PREPARED BY EES CONSULTING

Benton County Public Utility District

Demand Response Potential Assessment

November 9, 2021

EES Consulting
a GDS Associates Company

EES Consulting
a GDS Associates Company

Amber Gschwend, Managing Director
Amber.gschwend@gdsassociates.com

November 9, 2021

Mr. Chris Johnson
Benton PUD
P.O. Box 6270
2721 W. 10th Avenue
Kennewick, WA 99336

SUBJECT: 2021 Demand Response Potential Assessment – Final Report

Dear Mr. Johnson:

Please find attached the final report summarizing the 2021 Benton Public Utility District Demand Response Potential Assessment (DRPA). This report covers the 10-year time period from 2022 through 2031.

This study was developed based on the demand response models developed by the Northwest Power and Conservation Council. The results show that demand response resources continue to be relatively expensive compared with supply-side alternatives. This finding is supported by the 2021 Power Plan initial modeling which found that, in some scenarios, larger generator resources were preferred over disaggregated DR and energy efficiency. Given the District's summer peak, irrigation demand response may be a cost-effective option if irrigation customers are able to reschedule pumping loads.

Very truly yours,

A Gschwend

Managing Director, EES Consulting

Contents

1 Executive Summary

This assessment evaluates demand response (DR) resources applicable to Benton Public Utility District's service area (District). The study evaluates resources available over the 10 -year period 2022-2031. This analysis has been conducted in a manner consistent with requirements set forth in the Washington Clean Energy Transformation Act (CETA) and is part of the District's compliance documentation. The results and guidance presented in this report will also assist the District in strategic planning for its future demand response programs. Finally, the resulting demand response supply curves can be used in the District's Integrated Resource Plan (IRP).

Demand response (DR) is a strategy designed to decrease load on the grid during times of peak use. It involves modifying the way customers use energy – particularly when they use it. For instance, businesses might work with a utility to voluntarily adjust their operations during a specified period of time. Residential customers might automate their usage with smart thermostats or water heaters. Demand response programs use incentives to obtain program participants and to ultimately reduce the cost of power supply and also to reduce the carbon footprint of customer usage patterns.

1.1 DR PRODUCTS

DR product data was taken directly from the DR modeling used by the Northwest Power and Conservation Council's DR modeling. There was a total of 23 products evaluated. Each product provides demand reduction potential in either summer, winter, or both. Table 1-1 below summarizes the products analyzed in this study.

TABLE 1-1: DR PRODUCTS

				Seasonality	
Type	Category	Product Description	Product ID	Summer	Winter
Firm/ Controlled	Demand Curtailment	Large Farm Irrigation Demand Curtailment	NRIrrLg	■	
		Small & Medium Farm Irrigation Demand Curtailment	NRIrrSmMed	■	
		Industrial Demand Curtailment	NRCurtailInd	■	■
		Large Commercial Demand Curtailment	NRCurtailCom	■	■
	Space Cooling	Medium Commercial Space Cooling - Switch	NRCoolSwchMed	■	
		Small Commercial Space Cooling - Switch	NRCoolSwchSm	■	
		Residential Space Cooling - Switch	ResACSwch	■	
	Space Heating	Medium Commercial Space Heating - Switch	NRHeatSwchMed		■
		Small Commercial Space Heating - Switch	NRHeatSwchSm		■
		Residential Space Heating - Switch	ResHeatSwitch		■
	Bring Your Own Thermostat	Small Commercial Bring Your Own Thermostat	NRTstatSm	■	■
		Residential Bring Your Own Thermostat	ResBYOT	■	■
	Water Heating	Residential Electric Resistance Water Heating - Switch	ResERWHDLCSwch	■	■
		Residential Electric Resistance Water Heating - Grid-Ready	ResERWHDLCGrd	■	■
		Residential Heat Pump Water Heating - Switch	ResHPWHDLCSwch	■	■
		Residential Heat Pump Water Heating - Grid-Ready	ResHPWHDLCGrd	■	■
	Electric Vehicle	Residential Electric Vehicle Supply Equipment	ResEVSEDLCSwch	■	■
	Utility System	Demand Voltage Regulation	DVR	■	■
Non-Firm/ Price Based	Rates	Industrial Critical Peak Pricing	IndCPP	■	■
		Industrial Real Time Pricing	IndRTP	■	■
		Commercial Critical Peak Pricing	ComCPP	■	■
		Residential Time-of-use Pricing	ResTOU	■	■
		Residential Critical Peak Pricing	ResCPP	■	■

1.2 METHODOLOGY

This study evaluates each of the DR products individually. The data was developed by the Northwest Power and Conservation Council (Council) in preparation for the 2021 Power Plan. Specific characteristics of the District's service area are applied to produce potential results specific to the District's service area. Key inputs include hourly system load shape, consumption by sector (residential, commercial, industrial, irrigation), number of homes, and appliance saturations (heat pump water heaters, electric resistance water heaters etc.).

1.3 RESULTS

The technical and achievable potential is summarized in the supply curves below in Figures 1-1 and 1-2 for summer and winter products.

FIGURE 1-1: 10-YEAR ACHIEVEABLE POTENTIAL LEVELIZED COST SUPPLY CURVE - SUMMER

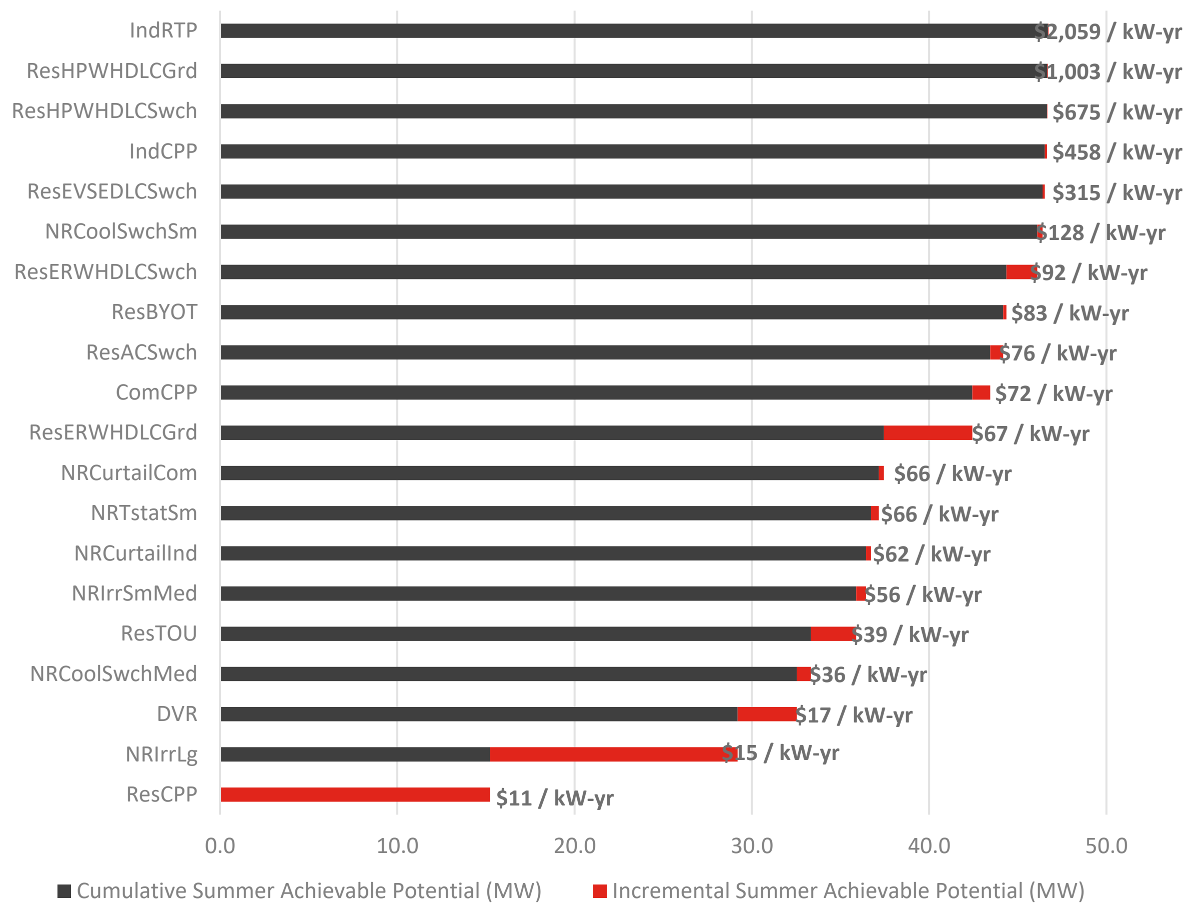
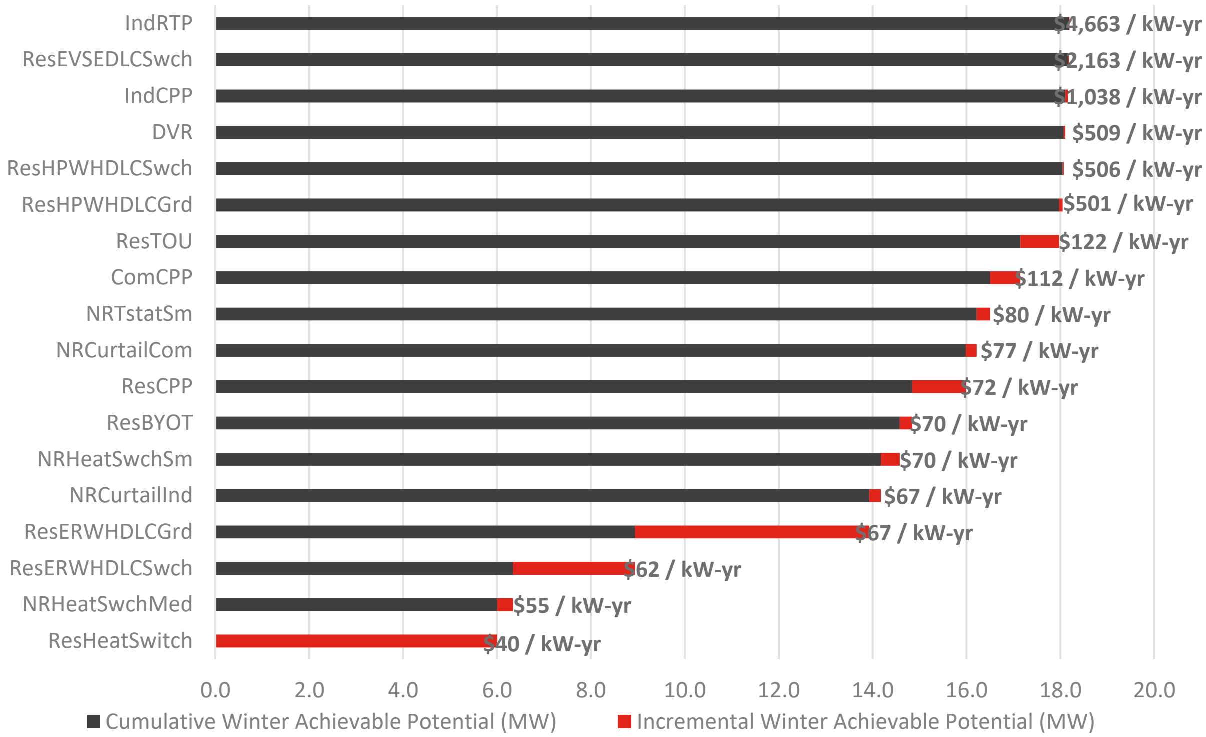


FIGURE 1-2: 10-YEAR ACHIEVEABLE POTENTIAL LEVELIZED COST SUPPLY CURVE - WINTER



1.3.1 Cost Screening

In addition to the supply curves, this analysis also provides a cost screening analysis using the District's avoided cost for capacity. Avoided capacity costs considered by season included generation, transmission investment deferral and distribution system investment deferrals. The 10-year levelized cost of capacity is $55.42 and $46.56/kW-year for summer and winter resources respectively. The value of the DR resources will in part be based on how well the District is able to utilize the resource and reduce peak demand in each month. If only the highest peak is avoided per season the levelized avoided cost decreases to $23.29 and $19.22/kW-year for summer and winter respectively.

Table 1-2 shows the estimated summer demand response potential where the avoided cost is below $55.42/kW-mo. Demand voltage regulation may have some double counting across the other products. Based on the results, irrigation and rate programs for residential customers could offer significant summer demand peak reduction potential. Economic peak demand reduction potential totals approximately 35.9 MW or 8.6% of the District's recent historic peak summer demand of 419 MW (July 2018).

TABLE 1-2: 10-YEAR COST-EFFECTIVE SUMMER DEMAND RESPONSE POTENTIAL

DR Product	Cost-Effective MW	Levelized Cost
ResCPP	15.2	$11/ kW-yr
NRIrrLg	14.0	$15/ kW-yr
DVR	3.3	$17/ kW-yr
NRCoolSwchMed	0.8	$36/ kW-yr
ResTOU	2.6	$39/ kW-yr
Total	**35.9**	

Table 1-3 shows the estimated winter demand response potential where the avoided cost is below $46.56/kW-mo. Only residential heating switches are cost effective. However, Residential CPP and TOU pricing could provide cost-effective demand reduction if the program is evaluated by bundling summer and winter costs and benefits. Residential TOU or CPP rates could add an additional 0.8 or 1.1 aMW of demand reduction potential respectively. Economic peak demand reduction potential totals approximately 6.0 MW or 2.1% of the District's recent historic peak winter demand of 284 MW (February 2018).

TABLE 1-3: 10-YEAR COST-EFFECTIVE WINTER DEMAND RESPONSE POTENTIAL

DR Product	Cost-Effective MW	Levelized Cost
ResHeatSwitch	6.0	$40/ kW-yr
Bundled Programs Winter Peak Reduction Potential		
ResCPP	1.1	$72/kW-yr
ResTOU	0.8	$122/kW-yr

1.4 SUMMARY

The above analysis provides a starting point for DR product potential and program considerations for the District. Because the many DR product assumption inputs were taken directly from the Council's modeling, the results warrant further analysis before programs can be implemented. Specifically, the District has identified several potential barriers to program implementation and savings achievement:

- Irrigation control products assume that, with incentives, irrigation peak demand can be reduced. However, regardless of the incentives, irrigators may not be able to reduce pumping loads at the time of the District's peak and risk losing crops to temperatures regularly above 100 degrees.

- Costs for direct load control equipment may be underestimated. Equipment failures may lead to increased claims against the District for damaged customer-owned equipment such as heating, cooling equipment and water heaters.

- Rate design options require additional considerations beyond what is provided in the base Council assessment. The cost differential and time of use periods for TOU and CPP rates will directly impact how willing customers are to shift their energy usage away from peak periods. Additionally, there are rate impacts to consider such as:

- If rate design changes are made at the same time as an overall rate increase, the rate design adjustment would need to be a very small change in order to mitigate rate shock to certain customers. Typically, utilities phase in rate structure changes over a period of years.

- Best practices for TOU rates include cost mitigation measures. These can vary depending on how aggressively utilities switch rate structures and the ability for consumers to shift usage within the rate structure design. These mitigation measures may include one or several of the following:

    - Opt-in TOU programs. Consumers participate by opting in but can also opt out at any time. Potentially low participation or high-opt out rates if bills increase significantly.

    - Bill protection. 12 months of bill protection is offered for default TOU rates. Bill protection decreases the incentive to shift usage.

    - Exclude Low Income. Low income customers may need to remain on a flat or tiered rate because their ability to shift usage patterns may be more limited.

As the region evaluates future capacity needs in an increasingly renewable power system, DR resources may be able to help mitigate the cost of higher-cost peaking resources such as battery storage. This assessment provides a starting point for the District to evaluate DR potential and it provides the input needed for future IRP portfolio modeling.

2 Introduction

The objective of this report is to describe the results of the Benton Public Utility District (District) 2021 Electric Demand Response Potential Assessment (DRPA). This assessment provides estimates of peak demand reduction potential by sector for the period 2022 to 2031. This analysis has been conducted in a manner consistent with requirements set forth in the Washington Clean Energy Transformation Act (CETA) and is part of the District's compliance documentation. The results and guidance presented in this report will also assist the District in strategic planning for its demand-side programs in the near future. Finally, the resulting demand response supply curves can be used in the District's Integrated Resource Plan (IRP).

Demand response (DR) is a strategy designed to decrease load on the grid during times of peak use. It involves modifying the way customers use energy – particularly when they use it. For instance, businesses might work with a utility to voluntarily adjust their operations during a specified period of time. Residential customers might automate their usage with smart thermostats or water heaters. Demand response programs may use incentives to attract program participants. The ultimate goal of demand response programs is to reduce the power supply cost and carbon footprint.

Demand response programs are voluntary, and once enrolled, customers usually receive notifications in advance of forecasted peak usage times. Depending on the program, this might mean, for example, that a customer's smart thermostat automatically warms their home or building earlier than usual, with no action required from the customer to initiate this reduction in load, and the customer could choose to opt out of the event. The demand response (DR) products used in this analysis are based on the products that were included in the Northwest Power and Conservation Council's draft 2021 Power Plan.

The District serves customers in Benton County where electric usage peaks during summer months due to the hot climate. As a summer peaking utility, the District is specifically interested in summer peak demand reduction measures; however, both summer and winter peaking DR products are evaluated in this study. The District does not currently offer demand response programs. This document is a starting point for program implementation as it highlights the programs that can both be cost-effective and provide a measurable reduction in peak demand.

2.1 DRPA METHODOLOGY

This section provides a broad overview of the methodology used to develop the District's DR potential. Specific assumptions and the methodology pertaining to compliance with CETA are provided in the Appendix of this report. The general approach is as follows:

1. Identify the DR products.
2. Estimate technical potential based on the utility's service area characteristics and apply achievability assumptions to produce achievable potential estimates.
3. Calculate levelized costs for each product to develop a supply curve.
4. Determine cost-effective potential by comparing supply curve costs with the District's avoided costs.

2.1.1 Types of Demand Response

Two types of DR programs are analyzed in the analysis:

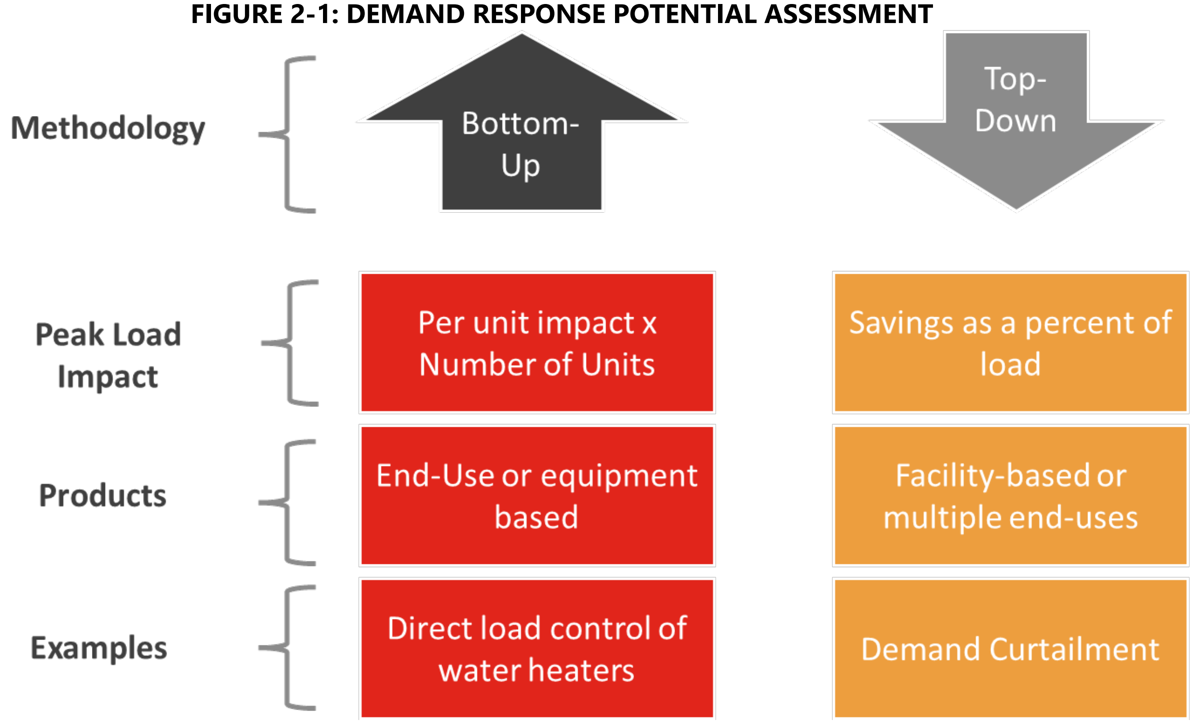
1. Firm/Controlled – these measures allow for either interruptions of electrical equipment or appliances that are directly controlled by the utility or are scheduled in advanced.
2. Non-firm/Price Based – These types of measures are outside of the utility's direct control and are driven by pricing signals.

Measures from both types of DR categories are analyzed in this study.

2.1.2 Modeling Methodology

This study uses both a top down and bottom-up approach to modeling demand response potential. Figure 2-1 illustrates how these methodologies are applied to analyze DR programs.

FIGURE 2-1: DEMAND RESPONSE POTENTIAL ASSESSMENT



2.2 CUSTOMER CHARACTERISTIC DATA

Assessment of customer characteristics includes estimating the number of locations where a measure could be feasibly installed as well as the share—or saturation—of measures that have already been installed. For this analysis, the characterization of the District's baseline was determined using data provided by the District and the District's 2021 Conservation Potential Assessment. Details of data sources and assumptions are described for each sector later in the report.

2.3 DR PRODUCT DATA

DR product data was taken directly from the Council's DR modeling and the DR product input assumptions are summarized within Appendix D. Each product provides demand reduction potential in either summer, winter, or both. Table 2-1 below summarizes the 23 products analyzed in this study.

TABLE 2-1: DR PRODUCTS

Type	Category	Product Description	Product ID	Seasonality Summer	Seasonality Winter
Firm/ Controlled	Demand Curtailment	Large Farm Irrigation Demand Curtailment	NRIrrLg	↓	
		Small & Medium Farm Irrigation Demand Curtailment	NRIrrSmMed	↓	
		Industrial Demand Curtailment	NRCurtailInd	↓	↓
		Large Commercial Demand Curtailment	NRCurtailCom	↓	↓
	Space Cooling	Medium Commercial Space Cooling - Switch	NRCoolSwchMed	↑	
		Small Commercial Space Cooling - Switch	NRCoolSwchSm	↑	
		Residential Space Cooling - Switch	ResACSwch	↑	
	Space Heating	Medium Commercial Space Heating - Switch	NRHeatSwchMed		↑
		Small Commercial Space Heating - Switch	NRHeatSwchSm		↑
		Residential Space Heating - Switch	ResHeatSwitch		↑
	Bring Your Own Thermostat	Small Commercial Bring Your Own Thermostat	NRTstatSm	↑	↑
		Residential Bring Your Own Thermostat	ResBYOT	↑	↑
	Water Heating	Residential Electric Resistance Water Heating - Switch	ResERWHDLCSwch	↑	↑
		Residential Electric Resistance Water Heating - Grid-Ready	ResERWHDLCGrd	↑	↑
		Residential Heat Pump Water Heating - Switch	ResHPWHDLCSwch	↑	↑
		Residential Heat Pump Water Heating - Grid-Ready	ResHPWHDLCGrd	↑	↑
	Electric Vehicle	Residential Electric Vehicle Supply Equipment	ResEVSEDLCSwch	↑	↑
	Utility System	Demand Voltage Regulation	DVR	↓	↓
Non-Firm/ Price Based	Rates	Industrial Critical Peak Pricing	IndCPP	↓	↓
		Industrial Real Time Pricing	IndRTP	↓	↓
		Commercial Critical Peak Pricing	ComCPP	↓	↓
		Residential Time-of-use Pricing	ResTOU	↓	↓
		Residential Critical Peak Pricing	ResCPP	↓	↓

Modeling	Seasonality Summer	Seasonality Winter
Top-Down	↓	↓
Bottom-Up	↑	↑

2.3.1 Firm/Controlled DR Products

Residential and non-residential DR products include direct load control (DLC) involving utility installation of two-way communicating load control switches on the customer's space heating, space cooling, or water heating equipment so that the appliances can be cycled during peaking events. DLC products also included grid ready enabled water heaters, programmable communicating smart thermostats and electric vehicle supply equipment, which all avoid the need for utility installed switches.

Non-residential DR products include demand curtailment products, where the customer is paid a fixed, monthly amount, per kilowatt of pledged curtailable load (a set percentage of a customer's monthly average load). Customers receive payments to remain ready for curtailment, even though actual curtailment requests may not occur. Customers may curtail any of their end-use loads to meet the curtailment agreement. These products represent a firm resource because it assumes that customers would be penalized for noncompliance. Participating customers control their own curtailment after the utility calls the event, except for Small & Medium Farm Irrigation Demand Curtailment, which relies on utility DLC.

2.3.2 Non-Firm/Price Based DR Products

Pricing products are exclusive of each other in that a customer would participate (opt-in or opt-out) in one tariff option. Each option is described below.

Time of Use – rates vary by time of day typically with higher priced periods during times with higher marginal cost of energy and capacity (on-peak). TOU periods can be designed at any length and may vary by season. Best practices indicate shorter super-peak periods with high rates to allow customers to adjust their consumption away form a shorter window to avoid higher rates. On-peak or shoulder periods and off-peak periods are priced relative to the super on-peak period. TOU rates are commonly used for residential and small commercial customers to mitigate reliability impacts during weather events and to reduce overall power costs.

Critical Peak Pricing – Pricing is adjusted during peaking events and customers are notified so that they can adjust their consumption. Generally, there are limitations to the number and duration of events each month or season. CPP tariffs are more common for non-residential customers.

Real Time Pricing – Hourly pricing is generally provided a day in advance based on day-ahead market conditions. RTP is generally used for large consumers only.

2.4 LEVELIZED COSTS

The levelized cost of energy for DR products is expressed in annualized cost of demand response divided by achievable kW load reduction. This assessment calculates the levelized costs for DR based on a total resource cost (TRC) perspective which includes all quantifiable costs and benefits regardless to whom they occur. The costs include set-up, program operation and maintenance, equipment costs, marketing, incentives, and transmission and distribution deferral costs. The various DR product costs are described below.

- **Set-Up Costs.** The cost includes the expenses incurred by the District to develop the DR program prior to program implementation.
- **Operation and Maintenance.** Some DR products require ongoing O&M costs to ensure the resource is available year after year. These expenses include administration, event dispatching, customer engagement, infrastructure maintenance, customer management, program evaluation, and recruitment of new loads.
- **Equipment Cost.** Equipment costs include labor, material, and communication costs needed to enable demand response technology for each participant. The cost applies only to each year's new participation. Once a participant enrolls, ongoing equipment costs are assumed to be $0.
- **Marketing Cost.** Expenses include program costs incurred to recruit program participation.
- **Incentive.** Cost includes incentive offered annually or on a one-time basis for program participation. This study assumes a certain level of incentive but does not designate how that incentive is delivered such as through fixed monthly or seasonal bill credits, based on load reduction. The incentive is used only to estimate the program costs to the utility and is not used in the cost-effectiveness evaluation.

2.4.1 DR Product Cost Assumptions

The cost for DR products is an important input for developing the supply curve. Specifically, program costs, O&M, equipment, and program costs are taken from the 2021 Power Plan supporting files. The products are evaluated as if the District were to design, implement, and maintain its own DR program for each product type. In the future, there may be regional programs operated by the Bonneville Power Administration, similar to how energy efficiency programs are operated now. However, this initial study assumes that the District would need to completely manage any DR programs individually.

A list of products and their assumptions are provided in Appendix D.

2.4.2 Discount and Finance Rate

In order to calculate the levelized cost of DR products, a discount rate is applied to future costs. The Council develops a real discount rate for each of its Power Plans. In preparation for the 2021 Power Plan, the Council proposed using a discount rate of 3.75%. This discount rate was used in this study to levelized DR product costs over the product or program life of 10 years. The discount rate is used to convert future costs and benefits into present values. The present values are then used to compare net benefits across measures that realize costs and benefits at different times and over different useful lives.

2.5 MODELING ASSUMPTIONS

The DR model requires input for seasonal definitions and number and duration of events. This analysis defined summer as the months of June, July, and August. Winter is defined as December, January, and February. For each season, a maximum of 5 events lasting 4 hours each (20 hours maximum) is assumed to occur during the season's highest peaking hours.

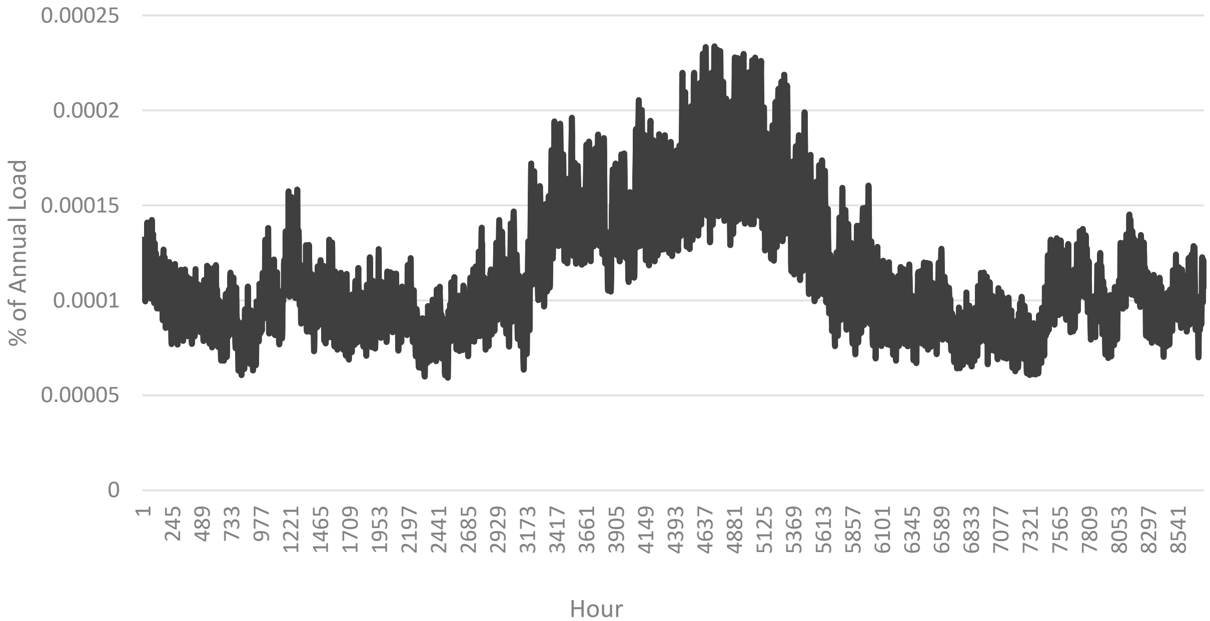
Line losses were valued assuming transmission and distribution losses total 5.4%. This is the same value used in the CPA.

2.6 DISTRICT LOAD PROFILE

Four years of hourly historic data were reviewed for a representative load shape (2017-2020). Due to its moderate shape (lack of extreme seasonal weather), 2018 was selected as a representative year. The 2018 calendar year had a summer peak of 419 MW in July and a winter peak of 284 MW in February. The winter peak may be considered a bit mild, therefore, the winter demand response potential in this study may be underrepresented. Future updates may want to consider modeling other weather profile scenarios, including extreme seasonal temperatures. The ability for demand response to respond to severe weather events may be limited based on comfort or business operations such as irrigation loads that are needed to preserve crops during times of extreme heat.

Figure 2-2 illustrates the hourly load profile that was an input to the model.

FIGURE 2-2: 2018 CALENDAR YEAR LOAD SHAPE



2.7 2021 POWER PLAN DR ANALYSIS

The following changes were made since the Seventh Power Plan in the DR potential assessment:

1. Since the Seventh Plan, the Council has formed a Demand Response Advisory Committee to evaluate DR resources for the 2021 Power Plan
2. 2021 Power Plan includes non-firm demand response (pricing programs)
3. DLC product potential savings for non-residential lighting and refrigeration controls are captured only within the Curtailment analysis (Interruptible rates)
4. DR Model development evaluates via top down or bottom-up approach
5. Updates to savings and costs based on several sources including Avista, PGE, PacifiCorp, BPA and Puget Sound Energy
6. Dispatch cost for DR resources in the Regional Portfolio Model (RPM) was $110/MWh which resulted in very little dispatch
7. The 2021 Power Plan preparation work has included significant investigation into interactions between DR and energy efficiency

The above additions for the 2021 Power Plan have largely been incorporated into this assessment. The dispatch cost is not evaluated since that cost only applies when DR is integrated into a portfolio model, which is not the focus of this study. Additionally, interactions between DR and energy efficiency resources are discussed but not fully vetted in this study since the final 2021 Power Plan and methodologies are not yet available.

3 Customer Characteristics Data

The District serves over 56,000 electric customers in Benton County, Washington, with a service area population of approximately 114,283. A key component of a demand response potential assessment is to understand the characteristics of these customers—primarily the building and end-use characteristics. These characteristics for each customer class are described below.

3.1 RESIDENTIAL

For the residential sector, the key characteristics include house type, space heating fuel, and water heating fuel. The tables below show relevant residential data for residential buildings in the District's service territory. The data is taken from the Benton PUD 2021 Conservation Potential Analysis.[1]

TABLE 3-1: RESIDENTIAL BUILDING CHARACTERISTICS

Heating Zone	Cooling Zone	Solar Zone	Residential Households	Total Population
1	3	3	44,546	117,952

TABLE 3-2: HOME HEATING & COOLING SYSTEM SATURATIONS

	Single Family	Multifamily – Low Rise	Manufactured Homes
Existing Stock, Homes	71%	16%	13%
Electric Forced Air Furnace	8%	16%	56%
Heat Pump	61%	0%	19%
Ductless Heat Pump	3%	0%	0%
Electric Zonal/Baseboard	8%	67%	0%
Central Air Conditioning	20%	12%	44%
Room Air Conditioning	12%	63%	13%

TABLE 3-3: APPLIANCE SATURATIONS

	Single Family	Multifamily – Low Rise	Manufactured Homes
Electric Water Heat	**79%**	**77%**	**94%**
Heat Pump	3%	3%	3%
Resistance Heat	76%	74%	91%
Grid-Enabled Electric Water Heat			
2022	5%	Excluded	5%
2031	59%		59%
Electric Vehicle Charging			
2022	1.1%		1.1%
2031	4.7%		4.7%

[1] EES Consulting. Benton PUD 2021 Conservation Potential Assessment. Final Report October 4, 2021.

TABLE 3-4: HOME HEATING & COOOLING SYSTEM, NUMBER

	Single Family	Multifamily – Low Rise	Manufactured Homes
Existing Stock, Homes	31,628	7,127	5,791
Electric Forced Air Furnace	2,530	1,140	3,243
Heat Pump	19,293	0	1,100
Ductless Heat Pump	949	0	0
Electric Zonal/Baseboard	2,530	4,775	0
Central Air Conditioning	6,326	855	2,548
Room Air Conditioning	3,795	4,490	753

TABLE 3-5: APPLIANCES AND EV

	Single Family	Multifamily – Low Rise	Manufactured Homes
Electric Water Heat	**24,986**	**5,488**	**5,444**
Heat Pump	949	214	174
Resistance Heat	24,037	5,274	5,270
Grid-Enabled Electric Water Heat			
2022	1,487	Excluded	290
2031	18,661		3,417
Electric Vehicle Charging			
2022	348		64
2031	1,487		272

Heat pump water heater saturation is estimated based on Council data.[2] Per the Council's product assumptions, the penetration of electric vehicles applies only to single family and manufactured homes. An EV ramp is applied that increases baseline saturation from 1.1% in 2022 to 4.7% in 2031 based on the Council's vehicle forecast.[3] This penetration of electric vehicles may be considered optimistic for the District's service territory.

3.2 COMMERCIAL

Annual electricity usage is the key parameter in determining demand response potential for the commercial sector. Table 3-6 shows estimated 2020 retail sales (MWh) in each of the 18 building categories as well as the share of total commercial load.

---

[2] Northwest Power and Conservation Council. Inputs_Product_ResHPWHDLC-Summer.xlsx. Res WH Data tab. https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655871094861

[3] May 21, 2020. https://nwcouncil.box.com/s/8qhiowvuok830lkmqtam717a1zt9y6fb

TABLE 3-6: COMMERCIAL BUILDING RETAIL SALES (MWH) BY SEGMENT

Segment	Share of Commercial MWh	2020 Retail Sales MWh
Large Office	1.5%	5,213
Medium Office	13.2%	44,920
Small Office	14.4%	48,844
Extra Large Retail	4.7%	16,073
Large Retail	8.0%	27,074
Medium Retail	1.6%	5,374
Small Retail	0.1%	409
School (K-12)	0.3%	1,088
University	1.1%	3,867
Warehouse	9.6%	32,704
Supermarket	13.7%	46,485
Mini Mart	2.6%	8,900
Restaurant	8.3%	28,324
Lodging	7.0%	23,854
Hospital	1.1%	3,646
Residential Care	2.1%	7,020
Assembly	3.3%	11,321
Other Commercial	7.2%	24,345
Total	**100%**	**339,461**

3.3 INDUSTRIAL

Industrial DR products consist mainly of whole building level products such as demand curtailment or pricing mechanisms. These DR products utilize MWh consumption to estimate peak demand reduction as shown in Table 3-7.

TABLE 3-7: INDUSTRIAL SECTOR LOAD BY SEGMENT

Industrial Segment	Share of Industrial Sales	2020 Sales (MWh)
Frozen Food	5.3%	9,456
Other Food	48.4%	86,332
Metal Fabrication	0.8%	1,462
Equipment	1.8%	3,160
Cold Storage	1.5%	2,599
Refinery	0.8%	1,431
Chemical	34.1%	60,908
Miscellaneous Manufacturing	7.4%	13,201
Total	**100.0%**	**178,548**

3.4 AGRICULTURE

Agriculture DR products consists of curtailment of irrigation pumping. Small irrigation and large irrigation 2020 retail sales are provided in Table 3-8. Based on the District's rate schedules, Small irrigators are those served where pumping use is 300 horsepower or less. Large irrigators apply to pumping loads greater than 300 horsepower. District definitions do not line up exactly with the DR products defined by the Council. Large Farms in the DR product model are defined as farms having irrigated acreage exceeding 2,000 acres and having a minimum of 100 horsepower. The difference in the DR product analysis between the two farm sizes is in the equipment cost ($1/kW for small farm and $5/kW large farms kW) and in eligibility, with larger farms having a slightly lower eligibility assumption (28% vs. 33% of customer count for large and small respectively). Because the MWh usage in small farms by District definitions, are small relative to large irrigators, the different sizing assumptions are not expected to have a large impact on estimated costs and potential.

TABLE 3-8: AGRICULTURAL INPUTS

Irrigation Class	2020 Sales (MWh)
Small Irrigation	16,644
Large Irrigation	444,132
Total	**460,132**

3.5 DISTRIBUTION EFFICIENCY

Distribution efficiency consists of demand voltage regulation (DVR)—also called demand voltage reduction. Peak demand reduction is estimated at 3% of either summer of winter utility system peak. This product applies across all sectors; however, this study does not adjust for savings from other DR or energy efficiency measures. To more accurately estimate DVR DR potential, demand from other measures should be reduced for other programs in order to eliminate the overlap in DR product impacts. The DVR estimates also need to be adjusted for distribution efficiency achieved through energy efficiency matters. Note that these adjustments were not made for these initial results.

4 DR Supply Curves

4.1 INTRODUCTION

The Council's models were utilized to develop supply curves for demand response products. The models can be used based on a bottom-up approach or a top-down approach, or both. The drawback for using both methods, depending on product type, is that there will be double counting of DR potential. For example, the top-down analysis for residential time of use rates will not factor in savings achieved if the District were to also implement a direct load control program for water heating. In order to develop a demand response potential analysis that factors in concurrent programs, the top-down method would need to be used for all DR products. This method would also require additional input assumptions be developed such as % peak reduction savings for each product considering interactions between overlapping products such as direct load control measures and tariff products.

Because the District does not currently have DR programs in place, the DR potential is estimated assuming the District may select programs to pursue on a stand-alone basis. Therefore, the analysis independently evaluated each product. Table 4-1 provides considerations when viewing the results of the supply curve analysis. The table summarizes the potential overlaps in savings with other DR products or energy efficiency measures. These overlapping impacts are not considered in this initial analysis but would need to be considered when evaluating DR in a portfolio analysis

TABLE 4-1: DR PRODUCT POTENTIAL INTERACTIONS

DR Product	Potential Interactions/Exclusions
Large Farm Irrigation Demand Curtailment	Excludes pricing programs except TOU
Small & Medium Farm Irrigation Demand Curtailment	Excludes pricing programs except TOU
Industrial Demand Curtailment	Likely excludes all other Industrial programs
Large Commercial Demand Curtailment	Likely excludes all other commercial programs
Medium Commercial Space Cooling - Switch	Could exclude commercial rate programs except TOU
Small Commercial Space Cooling - Switch	Could exclude commercial rate programs except TOU
Residential Space Cooling – Switch	Excludes pricing programs except TOU
Medium Commercial Space Heating - Switch	Could exclude commercial rate programs except TOU
Small Commercial Space Heating Switch - Switch	Could exclude commercial rate programs except TOU
Residential Space Heating Switch - Switch	
Small Commercial Bring Your Own Thermostat	Excludes pricing programs except TOU
Residential Bring Your Own Thermostat	Excludes pricing programs except TOU
Residential Electric Resistance Water Heating - Switch	Excludes pricing programs except TOU
Residential Electric Resistance Water Heating - Grid-Ready	Excludes pricing programs except TOU
Residential Electric Heat Pump Water Heating - Switch	Excludes pricing programs except TOU
Residential Electric Heat Pump Water Heating - Grid-Ready	Excludes pricing programs except TOU
Residential Electric Vehicle Supply Equipment	Excludes pricing programs except TOU
Demand Voltage Regulation	System level, therefore, overlaps across all other DR potential and EE potential
Industrial Critical Peak Pricing	Would not be combined with other pricing programs
Industrial Real Time Pricing	Would not be combined with other pricing programs
Commercial Critical Peak Pricing	Would not be combined with other pricing programs such as RTP or TOU.
Residential Time-of-Use Pricing	Excludes CPP pricing program
Residential Critical Peak Pricing	Excludes TOU pricing program and controllable DR

4.2 RESULTS

The District's unique customer data was used to update the DR models developed by the Council. Based on the assumptions detailed in this study, Figures 4-1 and 4-2 and Tables 4-2 and 4-3 summarize the supply curve results. The potential peak reduction is technically feasible and achievable subject to the assumptions used in the analysis. Economic potential will be determined through the District's IRP process.

FIGURE 4-1: 10-YEAR ACHIEVEABLE POTENTIAL LEVELIZED COST SUPPLY CURVE - SUMMER

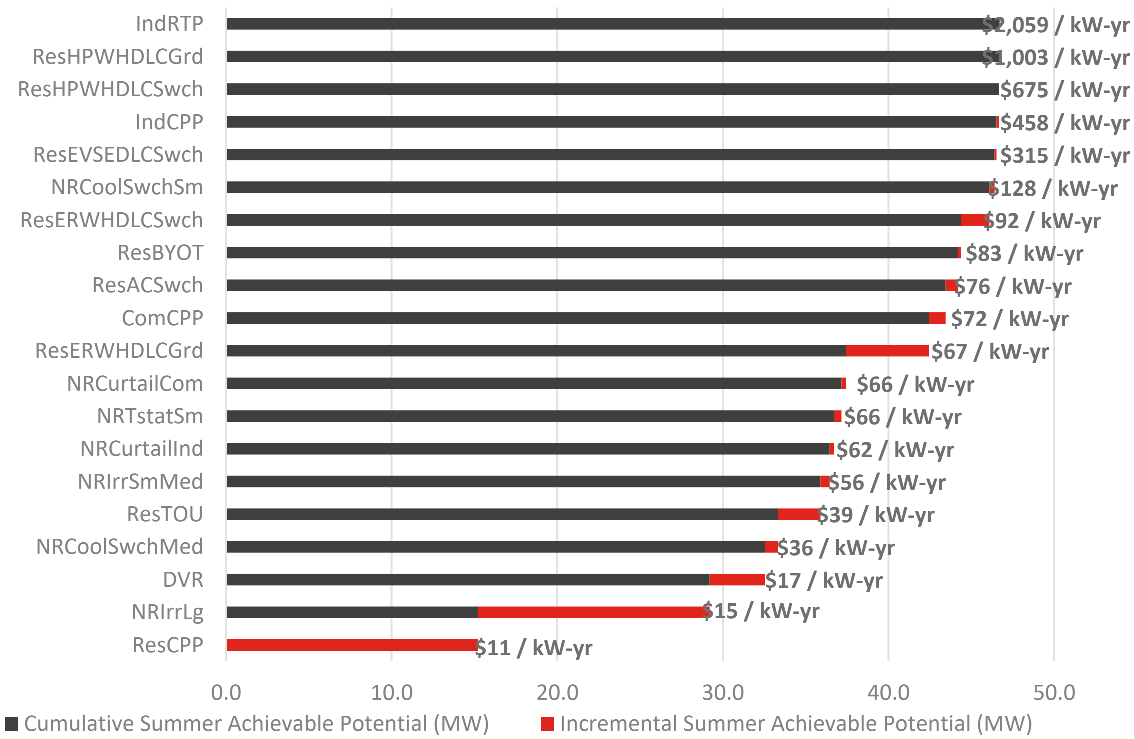


TABLE 4-2: DR POTENTIAL: SUMMER RESULTS

Product	Summer Achievable Potential (MW)	Percent of Area System Peak - Summer	Levelized Cost ($/kW-year)
ResCPP	15.2	3.6%	$11 / kW-yr
NRIrrLg	14.0	3.3%	$15 / kW-yr
ResERWHDLCGrd	5.0	1.2%	$67 / kW-yr
DVR	3.3	0.8%	$17 / kW-yr
ResTOU	2.6	0.6%	$39 / kW-yr
ResERWHDLCSwch	1.7	0.4%	$92 / kW-yr
ComCPP	1.0	0.2%	$72 / kW-yr
NRCoolSwchMed	0.8	0.2%	$36 / kW-yr
ResACSwch	0.7	0.2%	$76 / kW-yr
NRIrrSmMed	0.6	0.1%	$56 / kW-yr
NRTstatSm	0.4	0.1%	$66 / kW-yr
NRCoolSwchSm	0.3	0.1%	$128 / kW-yr
NRCurtailCom	0.3	0.1%	$66 / kW-yr
NRCurtailInd	0.3	0.1%	$62 / kW-yr
ResBYOT	0.2	0.0%	$83 / kW-yr
IndCPP	0.1	0.0%	$458 / kW-yr
ResEVSEDLCSwch	0.1	0.0%	$315 / kW-yr
ResHPWHDLCGrd	0.0	0.0%	$1,003 / kW-yr
IndRTP	0.0	0.0%	$2,059 / kW-yr
ResHPWHDLCSwch	0.0	0.0%	$675 / kW-yr

FIGURE 4-2: 10-YEAR ACHIEVEABLE POTENTIAL LEVELIZED COST - WINTER

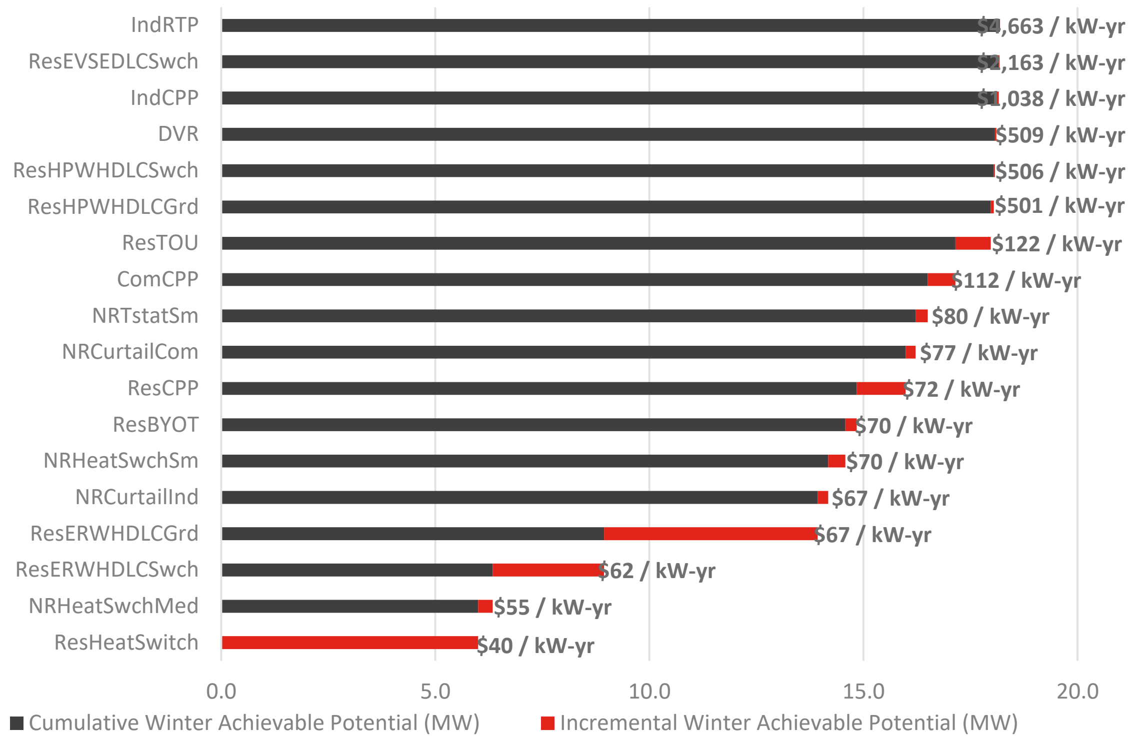


TABLE 4-3: WINTER RESULTS

Product	Winter Achievable Potential (MW)	Percent of Area System Peak - Winter	Levelized Cost ($/kW-year)
ResHeatSwitch	6.0	2.1%	$40 / kW-yr
ResERWHDLCGrd	5.0	1.8%	$67 / kW-yr
ResERWHDLCSwch	2.6	0.9%	$62 / kW-yr
ResCPP	1.1	0.4%	$72 / kW-yr
ResTOU	0.8	0.3%	$122 / kW-yr
ComCPP	0.6	0.2%	$112 / kW-yr
NRHeatSwchSm	0.4	0.1%	$70 / kW-yr
NRHeatSwchMed	0.3	0.1%	$55 / kW-yr
NRTstatSm	0.3	0.1%	$80 / kW-yr
ResBYOT	0.3	0.1%	$70 / kW-yr
NRCurtailInd	0.2	0.1%	$67 / kW-yr
NRCurtailCom	0.2	0.1%	$77 / kW-yr
ResHPWHDLCGrd	0.1	0.0%	$501 / kW-yr
IndCPP	0.1	0.0%	$1,038 / kW-yr
DVR	0.0	0.0%	$509 / kW-yr
ResHPWHDLCSwch	0.0	0.0%	$506 / kW-yr
ResEVSEDLCSwch	0.0	0.0%	$2,163 / kW-yr
IndRTP	0.0	0.0%	$4,663 / kW-yr

5 Cost-Effective Demand Response

The previous section provided the technical potential for each DR product and estimated product costs. This section provides a cost-effectiveness screening analysis based on a total resource cost analysis. The District's avoided cost for peak demand reduction is compared with the levelized cost of each DR product. As with the technical potential and supply curves, each DR product should be viewed individually since product interactions have not yet been analyzed.

5.1 PEAK DEMAND VALUE

Peak demand reductions have both power cost impacts as well as impacts on distribution system and transmission system investments. The value of peak demand savings is estimated for the following three components:

1. Distribution investment deferral[4]
2. Transmission investment deferral
3. Generation

The analysis assumes that the District's summer peak is the planning criteria for distribution system investments. The Council's estimated value of $7.26/kW-year are used to approximate the District's marginal cost of distribution.

The Pacific Northwest is a winter-peaking region. Therefore, the avoided cost for winter DR product savings is valued at the $3.23/kW-year estimated by the Council.[5] For comparison, the current BPA NT transmission rate is $2.031/kW-mo (FY2022-2023). This rate represents the average cost of transmission on BPA's system.

5.1.1 Avoided Generation Cost

DR products were analyzed given the following assumptions about the number and duration of events:

[4] Note that the Seventh Power Plan included only transmission system deferrals for DR due to the regional nature of the plan and likely timing of programs to target system peaks rather than local peaks. https://nwcouncil.app.box.com/s/gqwzxxvj4b77g1utvz4gi7l8l8yhb9m5. The Draft 2021 Power Plan includes estimates for both distribution and transmission investment deferrals. https://www.nwcouncil.org/2021powerplan_demandresponse-assumptions

This analysis considers distribution system deferrals as benefits of DR for the appropriate seasonal peak.

[5] https://www.nwcouncil.org/sites/default/files/2019_0312_p3.pdf

1. Summer peak savings = 4-hour event duration, 20 hours maximum (5 events)
2. Winter peak savings = 4-hour event duration, 20 hours maximum (5 events)

Based on these 5 events per season, the District would need to predict accurately the timing of the monthly peak in order to receive the benefit. Since the District is unlikely to execute events perfectly, it is assumed that 4 out of 5 peaks are reduced through DR events. The avoided cost analysis assumes that the peaks avoided correspond to the most expensive months according to BPA BP-22 rate period demand rates, as listed below.

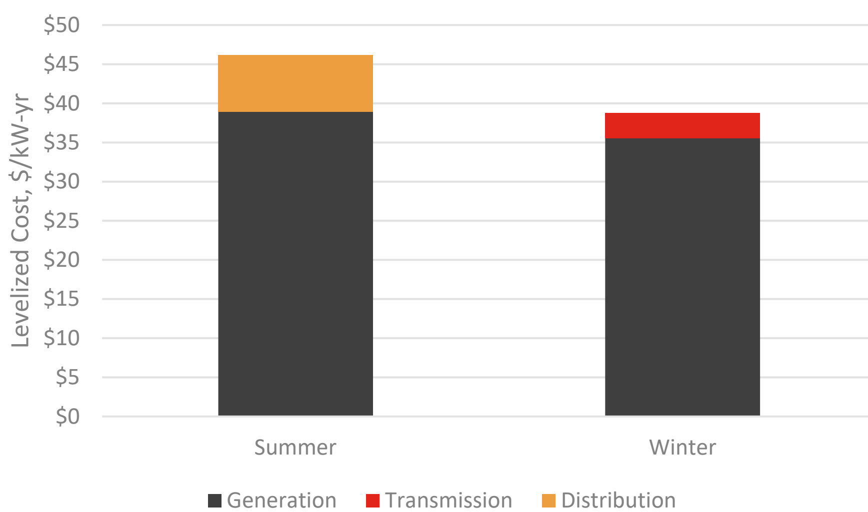
Month	Rate in $/kW
October	9.87
November	10.46
December	12.78
January	11.31
February	11.47
March	9.09
April	6.83
May	5.36
June	5.65
July	12.14
August	11.83
September	9.29

For Summer, peak values are based on June through September BPA demand rates as a proxy for generating resource costs related to capacity needs. Similarly, winter values are based on December through February BPA demand rates. These monthly demand rates are added together to produce the seasonal avoided costs below. Annual benefits are then levelized over the life of the program.

5.1.2 Total DR Avoided Cost

Figure 5-1 compares the relative value of summer and winter peaks in $2021.

FIGURE 5-1: SEASONAL CAPACITY VALUES



When escalated at 3% annually, the 10-year levelized cost of capacity is $55.42 and $46.56/kW-year for summer and winter resources respectively. The value of the DR resources will in part be based on how well the District is able to utilize the resource and reduce peak demand in each month. If only the highest peak is avoided per season the levelized cost decreases to $23.29 and $19.22/kW-year for summer and winter respectively.

Table 5-1 shows the estimated demand response potential where the avoided cost is below $55.42/kW-mo. Demand voltage regulation may have some double counting across the other products. Based on the results, irrigation and rate programs for residential customers could offer significant summer demand peak reduction potential. Economic peak demand reduction potential totals approximately 35.9 MW or 8.6% of the District's recent historic peak summer demand of 419 MW (July 2018).

TABLE 5-1: 10-YEAR COST-EFFECTIVE SUMMER DEMAND RESPONSE POTENTIAL

DR Product	Cost-Effective MW	Percent of Peak Demand
ResCPP	15.2	3.62%
NRIrrLg	14.0	3.34%
DVR	3.3	0.79%
NRCoolSwchMed	0.8	0.19%
ResTOU	2.6	0.62%
Total	**35.9**	**8.56%**

Table 5-2 shows the estimated demand response potential where the avoided cost is below $46.56/kW-mo. Economic peak demand reduction potential totals approximately 6 MW or 2.1% of the District's recent historic peak winter demand of 284 MW (February 2018). Residential TOU and CPP products may be cost-effective when bundled with summer products. These rate products could reduce the District's peak demand by another 0.8-1.1 MW or about 0.3% of the District's 2018 winter peak.

TABLE 5-2: 10-YEAR COST-EFFECTIVE WINTER DEMAND RESPONSE POTENTIAL

DR Product	Cost-Effective MW	Percent of Peak Demand
ResHeatSwitch	**6.0**	**2.1%**

Figures 5-2 and 5-3 summarize the cost-effective potential over the first 10 years by season. In all cases, DR program potential ramps up over the first 5 years and remains at that level with additions only due to load growth.

FIGURE 5-2: 10-YEAR COST-EFFECTIVE SUMMER DEMAND RESPONSE POTENTIAL

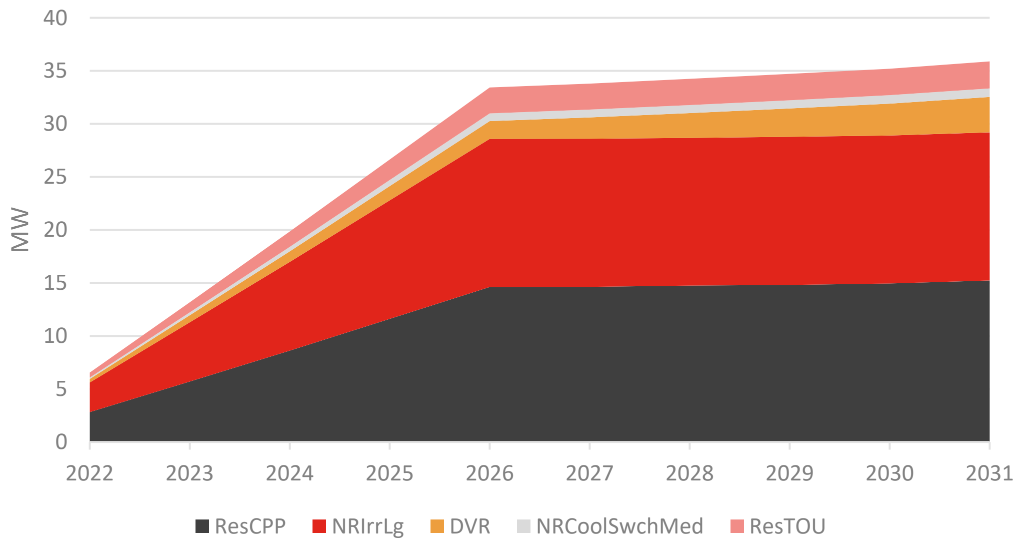
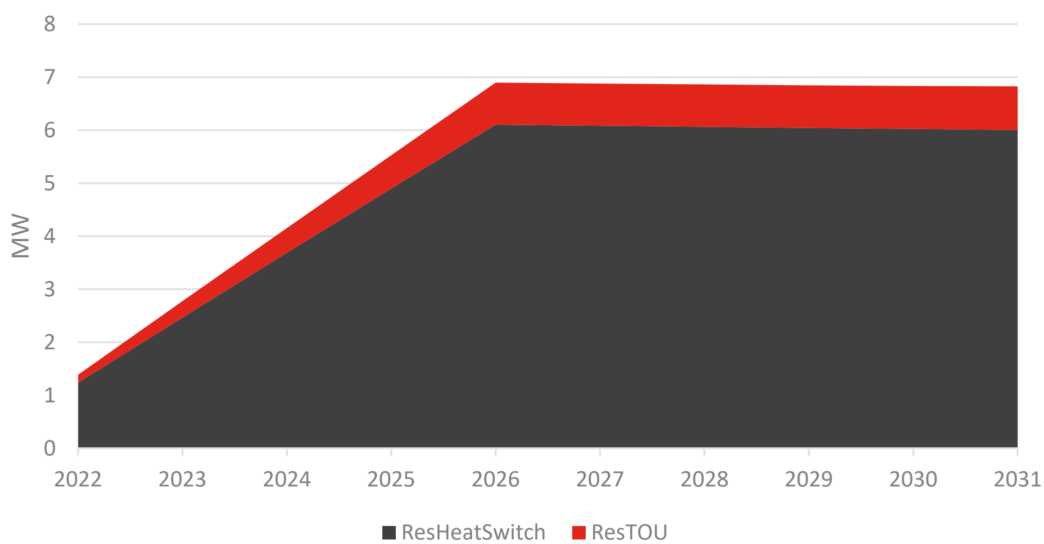


FIGURE 5-3: 10-YEAR COST-EFFECTIVE WINTER DEMAND RESPONSE POTENTIAL



Residential TOU demand reduction potential is included in Figure 5-3 since that product is cost effective in the summer season. Utilities typically implement time of use rates for residential customers prior to CPP rates.

6 Summary

This section first discusses a barriers assessment for acquiring the DR resource potential described in this study.

6.1 BARRIERS ASSESSMENT

The above analysis provides a starting point for DR product potential and program considerations for the District. The cost screening showed that if the District can successfully reduce monthly peaks for 3 or 4 months during each season, several programs could be considered. Because the many DR product assumption inputs were taken directly from the Council's modeling, the results warrant further analysis before programs can be implemented. Specifically, the District has identified several potential barriers to program implementation and savings achievement. A barriers assessment is provided by DR product type below.

Irrigation control products assume that, with incentives, irrigation peak demand can be reduced by 80% at the time of the District system peak. This savings is applied to approximately one third of irrigation meters where 50% of meters participate in each event. These may be optimistic assumptions considering the following characteristics in The District's service area:

- Irrigation loads are high during periods of high temperatures. Regardless of the incentives, irrigators may not be able to reduce pumping loads at the time of the District's peak and risk losing crops to temperatures regularly above 100 degrees. The Council notes that potato growers and wineries are particularly unwilling to reduce water to crops.[6]

- Costs for direct load control equipment may be underestimated. Equipment failures may lead to increased claims against the district for damaged owner-owned equipment such as heating, cooling equipment and water heaters.

- Rate design options require additional considerations beyond what is provided in the base Council assessment. The cost differential and time of use periods for TOU and CPP rates will directly impact how willing customers are to shift their energy usage away from peak periods. Additionally, there are rate impacts to consider such as:

    - If rate design changes are made at the same time as an overall rate increase, the rate design adjustment would need to be a very small change in order to mitigate rate shock to certain customers. Typically, utilities phase in rate structure changes over a period of years. The Council assumes that full implementation of TOU or CPP rate structures can be achieve within 5 years,

[6] https://nwcouncil.app.box.com/s/n99gxozkktw1kcyo90edm3fukiweapam

and this assumption could be optimistic depending on other factors such as overall cost escalation from year to year.

- Best practices for TOU rates include cost mitigation measures. These can vary depending on how aggressively utilities switch rate structures and the ability for consumers to shift usage within the rate structure design. These mitigation measures may include one or several of the following:
  - Opt-in TOU programs. Consumers participate by opting in but can also opt out at any time. Potentially low participation or high-opt out rates if bills increase significantly.
  - Bill protection. 12 months of bill protection is offered for default TOU rates. Bill protection decreases the incentive to shift usage.
  - Exclude Low Income. Low income customers may need to remain on a flat or tiered rate because their ability to shift usage patterns may be more limited. TOU for low income customers could be paired with other programs that target programmable energy usage, weatherization, or bill protection. These program issues increase the cost of the DR resource.

These above barriers can be analyzed through pilot programs. As with any new program, it is recommended that program design best practices should be reviewed prior to any program implementation.

6.2 FLEXIBILITY

As described in this study, some DR products are dispatchable in that, events can be triggered creating an ask for load curtailment for a set period of time. This dispatchability creates many benefits including peak shaving, reducing the slope of system ramps, firming intermittent resources, and relieving network congestion.

6.3 ENERGY EFFICIENCY ADOPTION

The barriers assessment above introduces considerations that may reduce the economic and feasible DR potential over the next 5 to 10 years. In addition to these potential barriers, there may be co-benefits for bundling DR programs with energy efficiency measures.

Residential bring-your-own-thermostat measures were screened in the CPA. Under the base assumptions, smart thermostat measures were not cost-effective. This result is due to the low savings (kWh and kW) in heating zone 1 relative to the cost ($235 or more) and expected life (5 years). However, smart thermostat measures are likely to be adopted despite not being cost-effective under current planning conditions. Given that smart thermostats may be adopted outside of programs, a DR program may be feasible.

6.4 ORDER OF IMPLEMENTATION

Price-based DR is generally less expensive to implement than controllable DR. DR through tariffs may also be a lower-risk program since the utility does not need to control equipment on private property. Therefore, pricing mechanisms may be acquired before DLC products. If a utility wishes to pilot residential DLC programs, a default TOU rate could be most appropriate as this strategy would incentivize customers to participate in the program to better control their energy costs. If a utility were to implement a CPP program, the DLC products may not be needed to achieve significant peak reduction.

6.5 SUMMARY

DR resources, when dispatched appropriately, can provide significant system reliability benefits in capacity strained seasons and reduce overall power costs. This potential assessment evaluates DR products using models and product assumptions developed by the Council. Because a combination of bottom-up and top-down analysis is utilized, the supply curves resulting from the analysis will need additional adjustment for products with interactions. Additionally, the supply curves may need adjustment according to the planned energy efficiency potential.

The cost screening analysis evaluated DR resources by valuing the avoided cost of generation capacity and investments in both the distribution and transmission systems. The screening resulted in primarily summer peak demand reduction potential.

7 References

EES Consulting. Benton PUD 2021 Conservation Potential Assessment. Draft July 7, 2021.

Northwest Power and Conservation Council. Inputs_Product_ResHPWHDLC-Summer.xlsx. Res WH Data tab. https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655871094861

Northwest Power and Conservation Council. *2021 Power Plan Technical Information and Data*. May 21, 2020. https://nwcouncil.box.com/s/8qhiowvuok830lkmqtam717a1zt9y6fb

Northwest Power and Conservation Council. *2021 Power Plan Technical Information and Data*. July 2020. Retrieved from: http://www.nwcouncil.org/energy/powerplan/2021/technical

Appendix A – Acronyms

ALH – Average Load Hours

AMI – Advanced Metering Infrastructure

aMW – Average Megawatt

BPA – Bonneville Power Administration

BYOT – Bring-your-own-thermostat

CAC – Central air conditioner

CETA – Clean Energy Transformation Act

CPA – Conservation Potential Assessment

CPP – Critical peak pricing

DLC – Direct load control

DR - Demand response

DVR – Demand voltage reduction

EIA – Energy Independence Act

ELCC – Effective load carrying capacity

ERWH – Electric resistance water heater

HLH – Heavy load hour energy

HPWH – Heat Pump Water Heater

HVAC – Heating, ventilation and air-conditioning

IRP – Integrated Resource Plan

kW – kilowatt

kWh – kilowatt-hour

LCOE – Levelized Cost of Energy

LLH – Light load hour energy

MW – Megawatt

MWh – Megawatt-hour

NEEA – Northwest Energy Efficiency Alliance

NPV – Net Present Value

O&M – Operation and Maintenance

RPS – Renewable Portfolio Standard

RTF – Regional Technical Forum

RTP – Real time pricing

TOU – Time of use

TRC – Total Resource Cost

Appendix B – Glossary

7th Power Plan: Seventh Northwest Conservation and Electric Power Plan, Feb 2016. A regional resource plan produced by the Northwest Power and Conservation Council (Council).

2021 Power Plan: A regional resource plan produced by the Northwest Power and Conservation Council (Council). At the time of this study, the Final plan is scheduled to be released in early 2022.

Average Megawatt (aMW): Average hourly usage of electricity, as measured in megawatts, across all hours of a given day, month or year.

Avoided Cost: Refers to the cost of the next best alternative. For conservation, avoided costs are usually market prices.

Achievable Potential: Conservation potential that takes into account how many measures will actually be implemented after considering market barriers. For lost-opportunity measures, there is only a certain number of expired units or new construction available in a specified time frame. The Council assumes 85% of all measures are achievable. Sometimes achievable potential is a share of economic potential, and sometimes achievable potential is defined as a share of technical potential.

Cost Effective: A measure is cost effective if the present value of its benefits is greater than the present value of its costs. The primary test is the Total Resource Cost test (TRC), in other words, the present value of all benefits is equal to or greater than the present value of all costs. All benefits and costs for the utility and its customers are included, regardless of who pays the costs or receives the benefits.

Economic Potential: Conservation potential that considers the cost and benefits and passes a cost-effectiveness test.

Levelized Cost: Resource costs are compared on a levelized-cost basis. Levelized cost is a measure of resource costs over the lifetime of the resource. Evaluating costs with consideration of the resource life standardizes costs and allows for a straightforward comparison.

MW (megawatt): 1,000 kilowatts of electricity. The generating capacity of utility plants is expressed in megawatts.

Northwest Energy Efficiency Alliance (NEEA): The alliance is a unique partnership among the Northwest region's utilities, with the mission to drive the development and adoption of energy-efficient products and services.

Northwest Power and Conservation Council "The Council": The Council develops and maintains a regional power plan and a fish and wildlife program to balance the Northwest's environment and energy needs. Their three tasks are to: develop a 20-year electric power plan that will guarantee adequate and reliable energy at the lowest economic and environmental cost to the Northwest; develop a program to protect and rebuild fish and wildlife populations affected by hydropower development in the Columbia River Basin; and educate and involve the public in the Council's decision-making processes.

Regional Technical Forum (RTF): The Regional Technical Forum (RTF) is an advisory committee established in 1999 to develop standards to verify and evaluate conservation savings. Members are appointed by the Council and include individuals experienced in conservation program planning, implementation and evaluation.

Renewable Portfolio Standards: Washington state utilities with more than 25,000 customers are required to meet defined percentages of their load with eligible renewable resources by 2012, 2016, and 2020.

Retrofit (discretionary): Retrofit measures are those that can be replaced at any time during the unit's life. Examples include lighting, shower heads, pre-rinse spray heads, or refrigerator decommissioning.

Technical Potential: Technical potential includes all conservation potential, regardless of cost or achievability. Technical potential is conservation that is technically feasible.

Total Resource Cost Test (TRC): This test is used by the Council and nationally to determine whether or not conservation measures are cost effective. A measure passes the TRC if the ratio of the present value of all benefits (no matter who receives them) to the present value of all costs (no matter who incurs them) is equal to or greater than one.

Appendix C – Documenting Demand Response Targets

References:

1) Report – "Benton Public Utilities 2021 Demand Response Potential Assessment". Final Report – November 9, 2021.
2) Model Output – "Reporter_summer_BPUD.xlsx" and "Reporter_winter_BPUD.xlsx" and supporting files

Statutory or Regulatory Requirement	DRPA Discussion	DRPA Reference
WAC 194-40-100 Social cost of greenhouse gas emissions(1) The social cost of greenhouse gas emissions to be included by utilities in resource planning, evaluation, and selection, in compliance with RCW 19.280.030(3), is equal to the cost per metric ton of carbon dioxide equivalent emissions, using the 2.5 percent discount rate, listed in table 2, technical support document: Technical update of the social cost of carbon for regulatory impact analysis under Executive Order No. 12866, published by the interagency working group on social cost of greenhouse gases of the United States government, August 2016, referred to in this rule as the "technical support document."	The supply curves from this analysis can be used as an input into the District's IRP. The IRP will value greenhouse gas savings from DR resources compared with alternative supply-side resources.	No reference from this study. See District's IRP.
WAC 194-40-200 Clean energy implementation plan (3)(b) Demand response resources. The CEIP must specify a target for the amount, expressed in megawatts, of demand response resources to be acquired during the period. The demand response target must comply with WAC 194-40-330(2).	This DRPA estimates potential and screens DR products based on an evaluation of avoided costs but does not specify a target. The DRPA is an input to the IRP and the IRP will inform the CEIP target.	No reference from this study. See District's CEIP.

Statutory or Regulatory Requirement	DRPA Discussion	DRPA Reference
WAC 194-40-210 Resource adequacy standard. (1) Each utility that is required to prepare an integrated resource plan under RCW 19.280.030(1) must establish by January 1, 2022, a standard for resource adequacy to be used in resource planning, including assessing the need for and contributions of generating resources, storage resources, demand response resources, and conservation resources. The resource adequacy standard must be consistent with prudent utility practices and relevant regulatory requirements and must include reasonable and nondiscriminatory: (c) Measures of resource contribution to resource adequacy, such as effective load carrying capability applicable to all resources available to the utility including, but not limited to, renewable, storage, hybrid, and demand response resources.	The capacity reduction potential due to DR resources is based on the District's unique load shape, customer mix, and applicable DR products. The ELCC assumed is consistent with assumptions utilized by the Council in their draft 2021 Power Plan demand response analysis. In short, in regional modeling, the Council assumes DR resources have resource adequacy values consistent with 4-hour battery storage while maintaining cost binning and seasonality characteristics: https://nwcouncil.app.box.com/s/42xie5u6srhjoonv0uwwmx4twxgv8119 https://nwcouncil.app.box.com/s/et2to8eiba5dd660g1mb9996tijfoxed All assumptions are embedded in the top down and bottom-up models developed by the Council. https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/folder/110995827164	For each product, input assumptions can be found in the respective file for winter/summer seasons: Inputs_Product_XXX – Season.xlsx Product Scenario Template End-Use load shapes, system load shapes, sector data, and financial assumptions can be found in: Inputs_Global_NW.xlsx
RCW 19.405.040(6) (a) In meeting the standard under subsection (1) of this section, an electric utility must, consistent with the requirements of RCW 19.285.040, if applicable, pursue all cost-effective, reliable, and feasible conservation and efficiency resources, and demand response. In making new investments, an electric utility must, to the maximum extent feasible: (i) Achieve targets at the lowest reasonable cost, considering risk;	This DRPA estimates potential and screens DR products based on an evaluation of avoided costs but does not specify a target. The DRPA is an input to the IRP and the IRP will inform the CEIP target.	No reference from this study. See District's CEIP.

Statutory or Regulatory Requirement	DRPA Discussion	DRPA Reference
WAC 194-40-330 **Methodologies for energy efficiency and demand response resources** **(2) Demand response resources:** (a) Assessment of potential. Each utility must assess the amount of demand response resource that is cost-effective, reliable, and feasible.	Cost-effective and achievable potential based on Council assumptions for reliability and feasibility.	Section 5 of this Report. Appendix D details input assumptions for achievability.
WAC 194-40-330 (2) **(b) Target.** The demand response target for any compliance period must be sufficient to meet the utility's obligation under RCW 19.405.040(6) and must be consistent with the utility's integrated resource plan or resource plan and any distributed energy resource plan adopted under RCW 19.280.100.	This DRPA estimates potential and screens DR products based on an evaluation of avoided costs but does not specify a target. The DRPA is an input to the IRP and the IRP will inform the CEIP target.	No reference from this study. See District's CEIP.

Appendix D – DR Product Data

PRICE BASED DEMAND RESPONSE (NON-FIRM)

TABLE D-1: RESIDENTIAL RATE PRODUCTS

		TOU	CPP
Setup Cost	$ per season	$75,000	$75,000
O&M Cost	$ per season	$37,500	$37,500
Equipment Cost	$ per new participant	$0	$0
Marketing Cost	$ per new participant, per season	$25	$25
Incentives (annual)	$ per participant per year		
Incentives (one time)	$ per new participant		
Attrition	% of existing participants per year		
Impact Parameters			
Eligibility	% of customer count (e.g. equipment saturation)	85%	85%
Peak Load Impact	% of applicable load	5.7% summer, 2.9% winter	12.5% summer, 7.5% winter
Program Participation	% of eligible customers	28%	15%
Event Participation	%	100%	100%
Ramp Period	Number of years to reach maximum achievable potential	5	5

TABLE D-2: COMMERCIAL AND INDUSTRIAL PRICE PRODUCTS

		RTP	CPP
Setup Cost	$ per season	$75,000	$75,000
O&M Cost	$ per season	$37,500	$37,500
Equipment Cost	$ per new participant		
Marketing Cost	$ per new participant, per season	$100	$100
Incentives (annual)	$ per participant per year		
Incentives (one time)	$ per new participant		
Attrition	% of existing participants per year		
Impact Parameters			
Eligibility	% of customer count (e.g. equipment saturation)	98%	Com – 90% Ind – 98%
Peak Load Impact	% of applicable load	8.4% summer, 4.2% winter	8.4% summer, 4.2% winter
Program Participation	% of eligible customers	4%	18%
Event Participation	% (switch success rate)	100%	100%
Ramp Period	Number of years to reach maximum achievable potential	5	5

RESIDENTIAL DIRECT LOAD CONTROL PRODUCTS

TABLE D-3: RESIDENTIAL ELECTRIC VEHICLE CHARGING

Setup Cost	$ per season	$75,000
O&M Cost	$ per season	$5
Equipment Cost	$ per new participant, per season	$140
Marketing Cost	$ per new participant, per season	$25
Incentives	$ per participant per season, per season	$8
Incentives (one time)	$ per new participant	
Attrition	% of existing participants per year	5%
Impact Parameters		
Eligibility	% of customer count (e.g. equipment saturation)	14%
Peak Load Impact	kW per participant at meter	0.34
Program Participation	% of eligible customers	20%
Event Participation	% (switch success rate)	95%
Ramp Period	Number of years to reach maximum achievable potential	20

TABLE D-4: RESIDENTIAL WATER HEATING

		Electric Resource		Heat Pump	
		Switch	Grid-Ready	Switch	Grid-Ready
Setup Cost	$ per season	$75,000	$75,000	$75,000	$75,000
O&M Cost	$ per season	$13	$13	$13	$13
Equipment Cost	$ per new participant, per season	$165	$25	$165	$25
Marketing Cost	$ per new participant, per season	$15	$15	$15	$15
Incentives	$ per participant per season	$3.75	$5	$3.75	$5
Incentives (one time)	$ per new participant				
Attrition	% of existing participants per year	5%	5%	5%	5%
Impact Parameters					
Peak Load Impact	kW per participant at meter	0.5 (summer), 0.75 (winter)	0.5	0.15 (summer), 0.2 (winter)	0.1 (summer), 0.2 (winter)
Program Participation	% of eligible customers	25%	50%	25%	50%
Event Participation	% (switch success rate)	94%	94%	94%	94%
Ramp Period	Number of years to reach maximum achievable potential	5	10	5	10

TABLE D-5: RESIDENTIAL SPACE HEATING

		Switch	Thermostat
Setup Cost	$ per season	$94,109	$75,000
O&M Cost	$ per season	$13	$4
Equipment Cost	$ per new participant, per season	$144	$0
Marketing Cost	$ per new participant, per season	$50	$50
Incentives	$ per participant per season	$10.50	$7
Incentives (one time)	$ per new participant		$7
Attrition	% of existing participants per year	5%	5%
Impact Parameters			
Population	Customer count	Eligible population will be subject to EE measure adoption for bring your own thermostat	
Peak Load Impact[1]	kW per participant at meter	1.61 (East)	1.09
Program Participation	% of eligible customers	25%	35%
Event Participation	% (switch success rate)	94%	70%
Ramp Period	Number of years to reach maximum achievable potential	5	5

1. 50% cycling for switch

TABLE D-6: RESIDENTIAL SPACE COOLING

		Switch	**Thermostat**
Setup Cost	$ per season	$92,361	$75,000
O&M Cost	$ per season	$12	$4
Equipment Cost	$ per new participant per season	$142	$0
Marketing Cost	$ per new participant per season	$35	$35
Incentives	$ per participant per season	$10.50	$7
Incentives (one time)	$ per new participant		$7
Attrition	% of existing participants per year	5%	5%
Impact Parameters			
Population	Customer count	Eligible population will be subject to EE measure adoption for bring your own thermostat	
Peak Load Impact[1]	kW per participant at meter	0.98 (East)	1.27
Program Participation	% of eligible customers	10%	20%
Event Participation	% (switch success rate)	95%	70%
Ramp Period	Number of years to reach maximum achievable potential	5	5

NON-RESIDENTIAL DIRECT LOAD CONTROL

TABLE D-7: SMALL COMMERCIAL SPACE HEATING

		Switch	Thermostat
Setup Cost	$ per season	$75,000	$75,000
O&M Cost	$ per season	$28	$4
Equipment Cost	$ per new participant, per season	$240	$0
Marketing Cost	$ per new participant, per season	$35	$38
Incentives	$ per participant per season	$21	$22
Incentives (one time)	$ per new participant		$6
Attrition	% of existing participants per year	5%	5%
Impact Parameters			
Peak Load Impact[1]	kW per participant at meter	2.5 (East)	1.2
Program Participation	% of eligible customers	10%	20%
Event Participation	% (switch success rate)	95%	70%
Ramp Period	Number of years to reach maximum achievable potential	5	5

TABLE D-8: SMALL COMMERCIAL SPACE COOLING

		Switch	Thermostat
Setup Cost	$ per season	$75,000	$75,000
O&M Cost	$ per season	$20	$4
Equipment Cost	$ per new participant, per season	$329	$0
Marketing Cost	$ per new participant, per season	$35	$38
Incentives	$ per participant per season	$21	$22
Incentives (one time)	$ per new participant		$6
Attrition	% of existing participants per year	5%	5%
Impact Parameters			
Peak Load Impact[1]	kW per participant at meter	1.25 (East)	1.2
Program Participation	% of eligible customers	10%	20%
Event Participation	% (switch success rate)	95%	70%
Ramp Period	Number of years to reach maximum achievable potential	5	5

TABLE D-9: MEDIUM COMMERCIAL SPACE HEATING

		Switch
Setup Cost	$ per season	$75,000
O&M Cost	$ per season	$20
Equipment Cost	$ per new participant, per season	$675
Marketing Cost	$ per new participant, per season	$43
Incentives	$ per participant per season	$72
Incentives (one time)	$ per new participant	
Attrition	% of existing participants per year	5%
Impact Parameters		
Eligibility	% of customer count (e.g. equipment saturation)	5,000-50,000 sq ft
Peak Load Impact[1]	kW per participant at meter	12.3 (East)
Program Participation	% of eligible customers	10%
Event Participation	% (switch success rate)	95%
Ramp Period	Number of years to reach maximum achievable potential	5

TABLE D-10: MEDIUM COMMERCIAL SPACE COOLING

		Switch
Setup Cost	$ per season	$75,000
O&M Cost	$ per season	$20
Equipment Cost	$ per new participant, per season	$967
Marketing Cost	$ per new participant, per season	$42.50
Incentives	$ per participant per season	$71.50
Incentives (one time)	$ per new participant	
Attrition	% of existing participants per year	5%
Impact Parameters		
Peak Load Impact[1]	kW per participant at meter	14.2 (East)
Program Participation	% of eligible customers	10%
Event Participation	% (switch success rate)	95%
Ramp Period	Number of years to reach maximum achievable potential	5

TABLE D-11: IRRIGATION

		Large Farm	Small Farm
Setup Cost	$ per season	$150,000	$150,000
O&M Cost	$ per kW per season	$0	$1
Equipment Cost	$ per new kW, per season	$1	$5
Marketing Cost	$ per new participant, per season	$20	$20
Incentives	$ per kW, per season	$14	$14
Incentives (one time)	$ per kW		
Attrition	% of existing participants per year	5%	5%
Impact Parameters			
Eligibility	% of customer count (e.g. equipment saturation)	28%	33%
Peak Load Impact[1]	% eligible load	80%	80%
Program Participation	% of eligible customers	50%	50%
Event Participation	% (switch success rate)	94%	94%
Ramp Period	Number of years to reach maximum achievable potential	5	5

TABLE D-12: LARGE COMMERCIAL DEMAND CURTAILMENT

Setup Cost	$ per season	$75,000
O&M Cost	$ per kW pledged per season	$15
Equipment Cost	$ per new kW pledged per season	$5
Marketing Cost	$ per kW pledged per season	$0
Incentives	$ per kW pledged per season	$11
Incentives (one time)	$ per kW pledged	
Attrition	% of existing participants per year	5%
Impact Parameters		
Population	Segment/end-use load	Com>150 kW
Peak Load Impact[1]	% eligible segment/end-use load (share of eligible load class)	25%
Program Participation	% of eligible customers	5%
Event Participation	% of nominated load	95%
Ramp Period	Number of years to reach maximum achievable potential	5

TABLE D-13: INDUSTRIAL DEMAND CURTAILMENT

Setup Cost	$ per season	$75,000
O&M Cost	$ per kW pledged per season	$5
Equipment Cost	$ per new kW pledged, per season	$5
Marketing Cost	$ per kW pledged, per season	$0
Incentives	$ per kW pledged per season	$15
Incentives (one time)	$ per kW pledged	
Attrition	% of existing participants per year	5%
Impact Parameters		
Population	Segment/end-use load	Ind>150 kW
Peak Load Impact[1]	% eligible segment/end-use load (share of eligible load class)	25%
Program Participation	% of eligible customers	15%
Event Participation	% of nominated load	90%
Ramp Period	Number of years to reach maximum achievable potential	5

TABLE D-14: DEMAND VOLTAGE REDUCTION (DVR)

Setup Cost	$ per season	$75,000
O&M Cost	$ per season	$5
Equipment Cost	$ per season	$35
Marketing Cost	$ per season	$0
Incentives	$ per season	
Incentives (one time)	$ per season	
Attrition	% of existing participants per year	
Impact Parameters		
Eligibility	% of segment/end-use load	100%
Peak Load Impact	% eligible segment/end-use load	3%
Program Participation	% of eligible customers	100%
Event Participation	% of nominated load	97%
Ramp Period	Number of years to reach maximum achievable potential	7