response impacts within WECC's recent transmission planning analyses may also have broader application, including to regional transmission planning organizations engaged in FERC Order 1000 compliance activities, individual utilities conducting integrated resource planning, and other interconnection-wide transmission planning efforts.

The report is organized as follows. In Chapter 2, we describe the demand response assumptions and analysis for the WECC 10-Year Common Case, which was developed during TEPPC's 2011 study cycle and formed the basis for WECC's first 10-Year Transmission Plan. Chapter 3 presents the corresponding information for the SPSC 10-Year High DSM Case, also developed within the 2011 study cycle. Chapter 4 moves to the 20-year planning horizon, and describes in detail the analysis and assumptions employed in developing the WECC 20-Year Reference Case during TEPPC's 2012 study cycle. Chapter 5 describes the development of the SPSC 20-Year High DSM Case, also during TEPPC's 2012 study cycle. Finally, Chapter 6 summarizes our recommendations identifying potential data, modeling, and process improvements for future TEPPC study cycles. The report includes a technical appendix with additional details on our approach and results.



Alberta Electric System Operator (AESO)
Arizona Public Service Company (AZPS)
Avista Corporation (AVA)
Bonneville Power Administration – Transmission (BPAT)
British Columbia Transmission Corporation (BCTC)
California Independent System Operator (CISO)
Comisión Federal de Electricidad (CFE)
Dynegy Energy Arlington Valley*
El Paso Electric Company (EPE)
Gila River Maricopa Arizona*
Griffith Energy, LLC (Griffith)*
Harquahala LLC*
Idaho Power Company (IPC)
Imperial Irrigation District (IID)
Los Angeles Department of Water and Power (LDWP)
NaturEner Power Watch (GWA)*
Nevada Power Company (NEVP)
NorthWestern Energy (NWE)
PacifiCorp — East (PACE)
PacifiCorp — West (PACW)
Portland General Electric Company (PGE)
Public Service Company of Colorado (PSCO)
Public Service Company of New Mexico (PNM)
PUD No. 1 of Chelan County (CHPD)
PUD No. 1 of Douglas County (DOPD)
PUD No. 2 of Grant County (GCPD)
Puget Sound Energy (PSE)
Sacramento Municipal Utility District (SMUD)
Salt River Project (SRP)
Seattle City Light (SCL)
Sierra Pacific Power Company (SPP)
Tacoma Power (TPWR)
Tucson Electric Power Company (TEP)
Turlock Irrigation District (TID)
Western Area Power Administration, Colorado-Missouri Region (WACM)
Western Area Power Administration, Lower Colorado Region (WALC)
Western Area Power Administration, Upper Upper Great Plains West (WAUW)

*Generation-only, controls no load

Source: WECC

Figure 1. WECC Balancing Authorities (circa 2011)

2. WECC 10-Year Common Case

The WECC 10-Year Common Case non-firm load forecasts for 2022 were developed in a two-part approach. First, the maximum DR resource capacity available for each WECC balancing authority (BA) was developed by validating—and, if warranted, adjusting—the BAs 2021 non-firm load forecasts submitted to WECC's Load and Resource Subcommittee (LRS). Second, an hourly load modifying profile of non-interruptible DR resources was developed using a simulated dispatch of those DR resources for each WECC load zone. This chapter describes both parts of the approach.

2.1 Developing DR Resource Quantities

WECC requires that each BA submits, on an annual basis, a 10-year non-firm load forecast consisting of monthly non-firm load segmented into four program types: interruptible load, direct load control (DLC), critical peak pricing (CPP) with controls, and load as a capacity resource (i.e., demand-side resources that can be committed for pre-specified load reductions under certain system conditions). These load forecasts are submitted as part of a broader data collection process administered by WECC's LRS, and are herein referred to as the "LRS non-firm load forecasts." Prior to the 2010 TEPPC study cycle, WECC directly used the LRS non-firm load forecasts as the TEPPC reference case load forecast. However, for the 2010 TEPPC study and again for the 2011 study cycle, the SPSC study request specifically recommended that the reference case non-firm load forecast be developed in a manner consistent with current state demand response policies and utility resource plans.[3] This required that the LRS non-firm load forecasts be validated and, if necessary, adjusted in order to bring them in line with current state policies and utility resource plans.

The 10-Year Common Case relied specifically on the non-firm load forecasts submitted in response to WECC's 2011 LRS data request, which covered the period 2011 to 2021 and were segmented into the four program types referenced above.[4] These program types are based on NERC's mandatory reporting requirements for dispatchable (i.e., controllable) DR resources. BAs were also requested to voluntarily submit demand response resource projections on a program-specific basis, breaking the aggregated four program type forecasts into individual demand response programs. This program-specific reporting on a voluntary-basis was incorporated in the LRS data collection process for the first time in 2011.

WECC BAs forecasted ~6,303 MW of DR resources in 2021 across all four program types. These forecasts represent the maximum available DR capacity and are on a non-coincident peak (NCP) basis. DLC programs accounted for the largest program type with ~2,633 MW (~42% of

[3] For the 2010 TEPPC study, WECC modeled one scenario based directly on the LRS non-firm load forecasts; that scenario was termed the "base case" scenario, and then a second scenario, termed the "SPSC Reference Case," which contained adjustments to the LRS data. In the 2011 study cycle, however, there was only a single Common Case, which followed the basic methodology used in the prior year for the SPSC Reference Case.

[4] The 2011 TEPPC Study used 2022 as its horizon. The LRS non-firm load forecasts were based on a 2021 horizon, so we assumed them to be constant to 2022 because DR capacity does not necessarily scale exactly with load. Also, drivers for DR capacity (e.g., program participation, incentive levels) were not likely to change significantly from one year to the next.

total DR resources) forecasted in 2021. The smallest program type across all WECC BAs was CPP with ~26 MW of maximum available resource. Table 1 summarizes the 2021 non-firm load forecasts by program type.

Table 1: 2021 Non-Firm Load Forecast

DR Program Type	2021 Forecast (MW; NCP)
Interruptible	2,335
DLC	2,633
CPP	26
Load as a capacity resource	1,309
Total	**6,303**

We validated the non-firm load forecasts by comparing each BA's forecast to utility Integrated Resource Plans (IRPs), FERC Demand Response Survey results, and state regulatory filings. We then contacted BA and utility staff responsible for non-firm load forecasts to understand differences between the WECC non-firm forecasts and what was included in the public validation sources. Preliminary adjustments were presented to the SPSC DSM Work Group and we received explicit approvals of recommended adjustments and, in some cases, instructive feedback from utility and state agency staff.

Adjustments to the LRS non-firm load forecast were as follows:

- **Arizona Public Service (APS).** We increased the interruptible load from 0 MW to 105 MW in 2021. This assumed the entire amount of 105 MW planned in the utility's IRP and the ability for DR to contribute towards compliance with the Arizona Energy Efficiency Standard (EES).

- **Imperial Irrigation District (IID).** We increased the interruptible load from 0 MW to ~10 MW in 2021 that was voluntarily reported as program-specific information. We confirmed with utility staff that the interruptible DR program was not included in the LRS non-firm load forecast submission.

- **Northern CISO (NISO).** We increased the interruptible load from 46 MW to ~308 MW, increased the direct load control load from 175 MW to ~543 MW, increased the pricing program load from 0 MW to ~350 MW, and decreased load as a capacity resource load from 574 MW to ~305 MW in 2021. These adjustments were based on the Pacific Gas and Electric (PGE) 2020 Ex Ante forecast to the California Public Utilities Commission (CPUC) Long Term Procurement Plan (LTPP). The increase in pricing program load is due to our use of a broader definition than NERC of event-based DR from pricing. We adjusted the NISO pricing program load to include the pricing programs that the California investor-owned utilities (IOUs) included in their resource plans and that are consistent with state policy towards DR. Time-of-use and permanent load shift (PLS) programs were not included as a pricing program, as they are considered non-event based DR.

- **Pacificorp–East (PACE).** We increased the interruptible load from 252 MW to 281 MW in 2021. This reflected the amount of interruptible load in the utility's 2011 IRP and was confirmed with utility staff.

- **Pacificorp–West (PACW).** We increased the interruptible load from 45 MW to 63 MW in 2021. This amount was recommended by utility staff.

- **Portland General Electric (PGN).** We increased the direct load control load from 0 MW to 60 MW and increased the pricing program load from 0 MW to 20 MW in 2021. These amounts were forecasted by the utility in the 2010 FERC DR Survey.

- **Puget Sound Energy (PSE).** We increased the direct load control load from 0 MW to 144 MW in 2021. This reflected the amount of direct load control programs forecasted in the utility's 2011 IRP.

- **Southern CISO (SISO).** We increased the interruptible load from 694 MW to ~723 MW, increased the direct load control load from 736 MW to ~1,082 MW, increased the pricing program load from 27 MW to ~582 MW, and decreased the load as a capacity resource load form 751 MW to ~157 in 2021. These adjustments were based on the Southern California Edison (SCE) 2020 Ex Ante forecast to the California Public Utilities Commission (CPUC) Long Term Procurement Plan (LTPP). Similar to the approach used in the NISO adjustment, we adjusted the SISO pricing program load to include the pricing programs that the California IOUs included in their resource plans and that are consistent with state policy towards DR. Real time pricing (RTP) programs were not included as a pricing program.

- **Sacramento Municipal Utility District (SMUD).** We increased the pricing program load from 0 MW to 143 MW in 2021. This was based on the utility's forecast of DR in the 2010 FERC DR Survey.

- **Salt River Project (SRP).** We increased the pricing program load from 0 MW to 78 MW in 2021. This was based on the utility's forecast of DR in the 2010 FERC DR Survey.

These adjustments to the 2021 non-firm load forecasts resulted in a net 1,660 MW or ~26% increase in the DR resource size, relative to the LRS non-firm load forecasts, and reflect current demand response policies and program plans (see Figure 2 which summarizes the adjusted non-firm load forecasts for those BAs that were adjusted). The largest adjustments (1,048 MW, or ~63% of the total adjustment) were made to the California IOU non-firm load forecasts, which account for ~51% of the adjusted 2021 non-firm load (~4,051 MW out of ~7,963 MW). Table 2 summarizes the California IOU program-level adjustments.

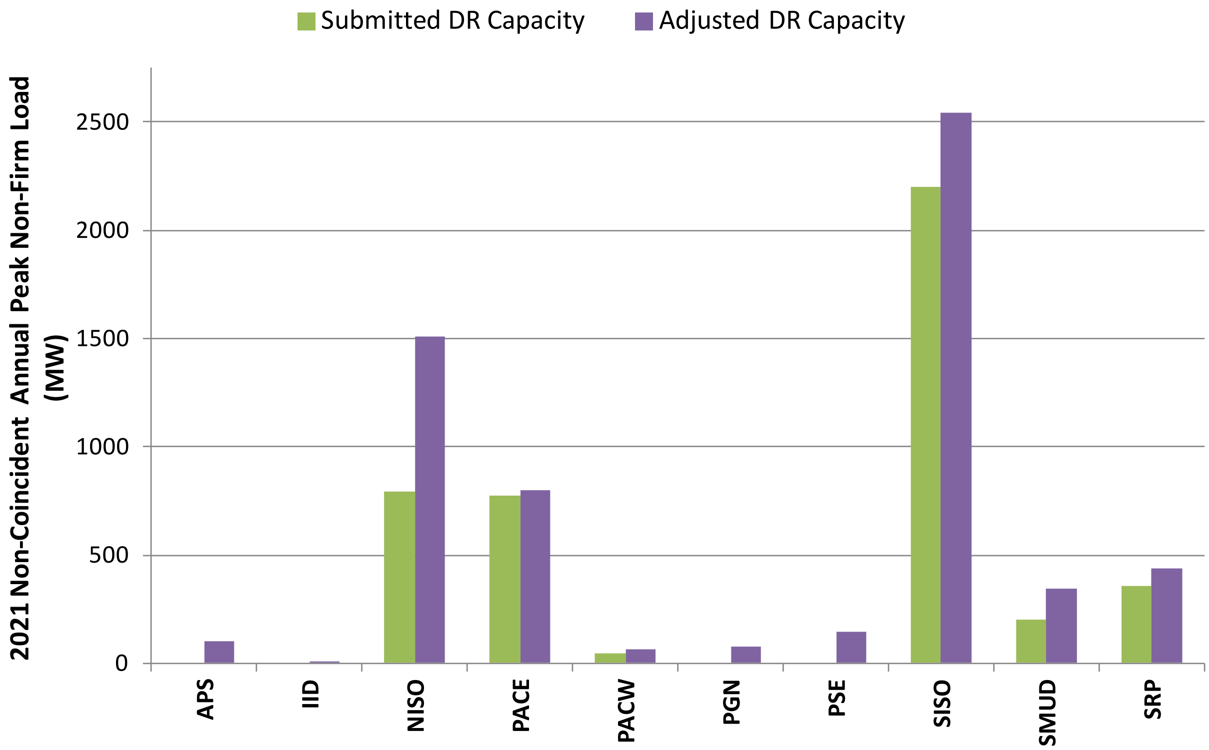


Figure 2: 2021 WECC BA adjusted non-firm load forecasts

Table 2: California IOU Program-Level Adjustments

DR Program Type	NISO Program Name	NISO Program Size (MW)	SISO Program Name	SISO Program Size (MW)
Interruptible	Base Interruptible Program (BIP)	308	BIP	678
			Agricultural and Pumping Interruptible Program (API)	44
DLC	Smart AC (residential and non-residential)	117	Summer Discount Plan (SDP) (emergency and non-emergency)	614
	AMI-enabled Load Control	427	AMI-enabled Load Control	468
Pricing	Peak Day Pricing (PCP) (residential and non-residential)	350	Critical Peak Pricing (CPP)	41
			AMI-enabled Dynamic Pricing	131
			AMI-enabled Peak Time Rebate (PTR)	410
Load as a Capacity Resource	Aggregator-Managed Program (AMP) (day-ahead and day-of)	209	DR Contract (day-ahead and day-of)	134
	Capacity Bidding Program (CBP) (day-ahead and day-of)	57	CBP (day-ahead and day-of)	14
	Demand Bidding Program (DBP)	13	DBP	9
	PeakChoice	26		

The 2021 WECC Common Case non-firm load forecasts, after all adjustments to account for current DR policies and program plans, totaled ~7,963 MW of maximum available DR capacity. DLC programs comprised the largest share of this amount, with ~3,615 MW of maximum available resources. After accounting for more DR pricing programs, in particular among the California IOUs, the 2021 WECC Common Case non-firm load forecast showed ~1,173 MW of maximum available pricing program capacity. Table 3 summarizes 2021 WECC Common Case non-firm load forecasts before and after adjustments.

Table 3: 2021WECC Common Case Non-Firm Load Forecast

DR Program Type	2021 BA Forecast (MW; NCP)	2021 Adjusted Forecast (MW; NCP)
Interruptible	2,335	2,714
DLC	2,633	3,615
Pricing	26	1,173
Load as a capacity resource	1,309	462
Total	**6,303**	**7,963**

Among the WECC BAs, California BAs accounted for the largest share of DR resources in the WECC Common Case with ~4,804 MW. The Southwest BAs had ~2,387 MW of DR capacity and the Northwest BAs had ~678 MW of DR capacity. There were several BAs that had no DR resources assumed in the WECC Common Case (see Figure 3).[5]

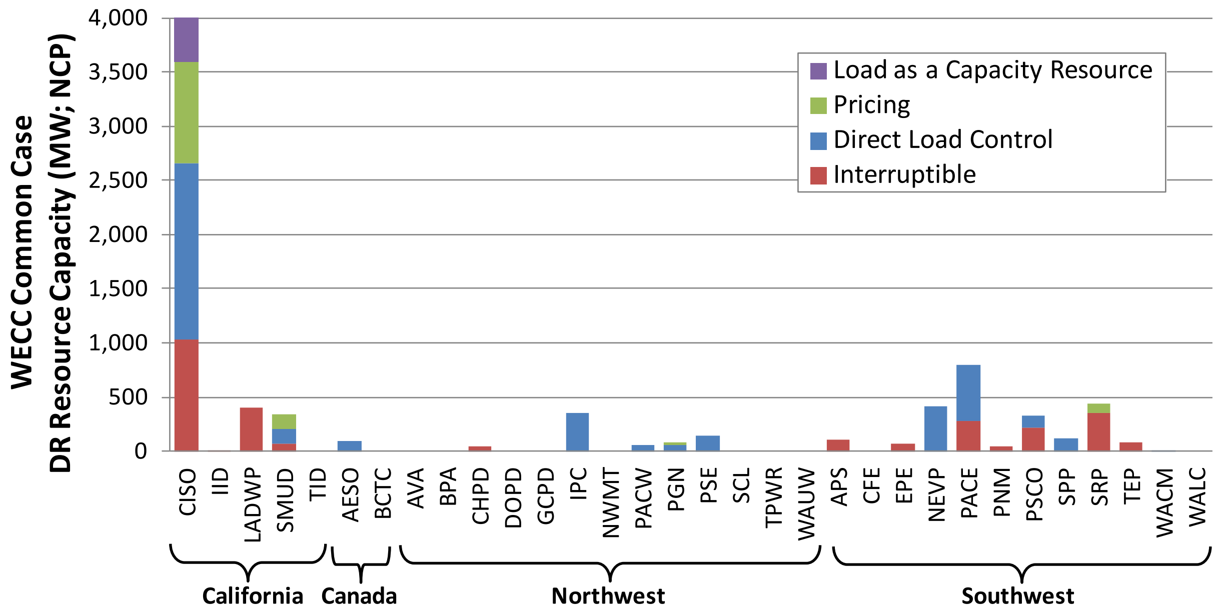


Figure 3: WECC Common Case Non-Firm Load Forecast by BA

Figure 4 shows the DR resources expressed as a percent of 2021 peak demand (on a non-coincident peak basis). WECC Common Case peak demand was 191,678 MW in 2021 and non-firm load represents ~4.2% of WECC peak demand. DR capacity as a percent of peak demand ranges from 0% for a number of BAs to ~8.2% (CISO).

[5] See Technical Appendix, Table A-1 for a table of DR resource capacities by BA and program type.

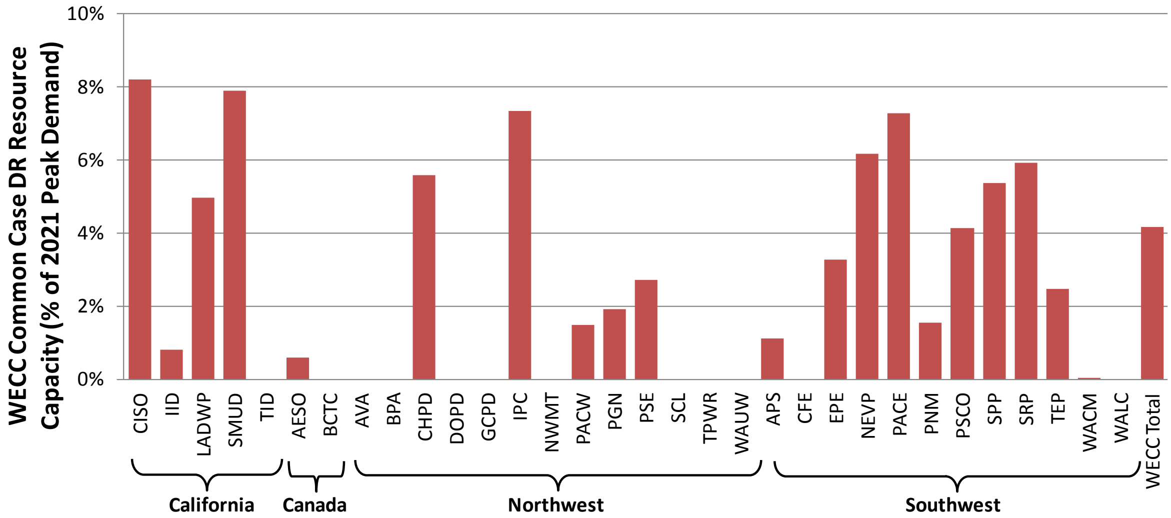


Figure 4: WECC Common Case DR Resources as Percent of 2021 Peak Demand

2.2 Hourly Shaping of DR Resource Availability

WECC non-firm load forecasts are expressed as the available monthly DR capacity in the peak-hour of each month. However, the availability of DR resources varies by month and hour for each BA and for some programs. It is important to capture the monthly and hourly availability in the modeling of DR resources in order to This step was critical to ensuring that DR programs typically used during system peak months and hours are not assumed to operate at full capacity in non-system-peak months and hours.

We shaped the DR resource capacity, for those DR program types included in our simulated dispatch (see 2.3), based on the hourly load profiles for each BA, by pro-rating the DR resource available in each hour based on the ratio of the total system load in that hour to the annual peak load. We assumed DR resources scaled with hourly load because those end-uses driving demand were also the end-uses that could respond to DR program signals. The hourly shaping factors represent the hourly load divided by the maximum annual load (i.e., annual peak), so that only one hour of the year had 100% DR resource availability.

Figure 5 shows an example of this hourly shaping applied to the SCE load zone on its peak day in 2022. The hour ending 1600 is the annual peak, and thus has 100% availability of the non-interruptible DR resources (~1,493 MW). The shaping factor and corresponding available DR resource changes on an hourly basis as the hourly load increases or decreases relative to the annual peak load.

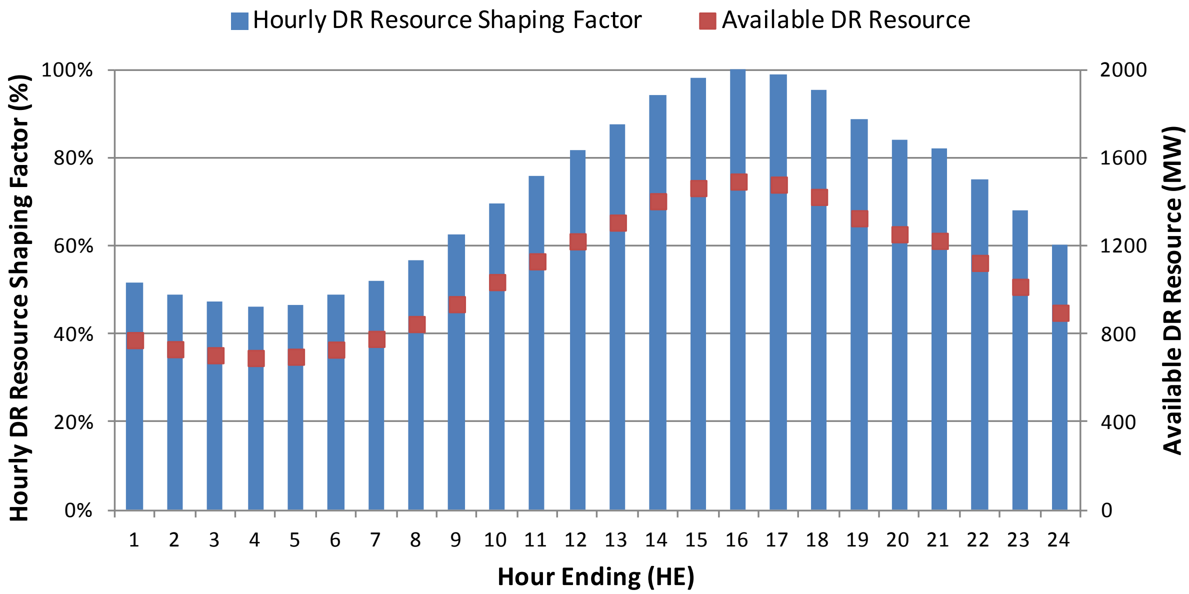


Figure 5: Example Hourly Shaping Factor for SCE on 2022 Peak Day

2.3 Simulated Dispatch of DR Resources

The 10-year transmission planning studies conducted by WECC utilize a production cost model (PROMOD) to model the dispatch of generation resources in the Western Interconnection. We sought to develop a procedure for realistically modeling the operation of DR resources within the constraints of PROMOD. This modeling approach employed a two-part methodology: (1) develop assumptions about the DR dispatch characteristics (e.g., expected hours of dispatch per year, resource availability) for each program type; and (2) simulate dispatch of DR resources in a manner consistent with the dispatch characteristics.

2.3.1 Developing DR Resource Dispatch Characteristics

To develop DR resource characteristics, we reviewed regulatory filings and other publicly available information related to the DR programs operated by load serving entities in WECC, focusing primarily on the California IOUs' DR programs, which collectively represent more than 50% of the WECC-wide non-firm load in the Common Case. Based on this information, we developed assumptions about the expected dispatch hours per year for each of the non-firm load forecast program types (see Table 4):

- **Interruptible load programs.** We assumed that these programs are utilized primarily for reliability-based events and are therefore rarely dispatched under 1-in-2 conditions (as the Common Case is intended to represent). Our review of California IOUs' DR program information showed that all California IOUs offer a Base Interruptible Program (BIP) with similar program rules, and 2009 event data showed that these interruptible programs were rarely, if at all, dispatched. This is not surprising because reliability-based events are infrequent. We assumed 10 hours of dispatch per year for the WECC Common Case (i.e., 2-3 interruptions per year, of 2-6 hours per event), given that some of these resources may be dispatched occasionally in response to “soft”, non-reliability-based triggers (e.g., energy market conditions).

- **DLC (direct load control) programs.** We assumed that DLC programs can be dispatched for both reliability and economic purposes. The California IOU 2009 event data for DLC resources confirmed that these resources were called more frequently than “reliability class” DR resources. Utilities typically compensate participating customers with a reservation payment (e.g. a capacity-based bill credit) for the right to control their load, and we therefore assumed that the utility will dispatch these DR resources for close to the maximum amount allowed under program rules, which we stipulate as 10 times per year, for 4 hours per event—or 40 hours per year.

- **Pricing programs.** We assumed that pricing programs are dispatched for both reliability and economic purposes. Pricing program participants receive discounted rates during non-peak hours, and in order to maintain revenue neutrality, we assumed that utilities will come close to maximizing the number of dispatch hours each year, even under 1-in-2 conditions. We therefore assumed 50 hours of dispatch (i.e., 10-12 peak events per year, at 4-6 hours per event) under 1-in-2 conditions, based on a review of the typical tariff program rules for pricing programs.

- **Load as a Capacity Resource programs.** DR capacity in this program type was reported only by the California Independent System Operator (CISO) in its non-firm load forecasts. We assumed that these programs are dispatched for both reliability and economic purposes. We further assumed that participating customers receive a capacity-based “reservation” payment, and that therefore the utility will also dispatch these DR resources relatively frequently, even during a 1-in-2 year, driven in part by the fact that many of these resources are “performance-based” contracts with Curtailment Service Providers (i.e., aggregators). We assumed 60 hours of dispatch (i.e., 15 dispatch events at 4 hours per event). These assumptions are based on a review of the program rules and operating history of the specific California aggregator managed programs. As a point of reference, Pacific Gas & Electric (PG&E) dispatched its Capacity Bidding Programs (CBPs) 14 times in 2010 and Southern California Edison (SCE) dispatched its CBPs 25 times in 2010 (Braithwait and Hansen, 2011). Therefore, we believe 60 hours of expected dispatch is a reasonable assumption.

Table 4: WECC Common Case Expected Dispatch Hours per Year

DR Resource Class	WECC Common Case Expected Dispatch Hours per Year
Interruptible Load	10
Direct Load Control	40
Pricing	50
Load as a Capacity Resource	60

2.3.2 Consideration of Alternative Approaches for DR Dispatch

DR programs are used by utilities for planning, operational, and reliability purposes in different ways and DR resources are dispatched in a manner distinct from supply-side resources. For example, DR programs are often subject to program rules limiting their operation to a maximum number of hours per year and have restrictions on the minimum or maximum number of continuous hours of operation and on the frequency with which the customers can be curtailed.

Production cost models such as PROMOD have limited functionality in terms of their ability to accurately model the dispatch and operation of DR programs. Several potential modeling approaches *within* PROMOD were tested and evaluated to simulate DR resource dispatch, each with advantages and disadvantages:

- **High-cost combustion turbine (CT) generating unit.** DR resources were modeled within PROMOD as a set of CT generation units. This is the method that WECC used for all DR resources prior to the 2010 study cycle. Under this approach, DR resources within each BA are represented as a proxy CT unit dispatched based on its merit order. The resource parameters (e.g., heat rate, fuel cost, and variable operations & maintenance costs) are "tuned" through an iterative process until the set of DR resources are dispatched for approximately the targeted number of hours per year. The disadvantages of this approach are, first, that the iterative "tuning" process cannot realistically be done for each BA individually, but rather only in an approximate manner across all DR resources in WECC. Second, the approach is unable to realistically simulate other important features of DR program operation (e.g., limited number of hours per event or frequency of events).

- **Peak-shaving hydroelectric ("hydro") unit.** DR resources were modeled as an energy-limited hydro resource by establishing a maximum energy output for each unit and setting the operating limits with respect to monthly dispatch assumptions. For example, an operating limit of zero would allow the DR resource to be dispatched over the entire month up to the set annual energy limit. In exploring this option further, it proved unrealistic for DR resources because they were often utilized to the maximum energy potential early in the year and not utilized in later months when the DR was more likely to be dispatched by the utility (e.g., summer peaking months).

- **Dispatchable transactions.** This was initially a promising approach whereby DR could be modeled and dispatched by load and price. It was assumed that DR resources could be dispatched in this manner by adjusting a price level to reach the desired dispatch assumptions. In effect, defining economic blocks of DR resources could build a DR supply stack to mimic the incrementally higher-cost DR resources. In testing this approach with varying size resources and price levels, however, it was determined that the DR was not dispatch realistically. The DR was dispatched at small amounts (often <1MW) and for thousands of hours per year.

Ultimately, none of the three aforementioned modeling options within PROMOD proved capable of realistically simulating the dispatch of DR resources used for both reliability and economic purposes. As a result, we instead developed a technique to produce hourly load modifying profiles for non-interruptible DR resources (i.e., DLC, pricing, and load as a capacity resource program types) that could be applied to the hourly load forecasts, thereby incorporating DR program operation into PROMOD via the hourly load data, rather than as a proxy generation unit. We continued to model interruptible programs as a high-cost CT unit within PROMOD, reflecting that the resource is used primarily for reliability purposes.

2.3.3 Demand Response Dispatch Tool

To develop these hourly load modifying profiles, we created the LBNL DR Dispatch Tool (DRDT). The DRDT dispatches DR resources during high-price hours according to program constraints and resource availability. The tool requires three user-defined inputs: (1) maximum monthly DR capacity for each (non-interruptible) DR program type and BA; (2) hourly energy load for each BA; and (3) hourly locational marginal prices (LMPs) for each BA from PROMOD runs without DR. These inputs were specific to the WECC Common Case (e.g., Common Case hourly loads and LMPs). The DRDT then identifies the highest-average LMP consecutive hour blocks for each BA and dispatches the DR resources in those hours. The amount of DR available to be dispatched in any given hour is based on the "hourly shaped" DR resource availability, as described previously. The DR load reductions in each hour are then deducted off of the load forecast, and PROMOD is re-run using the modified (post-DR) hourly load forecast for each BA.

Figure 7 shows the results of the simulated dispatch of non-interruptible DR resources (i.e., DLC, pricing, and LCR program types) for the SCE load zone on a representative day. The left-axis and corresponding line shows the amount of DR resource dispatched in each hour of the day, and the right-axis and corresponding dashed-line shows the SCE load zone LMP in each hour. The results show the DR resource dispatched during the highest-average, contiguous LMP period. These results provide a more realistic approach of modeling DR resources because the approach factors in typical program tariff rules (e.g., maximum and expected hours of dispatch per year), resource availability, and system price (i.e., LMP) as a dispatch trigger.

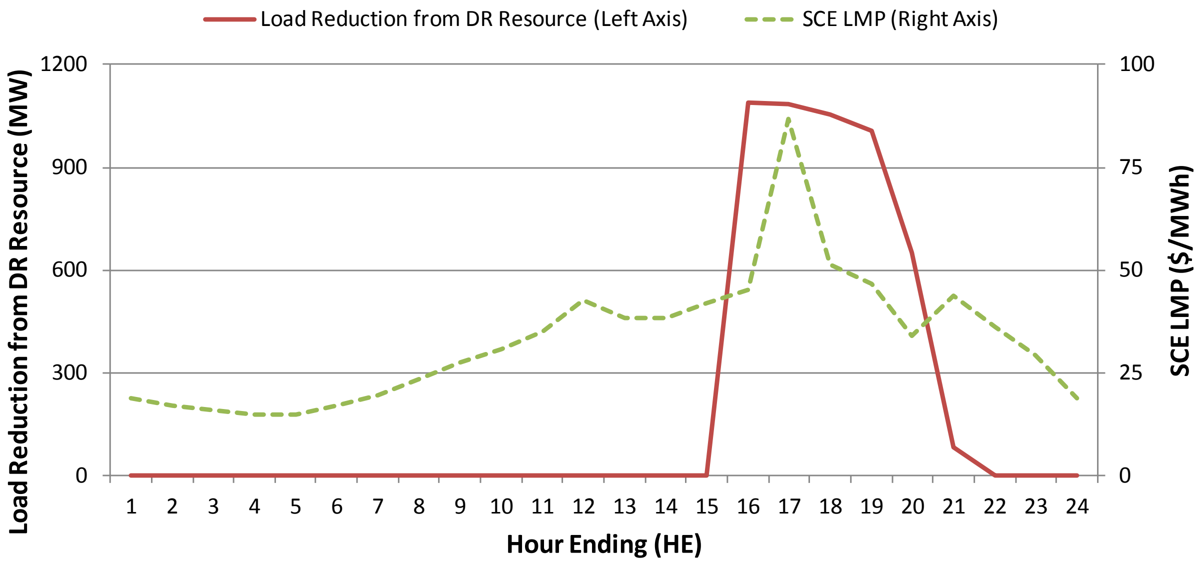


Figure 6: Simulated Dispatch Results for SCE Load Zone on Representative Day

Figure 7 summarizes the results of the simulated DR dispatch in terms of the average load reduction per simulated DR event (blue bars) compared to the maximum available DR resource (red bars).[6] The results are reported here for each WECC load zone with non-interruptible DR capacity (the figure does not include WECC load zones that only had interruptible DR programs that were modeled within PROMOD as a high-cost CT unit). Average peak load reductions in the 10-year Common Case ranged from less than 1 MW (WACM) to more than 900 MW (SCE). All load zones exhibited a difference between the average load reduction and the maximum DR resource size where the average load reduction was less than the maximum available DR resource (expressed as a MW reduction in load). This difference shows the effect of the hourly shaping, as well as cases where some DR programs had fewer dispatch hours than other programs (e.g., DLC programs were dispatched for 40 hours per year and load as a capacity resource programs were dispatch for 60 hours per year).

[6] We did not calculate the results of the simulated dispatch in terms of a percent reduction in annual peak because DR resources were dispatched based on highest-average LMP periods that were not perfectly coincident with the WECC load zone's annual peak demand.

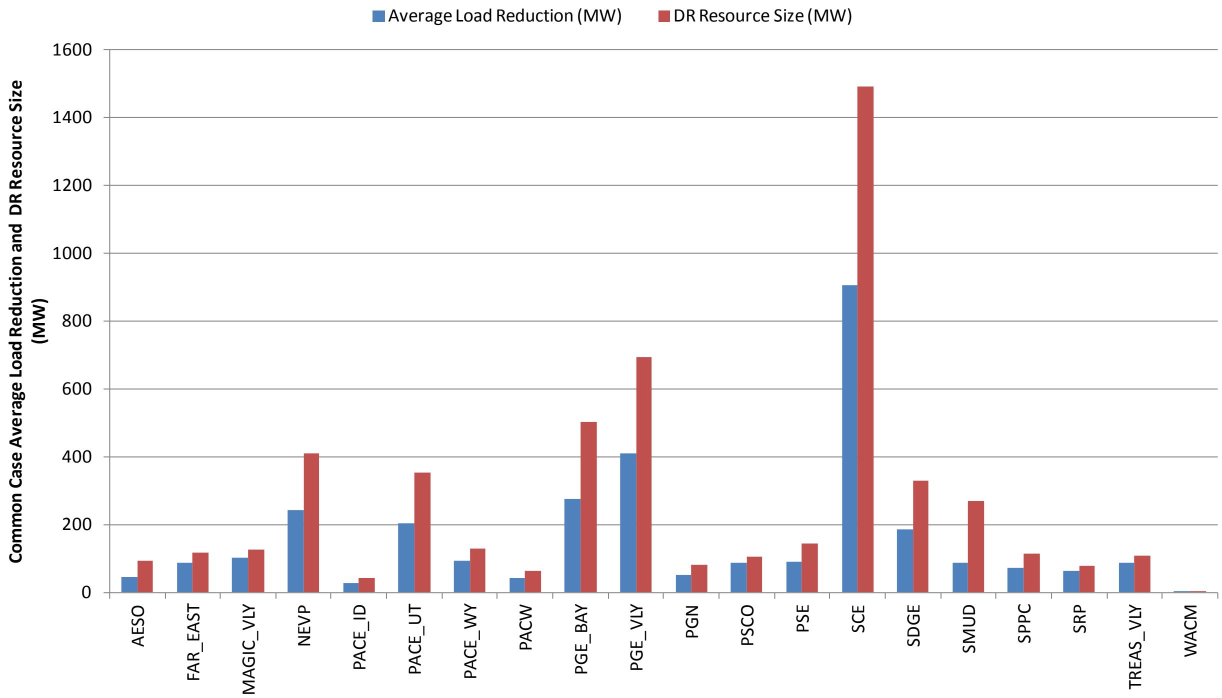


Figure 7: Simulated Dispatch Results for WECC Common Case Non-Interruptible DR Programs

3. SPSC 10-Year High DSM Case

In the WECC Common Case, we validated and adjusted the non-firm load forecasts to account for current state DR policies and utility programs. Pursuant to the SPSC study request, the 10-Year High DSM Case extended this analysis by assuming more aggressive peak demand savings from larger and more advanced DR programs throughout the west over the 2011-2022 timeframe.[7] We developed the SPSC 10-year High DSM Case DR using a two-part process, similar to the WECC Common Case. First, DR resource size for each WECC BA was developed from an updated version of the state-level DR potential estimates in the FERC 2009 Study, *A National Assessment of Demand Response Potential*, that was updated to reflect major developments in DR program design and participation. Second, an hourly load modifying profile of non-interruptible DR resources was developed using a simulated dispatch of those DR resources for each WECC load zone. This chapter describes both parts of the approach.

3.1 Developing DR Quantities

The FERC 2009 Study, the most comprehensive state-level DR potential estimates available at the time of the 2011 TEPPC study, was based on a "bottom-up", state-by-state analysis of DR potential for the entire nation over a ten-year timeframe. These DR potential estimates were broken out among five programs types: pricing with enabling technology, pricing without enabling technology, direct load control, interruptible tariffs, and other programs (e.g., demand bidding and aggregator programs). The program-level DR potential estimates were driven by various inputs and assumptions at the customer-class (e.g., residential and non-residential) level across four scenarios. The inputs and assumptions included, among other things, current and expected program participation, program impacts, and advanced metering infrastructure (AMI) deployment (assumed to be an enabler of certain DR programs). The study included a spreadsheet model with the underlying assumptions and calculations.

We relied on two scenarios from the FERC 2009 Study as the basis of our DR resource capacity in the SPSC 10-year High DSM Case (see Table 5). For all states other than California, we relied on the "Expanded Business-As-Usual (BAU)" scenario, which assumes that the current mix of DR programs is expanded to all states in the west and programs achieve "best practices" levels of participation and performance. The scenario program mix included a moderate amount of pricing programs and advanced metering infrastructure (AMI) deployment. For California BAs, however, we relied on the "Achievable Participation" scenario, which assumes the roll-out of default dynamic pricing tariffs and higher participation in pricing programs. The scenario also assumed universal AMI deployment and a higher percentage of customers with enabling technology (e.g., in-home displays, programmable communicating/controllable thermostats) that resulted in higher amounts of load reduction per event.

[7] The SPSC-criteria for EE in the High DSM Case assumed achievement of all cost-effective energy efficiency and related directly then to the "economic potential" in efficiency potential analyses.

Table 5: Comparison of Major Assumptions in FERC 2009 Study

	Dynamic Pricing Enrollment	Customers Accepting Enabling Technology	Penetration of Residential DLC	Penetration of C&I Interruptible Tariffs
Expanded BAU	5% (voluntary)	0%	25%	16-25% (large C&I)
Achievable Participation	75% (default)	60%	25%	16-25% (large C&I)

3.1.1 Updates to the FERC 2009 Study

Because the FERC 2009 Study relied on inputs and assumptions from 2008 and earlier, the Brattle Group was engaged to update the DR potential estimates to reflect major developments in DR program design and participation. The FERC DR potential model ("The Model") was updated for the SPSC 10-year High DSM Case using the best data that was available at the time of the update, which was in late 2011. Two specific types of updates were implemented. First, we updated basic model inputs. This included estimates of current DR participation, current AMI deployment, and system peak load forecasts. Second, we updated the assumptions that drive the forecasts in the Expanded BAU and Achievable Participation scenarios. These updates relate to assumptions such as future DR participation rates and per customer impacts of the DR programs. We also expanded the Model's forecast horizon from 2019 to 2022 using a linear extrapolation of the potential estimates for the last three years of the projection.

We maintained the four customer classes in the Model, which were residential, small commercial and industrial (C&I), medium C&I, and large C&I. We also continued to use the five types of demand response programs in the Model (i.e., pricing without enabling technology, pricing with enabling technology, automated or direct control, interruptible tariffs, and other DR).

3.1.1.1 Data Updates

Data updates were conducted for three types of inputs to the Model: current participation rates in DR programs, current AMI deployment, and system peak load forecasts (see Table 6). Current participation in DR programs was originally based on survey results from FERC's 2008 *Assessment of Demand Response and Advanced Metering* ("the FERC Survey"). We updated these inputs to reflect the more recent 2010 FERC survey. Overall, this led to an increase in peak load reduction capability for all customer classes and programs due to higher initial current participation rates.

AMI deployment rates were also updated. In the original Model, AMI deployment was calculated from six different sources, as shown in Table 6. For the purposes of this update, we again relied on the 2010 FERC Survey. Due to higher starting rates of AMI deployment, this change also leads to slightly higher demand response potential in the first years of the forecast, as the base of customers eligible to participate in dynamic pricing increased.

Finally, we updated the system peak load forecast for each of the eleven WECC states. The original Model relied on results of NERC's *2008 Long-Term Reliability Assessment*, which forecasts system peaks by region. The system peak was allocated across the states in that region using 2006 electric sales by state from the EIA. We updated the WECC system peak forecasts using the same methodology, with both the updated 2010 *Long-Term Reliability Assessment* and 2009 electric sales by state from the EIA. The system peak load forecast was significantly lower in absolute megawatt terms in the 2010 NERC Assessment. The EIA sales breakdown between the WECC states did not change significantly. As a result, this input change leads to lower DR impacts in terms of absolute megawatts, but the DR potential in percentage terms does not change significantly.

Table 6: FERC 2009 Study Data Updates

Original	Update	Effect on Results
Current participation in DR programs		
Based on analysis that used the 2008 FERC Demand Response Survey data	Updated using the 2010 FERC DR and AMI Survey data	Overall, this change increases the potential DR by a small amount
Current AMI Deployment		
Based on analysis of six different sources: KEMA's Perspectives for Job Creation (2008), 2008 FERC Survey, 2008 Utilipoint examination of AMI initiatives, Enermex Smart Meter Data, 2008 FERC Staff Report, and IEE survey on smart meter deployment	Updated Using the 2010 FERC DR and AMI Survey	This change leads to slightly higher DR potential in the first years of the forecast
System Peak Load Forecast		
Based on regional system peak forecasts from NERC's 2008 Long-Term Reliability Assessment; Allocated across states using total 2006 electric sales by state from EIA data	Updated using same methodology with NERC's 2010 Long-Term Reliability Assessment and 2009 electric sales data from EIA	There is no significant change in DR potential in potential terms, but there is a large drop in MW terms (both system peak load forecast and DR potential decrease)

3.1.1.2 Assumption Updates

We also updated assumptions regarding program participation and per-customer impacts, which vary by scenario (see Table 7). For the pricing programs, the Expanded BAU Scenario previously assumed that 5 percent of eligible customers would enroll in the new dynamic rates. We updated this assumption on a state-by-state basis using *Brattle's* 2011 *Survey of Energy Efficiency and Demand Response Experts*.[8] This update resulted in slightly higher DR potential. In the Achievable Participation scenario, we maintained the assumption that 60 percent of eligible medium and large C&I customers enroll and that 75 percent of residential and small C&I customers would remain enrolled in default dynamic pricing.

For the three non-pricing programs, the original Model used FERC's 2008 survey to determine "best practices" participation rates in each program in both scenarios. Again, we updated these assumptions using the 2011 *Brattle* survey of experts. This update did not change the results in a significant way.

Another key assumption that drives the results of the model is the average program impact per participant. Originally, pricing program impacts were based on simulations relying on estimates of customer price elasticity that were measured during the California Statewide Pricing Pilot (SPP). In our update, we instead relied on a portfolio of results from more recent dynamic pricing experiments. When the demand response estimates from these experiments are plotted against the peak to off-peak price ratio of the rates tested in the pilots, they yield an "Arc of Price Responsiveness" (Faruqui and Palmer 2012). This new approach resulted in slightly lower peak impacts per customer and, therefore, slightly lowers overall DR potential.

For the non-pricing programs, the per customer impact assumptions were originally based on state-by-state impacts reported in the 2008 FERC Survey. We scaled the 2008 FERC results using a factor derived from the 2010 FERC Survey and this resulted in slightly higher DR potential.

[8] The survey included 50 experts in academia, utilities, consulting, government, and non-profit organizations, with locations distributed across the U.S. and Canada.

Table 7: FERC 2009 Study Assumption Updates

Scenario	Original	Update	Effect on Results
Pricing Program Participation			
Expanded BAU	5% of eligible customers enroll	Created new state-by-state assumptions using 2011 Brattle Survey of EE and DR experts	Slightly higher DR potential
Achievable Participation	60% of eligible medium and large C&I customers enroll;75% of eligible residential and small C&I customers enroll	No change	No change
Non-Pricing Program Participation			
Expanded BAU	Determined using "best practices" developed from FERC's 2008 DR Survey	Used results from 2011 Brattle Survey of DR and EE Experts for residential and large C&I; No changes made to small and medium C&I	No significant changes
Achievable Participation	Same as above	Same as above	No significant changes
Pricing Program Impacts (per customer)			
Expanded BAU	Based on PRISM analysis derived from SPP results	Based on Brattle's latest Arc of Price Responsiveness	Lowers DR potential slightly
Achievable Participation	Same as above	Same as above	Same as above
Non-Pricing Program Impacts (per customer)			
Expanded BAU	Based on range of reported impacts from 2008 FERC DR Survey	Scaled up state-by-state results using scaling factor derived from 2010 FERC DR Survey	Increases results slightly
Achievable Participation	Same as above	Same as above	Same as above

We also considered two other key assumptions in the Model—forecasted AMI deployment and the percent of customers with enabling technology—and determined that the inputs already in the Model still reflect the best available information. In the Expanded BAU Scenario, the forecasted AMI deployment varies by state and is based largely on a continuation of current trends. In the Achievable participation Scenario, the Model assumes 100 percent deployment by the end of the forecast horizon. The Achievable participation scenario also assumes that eligibility for enabling technology varies by state and that 95 percent of those eligible customers participating in dynamic pricing programs are equipped with enabling technologies.

3.1.1.3 Updated State-Level DR Potential Estimates

Each of the changes described above produced a small change in the overall DR potential of each WECC state. The resulting DR potential across all WECC states is 11,092 MW, or 7.4 percent of peak demand, in the Expanded BAU Scenario. In the more aggressive Achievable Scenario, the DR potential was 21,885 MW, or 14.5 percent (see Figure 8).

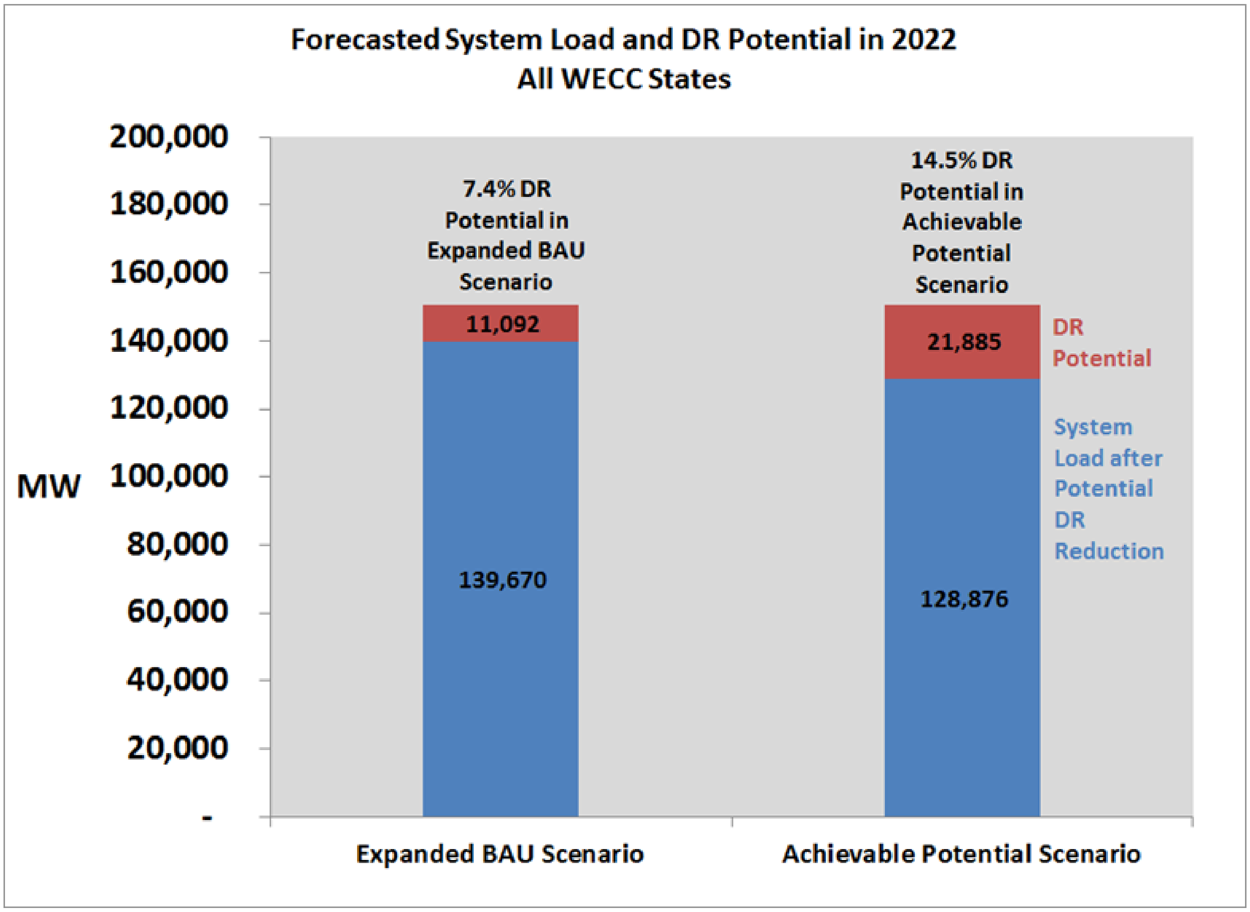


Figure 8: Summary of 2022 WECC-wide DR Potential

The estimated DR impacts vary by state. In MW terms, California led the WECC states with nearly 5,000 MW projected peak demand reduction potential in the Expanded BAU scenario and 7,700 MW in the Achievable Participation Scenario. In percentage terms, the largest DR potential occurred in Nevada and Utah. The state-by-state results for both scenarios are shown in Table 8.

Table 8: State-by-State DR Potential Estimates Assumed in SPSC 10-Year High DSM Case (2022)

	System Peak without DR	Expanded BAU Peak Reduction		Achievable Participation Peak Reduction	
	MW	MW	%	MW	%
AZ	16,801	915	5.4%	2,682	16.0%
CA	59,391	4,971	8.4%	7,732	13.0%
CO	11,677	828	7.1%	1,925	16.5%
ID	5,206	327	6.3%	784	15.1%
MT	3,278	125	3.8%	434	13.2%
NM	4,953	430	8.7%	821	16.6%
NV	7,844	775	9.9%	1,958	25.0%
OR	10,883	389	3.6%	1,125	10.3%
UT	6,312	936	14.8%	1,555	24.6%
WA	20,629	1,054	5.1%	2,265	11.0%
WY	3,789	341	9.0%	603	15.9%

3.1.2 DR Resource Capacities for the SPSC 10-year High DSM Case

The DR potential estimates developed using the approach described above are expressed at a state-level. For all states, other than California, we relied on the DR potential estimates in the "Expanded BAU" scenario, and for California we relied on the "Achievable Participation" scenario. We then allocated those state-level potential estimates to the WECC BA-level with the following methodology:[9]

1. **Derived the percentage break-down in energy sales, by customer class, for each WECC BA within each state.** EIA-861 data (i.e., percent of total retail sales) was used to derive the percentage split in retail sales between residential and non-residential customers. FERC Form 1 data, compiled by Global Energy Partners (GEP) as part of its work on the FERC 2009 Study, was used to estimate the percentage split of non-residential sales among the small C&I, medium C&I, and large C&I customer segments. For those BAs for which we did not have FERC Form 1 data, we used the state-wide average percentage split among the C&I groups. For AESO (Alberta, Canada), we used forecasted energy in its 2009 Future Demand and Energy Outlook and allocated all energy sales to the Oil Sands industry as large C&I. All remaining commercial and industrial sales were then allocated among the small and medium C&I customer segments based on the Montana state average percentage splits. For BCTC (British Columbia, Canada), we used the Washington state averages.

[9] See Technical Appendix, Figure A-1 for a graphical depiction of this methodology.

2. **Calculated energy sales by customer class for each BA, under the High DSM load forecast.** Annual GWh in the High DSM Load forecast for 2022 were applied against the percentage breakdown in energy sales, by customer class, derived in Step 1.

3. **Calculated load factors for each customer class in each state.** State-level retail sales and peak demand data, provided by GEP, was used to calculate load factors (i.e., peak MW per annual GWh). For AESO we assumed the same load factors as Montana and for BCTC we assumed the same load factors as Washington.

4. **Calculated the percent of peak demand by customer class for each BA.** The energy sales calculated in Step 2 were applied against the load factors in Step 3 to calculate the percentage break-down in peak demand across the customer classes.

5. **Calculated the peak demand by customer class for each BA, under the High DSM peak load forecast.** The percentage break-down in peak demand by customer class for each BA calculated in Step 4 was applied against the state-adjusted peak demand in 2022.

6. **Calculated the percent of peak load by customer class for each BA.** Peak load data for each state, provided by GEP, was used to calculate the percent of total state peak load for each customer class. For AESO and BCTC we assumed the same peak load percentages calculated in Step 4.

7. **Calculated the DR potential by customer class.** The percent of peak load by customer class, calculated in Step 6, was used to derive the customer class level DR potential from the FERC Study. For AESO we assumed the same DR potential as Montana and for BCTC we assumed the same DR potential as Washington.

8. **Calculated the DR resource capacity for each customer segment and program type within each BA.** The FERC 2009 Study identified the DR potential for each customer segment and program type in each state, as a percentage of that customer segment's peak demand. The class level DR potential, calculated in Step 7, was applied against the High DSM peak demand calculated in Step 5. For AESO we assumed the same DR potential as Montana and for BCTC we assumed the same DR potential as Washington.

We then summed the DR resource capacities across all customer segments to calculate the total DR resource capacities for each BA by program type. The SPSC High DSM Case had ~14,390 MW of DR resource capacity in 2022, a ~45% increase from the WECC Common Case DR resource capacity (see Table 9). Among the DR programs, Interruptible programs accounted for the largest DR capacity in the SPSC High DSM Case at ~5,028 MW (~35%). Pricing programs accounted for ~4,266 MW (~30%) of DR capacity in the SPSC High DSM Case and increased significantly from the WECC Common Case (more than tripled in DR capacity). This was driven by the high assumed participation and enrollment in dynamic pricing programs in the FERC 2009 Study.

Table 9: Comparison of WECC Common Case and SPSC High DSM Case DR Resource Capacities by DR Program Type

DR Program Type	2022 WECC Common Case Forecast (MW; NCP)	2022 SPSC High DSM Case Forecast (MW; NCP)
Interruptible	2,714	5,028
DLC	3,615	2,561
Pricing	1,173	4,266
Load as a capacity resource/Other	462	2,535
TOTAL	**7,963**	**14,390**

The WECC BAs in California had the largest DR resource capacities because the values were based on a more aggressive set of assumptions in the FERC 2009 Study "Achievable Participation" scenario. The SPSC High DSM Case assumed some DR resource capacity for all Canadian and U.S. WECC BAs and among all four DR program types (see Figure 9).

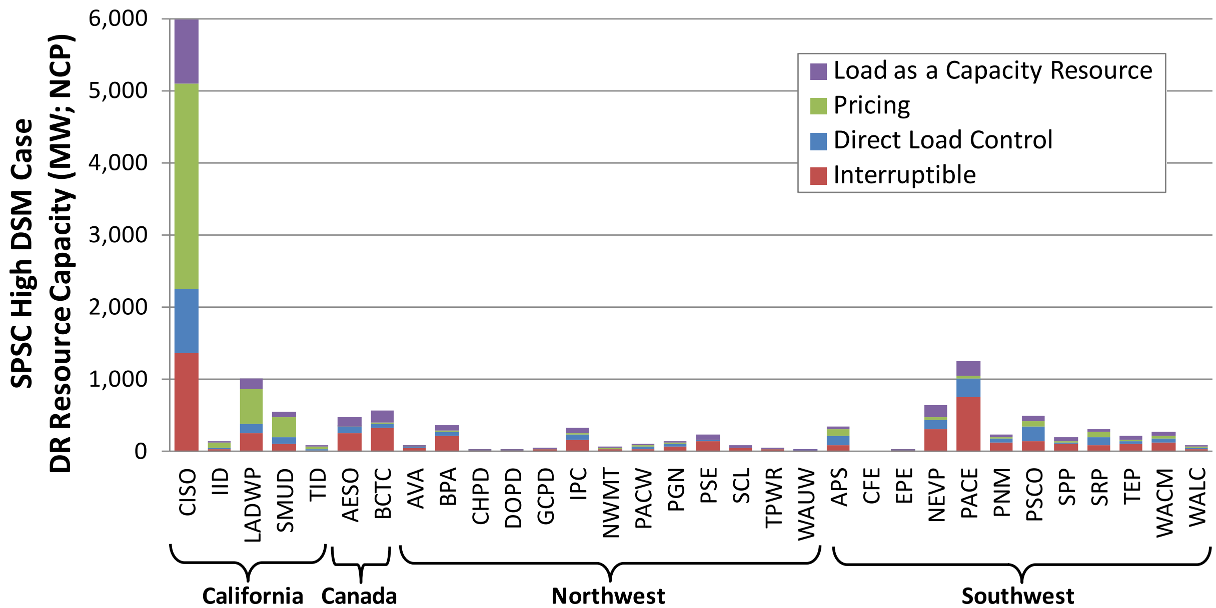


Figure 9: SPSC High DSM Case DR Resource Capacity by WECC BA and DR Program Type

Expressed as a percent of 2021 peak demand (and on a non-coincident peak basis), Figure 10 shows the SPSC High DSM Case DR resources. SPSC High DSM Case peak demand was 172,960 MW in 2021 and non-firm load represented ~8.3% of WECC peak demand. DR capacity as a percent of peak demand ranges from ~1.2% (EPE) to ~13.8% (IID).

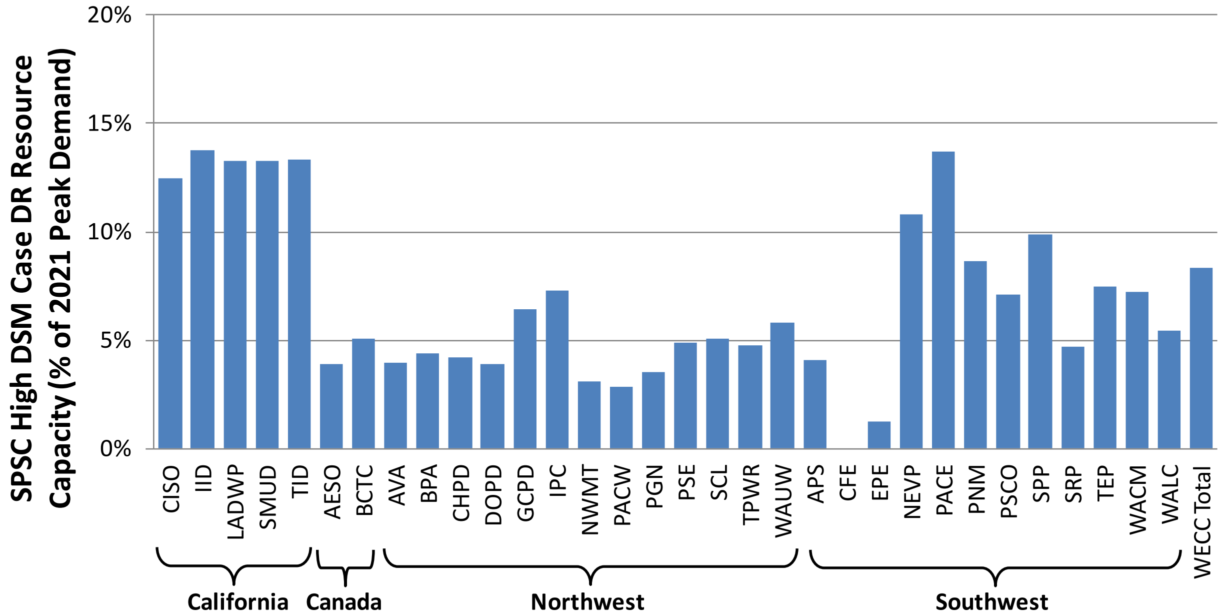


Figure 10: SPSC High DSM Case DR Resource Capacities as a Percent of 2021 Annual Peak Demand

3.2 Hourly Shaping of DR Resource

Similar to the WECC Common Case, we developed the SPSC High DSM Case DR Capacities as the maximum monthly DR capacity in the peak-hour of each month. However, the availability of DR resources varies by month and hour for each BA and for some programs. We captured this availability using the same hourly shaping approach as in the WECC Common Case in order to ensure DR programs typically used during system peak months and hours are not utilized at full availability in non-system-peak months and hours.

We shaped the DR resource capacity to the hourly load profiles for each BA. We assumed DR resources scaled with hourly load because those end-uses driving demand were also the end-uses that could respond to DR program signals. The hourly shaping factors represent the hourly load divided by the maximum annual load (i.e., annual peak), so that only one hour of the year had 100% DR resource availability.

3.3 Simulated Dispatch of DR Resources

The SPSC High DSM Case was a scenario of the 2011 TEPPC Study that utilized a production cost model (PROMOD) to model the dispatch of generation resources in the Western Interconnection. In order to provide an appropriate comparison of results to the WECC Common Case, we employed the same two part approach to modeling DR resource dispatch: (1) develop assumptions about the DR dispatch characteristics (e.g., expected hours of dispatch per year and resource availability); and (2) simulate dispatch of DR resources in a manner consistent with the dispatch characteristics.

3.3.1 Developing DR Characteristics

To develop DR resource characteristics, we started with the assumptions in the WECC Common Case and considered how the SPSC High DSM Case scenario, that assumed advancements in DR programs, would potentially change the WECC Common Case dispatch assumptions. We developed DR dispatch characteristics with the following considerations for each of the DR program types (see Table 10):

- **Interruptible programs.** Our assumptions built on the expected hours of dispatch in the WECC Common Case of 10 hours, where we assumed that these programs were utilized primarily for reliability-based events and are therefore rarely dispatched under 1-in-2 conditions. In a High DSM scenario, we assumed these resources would be dispatched somewhat more frequently for economic conditions. We assumed 20 hours of dispatch in a normal year (i.e., 4-5 interruptions per year, or 4-6 hours per event).

- **Automated or direct load control (DLC) programs.** Similar to the Common Case, we assumed that most DLC programs could be dispatched for both reliability and economic purposes. We assumed that a High DSM scenario, with higher levels of DR resources, would also entail a modestly more frequent use of automated or direct control programs. We therefore assumed that, in a typical year, utilities would dispatch these programs up to 10-12 times per year, for 4-5 hours per event—or 50 hours per year.

- **Pricing and other DR programs.** The most significant advancement in DR resource utilization in a High DSM scenario would likely come from dynamic pricing and aggregator-managed DR programs. These DR programs are becoming more prevalent as wholesale markets begin to create DR-specific market rules and customers become more aware of managing energy costs. In the WECC Common Case, DR resources in these two classes were reported only by CISO; all other balancing authorities reported only interruptible load or DLC. In the High DSM Case, we assumed that all WECC BAs include some type of these programs by 2022 that would be dispatched for both reliability and economic purposes. For dynamic pricing programs (e.g. CPP), we assumed that participants receive discounted rates during off-peak hours, and that in order to maintain revenue neutrality, utilities would come close to maximizing the number of dispatch hours each year, even under 1-in-2 conditions. Similarly, for aggregator managed DR programs, we assumed that participating customers receive a capacity-based "reservation" payment, and that therefore utilities will also dispatch these DR resources relatively frequently, even during a 1-in-2 year, driven in part by the fact that many of these resources are "performance-based" contracts in which the aggregator bears a risk of achieving savings. For both dynamic pricing and other DR programs, we assumed 80 expected hours of dispatch in an average year, based on our initial assumptions in the WECC Common Case and expected advancement of these programs in the SPSC High DSM Case.

Table 10: Comparison of WECC Common Case and SPSC High DSM Case Expected Dispatch Hour per Year

DR Resource Class	WECC Common Case Expected Dispatch Hours per Year	SPSC High DSM Case Expected Dispatch Hours per Year
Interruptible Load	10	20
Direct Load Control	40	50
Pricing	50	80
Load as a Capacity Resource/Other DR	60	80

3.3.2 Demand Response Dispatch Tool

We used the LBNL DRDT to develop hourly load modifying profiles similar to the approach in the WECC Common Case, dispatching the non-interruptible DR resources during high-price hours according to program constraints and resource availability. We used three inputs specific to the SPSC High DSM Case: (1) maximum monthly High DSM Case DR capacity for each (non-interruptible) DR program type and WECC load zone; (2) High DSM Case hourly energy load for each WECC load zone; and (3) High DSM Case hourly PROMOD locational marginal prices (LMPs) for each WECC load zone from PROMOD runs without DR. The DRDT identified the highest-average LMP consecutive hour blocks for each WECC load zone and dispatched the DR resources in those hours.

Also similar to the WECC Common Case, the amount of DR available to be dispatched in any given hour was based on the "hourly shaped" DR resource availability, as described previously. The DR load reductions in each hour were then deducted off of the load forecast, and PROMOD was re-run for the High DSM Case using the modified (post-DR) hourly load forecast for each WECC load zone.

Figure 11 shows the results of the simulated dispatch of non-interruptible DR resources in the SPSC High DSM Case and summarizes the results on an average load reduction-basis per DR event. The average load reduction per event (blue bars) is compared to the maximum DR resource size (red bars). The results are reported for all WECC load zones. The WECC load zones show average load reductions from non-interruptible DR programs that range from ~2 MW (WACM) to more than 1,150 MW (SCE). The average load reductions are less than the non-interruptible maximum DR resource size due to the hourly shaping that takes into account DR resource availability.

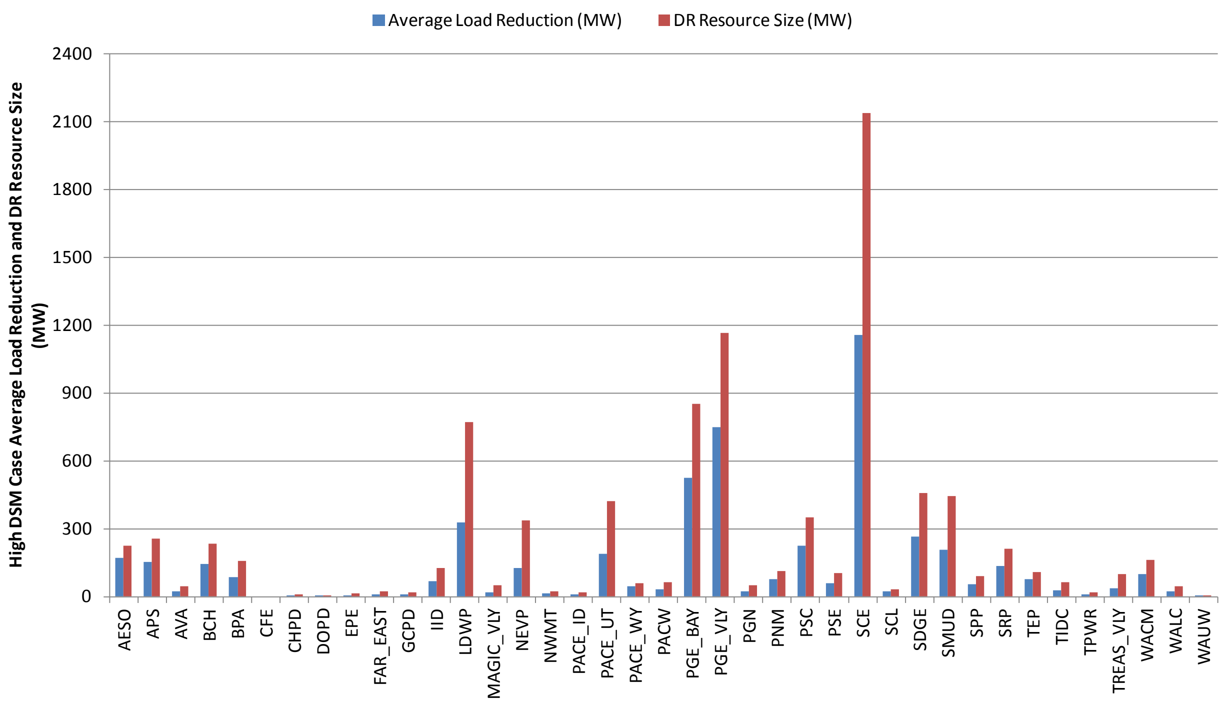


Figure 11: Simulated Dispatch Results for SPSC High DSM Case

4. WECC 20-Year Reference Case

WECC's 20-year study relied on a capacity expansion model which seeks to build out generation capacity in order to meet demand for four system conditions (represented by four specific hours in the year). DR impacts are an *input* to the model and are specified in terms of the reduction in demand for each of the four system conditions.

To derive the demand reductions for each system condition, we executed a three-part approach: (1) simulated the hourly dispatch of DR, based on the DR resource levels assumed in the WECC 10-Year Common Case; (2) calculated the associated load reduction for each of the four system conditions in 2022; and (3) extrapolated the 2022 load reductions to 2032, based on the peak demand growth rates in the 20-Year Reference Case. This chapter describes the three-part approach.

4.1 Developing the Peak Demand Reductions in the WECC Reference Case

The WECC 20-Year Reference Case load forecast is an extrapolation of the WECC 10-Year Common Case, and as such, we used the DR resource capacities in the 10-Year Common Case as our starting place (see Chapter 2). We also used the hourly loads for each WECC load zone from the 10-Year Common Case to calculate both the pre-DR loads and to trigger dispatch of the DR resources.

4.1.1 Simulated Hourly Dispatch

We utilized the LBNL DRDT to produce an hourly profile of DR load reductions for each WECC load zone, using the DR resource capacities from the 10-Year Common Case. When dispatching the DR resources within the LBNL DRDT, we made the following assumptions about the expected hours of dispatch for each of the DR program types, which are generally consistent with the assumptions made in the 10-Year Common Case (see Chapter 2):

- **Interruptible load programs.** The 10-year studies modeled interruptible load programs as a high-cost CT unit within WECC's production cost model, adjusting unit operating parameters (e.g., fuel cost, heat rate) to achieve a desired number of hours of dispatch per year. For the 20-year study, the dispatch of interruptible load programs was modeled using the LBNL DRDT, assuming 10 hours of dispatch per year (i.e., five events at two hours per event).

- **Direct load control (DLC) programs.** We assumed that DLC programs were dispatched 40 hours per year (i.e., ten events at four hours per event).

- **Pricing programs.** We assumed that pricing programs were dispatch 50 hours per year (i.e., ten events at five hours per event).

- **Load as a capacity resource programs.** We assumed load as a capacity resource programs were dispatched 60 hours per year (i.e., ten events at six hours per event).

We also applied an hourly shaping to the available DR resource capacity in each hour to ensure DR programs typically used during system peak months and hours are not utilized at full availability in non-system-peak months and hours. The same hourly shaping approach was used as in the 10-year studies in which we assumed that the size of the available DR resource in each hour was proportional to the ratio of total load in each hour to the annual peak load.

We then simulated the operation of the DR resources, using the 10-Year Common Case hourly loads for each load zone. However, unlike the 10-year studies, we did not use LMPs as the trigger for the simulated dispatch of DR. We instead triggered DR dispatch in response to hourly loads, using the hourly load profiles for each BA from the 10-Year Common Case as the source of the trigger. This dispatch logic was used in order to maximize the value of the available DR resources for deferring or avoiding new generation build-out within WECC's capacity expansion model.

4.1.2 2022 Demand Reductions for the Four System Conditions

The next step in our approach was to calculate the demand reductions under each system condition, based on the hourly load reductions produced by the LBNL DRDT. WECC defined the four system conditions as follows:

- Light Spring (LSP): March 31, 2022 at 1400
- Heavy Summer (HS): July 21, 2022 at 1600
- Light Fall (LF): November 4, 2022 at 200
- Heavy Winter (HW): December 15, 2022 at 1900

For the HS system condition, we defined the DR load reduction for each BA as the simulated reduction in its non-coincident peak demand for the month of July. Similarly, for the HW system condition, we defined the DR load reduction for each BA as the simulated reduction in its non-coincident peak demand for the month of December. For the LSP and LF system conditions, there were no DR load reductions, because the DR resources were not dispatched during low load conditions (per the dispatch logic specified within the LBNL DRDT).

Deriving the DR load reductions for the HS and HW system conditions required that we calculate the reduction in each BA's non-coincident monthly peak demand for July and December. To do this, we subtracted the hourly load profiles of DR resources from the WECC 10-Year Common Case hourly load forecast (i.e., "pre-DR") to produce a 2022 hourly load forecast post-DR. We then calculated monthly peak demand for each WECC load zone pre- and post-DR. The last step was to calculate the 2022 monthly peak demand impacts as the difference of the pre- and post-DR monthly peak demand. The monthly peak demand *reduction* is, therefore, equal to the difference between the monthly peaks with and without DR.

4.1.3 Extrapolating Demand Reductions to 2032

The last step in our approach was to extrapolate the DR load reductions for each system condition from 2022 to 2032. Because the WECC 20-Year Reference Case was an extrapolation of the WECC 10-Year Common Case, we used the same compound annual growth rates

(CAGRs) assumed for the peak load forecasts for each WECC load zone to extrapolate the 2022 DR impacts to 2032.

4.2 Results

Table 11 shows the 2032 load reductions for the four system conditions modeled in WECC's 20-Year Study.[10] The California and Pacificorp load zones (e.g., PACE_UT, PGE_BAY, PGE_VLY, SCE, and SDGE) have the largest demand reductions, which are expected given the large DR resource capacities for those BAs. On a system-condition-basis, the results show the Heavy Summer (HS) with the highest frequency of demand reductions, which is consistent with those load zones whose system peak demands occur in July (i.e., the month of the HS system condition hour). For those load zones that typically have system peaks occurring in the winter, we observe monthly peak demand reductions in the respective Heavy Winter system condition (i.e., December). As described earlier, under our assumed DR dispatch logic, DR demand reductions did not occur for the Light Spring (LSP) and Light Fall (LF) system conditions.

On an annual peak reduction basis, WECC load zones with DR resources in the WECC Reference Case had annual peak reductions, on a non-coincident peak basis, ranging from 0% to ~7% (see Figure 12).[11] Comparing the annual peak reduction with the DR resource size, several load zones with sizeable DR resources showed lower peak reductions. In general, this is due to a shift in the peak day within the year and illustrates the difference between the resource potential (i.e., DR resource size) and how the DR has been shaped and dispatched over the entire year. Thus, although the percentage reduction in peak demand may be relatively large for an individual day when DR is dispatched, the percentage reduction in the annual peak demand may be much smaller if the peak demand is simply shifted to another day when DR was not dispatched.

[10] See Technical Appendix, Table A-3 for 2022 and 2032 WECC Reference Case quarterly peak demand reductions by WECC load zone.
[11] Unlike the WECC 10-Year Common Case and SPSC 10-Year High DSM Case, results of the simulated dispatch are presented in terms of annual peak reduction because DR resources were dispatch based on high load periods and coincident with a load zone's annual peak demand.

Table 11: 2032 WECC Reference Case System Condition Peak Demand Reductions

WECC Load Zone	Heavy Summer (HS)	Light Spring (LSP)	Light Fall (LF)	Heavy Winter (HW)
AESO	0	0	0	91
APS	138	0	0	0
AVA	0	0	0	0
BCH	0	0	0	0
BPA	0	0	0	0
CHPD	0	0	0	16
DOPD	0	0	0	0
EPE	71	0	0	0
FAR EAST	64	0	0	0
GCPD	0	0	0	0
IID	11	0	0	0
LDWP	205	0	0	0
MAGIC VLY	94	0	0	0
NEVP	254	0	0	0
NWMT	0	0	0	0
PACE_ID	24	0	0	0
PACE_UT	598	0	0	0
PACE_WY	1	0	0	0
PACW	65	0	0	0
PG&E_BAY	333	0	0	0
PG&E_VLY	90	0	0	0
PGN	0	0	0	67
PNM	13	0	0	0
PSC	133	0	0	0
PSE	0	0	0	157
SCE	676	0	0	0
SCL	0	0	0	0
SDGE	230	0	0	0
SMUD	279	0	0	0
SPP	56	0	0	0
SRP	234	0	0	0
TEP	56	0	0	0
TIDC	0	0	0	0
TPWR	0	0	0	0
TREAS VLY	151	0	0	0
WACM	1	0	0	0
WALC	0	0	0	0
WAUW	0	0	0	0
WECC Total	**3777**	**0**	**0**	**331**

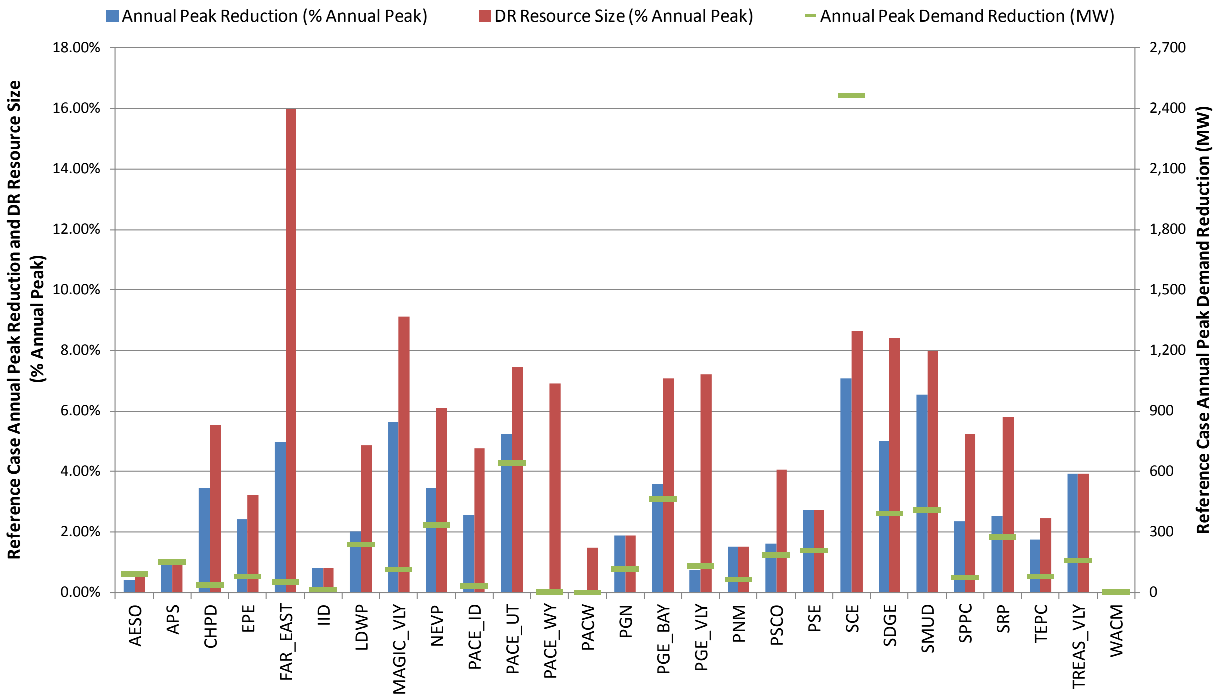


Figure 12: 2032 WECC Reference Case Annual Peak Reduction from DR (Non-Coincident Peak Basis)

5. SPSC 20-Year High DSM Case

The basic principle for the SPSC 20-Year High DSM Case was to develop peak demand reductions from more aggressive DR resource levels and larger and more advanced DR programs than what was assumed in the 20-Year Reference Case. WECC's 20-year study relies on a capacity expansion model that optimizes generation build-out for four system conditions. Similar to the 20-Year Reference Case, we developed DR impacts as an input to the capacity expansion model, specified in terms of the load reductions for each of the four system conditions.

We followed a three-part approach to develop monthly peak demand reductions in the 20-Year High DSM Case: (1) Updated and extended the FERC 2009 Study Model DR potential estimates to 2032; (2) simulated the hourly dispatch of the 2032 DR capacities; and (3) calculated the associated load reductions in 2032 for each of the four system conditions modeled in WECC's 20-Year study. This chapter describes this three-part approach.

5.1 Developing 2032 DR Potential Estimates

The first part of our approach was to determine the 2032 DR capacity for each BA. Similar to the 10-Year High DSM Case, we relied on the statewide DR potential estimates from the FERC 2009 Study. The Brattle Group was engaged to update the potential estimates from the FERC 2009 Study for the 10-Year High DSM Case, and they developed a DR potential forecast for 2023-2032 based on long-run trends in DR. We then allocated the statewide DR potential estimates to the WECC BA-level using a multi-step allocation approach.

5.1.1 Developing a High DR Scenario

The 20-year DR forecast was developed to reflect expectations about emerging long-run DR trends. Whereas the update to the DR potential estimates for the 10-year High DSM study case largely focused on updating the 2009 FERC study with more current data, the 20-year DR potential forecast more broadly relies on expert judgment to explore the potential impact of emerging trends on DR over the second decade of our forecast horizon (i.e., 2023 to 2032). Our 20-year forecast is a "High DR" scenario that is based on aggressive, yet plausible, assumptions about DR resource potential.

In developing the 20-year projections, we identified key forecast assumptions that we expect to change relative to the assumptions in the 10-year forecast. These key assumptions included AMI market penetration, residential central air-conditioning (CAC) saturation, DLC participation rates, and dynamic pricing participation rates. Specific adjustments to these assumptions for the 20-year forecast are described later in this chapter. Other assumptions were assumed to continue at the same trends embedded in the 10-year forecast. Those unchanged assumptions include C&I participation in non-pricing programs, average per-customer impacts from DR programs, and system characteristics like load growth and customer growth.

5.1.1.1 Drivers of Long-Run DR Trends

Overall, long-run DR developments are likely to be driven by three key drivers: regulatory and policy decisions, market developments, and technology deployment.

- *Regulatory/policy drivers.* The extent to which state regulators and policy makers support the expansion of DR initiatives is possibly the single most influential driver of future DR market penetration. For example, California's Energy Action Plan prioritizes demand-side resources in the state's energy mix, and the California IOUs have built significant DR portfolios as a result. Even a general policy focus on demand-side participation, such as the Arizona Energy Efficiency Standard's energy reduction goal of 22% by 2020, has been shown to correlate with greater impacts from DR programs (Smith and Hledik 2012). On the other hand, states without substantial policy support for demand-side initiatives, such as Montana and Wyoming, have demonstrated little DR market penetration. State policy initiatives have played a key role in our development of the 20-year DR forecast.

- *Market drivers.* Changing system characteristics and economic conditions will also affect the likely long-run impact of DR. For example, in the Pacific Northwest, an ample supply of hydropower has historically tended to limit the need for new peak-focused resources among many utilities. However, this situation could change as operational constraints on hydro units increase and new resources are needed to integrate large amounts of intermittent renewable generation that is expected to come online. Service territories with hot summer weather and peaky load conditions, such as those in California and the Southwest, tend to be more attractive locations for the use of DR programs, where load reductions in a limited window of hours can lead to a significant drop in system peak demand. Similarly, regions with customers that are more "energy conscious" and have a longer history of experience with DR programs are likely candidates for larger DR impacts in the future. Such region-specific market characteristics are key drivers that were considered in developing the 20-year forecast.

- *Technology drivers.* Expectations about technology deployment will contribute to variability in DR impacts across states. In particular, the availability of AMI will allow dynamic pricing and new energy management technologies to be offered to the mass market. Large full-scale deployments of AMI are already completed or significantly underway in Arizona, California, Nevada, and Oregon. Additionally, service territories with peak demand that is driven by easily-controlled (and large) sources of load, such as air-conditioning and irrigation, are also more likely to have significant DR programs; for example, Utah and Idaho have a significant amount of existing DR in irrigation load control programs.

5.1.1.2 High DR Scenario Assumptions

Relative to the 10-year DR forecast, modifications were made to assumptions about AMI market penetration, residential CAC saturation, DLC participation, and dynamic pricing participation. Other assumptions were assumed to continue at trends observed in the 10-year forecast.

AMI deployment was assumed to reach full market penetration (99 percent) in all states by 2032.[12] This assumption is driven by the likelihood that technological risk and customer concerns will lessen over the next two decades as experience with smart meters increases. Full deployment of AMI could also result from decreasing technology costs and an expectation that maintenance of electromechanical meters becomes increasingly expensive (as metering companies shift the focus of their operations to digital meters). A comparison of AMI market penetration assumptions in 2022 and 2032 is shown in Figure 13.

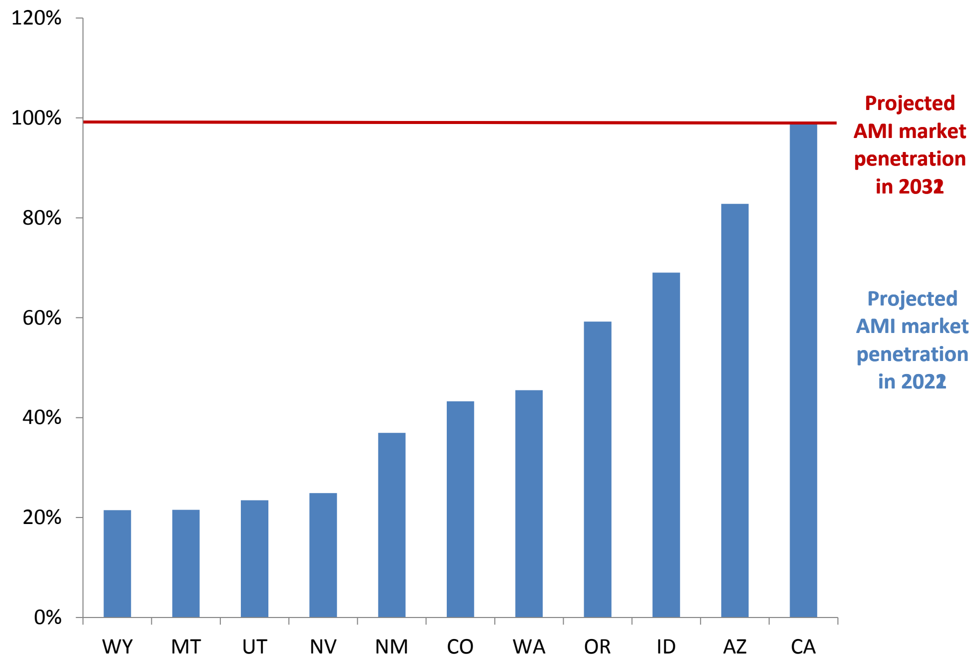


Figure 13: Assumed AMI Market Penetration in 2022 and 2032

Residential CAC saturation is an important forecasting assumption, because it determines the number of customers who will be eligible for air-conditioning DLC programs. It also plays a role in determining customer responsiveness to dynamic pricing, since CAC is a large source of easily controlled load during peak hours. For example, several utilities in the Pacific Northwest expect that the market penetration of CAC will increase significantly over the next two decades. CAC has become increasingly common in new construction. To develop our forecast of CAC saturation, we relied on U.S. EIA Residential Energy Consumption Survey (RECS) data, which includes historical information about air-conditioning market penetration and is available at the

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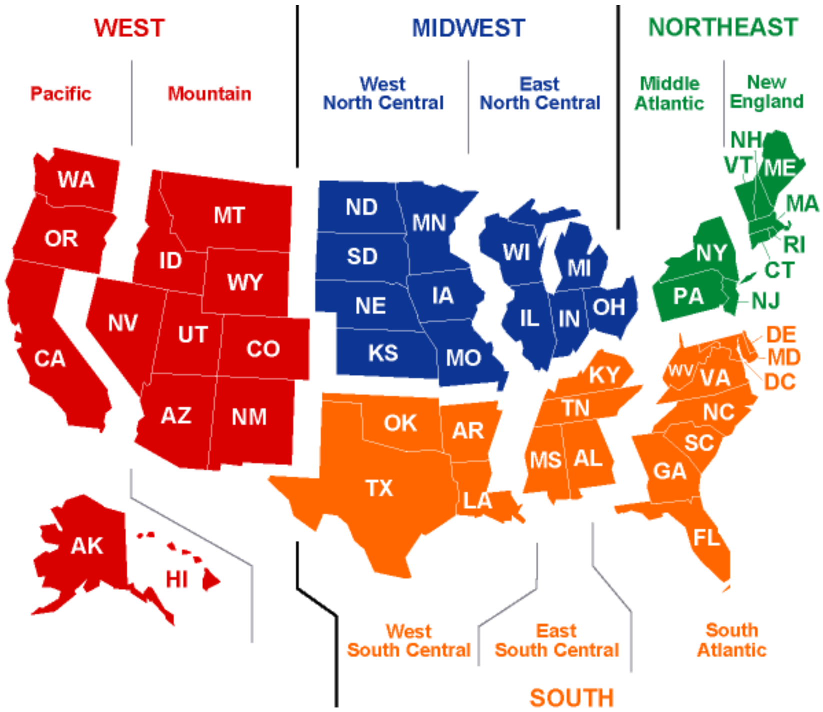
[12] We assumed 99 percent as the maximum in order to account for opt-out policies and minor technical limitations to deployment.

Census Division level.[13] As shown in Figure 14, the west is divided into two Census Divisions, Pacific and Mountain.



Source: U.S. Energy Information Administration

Figure 14: The U.S. Census Divisions

For the two Census Divisions, we assumed that historical growth rates in air-conditioning adoption would slowly level-off in the future as the market approaches full saturation. CAC share of all A/C is assumed to slowly increase, as housing stock turns over and older homes with window A/C are replaced by new homes with CAC. Results of the projection are shown in Figure 15. Note that the Mountain Division includes the Southwest, which is already at or near full saturation (roughly 90% CAC in AZ and NV), so future growth in the other Mountain states is higher than is represented by the Division average

[13] EIA Website: http://www.eia.gov/consumption/residential/

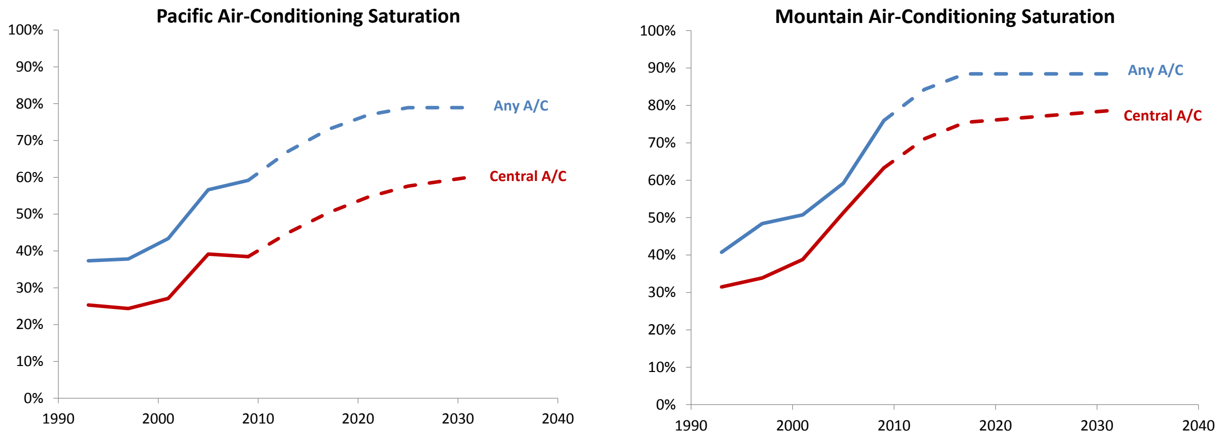


Figure 15: Air-conditioning Market Saturation Projections

At the state level, our CAC projections assume significant growth in market penetration for most states in the West, with the exception of Arizona and Nevada, which are already nearly fully saturated at rates of almost 90%. CAC market penetration among Pacific states was assumed to grow roughly at the rate of the Census Division forecast. Mountain states other than Arizona and Nevada were assumed to growth at twice the forecasted Mountain Division growth rate, to offset the lack of potential growth in the Southwest. Idaho's CAC saturation was capped at nearly 90 percent, which is assumed to be full saturation. The state-level CAC saturation estimates are summarized in Figure 16.

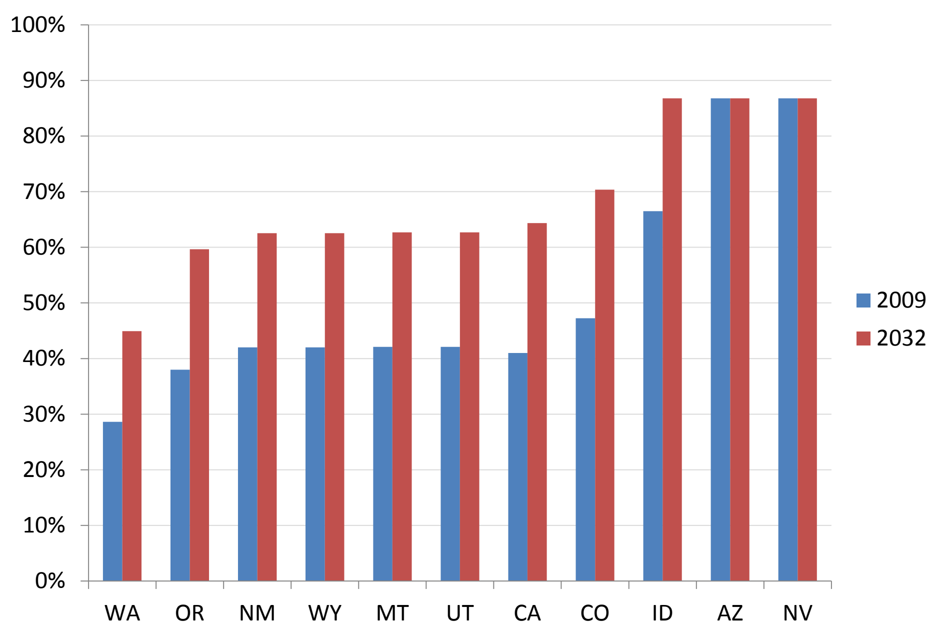


Figure 16: CAC Saturation in 2009 and 2032

DLC participation was also assumed to increase over the next two decades. This expectation is supported by a trend toward new appliances being wired with communications technology. For example, ThinkEco has developed a "modlet" for remotely controlling window air-conditioning, and this technology is being tested by ConEd in New York City. Devices like the Nest Learning Thermostat are improving efficiency in air-conditioning use and also come with remote control capability via websites and smart phone applications. To capture the potential impact of this trend, we have assumed that air-conditioning DLC participation will increase in varying degrees across the Western states over the next two decades.

In the 10-year DR forecast, all states except for Utah were projected to reach the Expanded BAU "best practices" participation rate of 12.5 percent for residential DLC.[14] In the 20-year forecast, participation was modified using existing participation rates as an indication of potential interest in future DLC programs. States with low current participation (i.e., less than two percent) were assumed to remain at 12.5 percent in 2032. States with moderate current participation (i.e., two percent to six percent) were assumed to grow to 15 percent in 2032. States with significant current participation (i.e., six percent to 10 percent) were assumed to grow to 17.5 percent by 2032. Utah, with an already high participation rate of 26 percent, was held at that rate. The resulting state-level DLC participation forecast is illustrated in Figure 17.

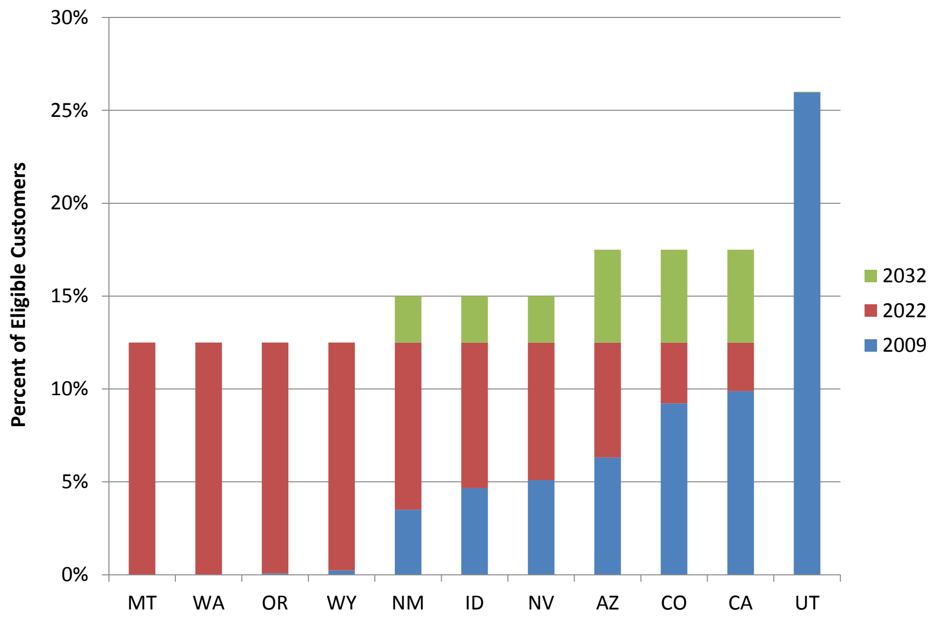


Figure 17: Air-Conditioning DLC Participation Forecast

Long-run dynamic pricing participation was modified in the 20-year forecast for all classes. There is a general lack of consensus in the industry as to the likely level of enrollment in dynamic pricing rates two decades from now. However, particularly for the purposes of developing a "High DR" scenario, it was important to recognize the significance of the increase in dynamic pricing offerings that have materialized in the U.S. over the past decade. This includes, for example, plans for default (i.e., opt-out) dynamic pricing in California, Maryland, and the District of Columbia, as well as plans for opt-in dynamic pricing in several other states. Based on this trend, it is plausible that, two decades from now, dynamic pricing participation will exceed the 5% to 14% opt-in estimate that was used as the Expanded BAU scenario assumptions in the 10-year DR forecast, even if most dynamic pricing rate plans are still offered on an opt-in basis.

[14] At the state level, Utah's average DLC participation rate of 25% is already one of the highest in the country and therefore was left unchanged.

In the 20-year forecast, we continued to use the Expanded BAU assumption that dynamic pricing would be offered on an opt-in basis to all customer classes for all states except California. However, we modified the opt-in participation rates on a regional basis. States were grouped into the following five “regions” based on geography and similarities in characteristics that would drive dynamic pricing participation: Northwest (Oregon, Washington, Montana, and Wyoming), Southwest (Arizona, Nevada, New Mexico, and Utah), Idaho, Colorado, and California. For California, we continued to use the “Achievable Participation” assumption that dynamic pricing will be offered on an opt-out basis to all customer classes, but we modified the opt-out participation rate.

In the Northwest, residential and C&I opt-in participation rates were held at the same level (i.e., five percent) that was used in the 10-year forecast. Some factors suggested that participation may be higher than this. For example, Portland General Electric has deployed AMI and has conducted a critical peak pricing pilot. Additionally, renewables integration challenges and constraints on hydro operations may lead to an increased need for flexible demand in the region in the future. However, large reliance on hydropower had led to relatively little energy price volatility in the region, and there is limited historical interest and experience with DR in the region, as it is primarily focused on energy efficiency. Due to the offsetting implications of these observations, the long-run participation rates remained unchanged from the 10-year forecast.

In the Southwest, residential participation was increased from 13.75 percent in 2022 to 20 percent in 2032, and C&I participation was increased from 20 percent to 30 percent. This was driven primarily by observation that Arizona Public Service has been able to achieve roughly 50 percent participation in its voluntary residential time-of-use (TOU) rates, and Salt River Project has achieved significant enrollment as well. Additionally, the hot climate in this region leads to “needle peaks” with substantial load concentrated in a few top hours of the year, making the region an ideal candidate for dynamic pricing.

In Idaho, residential participation was assumed to increase from five percent in 2022 to 15 percent by 2032. C&I participation was assumed to increase from five percent to 20 percent. This is because the Idaho PUC has expressed interest in TOU rates in the context of Idaho Power’s smart metering program. Additionally, the Idaho PUC has also requested that Rocky Mountain Power do more to promote its TOU rate. Such factors are indicators of growing interest in time-varying retail rates.

In Colorado, residential participation was assumed to increase slightly from 13.75 percent in 2022 to 15 percent in 2032, and C&I participation was held constant at 20 percent. Regulators in Colorado have demonstrated progressive views on retail ratemaking through recent adoption of inclining block rates for residential customers. Further, state legislation has mandated peak reduction goals for IOUs. Offsetting these factors, however, is a sense that controversy surrounding the Boulder SmartGridCity pilot may have soured policy-makers views of smart grid programs. Further, there has been relatively little activity related specifically to time-varying rates in the state. The net effect of these observations, for the purpose of our long-term forecast, was a modest increase in assumed residential participation.

In California, participation rates were held constant at 60 percent in 2022 and 2032 for both residential and C&I customers. This is driven primarily by lower-than-expected enrollment in CPP rates being offered by the IOUs on a default basis, as well as resistance to rolling out peak time rebates (PTRs) to residential customers across the IOU's service territories. Table 12 summarizes the dynamic pricing participation rate assumptions by state among the four customer classes in 2022 and 2032.

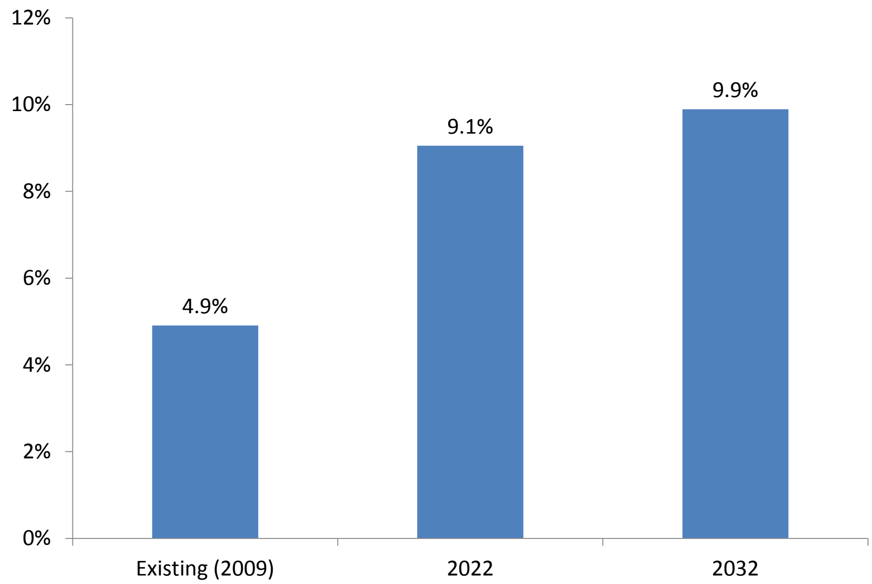
Table 12: 2022 and 2032 Dynamic Pricing Participation Rate Assumptions by State and Customer Class

	Residential		Small C&I		Medium C&I		Large C&I	
	2022	2032	2022	2032	2022	2032	2022	2032
AZ	14%	20%	20%	30%	20%	30%	20%	30%
CA	60%	60%	60%	60%	60%	60%	60%	60%
CO	14%	15%	20%	20%	20%	20%	20%	20%
ID	5%	15%	5%	20%	5%	20%	5%	20%
MT	5%	5%	5%	5%	5%	5%	5%	5%
NM	14%	20%	20%	30%	20%	30%	20%	30%
NV	14%	20%	20%	30%	20%	30%	20%	30%
OR	5%	5%	5%	5%	5%	5%	5%	5%
UT	14%	20%	20%	30%	20%	30%	20%	30%
WA	5%	5%	5%	5%	5%	5%	5%	5%
WY	5%	5%	5%	5%	5%	5%	5%	5%

5.1.1.3 20-Year High DR Resource Potential

Across WECC, DR resource potential is projected to be nearly 10 percent of peak demand over the next two decades in our "High DR" scenario. We are projecting the potential for significant growth in the first decade, moving from existing impacts in the five percent range to impacts of around 9 percent by 2022. In the second decade, growth is projected to be modest on a percentage basis and reach 10 percent by 2032. Figure 18 summarizes the DR potential in WECC as a percent of peak demand.

Figure 18: WECC High DR Resource Potential in 2022 and 2032 (as % of Peak Demand)



DR impacts are expected to vary significantly by state. The policy, market, and technology drivers discussed earlier in this chapter could lead to 20-year DR impacts that are as low as four percent in states with little DR experience like Oregon and Montana, or higher than 10 percent in states with significant DR activity like California, Idaho, New Mexico, and Utah. Figure 19 summarizes state-level DR potential.[15] A detailed breakout of DR impacts by customer class, program type, state, and forecast year is provided in Technical Appendix, Table 18.

[15] Existing DR is included here as it was reported by utilities to FERC for its 2008 and 2010 Assessment of Advanced Metering and Demand Response. Additional information on existing DR in Idaho was provided by Idaho PUC staff.

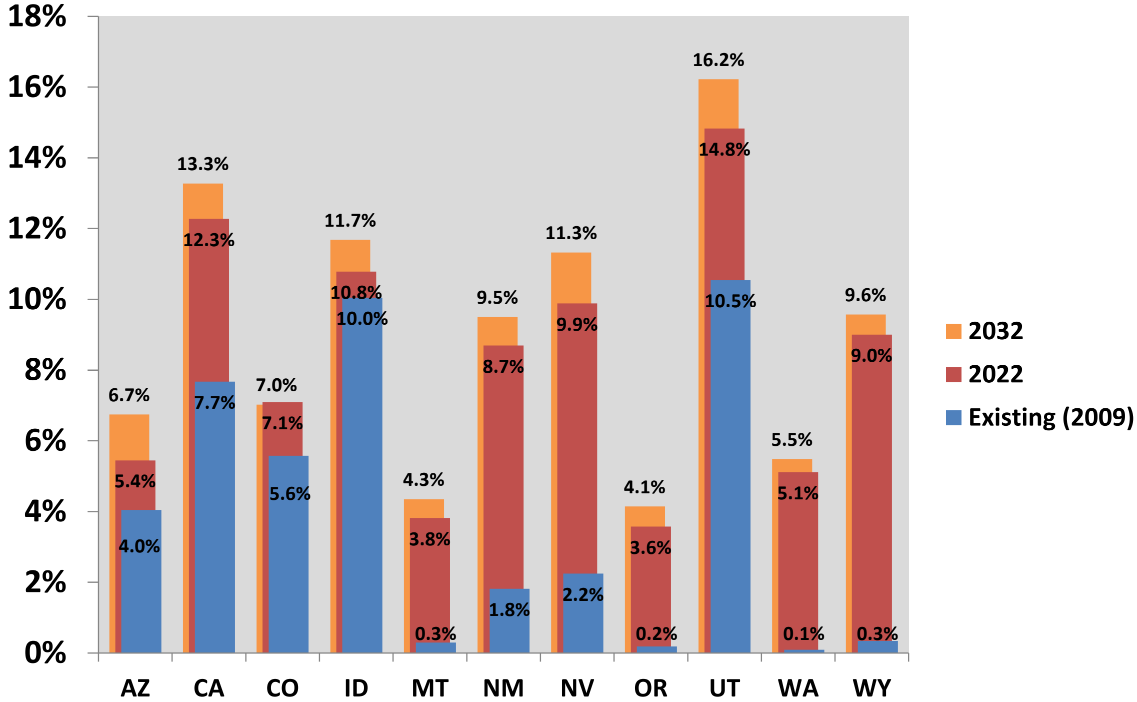


Figure 19: Forecast of State-Level DR Resources (as % of Peak Demand)

5.1.2 Balancing Authority DR Capacities

The updated 2032 DR potential estimates were developed at a state-level, and we allocated those state-level potential estimates to the WECC BA-level using a similar methodology as in the 10-Year High DSM Case (see Section 3.1.2). We updated several steps to incorporate the 2032 High DSM annual energy and peak demand forecasts, in order to correctly allocate DR potential based on the 2032 High DSM load forecast.

The 2032 High DSM Case had ~14,650 MW of DR resource capacity. Among the DR program types, pricing programs accounted for the largest DR capacity (on a non-coincident basis) in the 20-Year High DSM Case at ~5,454 MW (~37%) (see Table 13). This was driven, in part, by high assumed AMI penetration and by the high assumed participation and enrollment in dynamic pricing programs in the updated FERC 2009 Study DR potential estimates.

Table 13: 20-Year SPSC High DSM Case DR Capacities by Program Type

DR Program Type	2032 SPSC High DSM Case Forecast (MW: NCP)
Interruptible	5,092
DLC	2,203
Pricing	5,454
Load as a capacity resource/Other	1,902
TOTAL	**14,650**

The 20-Year High DSM Case assumed some DR resource capacity for all Canadian and U.S. WECC BAs and among all four DR program types (see Figure 20). In many cases, the DR capacity in the 2032 High DSM Case is lower than in the 2022 High DSM Case (on an absolute basis). Of particular note, the CISO BA had ~5,408 MW of total DR capacity across the four program types in the 20-Year High DSM Case, which is less than the ~5,984 MW of DR capacity in the 2022 High DSM Case. The peak load forecasts in 2032 were lower than 2022 due to the effects of energy efficiency programs. Because the DR capacities are derived from the DR potential expressed as a percent of peak load, the lower peak load forecasts in 2032 result in lower DR capacities, compared to the 2022 High DSM Case (even though the DR resource size on a percentage basis is somewhat larger).

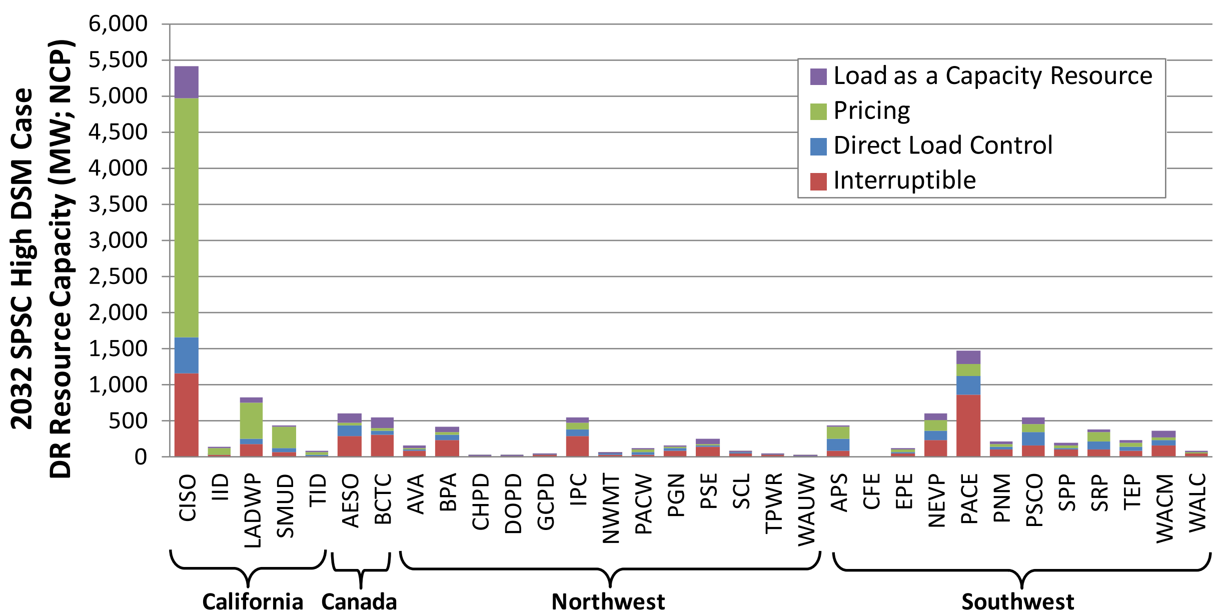


Figure 20: 2032 SPSC High DSM Case DR Resource Capacity by WECC BA and DR Program Type

5.1.3 Simulated Hourly Dispatch

The next step in our approach was to simulate the dispatch of DR resources in the 20-Year High DSM Case. As in the 20-Year Reference Case, we utilized the LBNL DRDT to simulate DR program operation, and we dispatched DR resources in response to hourly loads. For the 20-Year

High DSM Case, we used the hourly load profiles produced by the production cost modeling runs for the 10-Year High DSM Case to identify high-load periods. (This is analogous to our use of the hourly load profiles from the 10-Year Common Case for modeling DR dispatch in the 20-Year Reference Case.) As with all other applications of the LBNL DRDT, the output of the DR program simulation was an hourly profile of DR load reductions for each WECC load zone.

When simulating DR program operation, we used the same assumptions about expected hours of dispatch for each of the DR program types as in the 20-Year Reference Case (see Chapter 4). We also applied the same hourly shaping approach as in the other study cases.

One critical difference in the DR dispatch simulation for the 20-Year High DSM Case was the use of a more "flexible" DR modeling logic, which is reflective of the High DSM Case's premise of larger and more advanced DR programs. Within other study cases (such as the 10-Year High DSM Case and 20-Year Reference Case), DR resources were dispatched in consecutive-hour periods (i.e., blocks), and all available DR programs were dispatched simultaneously. This logic was based on typical DR program tariffs that establish minimum and maximum hours of consecutive dispatch and historical dispatch of DR resources over a limited number of peak days per year. For the 20-Year High DSM Case, we instead allowed DR to be dispatched in non-consecutive hour periods and with independent program dispatch. For example, a program with an expected 50 annual operating hours might be dispatched on 50 separate days for a single hour each day, rather than on 10 days for 5-hour blocks each day. This change in modeling logic was predicated on the assumption that advances in DR program design and enabling technology will allow the utility to dispatch DR resources in smaller, more flexible amounts and will provide customers with better information to respond to DR events in real-time. This would ultimately ease certain constraints on DR program rules and increase the operational flexibility of the DR resource.

This flexible DR dispatch logic included three constraints on DR program operation: (1) expected hours of dispatch per year, with annual expected hours the same as in the 20-Year Reference Case; (2) a maximum number of hours per event a program can be dispatched, with maximum event hours the same as in the 20-Year Reference Case; and (3) no individual program could be called more than once in a single hour.

The next step in our approach was to calculate the load reductions for each of the four system conditions. As in the 20-Year Reference Case, the DR load reductions for the HS and HW system conditions were based on each BA's non-coincident load reduction for the months of July and December, respectively; and no DR load reductions occurred for the LS and LF system conditions. The monthly load reductions for July and December were calculated following the same procedure as described for the 20-Year Reference Case (see Section 4.1.3).

5.2 Results

Table 13 shows the DR load reductions for the 20-Year High DSM Case for each of the four WECC system conditions. The California load zones have the largest monthly peak demand reductions during the Heavy Summer (HS) system condition (e.g., LADWP, SMUD, PGE_BAY, PGE_VLY, SCE, and SDGE), which is expected given the large DR resource capacities for those load zones. On a system-condition-basis, the results show the HS system condition with the highest frequency of peak demand reductions and are consistent with those load zones whose system peak demands occur in July (i.e., the month of the HS system condition hour). For those load zones that typically have system peaks occurring in the winter, we observe peak demand reductions in December (i.e., the month of the Heavy Winter (HW) system condition hour). We did not assume DR resources for the Light Spring (LSP) and Light Fall (LF) system conditions because they were predicated on lower total loads during shoulder months (March and November, respectively) when DR resources are typically not available.

On an annual peak reduction basis, WECC load zones with DR resources in the High DSM Case had annual peak reductions, on a non-coincident peak basis, ranging from ~1.5% to ~10.3% (see Figure 21) which was higher than in the WECC Reference Case. Similar to the WECC Reference Case, several load zones showed lower annual peak demand reductions than the maximum available DR resource potential typically due to a shift in the peak day within the year. Thus, although the percentage reduction in peak demand may be relatively large for an individual day when DR is dispatched, the percentage reduction in the annual peak demand may be much smaller if the peak demand is simply shifted to another day when DR was not dispatched.

Table 14: 2032 SPSC High DSM Case Quarterly Peak Demand Reductions

WECC Load Zone	Heavy Summer (HS)	Light Spring (LSP)	Light Fall (LF)	Heavy Winter (HW)
AESO	0	0	0	195
APS	514	0	0	0
AVA	39	0	0	39
BCH	0	0	0	536
BPA	0	0	0	394
CHPD	0	0	0	20
DOPD	0	0	0	12
EPE	125	0	0	0
FAR EAST	65	0	0	0
GCPD	30	0	0	0
IID	85	0	0	0
LDWP	704	0	0	0
MAGIC VLY	110	0	0	0
NEVP	471	0	0	0
NWMT	53	0	0	0
PACE_ID	29	0	0	0
PACE_UT	608	0	0	0
PACE_WY	25	0	0	0
PACW	109	0	0	14
PG&E_BAY	557	0	0	0
PG&E_VLY	254	0	0	0
PGN	116	0	0	21
PNM	84	0	0	0
PSC	252	0	0	0
PSE	0	0	0	168
SCE	499	0	0	0
SCL	0	0	0	67
SDGE	186	0	0	0
SMUD	387	0	0	0
SPP	123	0	0	0
SRP	377	0	0	0
TEP	169	0	0	0
TIDC	48	0	0	0
TPWR	0	0	0	37
TREAS VLY	249	0	0	0
WACM	203	0	0	78
WALC	75	0	0	0
WAUW	6	0	0	0
WECC Total	**6552**	**0**	**0**	**1581**

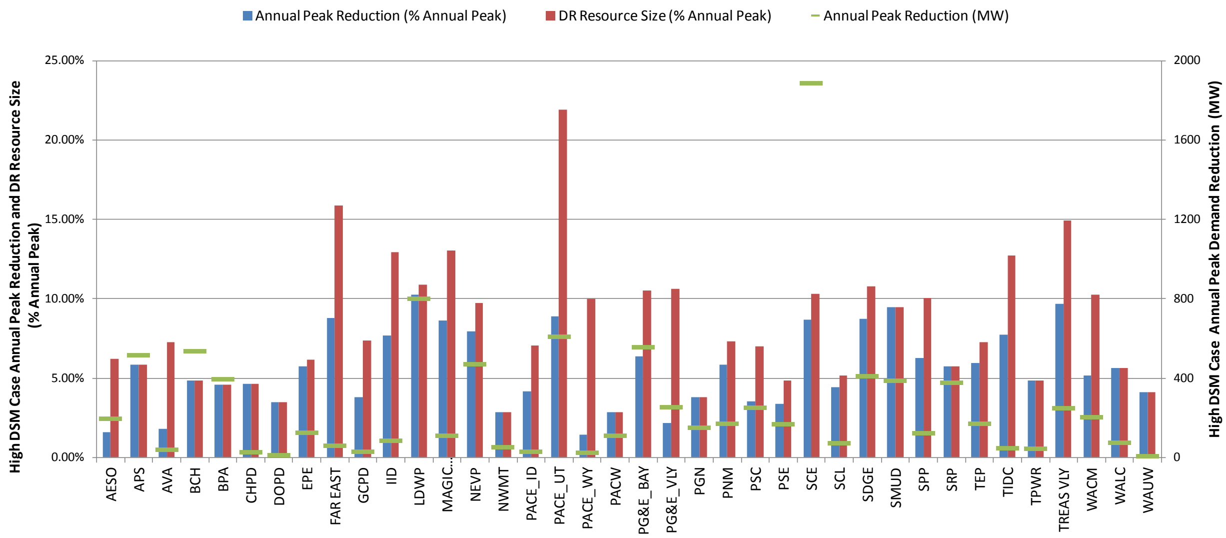


Figure 21: 2032 SPSC High DSM Case WECC Reference Case Annual Peak Reduction from DR (Non-Coincident Peak Basis)

6. Recommendations: Potential Improvements to Data, Methodology, and Process for Future TEPPC Study Cycles

Stakeholders and participants in WECC's planning processes could benefit from several improvements to the TEPPC Study Cycle data collection and study methodology and process concerning demand response. These improvements would enable stakeholders to obtain greater understanding and awareness regarding the potential role of different types of DR resources and the ongoing need to develop more realistic modeling approaches in order. This could lead to better incorporate DR resources into WECC's regional transmission and capacity expansion plans. This would allow BAs and utilities to more fully realize the benefits of DR resources.

Recommendations:

- **Report BA non-firm load at the program-level.** The LRS data collection manual currently requires BAs to report non-firm load aggregated among four DR program types (i.e., interruptible, DLC, critical peak pricing, and load as a capacity resource). Program-level data is only voluntarily reported by BAs. Requiring BAs to report non-firm load disaggregated among individual DR programs would enable better review and validation of the non-firm load forecasts to ensure that they are consistent with current demand response policies and resource plans, and would enable better simulation of DR program operation within WECC's transmission planning models.

- **Report dispatch of DR programs.** The LRS data collection manual contains no reporting elements for the number and duration of DR program dispatch. The LRS data collection manual instead specifies the expected amount of DR available at the time of the BA system peak. This DR capacity can differ from the actual amount of actual peak demand reduction and it is likely that DR programs are used in hours other than the BA system peak. Collection of actual DR event dispatch information would provide better assumptions for simulated dispatch of non-interruptible DR resources and provide more accurate study assumptions about the load impact, availability, and frequency of DR program events.

  NERC is developing a Demand Response Availability Data System (DADS) that will include the mandatory reporting of DR event information. The data collection of DR dispatch and events by LRS could be structured similar to the NERC reporting requirements to ease reporting burdens on BAs.

- **Expand the non-firm load DR program types to include economic and ancillary services DR resources.** The LRS data collection manual currently specifies four types of "dispatchable" DR programs: interruptible, direct load control, critical peak pricing with controls, and load as a capacity resource. These program types are just a subset of the many DR programs offered by utilities. Thus, the DR resource capacities in the TEPPC studies may be somewhat, undercounting and under-representing the size of DR resources in WECC.

NERC is collecting DR enrollment and performance data across multiple program types, including dispatchable, economic, and ancillary service DR programs. While this data is currently voluntarily submitted, it will soon be mandatory for reporting to NERC through the DADS. The LRS data collection manual should include these additional DR program types (e.g., economic and ancillary services) in the required DR program types for non-firm load forecasts, as they become mandatory DR programs for reporting to NERC.

- **Enhance the calculation of DR resource availability through end-use load profiles.** Our calculation of DR resource availability assumed a perfect relationship with total system load, so that the availability of end-uses driving electricity demand increased as total system load increased. This assumption could be enhanced by constructing end-use based profiles for DR program availability. Accounting for hourly end-use profiles for each DR program would yield more precise profiles of DR resource availability. This increased specificity and precision would need to be weighed against the additional time and data intensive requirements for constructing such end-use load profiles for DR programs.

- **Develop utility-level DR potential estimates for High DSM Cases.** Projected DR impacts in the High DSM Cases rely on state-level DR potential estimates. These potential estimates could be further disaggregated at the utility-level rather than at the state-level. The results of DR potential studies for WECC utilities could be used in place of statewide averages and, where such studies have not been conducted, bottom-up estimates could be developed for the larger WECC utilities. Utility-level potential studies are able to take into account system-specific factors that are not accounted for in state-level studies, like the FERC Study.

  Another improvement in the DR potential estimates could occur from the use of state- or utility-level market participation information. Primary market research on customer acceptance of DR programs would reflect the specific preferences and characteristics of WECC states and/or utilities, rather than relying broadly on the best available information from DR programs across the United States.

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Technical Appendices

Table A-1: 2021 Common Case DR Capacities

Region	**BA**	Interruptible	DLC	CPP	Load as a Capacity Resource	**Total**
California	CISO	1,031	1,626	932	462	**4,051**
California	IID	10	-	-	-	**10**
California	LADWP	400	-	-	-	**400**
California	SMUD	75	126	143	-	**344**
California	TID	-	-	-	-	**-**
Canada	AESO	-	94	-	-	**94**
Canada	BCTC	-	-	-	-	**-**
Northwest	AVA	-	-	-	-	**-**
Northwest	BPA	-	-	-	-	**-**
Northwest	CHPD	40	-	-	-	**40**
Northwest	DOPD	-	-	-	-	**-**
Northwest	GCPD	-	-	-	-	**-**
Northwest	IPC	-	351	-	-	**351**
Northwest	NWMT	-	-	-	-	**-**
Northwest	PACW	-	63	-	-	**63**
Northwest	PGN	-	60	20	-	**80**
Northwest	PSE	-	144	-	-	**144**
Northwest	SCL	-	-	-	-	**-**
Northwest	TPWR	-	-	-	-	**-**
Northwest	WAUW	-	-	-	-	**-**
Southwest	APS	105	-	-	-	**105**
Southwest	CFE	-	-	-	-	**-**
Southwest	EPE	72	-	-	-	**72**
Southwest	NEVP	-	411	-	-	**411**
Southwest	PACE	281	521	-	-	**802**
Southwest	PNM	45	-	-	-	**45**
Southwest	PSCO	219	105	-	-	**324**
Southwest	SPP	-	113	-	-	**113**
Southwest	SRP	359	-	78	-	**437**
Southwest	TEP	77	-	-	-	**77**
Southwest	WACM	-	1	-	-	**1**
Southwest	WALC	-	-	-	-	**-**
	WECC Total	**2,714**	**3,615**	**1,173**	**462**	**7,963**

Table A-2: 2022 SPSC High DSM Case DR Capacities

Region	**BA**	Interruptible	DLC	CPP	Load as a Capacity Resource	**Total**
California	CISO	1,369	883	2,849	883	**5,984**
California	IID	26	28	78	18	**150**
California	LADWP	244	142	475	156	**1,017**
California	SMUD	105	95	278	71	**549**
California	TID	19	12	39	12	**82**
Canada	AESO	249	96	9	118	**472**
Canada	BCTC	332	42	18	175	**567**
Northwest	AVA	40	21	5	18	**84**
Northwest	BPA	216	53	16	87	**372**
Northwest	CHPD	13	2	1	7	**23**
Northwest	DOPD	7	2	1	4	**14**
Northwest	GCPD	28	2	1	15	**46**
Northwest	IPC	151	81	16	74	**322**
Northwest	NWMT	28	11	1	13	**53**
Northwest	PACW	38	31	16	16	**101**
Northwest	PGN	76	33	8	10	**127**
Northwest	PSE	138	21	8	74	**241**
Northwest	SCL	48	6	2	25	**81**
Northwest	TPWR	24	4	1	13	**42**
Northwest	WAUW	5	1	-	2	**8**
Southwest	APS	91	121	102	33	**347**
Southwest	CFE	-	-	-	-	**-**
Southwest	EPE	12	6	3	5	**26**
Southwest	NEVP	300	138	44	154	**636**
Southwest	PACE	758	252	36	206	**1,252**
Southwest	PNM	129	42	18	54	**243**
Southwest	PSCO	147	191	74	87	**499**
Southwest	SPP	97	31	13	48	**189**
Southwest	SRP	94	94	81	35	**304**
Southwest	TEP	101	33	33	44	**211**
Southwest	WACM	116	68	25	67	**276**
Southwest	WALC	27	19	15	11	**72**
	WECC Total	**5,028**	**2,561**	**4,266**	**2,535**	**14,390**

Figure A-1: 2022 High DSM Case FERC 2009 Study Allocation Methodology

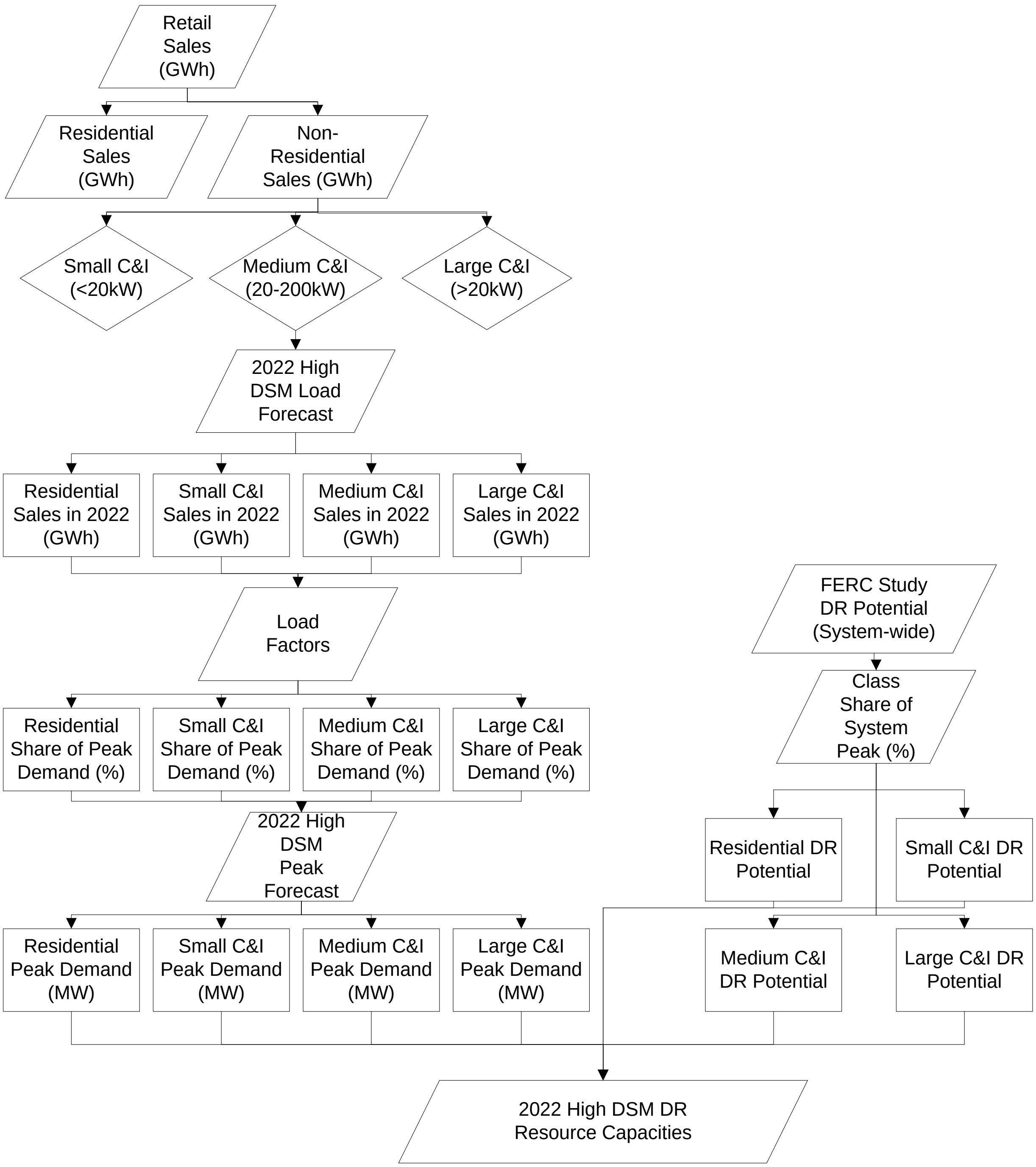

Table A-3: 2022 and 2032 WECC Reference Case Peak Demand Reductions

WECC Load Zone	2022 WECC Reference Case Quarterly Peak Demand Reductions (MW)				2032 WECC Reference Case Quarterly Peak Demand Reductions (MW)			
	Q1	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
AESO	67	0	0	63	97	0	0	91
APS	0	0	105	0	0	0	138	0
CHPD	25	0	0	14	29	0	0	16
EPE	0	46	54	0	0	60	71	0
FAR_EAST	0	36	43	0	0	54	64	0
IID	0	0	10	0	0	0	11	0
LDWP	0	0	165	0	0	0	193	0
MAGIC_VLY	0	55	78	0	0	67	94	0
NEVP	0	0	232	0	0	0	254	0
PACE_ID	0	30	22	0	0	33	24	0
PACE_UT	0	0	444	0	0	0	598	0
PACE_WY	0	0	1	0	0	0	1	0
PACW	0	0	59	0	0	0	65	0
PGN	80	0	0	59	91	0	0	67
PGE_BAY	0	381	321	0	0	396	334	0
PGE_VLY	0	0	91	0	0	0	90	0
PNM	0	0	45	0	0	0	50	0
PSCO	0	0	128	0	0	0	133	0
PSE	138	0	0	144	150	0	0	157
SCE	0	0	1704	0	0	0	1763	0
SDGE	0	268	271	0	0	305	309	0
SMUD	0	0	282	0	0	0	279	0
SPPC	0	0	51	0	0	0	56	0
SRP	0	0	190	0	0	0	214	0
TEPC	0	0	55	0	0	0	56	0
TREAS_VLY	0	0	109	0	0	0	151	0
WACM	0	1	1	0	0	1	1	0

Table A-4: 10- and 20-year state-by-state summary of DR potential in High DSM Cases

DR Potential in 2022

AZ

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	0.00%	0.00%	0.00%	0.00%	**0.00%**
Pricing Without Enabling Technology	1.02%	0.03%	0.22%	0.08%	**1.34%**
Automated or Direct Control DR	1.34%	0.03%	0.03%	0.00%	**1.40%**
Interruptible Tariffs	0.00%	0.00%	0.86%	1.25%	**2.10%**
Other DR	0.00%	0.00%	0.03%	0.57%	**0.60%**
Total	**2.36%**	**0.06%**	**1.14%**	**1.89%**	**5.45%**

CA

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	1.66%	0.00%	0.80%	0.33%	**2.79%**
Pricing Without Enabling Technology	1.27%	0.04%	0.61%	0.59%	**2.51%**
Automated or Direct Control DR	1.63%	0.06%	0.10%	0.00%	**1.80%**
Interruptible Tariffs	0.08%	0.00%	0.34%	2.74%	**3.17%**
Other DR	0.24%	0.05%	0.02%	1.70%	**2.01%**
Total	**4.88%**	**0.15%**	**1.88%**	**5.36%**	**12.28%**

CO

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	0.00%	0.00%	0.00%	0.00%	**0.00%**
Pricing Without Enabling Technology	0.35%	0.00%	0.41%	0.27%	**1.04%**
Automated or Direct Control DR	1.06%	0.06%	1.52%	0.00%	**2.64%**
Interruptible Tariffs	0.00%	0.00%	0.50%	1.64%	**2.14%**
Other DR	0.00%	0.00%	0.04%	1.24%	**1.28%**
Total	**1.41%**	**0.06%**	**2.47%**	**3.15%**	**7.09%**

ID

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	0.00%	0.00%	0.00%	0.00%	**0.00%**
Pricing Without Enabling Technology	0.23%	0.00%	0.13%	0.03%	**0.39%**
Automated or Direct Control DR	1.03%	0.03%	0.72%	0.00%	**1.78%**
Interruptible Tariffs	0.00%	0.00%	0.53%	6.22%	**6.76%**
Other DR	0.01%	0.00%	0.58%	1.27%	**1.85%**
Total	**1.27%**	**0.03%**	**1.96%**	**7.53%**	**10.78%**

DR Potential in 2032

AZ

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	0.00%	0.00%	0.00%	0.00%	**0.00%**
Pricing Without Enabling Technology	1.74%	0.05%	0.39%	0.13%	**2.32%**
Automated or Direct Control DR	1.77%	0.02%	0.03%	0.00%	**1.82%**
Interruptible Tariffs	0.00%	0.00%	0.76%	1.31%	**2.06%**
Other DR	0.00%	0.00%	0.03%	0.50%	**0.53%**
Total	**3.51%**	**0.08%**	**1.21%**	**1.94%**	**6.74%**

CA

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	2.51%	0.00%	0.81%	0.33%	**3.65%**
Pricing Without Enabling Technology	2.13%	0.05%	1.14%	0.85%	**4.17%**
Automated or Direct Control DR	0.93%	0.05%	0.11%	0.00%	**1.10%**
Interruptible Tariffs	0.07%	0.00%	0.35%	2.77%	**3.19%**
Other DR	0.21%	0.05%	0.02%	0.89%	**1.16%**
Total	**5.86%**	**0.15%**	**2.43%**	**4.84%**	**13.28%**

CO

	Residential	Small	Medium	Large	
Pricing With Enabling Technology	0.00%	0.00%	0.00%	0.00%	**0.00%**
Pricing Without Enabling Technology	0.69%	0.01%	0.57%	0.19%	**1.46%**
Automated or Direct Control DR	0.95%	0.06%	1.34%	0.00%	**2.34%**
Interruptible Tariffs	0.00%	0.00%	0.52%	1.44%	**1.97%**
Other DR	0.00%	0.00%	0.04%	1.21%	**1.25%**
Total	**1.63%**	**0.06%**	**2.48%**	**2.85%**	**7.02%**

ID

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	0.00%	0.00%	0.00%	0.00%	**0.00%**
Pricing Without Enabling Technology	1.08%	0.01%	0.67%	0.18%	**1.93%**
Automated or Direct Control DR	1.45%	0.02%	0.63%	0.00%	**2.11%**
Interruptible Tariffs	0.00%	0.00%	0.56%	5.47%	**6.03%**
Other DR	0.01%	0.00%	0.51%	1.10%	**1.61%**
Total	**2.53%**	**0.03%**	**2.37%**	**6.75%**	**11.69%**

DR Potential in 2022

MT

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	0.00%	0.00%	0.00%	0.00%	**0.00%**
Pricing Without Enabling Technology	0.05%	0.01%	0.01%	0.01%	**0.07%**
Automated or Direct Control DR	0.69%	0.07%	0.01%	0.00%	**0.77%**
Interruptible Tariffs	0.00%	0.00%	0.07%	1.94%	**2.01%**
Other DR	0.00%	0.00%	0.01%	0.95%	**0.96%**
Total	**0.74%**	**0.08%**	**0.10%**	**2.90%**	**3.82%**

NM

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	0.00%	0.00%	0.00%	0.00%	**0.00%**
Pricing Without Enabling Technology	0.21%	0.01%	0.24%	0.17%	**0.62%**
Automated or Direct Control DR	0.77%	0.05%	0.14%	0.40%	**1.36%**
Interruptible Tariffs	0.00%	0.00%	0.34%	4.39%	**4.73%**
Other DR	0.00%	0.00%	0.03%	1.95%	**1.98%**
Total	**0.98%**	**0.06%**	**0.74%**	**6.92%**	**8.69%**

NV

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	0.00%	0.00%	0.00%	0.00%	**0.00%**
Pricing Without Enabling Technology	0.40%	0.01%	0.05%	0.14%	**0.60%**
Automated or Direct Control DR	1.93%	0.05%	0.03%	0.00%	**2.01%**
Interruptible Tariffs	0.00%	0.00%	0.10%	4.66%	**4.76%**
Other DR	0.00%	0.00%	0.01%	2.50%	**2.51%**
Total	**2.33%**	**0.06%**	**0.19%**	**7.30%**	**9.88%**

OR

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	0.00%	0.00%	0.00%	0.00%	**0.00%**
Pricing Without Enabling Technology	0.11%	0.00%	0.07%	0.02%	**0.21%**
Automated or Direct Control DR	0.67%	0.04%	0.14%	0.00%	**0.85%**
Interruptible Tariffs	0.00%	0.00%	0.38%	1.84%	**2.22%**
Other DR	0.00%	0.00%	0.03%	0.26%	**0.30%**
Total	**0.78%**	**0.04%**	**0.62%**	**2.12%**	**3.57%**

DR Potential in 2032

MT

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	0.00%	0.00%	0.00%	0.00%	**0.00%**
Pricing Without Enabling Technology	0.19%	0.01%	0.02%	0.03%	**0.26%**
Automated or Direct Control DR	0.92%	0.07%	0.01%	0.00%	**1.01%**
Interruptible Tariffs	0.00%	0.00%	0.07%	2.04%	**2.11%**
Other DR	0.00%	0.00%	0.01%	0.96%	**0.97%**
Total	**1.11%**	**0.09%**	**0.11%**	**3.03%**	**4.35%**

NM

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	0.00%	0.00%	0.00%	0.00%	**0.00%**
Pricing Without Enabling Technology	0.65%	0.03%	0.60%	0.43%	**1.70%**
Automated or Direct Control DR	0.68%	0.04%	0.11%	0.36%	**1.19%**
Interruptible Tariffs	0.00%	0.00%	0.35%	4.60%	**4.95%**
Other DR	0.00%	0.00%	0.02%	1.64%	**1.66%**
Total	**1.32%**	**0.07%**	**1.09%**	**7.02%**	**9.50%**

NV

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	0.00%	0.00%	0.00%	0.00%	**0.00%**
Pricing Without Enabling Technology	1.46%	0.05%	0.18%	0.53%	**2.22%**
Automated or Direct Control DR	2.03%	0.04%	0.02%	0.00%	**2.10%**
Interruptible Tariffs	0.00%	0.00%	0.11%	4.88%	**4.99%**
Other DR	0.00%	0.00%	0.01%	2.01%	**2.01%**
Total	**3.50%**	**0.09%**	**0.32%**	**7.41%**	**11.32%**

OR

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	0.00%	0.00%	0.00%	0.00%	**0.00%**
Pricing Without Enabling Technology	0.20%	0.00%	0.12%	0.04%	**0.36%**
Automated or Direct Control DR	1.02%	0.04%	0.14%	0.00%	**1.20%**
Interruptible Tariffs	0.00%	0.00%	0.39%	1.89%	**2.28%**
Other DR	0.00%	0.00%	0.03%	0.27%	**0.30%**
Total	**1.22%**	**0.05%**	**0.68%**	**2.19%**	**4.14%**

DR Potential in 2022

UT

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	0.00%	0.00%	0.00%	0.00%	**0.00%**
Pricing Without Enabling Technology	0.18%	0.00%	0.18%	0.10%	**0.47%**
Automated or Direct Control DR	1.79%	0.04%	1.62%	0.00%	**3.44%**
Interruptible Tariffs	0.00%	0.00%	5.50%	3.50%	**9.00%**
Other DR	0.00%	0.00%	0.03%	1.89%	**1.92%**
Total	**1.97%**	**0.04%**	**7.32%**	**5.49%**	**14.83%**

WA

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	0.00%	0.00%	0.00%	0.00%	**0.00%**
Pricing Without Enabling Technology	0.09%	0.00%	0.04%	0.03%	**0.16%**
Automated or Direct Control DR	0.26%	0.05%	0.07%	0.00%	**0.38%**
Interruptible Tariffs	0.00%	0.00%	0.23%	2.77%	**3.00%**
Other DR	0.00%	0.00%	0.02%	1.56%	**1.58%**
Total	**0.35%**	**0.05%**	**0.36%**	**4.35%**	**5.11%**

WY

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	0.00%	0.00%	0.00%	0.00%	**0.00%**
Pricing Without Enabling Technology	0.03%	0.00%	0.01%	0.04%	**0.08%**
Automated or Direct Control DR	0.33%	0.04%	0.05%	0.00%	**0.41%**
Interruptible Tariffs	0.00%	0.00%	0.11%	5.34%	**5.45%**
Other DR	0.00%	0.00%	0.01%	3.05%	**3.06%**
Total	**0.35%**	**0.04%**	**0.18%**	**8.43%**	**9.00%**

DR Potential in 2032

UT

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	0.00%	0.00%	0.00%	0.00%	**0.00%**
Pricing Without Enabling Technology	0.87%	0.02%	0.69%	0.40%	**1.98%**
Automated or Direct Control DR	2.07%	0.03%	1.43%	0.00%	**3.52%**
Interruptible Tariffs	0.00%	0.00%	5.52%	3.67%	**9.19%**
Other DR	0.00%	0.00%	0.03%	1.51%	**1.54%**
Total	**2.94%**	**0.05%**	**7.67%**	**5.57%**	**16.22%**

WA

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	0.00%	0.00%	0.00%	0.00%	**0.00%**
Pricing Without Enabling Technology	0.19%	0.00%	0.07%	0.05%	**0.31%**
Automated or Direct Control DR	0.40%	0.05%	0.07%	0.00%	**0.51%**
Interruptible Tariffs	0.00%	0.00%	0.24%	2.84%	**3.08%**
Other DR	0.00%	0.00%	0.02%	1.57%	**1.59%**
Total	**0.59%**	**0.05%**	**0.39%**	**4.46%**	**5.49%**

WY

	Residential	Small	Medium	Large	Total
Pricing With Enabling Technology	0.00%	0.00%	0.00%	0.00%	**0.00%**
Pricing Without Enabling Technology	0.09%	0.01%	0.03%	0.08%	**0.22%**
Automated or Direct Control DR	0.43%	0.04%	0.05%	0.00%	**0.51%**
Interruptible Tariffs	0.00%	0.00%	0.12%	5.60%	**5.72%**
Other DR	0.00%	0.00%	0.01%	3.11%	**3.12%**
Total	**0.52%**	**0.05%**	**0.21%**	**8.80%**	**9.57%**

Table A-5: 2032 SPSC High DSM Case Quarterly Peak Demand Reductions – 'Initial' and 'Flexible' Dispatch Approaches

WECC Load Zone	2032 SPSC High DSM Case Quarterly Peak Demand Reductions (MW): "Initial" Approach Q1	Q2	Q3	Q4	2032 SPSC High DSM Case Quarterly Peak Demand Reductions (MW): "Flexible" Approach Q1	Q2	Q3	Q4
AESO	0	0	0	64	80	0	0	195
APS	0	0	266	0	0	0	514	0
AVA	19	0	36	4	39	0	39	39
BCTC	21	0	0	495	335	0	0	536
BPA	248	0	0	394	370	0	0	394
CHPD	26	0	0	12	26	0	0	20
DOPD	13	0	0	12	13	0	0	12
EPE	0	54	66	0	0	103	125	0
FAR_EAST	0	47	56	0	0	59	65	0
GCPD	0	0	27	0	0	0	30	0
IID	0	0	54	0	0	4	85	0
LDWP	0	0	781	0	0	421	801	315
MAGIC_VLY	0	76	99	0	0	94	110	0
NEVP	0	0	467	0	0	183	471	0
NWMT	0	0	53	0	0	0	53	0
PACE_ID	0	30	23	0	0	38	29	0
PACE_UT	0	0	334	0	0	98	608	0
PACE_WY	0	0	6	0	0	0	25	0
PACW	13	0	96	0	104	0	109	14
PGE_BAY	0	403	348	0	0	541	557	0
PGE_VLY	0	0	61	0	0	0	254	0
PGN	128	0	149	0	141	0	149	21
PNM	0	0	141	0	0	0	169	0
PSC	0	160	150	0	0	285	252	0
PSE	139	0	0	168	232	0	0	168
SCE	0	0	1594	0	0	0	1885	0
SCL	30	0	0	30	72	0	0	64
SDGE	0	0	247	0	0	63	409	0
SMUD	0	0	187	0	0	62	387	0
SPP	0	0	97	0	0	29	123	0
SRP	0	54	229	0	0	232	377	0
TEP	0	0	99	0	0	22	169	0
TIDC	0	0	36	0	0	13	48	0
TPWR	44	0	0	32	44	0	0	37
TREAS_VLY	0	0	215	0	0	96	249	0
WACM	0	34	135	0	0	130	203	78

WECC Load Zone	2032 SPSC High DSM Case Quarterly Peak Demand Reductions (MW): "Initial" Approach				2032 SPSC High DSM Case Quarterly Peak Demand Reductions (MW): "Flexible" Approach			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
WALC	0	0	69	0	0	17	75	0
WAUW	0	0	3	0	1	2	6	0