CHAPTER 14: DEMAND RESPONSE

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KEY FINDINGS

The Seventh Power Plan assumes the technically achievable potential for demand response in the region is over eight percent of peak load during winter and summer peak periods by 2035. This assumption is based on the Demand Response Program Potential Study commissioned by the Council[1] and feedback from regional stakeholders. This figure represents approximately 3,500 megawatts of winter peak load reductions and nearly 3,300 megawatts of summer peak load reductions by the end of the study period. In addition, the study identified additional potential for summer and winter demand response that could be available by the end of the study period to provide for load and variable generation balancing services.

While the study included an assessment of the demand response potential for balancing services, this use of demand response was not modeled in the Council's Regional Portfolio Model (RPM) analysis. Only the technically achievable potential for demand response to provide peaking services was included in the RPM analysis. The RPM used this data to determine the amount of demand response to develop in the least cost resource strategy for each of the scenarios tested by the model. In order to model the technical and economic viability of demand response resources to provide balancing services, further modeling enhancements and research are necessary.

INTRODUCTION

The Council's definition of Demand Response (DR) is a voluntary and temporary change in consumers' use of electricity when the power system is stressed. The change in consumer use is usually a reduction, although there are situations in which an increase in use would relieve stress on the power system and would qualify as DR.

The need for DR arises from the mismatch between power system costs and consumers' prices. While power system costs vary widely from hour to hour as demand and supply circumstances change, consumers generally see prices that change very little in the short term. The result of this mismatch is that consumers do not have the information that might incent them to curb consumption at high-cost times and/or shift consumption to low-cost times. The ultimate result of the mismatch of costs and prices is that the increased power system needs require building more peaking capacity, building more transmission, and incurring more system upgrades than would be necessary if customers changed their use in response to price changes in the market. Programs and policies to encourage demand response are efforts to provide this information to consumers and create the infrastructure to allow them to respond to price signals in the market.

[1] The Navigant Potential Report, "Assessing Demand Response (DR) Program Potential for the Seventh Power Plan", was delivered as a document and a supporting spreadsheet, , NPCC_Assessing DR Potential for Seventh Power Plan_UPDATED REPORT_1-19-15.pdf and NPCC_7thPowerPlan_DR_Programs_UPDATE_2015 01 16.xlsx, respectively.

Demand response has the potential to provide significant value to the Northwest's power system by:

- Reducing Peak Load, which,
  - Defers the build of generating resources that provide peaking capacity[2].
  - Defers the build of new transmission and/or distribution resources
- Providing Ancillary Services[3], including,
  - Contingency reserves
  - Operating reserves (e.g. load following and regulation)
  - Transmission and/or distribution congestion relief

In the Seventh Power Plan, the Council focuses primarily on DR that reduces peak load, and even more specifically, DR that defers the build of generating resources and new transmission resources. Other potential applications of demand response resources, such as the integration of variable resources like wind, were not explicitly modeled for the development of the Seventh Power Plan. However, this does not mean that such applications of demand response would not provide cost-effective options for providing such services. Therefore, the Seventh Power Plan resource strategy also recommends that demand response resources be considered for the provision of other ancillary services, such as variable resource integration.

DEMAND RESPONSE IN PREVIOUS POWER PLANS

The Council considered demand response as a potential resource[4] in its Sixth Power Plan[5] after considering it for the first time in its Fifth Power Plan.[6] The Sixth Power Plan described pricing and program options to encourage demand response. It also developed a very rough estimate of 2,000 megawatts of demand response that might be available in the Pacific Northwest over the 2010-2029 planning period, and described some estimates of the cost-effectiveness of demand response. The Sixth Plan included an action item to advance the state of knowledge of demand response in the region.[7]

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[2] See definitions of generation resource options in Seventh Power Plan, Chapter 13: Generating Resources.
[3] See definitions of ancillary services in Seventh Power Plan, Chapter 10: Operating and Planning Reserves.
[4] According to the strict legal definitions of the Northwest Power Act, demand response is probably not a "resource" but a component of "reserves." For ease of exposition, the plan refers to demand response as a resource in the sense of the general definition of the word - "a source of supply or support."
[5] The Sixth Power Plan is posted at https://www.nwcouncil.org/energy/powerplan/6/plan/ with Chapter 5 on DR at https://www.nwcouncil.org/media/6368/SixthPowerPlan_Ch5.pdf and Appendix H on DR at https://www.nwcouncil.org/media/6314/SixthPowerPlan_Appendix_H.pdf.
[6] The Fifth Power Plan is posted at http://www.nwcouncil.org/energy/powerplan/5/Default.htm, with Chapter 4 on DR at http://www.nwcouncil.org/energy/powerplan/5/(04)%20Demand%20Response.pdf and Appendix H on DR at http://www.nwcouncil.org/energy/powerplan/5/Appendix%20H%20(Demand%20Response).pdf
[7] The Sixth Power Plan's treatment of demand response is laid out in more detail in Appendix H of that plan.

Progress Since the Sixth Power Plan

Since the release of the Sixth Power Plan, the region has made progress on developing demand response programs. Idaho Power, PacifiCorp, and Portland General Electric have expanded existing demand-response programs. Multiple utilities within the region have continued progress towards installing advanced metering for all their customers, which facilitates demand response programs and enables time-sensitive pricing. Utilities in the region continue to evaluate demand response as an alternative to peaking generation in their integrated resource plans.

The Council and the Regulatory Assistance Project have continued to work together to coordinate the Pacific Northwest Demand Response Project (PNDRP), composed of parties interested in the development of demand response in the region. PNDRP has historically mostly focused on defining cost-effectiveness of demand response, discussing a role for pricing, and considering the transmission and distribution system costs that can be avoided by demand response. However, focus seems to be shifting to studying DR usefulness in mitigating system needs for balancing and flexibility. The region’s system operators are increasingly concerned with the system’s ability to achieve minute-to-minute balancing when faced with increasingly peaky demands for electricity and increasing amounts of variable generation. Demand response is recognized as a potential source of some of the “ancillary services” necessary for this balancing. Bonneville has partnered with Energy Northwest, City of Port Angeles, and Emerald Public Utility District in pilot programs exploring the use of DR as a balancing resource.

These areas of progress are covered in more detail in Appendix J.

DEMAND RESPONSE IN THE SEVENTH POWER PLAN

Estimation of Available Demand Response

In order to evaluate the potential role that demand response might play in a least cost resource strategy for the region, it was first necessary to develop the inputs for evaluating the cost-effectiveness of DR resources in the Regional Portfolio Model (RPM). These inputs include each DR resource’s seasonal shape, its fixed and variable costs, and its associated capacity and energy value. To develop these inputs the Council commissioned a regional DR Program Potential Study. The scope of this study was limited to a review of information from previous DR program potential studies for investor owned utilities, existing DR program literature and interviews with regional stakeholders. The Council released for stakeholder review the initial results of the study early in 2015. Stakeholder comments were then integrated with the results of the potential study.

A description of the major forms of DR considered for the Seventh Power Plan appears below.

Direct load control (DLC) for air conditioning. Direct control of air conditioners, by cycling or thermostat adjustment, is one of the most common demand-response programs across the country, and is most attractive in areas where electricity load peaks in the summer. The Pacific Northwest as a whole is still winter-peaking, but forecasts continue to show the region’s summer peak load growing faster than winter peak load. PacifiCorp's Rocky Mountain Power division and Idaho Power already face summer-peaking loads. Idaho Power has almost 45 peak megawatts of demand response from direct control of air conditioning under contract within the region. In the RPM, this resource is limited to 50 hours in the summer.

Irrigation. PacifiCorp and Idaho Power are currently reducing irrigation load by more than 450 megawatts through scheduling controls. Both utilities are in the process of modifying their programs to give them more control of the resource, increasing the load reduction available when the utilities need it. In the RPM, this resource is limited to 50 hours in the summer.

Direct load control of space heat and water heat. Direct load control of electric space heating (i.e. heat pumps, forced air furnaces, baseboard) and electric resistance water heating, by cycling or thermostat adjustment, is useful in reducing winter peak electricity use. While there has been some experience with direct control of water heating in the region, experience with direct control of space heating is limited to pilot programs. The assumption for space heating DLC is a maximum of 50 hours per winter whereas water heating DLC can be dispatched 50 hours year round.

Load Aggregators. Increasingly, load aggregators facilitate demand response by acting as middlemen between utilities or system operators on the one hand and the end-users of electricity on the other. These aggregators are known by a variety of titles such as "demand response service providers" for the independent system operators in New York and New England and "curtailment service providers" for the regional transmission organization in the Mid-Atlantic States (PJM). Aggregators could recruit customers to participate in demand response programs already described here, in which case aggregators would not add to the total of available demand response. However, in the Council's analysis, aggregators are assumed to achieve additional demand response by recruiting commercial and small industrial load that is not otherwise captured. The resource is assumed available for a maximum of 60 hours year round.

Curtailable/Interruptible contracts. Interruptible contracts offer rate discounts to customers who agree to have their electrical service interrupted under defined circumstances. This is a well-established mechanism, even within the Pacific Northwest, for reducing load in emergencies. Bonneville has had agreements with its direct service industry customers to reduce load at times of peak need. These contracts usually are arranged with large industrial customers, and PacifiCorp, PGE, and Bonneville have had almost 300 megawatts of interruptible load under such contracts in the region.

The study separated the DR programs into three sectors: Residential, Commercial, and Industrial/ Agricultural. The percentage of potential in each sector by year and season is in Table 14 - 1.

Table 14 - 1: Demand Response Potential Percentage by Sector

	Winter Potential in 2021	Winter Potential in 2026	Winter Potential in 2035	Summer Potential in 2021	Summer Potential in 2026	Summer Potential in 2035
Residential	48%	48%	48%	35%	35%	35%
Commercial	8%	8%	8%	17%	17%	17%
Ag/Industrial	44%	44%	44%	48%	48%	48%

The individual programs considered in the development of regional DR potential are categorized by sector in Table 14 - 2.

Table 14 - 2: Demand Response Programs Studied

	DR Sector	DR Component	DR Technology[8]	Seasonality
1	Residential DR	Space Heating	Direct Load Control (DLC) and Programmable Communicating Thermostats (PCT)	Winter Only
		Water Heating	DLC and Automatic Water Heater Controls	Summer and Winter
		Space Cooling – Central Air Conditioning (CAC)	DLC and PCT	Summer Only
		Space Cooling – Room Air Conditioning (RAC)	DLC and PCT	Summer Only
2	Commercial DR	Space Cooling, Small Commercial - Central Air Conditioning	DLC and PCT	Mostly Summer
		Space Cooling, Medium Commercial - Central Air Conditioning	DLC and PCT	Mostly Summer
		Lighting Controls	AutoDR	Summer and Winter
3	Agricultural / Industrial DR	Irrigation Pumping	DLC and AutoDR	Mostly Summer
		Curtailable/Interruptible Tariffs	DLC and AutoDR	Summer and Winter
		Load Aggregator	AutoDR	Summer and Winter
		Refrigerated Warehouses	AutoDR	Summer and Winter

[8] "DLC programs for space cooling and water heating typically require installation of a receiver system to signal the interruption or cycling of equipment. Water heaters can either use a radio- or digital internet gateway- activated switch. Historically, DLC for cooling has relied on switches but increasingly utilities are utilizing more advanced programmable communicating thermostats (PCTs). DLC programs for space heating are also trending toward the use of PCTs. While still in pilot phases, there is increasing interest toward using certain types of DLC for load balancing purposes, particularly for water heating applications. The technology application for water heating DLC for balancing purposes is exclusively aimed toward internet gateway-activated switches…. AutoDR consists of fully automated signaling from the utility to provide automated connectivity to customer end-use control systems, devices and strategies", per the DR Potential Study.

Demand Response Assumptions

Demand Response in the Regional Portfolio Model

In the Seventh Power Plan, the Regional Portfolio Model (RPM) explicitly analyzes the need for peak capacity.[9] Thus, the need for peaking resources forms the basis for the modeling of DR resources in the RPM.

DR can be characterized by the following attributes:

- Seasonality – Some DR resources are only available and/or most effective to reduce peak loads during summer (space cooling, irrigation) or winter (space heating) whereas others are available year-round (lighting, water heating, curtailable/interruptible tariffs, load aggregators).

- Firmness – DR resources allowing either interruptions of electrical equipment or appliances that are directly controlled by the utility or are scheduled ahead of time are considered to be firm. Non-Firm DR resources are outside of the utility's direct control and are driven by modified customer usage based on pricing mechanisms that pass on some portion of the changing price of electricity to the customer.

- Sector – Residential, commercial, industrial, and agricultural sectors have different characteristics and methods of acquisition.

For RPM modeling purposes, the primary distinguishing attributes for DR resources are cost, and secondarily, seasonal shape. The Council modeled four DR resources in the RPM. Each of the demand response programs listed in Table 14 - 1 above was assigned to one of four bins, characterized by cost and seasonal shape. The cost and seasonal shape of each bin represents the weighted average cost and shape of the programs making up the bin.

Council Assumptions

Based on the DR Potential Study results, stakeholder comments and experience elsewhere, the Council adopted cost and availability assumptions for nineteen demand response programs listed in Table 14 - 1 above. The Council sorted all the programs into one of four price bins based on the Total Resource Cost (TRC)[10] net levelized cost of the resource. Table 14 - 3, Table 14 - 4, Table 14 - 5, and Table 14 - 6, show the cumulative annual build-out available from each of the bins, and are indicative of which programs have a larger influence in the price of the bins. Note that both the winter and summer potential of each program is listed.

[9] See discussion in Appendix L of the Seventh Power Plan related to RPM redevelopment for more detail.
[10] TRC net levelized cost is "all quantifiable costs and benefits" associated with a particular DR program, as described in more detail in the Methodology section of Chapter 12 of Seventh Power Plan.

Table 14 - 3: Price Bin 1 Cumulative Achievable Potential in MW

	Winter Potential			Summer Potential		
Bin 1 - Cumulative MW	2021	2026	2035	2021	2026	2035
Irrigation Pumping - DLC	-	-	-	10	10	11
Curtailable/Interruptible Tariff - DLC	557	583	646	557	583	646
Curtailable/Interruptible - AutoDR	557	583	646	557	583	646
Load Aggregator - AutoDR	139	146	161	139	146	161
Space Cooling, Medium Commercial– DLC	9	10	11	47	49	54

Table 14 - 4: Price Bin 2 Cumulative Achievable Potential in MW

	Winter Potential			Summer Potential		
Bin 2 - Cumulative MW	2021	2026	2035	2021	2026	2035
Space Cooling, Small Commercial – DLC	4	4	4	18	18	20
Refrigerated Warehouses - AutoDR	92	96	106	102	107	118
Space Heating – DLC	280	294	325	-	-	-
Lighting Controls – AutoDR	171	179	198	171	179	198
Irrigation Pumping - AutoDR	-	-	-	5	5	6
Water Heating – DLC	483	508	562	483	508	562

Table 14 - 5: Price Bin 3 Cumulative Achievable Potential in MW

	Winter Potential			Summer Potential		
Bin 3 - Cumulative MW	2021	2026	2035	2021	2026	2035
Space Cooling - CAC DLC	-	-	-	102	108	119
Space Cooling, Medium Commercial - AutoDR	44	46	51	219	230	254
Space Cooling - RAC DLC	-	-	-	5	5	5
Space Cooling, Small Commercial – PCT	4	4	5	20	21	24

Table 14 - 6: Price Bin 4 Cumulative Achievable Potential in MW

	Winter Potential			Summer Potential		
Bin 4 - Cumulative MW	2021	2026	2035	2021	2026	2035
Water Heating - WH Controls	54	56	62	54	56	62
Space Cooling - CAC PCT	-	-	-	239	251	278
Space Cooling - RAC PCT	-	-	-	107	113	125
Space Heating – PCT	653	687	759	-	-	-

The Total Resource Cost (TRC) levelized cost calculation includes two major components: implementation costs and enablement costs. Implementation costs are the costs associated with continually running a DR program such as staffing costs, marketing costs, and customer incentive payments. Enablement costs are the costs associated with getting a demand response resource set up for use, such as technology costs and installation costs. The use of these costs in the calculation of the TRC levelized costs is discussed further in Appendix J.

Figure 14 - 1 shows the TRC levelized cost of each price bin in the blue columns, and the subsequent weighted average levelized costs of each bin into which it was sorted. Each bin was sized to best fit programs with similar costs together while minimizing cost variation within the bin. This was done to ensure that if the RPM selected the minimum amount of megawatts from any price bin (i.e., 10 MW) it would be fairly representative of any program within the same bin.

Figure 14 - 1: Demand Response Programs and Cost Bins

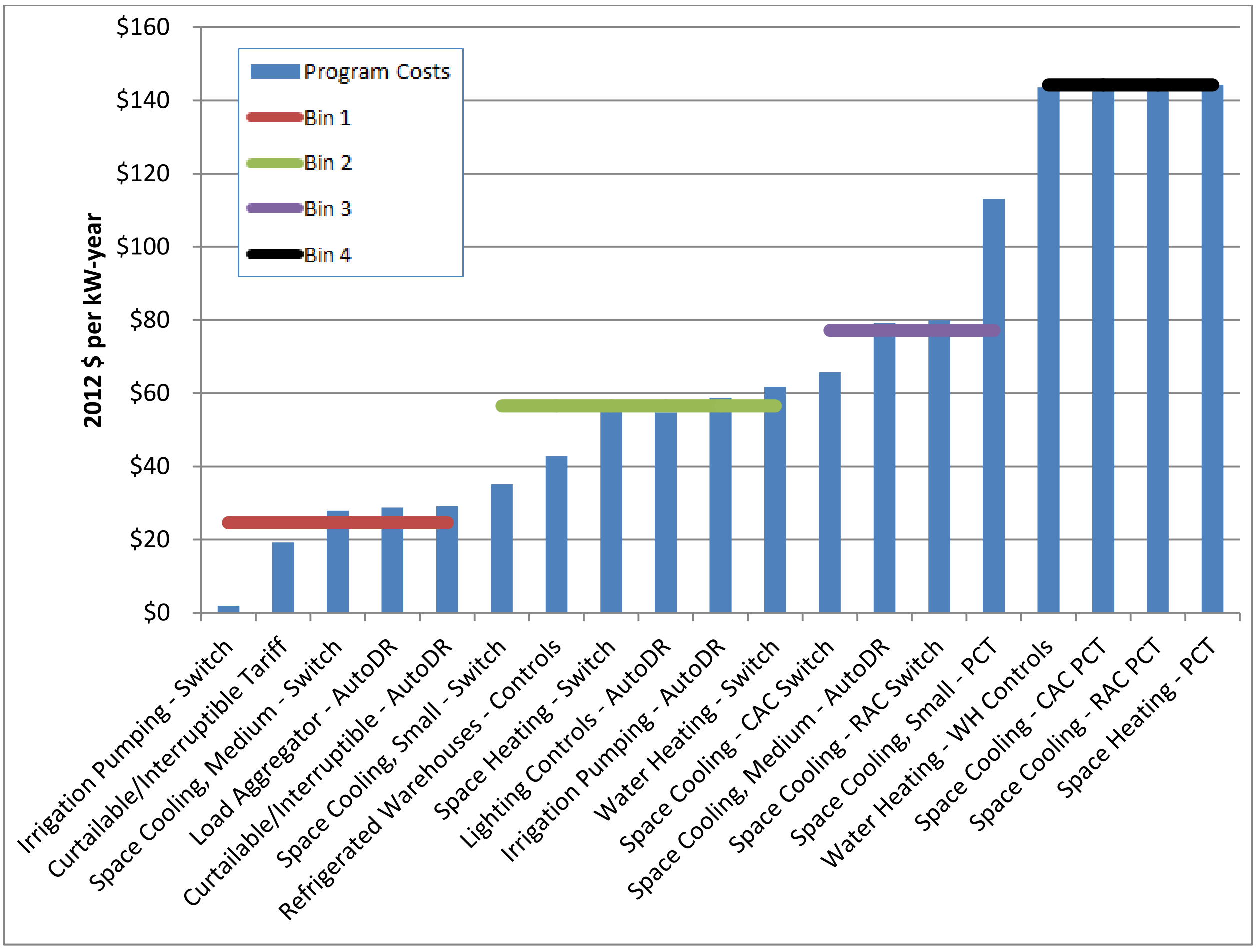
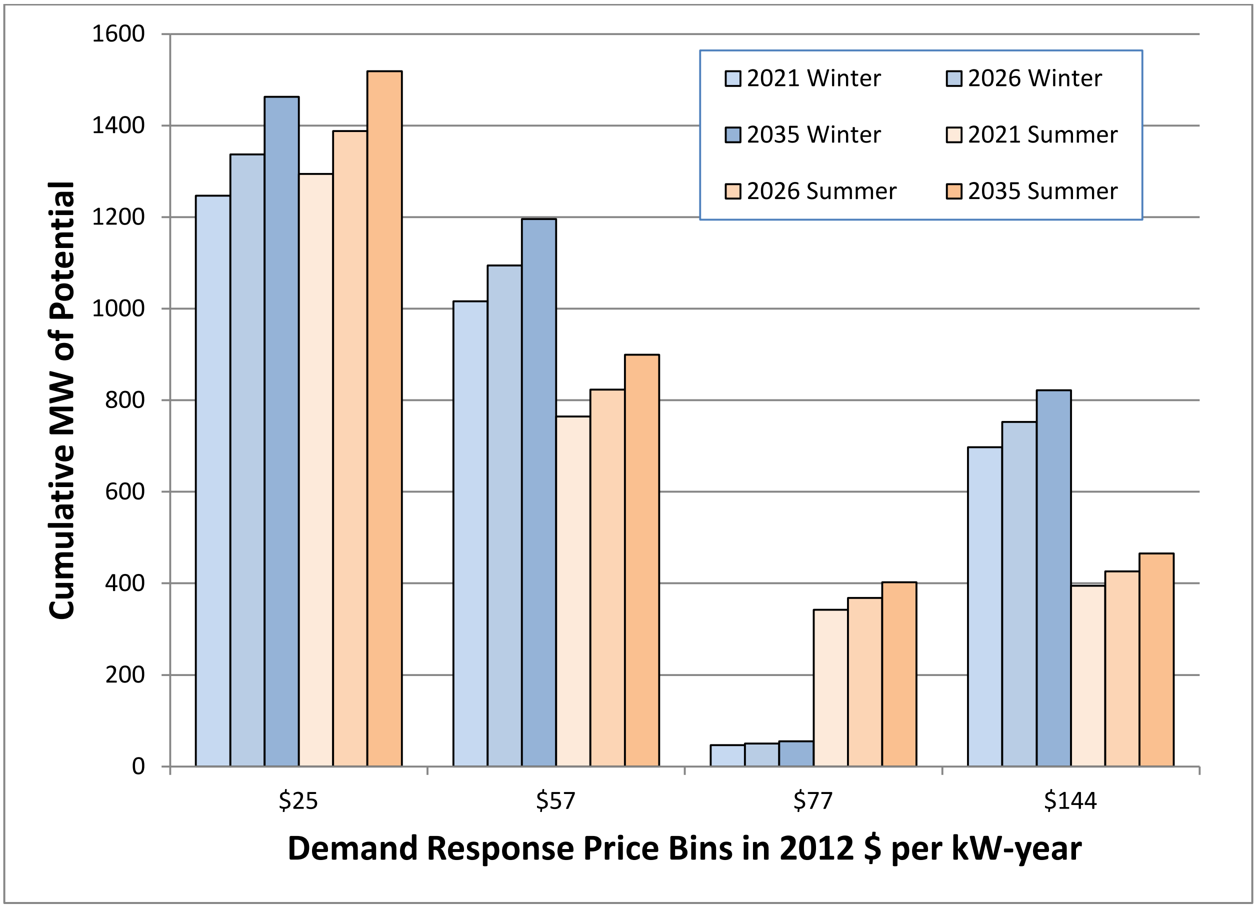


Figure 14 - 2 shows the cumulative technical DR potential of each price bin (in megawatts) to meet summer and winter peak load needs by the years 2021, 2026, and 2035. This figure highlights the different seasonal aspects of the price bins.

Figure 14 - 2: Demand Response Resource Supply Curve



Caveats for Demand Response Assumptions

The cost and DR potential shown in Figure 14 - 2 were provided as input into the RPM to analyze the impact of DR on the expected system costs and risk of alternative resource strategies. Accordingly, for the purposes of the Seventh Power Plan they are regarded as technically achievable potential, with the portfolio model analysis determining the programs and amounts that are cost-effective and/or mitigate risk less expensively than other options.[11] The technically achievable potential does not include consideration of institutional barriers for entities like Bonneville, but does consider market impediments such as customer turnover, participation, and availability.

While the Council regards these assumptions as reasonable for the region as a whole, each utility service area has its own unique characteristics that determine the demand response available and the programs that are cost-effective for that particular sub-region.

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[11] For more information about the portfolio model, see Chapters 3 and 15.

Discussion of Demand Response Not Modeled in the Regional Portfolio Model

Non-Firm Demand Response

The Council is not currently using assumptions about the amount of demand response that might be available from pricing structures, often described as non-firm demand response. There is no doubt that time-sensitive prices can reduce load at appropriate times, but the region does not yet appear to be ready for general adoption of these pricing structures. While hourly meters are becoming more common, many customers do not have them yet, which make time-of-day pricing, critical-peak pricing, peak-time rebates, and real-time pricing programs currently unavailable to those customers. Many in the region are concerned that some customers will experience big bill increases with different pricing structures. There also is the possibility for overlap in the assumed potential between firm demand-response programs and any pricing structure initiatives.

The Pacific Northwest Demand Response Project is continuing to pursue the subject of pricing structures as a means to achieve demand response. In addition, Idaho Power and Portland General Electric have and continue to conduct pilot projects of time-sensitive electricity pricing structures, which have achieved only mixed acceptance among customers.

Dispatchable Standby Generation

This resource is composed of emergency generators in office buildings, hospitals, and other facilities that need electricity even when the power is unavailable from the grid. The generators also can be used by utilities to provide contingent reserves, an ancillary service. Ancillary services are not explicitly simulated in the RPM, but dispatchable standby generation (DSG) is a resource fulfilling a similar niche as demand response that has significant potential and cannot be overlooked. Portland General Electric (PGE) has pursued this resource aggressively, taking over the maintenance and testing of the generators in exchange for the right to dispatch them as reserves when needed. PGE had 93 megawatts of dispatchable standby generation available in 2013, and plans to have 116 megawatts by 2017. This potential will grow over time as more facilities are built with emergency generation and existing facilities are brought into the program. The Council does not currently incorporate potential from new dispatchable standby generation explicitly in the RPM modeling, but considers existing DSG in the reliability modeling in GENESYS.

Providing Ancillary Services with Demand Response

Demand response usually has been regarded as an alternative to generation at peak load (or at least near-peak load), that occurs a few hours per year. But demand response can do more than help meet peak load. It can help provide ancillary services such as contingency reserves, regulation and load following. Historically, additional supply of ancillary services has not been considered a need in the Pacific Northwest due to the large supply of flexible hydropower in the region. As loads have grown, and as variable energy resource generation (primarily wind) has increased, power system planners and operators have become more concerned about ancillary services. Not all demand response resources can provide such services because they have different requirements than meeting peak load.

Ancillary services are not explicitly simulated in the RPM so the potential value of using demand response resources to meet these needs was not evaluated in the Seventh Power Plan. However, the Demand Response Potential Study conducted for the Council identified some DR resources available in the region for meeting ancillary service needs and regional entities have explored DR resources for this purpose, so further study of the use of DR is encouraged.