Technical Appendix I: Demand Response Methodology and Potential

Contents

Introduction to Demand Response

Demand response (DR) allows utilities to adjust electricity demand by consumers at specific times to help reduce the power demand on the system, either through direct adjustments or by encouraging consumers with rates. Unlike supply-side generating resources, demand response operates on the demand side by modifying how and when electricity is used. As such, it can serve as an alternative to constructing new generation resources.

The Ninth Power Plan is analyzing demand response products in the residential, commercial, industrial, and agricultural sectors, as well as the utility distribution system. These products include utility-controllable and price-responsive options across the sectors. Utility-controllable products can change the operation of end-use equipment to reduce peak. Price-responsive products allow end-use customers to choose how to modify their energy consumption based on a price signal from the utility. Table I - 1 includes the list of demand response products that are evaluated in the Ninth Plan listed by sector. More details regarding the demand response products are included later in this section.

To estimate the demand response resource for the Ninth Plan, the Council develops supply curves that cover a range of demand response products. Demand response supply curves provide comparisons with generating resources and other demand side resources like energy efficiency. These supply curves serve as inputs into the Council's resource optimization models, along with generating resource reference plants, load forecasts, market conditions, etc. The Council considers results from these models in developing a resource strategy for the region. This appendix details how demand response supply curves have been developed for the Ninth Plan.

Table I - 1: List of Demand Response Products in the Ninth Power Plan

Residential	Commercial	Industrial and Agriculture
AC Switch	AC Switch	Irrigation Control (Ag)
Heating Switch	Heating Switch	Demand Curtailment (Ind)
Bring-your-own-thermostat	Bring-your-own-thermostat	Real Time Pricing (Ind)
Water Heater Control	Demand Curtailment	Critical Peak Pricing (Ind)

Residential	Commercial	Industrial and Agriculture
Critical Peak Pricing	Critical Peak Pricing	Demand Voltage Regulation (All)
Time-of-Use	Electric Vehicle Time-of-Use	
Electric Vehicle Charging Control	Demand Voltage Regulation	
Electric Vehicle Time-of-Use		
Demand Voltage Regulation		
Battery		

* Res = Residential; Com = Commercial, Ind = Industrial, Ag=Agricultural

Total Demand Response Potential

The aggregate demand response potential presented in the Ninth Power Plan reflects the combined contribution of a diverse portfolio of residential, commercial, industrial, and agricultural demand response products evaluated over the 20-year planning horizon. These products vary widely in technology type, customer participation model, seasonal availability, and cost. The Council assesses on a consistent basis so that their impacts can be directly compared with supply-side generating resources and energy efficiency measures. The resulting estimates represent the achievable level of peak load reduction that could be realized through utility programs, accounting for realistic participation rates, program performance, and operational constraints. Within this framework, achievable potential is defined as the amount of demand reduction that is expected to be reliably available to the power system under programmatic deployment.

Using these assumptions, the Ninth Power Plan estimates that total achievable demand response potential reaches approximately 6,636 megawatts in the summer period and 5,756 megawatts in the winter period by the end of the 20-year planning horizon. These totals represent the cumulative contribution of all modeled demand response products at their highest seasonal availability and form the basis for the demand response supply curves used in the Council's optimization modeling.

The supply curve for the demand response potential is provided in Figure I - 1 below. The figure represents the net levelized cost (in 2024 dollars) of each product, with the least cost products at the bottom of the chart and costs increasing from the bottom up. For products that operate in both the summer and winter the highest seasonal potential is represented. The incremental potential for a given product is illustrated in red, while the cumulative potential of all lower cost products is shown in blue. Table I - 2 provides the full product names corresponding to the abbreviations used in the figure.

Figure I - 1: 2046 Achievable Demand Response Potential with Net Levelized Cost - Combined

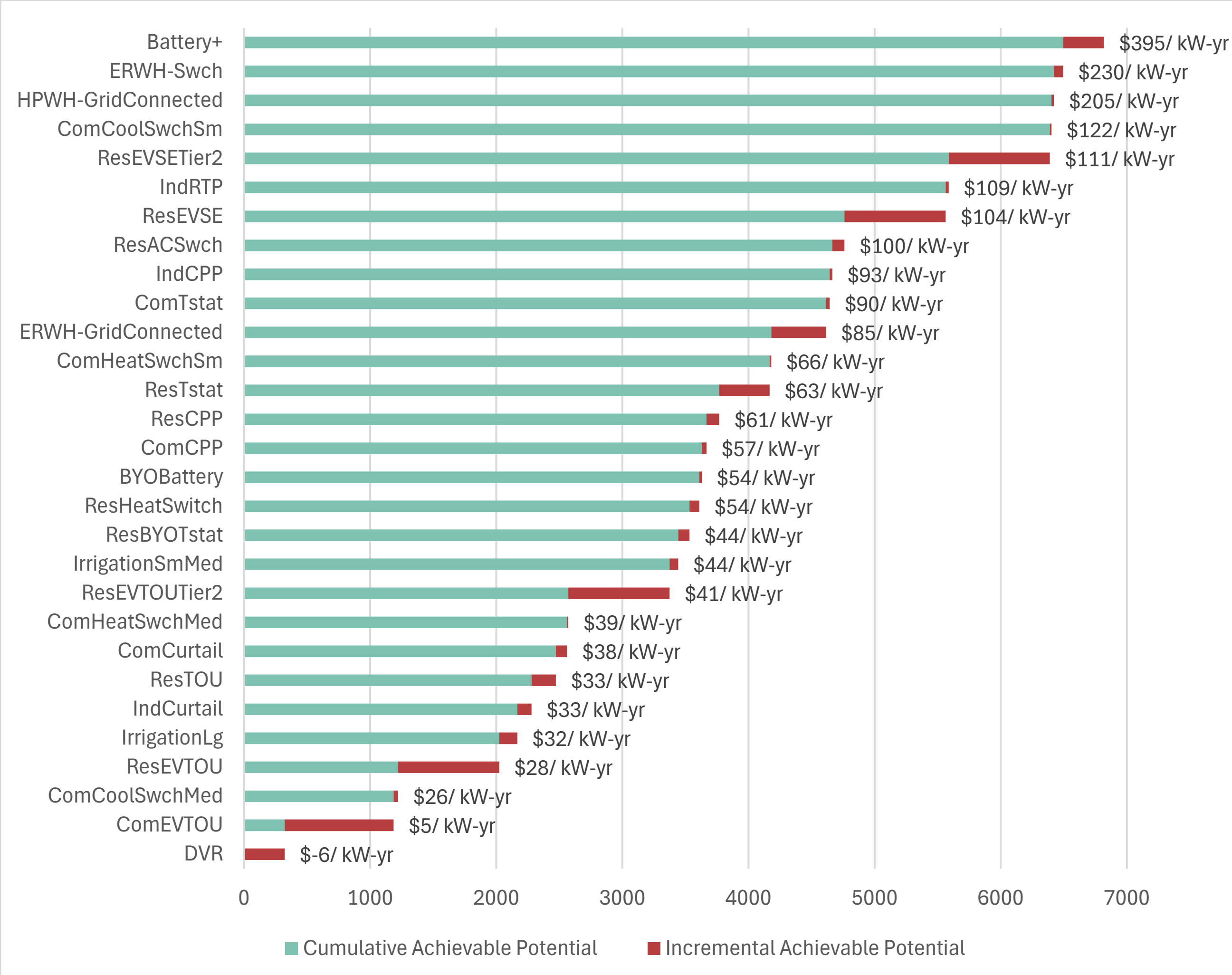


Table I - 2: Demand Response Products and their Abbreviations

Abbreviation	Full Name
DVR	Demand Voltage Regulation
ResBYOTstat	Residential Bring-Your-Own Thermostat
ResTOU	Residential Time-of-Use
ComCurtail	Commercial Curtailment
IndCurtail	Industrial Curtailment
ResCPP	Residential Critical Peak Pricing
ComCoolSwitchSm	Small Commercial Building Cooling Control Switch
EVTOU	Electric Vehicle Time-of-Use
ResTstat	Residential Thermostat

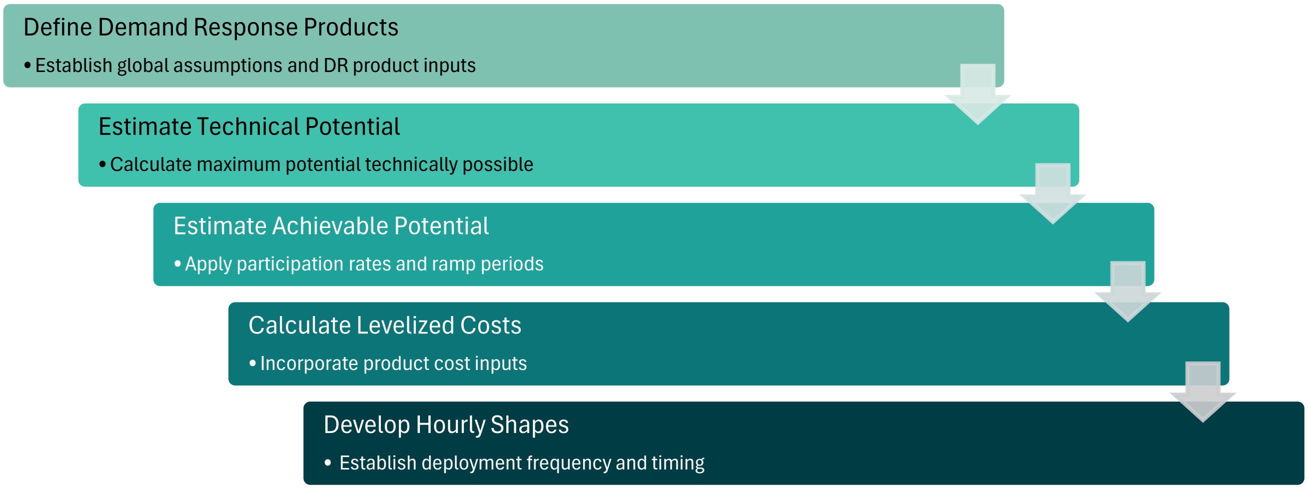
Abbreviation	Full Name
BYOBattery	Bring Your Own Battery
IrrigationLg	Irrigation Control for Farms
ComTstat	Commercial Building Thermostat
ComHeatSwitchMed	Medium Commercial Building Heating Control Switch
ERWH-GridConnected	Electric Resistance Water Heater Connected to the Grid
ResHeatSwitch	Residential Heating Control Switch
IndRTP	Real Time Pricing for the Industrial Sector
ResACSwitch	Residential Air Conditioning Switch
ComCoolSwitchMed	Medium Commercial Building Cooling Switch
HPWH-GridConnected	Heat Pump Water Heater Connected to the Grid
ERWH-Switch	Electric Resistance Water Heater Switch
Battery+	Battery Storage Purchased for Demand Response

Developing Demand Response Supply Curves

Council staff worked with the Demand Response Advisory Committee (DRAC) to determine the cost and impact input parameters for each demand response product. In addition, the product eligibility was largely based on external data sources such as: the residential building stock assessment (RBSA),[1] the commercial building stock assessment (CBSA),[2] and the Regional Technical Forum (RTF) work products.[3] Where appropriate, assumptions are consistent between the demand response and energy efficiency supply curves.

[1] 2022 Residential Building Stock Assessment: https://neea.org/residential-building-stock-assessment.
[2] Commercial Building Stock Assessment: https://neea.org/commercial-building-stock-assessment.
[3] RTF Demand Response Technologies: https://rtf.nwcouncil.org/demand-responses.

Figure I - 2: Demand Response Product Development Workflow



Demand Response Products

A demand response product is a resource that modifies electricity demand during a defined event. Demand response products in the Ninth Plan carry a bundle of characteristics that define their cost, impact, capabilities, and the end-use loads that it can impact. Products are proxy resources and are meant to best describe a representative demand response program structure rather than specific utility implementation. Demand response programs developed by different utilities using the same technology can vary significantly in costs, deployment strategies, and use cases. Variations in inputs and available load geographically within the region are captured when appropriate. Certain demand response products may be available in the summer, winter, or bi-seasonal, as listed in Table I - 3. The impact, cost, and deployment assumptions that define each demand response product are discussed further in this appendix.

Table I - 3: Demand Response Products by Season

Both Seasons	Summer Only	Winter Only
Smart Thermostat	AC Switch	Heat Switch
Water Heater Control	Irrigation	
Electric Vehicle Charging		
Curtailment		
Critical Peak Pricing		
Time-of-Use		
Real Time Pricing		
Demand Voltage Regulation		
Battery		

Global Assumptions

To calculate the demand response achievable technical potential, there are several key input parameters needed: global assumptions (economic and system) and product inputs (impact and cost). The global assumptions are listed in

Table I - 4 and the product inputs are listed in Table I - 6. Global assumptions are key data points that are applicable across the demand response products assessed and define the system and cost landscape that is used to estimate demand response potential and cost. System assumptions are discussed below while economic assumptions are discussed in the section on net levelized costs.

Table I - 4: Global Assumptions

Economic	System
Planning Horizon	Peak Definition
Discount Rate	Hourly System Load Profile
Inflation	System Sales Forecast
	Sector, Segment, End Use Shares
	Line Losses

Peak Definition

Peak definition is used to determine peak coincidence factors for demand response products as well as to develop hourly demand response deployment shapes. For peak coincidence analysis, peak is allowed to be any hour in the summer (June, July, August) or winter (December, January, February). Event time is limited to 4 hours and maximum hours per season is 40. This allows the potential assessment model to determine peak events throughout the year based on the system load shape and calculate coincidence factors for different end use loads that are impacted by demand response products. To develop hourly deployment shapes, peak is defined as 7-10 am and 5-9 pm in the winter and 6-10 pm in the summer. Actual deployment profiles may vary in duration than these based on the characteristics of the demand response product.

System Demand Forecast and Hourly Load Profile

The system demand forecast establishes baseline electricity sales in MWh by sector. Load is further disaggregated by segment and end-use shares when possible, to parse out load at the end use level. The disaggregated demand forecast is an important input to the demand response model as it serves as the starting point for the load that can be potentially impacted by demand response products. For more information on the load forecast see Technical Appendix F – Electricity Demand Forecast.

While most disaggregation of energy demand was developed in the load forecast, defining agricultural sales required further work as it was built into the industrial forecast. Data from the 2023 USDA

Census of Agricultural Irrigation and Water Management Survey[4] were used to approximate agricultural load by balancing authority. Using a conversion of 0.8 kW per pump horsepower (HP), total pump HP was converted to total MWh, which was then expressed as a percentage of the industrial demand forecast.

An hourly system load profile was developed using the regional hourly demand forecast and normalized to an 8,760-hour annual load shape. This provides the temporal framework for estimating peak coincidence factors.

Line Losses

The transmission and distribution power lines incur losses when transmitting electricity from one location to another. These losses need to be accounted for when estimating the difference in savings at the end-use site versus the utility busbar. For the Ninth Plan, the Council conducted research[5] and collected data from utilities and the Energy Information Administration (EIA) to determine the average losses on both the distribution and transmission systems. These values were found to be 4.4 percent for the distribution system and 2.8 percent for the transmission system.[6]

Potential and Cost by Modeling Zone

Previous power plans estimated demand response potential for the region as a whole. While this represents a picture of the region's overall demand response availability, it cannot represent potential differences in the types of demand response available on a sub-regional level or potential differences in the value of demand response on a sub-regional level. For example, some sub-regions of the Council's overall planning region may be willing to pay higher prices for demand response, given the unique characteristics and constraints of their sub-region.

For the first time, the Ninth Plan estimated demand response potential and cost for a set of seventeen smaller sub-regions or "modeling zones". The modeling zones, summarized in Error! Reference source not found., correspond approximately to Northwest balancing authorities, or portions of balancing authorities. However, their main purpose is to reflect where different types and magnitudes of demand response are distributed across the region, as well as the differing costs that may be represented. In addition to allocating electric loads, customers, and equipment stocks across zones, other zone-specific adjustments are described later in this section for each demand response end use.

[4] 2023 USDA Census of Agricultural Irrigation and Water Management Survey: https://www.nass.usda.gov/Publications/AgCensus/2022/Online_Resources/Farm_and_Ranch_Irrigation_Survey.
[5] Research findings presented to the Council's Conservation Resources Advisory Committee available here: https://nwcouncil.box.com/s/opdoxu8ullwi3o0uedeodavgekid2ttt.
[6] More information on line losses can be found in Technical Appendix A – Global Assumptions.

Table I - 5: Modeling Zones

Modeling Zone Name	Modeling Zone Abbreviation
Avista Utilities	AVA
Bonneville Power Administration, Idaho and Montana	BPA_IDMT
Bonneville Power Administration, Oregon	BPA_OR
Bonneville Power Administration, Washington	BPA_WA
Chelan County PUD	CCPUD
Douglas County PUD	DCPUD
Grant County PUD	GCPUD
Idaho Power Company	IPCO
NorthWestern Energy	NWMT
PacifiCorp, East	PACE
PacifiCorp, West	PACW
Portland General Electric	PGE
Puget Sound Energy, Central	PSE_Central
Puget Sound Energy, North	PSE_North
Puget Sound Energy, Olympia	PSE_Olympia
Seattle City Light	SCL
Tacoma Power	TPWER

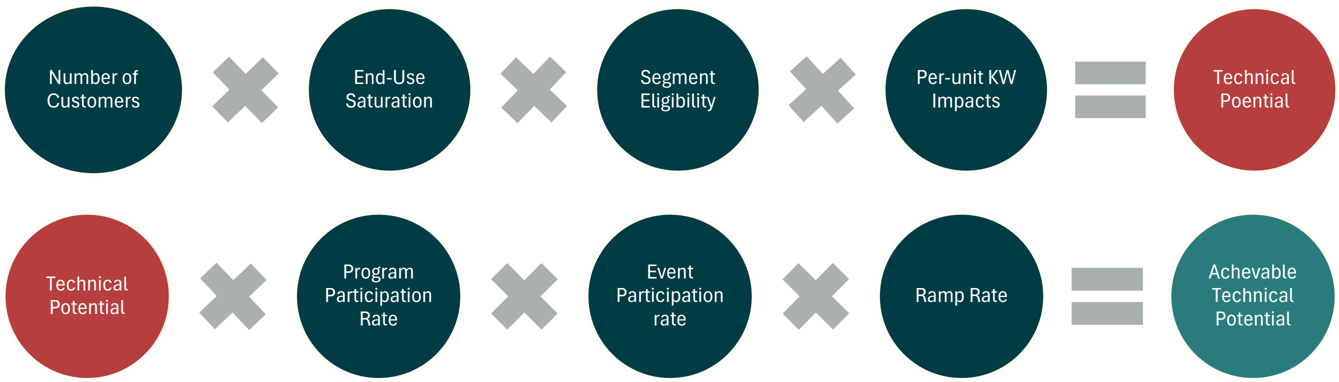
Estimate Technical Potential

Technical potential assumes 100% participation of eligible customers in all programs included in the assessment. Hence, technical potential represents a theoretical limit for unconstrained potential. Depending on the type of demand response product, technical potential is typically estimated using either a bottom-up or top-down method.

Bottom-Up Methodology

The bottom-up method (Figure I - 3) is used to assess potential for demand response products that affect a piece of equipment in a specific end use. This method is therefore applicable to demand response products such as direct control of space and water-heating equipment or smart thermostats. In the bottom-up method, technical potential is determined primarily as the product of three variables: number of eligible customers, equipment saturation rate, and the expected per-unit (kW) peak load impact. The bottom-up method is intended to simplify the estimation potential for equipment-based products.

Figure I - 3: Illustration of Bottom-Up Methodology to Estimate Potential



Top-Down Methodology

The top-down method (Figure I - 4) estimates technical potential as a fraction of the participating facility's total peak-coincident demand. The calculation begins with disaggregating system electricity sales by sector, market segment, and end use, then estimates technical potential as a fraction of the end-use loads. Total potential is then estimated by aggregating the predicted load reductions of the applicable end uses. The top-down estimation method is applied to demand response products that target the entire facility or load (rather than specific equipment), such as commercial and industrial demand curtailment, time-varying rates, or programs offered to entire sectors, such as to the irrigated agriculture sector.

Figure I - 4: Illustration of Top-Down Methodology to Estimate Potential

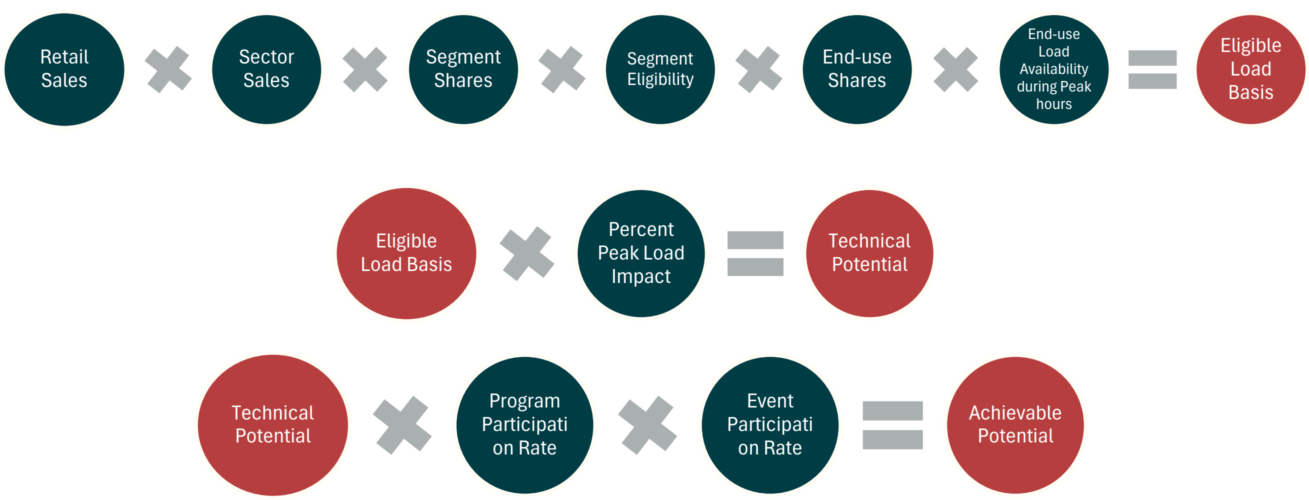


Table I - 6: Demand Response Products Listed by Assessment Methodology

Bottom-Up	Top-Down
AC Switch (Res and Com)	Irrigation Control (Ag)
Heating Switch (Res and Com)	Demand Curtailment (Com and Ind)
Bring-your-own-thermostat (Res and Com)	Real Time Pricing (Ind)
Water Heater Control (Res)	Critical Peak Pricing (Res and Com)
Battery (Res)	Time-of-Use (Res)
	Demand Voltage Regulation (All)
	Electric Vehicle Charging (Res and Com)

Res = Residential, Com = Commercial, Ind = Industrial, Ag=Agricultural

Estimate Achievable Potential

Achievable potential reflects a subset of technically feasible demand response opportunities that are assumed to be reasonably obtainable, based on market conditions and the end-use customers' ability and willingness to participate in the demand response market. There are two components for estimating achievable potential: market acceptance (or participation) and the ramp rate. Participation is also broken down into program participation (the likelihood of eligible population enrolling in a demand response program) and event participation (the probability that customers participating in a program will respond to a demand response event), an important consideration in voluntary demand response programs.

Ramp rates indicate the time needed for product design, planning, and deployment. Ramp rates vary depending on the type of demand response product and the stage in the product's life cycle. Ramp rates indicate how quickly the maximum achievable potential may be reached, but they do not affect the amount of maximum achievable potential.

A full list of potential and cost inputs as well as eligibility calculations for each DR product can be found on in the demand response supply curve workbooks listed on the Council's Ninth Plan website.[7]

[7] https://www.nwcouncil.org/energy/ninthpowerplan/technical-elements. Direct link to demand response supply curve workbooks is available here: https://www.nwcouncil.org/energy/ninthpowerplan/technical-elements.

Table I - 7: Demand Response Product Assumptions

Impact Assumption	Cost Assumptions
Eligibility	Setup Cost
Peak Load Impact	Operations and Maintenance Cost
Program Participation	Marketing Cost
Event Participation	Equipment Cost
Ramp Rates	Value of Lost Service
Attrition	

Impact Parameters

Estimating demand response potential depends on clearly defining which customer sectors, segments, and end-uses are eligible to participate. This determines the total load available for potential reduction. Within this framework, several key parameters shape the final estimates. Product parameter inputs are based on a review of existing program impact evaluation studies and technology performance characteristics, along with input and review from the Demand Response Advisory Committee.

Eligibility

The potential for demand response is a function of the customer sectors, segments, and end uses that the demand response product effects. Defining these eligible classes narrows down the potential load or population that can be part of a demand response product. Equipment stock saturation forecasts and advanced metering infrastructure (AMI) deployment are often used as well to define customer eligibility. When notable, specific methods for determining eligibility for certain demand response products are described in the Demand Response Products and Summaries section of this appendix.

Peak Load Impact

Peak load impact estimates the expected demand reduction when a demand response product is deployed. For bottom-up demand response products, this is defined as a kW per participant value, usually reflecting the load reduction expected for each individual piece of equipment enrolled in the program. This value is used as the basis to estimate technical potential along with population, equipment stock saturations, and eligibility. For top-down demand response products, peak load impact is defined as the percent of the eligible load basis that is reduced during a peak event. The actual level of load impact may differ from event to event depending on when it is called, or even between hours of a given event. To the extent that this was reliably quantifiable it is reflected in the hourly shape profiles of the demand response products.

Program Participation

Program participation represents the fraction of the eligible population or load expected to enroll in a fully deployed demand response program. Participation assumptions are deliberately conservative estimates to account for potential cannibalization between different demand response products. For example, certain products may impact the same end use, such as a residential time of use rate and a smart thermostat program both potentially impacting space heating and cooling. While it is prohibitively difficult to model interaction between these products should they both be selected in a portfolio, being conservative on participation rate assumptions minimizes any double counting of potential capacity.

Event Participation

Event participation captures the share of enrolled customers expected to respond to a dispatch call during an event. This can reflect load switch failure, connectivity issues, and participant opt-outs and overrides. For bottom-up demand response products the coincidence of the impacted end uses energy usage with the time of the demand response call may be incorporated in the event participation. For top-down demand response products, this is already embedded within the estimated coincidence factors derived from load-shape analysis.

Ramp Rates

A program ramp rate is included for each demand response product to reflect the number of years it may take to reach full participation. For example, for the AC Switch product, the full participation rate is 10 percent, but the assumption is that it will take five years to reach that level. Due to evidence that much of the enrollment in programs occurs in the first year of availability, participation begins at 50% of its final assumed rate and increases linearly over its ramp period – so 5 percent of the population in year one, 6 percent in year two, up towards 10 percent in year five and beyond. All products assumed five-year ramps.

Calculate Net Levelized Cost

In addition to the total impact that could be achieved, by year, for a given product, the supply curves also include an estimate of what it would cost, on a per-kilowatt-year basis, to acquire these impacts. Consistent with all cost assumptions in the Ninth Plan, all costs are in 2024 dollars. To fairly compare all resources in the resource strategy analysis, these costs are expressed as a net levelized cost of the capacity resources provided. Net levelized costs are measured as the discounted life-cycle $/kW-year cost of deploying a demand response product, which accounts for both positive and negative costs (e.g. benefits), and are calculated as the net present value (NPV) of the product costs divided by the NPV of the energy impact of the product. For demand response, the only benefit (negative cost) included is the value of demand response to defer transmission and distribution investment (T&D deferral). In the Ninth Plan, T&D deferral is estimated to be about $30.85 per kilowatt-year, where $11.13 is from transmission deferral and $19.71 from the distribution system. These values are based on input from regional utilities. See Technical Appendix A – Global Assumptions for more information.

Net levelized costs are based on the total resource cost perspective which includes all known and quantifiable costs related to demand response products and programs. The calculation of each demand response product's levelized cost accounts for the relevant direct costs of a demand response product, including setup costs, operations and maintenance costs, equipment costs, marketing costs, and value of lost service. These, along with the T&D deferral, are the components of the net costs, which are then levelized to 2024 dollars using a 3.7 percent discount rate.[8] Notably, not all cost categories apply to every demand response product. For example, a bring-your-own thermostat program will not have any equipment cost as it is assumed the customer already owns the thermostat. Additionally, net levelized costs for products may vary across modeling zones due to zone size, total potential, or differing cost assumptions between zones. Illustrated in this appendix are weighted average costs of each product across the different modeling zones.

Finally, net levelized cost for each product is calculated with assumptions based on summer and winter impacts. Impact assumptions for each season may differ, impacting the assessed cost and potential for the product for each season. Since it is assumed that each dual season product will be deployed for both seasons, however, the net levelized cost ultimately used for the product is that for the season with the greatest amount of assessed potential.

Cost Parameters

Setup Cost

The setup cost is a one-time cost experienced by a utility to initiate a new demand response program. This was roughly estimated at $175,000.[9] There are many factors that may go into the actual cost a utility may experience to start up a new demand response program that could make it vary widely from this amount. A utility with no demand response experience or infrastructure starting up their first demand response program will likely experience significantly different costs than a utility that has already developed several programs. This setup cost was chosen as a proxy to represent the costs unique to developing a single demand response program irrespective of the existing demand response infrastructure. For modeling zones that align with one geographic section of a given utility (e.g. PSE North) the setup cost is split between the number of modeling zones that make up that utility.

In accordance with feedback from the Demand Response Advisory Committee, this value was increased to $500,000 only for price-based demand response products like TOU and CPP. This reflects the significant cost experienced by utilities to implement new billing systems to accommodate these types of rates.

The one-time nature of this cost means that it has differing magnitudes of impacts on the levelized cost depending on both the size of the modeling zone as well as the size of the potential for the given demand response product. For larger modeling zones with greater load and thus, often, greater

[8] See Technical Appendix A – Global Assumptions for more information.

[9] Based on professional judgement and discussion with the Demand Response Advisory Committee.

potential, the impact of the setup cost on the levelized cost is diluted, as other costs scale up with the size of the potential while the setup cost does not. For smaller modeling zones and smaller products, the setup cost represents a larger share of the levelized cost. Utilities in these smaller modeling zones are also less likely to already have demand response enabling infrastructure like advanced billing systems and are more likely to experience this higher cost as well as have it impact the levelized cost.

Operations and Maintenance Cost

Operations and maintenance (O&M) costs reflect the ongoing cost experienced on an annual basis for keeping a demand response program in operation, usually including the cost of distributed energy resource management systems (DERMS). There are several different ways that demand response programs can be operated, whether that be in house or through a third-party vendor. The structure of those costs can be different from program to program. Further, there can be other unique ongoing costs like the cellular fee required for communication with a load control device. This proxy cost summarizes the best available data for the demand response products assessed. For direct load control demand response products, this cost is expressed in dollars per kW per year. For price-based demand response products it is expressed in dollars per year, with the cost being half the estimated cost of one full time employee ($87,500).

Marketing Cost

Marketing costs reflects the cost of recruiting each new participant into the demand response program. Costs are mostly standardized but may be different to reflect the challenge of spreading awareness of a program to potential participants. In this sense, it is somewhat connected to incentives in that it reflects the cost to get a customer willing to participate in the program. Marketing cost is expressed on a dollar per new participant basis.

Equipment Cost

Equipment cost reflects the incremental cost required to enable an end-use to respond to a demand response event. This can be the cost of a load switch device, which has traditionally been used in demand response programs, or any other additional equipment needed to enable device communication. This is expressed on a dollar per new participant basis. Unique examples of equipment costs are discussed in the individual sections for each demand response product/end use.

Portion of Incentive Impacting Levelized Cost/Value of Lost Service

Value of lost service represents the loss of utility experienced by a customer from participation in a demand response program. This value is derived as a percentage of incentive cost, with the idea being that the incentive cost is the maximum amount of cost a participant would be willing to incur in the form of lost utility. If the value of lost service were greater than the incentive value the participant is receiving, then they would not participate in the program. The value of lost service is estimated as a percentage of the assumed incentive, with the percentage being based on sector: 75% for industrial, 55% for commercial, and 25% for residential, reflecting the fact that interrupting service is often more disruptive for industrial/commercial customers than it is for residential (see Table I - 8).[10]

Additionally, the value of lost service for demand response products that are assumed to be frequently deployable is reduced to just 10% of the incentive value. These demand response products are assumed to be frequently deployable because the design of the program should be such that the impact on the participant is nearly negligible, and thus there does not need to be a limitation on the number of instances per season that it can be deployed. The lack of impact on the participants suggests that a lower value of lost service should be utilized.

Incentives

Incentives are collected as a basis for calculation of the values of lost service in the form of an annual incentive (dollar per participant per year) and/or a one-time incentive (dollar per participant). A variety of different structures can be used in utility demand response programs, including a performance-based incentive (dollar per kWh or event participated), but this analysis is limited to annual and one-time incentives. While used as a guide for the value of lost service calculations and captured in connection with expected participation rates, incentives are not included as an explicit cost in the net levelized cost calculation. The Ninth Plan uses a regional total resource cost test, which sees incentive payments as both a cost to the utility and a benefit to the participants, and thus not a cost to the region.[11]

Table I - 8: Share of Incentive Included as a Cost

Sector	Percent of Incentive in Levelized Cost
Frequently Deployable	10%
Residential	35%
Commercial	55%
Industrial	75%
Agricultural	75%

Transmission and Distribution Deferral

There are certain resources that can defer investment in transmission and/or distribution systems (T&D), including demand response. The value associated with deferring these investments is attributed to resources that have the capability to do so. The T&D deferral credit for zones west of the

[10] These values are based on the California PUC Demand Response Cost Effectiveness Protocol: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-cost-effectiveness.

[11] This approach is consistent with the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources: https://building-performance.org/education/resources/nesp-national-standard-practice-manual-nspm.

cascades is $38.87/kW-yr, while the T&D deferral credit for zones east of the cascades is $16.48/kW-yr. The BPA Oregon and Washington zones, that cover areas both east and west of the cascades, have a regional T&D deferral credit of $30.85, where $11.13 is from transmission deferral and $19.71 from distribution deferral. These values are based on input from regional utilities. See Technical Appendix A – Global Assumptions for more information.

T&D peak is defined as hours ending 8 and 9 am and hours ending 6 and 7 pm for winter-peaking zones (December, January, and February) and hours ending 5 through 8 pm for summer-peaking zones (July and August). The amount of this credit value that demand response products are attributed is dependent on the deployment shape and capabilities of each product and how they align with those peaks.

Frequently deployed demand response programs (like EV time-of-use charging) are modeled with a fixed shape deployment in the Ninth Plan. To determine the T&D deferral value from these resources the hourly shape is assessed against the hours of highest load in the demand forecast.[12] If the demand response program provides full value in these hours, it receives the full T&D deferral credit. If the program effectiveness is lower in these hours, the T&D deferral credit is reduced.

Limited deployment demand response products receive only half of the calculated T&D deferral credit. This is because, while they are deployed specifically for peak events, there may be instances where T&D peak occurs over multiple consecutive days. Many demand response programs have limitations on how many times per week load reduction can be called, or customers may be more likely to opt out if load reduction is called for too frequently. Additionally, utilities may run into their seasonal deployment limitation (15 events per season) before T&D peak is realized, creating some unpredictability as to how confidently limited deployment demand response can successfully defer transmission and distribution upgrades. The 50% T&D deferral credit is a proxy to represent this constrained deferral value.

Dispatch and Deployment Assumptions

Demand response has traditionally been limited to being deployed a handful of times per season during peak hours when the grid is strained. This is often still the case, but as demand response technologies have evolved, demand response programs have evolved as well. The hourly nature of resource modeling for this plan allows the Council to represent the dispatch and deployment of different demand response products with more granularity. The Ninth Plan distinguished between limited and frequent dispatch categories to capture this difference.

[12] Hours ending 8, 9, 18, and 19 were assessed in the winter, hours ending 17 through 20 in the summer. Actual peak hours can vary based on load forecast and weather pattern.

Limited Dispatch

Demand response products that are designated as limited dispatch products may be deployed up to 15 times per season that they are available. Their dispatch is limited because the curtailment is significantly disruptive such that customers would likely be unwilling to participate in the program if curtailment were requested more than 15 times per season. These products target the seasonal peak events when the grid is most strained.

Frequent Dispatch

Demand response products that are designated as frequent dispatch have the flexibility to be deployed for more than just the handful of seasonal peaks throughout the year. These products can be used for price mitigation, shifting loads from times of high energy cost to low energy cost, as well as targeting peak events when the grid is strained. Because these products can be deployed frequently throughout the winter and/or summer seasons, they are treated with a fixed shape similar to conservation.

Table I - 9: Demand Response Products Listed by Deployment Type

Limited	Frequent
Space Heating and Cooling (Res and Com)	Electric Vehicle Charging (Res and Com)
Irrigation Control (Ag)	Water Heating (Res)
BYO Battery (Res)	Time-of-Use (Res)
Demand Curtailment (Com and Ind)	Battery Plus (Res)
Critical Peak Pricing (Res and Com)	Demand Voltage Regulation (All)
Real Time Pricing (Ind)	

Demand Response Products and Summaries

This section describes the demand response products evaluated in the Ninth Power Plan. Each product represents a distinct method for reducing or shifting electricity consumption during periods of high system demand. The summaries below highlight how these products function, their eligibility criteria, net levelized costs for the region, and estimated potential by 2046. The input assumptions informing the total potential and cost for each product are developed through a combination of demand response program evaluations, utility potential assessments, and DRAC professional judgment. Unless otherwise noted, assumptions listed in these sections are based on professional judgment.[13] Each summary also has a figure illustrating a 24-hour deployment shape for the product.

[13] See "DR_Database" workbook in the Inputs folder for full list of input assumptions for all demand response products available here: https://nwcouncil.box.com/v/ninthplanDRsupplycurves.

These deployment shapes are set for the winter season to show how they may also address the winter morning peak when needed.[14]

Electric Vehicle Charging

Electric vehicle charging is one of the fastest growing loads in the region and also one of the most flexible. Presently, most EV charging at the residential level occurs in the early evening hours as drivers return home – typically aligning with evening peak hours. However, the charging does not need to be performed during those hours, so long as the vehicle is charged to the expected level when the user wishes to drive again, usually the following morning. If the correct signal is given, charging load can be shifted away from evening peak hours to hours of lesser need. This can be done either actively through direct control of the charging load or passively through price signals that encourage customers to shift their charging behaviors. Separate demand response products are modeled for these methods, but all are attributed an equipment cost of $60 representing the incremental cost of charger Wi-Fi enablement. Participation for residential EV charging demand response products is assumed at 40% of eligible load and split to 20% each between active managed charging and EV time of use.

When done correctly, EV charging demand response should not impact the program participant as their vehicle should be charged appropriately in the morning regardless of whether it started charging in an unmanaged scenario versus under a managed program. EV charging demand response is thus treated as frequently deployable. Additionally, it is assumed that managed charging demand response events can last for six hours rather than four since it does not matter to the participant when or how long the vehicle is charged, so long as it is charged in the morning. The Council's internal electric vehicle forecast is used to generate customer count and available charging load.[15]

Active Managed EV Charging (EVSE)

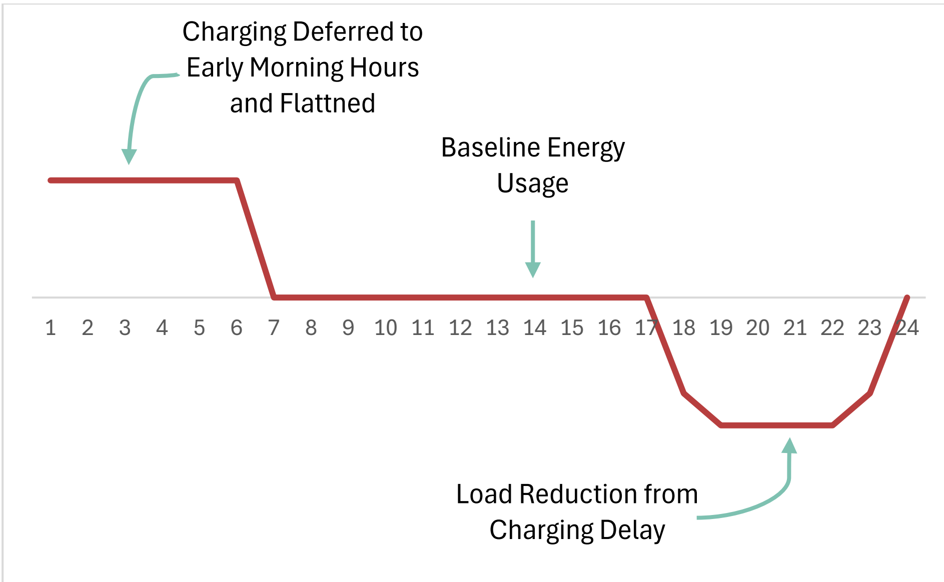
The active managed charging demand response product shifts EV charging times to off-peak hours through WiFi-enabled charger controls or vehicle telematics. The operating utility dispatches a signal to the charger or the vehicle telematics system to delay charging until a certain time in the evening. Under the active managed charging product, the utility provides incentives to the customer in exchange for the ability to shift their charging time. The operator of an active managed charging program can stagger the times in which charging returns for different vehicles or adjust the throttle level of the charger. This flattens and extends the return charging load, such that all the chargers do not begin charging simultaneously, avoiding creating a new local peak and potential subsequent transformer upgrade costs. It is also a more reliable and predictable form of load reduction because

[14] Deployment shapes for DR products that are only available in the summer such as Irrigation and AC Switch are set for summer deployment.
[15] See Technical Appendix F – Electricity Demand Forecast.

the utility has direct control rather than relying on the customer to change their behavior with price signals.

Figure I - 5 and subsequent figures in this section show the shape assumed for the DR product. They assume the baseline energy usage, load reduction, and any shift in load or bounce back resulting from the event.

Figure I - 5: Active Managed EV Charging – 24 Hour Demand Response Deployment Shape

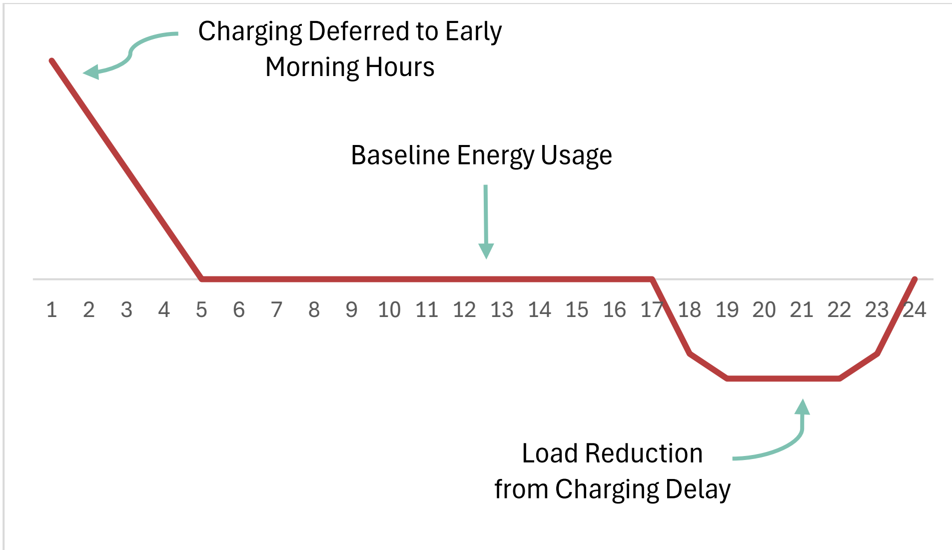


EV Time of Use

Time-varying rates targeted towards EV owners are designed to encourage drivers to shift charging to off-peak hours. The EV TOU product relies on participants to manually change their charging behavior, either through actively plugging the charger in when off peak rates begin or setting their charger to start charging at that time. Unlike the active managed charging demand response product, the utility does not have control or ability to stagger or flatten the returning charging load. The shape of the EV TOU product thus has a more pronounced immediate spike of returning load at the end of the demand response event times than the active managed charging product.

The EV TOU product relies on the customer's existing meter. TOU customers require advanced metering infrastructure (AMI) in order to participate, so eligibility for EV TOU was determined based on AMI saturation in each modeling zone. Residential and Commercial EV TOU products are separately modeled in this analysis, as the residential and commercial charging load forecasts are developed separately.

Figure I - 6: EV TOU – 24 Hour Demand Response Deployment Shape



Extra Tiers of EV Demand Response

Electric vehicle charging represents one of the largest sources of new load growth relative to the Council's previous plan. While a significant share of this load is expected to be subject to some form of managed charging in practice, the underlying load forecast assumes a fully unmanaged charging profile and therefore does not reflect the impacts of load flexibility. The purpose of this approach is to identify the cost-effective amount of charging for the region. To account for this disconnect, an additional tier of demand response potential was modeled for both active managed charging and EV time-of-use (TOU) programs, each assuming an incremental 20% increase in program participation. These additional tiers incorporate higher incentive levels – and corresponding values of lost service – to reflect the increased effort and cost required to achieve deeper levels of customer engagement and participation beyond the base program assumptions.

Table I - 10: EV Charging Demand Response Potential and Cost

Demand Response Product	2046 Achievable Potential (MW)	Net Levelized Cost ($/kw-year)
EVSE	802	$104
ResEVTOU	802	$28
ComEVTOU	863	-$5

Water Heating

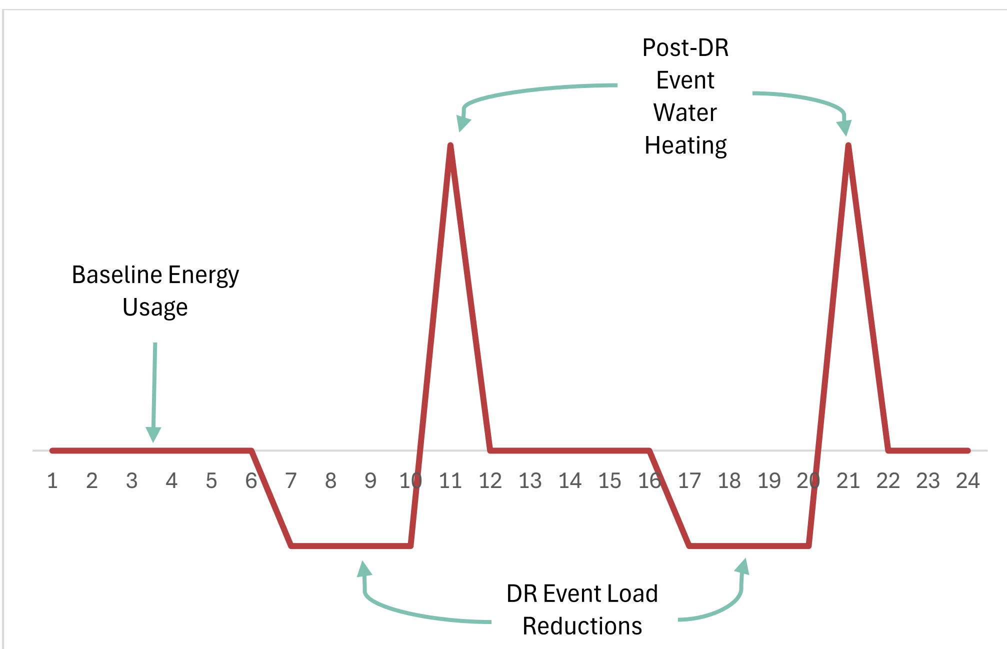
Electric tank water heaters can be readily integrated into demand response programs. Water heaters can use electricity to heat the water at times when the grid is less strained and energy is less expensive and then store the heat for hours until hot water is needed, acting as a thermal battery. This can be done by delaying the reheating of water during peak demand periods of scarce and expensive energy until the hot water in the tank gets below a certain level. It may also be done by preheating tank water in the hours leading up to peak periods, which allows the hot water to go longer before needing to be heated again. Water heating demand response products are assumed to be frequently deployable as they have been shown to have little to no effect on participant comfort. Water heaters are either able to ride out demand response events with the heated water in the tank or will automatically opt out of the event once there is insufficient hot water, which is reflected in event participation rates.

Electric Resistance Water Heating (ERWH)

Load Switch

Traditional water heater demand response programs in the region have relied on the installation of a load switch on the water heater. Under this demand response product, the water heater load is curtailed completely during the demand response event period unless the water falls below a certain temperature. The equipment cost for load switch water heating demand response is $300, reflecting the cost of the device and installation in line with the water heater. In Washington modeling zones, the equipment cost is $350 to reflect the state requirement that installation be performed by a licensed electrician.

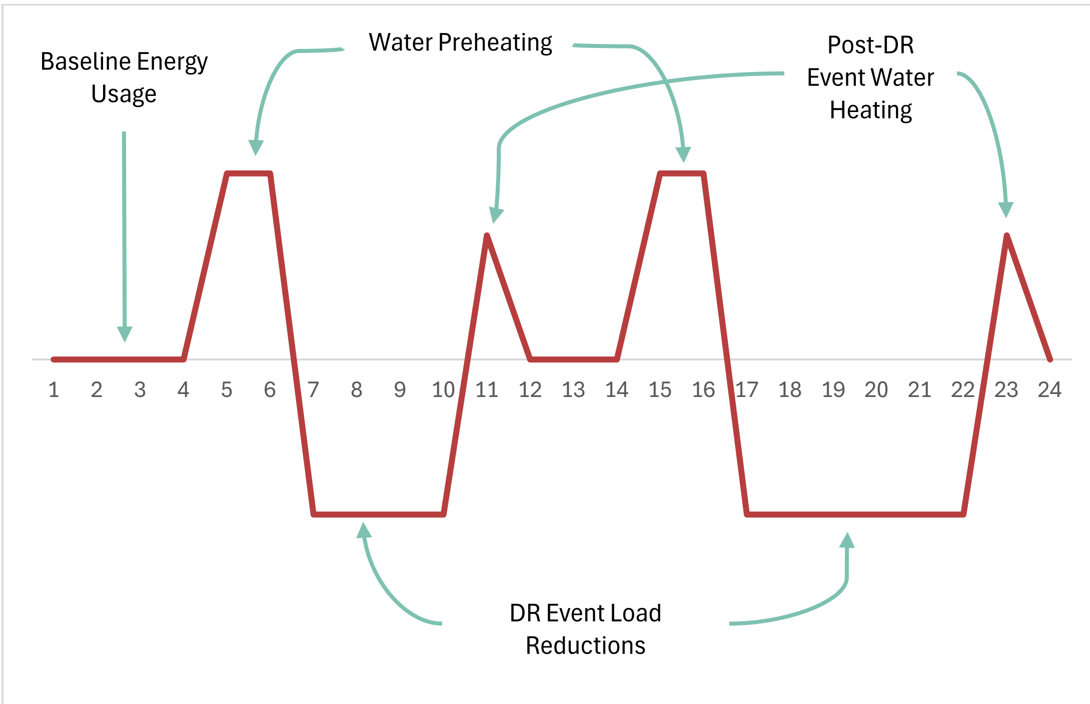
Figure I - 7: Load Switch Water Heating - 24 Hour Demand Response Deployment Shape



Grid-Connected

Technological advances have introduced a new method of interaction with water heaters. Grid interactive water heaters can have a communications module installed that gives demand response program operators more precise control over water heating loads. This can allow operators to preheat storage tanks in advance of demand response events, allowing the water heater to ride out longer periods of load reduction. This also distributes much of the shifted load away from the bounce back hour immediately after the demand response event. It also allows this product to serve up to six-hour demand response events. The equipment cost assumption for the grid-connected product is $110. While there is not yet significant market deployment of the universal communications modules required by this product, this assumption relies on estimates of bulk order costs for a well-developed demand response program.

Figure I - 8: Grid Connected Water Heating – 24 Hour Demand Response Deployment Shape



Heat Pump Water Heating (HPWH)

Heat pump water heaters are modeled separately due to their higher efficiency and smaller available load for shifting. Early study results have shown that HPWHs can provide approximately half of the peak load impact per water heater relative to ERWHs. Nearly all HPWHs are installed with grid-interactive capabilities, so no switch-based product was developed for this class of water heater.

Eligibility for ERWH and HPWH programs was determined using residential stock forecasts developed by the load forecast team using RBSA data.[16] The analysis assumed that all new water heaters in Washington and Oregon would be grid-enabled water heaters in alignment with regulation mandating that new water heaters in these states be built with this capability through a CTA-2045 standard port.

[16] See Technical Appendix F – Electricity Demand Forecast.

The overall deployment shape for heat pump water heating is the same as that for grid-connected water heating.

Table I - 11: Water Heating Demand Response Potential and Cost

Demand Response Product	2046 Achievable Potential (MW)	Net Levelized Cost ($/kw-year)
ERWH-Switch	73	$230
ERWH-GridConnected	434	$85
HPWH-GridConnected	19	$205

Space Heating and Cooling

Space heating and cooling systems are a significant contributor to peak demand and therefore a prime target for demand response programs. These demand response products reduce load by adjusting indoor temperature settings or cycling equipment operation during events. Because comfort is typically affected, all HVAC-related programs are modeled as limited deployment resources that can be deployed a finite number of times per season. Further, these programs can only be deployed for 3 hours, as evaluations have shown that opt-outs increase significantly after this time.

Load Switch

Load switch programs directly curtail central AC or heating load through a load control switch installed on a customer's air conditioning or heating unit. This can curtail load entirely or cycle the cooling or heating load on and off for increments of time. There is no capability to preheat or precool in advance of the demand response event windows so all increase in demand occurs after the demand response event. Figure I - 9 shows the evening peak that is addressed in summer by the AC Switch product while Figure I - 10 shows the morning and evening peaks that can be addressed in winter by the Heat Switch product.

Figure I - 9: AC Switch – 24 Hour Demand Response Deployment Shape

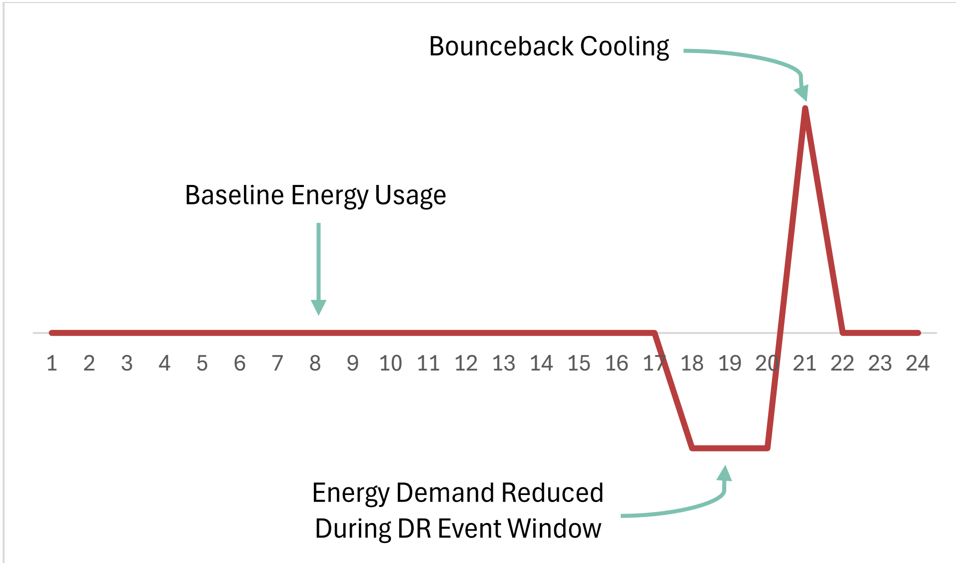
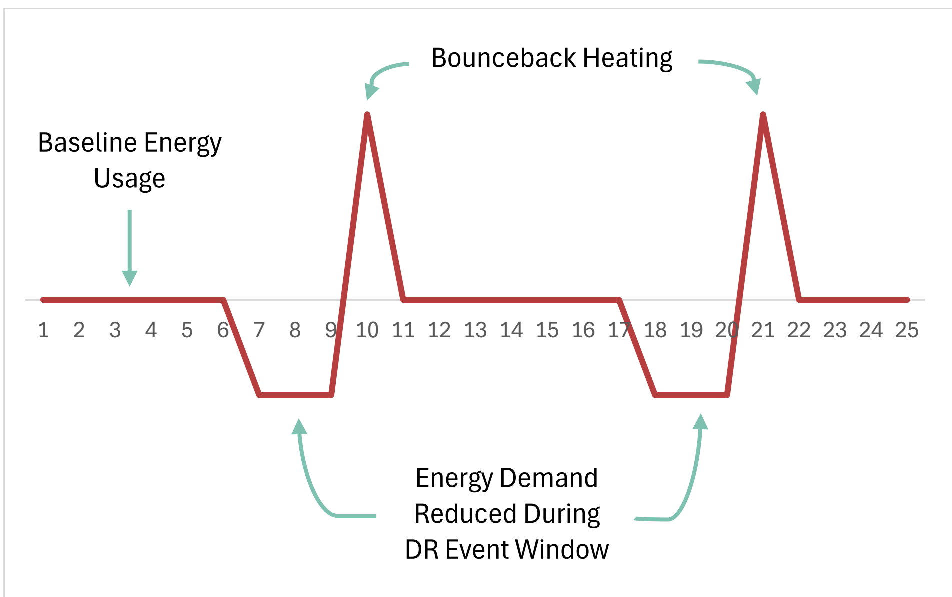


Figure I - 10: Heat Switch – 24 Hour Demand Response Deployment Shape



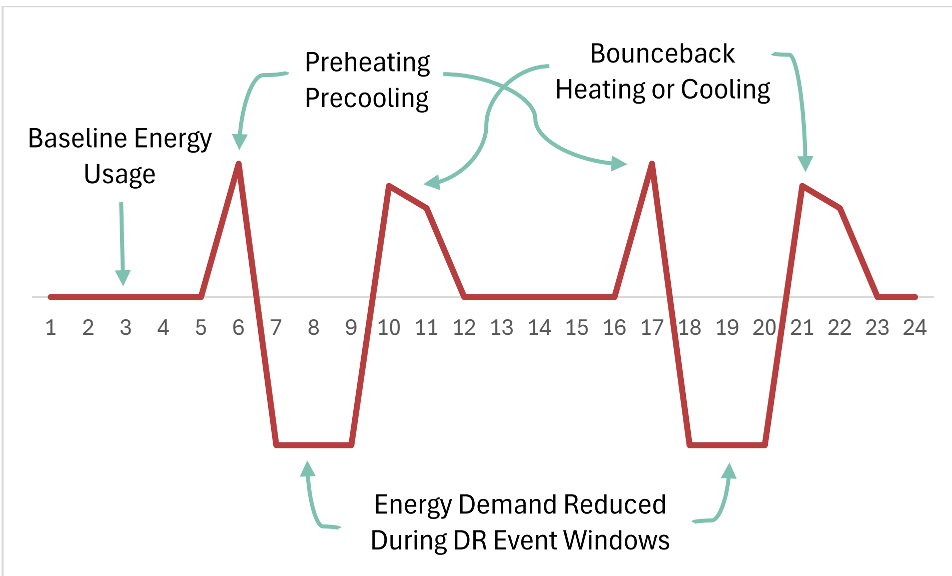
Smart Thermostat

Smart thermostat programs use WiFi-enabled thermostats to reduce load during demand response events. These programs automatically change the setpoint temperature on heating or cooling systems before a demand response event to preheat or precool in order to avoid loss of comfort. During the demand response event the thermostat is adjusted a few degrees to reduce heating and cooling energy demand. Residential and commercial smart thermostat products are modeled in the Ninth Plan.

- Bring Your Own Thermostat (BYOT): The BYOT product relies on existing smart thermostats that customers enroll in the program. Because the product relies on an existing smart thermostat there is no added equipment cost for the product.
- ResTstat: The ResTstat product assumes the procurement and installation of the smart thermostat by the utility and thus includes the $170 equipment cost of providing a smart thermostat to the customer to be used in the demand response program. This expands eligibility to all homes with central heating and cooling systems

Eligibility for space heating and cooling demand response products was determined through heating and cooling stock saturation forecasts developed from RBSA data.[17] Central electric heating and cooling equipment are eligible for these demand response products. Existing smart thermostat saturations to determine eligibility were taken from RBSA, and a modest annual growth rate of 3.6% was incorporated to model natural adoption. Eligibility for switch products and thermostat procurement are determined by the subset of customers with central electric heating or cooling that are outside of the start thermostat saturation.

Figure I - 11: Smart Thermostat – 24 Hour Demand Response Deployment Shape



[17] 2022 Residential Building Stock Assessment: https://neea.org/residential-building-stock-assessment.

Table I - 12: Space Heating and Cooling Demand Response Potential and Cost

Demand Response Product	2046 Achievable Potential (MW)	Net Levelized Cost ($/kw-year)
ResBYOT	98	$44
ResTstat	398	$54
ResACSwitch	96	$100
ResHeatSwitch	79	$48
ComACSwitchSm	14	$122
ComACSwitchMed	39	$26
ComHeatSwitchSm	15	$63
ComHeatSwitchMed	11	$33

Irrigation

Irrigation demand response curtails load from irrigation pumps during the summer months in response to a limited number of calls from the program operator. Customers can participate through automatic dispatch in which a shutoff signal is sent by the program operator or through manual dispatch where a customer manually shuts off their pumps when notified of a demand response event. The automatic dispatch option typically requires the installation of a load control switch on the irrigation pumps. The dispatch structure mirrors established irrigation programs in the region.[18] Groups of participants are given staggered dispatch times between 2 pm and 10 pm, with each group providing four hours of curtailment. It assumes that participants enroll 80 percent of their available irrigation load for curtailment, while peak coincidence is accounted for using the top-down evaluation method.

To reflect the differing costs and enrollment dynamics across the agricultural sector, two irrigation demand response products are modeled: one for large farms (more than 2,000 irrigated acres) and another for small to medium farms. USDA data from the 2024 Census of Agricultural Irrigation and Water Management Survey[19] for total acres irrigated and irrigated acres per farm was used to develop customer count for each product. The suitability of irrigation demand response varies significantly across the region due to factors such as dominant crop types, irrigation methods (e.g., well versus canal), and well depth, all of which influence both program and event participation. The Ninth Plan's increased geographic granularity allows these differences to be reflected to some extent, with each

[18] Idaho Power's Irrigation Peak Rewards program and Rocky Mountain Power's Irrigation Load Control Program helped guide the development of this DR product.
[19] 2024 Census of Agricultural Irrigation and Water Management Survey: https://www.nass.usda.gov/Publications/AgCensus/2022/Online_Resources/Farm_and_Ranch_Irrigation_Survey.

balancing authority's location east or west of the Cascades used as a distinguishing factor to adjust inputs where appropriate and illustrate regional variation.

Idaho Power has maintained an irrigation demand response program for over two decades. This program has been substantial and consistent enough that its impacts are likely being baked into the Council's irrigation load forecast. For this reason, 200 MW of capacity was removed from the Idaho Power zone's demand response potential.

Figure I - 12: Irrigation Control – 24 Hour Demand Response Deployment Shape

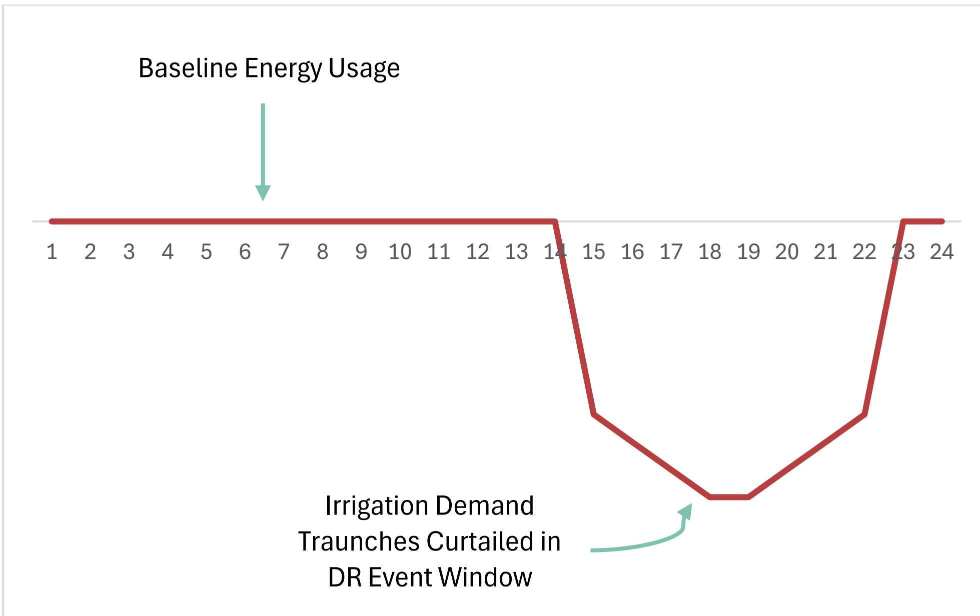


Table I - 13: Irrigation Demand Response Potential and Cost

Demand Response Product	2046 Achievable Potential (MW)	Net Levelized Cost ($/kw-year)
IrrigationSmMed	69	$44
IrrigationLg	143	$32

Batteries

Home battery storage provides a flexible means of reducing peak load by discharging stored energy during high-demand hours in the evening. Two battery demand response product configurations are modeled.

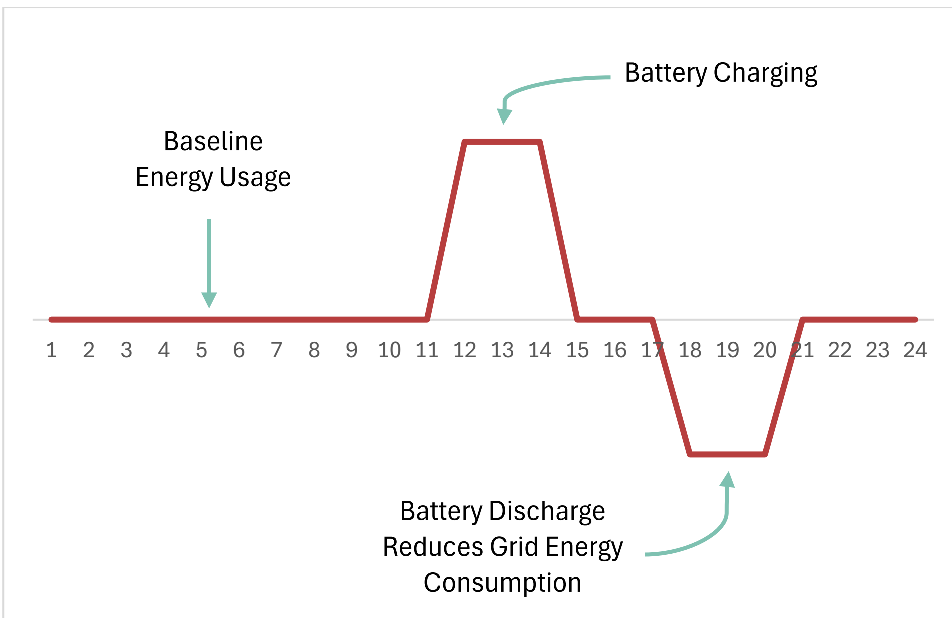
Bring Your Own Battery (BYO Battery)

The BYO Battery product assumes the customer already owns a battery system, often paired with rooftop solar, and enrolls it in a demand response program. The utility compensates participants for allowing controlled dispatch of their battery during peak events. Eligibility for BYO Battery is linked to the rooftop solar frozen forecast of adoption for the region (see Technical Appendix F – Electricity Demand Forecast). With the forecast in MW an average size of 7.2 kW[20] was used to calculate the number of solar installations. Five percent of forecasted solar installations are assumed to naturally adopt and attach a home battery system to be eligible for the BYO Battery product. It is assumed that 80% of the battery capacity is enrolled in the program for load shifting with an 85% roundtrip efficiency.

Battery+

Battery+ represents systems installed specifically for demand response purposes, where the program sponsor covers the equipment costs in exchange for direct operational control. The Battery+ demand response product uses the residential rooftop solar potential analysis (see Technical Appendix J – Rooftop Solar Methodology and Potential) to define eligibility. This assumes that all achievable rooftop solar units can have a battery attached and includes the cost of the battery procurement for the demand response product. The Battery+ product is designated as frequently deployable because the demand response operator has fronted the cost of the battery storage system in exchange for being allowed to use it consistently to load shift.

Figure I - 13: Battery Storage – 24 Hour Demand Response Deployment Shape



[20] Based on NREL's 2022 Annual Technology Baseline industry median sizing for a residential PV system

Table I - 14: Battery Demand Response Potential and Cost

Demand Response Product	2046 Achievable Potential (MW)	Net Levelized Cost ($/kw-year)
BYO Battery	27	$36
Battery+	452	$278

C&I Demand Curtailment

Demand curtailment targets large commercial and industrial (C&I) customers who can temporarily reduce operations or shift processes in response to dispatch calls. Programs may combine manual actions, automated controls, or behavioral adjustments, depending on facility capability.

Eligible participants for this product have monthly average demand exceeding 150 kW and receive incentives for verifiable reductions during events. This product type provides short-duration capacity during the most constrained system hours and is treated as a limited-deployment resource.

Figure I - 14: C&I Demand Curtailment - 24 Hour Demand Response Deployment Shapes

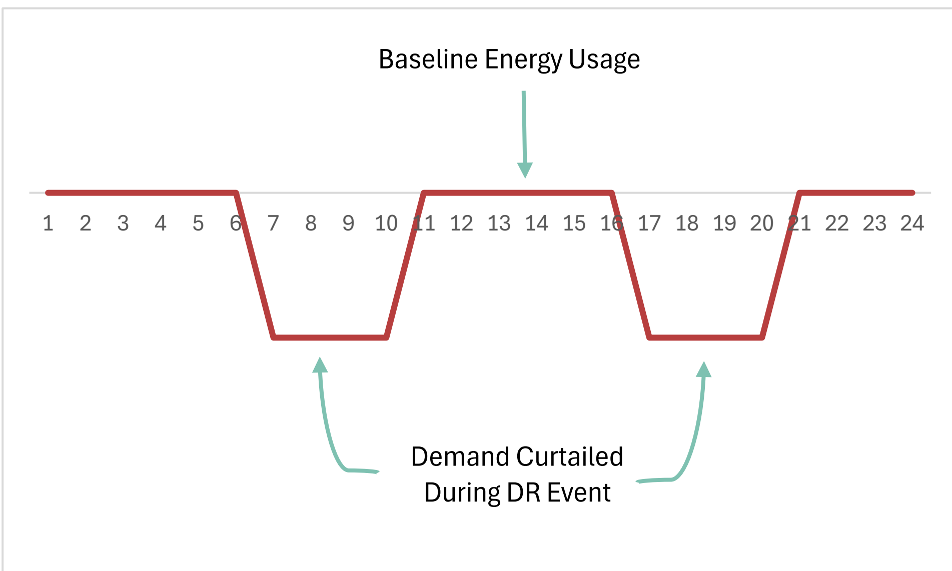


Table I - 15: Demand Curtailment Demand Response Potential and Cost

Demand Response Product	2046 Achievable Potential (MW)	Net Levelized Cost ($/kw-year)
ComCurtail	89	$38
IndCurtail	112	$33

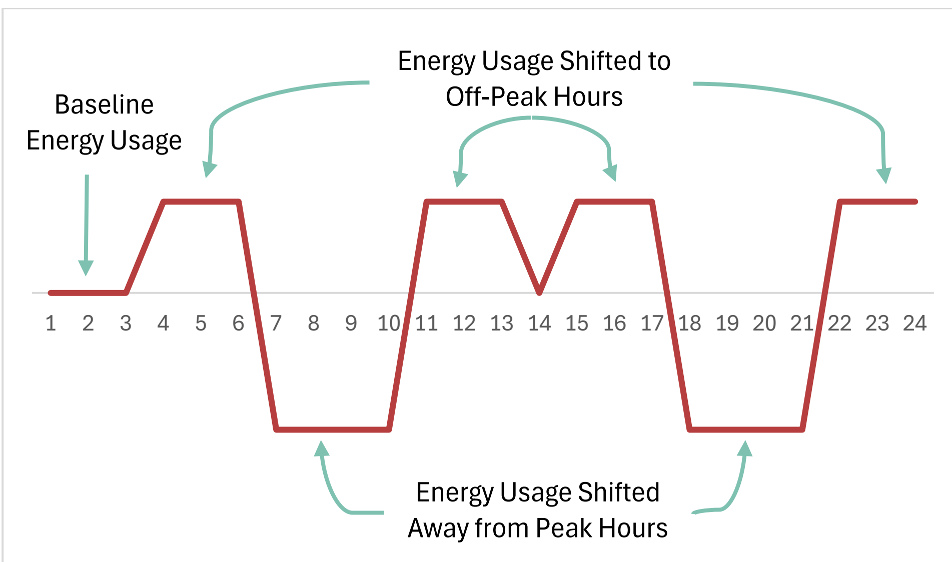
Price-Based Demand Response

Price-based demand response relies on dynamic rate structures that encourage customers to modify usage based on electricity prices. These products influence multiple end uses simultaneously and are evaluated using the top-down method. Eligibility for all price-based demand response products is based on advanced metering infrastructure (AMI) saturations available in EIA Form 861 data[21] and plans for AMI deployment by zone.

Time-of-Use

Time of Use (TOU) is a rate structure where electricity rates are set lower during off-peak hours and higher during peak hours to encourage customers to shift their energy usage to preferrable time periods. There are no events called, and the rate structure remains the same. The TOU product is assumed to be opt-in, meaning that customers voluntarily elect to participate in this rate structure. Opt-out TOU rates, in which customers are automatically enrolled in the rate structure, do exist elsewhere in the country, but are not currently common in the region. The opt-in structure generally has less potential program participation than an opt-out. Peak hours align with peak targets for direct load control demand response products, set for four hours in the AM and PM in the summer and four hours in the AM in the Winter. The reduced load during these hours is assumed to be shifted to the three hours immediately before and after the on-peak hours.

Figure I - 15: Time of Use – 24 Hour Demand Response Deployment Shape



[21] Energy Information Administration Annual Electric Power Industry Report, Form EIA-861 detailed data files: https://www.eia.gov/electricity/data/eia861.

Table I - 16: Time of Use Demand Response Potential and Cost

Demand Response Product	2046 Achievable Potential (MW)	Net Levelized Cost ($/kw-year)
ResTOU	194	$33

Critical Peak Pricing

Critical Peak Pricing (CPP) is a rate structure that is designed to encourage reduced energy consumption during periods of high wholesale market prices or system contingencies. CPP typically offers a slightly discounted energy rate year-round in exchange for setting higher rates during a limited number of “critical peak” events to discourage energy usage during those times. These critical peak rates are typically significantly higher than peak rates one might see on a TOU rate, and thus have a higher level of load impact. However, CPP dispatch is assumed to be limited. CPP potential is modeled for residential, commercial, and industrial customers in separate demand response products

Figure I - 16: Critical Peak Pricing - 24 Hour Demand Response Deployment Shape

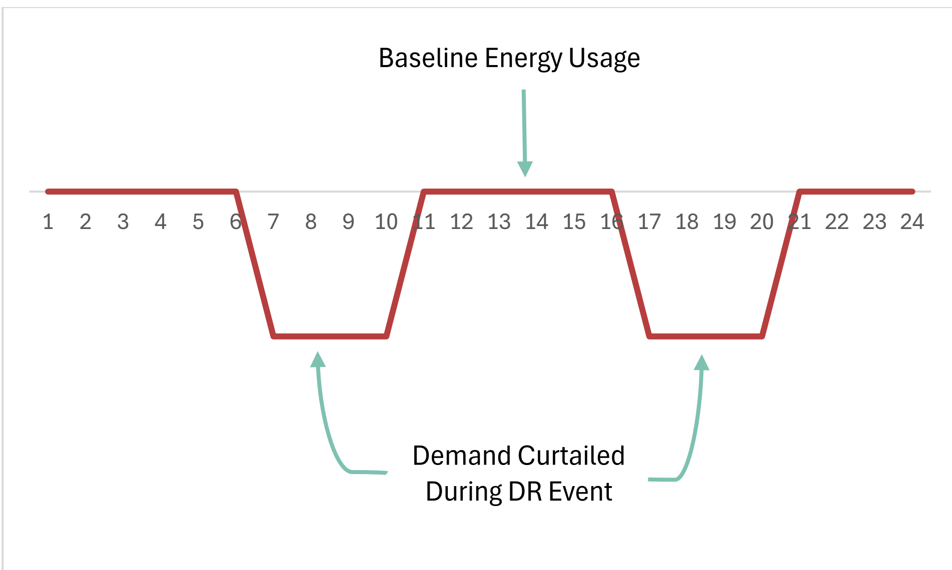


Table I - 17: Critical Peak Pricing Demand Response Potential and Cost

Demand Response Product	2046 Achievable Potential (MW)	Net Levelized Cost ($/kw-year)
ResCPP	102	$62
ComCPP	37	$58
IndCPP	22	$94

Demand Voltage Regulation

Many utilities can reduce the voltage on their primary distribution circuits but still be within the acceptable range defined by the American National Standards Institute.[22] This voltage reduction has minimal impact on the end-use customer and results in lower losses, thus saving energy. This could be done on a permanent basis (conservation voltage reduction, or CVR) or during short-duration events (demand voltage regulation, or DVR). DVR lowers the system operating voltage during the forecast peak window, thus reducing the energy delivered, which results in lower demand. DVR can be used daily to reduce energy use in periods of peak load and high prices but avoid reducing load when prices are low. DVR is currently being implemented by a number of regional utilities, namely Avista, PGE, Idaho Power, and PacifiCorp. For the modeling zones that align with these utilities it is assumed that there is no DVR potential available.

Figure I - 17: Demand Voltage Regulation – 24 Hour Demand Response Deployment Shape

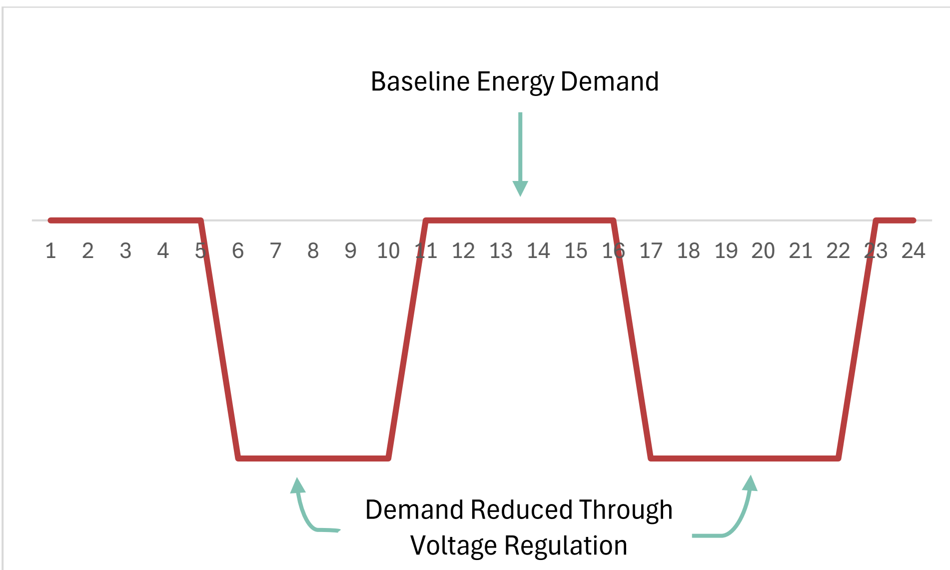


Table I - 18: Demand Voltage Regulation Demand Response Potential and Cost

Demand Response Product	2046 Achievable Potential (MW)	Net Levelized Cost ($/kw-year)
DVR	322	$-6

[22] ANSI C84.1-2020 sets nominal voltage ratings and operating tolerances for 60 Hz electric power systems: https://blog.ansi.org/ansi/ansi-c84-1-2020-electric-voltage-ratings-60-hz.

Demand Response Technologies Considered but Not Modeled

Data Center Load Flexibility

Data centers represent a rapidly growing and increasingly significant load class within the electric system, driven by continued expansion in cloud computing, artificial intelligence, and digital services. As electricity demand from data centers grows, so does interest in their potential to provide demand flexibility during periods of system stress or elevated energy prices. Several pathways exist through which data center loads can be adjusted or managed in response to grid conditions, though these capabilities vary widely by facility design, workload type, and operational constraints.

One source of flexibility comes from workload management. Certain computing tasks – particularly machine learning model training, batch processing, and other non-time-sensitive workloads – can accommodate delays or temporary curtailment, allowing energy consumption to be shifted away from peak periods. In addition, many data centers maintain on-site generation and storage assets, typically in the form of diesel backup generators or battery systems installed for reliability purposes. In some cases, these resources can be used strategically to reduce grid demand during peak hours, effectively providing load relief without interrupting service. Data centers may also provide flexibility through geographic load shifting, whereby workloads are dynamically reallocated across facilities in different regions in response to local grid conditions. This approach has been demonstrated in practice, including a pilot conducted by Google in partnership with North Wasco PUD in Oregon, which showed the feasibility of using demand response signals to shift data center load geographically.[23]

Despite this potential, data centers are not explicitly modeled as a demand response resource in this analysis. There is currently insufficient publicly available data on the cost, duration, reliability, and scalability of data center flexibility to support robust modeling assumptions. Participation is highly dependent on site-specific configurations, contractual arrangements, and operational priorities, and existing examples remain limited in scope. Nevertheless, data centers represent an important emerging opportunity for future demand-side flexibility and warrant continued monitoring as technologies, market structures, and operational practices mature.

Vehicle to Grid

Vehicle-to-Grid (V2G) services represent a potentially significant future demand response and grid-support resource, enabling bidirectional power flow between electric vehicles (EVs) and the grid. Under a V2G framework, aggregated EV batteries can provide peak load reduction, load shifting, ancillary services, and resilience benefits by discharging stored energy during periods of system stress and recharging during off-peak hours. However, despite its technical feasibility, V2G remains at

[23] https://cloud.google.com/blog/products/infrastructure/using-demand-response-to-reduce-data-center-power-consumption.

an early stage of commercial deployment in most regions, with limited large-scale operational experience.

V2G is not explicitly modeled in this analysis due to several unresolved implementation and market barriers. These include low penetration of V2G-enabled vehicles and chargers, lack of standardized interconnection and compensation frameworks, uncertain customer participation and behavioral response, and concerns around battery degradation and warranty impacts. In addition, most existing EV programs focus on unidirectional managed charging, which provides more predictable and lower-cost load shifting benefits without requiring bidirectional hardware or complex control systems. While V2G may become a meaningful demand response resource in the longer term – particularly for fleet-based applications such as school buses, delivery vehicles, or municipal fleets – it is excluded from the current modeling due to its limited near-term scalability, uncertain cost-effectiveness, and absence of established market structures to support reliable dispatch.

Modeling Demand Response Supply Curves

Binning and Preparation for OptGen

To model demand response in the Council's capital expansion model (OptGen), it is necessary to aggregate or bin demand response products together to represent larger resource options for the model to select. In prior power plans, the sole criteria used to bin demand response was cost – products within the same levelized cost "bin" were aggregated together.

For the Ninth Plan, the additional granularity offered by the OptGen model, both in terms of sub-regional modeling zones and hourly modeling capabilities, allows additional factors to bin demand response for modeling. The ultimate bundling strategy for the Ninth Plan utilizes three factors to aggregate demand response products: modeling zone, levelized cost, and deployment capabilities. There are seventeen modeling zones, six levelized cost bins, and two deployment types.

Table I - 19: Demand Response Modeling Bins

Modeling Zone Bin	Levelized Cost Bin	Deployment Type Bin
AVA	< $20	Frequent
BPA_IDMT	> $20 - $50	Limited
BPA_OR	> $50 - $80	
BPA_WA	> $80 - $110	
CCPUD	> $110 - $140	
DCPUD	> $150	
GCPUD		
IPCO		
NWMT		

Modeling Zone Bin	Levelized Cost Bin	Deployment Type Bin
PACE		
PACW		
PGE		
PSE_Central		
PSE_North		
PSE_Olympia		
SCL		
TPWER		

Figure I - 18 and Figure I - 19 show the regional demand response potential, by levelized cost bin, for frequent deployment and limited deployment demand response products, respectively.

Figure I - 18: Frequent Deployment Demand Response Supply Curve by Levelized Cost Bin

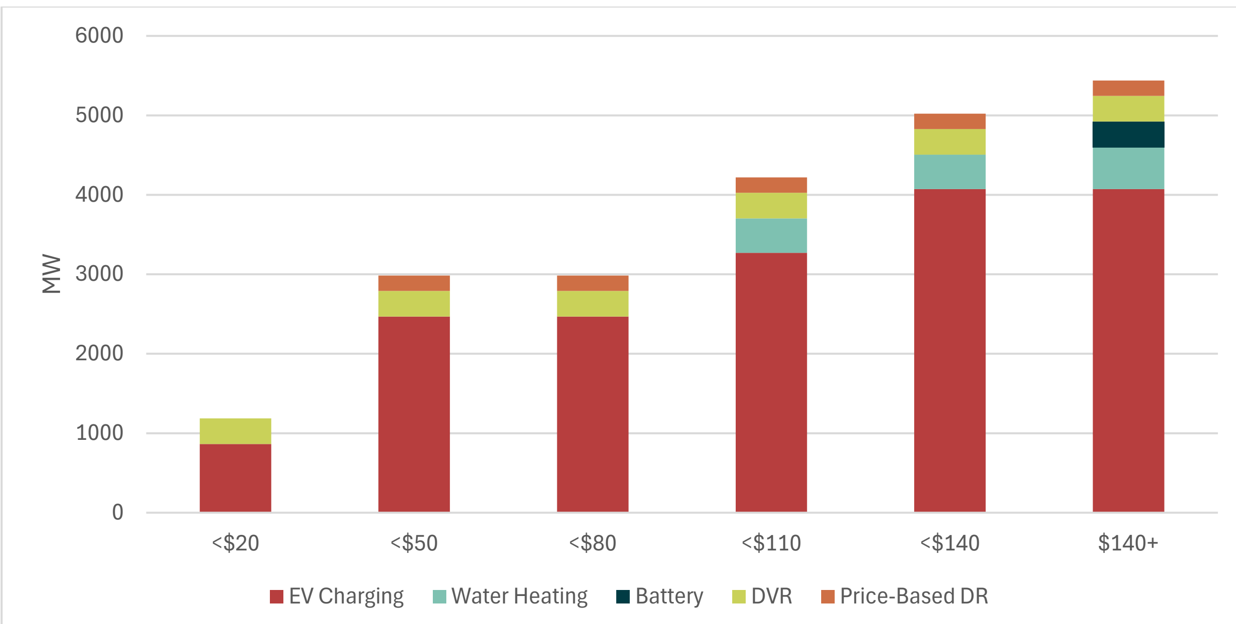
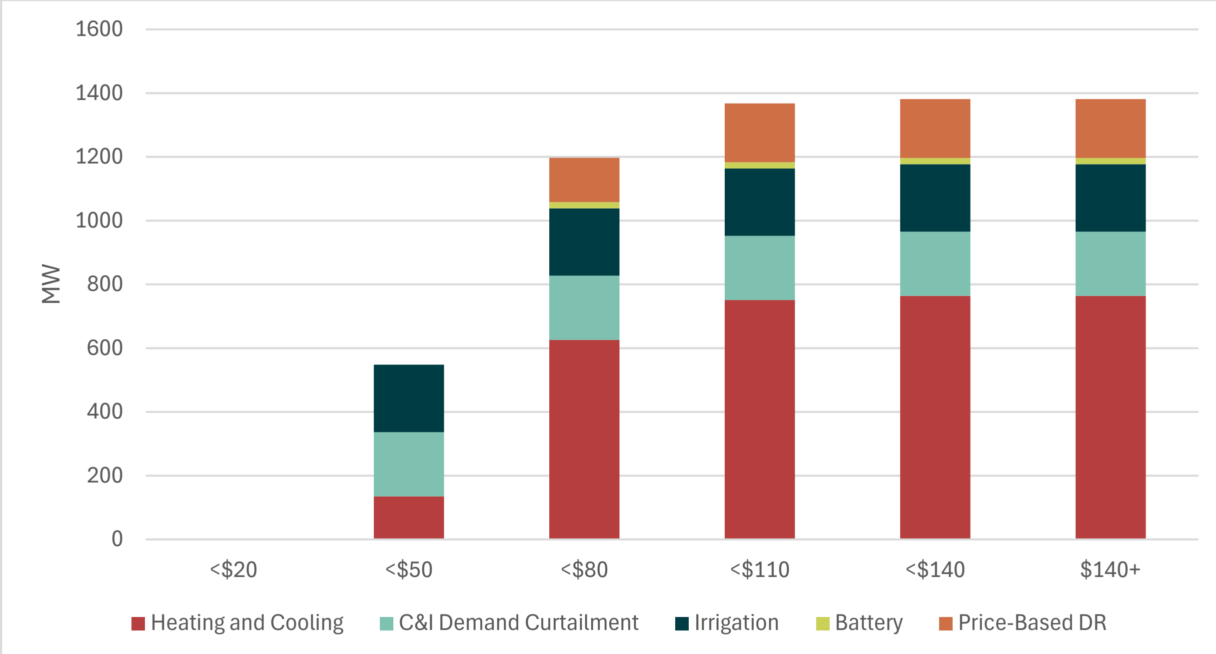


Figure I - 19: Limited Deployment Demand Response Supply Curve by Levelized Cost Bin



Demand Response Interaction with Energy Efficiency

Demand response and energy efficiency are part of a larger suite of activities that utilities use to call upon their end-use customers to modify their demand (collectively referred to as demand side management). Both demand response and energy efficiency rely upon end-use equipment and thus there is overlap between the potential of each. The interaction may be complementary or reductive, meaning that installing efficiency measures may increase or decrease the availability of demand response. This is reflected in the modeling for the Ninth Plan through residential water heating. Since demand response potential for ERWHs and HPWHs is developed through separate demand response products, a change in the water heating equipment saturations would naturally affect total potential available for each. Adoption of the ~450 aMW of residential HPWHs in an energy efficiency program would significantly increase the HPWH equipment saturation, while also lowering the ERWH equipment saturation.[24] Given the relatively low-cost nature of the efficiency measure (~$60/MWh), water heating equipment saturations that reflect the adoption of the HPWH efficiency potential were used to develop the water heating demand response potential that was ultimately modeled. This results in the reduction of 290 MW of ERWH demand response and the addition of 195 MW of HPWH demand response as electric resistance transitions to heat pump.

[24] Technical Appendix H – Conservation Methodology and Potential has more details on the conservation supply curve development for water heating and other products.

Adjusting for Load Futures and Scenarios

There is ultimately not a single set of demand response supply curves for the Ninth Plan, but rather many variations, depending on the load future and analysis scenario being run in the model. Load futures and scenarios are similar in that they can both have changing assumptions that alter the shape, magnitude, and/or costs of the demand response supply curves; however, they are different in that all load futures are present in every scenario, but scenarios are distinct from one another.

Table I - 20 summarizes the adjustments made to the demand response supply curves, depending on the specific load future and scenario. As the table highlights, there are two main drivers of change for the supply curves, depending on the load future and scenario, and they are: the presence of high building electrification and whether there is any assumed delay in demand response availability.

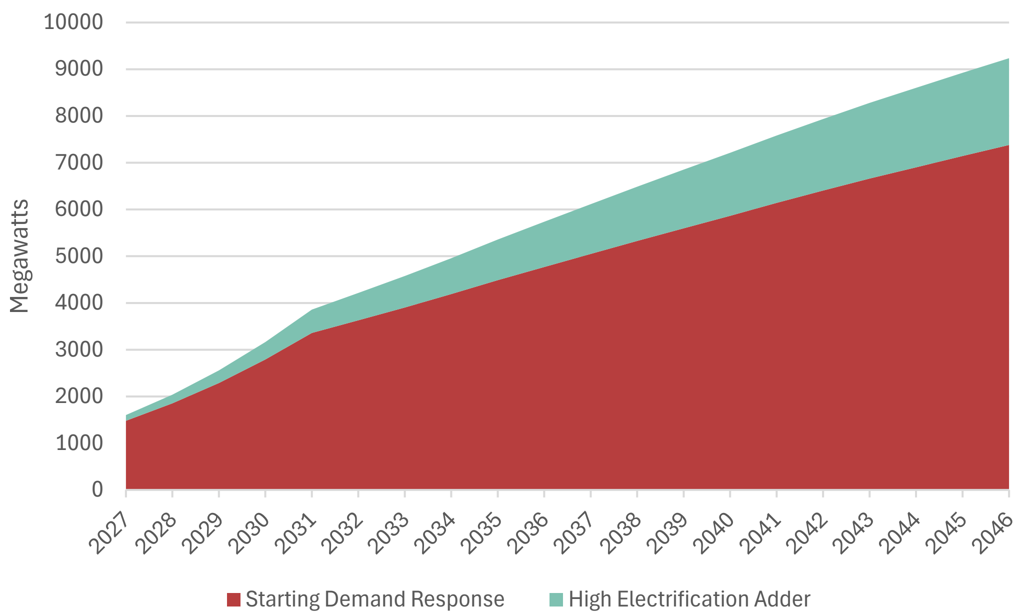
Table I - 20: Adjustments to Demand Response Supply Curves

Analysis Sensitivities	High Electrification	DR Availability Delayed	Storage Availability Delayed
Changing Hydro Operations	No	No	No
	Yes	No	No
Constrained World	No	No	No
	Yes	No	No
Evolving Federal Landscape	No	No	No
	Yes	No	No
Emerging Tech Uncertainty	No	No	No
	Yes	No	No
	No	No	No
	Yes	No	No
Transmission Availability Uncertainty, Short-Duration Storage Limitations	No	No	Yes
	Yes	No	Yes
Demand Side Resource Limitations	No	Yes	No
	Yes	Yes	No

The first driver, "High Electrification", is a function of the load futures, and therefore, its effect shows up in every scenario and sensitivity tested. For context, the load futures contain a wide range of potential future load trajectories, and most relevant for demand response, some of these trajectories have lower (status quo) building electrification and some contain significantly higher electrification (see Technical Appendix F – Electricity Demand Forecast). As more loads are electrified, there is more demand response potential relative to the current practice baseline; therefore, load futures with higher building electrification will have higher available demand response. Note that higher electrification loads are only assumed for water heating and space heating end uses in Oregon and

Washington.[25] Figure I - 20 shows the incremental demand response available due to building and vehicle electrification every year over the 20-year horizon from 2027 to 2046.

Figure I - 20: Demand Response Achievable Potential with Electrification

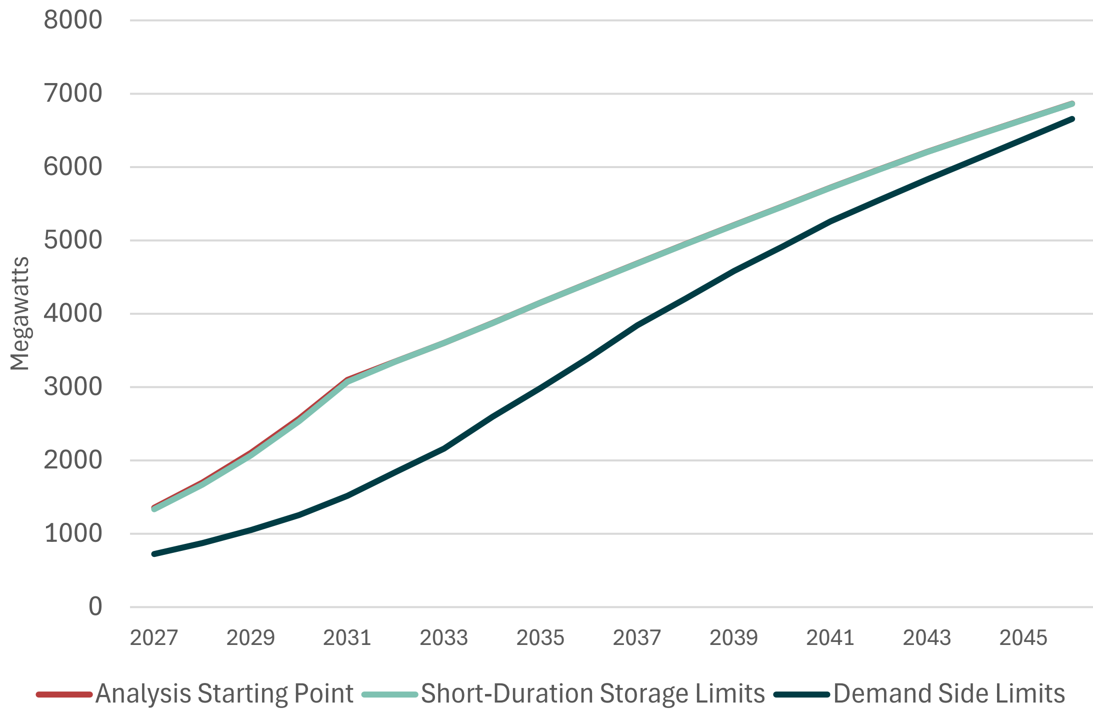


The remaining two drivers shown Table I - 20, relating to delayed storage availability and delayed demand response availability, are all a function of the sensitivity, and therefore their effects are isolated to each individual sensitivity.[26] The sensitivity is designed to examine how demand response, and other demand and supply side resources, may be selected differently depending on several different important factors. The sensitivity impacting demand response examines the availability of the resource with limitations introduced to short-duration storage availability and demand side resource availability. For short duration storage limitations, demand response products that use battery storage technology are limited in availability for the first six years of the study. For demand side limitations, all demand response products are limited in availability using slower ramp rates throughout the study that align with the ramp rates used for conservation in this scenario. Figure I - 21 shows the difference in annual achievable potential available in the analysis starting point versus the Demand Side Resource Limitations and Short-Duration Storage Limitations sensitivities.

[25] Consistent with the Ninth Plan load forecast.

[26] See Technical Appendix N – Scenario Modeling and Results.

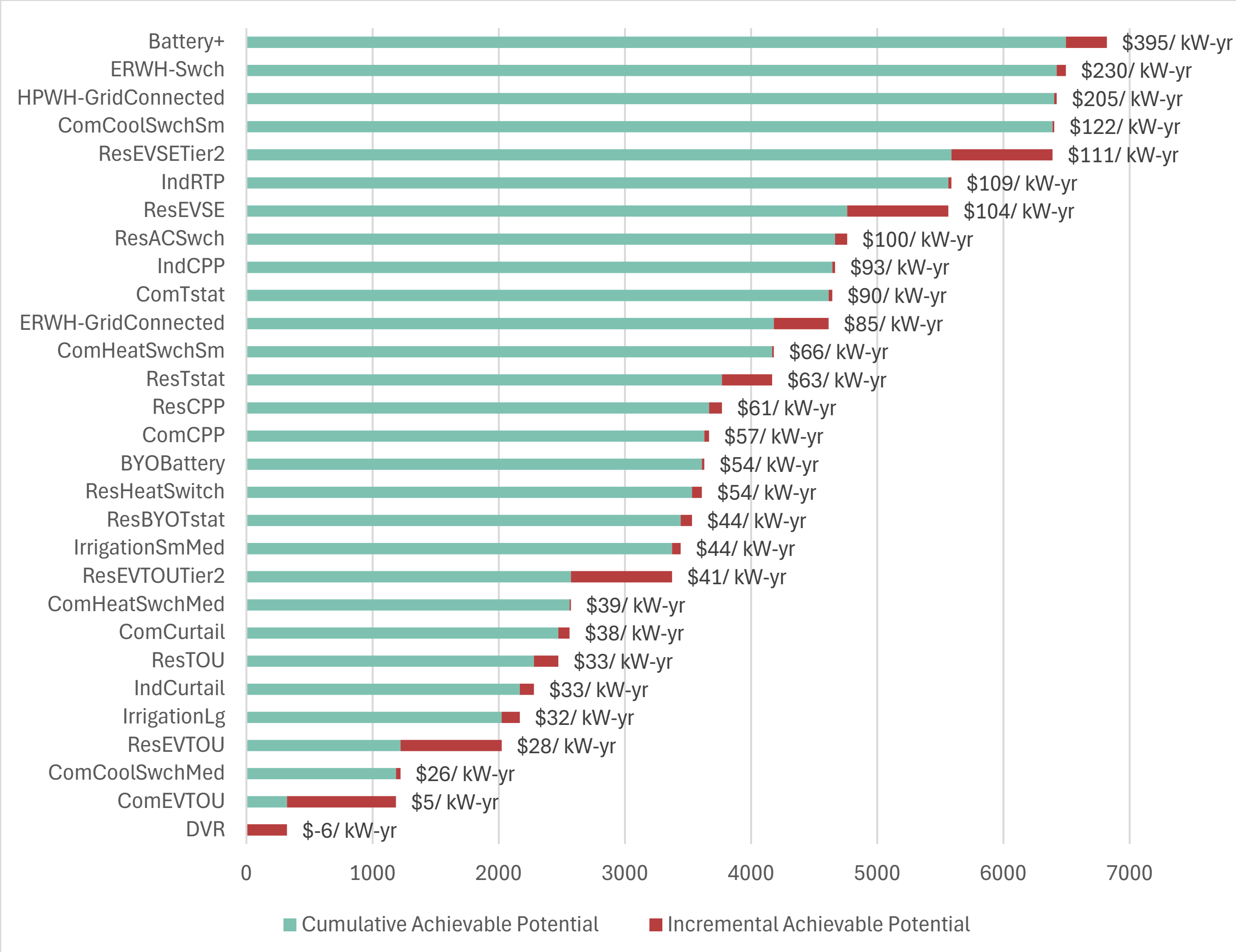
Figure I - 21: Annual Demand Response Achievable Potential Compared to Limited Availability Sensitivities



Total Demand Response Potential

All the work described thus far in this appendix results in a final technical achievable demand response resource that is used to compete against other demand and supply side resources in the Council's capital expansion model. The final demand response resource can be illustrated by a supply curve, which shows the cumulative demand response potential available up to a given price point, in this case the net levelized cost. Figure I - 22 shows the final Ninth Plan technical achievable demand response supply curve, by sector, over the 20-yr period from 2027 to 2046. Figure I - 23 and Figure I - 24 show the summer and winter supply curves respectively. Each levelized cost bin is cumulative and includes all the potential from lower cost bins.

1 **Figure I - 22: 2046 Achievable Demand Response Potential with Net Levelized Cost - Combined**



2

Figure I - 23: 2046 Achievable Demand Response Potential with Net Levelized Cost - Summer

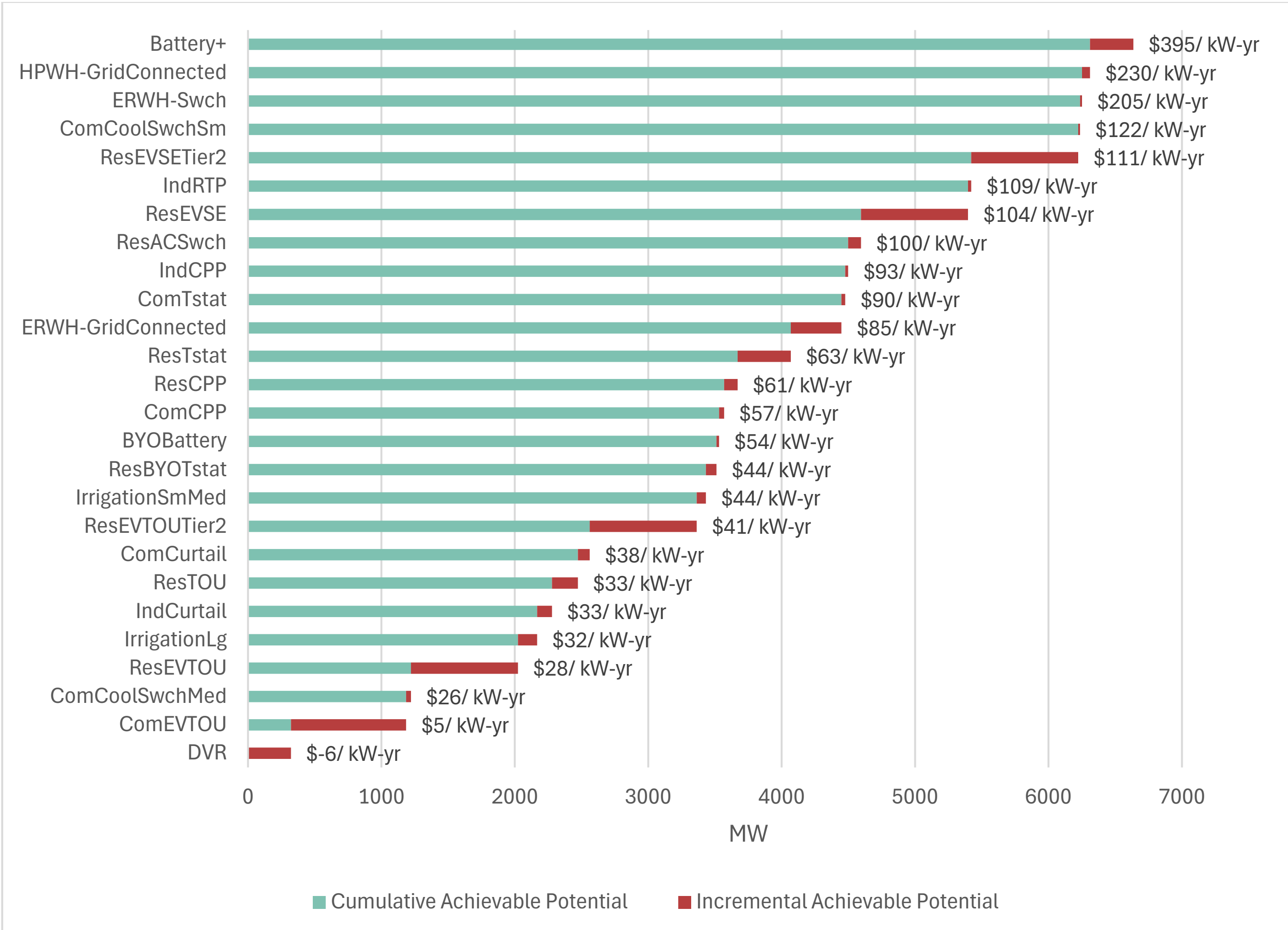
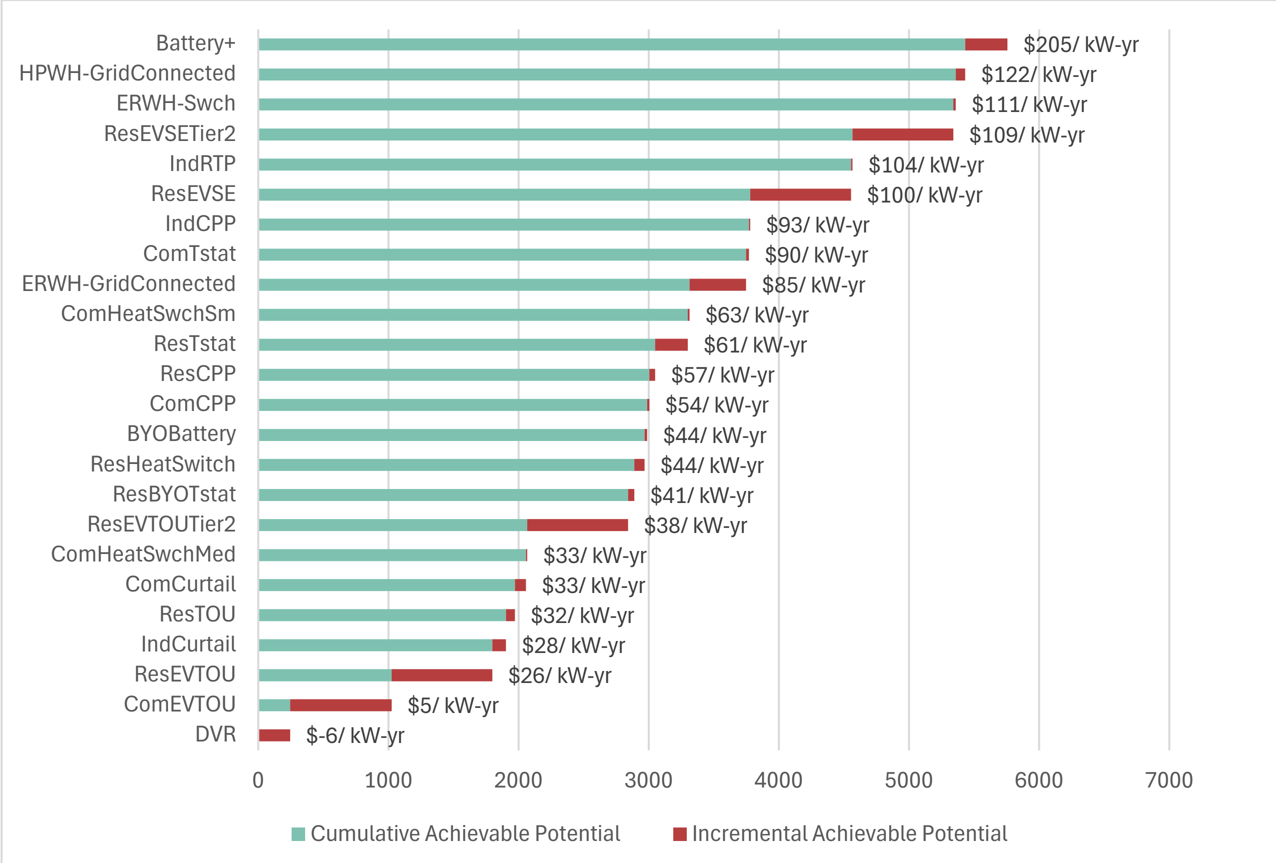


Figure I - 24: 2046 Achievable Demand Response Potential with Net Levelized Cost - Winter



Excel Workbooks and Tools

Ninth Plan demand response supply curves and the supporting workbooks can be found on the Council's Ninth Plan Technical Elements page[27] as well as directly in the 9thPlanDRSupplyCurves folder.[28]

Input Assumptions

All input assumptions reside within the Inputs folder.[29] All demand response product inputs reside within the DR_Database workbook.[30] This workbook contains the cost, impact, and deployment assumptions for all demand response products for the Ninth Power Plan, as well as much of the contextual data informing eligibility such as customer, stock, and load forecasts. Each demand

[27] https://www.nwcouncil.org/energy/ninthpowerplan/technical-elements.
[28] https://nwcouncil.box.com/v/ninthplanDRsupplycurves.
[29] Ibid. See "Inputs" folder.
[30] Ibid. See "DR_Database" workbook.

response product has specific assumptions for each of the 17 regional zones being modeled, roughly aligning with the region's balancing authorities. Inputs are pulled from this database to iterate through combinations of season, modelling zone, and impact and cost assumptions for all demand response products considered in order to develop total potential and net levelized costs. Descriptions of each demand response product and the different input parameters are listed here as well. Global input assumptions are located in the Inputs_Global_All workbook[31]. This includes the economic and system global inputs as well as the sector and end use shares used to disaggregate the load forecast and develop customer counts.

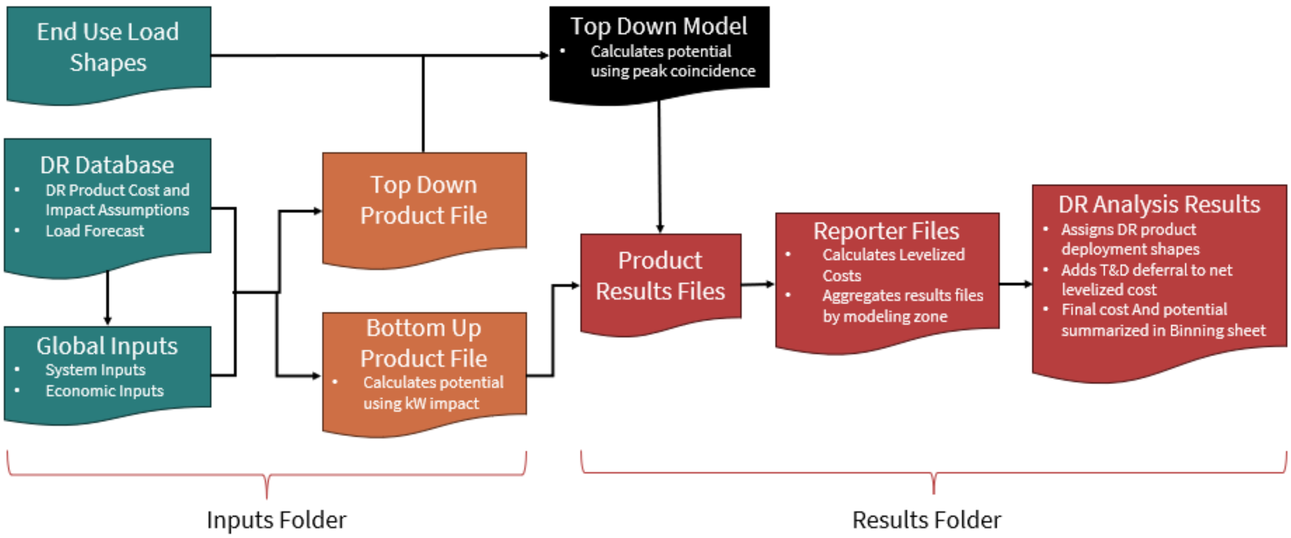
Modeling Steps

A number of workbooks are used to conduct the analysis developing achievable demand response potential. The analysis workflow and file and folder structure is summarized in Figure I - 25. The DRProductTopDown and DRProductBottomUp workbooks contain the template for how achievable potential is calculated for each iteration of demand response product, zone, and season for the bottom up and top down methodologies. In the ProductScenarioTemplate sheet of the DRProductBottomUp workbook, for example, dropdowns in the Region, Product Name, and Scenario Name cells allow the user to select different combinations that will then pull data from the demand response Database into the worksheet. The underlying formulas then calculate achievable potential for the plan years in columns DZ:FE. The Top Down methodology works somewhat differently, using the TopDownModel workbook to integrate the load forecast in the Global Inputs file, the end use load shape files, and inputs pulled into the DRProductTopDown file. VBA macros for both these DRProduct workbooks iterate through each combination of demand response product, modelling zone, and season, and export results files to the Results folder.[32] Each modelling zone has its own results folder, with a results file for each demand response product-season combination.

Levelized cost is calculated and potential aggregated using the Reporter_summer and Reporter_winter workbooks. VBA modules for both these workbooks create Reporter files for each of the 17 zones that are exported to the Results folder. Levelized cost figures as well as 20-year achievable potential are summarized in the Portfolio Summary sheets of these workbooks. The Reporter results files are aggregated using an R script and input into the Combined Data sheet of the DRAnalysisResults workbook.[33] This workbook assigns deployment shapes to each demand response product and incorporates T&D deferral credit into net levelized cost. Supply curves for each modeling zone can be viewed by toggling the Zone dropdown. Potential and cost are summarized in this appendix for the entire region with levelized costs developed as a weighted average of the costs for each zone.

[31] See "Inputs_Global_All" in the Inputs folder here: https://nwcouncil.box.com/v/ninthplanDRsupplycurves.
[32] See "Results" folder: https://nwcouncil.box.com/v/ninthplanDRsupplycurves.
[33] Ibid. See "DRAnalysisResults" workbook.

Figure I - 25: Supply Curve Analysis Workflow and File Structure



Where to Find More Information

For more information on these supply curve materials, please visit the Council's Ninth Plan website,[34] which contains a number of presentations, videos, and supporting materials for this work. You can also visit the Council's Demand Response Advisory Committee website,[35] which also contains presentations and discussions that helped guide and shape this work.

[34] https://www.nwcouncil.org/energy/ninthpowerplan.
[35] https://www.nwcouncil.org/energy/energy-advisory-committees/demand-response-advisory-committee.