

Bonneville Power Administration
Provider of Choice Concept Paper
July 2022



Table of Contents

1. INTRODUCTION	1
1.1 Background	1
1.2 Provider of Choice Process 2016 – 2022.....	3
1.3 Energy Landscape	4
2. GOALS AND PRINCIPLES	5
3. PROVIDER OF CHOICE FRAMEWORK	7
3.1 Current Product and Rate Offerings	7
3.2 Basic Contract Framework	10
3.3 Provider of Choice – Looking Ahead	12
4. SERVICE TO UTILITIES	14
4.1 Net Requirements	15
4.2 System Size.....	16
4.2.1 Setting the Tier 1 System Size	16
4.2.2 Adjusting Tier 1 System Size for Future Load Growth	22
4.2.3 Calculating Contract High Water Marks for the Provider of Choice Contracts.....	22
4.2.4 Non-federal Resources.....	26
4.3 Products	29
4.3.1 Priority Firm Power Products	29
4.3.1.1 Load Following	29
4.3.1.2 Block.....	29
4.3.1.3 Slice/Block.....	30
4.3.2 Above-Rate Period High Water Mark Load Service	32
4.3.3 Capacity Option.....	32
4.3.4 5(b) for IOUs.....	33
4.3.5 New Large Single Loads.....	33
4.3.6 Direct Service Industry Customer	34
4.4 Other	34
5. CARBON AND OTHER ENVIRONMENTAL ATTRIBUTES	36
6. TRANSFER SERVICE	39
7. TRANSMISSION	43
8. LONG-TERM COST MANAGEMENT	44
9. DISPUTE RESOLUTION	51
10. POST-2028 INITIATIVE PROCESSES	52
10.1 Post-2028 Rate Methodology	52
10.2 Residential Exchange Program.....	55
10.3 Conservation	61
11. BECOMING THE PROVIDER OF CHOICE	63
APPENDIX – ABBREVIATIONS/ACRONYMS	66

1. INTRODUCTION

The Bonneville Power Administration has supplied reliable, affordable and low-carbon wholesale electric power to public power utility and investor-owned utility (IOU) customers serving retail consumers throughout the Northwest for over 80 years. This proud tradition is rooted in the agency’s enabling legislation, and Bonneville looks forward to building on this legacy in the years ahead.

As directed by Section 5(b) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), Bonneville is obligated to offer firm power sales contracts whenever requested by regional public power utilities and IOUs that have the statutory right to request Bonneville offer a power sales contract. Before offering these contracts, Bonneville leads a regional contract-development effort. As Bonneville initiates this process to develop new power sales contracts, it looks to affirm its status as customers’ “Provider of Choice.”

With the release of the paper, Bonneville officially launches the policy development process that will engage the region in the design of a policy that supports its products and services offerings. This is a starting point rather than a conclusion. This paper is intended to spark regional discussion that leads to a long-term policy that has broad support. The paper primarily focuses on service to publicly owned utilities, given that it builds off of the current contract framework and the footprint of customers’ purchasing power pursuant to Section 5(b) from Bonneville today. Bonneville recognizes that there are a number of questions to address and much yet to consider in assessing regional perspectives and evolving utility customer needs. Bonneville looks forward to constructive conversations with regional utilities, including IOUs interested in 5(b) contracts, and other interested parties in the region to define the new power sales contracts.

1.1 Background

Bonneville is a federal power marketing administration that sells wholesale power at cost from 31 federal dams in the Columbia River Basin. The U.S. Army Corps of Engineers and Bureau of Reclamation own and operate the federal dams. The system of federal dams marketed by Bonneville is often referred to as the Federal Columbia River Power System (FCRPS) and includes the transmission system constructed and operated by Bonneville. Bonneville also sells the output of the region’s only nuclear power plant, operated by Energy Northwest. Today, Bonneville sells this power to more than 100 Northwest electric utilities that serve millions of customers and businesses in Washington, Oregon, Idaho, western Montana and parts of California, Nevada, Utah and Wyoming.

Regional utilities can request Bonneville to offer a power sales contract to provide power on a continuous basis at cost-based rates. These contracts set forth the terms and conditions under which federal power is sold by Bonneville and purchased by a customer. Contracts provide for long-term service and by statute cannot exceed a 20-year term. Before its long-term contracts expire, Bonneville leads a multi-year regional effort to develop a successor power marketing policy from which to negotiate long-term power sales contracts.

1.1.1 Regional Dialogue

Bonneville currently delivers firm power to regional public power customers under Long-Term Regional Dialogue power sales contracts, which were offered and executed in 2008. These agreements provide reliable, cost-effective, low-carbon power sufficient to meet the firm power loads of public power utility

customers throughout the Pacific Northwest region. For Bonneville, these agreements provide essential revenues to recover its costs and support its ongoing viability, providing an estimated 76% of Power Services' revenue requirement under current rates.

A collaborative multi-year process resulted in the creation of the Regional Dialogue contracts and accompanying tiered rate construct. These contracts were designed with lessons learned from the West Coast energy crisis and an expectation that public power customers would face varying degrees of load growth in the future. Tiered rates were designed to prevent the dilution of existing low-cost power from the federal power system by avoiding the melding of costs of future resources into the existing system. The contracts and the tiered rate construct empowered individual customers to determine how to best meet their own future power needs.

While the expected load growth largely did not materialize, the Regional Dialogue contracts, in concert with the tiered rate construct, have provided contractual certainty and rate stability to public power customers over the past 10 years. The contract period started with the Great Recession, which led to a major reduction in load across the region as the economic impact reverberated through commercial and industrial consumers. Economic recovery was slow in many communities and permanently changed the consumer demand for others. During this time, building standards, appliances and electronics rapidly became more energy efficient, leading to lower load growth across the region. By exception, some public power customers experienced major load growth, often from new high-tech industries locating in their service territories.

In light of the experiences over the past 10 years and the changes in the wholesale electric power industry, products and services provided by Bonneville under its Regional Dialogue contracts have generally met the changing needs of customers. Working with customers, Bonneville has added services or tailored products when necessary. As Bonneville begins to engage with its customers and the region to develop the next round of power sales contracts, it intends to leverage existing product and service features that work well and explore potential areas for improvement.

1.1.2 Bonneville Strategy and Major Initiatives

Bonneville has taken decisive steps to outline its strategic future and invest in major initiatives that support service to customers. The agency's goals were published in Bonneville's 2018 – 2023 Strategic Plan. The plan articulates how Bonneville is moving forward and focusing on the right investments for the agency, its power and transmission customers, and the public. Bonneville intends to release a refreshed plan in early 2023.

One major Bonneville initiative, the Grid Modernization Key Strategic Initiative, began in 2018. This initiative represents a six-year plan to modernize operations of the federal power and transmission systems to enhance situational awareness, improve capability to provide products and services customers seek, and participate in developing markets. For example, grid modernization enabled Bonneville to join the Western Energy Imbalance Market and adapt to the evolving electric utility industry. Keeping pace with industry change and offering competitive products and services enables Bonneville to fulfill its various public purposes that benefit the Pacific Northwest.

Bonneville also released a detailed financial plan in 2018 that led to the development of the revised Financial Reserves Policy and Leverage Policy, which improved the way Bonneville manages its finances.

Bonneville is currently updating its financial plan, which will refine the framework for how the agency will maintain and strengthen its financial health.

1.2 Provider of Choice Process 2016 – 2022

Bonneville coined the term “Provider of Choice” in 2016 during a series of regional conversations known as Focus 2028. At that time, Bonneville recognized many factors were putting upward pressure on its long-term cost structure, which could adversely impact its long-term competitiveness. Focus 2028 was a forum for regional leaders to begin to develop a common understanding of the types of industry changes and strategic choices Bonneville may face to maintain its cost competitiveness and financial strength. Bonneville engaged the public to develop a shared understanding of the interplay and balance between industry changes, program management, costs and long-term rates. These discussions informed Bonneville’s subsequent strategic plan and solidified the agency’s focus on being the low-cost energy provider of choice when new power sales contracts are offered for the post-2028 timeframe.

In late 2019, Bonneville began meeting informally with public power customers to discuss post-2028 firm requirements power sales issues. Bonneville’s primary goal for this engagement was to listen and learn. In October 2020, Bonneville released the [Provider of Choice 2020 Customer Engagement Summary](#) that synthesized the key findings from these informal customer conversations. These findings provided the foundational launching pad as Bonneville shifted from a listening and information gathering mode into the more iterative concept development phase.

In early 2021, Bonneville was invited to participate in a series of Public Power Council (PPC)-hosted Rates and Contracts forum sessions to provide ongoing educational opportunities and have discussions with public power customers. The series’ purpose was to gain a shared understanding, highlight areas of interest, and set the stage for the subsequent public policy phase. Bonneville also engaged with other interested parties as requested. Bonneville materials from the 2021 PPC Rates and Contracts forum sessions are posted on [Bonneville's Provider of Choice webpage](#).

1.2.1 Public Power Concept Papers

Bonneville’s informal customer engagements from late 2019 through 2021 were intended to conclude with the release of the Bonneville Provider of Choice Concept Paper. While Bonneville initially planned to release its concept paper immediately following the customer engagement phase in late 2021, Bonneville received requests for a delay in October 2021 from PPC, Northwest Requirements Utilities (NRU) and Washington Public Agencies Group (WPAG). The purpose of the pause was to give public power customers time to gather and collaborate with the goal of developing a public power concept paper. Bonneville supported the approach.

In late March 2022, Bonneville received a [Public Power Post-2028 Concept Paper](#) submitted jointly by and representing the member utilities of PPC, WPAG, NRU and PNGC Power (PNGC). Bonneville also received an additional paper, [Post-2028 BPA Contract Framework and Concept Paper](#), from PNGC.

There are many areas where public power emerged unified in their concept papers, including: alignment on moving forward with a tiered rate construct, the establishment of Contract High Water Marks (CHWMs), and with the general idea of Bonneville offering Load Following, Block and Slice/Block products with modifications to address some customers’ capacity concerns. There appears to be alignment on exploring ways to offer clean power products and associated renewable energy credits

(RECs) that will support customers subject to state carbon legislation, while crafting products to ensure equity in pricing. Public power has also preliminarily aligned in support of transfer service for federal power and the Low Density Discount (LDD) and Irrigation Rate Discount (IRD) programs.

Public power also asked Bonneville to prioritize early workshop discussions around Tier 1 system size and potential system size augmentation, calculation of CHWMs and capacity. These are among the most challenging and foundational issues ahead.

1.3 Energy Landscape

As Bonneville initiates policy and contract development with the region, it does so amidst substantial industry change. A number of energy landscape changes are expected to unfold over the next 20 years, driven in part by new state laws and regulations requiring decarbonization and electrification, and by regional market development. As described below, changes will bring both opportunities and challenges. Bonneville offers an overview here to highlight drivers that may change the needs and expectations of public power utilities and IOUs for Bonneville power sales.

Day-Ahead Market or Regional Transmission Operator (RTO). In addition to regional coordination on a resource adequacy program, the region has started to discuss whether it should form a regional day-ahead market. There are two efforts underway today to evaluate a day-ahead market: the California Independent System Operator's (CAISO) Extended Day-ahead Market (EDAM) Initiative and the Southwestern Power Pool's (SPP) Markets+ process. There are also nascent discussions regarding a potential West-wide RTO. The current day-ahead market efforts, as well as potential future developments toward an RTO, could impact the power sales contracts even if Bonneville is not a direct market participant.

Resource Adequacy. Early retirements of coal plants have affected the availability of power in the wholesale electricity market and spurred increased investments in renewable resources. These investments are transforming the region's energy profile and will change how and when energy and capacity are needed in the future. A greater emphasis on capacity is already seen through the ongoing effort to develop the Western Resource Adequacy Program (WRAP) to ensure that utilities plan and bring enough power to meet their own needs and help the region avoid generation shortfalls. Bonneville continues to evaluate the WRAP and expects to make a decision regarding its potential participation by the end of 2022.

Columbia Generating Station. The Columbia Generating Station is operated by Energy Northwest and its current license expires in 2043. Bonneville expects discussions and decisions regarding future Columbia Generating Station licensing to occur well in advance of this expiration date.

Electrification. Electrification refers to the increase in load as the result of efforts to reduce greenhouse gas emissions. This is fueled by laws and regulations as well as by market forces. Substantial electrification would result in increased load for electric utilities, likely with an expectation that load is served by carbon-free resources.

Decarbonization. There is a move in some states to reduce the carbon emissions of the fuels that are expended to produce energy. Washington state has passed two sets of legislation that are changing the demand of Washington utilities for certain resources in the future. The Clean Energy Transformation Act (CETA) outlines requirements for retail utilities in Washington to eliminate coal by 2026 along with

targets to be carbon-neutral by 2030 and carbon-free by 2045. The Climate Commitment Act establishes a cap-and-invest program which begins in January 2023. Bonneville recognizes that currently over 63% of its long-term power sales are made to Washington customers who will be seeking ways to meet those regulations. Bonneville also recognizes other local, state or federal government carbon regulations could emerge over the next decade, which may also require changes from customers or Bonneville.

[Columbia River Treaty \(Treaty\)](#). The year 2024 is a critical year for the Treaty between the United States and Canada. In that year, the current flood risk management provisions change to a less-defined approach for hydrological coordination. There is also the opportunity for both countries to seek to modernize how the Treaty is implemented beginning in 2024, such as providing for greater ecosystem cooperation and working toward achieving a more equitable balance on Treaty power costs and value. The U.S. and Canada began negotiations to modernize the Treaty regime in May 2018, and these negotiations continue today.

Past experience demonstrates that the changes the region faces are not insurmountable. Bonneville is confident the region will again come together to develop new contracts that will be as adaptive as the Regional Dialogue contracts have proven to be. The policy workshops will help Bonneville understand regional perspectives on how the agency fits into the evolving energy landscape.

2. GOALS AND PRINCIPLES

The Provider of Choice goals and principles are a cornerstone of this concept paper and are intended to guide the Provider of Choice policy and contracts. They convey Bonneville's vision for what future power sales contracts could provide to regional customers through new or improved products and services. They also provide a framework against which Bonneville and the region may assess policy and contract direction. Bonneville recognizes these goals and principles may evolve over the course of public discussion.

The goals described below embody Bonneville's aspirations for the Provider of Choice policy and contracts, while the principles represent fundamental assumptions that Bonneville's Provider of Choice policy and subsequent contract development must meet.

These goals and principles are meant to shepherd the Provider of Choice process. They are not intended to apply to the other Post-2028 Initiative processes discussed in Section 10 or areas outside the scope of this concept paper. Bonneville recognizes that its contracts can support customer implementation of regional and national regulations and initiatives; Bonneville's direct role in that is providing wholesale power. Further, because the contracts are power contracts, any changes to Transmission Services' policies or tariff are outside the scope of this effort. Bonneville's Power Services will work closely with Transmission Services on a One-Bonneville policy approach.

Bonneville presented draft Provider of Choice goals and principles at a workshop on May 19, 2022. The public was invited to provide feedback during the workshop or in written comments following the presentation. Bonneville appreciates the feedback it received. Bonneville heard these goals and principles generally align with public power interests. There is general interest in being flexible on these goals and principles if emerging needs warrant adjustment.

Some of the feedback Bonneville received, which can be found on the [Provider of Choice webpage](#), has been folded into the revised goals and principles below. Bonneville would characterize the feedback

received as reflecting how regional customers and the public want to see themselves and their interests more clearly incorporated into certain goals or principles. The feedback not reflected in edits to the goals and principles is being considered by Bonneville for focused discussions in policy workshops this fall.

2.1 Goals

Bonneville looks forward to working with customers and the region to evaluate how these goals can best be met under future product offerings. The Provider of Choice goals are as follows:

- 1. Regionally supported Provider of Choice policy and contracts.** Bonneville's regional firm power customers and the region generally support the new policy and contracts offered by Bonneville. The region will be engaged throughout the transparent process and regular input will ensure Bonneville meets this goal.
- 2. The Federal Base System is fully subscribed to supply customers' net requirements.** Bonneville offers attractive products and services at competitive rates.
- 3. Product and service offerings are equitable.** Bonneville's product offerings balance the benefits, costs and risks while recognizing differences in needs and interests.
- 4. Contracts offer customers flexibility to invest in and integrate non-federal resources.** Bonneville will look for opportunities to accommodate the use and integration of customers' non-federal resources as part of power sales contracts and support customers meeting their firm power supply needs while limiting risk and cost increases to applicable power rates.
- 5. Contracts support customers meeting national and regional objectives.** Bonneville supports customers in meeting their applicable compliance requirements. Current and emerging issues to be considered include clean energy policies, distribution of environmental attributes, emerging markets and electrification.
- 6. Administratively straightforward and implementable contracts.** Bonneville's contracts simplify the implementation of products and services in a way that minimizes administrative complexity and costs while taking into consideration customers' needs.
- 7. Provider of Choice policy and contracts build on a long history of stewardship and regional relationship.** Bonneville values its relationships and commitments in the Pacific Northwest.

2.2 Principles

The Provider of Choice principles are as follows:

- 1. Tier 1 firm power rates are set at the lowest possible rates consistent with sound business principles.** Bonneville sells federal power at cost to its customers and strives to provide competitive rates. This includes considering its business needs and preserving the near and long-term value of the Federal Columbia River Power System for the region.
- 2. Provider of Choice policy and contracts are consistent with Bonneville's statutes.** Bonneville offers contracts to provide power to customers to meet their firm power load net of their non-

federal resources. This principle includes ensuring there are adequate resources to meet Bonneville's contractual load obligations.

- 3. Contracts provide long-term supply of electric power through standardized products and services and transparent processes.** Bonneville develops its policy and offers and implements standardized contracts transparently.
- 4. Provider of Choice policy and contracts provide financial stability for Bonneville and support Bonneville's regional obligations and commitments.** Bonneville's policy and contracts support its financial obligations and objectives, such as its ability to meet all debt obligations. Options, alternatives or concepts provide value to customers and the region while minimizing risk for Bonneville and customers.

3. PROVIDER OF CHOICE FRAMEWORK

This paper provides a starting point for Bonneville and the region to develop a formal policy with detailed product offerings for the post-2028 power sales contracts. Bonneville welcomes regional perspectives and ideas and anticipates that additional options or alternatives will be considered during the policy workshops.

The concepts provided in this paper build on the current power sales contract product offerings and rate methodology based on feedback from public power customers that the current offerings generally work well. However, Bonneville expects aspects of these offerings to evolve and that the region will explore new ideas on how best to meet emerging customer and regional needs as discussed in Section 1.3. To initiate this evolution, this concept paper outlines some options that represent possible new flexibility to products and services.

As a more holistic framework emerges in the form of a draft policy, some flexibilities may be eliminated to maintain balanced power contracts. For example, if Bonneville and its customers were to agree to a substantially larger Tier 1 system that requires Bonneville to take on resource acquisition, then Bonneville would likely take a conservative stance toward non-federal resource development that would offset Tier 1 take-or-pay obligations, as ensuring cost recovery of the additional resource acquisition will be key to the future agreements. These trade-offs are mentioned throughout this paper and will be central to upcoming policy conversations.

This Provider of Choice Framework section provides the elements underlying the Provider of Choice concept. It includes an overview of the existing products and services offered under existing contracts and current tiered rate methodology. It also highlights some of the major changes Bonneville is proposing to explore as it begins the process of collaborating with the region on the post-2028 power sales contracts.

3.1 Current Product and Rate Offerings

In the late 2000s, Bonneville established a new approach for the sale of firm requirements power for regional public power customers through the Regional Dialogue power sales contracts with the Tiered Rate Methodology (TRM) and CHWM construct. Below is an overview of those constructs and the three products offered under current contracts, as well as the original design intent.

3.1.1 Tiered Rate Methodology

Bonneville established the current TRM through a section 7(i) rate proceeding in 2008 and 2009 and was first used to set power rates for the BP-12 rate period. The TRM establishes a two-tier rate design that applies to sales of firm requirements power at the Priority Firm (PF) power rates. These sales are limited to Bonneville's public power customers that signed Regional Dialogue contracts. Under this methodology, customers are entitled to purchase up to a certain amount of firm power from the existing federal system, based on firm water conditions, at the applicable PF Tier 1 rate. If a customer's needs exceed that amount, they contractually elect whether to be supplied by 1) non-federal resources secured by the customer; 2) additional Firm Requirements Power supplied by Bonneville at the applicable Tier 2 rate; or 3) a combination of 1 and 2.

The tiered structure of Bonneville's power rates did not eliminate Bonneville's requirement to serve a customer's full net requirements. Rather, it differentiates the costs and risks associated with supplying power above Bonneville's firm system compared to market purchases or other resource acquisitions needed to supply a customer's full net requirements obligation.

The tiered rate construct guaranteed all customers access to purchase low-cost Tier 1 power up to their high water mark for the term of the contract. It then provided customers with the choice for managing load above their high water mark, whether through electing Bonneville to serve the load through Tier 2 rates, securing non-federal resources, or purchasing surplus power if available from Bonneville.

While generally Bonneville proposes to retain the tiered rate construct in Provider of Choice, the TRM itself is only applicable through the term of Regional Dialogue. Therefore, another process would be needed to extend or modify a tiered rate approach to the term of the post-2028 power sales contracts, as well as to adapt and update the rate methodology to reflect any changes made to products and services. More information about the Post-2028 Rate Methodology process is available in Section 10.1.

3.1.2 Contract High Water Mark

In tandem with the TRM, the Regional Dialogue power sales contract incorporates the construct known as CHWMs. A CHWM sets a public power customer's maximum eligibility to purchase power priced at the PF Tier 1 rate for the duration of the contract. Regional Dialogue CHWMs were calculated based on customer loads in fiscal year (FY) 2010, adjusted for weather-normalization, conservation and the economic downturn experienced in the region at that time. CHWMs are fixed through 2028, the term of the Regional Dialogue contract, with only minor exceptions for annexations between customers, new utility formation and growth of tribal utilities.

Every rate period, Bonneville implements adjustments based on the Tier 1 firm system size for that rate period, resulting in a Rate Period High Water Mark (RHWM). The RHWM is the amount of power service at the PF Tier 1 rate available during the defined rate period. During the RHWM process, Bonneville recalculates the Tier 1 firm system size to adjust for changes in river operations, fish operations, Treaty and the expiration of power purchases. This results in changes to the amount of power at the PF Tier 1 rate available for CHWMs over time. Over the course of Regional Dialogue, the Tier 1 firm system size has varied from 6,667 average megawatts (aMW) to 7,136 aMW.

Any load above the RHWM is considered Above-Rate Period High Water Mark (Above-RHWM) load. Customers may choose to have Bonneville serve their Above-RHWM load with power sold at a Tier 2 rate, with non-federal resources, or a combination of the two. Customers make their election of how to

serve their Above-RHWM load three years in advance of a five-year commitment, via their purchase period election.

A customer looking for Bonneville to meet their full net requirements load obligation could elect to have Bonneville serve any Above-RHWM load with Tier 2 power. The CHWM construct establishes a point at which customers get a choice over how to serve Above-RHWM load in alignment with the intent of the TRM to prevent dilution of the Tier 1 system cost.

Bonneville proposes that the CHWM construct would continue to support tiered rates under Provider of Choice. Under Section 4.2.3, Bonneville proposes how future CHWMs would be calculated.

3.1.3 Product Offerings

Under Regional Dialogue, Bonneville offers three products (or purchase obligations as they are defined in the contracts) – Load Following, Block and Slice/Block. These products reflect different options public power customers could choose among to serve their own load. Load Following represents a full-service product where customers can opt to rely entirely on Bonneville to meet their full net requirements needs (both RHWM and Above-RHWM load). The Block and Slice/Block are partial requirements products that were designed to provide more flexibility and potential opportunity in how customers managed their loads and resources, as applicable. All three products provide service at the PF Tier 1 rate as well as options to have Above-RHWM load served at a Tier 2 rate. Below is a description of how these products function under Regional Dialogue. A full description of current products and services can be found in the [Regional Dialogue Guidebook](#). Bonneville’s proposed Provider of Choice product offerings can be found in Section 4.3.

3.1.3.1 Load Following

The Load Following product provides firm power service to meet a customer’s actual total retail load net of the customer’s dedicated Section 5(b) resources. This means that Bonneville supplies the power needed to meet a customer’s net firm power load in any given hour. Dedicated resources can be applied in pre-established amounts, called shapes, or simply as the resource generates. Depending on the size and type of resource, the customer may be required to purchase Resource Support Services (RSS) from Bonneville to account for the cost of resource unpredictability and shape.

If Bonneville decides to join a resource adequacy program, like the WRAP currently under development, the program would be expected to facilitate Bonneville’s ability to meet resource adequacy needs for a customer with Load Following during the term of Regional Dialogue. The Load Following product is not available to a customer operating its own balancing authority area.

3.1.3.2 Block

The standalone Block product provides a planned annual amount of firm power to meet a customer’s planned annual net requirements load. The customer serves any load in excess of its planned monthly Block purchase. Customers purchasing the Block product must manage their own resources and acquire additional power to meet their loads, if needed. Block customers can opt to have Bonneville serve their additional power needs under a Tier 2 product if they elect to do so.

The Block product provides a predefined amount of power each hour and can be purchased in two different shapes. The first is a flat annual block shape, which provides the same amount of power every

hour in a defined year. The second is a shaped block of power which is shaped to the customer's forecast net requirement. Shaped blocks of power can vary by month and between heavy and light load hours (HLH and LLH) based on the customer's actual FY 2012 net requirements shape.

Bonneville also offers a Block product with Shaping Capacity option available to customers purchasing the standalone Block product. The shaping option establishes a daily range for each month within which a customer may reshape the daily HLH energy amount of its Block purchase. The shaping capacity option selected by a customer is contractually added to its take-or-pay purchase of power as Bonneville must reserve that capacity to meet a customer's shaping request. No customers elected to take this option during the Regional Dialogue contract term.

3.1.3.3 *Slice/Block*

The Slice/Block product provides for the combined sale of two distinct power products to meet a customer's planned annual net requirements: the Slice product and the Block product. The Block portion of Slice/Block is the same as the standalone Block product described above except the Block portion of the Slice/Block product has less flexibility in shape than under the standalone Block product because the Slice portion provides significant shaping flexibility. A customer purchasing the Slice/Block product is responsible for meeting its total retail load each hour and is responsible for supplying any amount of power needed to meet its load beyond the Slice/Block purchase. The Block portion of the product must be equal throughout a month although customers can opt for a flat annual or flat within-month shape. The annual amount of Block is calculated as the difference between the customer's planned annual net requirements load and the firm Slice amount from the Slice product.

A key component of the Slice product is that the Requirements Slice Output (RSO) shall be used solely for the purpose of serving total retail load, which is demonstrated by the monthly RSO test. The test compares the Slice output energy delivered to its actual total retail load plus loss return schedules to Transmission Services. If a Slice customer fails to meet the RSO test, it is charged a penalty.

The Slice portion of the Slice/Block product is a federal system sale of power that includes firm requirements power, hourly scheduling rights and surplus power. The customer's Slice output is calculated based on a percentage of the annual firm portion of the Tier 1 system. From time to time, the Slice product may deliver more or less power due to water availability and system operations. Slice customers take on the variability risk as part of the product.

The Slice/Block product is not a sale of operational rights, Tier 1 system resources, resource capability, or transfer of control of any federal resources. Federal operating agencies retain all operational control of all resources that comprise the FCRPS at all times.

3.2 Basic Contract Framework

The following sections outline Bonneville's proposal for contract terms for the following three elements: term of the contracts, standardized agreements, and take-or-pay contracts.

3.2.1 Term of the Contracts

Bonneville proposes a 20-year term for the Provider of Choice contracts, which is the longest term allowed by statute. Twenty-year contracts assume the agreements would become effective in late 2025

upon execution by the parties, with power deliveries beginning in October 2028, and expiring September 2045.

Long-term contracts have historically served the region well, providing long-term stability and planning for both Bonneville and its customers. Long-term contracts provide predictability and certainty, and accordingly serve to secure many, if not most, of the Provider of Choice goals and principles.

Long-term contracts are fundamental to maintaining Bonneville's overall financial health. They are also a key driver in preserving the agency's access to low-cost debt capacity and maintaining adequate liquidity, including for continued successful U.S. Treasury repayment. Long-term contracts best accommodate long capital recovery periods for acquiring fixed assets, technologies and associated financial commitments, when needed. They provide certainty for financial planning, which is essential for Bonneville to meet its long-term responsibility to the region to invest in and maintain the FCRPS.

Long-term contracts have an administrative benefit for Bonneville and its customers. They offer Bonneville and customers a respite from back-to-back continuous cycles of contract design and negotiation, during which the region focuses on reliable and cost-effective service delivery. Design of subsequent contracts then benefit from lessons learned and experiences collected during contract administration, much as is being experienced now in the transition between Regional Dialogue and Provider of Choice. By executing agreements ahead of the delivery term, it provides an essential preparatory window to adapt systems and processes for new contract terms.

Power from the FCRPS will continue to become increasingly valuable. Locking in long-term agreements provides customers' rights to be supplied from the FCRPS, which is carbon-free and competitively priced. Bonneville has heard guarded support for long-term agreements, tempered with concerns over cost management. Bonneville has also heard public power concerns associated with extended cost exposure risk that comes with long-term contracts. However, it is Bonneville's assessment that the substantial benefits that come with a long-term agreement outweigh these considerations. See Section 8 for a more full discussion on cost management.

While Bonneville is proposing a 20-year contract, it is cognizant of Washington state clean energy standards, which shift from carbon-neutral requirements in 2044 to carbon-free requirements in 2045 (see Section 5 for more detail). Bonneville is open to exploring 19-year contracts that would provide power deliveries through 2044. With a 19-year contract expiring in 2044, the Washington 100% clean standard would fall under the subsequent power sales agreements and associated negotiations would give all parties the additional time to prepare. Bonneville proposes raising this issue of contract term in the upcoming workshops so that all customers and stakeholders can gain insights and provide input on whether to pursue 19- versus 20-year contracts.

Lastly, Bonneville proposes that all customers' Provider of Choice contracts have the same effective date and expiration date at the time of contract offer. Service under such contracts would commence and proceed through uniform dates. Uniform service dates for all customers enables an orderly transition into new contract administration, including any necessary system or process adjustments, minimizes the risk of cost-shifts among customers, promotes standardization, and presents the future opportunity for holistic, inclusive future product, service and contract development.

3.2.2 Standardized Agreements

Bonneville proposes standardized contracts for each product offering (Load Following, Block and Slice/Block) including the use of as many standardized terms and conditions across all contracts as is practical. This is consistent with the Provider of Choice principle that, “Contracts provide long-term supply of electric power through standardized products and services and transparent processes.” Bonneville will create contract templates for each product and, to the maximum extent practicable, contracts would leverage standardized terms and conditions and rely on routine processes for administration.

It is intended that the standardization principle will apply not only as contracts are developed and offered, but will apply after individual contracts are executed, during the contract implementation phase. Standardizing terms and conditions reduces the risk of inconsistent treatment between customers electing similar products and services. Standardized template contracts create confidence in uniform and fair treatment of all customers and ensures questions of inter-customer equity are addressed up-front and transparently. Standardized contracts also reduce ongoing burden and costs associated with contract administration and help reduce the risk of errors throughout contract administration.

Bonneville’s focus on standardization is pragmatic; Bonneville does intend to accommodate a range of general, predicted and relatively common variations among customers. The contracts will include options that will capture customers’ elections through option-specific clauses. Bonneville also acknowledges that some customer circumstances are unique and not well-suited to inclusion in the general contract template. Bonneville would continue to capture unique and special provisions in individual contracts.

3.2.3 Take-or-pay Contracts

Bonneville proposes that, similar to current contracts, power purchases under Provider of Choice contracts will be take-or-pay for the amount of federal power purchase obligation from Bonneville at PF Tier 1 and Tier 2 rates. Provider of Choice contracts will create long-term certainty for customers about their access to power from Bonneville, with a reciprocal take-or-pay commitment from customers for the federal power purchased that minimizes cost shifts between customers as Bonneville recovers its costs through its power rates over the term of the contract.

Under Regional Dialogue, there are mechanisms built in to ease a customer’s take-or-pay risk. Bonneville anticipates similar mitigations under Provider of Choice agreements. The purpose of including a take-or-pay provision is two-fold: (1) to discourage a customer from advantageously offsetting its federal power purchase obligation with non-federal options at the expense of other customers, and (2) to provide assurance that Bonneville will be able to recover all of its costs, inclusive of making its payments to the U.S. Treasury in full and on time.

3.3 Provider of Choice – Looking Ahead

The combination of the Regional Dialogue contract coupled with the TRM has proven to be a resilient construct that has provided long-term rate stability and predictability. Even so, over the last 10 years, Bonneville and its customers have learned what works well and what could be improved under the current construct. Contractual enhancements and improvements will consider the expected industry changes outlined in Section 1.3. To that end, Bonneville believes that the post-2028 power sales

contracts should start with the framework of the current mode of service, with a number of improvements described in the following sections.

In general, Bonneville sees four priority issues, not addressed under Regional Dialogue, which will need further development and refinement in the next round of power sales contracts: capacity, carbon, non-federal resource flexibility and evolving market development. The Provider of Choice concept that Bonneville discusses in this paper offers a number of options to address these individual but linked issues through product design, service offerings and policy decisions. These concepts are summarized below, and details are provided later in this paper.

3.3.1 Capacity and Resource Adequacy

Sufficient resource capacity to meet current and future energy demands is a key issue Bonneville and the region will be facing in the post-2028 period. The issue of sufficient resource capacity is highlighted by early resource retirements, increased intermittent renewable resource development, and the emerging WRAP. The Northwest has long been a capacity-rich region and while capacity has been acknowledged in previous contract discussions, it was never as critical as it is today.

If Bonneville, with support of its customers, decides to join the binding WRAP, there are several issues that may need to be addressed in future product offerings. There may be new planning requirements around the accounting and application of non-federal resources, both specified and unspecified, used by customers to supply their load. Bonneville and the region will need to determine how WRAP requirements should be enforced and how costs associated with non-compliance should be allocated. The Provider of Choice effort will continue to work in concert with the proposals from the WRAP process to ensure that any new requirements presented by the WRAP are considered in policy discussions for post-2028 product offerings.

Bonneville recognizes the growing importance of ensuring adequate capacity and has suggested modifications in the Provider of Choice Concept Paper of how to meet emerging needs. First and foremost, Bonneville proposes to determine the capability of non-federal resources used by customers to supply their load, which includes the firm peaking and energy of such resources (referred to as “peak net requirements”). Section 4.1.1 outlines the case for adoption and Bonneville’s proposal for how such peaking capability could be calculated.

Second, Bonneville proposes product changes for the Block and Slice/Block products in Section 4.3.1. The discussion outlines the need to develop a Block product with Shaping Capacity option to better meet customers’ peak needs. Bonneville also outlines the case for applying peak net requirements to the Block and Slice/Block product.

Finally, Bonneville suggests that it may need to rethink how capacity is charged through rates. With the growing focus on capacity needs, there will likely be a need to provide distinct energy and capacity products or consider a tiered approach to capacity charges in future rates. More on the potential rate methodology design can be found in Section 10.1.

3.3.2 Carbon

The carbon content of Bonneville’s power sales is one of the most important issues to many existing public power customers and regional interests. Bonneville’s current system sales are about 95% carbon-free on average. The federal hydropower system and Columbia Generating Station provide reliable,

carbon-free power to the region. Bonneville also procures power from the market to balance its resources and loads, which comprise 3% to 12% of the federal system in any given year. States attribute emissions to these unspecified market purchases. However, there have been requests to further decrease the carbon content of Bonneville’s system or look at a product or set of options that would allow customers to purchase 100% carbon-free power from Bonneville. Bonneville discusses the impact of carbon in its discussion on system size in Section 4.2.1.5 and in the proposal for how to serve Above-RHWM load in Section 4.3.2. Section 5 outlines some of the options Bonneville could offer to support these requests for further reduction of carbon content and requests for a carbon-free product. Section 5 also describes some of the concerns Bonneville has in developing such a product.

3.3.3 Non-federal Resource Flexibility

Bonneville has heard from customers and the region that additional flexibility will be important given the changes the region and energy industry are facing. Bonneville is recommending new opportunities or improvements that could provide more non-federal resource flexibility.

An example of increased non-federal resource flexibility is how and when customers can add non-federal resources. In Section 4.2.4, Bonneville shares a proposal to allow for resources to offset a customer’s Tier 1 take-or-pay obligation. Bonneville discusses an alternative approach for Resource Support Services (RSS), a service offered for the Load Following product, through rate design and some of the trade-offs with these options in Section 10.1.1.2.

3.3.4 Day-ahead Market and Regional Transmission Operator Exploration

In May 2022, Bonneville joined the Western EIM. This was an important step for Bonneville to gain experience in an organized market. Since the inception of the EIM in 2014, there have been regional conversations about the creation of a day-ahead market or establishing an RTO. These conversations are beginning with two proposals for developing centralized, day-ahead markets – CAISO’s EDAM initiative and SPP’s Markets+. Bonneville is actively participating in the development and evaluation of potential opportunities.

If Bonneville were to determine it should pursue participation in a regional day-ahead market or potential RTO, it would conduct a public process to discuss potential opportunities and the impacts to its customers. Bonneville has a statutory obligation to serve its preference customers with federal power and could only support a market design that is consistent with these legal obligations. Bonneville’s ongoing engagement in the existing processes is aimed at ensuring the market designs would allow it to meet these obligations.

Regardless of whether Bonneville decides to pursue participation, Bonneville must evaluate how emerging markets will impact its power marketing. For the purpose of this Provider of Choice Concept Paper, Bonneville has not factored in future market participation in the design of products and services, since such markets have not yet been developed. In the meantime, Bonneville will continue to coordinate its Provider of Choice and market evaluation efforts.

4. SERVICE TO UTILITIES

As noted under Section 3, the Provider of Choice Framework, Bonneville’s products and service offerings provide the essential building blocks of the Provider of Choice policy, laying the groundwork for long-term contracts that meet Provider of Choice goals and principles. The following section describes how

Bonneville would provide service to utilities. Additional conversations will be required to refine these offerings ahead of the Provider of Choice policy.

4.1 Net Requirements

Section 5(b) of the Northwest Power Act provides that, whenever requested, Bonneville must offer to sell power to meet the firm power (e.g., retail consumer) load of any public body, cooperative or IOU located within the Pacific Northwest region. The amount of power Bonneville is obligated to supply to the customer under Section 5(b) is equal to the customer's firm power load that is not otherwise served by the customer's own resources. This is referred to as the customer's net requirements.

Under Bonneville's organic statutes, Bonneville has broad contract and rate design authority. Bonneville has discretion to develop different ways of supplying power to meet its customers' net requirements load. Bonneville also has discretion to establish reasonable terms and conditions for those sales. As discussed in Section 4.3.1 below, Bonneville proposes to continue to offer a Load Following product that meets all of a customer's actual hourly net requirements load. In addition, Bonneville proposes to continue to offer the Block and Slice/Block products based on a forecast of the customers' net requirements. For purposes of cost allocation and applying rates under the tiered rate and CHWM constructs, a customer's firm power load is split into load below a customer's RHW and Above-RHW load. Power sold to supply a customer's load that is below its RHW is subject to the PF Tier 1 rate. Load that is above the RHW is served with power priced at an applicable Tier 2 rate or through non-federal resources. More information on how net requirements are determined can be found in [Bonneville's Policy on Determining Net Requirements of Pacific Northwest Utility Customers Under Sections 5\(b\)\(1\) and 9\(c\) of the Northwest Power Act.](#)

4.1.1 Peak Net Requirements

Under Regional Dialogue, Bonneville calculated customers' energy net requirements but did not calculate capacity specific to individual customers. However, Bonneville identified peak net requirements under Regional Dialogue as a potential future need in the [Block](#) and [Slice/Block](#) contracts (the reference can be found in the contracts under Section 3.4 – Peak Amount Methodologies). It stated that Bonneville may need to adopt a methodology that "shall include a calculation of a customer's total peak load, customer's peaking energy capability from its resources, and Bonneville's peaking energy capability for the federal system." Bonneville has not implemented this option during the Regional Dialogue contracts. Bonneville proposes to calculate peak net requirements under its Provider of Choice contracts using the same criteria and components for the peak net requirements methodology noted in the Regional Dialogue contract language.

The first component would be determining a customer's total peak load. Just as it does in the energy net requirements calculation, Bonneville plans to use the customer's total retail load forecast for this purpose. The forecast used will be the 50th percentile (also referred to as P50), which establishes the customer's average peak load.

The second component would be determining a customer's peaking energy capability from its resources. At this time, Bonneville proposes to explore using the method being established in the WRAP by the Western Power Pool to determine a resource's peaking energy capability. Bonneville believes that leveraging this program's methodology could help ensure there is a standard metric that is used across

planning horizons and eliminate the need to create a second set of capacity values. As conversations continue, Bonneville recognizes its thinking may need to evolve.

The final component of the methodology would be determining Bonneville's peaking energy capability of the federal system. Bonneville proposes to address this using the methodology used to determine a customer's non-federal resource's peaking energy capability.

Bonneville looks forward to discussing a peak net requirements methodology and how it applies to specific products in policy workshops. While Bonneville's current leaning is to leverage WRAP's methodology for defining peaking capacity needs, Bonneville is open to discussion of other methods.

4.2 System Size

The Northwest Power Act requires Bonneville to offer contracts to meet the net requirements loads of Northwest utilities when requested, and Bonneville remains committed to serving all load obligations upon request. However, there are finite existing resources in the Federal Base System (FBS). Determining the Tier 1 system size and how that system cost is allocated among customers will be a critical question to discuss during the Provider of Choice process and related rates methodology development. Bonneville and the region must come together to determine how to best meet future load growth and how to propose to allocate the costs of those resources in Bonneville rate processes. The region has placed major emphasis on looking at opportunities to develop non-federal resources and ways to enable a carbon-free future for some utilities.

As discussed in Section 3.1.1 and Section 10.1, Bonneville proposes to continue the tiered rate construct, which, under the TRM, serves to allocate incremental resource costs incurred to serve Above-RHWM load to Tier 2 rates. If Bonneville were to instead choose to not tier rates in this way, Bonneville could return to a buy and meld rate construct as was done prior to the Regional Dialogue contracts.

Some existing customers have expressed a desire to increase the size of the Tier 1 system to maximize the amount of power sold at the PF Tier 1 rate for each customer at the outset of the contract, even if this means a certain amount of augmentation to the FBS. Depending on scale, such increases may start to have characteristics of a buy and meld construct, even under a tiered rates construct. Bonneville expects the conversation on its proposal to retain a tiered rate construct to be one of the foundational policy discussions during workshops.

Related to system size, rate methodologies like that which was established in the TRM will also need to determine a basis upon which to allocate costs among the tiered cost pools, such as the use of a customer's CHWM load. Bonneville proposes to extend the CHWM construct that was designed alongside the tiered rate construct.

4.2.1 Setting the Tier 1 System Size

Fundamental to any discussion of the Tier 1 system size is understanding how Bonneville plans to meet firm power obligations and how it sets the system size for rate-making constructs. Bonneville's planning process evaluates the firm capability of its resources and their ability to meet firm load. Also known as firm planning, the process is an inherent planning methodology that underlays all of Bonneville's business processes to assure that it has enough power available to meet its firm load obligations.

Today, the Tier 1 System Firm Critical Output (T1SFCO) is calculated as the firm output of the Tier 1 system resources less Tier 1 system obligations. Bonneville proposes to continue using this methodology for Provider of Choice. Tier 1 system resources include the FCRPS, designated non-federal resources (like the Columbia Generating Station), and designated contract purchases. Tier 1 system obligations are any firm obligations placed on Bonneville based on signed contract provisions, Treaty, statute, regulations, court orders, memoranda of agreement, or executive orders. One example of this is the Canadian entitlement. More information on this calculation can be found in Section 3 of the [TRM](#).

If Bonneville's obligation grows larger than the firm capability of the base federal resources, Bonneville would need to meet the increase in its load obligation through the acquisition of additional resources. This could introduce additional risk and result in cost increases.

Prior to Regional Dialogue, the cost of resources acquired by Bonneville to serve its firm power loads was done on a buy and meld basis. From a rate and cost perspective, Bonneville did not distinguish between the need to acquire resources to meet customers with fast-growing loads and customers whose loads were slow growing. The development of the contract high water mark concept and the TRM has enabled Bonneville to allocate costs, for rates purposes, based on resources acquired to meet load growth. Today, Bonneville uses the T1SFCO to establish the amount of power available at the PF Tier 1 rate. Any risk or cost associated with resource acquisition beyond this firm capability is passed on through the Tier 2 rates.

In determining a need to acquire on a long-term basis additional resources (e.g., other than short-term market purchases to balance Bonneville's system and loads), Bonneville would follow guidance from the Northwest Power and Conservation Council's (Council) power plan and Bonneville's own loads and resources forecasting from the Resource Program. The Resource Program is a planning study and does not result in any resource acquisition. It provides analysis and insight into long-term, least-cost power resource acquisition strategies, examines uncertainty in loads, water supply, resource availability, natural gas prices, and electricity market prices to develop a least-cost portfolio of resources that meet Bonneville's obligations. More information on the Resource Program including past publications can be found on the [Resource Program webpage](#). Bonneville will leverage this existing tool as part of its evaluation of different Tier 1 firm system sizes.

The Tier 1 system size is an integral part of the discussion surrounding how to establish or modify CHWMs. As discussed in Section 3.1.2, the CHWMs were designed to help implement the tiered rate construct. They determine what amount of each customer's load could be served at the PF Tier 1 rate. A larger Tier 1 system would allow customers to have more load served at the PF Tier 1 rate. Conversely, if Bonneville more conservatively set the Tier 1 system size, it would reduce the amount of federal power available at the PF Tier 1 rate.

In developing this paper, Bonneville contemplated four options to establish the size of the Tier 1 system used to set CHWMs. These options are denoted as: 1) P10 firm monthly, 2) fixed system, 3) fixed amount, and 4) P35 firm monthly. Table 1 illustrates the four approaches using BP-22 RHWM Tier 1 system data as well as forecast net requirements for FY 2026. Bonneville proposes that it would set the Tier 1 system size when it sets CHWMs. Bonneville proposes in Section 4.2.3 that it would set CHWMs based on FY 2026. Therefore, the assumption for all system size options is that the system would be calculated based on data from FY 2026.

The forecast net requirements is based on load forecasts from BP-22 and includes scenarios based on whether or not certain resources are included in that calculation of the net requirements. In the low scenario, Bonneville assumes all current dedicated resources remain dedicated to load in 2026 and beyond. The high scenario assumes that a few existing resources are granted permanent resource removal and contracted new resources are not renewed for the post-2028 time period. Neither scenario includes potential net requirements loads from returning public power utilities.

One important point outlined in the table is that, while Bonneville can agree to a larger system size, it will only serve up to the total net requirements load obligation placed on Bonneville. The “Delta between Firm and CHWM Tier 1 Systems” row shows the amount of energy that would be required to meet the new Tier 1 system size. The “Energy Needed to Firm to Net Requirements” rows show the actual energy Bonneville would need to acquire based on the projected net requirements. Bonneville is committed to serving any net requirements power load placed on it, but Bonneville will only procure additional resources when required for load service.

Table 1. Tier 1 Firm System Size Options

Using BP-22 RHWMTier 1 System Studies (annual aMW)	P10 Firm Monthly	Fixed System		Fixed Amount		P35 Firm Monthly
			Recommended			
Total Tier 1 Firm System Output	6,667	6,667	6,667	6,667	6,667	6,667
CHWM Tier 1 System	6,736	6,736	7,000	7,400	9,000	8,012
Delta between Firm and CHWM Tier 1 Systems	69	69	333	733	2,333	1,345
FY 2026 Net Requirements (Low Scenario)	6,981	6,981	6,981	6,981	6,981	6,981
FY 2026 Net Requirements (High Scenario)	7,180	7,180	7,180	7,180	7,180	7,180
Energy Needed to Firm to Tier 1 Net Requirements	69	69	314	314	314	314
	69	69	333	513	513	513

Each option in Table 1 would be shaped to align with the load and resource profile similar to how Bonneville applies monthly/diurnal shaping to the Tier 1 system today. Monthly/diurnal, as defined in the TRM, refers to the 24 periods of the year, consisting of 12 HLH periods and 12 LLH periods (one for each month). The table uses BP-22 information, as the BP-24 RHWMTier 1 process kicked off in June and results are subject to change. The Tier 1 system size variability that can occur between rate cases. As discussed in Section 3.1.2, the Tier 1 system size has varied from 6,667 aMW to 7,136 aMW under Regional Dialogue.

Bonneville proposes to establish a fixed system of 7,000 aMW. As outlined in Section 4.2.1.2, Bonneville believes this option offers customers increased planning capability, lowers the administrative burden for both Bonneville and customers, and provides a potentially lower-cost option to alter the system size. However, Bonneville remains open to options beyond those proposed in the table, including what size(s)

should be contemplated for each option. The range included in Table 1 is meant to provide an illustrative example of the potential impact of different options.

4.2.1.1 P10 Firm Monthly

Historically Bonneville used a single fiscal year of generation (October 1936 – September 1937) that overlaps with the critical period when the system is most deficit to load (September 1936 – April 1937) to define the annual T1SFCO. Efforts from Bonneville’s climate change resiliency work have prompted a recent decision to adopt a 30-year period of record (1989 – 2018) for Bonneville’s long-term generation forecasts. Along with the new period of record, Bonneville adopted monthly 10th percentiles to define firm output. The P10 firm monthly profile provides a consistent meaning of firm for every month of the year and uses information from all 30 water years in the distribution. See the [Climate Change and FCRPS webpage](#) for more details.

The firm water approach to setting the Tier 1 system would, similar to current practice, result in a Tier 1 firm system size that could change over time, as hydrologic conditions and operations change.

4.2.1.2 Fixed System

Bonneville’s proposed option is to fix the system size for the term of the Provider of Choice contract. Under this option, the Tier 1 system size would be set at either the firm energy as calculated at the time CHWMs are set, for example in FY 2026, or at a fixed number, likely slightly above firm. Bonneville proposes to fix the system size at 7,000 aMW.

As described in Section 3.1.2, in Regional Dialogue Bonneville established how much power a customer would actually get in a rate period by multiplying the customer’s CHWM percentage by the size of the system in each FY to derive that customer’s RHWM. This means that, in Regional Dialogue, the amount of power a customer receives goes up and down with changes to the federal system. Under this proposal, RHWMs would generally be equal to CHWMs for the duration of the contract, as the Tier 1 system size would not change from rate period to rate period. This should give customers better visibility in determining how to meet future load growth because it would largely eliminate the variability in RHWM, which today varies from rate case to rate case based upon projected changes in river operations, fish operations, the Treaty and the expiration of power purchases. It would simplify the RHWM process and result in a lower administrative burden for both customers and Bonneville. Bonneville would still conduct the RHWM process each rate period to calculate each customer’s load forecast and Above-RHWM load amounts.

Under a fixed system construct, if there is a deficit between Bonneville’s firm water planning and the calculated RHWM net requirements, the difference would be served by Bonneville acquiring resources. While this option would give customers more certainty on the amount of power they can purchase at the PF Tier 1 rate, it also would result in risk to the PF Tier 1 rate itself, as any costs that cover the variation in the actual system would be recovered in the PF Tier 1 rate. However, this is true of any option that increases the size of the Tier 1 system above firm energy.

While Bonneville’s preferred approach is to fix the system at 7,000 aMW, a fixed system closer to firm energy is also provided for consideration. In this example, Bonneville would set the system at 6,736 aMW. If Bonneville were to set the system closer to P10 firm monthly water, it would lower some

of the cost risk to the PF Tier 1 rate because it would lower the resource acquisition Bonneville would need to take on.

4.2.1.3 Fixed Amount

A third option is to add a fixed amount to the Tier 1 system size. Under this option, Bonneville would calculate firm energy in FY 2026 and then add a fixed amount of additional energy. This new system size would be used to establish CHWMs for the Provider of Choice contract term.

Bonneville would conduct the RHW process every rate period as it does today. The Tier 1 system would be updated every rate period to reflect the firm generation projected in the most current hydro studies. This would create variation in RHWs from rate period to rate period to align with changes in firm generation, and would provide a higher CHWM or RHW to customers than P10 firm monthly profile. It is important to note the full fixed amount may not be needed from rate period to rate period as it would depend on there being a calculated net requirements need. Therefore, the actual resources acquired by Bonneville to meet load may be less than the fixed amount determined.

Table 1 provides two examples of adding a fixed amount, one that adds 733 aMW to reach a Tier 1 system size of 7,400 aMW and one that adds 2,333 aMW for a total of 9,000 aMW. Based on current forecast net requirements, Bonneville does not anticipate it would set the Tier 1 system size close to 9,000 aMW but included this as an example to address customer concerns about a potential future scenario with significant electrification load growth.

4.2.1.4 P35 Firm Monthly

A final option considered by Bonneville is to use a monthly hydro profile that produces a Tier 1 system size larger than P10 firm monthly. Bonneville suggests a 35th percentile (P35) firm monthly hydro profile as it increases the system size closer to average water but limits some of the risk associated with moving all the way to average water. Under this option, the Tier 1 system size would be set at the P35 firm monthly profile based on FY 2026 hydro studies. Bonneville would acquire resources as needed to meet the difference between firm generation and the P35 firm monthly profile.

Similar to the current paradigm, each rate period Bonneville would recalculate the P35 firm monthly profile to set the Tier 1 system size for the RHW process. RHWs would then be reset each rate period based on the hydro studies. Bonneville would also calculate the firm system size each rate period, and any difference between the firm system and the RHW net requirements obligation would be served by resource acquisition.

This option would likely create the greatest risk for Bonneville and its customers from a load and resource planning perspective. For Bonneville, there would be variation in the resource acquisition needed from rate period to rate period that could create greater cost risk associated with those acquisitions. For customers, while this option would limit some Above-RHW load exposure compared to a firm system option, it would not eliminate rate case to rate case variability and would therefore not improve customers' ability to plan for how to meet future load growth. Bonneville and customers would face incremental risk if resource limitations manifest because there would be a limited timeframe to secure potentially large volumes of generation.

4.2.1.5 Considerations for Setting the Tier 1 System Size Greater than Firm Generation

If Bonneville sets the Tier 1 system size at an amount greater than firm generation, there are several benefits and risks that will need to be considered. Below is a qualitative assessment of considerations that will be addressed during system size policy workshops. It is also important to more broadly consider the trade-offs of locking in a higher system size compared to offering new non-federal resource flexibility in contracts as discussed in Section 4.2.4.

1. Resource Acquisition. Most recently, Bonneville has been able to meet its firm obligation from the resources it has available to it without needing to acquire additional resources. This practice would likely need to change if Bonneville's CHWM firm load obligation exceeds its firm resources. Eventually Bonneville's firm resource deficit would require that Bonneville acquire additional resources. At that time, Bonneville would develop a strategy that would leverage the Resource Program to determine the best way to meet forecast needs as they arise, whether that is through market purchases or acquisition of physical resources, consistent with the Council's plan. During this process, Bonneville could consider additional constraints such as what type of resources best comply with WRAP requirements or if only carbon-free resources should be considered.

Another important consideration with increasing the size of the Tier 1 system is the lead-time that may be required to acquire substantial resources. If the need to acquire resources is not identified until the rate case process (and it can change from rate period to rate period), Bonneville's options for meeting the delta between firm generation and the established Tier 1 system becomes more complex due to time constraints. If Bonneville acquires a major resource with a planned capability greater than 50 aMW for a period of greater than five years, it must follow the statutory Section 6(c) process prescribed by the Northwest Power Act. Section 6(c) of the Northwest Power Act requires the Administrator to conduct public hearings on any Bonneville proposal to acquire a major resource to determine whether the proposal is consistent with the Council's regional power plan. This process can be time-consuming and complex. With a short lead time, Bonneville may have fewer options available when there is a need to acquire resources because of the complexities associated with major resource acquisitions.

2. Federal Base System Resource Loss. One potential scenario that could change Bonneville's Tier 1 system size is the loss of a large generating resource. In such event, Bonneville would remain obligated to serve contracted net requirements loads, but may be confronted with the need to acquire substantial resources. Bonneville plans to discuss options of how resource loss should be addressed in policy and contracts in future workshops.

3. Carbon. If Bonneville must acquire resources to close the delta between firm generation and a larger Tier 1 system, the amounts and types of resources acquired will impact the carbon content of Bonneville's system mix. This could impact Bonneville's ability to support some customers in meeting their state and local carbon reduction or clean energy requirements. Today, Bonneville augments the system with the least-cost option to serve load without consideration of resource carbon attributes. Bonneville would need to reconsider this practice and reach a decision on what types of resources it would acquire in the future. A smaller system size would reflect the firm capability of the existing federal system and provide more certainty about system composition. Bonneville recognizes carbon is a key issue for the region and has further contemplated its fuel mix and carbon content for Provider of Choice in Section 5.

4. **Secondary Sales.** Secondary sales are driven by Bonneville’s actual load obligations and water conditions compared to rate case assumptions. An increase in the Tier 1 system would require a firming of the delta between where the Tier 1 system is set and firm generation. Therefore, any actual surplus could remain unchanged. If Bonneville sets a larger Tier 1 system size and there is not an increase in Bonneville’s load obligation, then it would likely not have an impact on net secondary sales. However, if the Tier 1 system size is larger and Bonneville’s load obligation increases, while holding water conditions constant, then net secondary sales would likely decrease. Bonneville does not foresee significant changes to secondary sales due to changes in the Tier 1 firm system size.

5. **Rate Stability.** Setting the Tier 1 system size at firm generation and adjusting it each rate period stabilizes the costs recovered in the PF Tier 1 rate. Bonneville does not acquire additional resources as RHWMs fluctuate to meet the changes in the firm system. If the Tier 1 system is set to something other than firm generation and/or is not adjusted each rate period, there will likely be more variability in the costs recovered via the PF Tier 1 rate, assuming a similar rate methodology is in place for Provider of Choice, because some amount of acquired resources would likely be included in the Tier 1 cost pool. This is a key trade-off to consider: Providing stability in the amount of load that is served at the PF Tier 1 rate increases cost variability in what customers would pay for that power.

4.2.2 Adjusting Tier 1 System Size for Future Load Growth

Under Regional Dialogue, Bonneville offers three categories for augmenting the Tier 1 system size and CHWMs. The three categories are: (1) newly formed public power utilities placing net requirements on Bonneville, (2) load growth for existing tribal utilities served by Bonneville, and (3) to serve U.S. Department of Energy Richland’s vitrification plant’s planned load. Bonneville proposes to retain these categories for adjusting the Tier 1 system size and CHWMs for Provider of Choice contracts. Bonneville is open to discussing the categories, size and term limits for each of these categories during policy workshops.

Some customers have suggested a fourth category, a mid-term update that would account for load growth from electrification and other industry changes. Bonneville believes that this proposal would undermine the tiered rates construct. The intent of tiered rates is to preserve the low-cost Tier 1 system by limiting incremental costs being melded into the PF Tier 1 rate to meet customer load growth with firm requirements power. Under the tiered rates construct, customers experiencing load growth have the option to purchase additional power from Bonneville at a Tier 2 rate or serve their own load growth with non-federal resources. Offering a mid-contract reset would provide a disincentive to the development of non-federal resources, which are advantageous for reasons such as decarbonization, resource adequacy and in some cases promoting local industry and reducing distance between resource and load. A mid-term update would undermine the tiered rates construct by allowing for customers to incorporate load growth in the PF Tier 1 rate’s cost pool similar to how it did under the previous buy and meld construct.

4.2.3 Calculating Contract High Water Marks for the Provider of Choice Contracts

CHWMs, as described in Section 3.1.2, set a public power customer’s eligibility to purchase an amount of power service at the PF Tier 1 rate. The CHWM construct provides a uniform methodology for determining eligibility for Tier 1 priced power that is applied across any Tier 1 system size at a point in time. In aggregate, CHWMs cannot exceed the Tier 1 system size. The Tier 1 system size and CHWMs are

extremely interdependent and decisions in one area will create impacts in the other. Bonneville plans to address these two issues on the same timeline and will likely have crossover in policy conversations.

CHWMs are calculated for each customer by taking the customer's total retail load net of existing resources and New Large Single Loads (NLSLs). Because a CHWM is based on a customer's load, each CHWM is specific to a customer and Bonneville is not contemplating any CHWM exchange or transfer.

Bonneville recognizes the significant importance customers place on how a future CHWM would be established. Within a tiered rates construct and a finite Tier 1 system, CHWMs become a zero-sum game. Through workshop discussions Bonneville will seek alignment on how to calculate CHWMs as a critical element of the Provider of Choice policy.

4.2.3.1 Provider of Choice CHWM Calculation

Bonneville proposes to calculate new CHWMs for the Provider of Choice contracts that would start that contract term with the most accurate and up-to-date calculation of customer loads. A refreshed CHWM is appropriate given the CHWM construct was created by policy and contract for Regional Dialogue. There is no statutory or contractual "right" to carry forward the Regional Dialogue's CHWM after the Regional Dialogue contracts expire in 2028.

Several factors will need to be considered and discussed around the calculation of CHWMs as part of policy workshops. Bonneville proposes a set of considerations below: recalculation years, resource treatment, NLSLs, weather normalization, conservation and pro rata scaling of CHWMs. Bonneville has taken a leaning on each consideration to start the dialogue on CHWM calculations but in most cases is open to considering alternative proposals.

1. Recalculation Years

Bonneville proposes that CHWMs under the Provider of Choice contracts should be based on customer load in FY 2026. This would allow Bonneville time to work with customers to establish CHWMs through its rigorous process ahead of power deliveries in FY 2029. Bonneville would perform the calculation using the most up-to-date information; relying on a single year of data will limit calculation complexities and review process. Bonneville believes a future year, rather than a past year or average of a past and future year, should be selected for the recalculation to best account for current loads in the region. There are other calculation components that can better account for customer choices over the Regional Dialogue period if customers are looking to maintain access to the Tier 1 system, which are described in Section 4.2.3.2 below. Bonneville suggests FY 2026 as the recalculation year is practical from a planning and resource acquisition perspective, but is open to alternative proposals for a different year or set of years.

2. Non-federal Resource Treatment

Bonneville proposes that any non-federal resources dedicated to load as of September 30, 2026, would be applied to serve a customer's load and reduce its CHWM. These would be considered existing resources for the Provider of Choice contract term. The Northwest Power Act requires Bonneville to consider all dedicated non-federal resources as applied to load, which leads to a reduction in the firm power load requirement placed on Bonneville, and thus establishes a customer's net requirements. 16 U.S.C. § 839c(b)(1). Therefore, under Bonneville's proposal, new resources added after September 30, 2026, would be added to offset Above-RHWM load growth, unless it adopts the non-federal resource flexibility proposal outlined in Section 4.2.4. Bonneville will continue to determine what qualifies as an

existing resource and what qualifies as a new resource during the term of the Provider of Choice contracts.

3. New Large Single Loads

Bonneville will not include NLSLs when determining a customer's CHWM, consistent with the [NLSL Policy](#). A customer's CHWM determines how much of its net requirements a customer can purchase at the PF Tier 1 rate. The Northwest Power Act requires NLSLs to be served at the New Resource Firm Power (NR) rate. Therefore, NLSL loads should not be included in the CHWM calculation.

4. Weather Normalization

Bonneville proposes to weather normalize the proposed FY 2026 load amounts used in the CHWM calculation. Power demand can vary significantly in abnormal weather conditions like a winter storm or heat wave, but it can also be very limited in a year where temperatures remain mild. Bonneville recognizes that setting loads based on any one year likely could create unexpected consequences.

Bonneville proposes to split load into irrigation loads and non-irrigation loads to complete the weather normalization calculation and then re-aggregate after the normalization is complete. Under Regional Dialogue, Bonneville and its customers determined to split these loads for the normalization process due to the unique profile of irrigation loads. Both the irrigation and non-irrigation weather normalization processes would include five years of data – FY 2021 through FY 2025. Bonneville completed a similar process for its original determination for CHWMs and would propose to take lessons learned from that normalization process as the starting point for Provider of Choice CHWM calculations.

5. Conservation

Bonneville pursues conservation with and through its customers as a cost-effective power resource. As such, conservation is intended to reduce the Administrator's load service obligation. Crediting CHWMs for conservation achievements to bolster a utility's CHWM is somewhat counter to treating conservation as a resource that reduces the Administrator's load service obligation. However, Bonneville recognizes that conservation has many unique characteristics. Distributed, sustained, ongoing investment and program management is necessary to deliver conservation savings. Bonneville seeks to support such opportunities and maintain conservation deliveries during the measurement window.

Bonneville proposes to allow customers to add self-funded conservation savings from FY 2022 through FY 2026 to their CHWM calculation for Provider of Choice contracts. Conservation continues to be an important resource in the region, and Bonneville is required to acquire conservation before considering the acquisition of major resources. Customers have used conservation as a tool in resource planning and to offset future load growth, and some have argued that they should not lose CHWM as a result of those prudent planning decisions. Bonneville previously included a conservation adjustment when it set CHWMs for the Regional Dialogue contract to ensure continued investment in conservation over the remaining years of the earlier Subscription contract. This ensured that customers continued to have an incentive to invest in conservation once they knew CHWMs would be based on load in a future year. Such an approach ensures that customers who spend more on conservation than they receive from Bonneville still have an incentive to do so.

Bonneville recognizes a broader conversation on how to handle conservation achieved over the Regional Dialogue contract term will be needed during policy workshops. Bonneville remains open to discussing whether and how a conservation savings adjustment should be included in CHWM calculations.

Bonneville expects to discuss the time period for conservation achievements, whether the funding source for conservation should be a factor, the magnitude of the conservation adjustment allowed, and other potential design considerations not included here.

6. Pro Rata Scaling of CHWMs

CHWMs and the size of the Tier 1 system are intrinsically linked. CHWMs cannot exceed the maximum intended Tier 1 system size. If the initial calculation of CHWMs aggregate to larger than the agreed upon Tier 1 system size, there will need to be a determination of how to adjust CHWMs to align with that Tier 1 system size. Bonneville proposes that if the Tier 1 system size is less than initial CHWMs, then all customers would share an equal pro rata decrement to their CHWMs. For example, if the Tier 1 system only meets 85% of the calculated net requirements need when calculated in FY 2026, Bonneville would equally reduce CHWMs of all customers so they had 85% of load at CHWM and 15% of load as Above-RHWM load. This option could provide an equitable share among customers of the Tier 1 system size.

4.2.3.2 Significant Net Requirements Changes from Regional Dialogue

Bonneville recognizes that the new calculation could result in significant CHWM changes for some customers and therefore suggests options for potential CHWM adjustments to take into account actions or events that occurred over the Regional Dialogue contract term. These options will require significant regional discussion and buy-in, as they could adjust CHWMs among customers and result in some customers receiving CHWMs with embedded headroom. Bonneville believes such adjustments could allow customers some flexibility to retain elements of CHWMs determined under Regional Dialogue. Without a broadly supported adjustment approach, initial CHWM levels would only embed headroom if the initial Tier 1 system size exceeds the sum of customer CHWMs.

Bonneville recognizes that customers are situated differently with respect to changes in net requirements during the Regional Dialogue contract term. Some customers experienced substantial load growth while others experienced load loss. Some customers heavily invested in conservation or added new non-federal resources, while others did not. Further, some have requested permanent loss of resource determinations for their existing resources. Bonneville recognizes that many unspecified contract resources currently dedicated to load may not be renewed for the Provider of Choice contract term. Finally, Bonneville also recognizes that some utilities did not pursue a CHWM through a Regional Dialogue contract but may request a Provider of Choice contract. Any of these scenarios could create major impacts on CHWMs, especially if the Tier 1 system size is set lower than total net requirements.

If the Tier 1 system size is lower than the total net requirements load, and if input indicates the pro rata scaling discussed above is widely unpalatable, Bonneville will need to determine whether load growth during the Regional Dialogue contract term could be included in CHWMs (rather than designated as Above-RHWM load). Likewise, Bonneville will need regional input to determine if customers that experienced a decrease in their net requirements load could be impacted. Outlined below are alternatives of how Bonneville could approach the recalculation of CHWMs.

For increases in net requirements due to load growth, loss of resource or a returning public power utility, Bonneville has considered three options: 1) include all increases in net requirements from Regional Dialogue CHWM to FY 2026 load in the calculation of the Provider of Choice CHWMs, 2) exclude all increases in net requirements from this timeframe in the calculation of the Provider of Choice CHWMs, or 3) only include a percentage of the increased net requirements from Regional

Dialogue CHWM to FY 2026 load in the calculation of the Provider of Choice CHWMs, with the remainder being Above-RHWM load. If a percentage of the increased net requirements is most palatable to customers, Bonneville sees merit in including a 50% increase to net requirements load to the total retail load used to calculate new CHWMs. The remaining 50% would be considered Above-RHWM load.

For utilities that experienced load loss during the Regional Dialogue period, unrelated to conservation, Bonneville could incorporate a way for those utilities to retain or reacquire CHWM if that load returns during the Provider of Choice contracts. One option would be to carry forward the provisional high water mark construct that was created under Regional Dialogue to address Great Recession load loss. Bonneville and the region could determine a period of time that those qualifying customers' load growth would be counted as CHWM load instead of Above-RHWM load growth. The amount that could be added back in would be limited to identifiable historical load loss. This option could address some of the concerns utilities have about electrification ramping up in the late 2020s.

As discussed in Section 4.2.3.1 above, Bonneville proposed one CHWM adjustment specific to conservation and expects substantive discussion on that or other conservation-related adjustments.

4.2.3.3 Unused Rate Period High Water Mark Exchanges or Transfers

Customers have suggested that Bonneville include a RHWM exchange or a RHWM transfer option for its customers. Such concepts would allow customers with headroom in a given rate period to exchange or transfer that amount of load eligible for the PF Tier 1 rate to a customer that is looking to offset its Above-RHWM load. The customer receiving the exchange or transfer would then be eligible to purchase that additional amount at the PF Tier 1 rate instead of selecting a Tier 2 rate option or self-supplying non-federal energy to meet its Above-RHWM load. Bonneville does not believe that either of these options should be included in the Provider of Choice contract.

The intent of tiered rates is to insulate the Tier 1 system costs. Bonneville serves load growth at Tier 2 rates, which reflect the cost of acquiring additional resources, or customers may self-supply to meet their load growth. If Bonneville allows an exchange or transfer option, it undermines the tiered rates construct by shifting when a customer must decide how to serve Above-RHWM load. If the RHWM load that a customer had exchanged or transferred were to appear, it could put additional operational and cost risk on any product Bonneville offers. If a customer were to rely on an exchange or transfer of RHWM to serve its Above-RHWM load needs and then needed to come back to Bonneville for a Tier 2 product, this could add additional load beyond what was originally anticipated. If Bonneville needed to acquire resources late in a planning period, this could result in high Tier 2 prices and Bonneville may not be able to offer a carbon-free product option if desired. Customers in the Tier 2 rate pool would share those costs and risks so all customers in that rate pool would be taking on additional cost risk based upon decisions of individual customers participating in exchanges. While Bonneville understands customers' interest in maximizing their access to unused Tier 1 system, Bonneville believes that the administrative burden and risks associated with this proposal outweigh its potential benefits.

4.2.4 Non-federal Resources

Another key priority for the Provider of Choice contracts that Bonneville has heard from customers and public interest groups is additional flexibility built into future contracts to more easily integrate non-federal resources in the future. The region anticipates a future where new non-federal resources could

be central to addressing changing resource retirements, potential load growth due to electrification, and meeting new state regulations. Bonneville recognizes this issue is important and included providing additional non-federal resource flexibility as one of its Provider of Choice goals.

Bonneville proposes to add a non-federal resource allowance to the Provider of Choice contracts to provide customers the flexibility to dedicate generating resources to offset and serve load that would otherwise be eligible to be served by federal power priced at PF Tier 1 rates. This is load that would have been subject to take-or-pay provisions. This proposal would allow customers to add specified non-federal resources up to an aggregate nameplate of 5 megawatts (MW) or 50% of their CHWM, whichever is less. Bonneville believes this approach would give customers the flexibility they are seeking for non-federal resource integration while ensuring Bonneville can adequately serve customers' remaining loads. This option would be in addition to customers having the choice to serve their Above-RHWM load with non-federal resources (see Section 4.3.2).

If customers add non-federal resources up to the proposed cap, this non-federal resource proposal would result in a reduction to load served by Bonneville and may potentially have associated costs that could shift to other customers. If the PF Tier 1 rate is lower than prevailing Mid-C Hub market prices, Bonneville assumes there is no risk of cost shift because Bonneville could sell any potential offset load as surplus and recoup the equivalent Tier 1 value or greater. If, however, the PF Tier 1 rate is higher than prevailing Mid-C Hub market prices, there is potential for a cost shift because Bonneville would likely have to sell the offset load at a price less than the PF Tier 1 rate. Cost shifts should not prevent consideration of this option but are an important factor customers will need to agree to in order to offer this flexibility in future contracts. The proposed cap would serve to limit the magnitude of this potential cost shift.

In addition to the potential for cost shifts, there are operational risks to consider. The addition of generating resources – especially variable resources such as solar – will require additional analysis of their impact on the operation of the federal system. These operational risks could be examined through the Resource Program.

4.2.4.1 Non-federal Resource Allowance to Offset Load at the PF Tier 1 Rate

As discussed above, Bonneville proposes to allow customers to dedicate generating resources to serve load that would otherwise be eligible to be served by federal power priced at PF Tier 1 rates. The resources would need to be customer-owned resources connected to the customer's distribution system. This proposal is modeled in large part after the Small Non-dispatchable New Resource Treated Equivalently to an Existing Resource Exception (SNEER Exception). The SNEER Exception was developed after the Regional Dialogue contracts were implemented. Under the exception, Bonneville treats a customer's small renewable resources like an existing resource, which means the resources can offset load that would otherwise be eligible to be served by federal power priced at the PF Tier 1 rate.

Under the tiered rate structure established for Regional Dialogue, Bonneville provides flexibility to add non-federal resources to serve Above-RHWM load. However, a customer's flexibility to add a non-federal resource to serve load that would otherwise be eligible to be served by federal power priced at the PF Tier 1 rate is limited due to the design intent of the take-or-pay agreement on CHWM load. As a result, customers that do not have Above-RHWM load have not pursued the development of non-federal resources. This proposal for Provider of Choice would allow customers to develop resources and

offset load that would otherwise be eligible to be served by federal power priced at the PF Tier 1 rate, up to an aggregate nameplate limit of 5 MW or 50% of their CHWM load, whichever is lower. This would allow customers additional flexibility for adding non-federal resources that is not bound to load growth that may or may not occur.

Bonneville would require these new generating resources, which must be physical resources connected to the customer's distribution system, to be included in the contract. Market purchases (unspecified resources) would be excluded from this option. Physical resources would be 5(b)1(b) dedicated resources that a customer is required to continue to apply to load, including under subsequent contracts, unless the customer requests resource removal pursuant to the 5(b)9(c) Policy. Bonneville proposes that the resources associated with this proposal would not require RSS but would be subject to any additional load shaping and capacity costs created by the addition of such resources. Customers would maintain the ability to add non-federal resources to serve load growth with this new flexibility.

The biggest risk associated with this option is how it could impact Bonneville's ability to recover costs within a rate period and shift costs to other customers over time. If Bonneville were to see substantial offsets within one rate period, this could create a case where Bonneville could be in a position to under-recover revenue. This risk could be mitigated by future rate mechanisms or provisions capping resource additions. Bonneville believes that providing an aggregate nameplate limit would help control this risk but recognizes it is a risk that customers will need to agree to in order to make this option work.

4.2.4.2 Minimum Threshold

Customers have asked Bonneville to reconsider the minimum threshold required for a customer's non-federal resource to be included and tracked in the power sales contracts. Bonneville is currently analyzing the feasibility of raising both the Power Services and Transmission Services minimum thresholds from 200 kilowatts (kW) to 1 MW. Bonneville's Power and Transmission business lines would like to remain aligned on information-sharing thresholds and may need to share metering requirements. Bonneville expects that these resources would be used to serve load. To that end, Bonneville proposes to include language in the policy or contracts that any resource a customer develops to serve its load is a 5(b)1(b) resource and must continue to serve load unless the customer requests resource removal pursuant to the 5(b)9(c) Policy.

Raising the threshold could increase Bonneville's and its customers' exposure to cost shifts. The addition of resources would result in a reduction of load for Bonneville to serve. This means the power that would have been sold to the customer at the PF Tier 1 rate would now be sold as surplus. This could benefit all customers, but price volatility year-to-year may result in years of no cost shifts and years of high cost shifts. In addition, there are some operational risks to consider from changing the 200 kW limit, such as reduced resource visibility, increasing imbalance and creating an unintended impact to transmission operations.

In addition, Bonneville would also need to work with the region to clearly define what constitutes a single resource for this threshold requirement. This guidance may be a part of the Provider of Choice policy and/or added to contract definitions.

Bonneville plans to discuss the results of its feasibility analysis during early Provider of Choice policy workshops and is willing to discuss updating the limits for dedicating resources, as well as other facets as part of policy development, pending the outcome of the forthcoming analysis.

4.3 Products

Bonneville proposes several options to update its power sales products offered under Provider of Choice. These options carefully consider improvements that fit the context of today, expectations for the future, and that account for lessons learned during Regional Dialogue. These options are described below.

4.3.1 Priority Firm Power Products

A description of the Load Following, Block and Slice/Block products as they exist under Regional Dialogue can be found in Section 3.1.3. The sections below describe how each product could be offered for Provider of Choice.

Bonneville intends to maintain the distinction between the Load Following product, which meets a customer's hourly energy and peak net requirements, and the Slice/Block and Block products, which are provided on an annual planned basis but provide no guarantee of meeting the customer's actual hourly needs. A customer that is seeking to have all of its hourly needs met, including WRAP requirements if necessary, through its Bonneville power sales contract would need to purchase the Load Following product.

4.3.1.1 Load Following

Bonneville's Load Following product serves a customer's net requirement load on an hourly basis, including meeting a customer's peak load. This product has proven to work well for both Bonneville and its public power customers in meeting customers' energy and capacity needs. Bonneville proposes to keep the core Load Following product as is and continue to meet hourly peak net requirements and resource adequacy under this product.

Bonneville is open to exploring how to remove barriers and increase opportunities for how Load Following customers add non-federal resources to their portfolio. These changes would not alter the basic design of the product but instead offer additional flexibility to how customers manage their loads and resources. Examples of the additional flexibility can be found in Section 4.2.4, which describes new flexibility for adding non-federal resources, and Section 10.1.1.2, which discusses the option to develop a new methodology for how rates are set for RSS.

4.3.1.2 Block

Bonneville currently offers a standalone Block product that includes a Block product with Shaping Capacity option and a Block product without Shaping Capacity option. For Provider of Choice, Bonneville proposes to offer a similar design and is open to modifications that may improve these product offerings. As discussed in Section 4.1.1, Bonneville proposes a peak net requirements be integrated into the Block product for Provider of Choice. Bonneville will need to ensure all product offerings are consistent with its decision on peak net requirements.

The Block product without Shaping Capacity option allows customers to supply their own load following service by pre-defining hourly amounts of power each month to meet a customer's forecast net requirement load each fiscal year. The product was not designed to meet the entirety of a customer's peak load. Bonneville proposes to continue the current option to shape energy amounts into hourly blocks that fit the monthly net requirements load of the customer's expected monthly load shape.

Bonneville is open to changes that may offer customers more options under this product. For example, Bonneville is willing to consider recalculating a customer's load shape at some point during the term of the contract, rather than locking in one load shape for the length of the contract. Minor changes to block shape parameters is another area Bonneville expects further discussions. Bonneville is also open to potential adjustments to the Block component of the Slice/Block product to meet the needs of a customer with a clear peak net requirements gap. Conversations associated with these options are expected to evolve during policy workshops.

Bonneville offered a second Block product option under Regional Dialogue which was the base Block product with Shaping Capacity option. The shaping capacity component was intended to offer Block customers additional support in meeting their peak load needs. No customer selected this option under the Regional Dialogue contract. However, Bonneville believes that, with some modifications, this product could offer customers valuable capacity support without creating overly complex product implementation. Bonneville proposes to redesign the Block product with Shaping Capacity option to better meet Block customers' peak net requirements needs. Customers may find a successful redesign provides needed peaking flexibility but without the operational burdens of Slice. It should be noted this option would only be offered under the standalone Block product given how it might interact with market opportunities provided under the Slice product.

Provider of Choice policy discussions will identify ways to simplify the administrative and operational burdens that Bonneville has heard were barriers for customers to elect the Block product with Shaping Capacity option under Regional Dialogue.

4.3.1.3 Slice/Block

Bonneville heard from existing Slice/Block customers that, while they would like to retain their current product offerings, there is a growing concern around resource adequacy and the region's ability to meet peak needs. Current customers asked Bonneville to look at enhancements to the Slice/Block product that may better meet future capacity needs.

The Slice portion of the current Slice/Block product provides firm power for a customer's net requirements load and an advanced sale of surplus energy based on the generation capability of the federal system. The product allows the customer to monetize secondary energy directly because the secondary energy is a component of the actual system output provided under the product. For some customers, this flexibility and market opportunity make the Slice/Block product an attractive product. Additional flexibility to the Slice portion does create some concerns given the operational flexibility granted today.

Bonneville believes the current Slice portion of the product provides customers significant flexibility in determining how to manage their resource portfolio both in meeting their own energy needs and in finding surplus market opportunities. Because capacity is expected to become more valuable, it is important to consider the surplus position of the existing Slice product.

Table 2 is an example of the current capacity offered by the Slice/Block product using data from FY 2020. It takes the total retail load customer system peak (MW) and subtracts the HLH Block (aMW), Slice right-to-power (MW) and dedicated resources (MW). The peak amounts for customer dedicated resources are based on capacity values from preliminary WRAP Qualifying Capacity Contribution estimates. Black

amounts represent when customers could be considered capacity short and red amounts are when customers are likely capacity surplus.

Table 2. Slice/Block Capacity (in MWs)

Customer	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Avg
Benton	44	8	(17)	23	(41)	(9)	3	41	54	84	92	65	29
Clark	226	170	144	115	139	151	53	(33)	88	181	188	192	135
Clatskanie	20	18	13	8	(5)	12	7	(2)	(19)	(9)	2	0	4
Cowlitz	36	(12)	(70)	(65)	(138)	(65)	(29)	(260)	(242)	(233)	(145)	(180)	(117)
Emerald	20	5	(0)	(1)	(0)	2	(7)	(24)	(24)	(17)	(12)	(13)	(6)
EWEB	52	50	26	(6)	3	(23)	(35)	(119)	(109)	(80)	(61)	(75)	(31)
Franklin	25	4	(3)	9	(24)	(15)	(18)	13	23	46	58	49	14
Grays Harbor	47	35	12	19	3	25	10	(56)	(73)	(76)	(62)	(60)	(15)
Idaho Falls	30	19	18	13	18	9	(5)	(25)	(24)	(10)	5	(12)	3
Lewis	46	36	14	19	11	28	4	(39)	(61)	(21)	(20)	(29)	(1)
Pacific	22	22	9	12	9	13	7	(13)	(19)	(20)	(17)	(15)	1
Snohomish	204	167	127	217	88	118	27	(293)	(356)	(179)	(74)	(101)	(5)
Tacoma	28	47	16	61	(25)	(11)	(160)	(329)	(411)	(328)	(266)	(295)	(139)
Total	799	570	290	424	39	236	(144)	(1,140)	(1,172)	(661)	(310)	(473)	(129)

The data in Table 2 shows that in some months the current Slice/Block product provides more firm capacity for some customers than would be established if Bonneville calculated their peak net requirements. Bonneville is concerned about extending this product as currently designed into Provider of Choice.

Bonneville proposes to include a peak net requirements calculation for the Slice/Block product in Provider of Choice contracts. Bonneville would calculate monthly firm peak net requirements for each customer and limit capacity to that monthly amount. In months where the customer's firm peak net requirements exceeds the firm capacity amounts that the Slice/Block contract is forecast to provide, a customer would see no change to the product in how it operates today. However, in months where a customer receives excess firm capacity, flexibility of the Slice could be limited, and Bonneville would have the right to reduce the excess firm capacity. Bonneville will explore a rate design to address these product changes.

While Bonneville has not formally calculated a peak net requirements version of Table 2, it estimates that many customers would have sufficient capacity in some months. If customers are looking to purchase additional capacity from Bonneville at PF rates, such a sale would only be possible in months where they have a demonstrated capacity deficit. Policy workshops will provide a forum to more fully explore the capacity needs around the peak net requirements calculations.

Bonneville also proposes to look at the details around the RSO test and explore approaches that might streamline implementation.

4.3.2 Above-Rate Period High Water Mark Load Service

Bonneville proposes to offer options for Above-RHWM load service similar to the options offered under Regional Dialogue. However, Bonneville is evaluating ways to simplify the Above-RHWM load service options offered while remaining responsive to customer concerns. Bonneville proposes to have two options for Above-RHWM load service during the Provider of Choice contract term: federal Above-RHWM service and non-federal Above-RHWM service. Customers would make a one-time election for either of these Above-RHWM load services prior to the Provider of Choice contract term.

Federal Above-RHWM Service. Customers would elect to have Bonneville serve Above-RHWM loads with firm requirements power sold at a Tier 2 rate. This option would be managed as a portfolio and Bonneville would acquire resources as needed to serve load growth. Bonneville would attempt to make the portfolio low carbon. If this option is selected, customers would retain the ability to lower their net requirements by dedicating a limited number of new generating resources as outlined in the non-federal allowance proposal in Section 4.2.4. Under this approach, there would be only one federal service option for Tier 2.

Non-federal Above-RHWM Service. Customers would elect to serve Above-RHWM loads with non-federal resources and be responsible for managing their own load growth. But, customers would have the option to request service for a defined amount of power at the Tier 2 rate from Bonneville before each rate period subject to possible limits based on resource availability. These requests would need to be made at least one year before a rate period's start to be eligible for service in that rate period as determined in conjunction with the rate case process. Bonneville would manage requests for federal service similar to its current Tier 2 short-term rate strategy by using market purchases or available firm surplus at market prices.

Bonneville would not require a notice deadline for adding non-federal resources as Bonneville recognizes this may put an undue administrative burden on both customers and Bonneville. It should be noted that allowing new non-federal resources to be added during a contract period represents risks of deferred cost shifts, but this risk may be warranted given the region's overall need for greater generation capacity.

Further analysis is required to fully understand risks that may exist under a scenario where customers who have opted for the non-federal option ask Bonneville to serve a significant amount of load under a short-term product. Bonneville will need to consider the regional market depth to accommodate large requests for return to federal service during the Provider of Choice contract period. To the extent possible, Bonneville wants to mitigate cost shifts created when customers attempt to arbitrage election decisions against market swings at the expense of other customers. If risks of shallow market depth exist, limitations on the quantity of such a short-term product may be required. Bonneville will discuss these considerations more as the policy workshops and rate methodology evolve.

4.3.3 Capacity Option

Bonneville recognizes that capacity is of increasing importance to the region. Outlined above in the PF power product section, there are a few ways Bonneville could alter products to help public power customers meet their capacity needs. Bonneville believes pursuing adjustments to current products should address capacity needs based on product design intent and proposes that a new capacity product should not be offered on top of existing products.

For any customer looking for Bonneville to meet its peak net requirements and resource adequacy requirements in their entirety, Bonneville has proposed to again offer a full requirements product and encourages such customers to explore the Load Following product. Bonneville proposes to extend its two partial requirements products to Provider of Choice. Under Block and Slice/Block, customers agree to take on the planning requirements to meet their load needs as well as any resource adequacy program requirements. Customers electing Block or Slice/Block take on the operational risk associated with meeting their actual hourly requirements. Bonneville does not believe that an additional preference capacity option fits the intent of the Block and Slice/Block products.

Bonneville remains open to designing a capacity option if it fits with the design intent of products developed. Any conversations about a capacity option would need to weigh the trade-offs to customers of committing firm capacity in advance, as well as lost revenue opportunities that could result in higher power rates for all customers.

4.3.4 5(b) for IOUs

Under Section 5(b) of the Northwest Power Act, IOUs have a statutory right to request that Bonneville sell them power to meet their net requirements load.

Sales of power to IOUs under Section 5(b) are sold at the Section 7(f), NR rate. The NR rate includes the cost of the FBS resources not otherwise allocated to preference customers under Section 7(b), new resources, and exchange resource costs. Additionally, the NR rate includes an allocation of the Section 7(b)(3) surcharge (if applicable).

While all of the region's IOUs have signed long-term NR contracts with Bonneville under the Regional Dialogue contract, none have placed any load on Bonneville because of the historically high cost of the NR rate. As discussed earlier in this paper, the energy outlook in the Northwest is experiencing major change. Bonneville understands that this changing landscape may influence IOU interest in seeking to purchase power from Bonneville. Bonneville will discuss IOUs needs for 5(b) power in the post-2028 period as part of the Provider of Choice policy workshops.

4.3.5 New Large Single Loads

An NLSL, as defined by the Northwest Power Act, is a load that results in an increase in power requirements of 10 aMW or more in any consecutive 12-month period. Sales of power to serve NLSLs are sold at the Section 7(f), NR rate. Bonneville published an [NLSL policy](#) in April 2001 and addressed NLSL issues in a [2002 ROD](#) and a February 2005 [Policy for Power Supply Role for Fiscal Years 2007-2011](#).

Bonneville recognizes there is interest in updating or changing its NLSL policy and/or the implementation of the policy. Bonneville is open to exploring potential changes and better defining how the NLSL policy is implemented in future contracts. During Provider of Choice policy workshops, Bonneville will offer opportunities to discuss NLSL changes and whether they would need to be achieved by a policy update or in the Provider or Choice contracts.

Another area Bonneville heard requests for change is around the rates associated with NLSLs. Bonneville will discuss the NR rate in the Post-2028 Rate Methodology process. Bonneville is open to discussing potential changes to the NR rate but notes that any conversation would need to review the legal confines of setting the NR rate and any risks of changing the current rate structure. Discussions of such

changes would also involve other regional customers, such as the IOUs, who have a right to purchase at the NR rate if they elect to place net requirements on Bonneville under Section 5(b).

Bonneville has heard requests to change the 10 aMW threshold for NLSLs. This is a statutory definition in the Northwest Power Act. Any change to the threshold would require action by Congress. This issue rests outside the scope of the Provider of Choice effort.

4.3.6 Direct Service Industry Customer

Bonneville is not statutorily required to offer contracts to direct service industry (DSI) customers. Although historically an important Bonneville customer group, the majority of past DSI customers are no longer eligible to purchase power from Bonneville as DSIs because they terminated their DSI contracts with Bonneville. Port Townsend Paper is Bonneville's only remaining DSI customer. Port Townsend Paper has a peak demand of 15.75 MW and its current DSI contract is expected to end September 30, 2028, commensurate with the expiration of the Regional Dialogue contracts.

Should Port Townsend Paper request a contract for service beginning October 1, 2028, Bonneville proposes a contract offer as follows. As required for a DSI contract, Bonneville will only offer Port Townsend Paper a contract if Port Townsend Paper requests a contract, and if an economic analysis determines that the contract will have a benefit to Bonneville and its customers. Bonneville conducts an equivalent benefits test and measures market price forecast and net revenues, value of reserves, avoided cost of transmission ancillary services, and demand charge to determine whether to offer Port Townsend Paper a subsequent DSI power sales contract at the Industrial Firm Power (IP) rate.

Bonneville is not authorized to sell power to any new DSI loads.

4.4 Other

Several other components are critical to customers in terms of service. These include the Low Density Discount (LDD) and Irrigation Rate Discount (IRD), as well as how Bonneville handles billing credits. Bonneville's positions on these are described below.

4.4.1 Low Density Discount

The LDD is authorized under Section 7(d)(1) of the Northwest Power Act, which provides: "In order to avoid adverse impacts on retail rates of the Administrator's customers with low system densities, the Administrator shall, to the extent appropriate, apply discounts to the rate or rates for such customers." The Administrator has discretion to determine whether it is appropriate to offer an LDD and to review and establish the criteria under which the LDD would be offered. Under Regional Dialogue, the LDD has been implemented as a variable percentage discount on power for utilities with a small number of widely dispersed customers. The LDD has been established in accordance with the Northwest Power Act and to promote the most widespread use of power in the region. The intent of LDD is to avoid adverse impacts on retail rates of utilities with low system densities.

Currently, Bonneville has 55 customers that receive the LDD at an annual cost of about \$40 million. Using FY 2022 data, this translates into an impact on the PF Tier 1 rate of about \$0.69 per megawatt hour. The current methodology for calculating LDD is explained in detail in Bonneville's General Rate Schedule Provisions (GRSPs). Currently, for customers to be eligible for LDD, they must meet certain criteria, which include but are not limited to: 1) agreement to pass the benefits of the discount through

to its eligible consumers within the region served by Bonneville, 2) they must have a consumers/pole miles ratio of less than 12 and, 3) the customer's average retail rate for the reporting year must exceed Bonneville's average PF rate for the most closely corresponding fiscal year by at least 25%.

Bonneville proposes to continue to review the LDD in future Section 7(i) general rate case proceedings, including implementation details relating to eligibility, the discount level and applicable rate. Bonneville also proposes working with customers and interested parties to analyze the methodology of LDD. Bonneville seeks to maintain flexibility in the administration of the program, while ensuring parity across the recipients. Simplifications could be achieved for LDD in Provider of Choice; one area for further discussion is an evaluation of the methodology of the applicable LDD percentage under the current GRSPs.

As noted previously, the level of LDD benefits can only be established in Bonneville's Section 7(i) rate proceedings. Bonneville and interested parties can, however, generally address the policy concerns or questions related to LDD benefits, and Bonneville is open to those discussions. Leading up to Regional Dialogue, Bonneville and interested parties engaged in a forum to discuss LDD issues and reached consensus on the methodology and program design before Bonneville's wholesale power rate proceeding and power deliveries under the Regional Dialogue contracts. Bonneville is open to holding discussions in future policy workshops on LDD.

4.4.2 Irrigation Rate Discount

Bonneville has mitigated the rate impacts to eligible customers serving irrigation consumers in various forms since 1942 (with the exception of 1979 to 1985), either as a seasonal surplus firm power sale or as a rate discount. Offering rate mitigation for irrigation is not statutorily required. However, Bonneville recognizes the importance of irrigated agriculture to many rural communities throughout the region and supports the continued economic health and competitiveness of irrigated agriculture in the region. While reducing the discount could provide an opportunity for cost savings, eliminating or phasing out the IRD could have adverse impacts on the economic vitality of these communities.

Under Provider of Choice, any discount, if adopted by the Administrator, would be included in Bonneville's GRSPs. A Section 7(i) rate proceeding would establish the amount of a discount applied to qualifying irrigation loads. Bonneville proposes that an irrigation rate discount would be in the form of a mills-per-kilowatt hour (kWh) discount under the PF rate schedule. Bonneville also proposes to offer customers qualifying for rate mitigation the same mills-per-kWh discount during the months of May, June, July, August and September.

The current construct of a mills-per-kWh discount with set kWh amounts for the term of the contract, along with an end-of-year true-up, has proven to be straightforward to administer. Therefore, Bonneville proposes a similar construct under Provider of Choice. Further discussion is needed to review the eligibility criteria, qualifying loads and methodology. Bonneville suggests these items be discussed at a future date, prior to finalizing the Provider of Choice policy.

Bonneville also proposes to continue requiring that participating customers implement cost-effective conservation measures on irrigation systems in their service territories as a condition of receiving the IRD.

4.4.3 Billing Credits

Under the Northwest Power Act, a customer may request billing credits from Bonneville for certain conservation or resource acquisition activities that reduce the load obligation for which the Administrator otherwise would have had to acquire resources. The rate impacts of billing credits on the Administrator's other customers are to be equal to the rate impact those customers would have experienced had the Administrator been obligated to acquire the resources.

Fundamental to the tiered rate construct is the principle that customers elect how to serve Above-RHWM load and are responsible for the associated costs. The rationale is that one customer should be insulated from another customer's resource decisions. The fact that a customer has acquired its own resource or undertaken conservation to serve its load should have no impact on the resource costs Bonneville would incur to serve customer load. Hence, there would be no basis for affording billing credits to a customer as it would create the opportunity to meld their resource costs with Bonneville.

To avoid any cost exposure to other customers, Bonneville proposes that customers again agree to forego any request that Bonneville provide billing credits for applicable non-federal resources, including conservation.

5. CARBON AND OTHER ENVIRONMENTAL ATTRIBUTES

Since the Regional Dialogue contracts were developed, there have been major shifts in regional public policy associated with decarbonization of the electricity sector, as noted under Section 1.3. Several utilities and local jurisdictions across the region have set goals for carbon reduction. Many states in the West, including Washington and Oregon, have enacted carbon pricing programs and clean energy standards. More than 60% of Bonneville's total firm power sales are made to preference customers in Washington who must comply with the state's Clean Energy Transformation Act (CETA). CETA requires retail utilities to be 100% carbon-neutral by 2030 and 100% carbon-free by 2045 and utilizes renewable energy credits (RECs) as a primary tool for compliance. Emissions from electricity sales into Washington are also covered under a cap-and-invest program that will go into effect in January 2023 (the Climate Commitment Act). Oregon also passed a clean energy standard in 2021, which requires the state's two largest IOUs to reduce emissions by 100% by 2040. This standard does not apply to consumer-owned utilities.

At present, carbon reduction requirements do not exist uniformly across the region. Some states, including Idaho and Montana, do not have mandates in place. Bonneville expects that carbon reduction and clean energy policies will continue to evolve throughout the term of the Provider of Choice contracts, even in those states already developing mechanisms to reduce carbon.

Bonneville has heard from its regional firm power customers that the carbon and environmental attributes associated with the federal system are a key consideration for Provider of Choice. The carbon content of Bonneville's power products and the role it plays in helping its customers meet their state requirements is also a consideration for Bonneville.

Bonneville proposes several options for products that address carbon and conveyance of environmental attributes as the starting points for Provider of Choice policy discussions. These options are not exclusive and could be combined.

5.1 Priority Firm Tier 1 Power Rate: Tier 1 System Carbon Content

Today, thanks to the carbon-free hydropower system and the Columbia Generating Station, the power Bonneville sells is roughly 95% carbon-free on average. Since the development of competitive wholesale electricity markets in the mid-1990s, Bonneville has acquired power through market purchases. Purchasing from the market on a short-term basis (less than five years) has provided a flexible and least-cost alternative to supplement Bonneville's power supply when needed to balance the inherent variability in hydro generation and meet Bonneville's load obligations beyond what the federal system can provide. For more information, see [Bonneville's 1995 Business Plan Environmental Impact Statement ROD](#). With the enactment of carbon reduction requirements, several states now consider power purchased from the market to be "unspecified," meaning the generation source for the power is unknown at the time of the transaction and therefore the carbon emissions associated with generating that power are unknown. As a result, states assign a default emissions factor to these unspecified market purchases. The emissions rate is roughly equal to the marginal resource, namely, a natural gas generation plant.

Consequently, the only "emitting" resources in Bonneville's system mix (according to state carbon regulation policies) are Bonneville's purchases of power from the market, which make up 3% to 12% of Bonneville's fuel mix depending on the year. This figure is based on over 20 years of Bonneville voluntarily reporting its fuel mix to the states of Washington, Oregon and California. The range in the amount of power containing emissions purchased by Bonneville from year-to-year is largely a result of hydro variability in the amount and timing of runoff, but other factors such as the availability and output of the Columbia Generating Station, regional loads and fish operations can also impact the amount of power Bonneville acquires from the market.

Bonneville proposes to assess and analyze options for acquiring power produced by carbon-free resources that would balance Bonneville's load and resource obligation and reduce reliance on unspecified (spot) market purchases. The goal is to gain a better understanding of projected costs and benefits associated with these options and gather additional feedback. Bonneville will also need to assess its statutory authority to pursue options, cost allocation and impacts, as well as the overall trade-offs, interactions and risks of these options in the context of the entire Provider of Choice contracts.

Bonneville considered three options for addressing the carbon content attributed to the Tier 1 system. The options are to:

- 1) Evaluate, in a future Resource Program process, options for acquiring power from carbon-free resources and adjusting Bonneville's conservation measures in addition to the current practice of acquiring least-cost power from the market.
- 2) Assess whether increasing the size of the Tier 1 system above firm generation levels requires resource acquisitions and if that acquisition should be done with carbon-free resources. Assessment of this option is closely connected to the determination of the size of the Tier 1 system and associated delta between Tier 1 system size and firm generation.
- 3) Develop Bonneville trading floor processes to seek out specified, clean power purchases for balancing load and/or consider including a price for carbon emissions in determining the least-cost resource.

5.2 Tier 2 Power Rate: Carbon Content and Attributes

Under Provider of Choice contracts, Bonneville proposes to convey the environmental attributes, including carbon content and RECs, to public power customers that are served with firm requirements power at a specific Tier 2 rate. This design would apply to any Tier 2 rates, for example, that recover the cost of resources (specified or unspecified) acquired by Bonneville to meet the customer's Above-RHWM load. One possibility is that Bonneville could convey any attributes of the resource on a pro rata basis among customers subject to that rate.

Since the attributes of power sold at Tier 2 rates will be conveyed to customers per their Tier 2 rate election, the attributes will not be included in the power sold at Tier 1 rates. This is consistent with Bonneville's policy under Regional Dialogue to convey RECs to customers electing to purchase at a Tier 2 vintage rate, and refines Bonneville's current emissions accounting practices under Regional Dialogue (the same fuel mix and emissions incurred to balance the supply of firm requirements power are attributed to all sales that are subject to PF Tier 1 and Tier 2 rates). This update for Provider of Choice provides for a more appropriate accounting of greenhouse gas emissions and RECs by directly conveying, through rates, the attributes to customers that are subject to the Tier 2 rate.

5.3 Conveyance of Renewable Energy Credits

Bonneville proposes to convey RECs created by the Tier 1 system commensurate with the actual amount of power purchased by a public power customer. Since Bonneville sells from a system of resources, this means that a customer's base allocation of RECs will depend on the megawatt hours purchased from Bonneville applied to the percentage of REC-eligible resources in the Tier 1 system. The federal system is expected to create additional RECs beyond those associated with PF sales. At this time, Bonneville is not proposing treatment for those additional RECs.

This method for conveying RECs is a change from the Regional Dialogue contracts, where all RECs created by the federal system are conveyed to public power customers based on their RHWMs and to IOUs through the 2012 Residential Exchange Program (REP) Settlement Agreement (2012 REP Settlement). Instead, this proposed method directly correlates power purchases with RECs. Bonneville anticipates this method will provide more transparency in accounting and more closely align with customers' compliance requirements under Washington's CETA and potentially other future carbon and clean energy programs. It should be noted that because CETA recognizes RECs from existing hydropower generation, Bonneville expects that the volume of RECs created by the federal system to be much higher in the future than today.

Bonneville has heard from IOUs expressing concerns about the conveyance of environmental attributes in the post-2028 period. Bonneville notes that, with this proposal, it is not determining whether or how to account for the value of RECs when developing its rates, and in particular, the PF Exchange rate for REP participants. Bonneville expects to address these issues in either the REP settlement phase or in the development of rates for the post-2028 period.

5.4 100% Carbon-Free Power Product

Bonneville recognizes there is interest in a 100% carbon-free product choice that would help customers meet their requirements under CETA and/or other local utility goals. Specifically, there is interest in separating out the fuel type and other attributes of the federal system and conveying them to a subset of

customers willing to pay a premium for it. Bonneville will continue to discuss the possibility and potential design of such an option. However, Bonneville notes three areas of concern:

- 1) **Statutory.** Bonneville is authorized to acquire resources to meet its total load obligations. Bonneville does not acquire resources to meet an individual power customer's need to comply with a state or local requirement to use power from specific types of resources. Related, Bonneville's obligations are met using its total system of resources. Bonneville is concerned that options that seek to separate Bonneville's system by resource types and attributes could be inconsistent with Bonneville's statutory, operational, and cost recovery requirements.
- 2) **CETA.** The design may not meet the intent and/or requirements of CETA.
- 3) **Cost.** Such a product would create additional costs in rates to cover the administrative workload of implementation.

Bonneville notes that whether such a product would meet the intent of CETA is a question for regulators in the state of Washington. Bonneville anticipates further discussion is needed between customers, Bonneville, and Washington regulators regarding such a product. However, to the extent the regulatory requirements would put Bonneville in a position of providing documentation to state regulators about fuel type and conveyance of attributes to individual customers, it would also raise statutory concerns associated with system sales.

If Bonneville were able to overcome the concerns noted here and offer such a 100% carbon-free option, an inter-customer dynamic would have to be explored and ultimately deemed acceptable. This option would not result in changes to the actual federal system carbon content.

6. TRANSFER SERVICE

Bonneville's transmission system was originally built to deliver federal power to regional customers. Other public power utilities and IOUs also built transmission facilities in the region to serve their customers. In some cases, Bonneville contracts with one or more of these other transmission owners to deliver (or "wheel") federal power to customers not connected to Bonneville's transmission system. This service is called transfer service and it is implemented through agreements with third-party transmission providers.

Transfer service refers to the transmission, distribution and other products and services provided by a third party transmission provider to deliver firm power sold by Bonneville to a preference customer pursuant to a 5(b) requirements power sales agreement. This service is an important part of the agency's effort to be the provider of choice to utilities in the Pacific Northwest. The number of transfer agreements has grown over time, and Bonneville currently has 84 preference customers that receive all or part of their federal power through transfer service.

Bonneville's provision of transfer service provides value to the region in many ways. By maximizing shared use of regional transmission assets to serve loads, Bonneville has avoided costly construction and duplication of transmission facilities, yielding significant cost savings over time to the region and its ratepayers. In addition, by consolidating effort and expertise on the acquisition of third-party transmission rights, Bonneville and its customers are able to minimize costs. Similarly, by capitalizing on existing staff expertise and business relationships with third-party transmission providers, Bonneville is able to maximize efficiencies in its contract administration. In many instances, customers relying on

transfer service may have limited staff and benefit from the value and service Bonneville provides in contracting directly with the third-party transmission provider.

In the Provider of Choice power sales contracts, Bonneville envisions that it will continue its long history of providing transfer service. The core elements of these offerings are described below.

6.1 Administration of Transfer Service

Bonneville proposes to continue its role as the contract holder for the transmission service agreements across third-party systems. As the contract holder, Bonneville would, in coordination with impacted preference customers, continue to negotiate, execute, administer and perform all transmission customer obligations contained in the transfer service agreements required for preference customer load service. This proposal would allow Bonneville to continue maximizing efficiencies in its contract administration with third-party transmission providers; e.g., participating in rate proceedings at the Federal Energy Regulatory Commission (FERC), reviewing third-party transmission providers' business practice processes, negotiating new interconnections, and verifying third-party invoices.

Because Bonneville proposes to continue rolled-in treatment of transfer costs for power sold at the PF rate, as described in Section 6.2, Bonneville's proposal to hold the contracts provides additional oversight of cost drivers flowing into Bonneville's rates. In the Regional Dialogue Policy, Bonneville contemplated instances where, on a case-by-case basis, a customer served by transfer may be permitted to be the contract holder of the transmission service. In such instances, the customer would be the party to interact with the transmission provider and pay initially for the costs of the transfer service, with Bonneville providing appropriate reimbursements. Bonneville proposes to continue this case-by-case exception, which would be decided at Bonneville's discretion.

6.2 Payment for Transfer Service for Federal Power Sold at the PF Rates

Across multiple contracts, Bonneville has historically paid for transfer service for federal power sold at the PF rates and generally has rolled in the costs of such transfer service into the PF rates. Under the TRM, the costs of transfer service for federal power sold, including power sold at Tier 2 rates, are included and recovered in the PF Tier 1 rate. Currently, power sold at the PF Tier 1 rate accounts for the vast majority of the transfer service Bonneville provides. Bonneville anticipates that for the post-2028 contract period, Bonneville would propose to continue rolled-in rate treatment for transfer service for federal power sold at the PF Tier 1 and Tier 2 rates with certain limitations that will be explored in future policy discussions.

6.3 Payment for Transfer Service for Federal Power Sold at Other Rates

As discussed throughout this concept paper, maintaining Bonneville's cost competitiveness is an important objective that public power customers have repeatedly mentioned in their comments and discussions with Bonneville. In line with those comments, Bonneville proposes to limit the scope of transfer service costs that Bonneville would propose to recover in its rates. Specifically, Bonneville proposes not to include the cost of transfer service for federal power sold at the 7(f) rate over a third-party transmission provider's system in any PF rates. Bonneville proposes that such cost, if incurred to assure delivery of federal power, would be direct assigned or allocated to and recovered in the applicable 7(f) rate. This change recognizes that rolled-in rate treatment is tied to 5(b) sales. As such, the cost of transmitting 5(f) surplus sales will not be included in 5(b) rates. In addition, this change is

consistent with Bonneville's rate directives in Section 7(b)(3) stating NLSLs are not part of a customer's general requirements for receiving power at the Section 7(b)(1) rates.

Bonneville recognizes that this proposal represents a change from the current policy in Regional Dialogue. However, Bonneville believes it is an appropriate change for the Provider of Choice construct. For one, there have been very few instances of transfer customers purchasing federal power at rates other than PF in the past. However, the frequency and scale of new NLSLs throughout the region has been increasing. This adjustment and new limitation will preserve the historical use of Bonneville transfer service for load service at PF rates and mitigate Bonneville's cost exposure in the event large loads seek to wheel federal power not sold at a PF rate over third-party transmission systems. Moreover, this limitation aligns with Bonneville's overall policy objective of maintaining the cost competitiveness of the PF Tier 1 rate for the post-2028 period.

6.4 Payment for Non-federal Transfer Service

Bonneville proposes to return to the pre-Regional Dialogue policy of not rolling the cost of transfer service for non-federal power into the PF rate. Instead, Bonneville proposes to pass the cost of transfer service for non-federal power through to the individual transfer customer.

Prior to Regional Dialogue, Bonneville's acquisition and payment for transfer service over third-party transmission systems was limited to federal power. Bonneville's broader policy goal in Regional Dialogue was to promote non-federal resource infrastructure development. The intent was that transfer service customers would develop local generation which would alleviate congestion and promote local community goals. Consistent with that policy, Bonneville paid for transfer service associated with non-federal resources serving transfer customer loads, with certain limitations, and applied a similar rolled-in rate treatment to the costs associated with non-federal transfer service as was applied to federal transfer service.

Major customer development of local resources serving transfer customer load has not materialized, and today most non-federal transfer service is energy that customers source from market purchases at the Mid-C Hub. These purchases provide little to no congestion relief and have created significant administrative complexities. The purchases have required the development and maintenance of new products and services, scheduling adjustments and accommodations, engagement with transfer providers, and incremental policy work to adjust as circumstances change. This has also created difficulties for Bonneville Transmission Services in planning for network transmission (NT) customers that purchase power from the market.

Under Regional Dialogue the cost associated with non-federal transfer service is rolled into the PF Tier 1 rate up to the limits on non-federal transfer service identified in the Regional Dialogue Policy. Continuing this approach would continue to apply upward cost pressure to the PF Tier 1 rate.

For these reasons, Bonneville proposes to pass the cost of transfer service for non-federal power through to the individual transfer customer. Additional work and discussion is needed to address what circumstances, terms and conditions would apply to those customers that have developed physical generating resources during the Regional Dialogue period.

6.5 Comparability of Service: Transfer Providers relative to Bonneville’s Transmission System

Under the Agreement Regarding Transfer Service (ARTS), Bonneville adopted a principle of “comparability” to inform future discussions related to direct assignment guidelines, quality of service, respective roles, and treatment of costs. The concept of comparability for transfer service is that transmission service and ancillary services provided to a transfer service customer, and the cost treatment for such, will be comparable to the service and cost treatment that Bonneville provides to its directly connected customers. Under Regional Dialogue, Bonneville adopted the principle of comparability related to direct assignment guidelines and treatment of costs. To the extent possible, Bonneville will continue to apply comparability related to cost issues as discussed in Section 6.6. Since Regional Dialogue addresses comparability and extends past the term of the ARTS agreement, Bonneville is not planning to rollover ARTS and instead plans to address ARTS related topics in Post-2028 Initiative processes.

However, related to quality of service, Bonneville proposes to no longer perpetuate the principle of comparability as it relates to transfer service. Comparable transmission service is increasingly an unachievable expectation on Bonneville, our customers and the third-party transmission providers.

Geographical limitations, cost limitations, transmission congestion and regional factors such as energy imbalance markets, carbon legislation and resource adequacy further complicate and challenge the principle of comparability. Bonneville cannot promise that third-party transmission providers will provide the same level of electric reliability that Bonneville provides its directly connected customers. Bonneville proposes that it continue to work with third-party transmission providers to provide reliable service. Bonneville remains committed to working with the transfer customers and the third-party providers to develop the best plan of service for transfer service loads.

For the Provider of Choice policy and contracts, Bonneville proposes to coordinate with third-party transmission providers, transfer customers and Bonneville Transmission Services under the established processes and Open Access Transmission Tariff (OATT) principles and requirements with regards to the following:

- Decisions to build facilities to directly connect a point of delivery (POD) to the Bonneville transmission system;
- Decisions to pursue transfer service for a customer’s new or existing load pursuant to the best overall plan of service.
 - This process was examined during the term of the Regional Dialogue contract, and Bonneville issued Guidelines Regarding Requests for Transfer Service to New PODs.
- Development of best overall plans of service to meet current and future transfer service customer loads.

6.6 Direct Assignment Guidelines and Ancillary Services

Bonneville proposes to continue the practice of publishing direct assignment guidelines that address how Power Services will pass through costs associated with improvements on third-party transmission systems related to transfer customer load service. These guidelines (currently included in Power GRSPs) will generally be in keeping with Transmission Services’ guidelines, but will continue to have unique language to address transfer service scenarios.

Bonneville proposes to also continue to pass through to transfer customers the cost of ancillary services associated with transfer service (e.g., certain ancillary services associated with the load-serving balancing authority area), such that transfer customers receive charges for all ancillary services when viewing Power Services and Transmission Services charges together, but ensure that transfer customers are not charged twice for ancillary services.

6.7 New and Annexed Load

Bonneville proposes to continue to allow for incremental transfer service in certain instances where new customers, tribal or otherwise, enter into a power sales agreement, or where annexed load may be added to a preference customer's power sales agreements. Power Services and Transmission Services will coordinate to identify the appropriate plan of service. Bonneville recognizes the continued need for flexibility in its offerings on these topics and looks forward to Provider of Choice policy workshops to determine the appropriate policy for new and annexed loads post-2028.

6.8 Day-ahead Market or Regional Transmission Operator Considerations

Bonneville recognizes that a day-ahead market or RTO could be implemented and would have potential implications for Bonneville's transfer service policy and related contractual provisions. The particular rules of that market will be critical to understand its implications. As discussed in Section 3.3.4, Bonneville plans to continue to participate in the design of these possible market changes. If a market is developed that affects transfer service, Bonneville will work with customers to adapt its transfer service policies and contracts accordingly.

7. TRANSMISSION

Bonneville Transmission Services is committed to being dependable and responsive, and to proactively navigating a changing environment to achieve economic and reliability benefits for our customers and the region. This includes a commitment to offering open access transmission and interconnection services through standardized and value-based products.

Transmission Services' priorities are to develop new approaches and solutions to address load service challenges, congestion, and new transmission and interconnection (large, small, and line and load) service requests; to meet current and future needs of customers through clear business practices and streamlined processes; and to offer more standardized products and services by aligning with FERC's *pro forma* OATT and industry best practices.

7.1 Transmission Challenges

Transmission Services continues to face an increasingly dynamic and uncertain environment, serving diverse customers with complex needs, some of which may be at odds with each other. Landscape drivers impacting transmission include the emergence of large loads, increasing electrification, population growth, infrastructure development, varying clean energy requirements, declining economic factors, deepening competitive forces, rising inflationary pressures, wildfire, cybersecurity, market seams, material and staffing shortages, and increasing complexity of assets.

This increasing complexity also points to a need for continued collaboration between Bonneville's Power Services and Transmission Services to ensure consistency, transparency and, most importantly, safe and reliable service to customers and the region.

7.2 Positioning for the Future

Bonneville is examining processes and identifying potential changes to continue to align with *pro forma* OATT service and to continue to improve planning processes. With an increasing number of entities wanting to connect to a system that is already constrained in certain areas, changes are being considered to ensure system planners have the best possible information.

Bonneville has been working to address growing constraints on transmission paths and a dramatic increase in the number of new loads and new generation resources seeking to connect to Bonneville's system. Bonneville's generation interconnection queue is growing at a staggering rate, leading to increasingly complex interconnection studies. In addition, Bonneville's recent cluster studies have included an unprecedented level of requests for new transmission service not previously seen. To provide customers insight into the system capabilities, Bonneville has developed external tools to assist with load siting and transmission acquisition. These mapping tools enable customers to assess viability of load placement and availability of transmission service.

As it pertains to NT service, changes in how NT customers forecast and designate resources are being contemplated. Bonneville encourages customers to engage with their transmission account executives well in advance to evaluate potential resources and loads and by providing 10-year forecasts as part of the NT annual load and resource forecasting process. This process helps customers meet their OATT requirement and provides customers with information so they can make informed decisions about their resources, capacity availability and transmission service.

Transmission Services and Power Services staff work together to plan for transfer service. Bonneville is facing challenges with an increasingly constrained regional transmission system. These challenges can be exacerbated by customer acquisition of generation requiring firm service on third-party transmission systems to deliver network resources to loads beyond Bonneville's balancing authority area. Bonneville encourages customers to locate new generating resources close to load or on less constrained paths to ensure reliable delivery, lessen costs and reduce potential transmission system planning challenges.

Bonneville is also undertaking a thorough review and update of its Line and Load Interconnection and Large and Small Generator Interconnection Business Practices to ensure the processes are efficient and transparent, and provide clear information to customers.

In the coming years, Transmission Services expects to continue to move toward standardized, *pro forma* products, to continue to improve and streamline its processes, and to continue collaborating with Power Services in order to better serve its customers and the region.

8. LONG-TERM COST MANAGEMENT

Bonneville understands the value customers place on the cost of power supplied by Bonneville and its need to practice prudence in cost management. A recurring theme leading up to and through the Regional Dialogue contracts has been customer concerns over Bonneville's cost management and the impact costs have on Bonneville's wholesale power rates. A critical component of Bonneville's and customers' success is efficient and rigorous cost management. For this reason, Bonneville intends to continue to promote accountability, trustworthiness and transparency to guide its projected costs and that customers continue to have ample opportunities to understand and provide input into those

projections. The Integrated Program Review (IPR) provides a robust and transparent public review of forecast costs prior to Bonneville’s rate-setting process.

Bonneville expects discussions regarding cost management during the negotiation, drafting and implementation stages of the Provider of Choice contracts. Evaluating Bonneville’s cost management from inside and outside the agency helps Bonneville find cost-effective solutions that meet its statutory obligations and balance competing objectives. Bonneville agrees that it must continue to set prudent and future-minded cost-management goals, demonstrate a diligent, long-term commitment to financial health, and fulfill its mandate to recover costs.

The post-2028 period presents uncertainties and an evolving, dynamic energy landscape. But uncertainties have always existed. Our challenge is to develop a sound policy, rate structure and contracts that are durable and flexible enough to weather these uncertainties.

Bonneville must meet its statutory requirement to recover its costs. At the same time, customers understandably want to be protected from unnecessary cost increases. A concern Bonneville has heard from its public power customers is that since they pay the costs Bonneville incurs, they bear a disproportionate amount of risk. Bonneville believes that too much flexibility in the customer’s obligation, such as trigger-based off-ramps, would undermine Bonneville’s ability to recover its costs and to make long-term investments in the federal system, and could saddle remaining customers with additional costs left by customers that exit. Bonneville is optimistic that it can reach solutions palatable to customers that provide flexibility without simply shifting risk to other customers, while allowing Bonneville to meet its mandate to recover costs.

8.1 Scope of Cost-Management Efforts

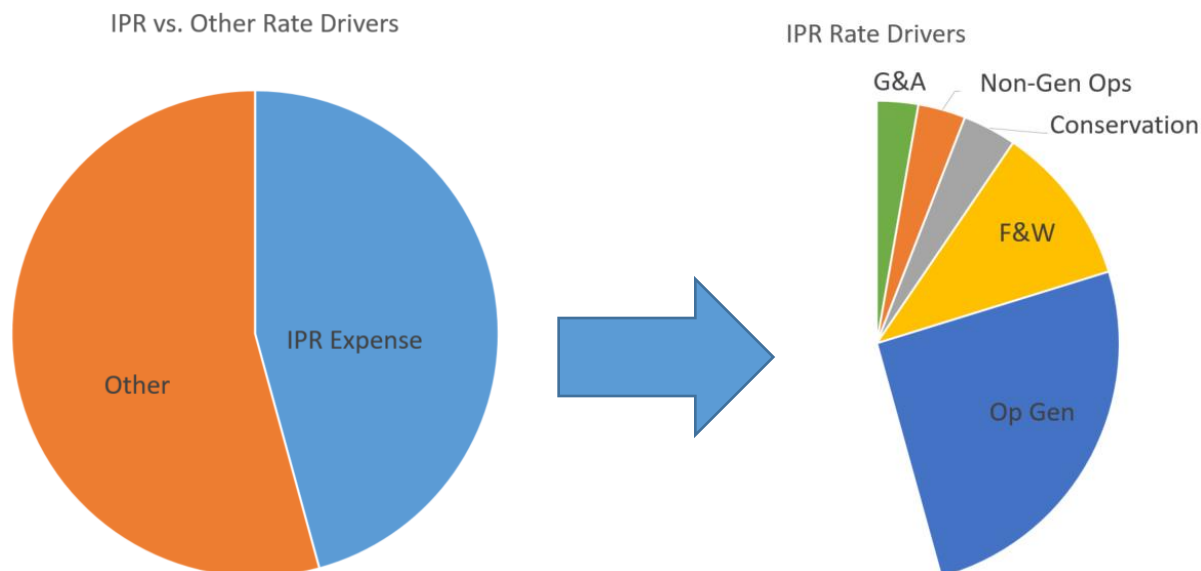
Bonneville would like to clearly outline limitations to what the agency will consider as part of the Provider of Choice contract negotiations, so that Bonneville and the region can productively explore management of costs and risks. Some limitations are driven by statutory requirements and others are based on limiting cost shifts among customers while preserving Bonneville’s ability to maintain its financial health and perform long-term planning.

Under Section 7(a) of the Northwest Power Act, Bonneville is directed to recover costs through rates based on Bonneville’s total system costs. Therefore, Bonneville cannot contractually agree to any provision that would inhibit or restrict its ability to recover costs. For example, Bonneville could not agree to a contractual provision that defined rate targets or limits Bonneville’s power rate changes. Bonneville is, however, open to exploring financial goals over specific cost areas. Flexibility must be built into any cost control goals to ensure that Bonneville is able to meet all of its statutory mandates and recover its costs.

Figure 1 includes the costs that make up Power Services’ revenue requirement. The IPR process provides customers and the public an opportunity to provide input on Bonneville’s projected program costs. IPR program costs represent 46% of Power Services’ total costs, on average, of the Regional Dialogue term to date, or 2012 – 2023. Of those costs, Op Gen is the largest cost category, representing 25% of Power Services’ revenue requirement. These are the costs from generation owners and operators that are needed for operations and maintenance of the resources that make up the federal system. Fish and Wildlife costs associated with Bonneville’s Environmental, Fish and Wildlife program implementation, and Conservation costs associated with Bonneville’s implementation of its Energy Efficiency program,

make up the next largest sets of costs. The remaining costs, Non-Gen Ops and General & Administrative (G&A), capture the remaining program costs that are needed to support Power Services’ operations or supporting services.

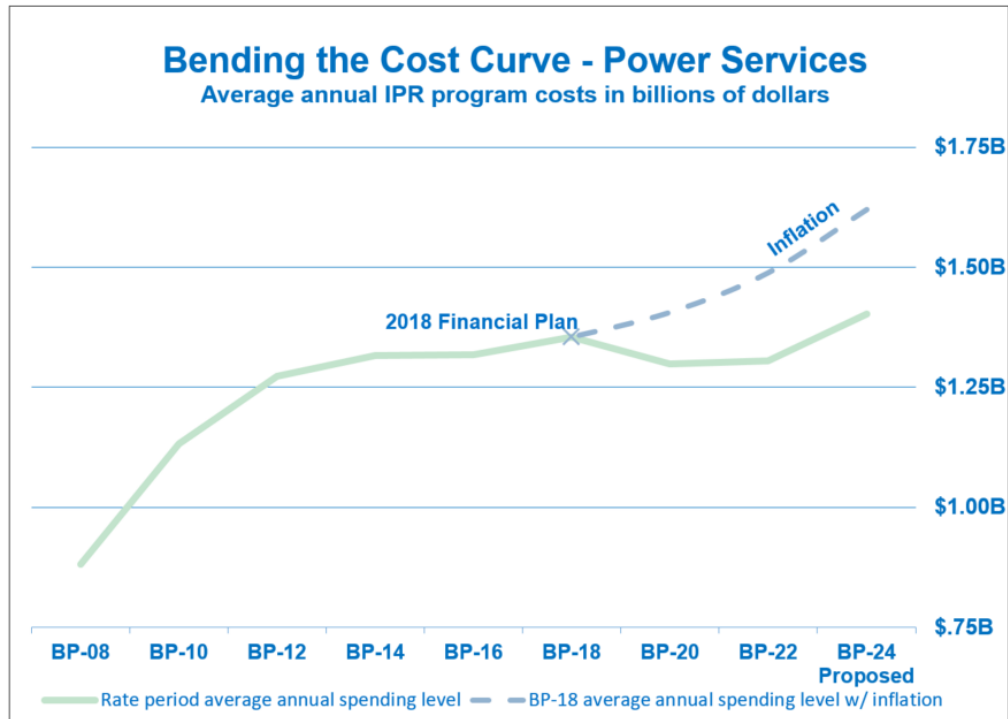
Figure 1. Power Services Revenue Requirement Cost Drivers (Average of Regional Dialogue 2012 – 2023)



The other category in Figure 1 refers to the costs that Bonneville either does not have direct influence over, or has less flexibility in changing from rate period to rate period. These include capital-related obligations; costs that are determined by contracts, formulas, or settlements such as Residential Exchange; costs that are modeled in the rate case such as transmission acquisition and power purchases; and compliance costs that result from legal actions or measures involving federal dams. While these costs must be recovered through power rates, projected costs of these programs are outside the scope of Provider of Choice policy discussion. Bonneville is open to a discussion on where these issues intersect in appropriate forums, but Bonneville will not include any cost caps or trigger-related off-ramps in the agreements tethered to these costs. Bonneville will continue to seek ways to provide more certainty in these areas in parallel to the Provider of Choice process with the goal of informing cost implications for Bonneville’s customers prior to contract signing.

As described above, the main sources of upward rate pressure have not been from program costs. Rather they have stemmed from factors including volatility of net secondary revenue, customer-supported 2012 REP Settlement cost, and the shift from capitalizing to expensing Bonneville’s conservation program which began in the BP-16 rate period. Bonneville’s commitment to providing competitively priced power services, while meeting its statutory obligations, is borne out by the recent trends in its cost trajectory. Over the past few years, Bonneville has been able to meet its obligations within existing cost projections, through efficiencies and project prioritization, with the result that Bonneville has bent the cost curve down to even below inflation. The success of these efforts are reflected in the cost projections Bonneville includes in the IPR processes as shown in Figure 2 below.

Figure 2. Average Annual Program Costs



Bonneville has also taken actions that were not contractually required, but were responsive to customer needs while ensuring cost recovery. Bonneville held an expedited 7(i) process in 2020 that resulted in the suspension of the Financial Reserves Policy Surcharge to provide timely rate relief at the onset of the COVID-19 pandemic. In addition, Bonneville made extended payment agreements available and implemented a flexible PF rate option during the pandemic. Bonneville responded to customers in an accountable, trustworthy and transparent way. These actions demonstrate the agency is responsive to customer needs and input, particularly when necessary to respond to the unexpected.

Even with this demonstrated commitment to efficient cost management, Bonneville recognizes that some of its public power customers want a larger say in how Bonneville sets its forecast costs. Bonneville appreciates these concerns, but as a federal agency tasked with meeting many statutory obligations, it would be inconsistent with Bonneville’s statutory requirements to provide its customers with decision authority on cost commitments. Decisions on the projected costs needed to meet Bonneville’s statutory obligation must remain with the Administrator and are ultimately submitted, as part of the government’s budget process, to Congress and the President.

Bonneville affirms its commitment to continue to give customers opportunities to provide input on its power asset management decisions and financial policies. The past 10 years under Regional Dialogue contracts have proven that the regional conversation on costs, such as the significant public review and input in the IPR processes and other public engagements such as Bonneville’s Financial Plan Refresh process, have provided valuable public input to the Administrator regarding how costs factor into meeting Bonneville statutory directives. Building from this foundation, Bonneville looks forward to finding ways to continue to improve the regional public and customer engagement on this important topic.

8.2 Financial Plan, Policies and Processes

Customers and the public are invited to participate in the development and review of Bonneville's financial plan. Over the past six months, Bonneville's Financial Plan Refresh effort has sought to engage the public to develop a policy that is durable in making measured progress toward long-term goals and in allowing flexibility within the policy to respond to changing circumstances.

Receiving broad public input when developing policies and rate structures helps Bonneville ensure appropriate financial liquidity, risk and debt management. Bonneville recognizes that its financial policies will influence customer consideration of post-2028 contracts. While Bonneville is not planning a comprehensive financial policy review ahead of the next long-term power sale offering, a change to Bonneville's financial risk and method of mitigating that financial risk may warrant revisiting existing policies. See Section 10.1.1.3 for more discussion of Bonneville's post-2028 risk methodology considerations. Bonneville understands that the interplay between Bonneville's financial policies and the post-2028 contract conversation is an important issue and looks forward to continuing the dialogue on this topic.

Bonneville has shown that it is committed to ensuring customers and the public have regular access to clear and transparent financial information and to providing opportunities for meaningful input on Bonneville program costs. While not legally required, Bonneville has established new norms in access and transparency to financial information by establishing the Quarterly Business Review (QBR) (including QBR Technical Workshop) and continuing the IPR process. The IPR provides an opportunity for the region to comment on Bonneville's projected costs for the upcoming rate period. The QBR offers quarterly updates on Bonneville's financial and business performance and offers an opportunity for customers and the public to ask questions about that performance.

8.3 Cost Controls and Off-ramps

Bonneville is open to policy and contract options that would increase cost certainty and provide customers with the flexibility to equitably reduce the amount of power purchased from Bonneville while also ensuring recovery of Bonneville's costs and maintaining its financial health. One method posited by public power customers to achieve this balance is the inclusion of "off-ramps" or exit clauses giving customers a contract right to reduce the amount of power they are obligated to purchase from Bonneville in the Provider of Choice power sales contracts that would trigger in the event Bonneville's costs exceeded certain identified thresholds.

Bonneville has considered the public power customers' proposal, but is not supportive of including such provisions in the post-2028 contracts. Such action could unfairly burden remaining customers, create price distortions, and impede cost recovery. Trigger-based off-ramps increase the cost risk to the customers that remain with Bonneville and would expose Bonneville to stranded costs, which in turn would erode Bonneville's long-term competitiveness. Bonneville is also concerned with the inherent conflict such a provision would introduce between public power customers choosing to stay with Bonneville (and therefore subject to Bonneville's costs) and those choosing to leave Bonneville. Developing appropriate limitations on the use of such a provision would also be difficult. For example, it would be untenable for customers to leave Bonneville when PF costs rise and then return to Bonneville when market prices make Bonneville PF rates more appealing. Bonneville must provide an equitable

approach for all customers to share the inevitable rate uncertainty during the contract period while also ensuring that Bonneville recovers all its costs.

8.4 Reducing Power Rate Risk by Removing Forecast Secondary Revenue from the Base PF rate

Bonneville's current and historical practice in each power rate case is to credit the PF rate with forecast revenue from sales of surplus power. This is inherently fraught with revenue risk given such forecast revenue is based upon market prices and water conditions. An alternative approach Bonneville proposes to explore with public power customers is to remove forecast secondary revenue from the base PF rates and instead provide the rate benefit at the end of each period based on the actual secondary revenue received. Under this proposal, Bonneville would still forecast secondary revenues for the purposes of setting performance goals and its other rates, including the PF Exchange and IP rates. This type of after-the-fact secondary revenue crediting framework would reduce volatility in the base PF rates and make more transparent the sources of Bonneville's cost pressures. Also, this would transparently signal to Bonneville and customers when unsustainable rate pressure is the result of cost increases as opposed to wholesale market dynamics.

Another benefit of removing secondary revenue from Bonneville's base rates is that it removes a substantial amount of revenue risk, which is currently managed with liquidity tools such as financial reserves, the short-term Treasury note, and rate mechanisms like the Financial Reserves Policy Surcharge and Cost Recovery Adjustment Clause. The current construct relies on the pooling of all cost and revenue risk, which can offset each other, and liquidity tools to smooth out rate impacts over time. Removing secondary revenue would reduce the likelihood of having to use tools like the Financial Reserves Policy Surcharge and Cost Recovery Adjustment Clause rate mechanisms. See the risk management section and length of rate period Section 10.1.1.1 for further discussion.

The TRM was appropriately silent on the risk mitigation Bonneville needed to demonstrate cost recovery because locking in a particular risk construct can undermine the entire point of the construct, which is to adapt to an uncertain future and protect Bonneville's ability to recover its costs. For this reason, Bonneville left risk to be addressed in the applicable rate period. With that choice, though, came rate uncertainty. If Bonneville were to adopt a rate methodology that removed Bonneville's biggest risk from its base rates, its secondary revenue risk, Bonneville may be able to provide some specificity around how it will manage its cost recovery risk during the Provider of Choice contract. This specificity could bring customers additional certainty around the costs they can expect to pay and the method Bonneville uses to recover those costs during the length of the contract.

Yet another benefit of removing secondary revenue from Bonneville's base rates is that it removes some of the complexity associated with product switching within the contract term. When secondary revenue is included in Bonneville's base rates, it can result in major changes in the amount of Bonneville's financial reserves – financial reserves would increase when market conditions and inventory are good and would decrease when market conditions and inventory are bad.

Bonneville has clarified with its Financial Plan the framework for managing secondary revenue volatility through the Treasury Payment Probability Standard and the Financial Reserves Policy. Bonneville is comfortable with the current framework which allows for the pooling of all risks and management of those risks with various liquidity tools such as reserves, short-term debt, and rate mechanisms. This

construct also supports Bonneville’s strong credit rating. However Bonneville is open to exploring the concept of removing secondary revenue from Bonneville’s base PF rate if there is mutual benefit to customers and Bonneville.

Bonneville recognizes that removing forecast secondary sales from the base PF rate is a significant change from the current ratemaking approach and would involve trade-offs and other factors to be considered. Bonneville is interested in having these conversations with customers through the public workshops prior to development of the Post-2028 Rate Methodology.

8.5 Additional Cost-Management Flexibilities: Non-Federal Purchases and Assignment of Power Sales Contracts

Bonneville’s goal is to provide customers contractual flexibilities to provide more local control over the source of power supply without materially creating a cost risk for other customers or impacting Bonneville’s ability to recover its costs. Given concerns customers have raised over exposure to Bonneville’s costs, Bonneville recognizes that a direct control a customer can exercise over its cost exposure is through controlling the amount of power it purchases from Bonneville. This is discussed in Section 4.2.4, where Bonneville is proposing increased non-federal resource flexibilities that will empower customers to diversify their resource portfolio and reduce purchases of power at the PF rate.

Bonneville is open to exploring win-win scenarios. While the legal, financial and logistical hurdles may prove prohibitive, Bonneville would consider an equitably designed “replacement required” off-ramp whereby customers could terminate their power sales agreement without being subject to the take-or-pay provisions if they found other regional preference customers with firm power load that need power supply and are willing to increase the amount of their federal power purchases, e.g., increase their Bonneville contract purchase obligation amounts at a rate equal to or greater than the applicable PF rate. Legal considerations would need to be evaluated and any such option must comport with net requirements sales and preference obligations. While a customer may facilitate seeking out an alternative buyer, the negotiation and contractual relationship would be between Bonneville and the buyer(s). In addition, since not all customers cost the same to serve, such replacement sales would need to have parameters addressing the characteristics of the power and transmission involved to ensure any replacement purchase lends an equitable result for all customers.

The current Regional Dialogue contracts provide customers a one-time right to change their purchase obligation through a change in purchased product. However, during Regional Dialogue, Bonneville has granted a limited number of customer requests to change their purchase obligation outside of the contractually allowed election window. Bonneville is open to exploring additional flexibility for customers to change their purchase obligation over the term of the Provider of Choice contracts.

8.6 Other Cost-Management Tools: Regulatory Assets Treatment and Contract/TRM Revisions

8.6.1 Regulatory Cost-Recovery Deferral

Bonneville provides regulatory cost recovery deferral as another example of its long-standing commitment to maintaining consistent and reasonable rates. In limited circumstances, when certain criteria are met, the Administrator can temporarily defer cost recovery of specific incurred expenses,

reflected on the FCRPS financial statements as regulatory assets. This shields customers from rate shock stemming from sudden, unforeseen, major, and one-time expenses. In FY 2006, the Administrator deferred a \$330 million write-off of research and development for Columbia River Fish Mitigation, and in FY 2020 the Administrator deferred a \$104 million impairment of the terminated I-5 Corridor Project. While the Administrator has used, and could use, regulatory cost-recovery deferral, its application is only on a case-by-case basis, under the criteria summarized above, and thus will not be considered for inclusion as a provision in the Provider of Choice contract or other planned implementation during the Provider of Choice policy process.

8.6.2 Ability to Change Contract and Rates

Unexpected events could affect future power sales contracts. Some examples of unexpected events faced by utilities include catastrophic weather conditions, operational changes required to meet physical or environmental conditions, resource decommissioning or regulatory changes related to climate change. Today, the TRM offers customers processes for TRM revisions due to unintended consequences or for improvements and enhancements. Bonneville proposes to continue using a rate methodology to explore opportunities to meet customer needs to mitigate risks that contribute to cost uncertainty. Bonneville understands that many cost control and risk management concerns are related to the impact of upward rate pressures. Bonneville is committed to working collaboratively with customers to mitigate risks associated with such events and address them as circumstances arise.

9. DISPUTE RESOLUTION

Bonneville maintains that there is no one-size-fits-all approach that would work for the many issues that may arise under customers' long-term contracts. As such, Bonneville proposes a continuation of the dispute resolution procedures used under the Regional Dialogue contracts and the TRM. These processes were carefully negotiated between Bonneville and the customers taking into consideration each party's needs while also addressing legal requirements. These dispute resolution provisions dovetail with Bonneville's Binding Arbitration Policy. Under the existing construct, final actions subject to Section 9(e) of the Northwest Power Act are not subject to arbitration and are within the exclusive jurisdiction of the Ninth Circuit Court of Appeals (court). For other issues, either party to the contract may request to engage in binding arbitration.

Going forward, any dispute resolution process ultimately included in the Provider of Choice contracts will need to continue to balance efficiency with a fair opportunity to raise disputes to a neutral third party for resolution. It is also important to recognize that not all issues are appropriate for resolution by a third party, and many matters for discussion under the contracts can be resolved informally. Finally, the Administrator must retain sole discretion to make policy decisions necessary to interpret and administer federal statutes and regulations.

With the details of Bonneville's Provider of Choice contracts yet to be determined, any dispute resolution process will also need to be reviewed to ensure compatibility with the ultimate contract framework. That said, Bonneville believes that the current approach is preferable for the Provider of Choice contracts. Bonneville would need to carefully consider any proposed change to the dispute resolution process to ensure that any change would be consistent with statutory requirements and Bonneville's Binding Arbitration Policy.

10. POST-2028 INITIATIVE PROCESSES

Bonneville’s Post-2028 Initiative encompasses Provider of Choice and related topics, including the Post-2028 Rate Methodology, REP and conservation. The Provider of Choice process is one part of this broader set of conversations. The scope of other Post-2028 Initiative processes are shared in the sub-sections below. While conversations about Post-2028 issues are likely to cross or be interrelated, processes are expected to run largely in parallel, with distinct scopes and decision-making processes of their own. Bonneville intends to tightly coordinate all Post-2028 Initiative work and ensure visibility to engagement opportunities across forums. More processes may be integrated to address emerging policy needs.

Figure 3 depicts the expected timeline for each Post-2028 Initiative process. This timeline is based on best available information at time of publishing and is subject to change as issues evolve.

Figure 3. Post-2028 Initiative Timeline



10.1 Post-2028 Rate Methodology

Bonneville plans to establish a Post-2028 Rate Methodology similar in scope to the existing TRM that would be applicable for the length of the Provider of Choice contracts. This means that it would be limited to the PF rate design and would not impact Bonneville’s other rates.

The process for reaching the Post-2028 Rate Methodology will be similar to the process Bonneville employed to reach consensus on the TRM. Bonneville staff would begin working on the Post-2028 Rate Methodology shortly after the BP-24 Rate Case, as noted in Figure 3. Following the BP-24 Rate Case, Bonneville staff would lead a series of educational workshops to establish a common baseline knowledge of rates and explain why certain choices were made in the TRM. Staff would also present potential options to explore for the rate design applicable to the Provider of Choice contract that were consistent with the previously established conceptual framework. These educational workshops would then transition to the collaborative identification of potential solution sets which would then be analyzed and evaluated. After this analytical and evaluation period, a preferred solution will be selected and the rate methodology will be drafted. Bonneville expects this drafting stage would include periods of public review, including focus groups with stakeholders. The proposed rate methodology would then be introduced in a 7(i) proceeding run concurrently with the BP-26 Rate Case.

10.1.1 Post-2028 Rate Methodology Considerations

10.1.1.1 *Timing of Rate Processes*

While all aspects of the current TRM will be available for potential change in the Post-2028 Rate Methodology, two interrelated areas—rate period length and risk mitigation—will likely receive particular attention. Bonneville is not recommending any changes to these areas at this time. Nevertheless, Bonneville acknowledges that concerns with these components of the TRM have come up frequently over the last 10 years. The concern Bonneville has heard is that rate cases every two years results in “7(i) process fatigue” as Bonneville and the region are on a cadence of almost perpetual rate case preparation. Thus, interest has been expressed in extending the rate period to a longer period, with less frequent rate cases.

In Bonneville’s experience, longer rate periods, such as the five-year rate periods Bonneville used in the late 1990s and early 2000s, tend to complicate rate setting and cause other tertiary inefficiencies and risks in the rate case process. The front-end administrative work to produce rates for longer periods of time requires substantially more effort and generates significantly more issues. The enormous administrative records produced to support the WP-96 and WP-02 rate proceedings are cases in point. Additionally, these cases tend to be more complex due to the higher risk that rate case forecasts will diverge from current market trends. This leads to a greater chance that work will be wasted, and the case will have to be reopened to make adjustments. The WP-02 rates for the FY 2002 – 2006 rate period is a good example of this problem. The WP-02 rate case commenced in August 1999 and was completed in June 2000, only to be reopened in December 2000 due to unprecedented market prices. The rate case eventually ended (again) in June 2001, meaning the region spent almost two continuous years in a rate case.

Longer rate periods also pose staffing challenges. In a five-year period, it is difficult to train and retain experienced staff to run models, perform studies and develop analysis that is used only once every five years. All told, setting rates on a longer-term basis generally requires a more robust risk mitigation package, increases the number of issues addressed in the rate case, and requires more time to prepare and conduct.

On the other hand, Bonneville recognizes that the two-year rate period directed by the TRM can produce what feels like a perpetual rate-setting cycle. However, Bonneville views this cadence as producing some efficiencies, as parties and staff develop routines and familiarity with studies and issues, resulting in more compromises and fewer litigated issues. Also, because decisions are for two years, Bonneville rate decisions have a shorter period of implementation, thus giving parties time to seek additional adjustments in the next rate proceedings. These types of short-term solutions would be less likely to occur if the impact of those concessions were to last five years as compared to two.

There is certainly much to consider with regard to the optimal rate period length, which would include both Power Services and Transmission Services and could also have implications on Bonneville’s tariff. Bonneville plans to once again revisit the approach for the Provider of Choice contracts.

10.1.1.2 *Capacity Pricing*

Another feature of the TRM that will require attention in the rate methodology discussions is the pricing of capacity. Bonneville tiered the use of capacity through the TRM. The Tier 1 cost of capacity was

bundled into the Tier 1 customer charges. The demand rate is the marginal cost of new capacity applied to any capacity need in excess of the amount bundled into the customer charges. This design allowed capacity needs placed on Bonneville to grow while mitigating the impact on other customers in that any additional use of FCRPS capacity would be matched by revenue at the long-run opportunity cost of that capacity.

Going forward, Bonneville intends to explore a return to a more traditional approach to charging for capacity and energy. Specifically, unbundling the cost of capacity from any power charges and charging for capacity explicitly as measured as the total amount of power purchased from Bonneville during a defined period of time. A more traditional approach to measuring and charging for capacity use would align with the growing focus on capacity needs as well as provide distinct energy and capacity product price differentiation.

Regardless of the approach used, it would make little sense to tier energy and not tier capacity. Under a tiered rate design, Bonneville would need to either limit the amount of available capacity or ensure that any demand above a defined level be set at Bonneville's marginal cost of that capacity.

With regard to Contract Demand Quantity (CDQ), Bonneville does not intend to use these values in the rate design applicable during the Provider of Choice contract period. These values were created for the sole purpose of mitigating rate impacts associated with the rate design change from the Subscription contract to the Regional Dialogue contract. Given that many factors have changed since that time, and that Bonneville may ultimately adopt a different rate design altogether, the CDQs included in customer contracts should expire with the Regional Dialogue contracts. That said, Bonneville may adopt a similar type of component in the new rate design to mitigate rate impacts if needed. Ideally, such a component would not be needed to present a level playing field for customers under the new Provider of Choice rate construct.

Further, Bonneville is open to simplifying its approach to RSS – potentially allowing resources to run to load and capture the impact that the resource has on the net load through the load billing determinants rather than through resource billing determinants. This approach, however, comes with some drawbacks that would need to be considered – such as more volatile demand charges for the customers, a known obligation but uncertain revenue for Bonneville, and an indistinguishable line between resource performance and load changes.

10.1.1.3 Long-term Risk Methodology

A critical component of Bonneville's rate design and its ability to demonstrate cost recovery is its risk mitigation package and any associated rate risk adjustments. Because flexibility and the ability to adapt is in and of itself a method for mitigating risk, Bonneville did not lock down its method for mitigating risk in the TRM. Rather, Bonneville chose to establish appropriate risk mitigation mechanisms in each rate case.

Bonneville did, however, specify the required length of a rate period during the Regional Dialogue contract period. This rate-period length requirement is an important factor in the required robustness of any risk mitigation strategy – shorter rate periods require less robust risk packages relative to longer rate periods because longer rate periods inherently include more uncertainty given the amount of time involved before the next rate-setting process. As discussed earlier in this concept paper, Bonneville plans to consider the pros and cons of different rate period lengths applicable during the Provider of

Choice contract period. In addition, Bonneville intends to explore removing secondary revenue from its base rates, which, if adopted, would impact the required robustness of its risk strategy.

Considered together, Bonneville believes it is important to evaluate these options and their impact on the risk mitigation package needed to sufficiently mitigate risk and demonstrate cost recovery during the Provider of Choice contract period. As such, Bonneville plans to provide customers as part of the Post-2028 Rate Methodology discussions with different risk packages for consideration that explore Bonneville's secondary revenue exposure, the term of the rate period, and the interplay between the two.

10.1.1.4 Residential Exchange Program for Public Customers Purchasing Power under a Tiered Rate Construct

The REP is complex and includes a lot of uncertainty with regard to the future. In line with the general view that cost certainty and preservation of the value of the FBS are important goals for public power customers in the post-2028 period, it follows that revisiting the paradigm of partial REP participation by public power customers is in order. To the extent we can find ways to simplify the REP and remove some of that uncertainty the better – particularly when the impact is relatively small as Bonneville expects it to be with public power customers. Bonneville has already established that an effective tiered rate structure requires that REP benefits as calculated by the Northwest Power Act be limited in some way to achieve a critical goal of tiering rates. A complete exclusion of REP benefits for public power customers who are purchasing power under a tiered rate structure would remove this complexity, reduce administrative burden, and allow other challenging decisions to be made without having to consider the potential impact on the REP.

In support of tiered rates and simplifying the implementation of the REP for consumer-owned utilities purchasing power under a tiered rate construct, Bonneville would like to build on the REP limitations agreed to under CHWM contracts and request that public power customers not pursue their Residential Exchange rights for the term of the Provider of Choice contract. Such request would be conditioned under the assumption that removal of REP benefits from customers eligible in BP-24 would not cause such customer to be an outlier as far as the overall rate impact experienced by other public power customers under the terms of the new contract and rate design.

10.2 Residential Exchange Program

The REP process described in this section is the second major process that will be run in conjunction with the Provider of Choice process. The Provider of Choice process described throughout this concept paper is designed to position Bonneville to meet its Section 5(b) power obligations to requesting utilities in the post-2028 period. Bonneville also has statutory obligations under Section 5(c) to participants in the REP, which are primarily IOUs. The current 2012 REP Settlement expires in FY 2028, meaning Bonneville must also take steps to be ready to meet these statutory obligation in the post-2028 period. This section describes the background of the REP, its current implementation, and Bonneville's plan for addressing its REP obligations in a multi-phased process held concurrent with the Provider of Choice process.

10.2.1 Statutory Overview of the Residential Exchange Program

The REP was developed to administer Section 5(c) of the Northwest Power Act, which provides residential and farm customers of high-cost Pacific Northwest utilities access to low-cost federal power. The Northwest Power Act was Congress' answer to solving Bonneville's pending administrative allocation of low-cost federal hydropower in the 1970s. At that time, the region's IOUs had lost their long-term access to federal power and were incurring increasingly higher costs for constructing and operating new thermal resources. These increases led to regional disputes over access to federal power. Public body and cooperative utilities, under the preference and priority provisions of federal law, received priority access to the limited supply of federal power, while states and certain cities served largely by IOUs sought to expand the scope of recipients of federal power through modifications to existing state laws. Congress eventually stepped in and instituted a regional compromise through the Northwest Power Act. That compromise included, among other matters, creation of the REP, which gave all regional utilities with high-cost resources (public power and investor-owned) access to the benefits of low-cost federal power for their residential and farm customers.

The REP is structured as a power exchange, where utilities with higher-cost resources (typically IOUs) may sell power to Bonneville at their average cost of resources, or Average System Cost (ASC). Bonneville purchases this power and then sells the same quantity of power back to the utility at Bonneville's cost of power (the PF Exchange rate), modified by certain rate adjustments. In practice, no power is transmitted, and the exchange is treated as a financial transaction. Instead, Bonneville pays the utility the net difference between the two sales multiplied by the utility's qualifying residential and farm load. The monetary "REP benefits" are passed on by the utility to its residential and farm consumers, and typically appear as a credit on residential power bills. Bonneville recovers the cost of the REP in its power rates.

10.2.2 Components for Determining Residential Exchange Program Benefits

The REP is implemented as a paper transaction that typically results in a net payment to the REP participants. The formula used to calculate that payments is as follows:

(ASC – Bonneville's PF Exchange Rate) x Exchanging Utility's Residential and Farm Load = REP benefits.

Each component of this calculation is informed by statutory provisions.

10.2.2.1 *Exchanging Utility's Average System Cost*

The ASC is the cost of an exchanging utility's resources. Bonneville develops an ASC methodology to determine which resource costs are allowed into the ASC calculation. As carbon requirements evolve in the region, utility discretion in how they comply and their compliance decisions may impact their ASCs in different ways. Bonneville is considering these impacts.

Section 5(c) of the Northwest Power Act provides Bonneville wide latitude to determine the ASC methodology in consultation with the Council, Bonneville customers and state regulatory bodies. Bonneville has developed three ASC methodologies over the last 40 years, the latest of which was developed in 2008. The ASC methodology must be reviewed and approved by FERC.

10.2.2.2 Priority Firm Exchange Rate

The PF Exchange rate is Bonneville's cost of power, modified by certain rate adjustments as provided for in sections 7(b)(1) and 7(b)(2) of the Northwest Power Act. To calculate this rate, Bonneville begins at the same level as the rate Bonneville would charge its preference customers for power under Section 7(b). Bonneville then performs a statutory rate test, known as the Section 7(b)(2) rate test, to determine whether the preference customer rate must be protected from certain costs created by the Northwest Power Act (including the REP). The rate test effectively creates a ceiling on the costs Bonneville can recover from its preference customers' rate. If the rate ceiling is reached, then the costs exceeding that ceiling must be allocated to all other power sold by Bonneville. The PF Exchange rate is one of the rates that receives the costs allocated away from the preference customers' rate. In general terms, as costs are allocated away from the preference customer's rates by the 7(b)(2) rate test, the PF Exchange rate increases and REP benefits decrease.

The Section 7(b)(2) rate test is a complicated provision of the Northwest Power Act. To assist in its interpretation, Bonneville has historically developed both a legal interpretation and 7(b)(2) methodology. The last legal interpretation and methodology were developed in 2008, but both were subsequently withdrawn after a regional settlement on the REP was reached.

10.2.2.3 Residential / Farm Load

Section 3(18) of the Northwest Power Act describes the type of load that is exchangeable under the REP. It includes "usual" residential and farm loads and irrigation pumping loads up to 400 horsepower (222,000 kWh per month). The benefits of the REP must be passed through directly to these users consistent with the parameters established by state public utility commissions.

10.2.2.4 Other Impacts to Residential Exchange Program Benefits

The components described above comprise the primary elements used in determining the base level of REP benefits for all exchanging utilities. Two other features of the REP exist and may be employed which would impact the level of REP benefits paid to individual utilities.

1. In Lieu – Discretionary Reduction in Current REP Benefits

Section 5(c)(5) provides that, in lieu of Bonneville purchasing power from an exchanging utility, Bonneville may purchase power from "other sources" if that other source is cheaper than the exchanging utility's ASC. The power purchased from that other source would then be sold to the exchanging utility at the PF Exchange rate, thereby reducing that utility's benefit payments under the REP. This feature of the REP, which is discretionary, permits the Administrator to reduce the cost of the REP for a utility with a high ASC.

2. Deemer – Reductions in Future REP Benefits

Section 5(c)(4) of the Northwest Power Act provides that if an exchanging utility's ASC falls below Bonneville's PF Exchange rate because of the supplemental charge imposed by the 7(b)(2) rate ceiling, the utility may "terminate" its participation in the REP. Historically, Bonneville has allowed utilities to remain in the REP in these instances, but "deem" its ASC equal to Bonneville's PF Exchange rate. Interpretation of Section 5(c)(4) has previously resulted in contractual provisions where the difference between the "deemed" ASC and PF Exchange rate is tracked in a separate account. The resulting

balance, referred to as a “deemer balance,” must then be paid off with prospective REP benefits before the utility is allowed to receive REP benefits for its end-use customers.

10.2.3 History of Residential Exchange Program Implementation

Historically, Bonneville’s implementation of the REP has been contentious. The REP creates an inherent conflict between the primary recipients of REP benefits (IOUs and their consumers) and the primary payers of the REP benefits (preference customers and their consumers). The first 20 years of implementation of the REP (1980 – 2000) saw multiple disputes over Bonneville’s implementation of the ASC methodology and limitations on the use of the in lieu provisions of law. In the late 1990s, Bonneville and IOU REP participants attempted to avoid continued litigation over ASCs by settling the REP. This approach led to the 2000 REP Settlement, which was challenged by public power customers in the court and ultimately overturned in 2007.¹ Following the court’s remand, Bonneville reinstated the traditional REP, revised the ASC methodology and the 7(b)(2) rate test methodology, and determined refunds were owed to preference customers for past overpayments of REP benefits to the IOUs. Bonneville’s decisions were challenged and at one point 56 petitions for review were pending before the court.

The prospect of endless litigation over the REP led many representatives of public power customers and IOUs to propose mediation of the REP disputes. Mediation sessions began in 2010 and continued into 2011. In 2011, a proposed settlement (2012 REP Settlement) was reached between public power and IOU representatives that, if agreed to by Bonneville, would settle the total aggregate amount of payments under the REP for IOU participants until 2028. Bonneville evaluated this proposal in a formal hearing, the REP-12 proceeding. In the REP-12 proceeding, Bonneville calculated the potential REP benefits paid to the IOUs under a number of litigation scenarios. Bonneville then compared these contested scenario values to the net present value of the 2012 REP Settlement. Bonneville’s analysis showed that the amount of REP benefits provided under the 2012 REP Settlement was less than the amount of REP benefits the IOUs would have received under most of the litigation scenarios. In light of this finding, the Administrator found that the 2012 REP Settlement was consistent with his statutory authorities and signed it. The Administrator also withdrew his prior contested records of decision (RODs) regarding the interpretations of the Section 7(b)(2) rate test. A party challenged the 2012 REP Settlement and the REP-12 ROD, and the court affirmed the Administrator’s decision to adopt the settlement in 2013.²

10.2.4 The 2012 Residential Exchange Program Settlement

The 2012 REP Settlement established a fixed stream of REP payments to the IOU REP participants as a group until 2028, though no individual IOU was guaranteed a particular amount of REP benefits. Additionally, the 2012 REP Settlement provided the following benefits to both publics and IOUs during the term of the settlement (until 2028):

- Paid roughly \$600 million in “refund payments” to publics for prior overpayments in REP benefits to the IOUs from 2002-2007.
- Allotted IOUs 14% of future environmental attributes from the FCRPS (until 2028).

¹ See *Portland Gen. Elec. v. Bonneville Power Admin.*, 501 F.3d 1009 (9th Cir. 2007) (*PGE*).

² See *Assoc. of Pub. Agency Customers v. Bonneville Power Admin.*, 733 F.3d 939 (9th Cir. 2013) (*APAC*).

- Waived Bonneville’s right to in-lieu parties and reset “deemer” status.
- Provided regional cost certainty through 2028.

By its terms, the 2012 REP Settlement expires on October 1, 2028. Before expiration of the settlement, Bonneville is required to “conduct a proceeding and issue a ROD to determine, for the period starting FY 2029, whether, and if so, how, to modify or replace its legal interpretation of, and methodology for implementing, sections 7(b)(2) and 7(b)(3).” REP Settlement at § 11.3.

10.2.5 Concepts and Roadmap for Future Residential Exchange Program Implementation

Although the 2012 REP Settlement does not expire until October 1, 2028, Bonneville and regional stakeholders will need to develop a path forward for the future implementation of the REP well before that date. For this concept paper, Bonneville is proposing a two-phased approach for developing the post-2028 implementation of the REP: (1) a regional settlement phase; and (if the settlement phase is unsuccessful), (2) an REP traditional preparation phase. Both phases are described more fully below.

10.2.5.1 Settlement Phase (September 2022 – September 2025)

The settlement phase builds on the foundation established by the 2012 REP Settlement. During the settlement phase, Bonneville’s focus would be to facilitate and encourage regional discussions toward a structured settlement of the REP consistent with the cases discussed in Section 10.2.3.

The settlement phase includes a number of benefits to regional parties, not least of which is that it allows regional stakeholders to have a substantial influence, through collaboration and cooperation, on how the REP should be implemented in the post-2028 period. The past decade of essentially no disputes over the REP or its component parts is a testament to the effectiveness of a regionally-designed settlement. The fixed nature of the 2012 REP Settlement also introduced unprecedented cost certainty in the REP for both public power customers (who pay the costs of the program) and to the IOUs (who are the greatest recipients of the payments). Historical REP payments were far more volatile. The settlement phase provides the best opportunity for regional customers to receive certainty on future REP costs/benefits in the nearest time-frame. If a settlement is reached early in the negotiation process, Bonneville can conduct its proceeding to determine its lawfulness at any time.

The settlement phase would be broken up into a number of distinct sub-phases described below.

1. REP Dry Run and Preparation Sub-Phase (Fall 2022 – Spring 2023)

Initial public engagement sessions would begin in the fall of 2022 to ground stakeholders on the foundations of the REP, the models used in running the rate test, and the relative impacts on REP benefits of various interpretations of the Section 7(b)(2) rate test, ASCs, in lieu, and other factors. To support these sessions, Bonneville intends to produce a dry run production of REP benefits using data from the BP-22 rate period and various assumptions on 7(b)(2) implementation from the REP-12 proceeding. The point of the REP benefits dry run is to provide a working educational model from which regional stakeholders may be able to familiarize themselves with, and get a sense of scale for, the various assumptions and factors that affect the REP benefits levels.

During this dry run and preparation phase, stakeholders will have an opportunity to inform and influence the working list of scenarios and assumptions that should be used in the REP settlement scenario analysis phase discussed below. Identifying the relevant scenarios, and discussing the relative

merits of them in negotiations, was essential during the REP-12 settlement proceeding since most of the issues had been in active litigation before the court. The dry run and preparation phase is intended to help orient parties to the outstanding issues regarding the REP implementation, consider which scenarios to pursue, which to abandon, and identify any new scenarios not previously considered.

Bonneville intends to use final study data from the BP-24 rate proceeding for REP scenario analysis in support of the REP contract negotiations sub-phase described below. The dry run and preparation phase is targeted to begin in fall of 2022 and be completed by spring of 2023. This phase will be conducted concurrent with the BP-24 Rate Case, so the cadence will be coordinated with rate case deadlines to avoid overlapping with critical deadlines.

At the conclusion of the dry run and preparation phase, Bonneville should have the main scenarios defined to use for the REP contract negotiations sub-phase. Stakeholders, in turn, should become familiar with the assumptions, operation, and functionality of the 7(b)(2) rate test. Bonneville believes this is an important step in preparing stakeholders for productive settlement negotiations.

2. REP Contract Negotiation (settlement negotiation period) Sub-Phase (Fall/Winter 2023 – Spring/Summer 2024)

The next phase of evaluation would begin in the fall/winter of 2023 after the BP-24 rate proceeding concludes, and after Bonneville has completed the dry run and preparation sub-phase. This sub-phase would begin the formal negotiation over the REP and potential settlement options among public power customers and IOUs, with support from Bonneville. Bonneville would turn to developing scenario runs consistent with the scenarios developed in the dry run and preparation sub-phase, and provide data and output for use in stakeholder-led negotiations. Scenario analysis was a key component of the 2012 REP Settlement and was critical in the region reaching a settlement. Bonneville staff would conduct the analysis initially, publishing results as appropriate, but with the end goal of assisting parties in developing their own analysis capabilities.

As noted above, the underlying data for these scenarios would be based on information from the BP-24 rate proceeding. With the data from these scenarios analyses, interested parties would have information from which to develop a consensus approach to the REP for the post-2028 timeframe.

3. REP Settlement Evaluation Process and Decision (7i) (Fall 2024 – Spring/Summer 2025)

If regional consensus on a post-2028 REP proposal is reached, Bonneville would need to engage in its own evaluation of the proposal, likely through a formal proceeding, to establish whether the settlement or proposal will meet statutory requirements and the direction of the court described in Section 10.2.3. This process would be conducted in a Section 7(i) process. The timing of this process would depend upon the progress of negotiations; however, the opportune time for conducting this process would be the fall of 2024 prior to the targeted date of execution of new long-term power contracts in late 2025. If the Administrator concludes that the proposed settlement meets Bonneville's statutory requirements, the Administrator would sign the settlement and provide his/her rationale in an accompanying ROD.

10.2.5.2 *Traditional Residential Exchange Program Preparation Phase (Fall 2025 – Summer 2027)*

The settlement phase is an important and critical first step in determining whether the region can solve, through collaboration and negotiation, the potential future implementation of the REP. However, Bonneville must be prepared to implement the traditional REP in time for the post-2028 period if a regional consensus is not reached. To that end, Bonneville will need to prepare for a second phase of REP preparation – the traditional REP preparation phase – if a settlement is not reached or not completed by the summer of 2025. During the traditional REP preparation phase, Bonneville would shift its focus from facilitating and supporting settlement discussions to preparing its positions and policies for traditional REP implementation. Bonneville anticipates that it would still support active negotiations for settlement during this time. But, given time constraints and the requirements of the 2012 REP Settlement, fewer resources will be available to support those efforts as Bonneville begins to set up the components of the traditional REP for the post-2028 period. A collection of processes, policies and proceedings would be needed to ensure that Bonneville has the necessary components of the REP developed and ready for the BP-29 implementation of the REP. Those processes would likely address, at a minimum, the following:

- 7(b)(2) legal interpretation.
- 7(b)(2) implementation methodology.
- ASC methodology, consultation process, FERC filing.
- 5(c)(5) In lieu Policy.
- Residential purchase and sales agreement negotiation and development.
- Treatment of environmental attributes of the FCRPS.

Importantly here, there would be little certainty on the level of REP benefits included in the BP-29 rates until completion of the BP-29 rate proceeding. Subsequent challenges, if any, to Bonneville's decisions on various REP matters would further delay certainty to regional parties, as the region must wait for FERC to rule on the BP-29 rates, and then wait further for any challenges filed with the court to be resolved.

10.3 Conservation

A fundamental purpose of the Northwest Power Act is to encourage the development of conservation to reduce, through efficient use of electricity, customer loads supplied with power from Bonneville. The Northwest Power Act prioritizes conservation as the priority resource Bonneville is to acquire before any other resources. Conservation is frequently referred to as energy conservation or energy efficiency. Cost-effective conservation helps ensure Bonneville's power rates are as low as possible. Under the Regional Dialogue and tiered rate construct, implementing conservation measures can also help customers mitigate the risk of exceeding their RHWI which could result in their buying power from Bonneville at Tier 2 rates or using non-federal resources.

Energy Conservation Agreements (ECAs) are the long-term contractual mechanism that Bonneville currently uses to acquire conservation from its customers. At the beginning of each two-year rate period, Bonneville establishes an Energy Efficiency Incentive (EEI) budget based on the overall energy savings target and estimated cost to achieve those savings. The overall EEI budget is allocated to individual customers using the Tier 1 Cost Allocator (TOCA). A TOCA is the billing determinant for the

customer charge for each customer purchasing power at the PF Tier 1 rate and is expressed in a percentage. Bonneville leverages the EEI budget to acquire qualifying conservation from its customers. Customers report additional self-funded energy savings to Bonneville.

In its Provider of Choice discussions with customers in 2021, Bonneville discussed three aspects of potential program evolution: 1) adjusting the funding model to support conservation acquisition, 2) adopting flexibility mechanisms customers could use to ease implementation, and 3) refining the approach to conservation infrastructure. Customer feedback about Bonneville's current program and program changes since 2012 was generally positive. Given this feedback and the success Bonneville has experienced achieving its conservation goals under the ECAs, Bonneville proposes to continue its current conservation program without major changes.

Nevertheless, Bonneville acknowledges that the market for conservation is shifting. Some state-level policies are changing rapidly and low-cost, high-volume opportunities for efficiency improvements are less available now than at the outset of the Regional Dialogue contract term. Bonneville's need to acquire conservation may change based upon the broader Provider of Choice conversation, changes in customer composition, or other outside factors like increasing electrification. As such, Bonneville remains open to discussing customer suggestions on the progression of its conservation program as the broader post-2028 picture becomes clearer.

10.3.1 Funding Model

Bonneville's current conservation acquisition model, based on load share allocation of EEI budget, has effectively balanced Bonneville's need to acquire cost-effective resources while providing an equitable opportunity for all firm power customers to implement conservation in the retail loads they serve. Going forward, Bonneville proposes to maintain its current funding model, while remaining open to customer input on incremental program adjustments.

10.3.2 Flexibility Mechanisms

Since the implementation of Bonneville's [Revised Energy Efficiency Post-2011 Implementation Program](#), Bonneville has made a number of improvements to its conservation acquisition model to improve flexibility for customers. These include increasing allowable budget rollover from one rate period to the next, increasing self-funding assumptions, and establishing a two-year cadence for updating Bonneville's Implementation Manual. Given generally positive customer feedback on these mechanisms, Bonneville does not propose major revisions to its approach for funding flexibility in the post-2028 period. Should customers have specific suggestions for changes, or should major revisions to the overall funding model necessitate a review of current approach, Bonneville is open to input.

10.3.3 Program Infrastructure

Bonneville currently offers regional implementation programs that provide technical expertise, support the implementation of priority measures, and complement customer-driven implementation efforts. This approach to regional infrastructure has created economies of scale and provided effective services and support that would otherwise be unavailable at the local utility level.

Given the general success of its regional programs, Bonneville believes it should maintain its current approach. With low-cost, high-volume conservation savings less abundant than they once were, Bonneville may need to consider other models, such as midstream programs, to achieve savings in

specific areas identified by Bonneville as high priority. These programs could be limited to specific technologies or market areas so as to limit their impact on Bonneville’s broader approach to conservation acquisition. If there is a need to consider such programs, Bonneville would work with its customers and partner organizations to ensure a balanced and effective approach.

10.3.4 The Intersection of Provider of Choice and Conservation

Conservation will be relevant to various Provider of Choice policy and cost discussions, such as determining whether to account for conservation savings and allocation of TOCA-based EEI budgets in a customer’s CHWM. Should customers wish to discuss changes to Bonneville’s conservation program more broadly, Bonneville would convene a separate public process parallel to the broader Provider of Choice process. The timing and design of such process would be guided by the scope of changes being considered. Bonneville is in the process of drafting an amendment to customers’ existing ECAs which would extend the ECAs through September 30, 2028, to align with the expiration of the Regional Dialogue contracts. At this time, Bonneville anticipates that subsequent ECAs between Bonneville and customers would be negotiated and executed between 2025 (after Provider of Choice contracts are executed) and October 1, 2028, which will mark the start of power deliveries under new contracts.

11. BECOMING THE PROVIDER OF CHOICE

For over 80 years, Bonneville has been an engine of economic prosperity and a steward of environmental sustainability. Bonneville seeks to remain the provider of choice, delivering clean, competitively priced power well into the future.

This Provider of Choice Concept Paper is the foreword to the next chapter in history: Bonneville’s power sales framework for the future beyond 2028. The industry is changing, and the future holds many challenges – and opportunities. From climate change to resource adequacy, there is a growing demand for increased access to power and decarbonized offerings. Working through these issues over the next few years in the Provider of Choice process will highlight both challenges and areas of regional harmony. But within this complexity, Bonneville sees promise in partnership. The almost century-long legacy of regional cooperation underscores the immense capabilities of Bonneville and interested parties to craft solutions that uniquely fit the needs of the future, reflecting the evolving demands and urgencies of the day.

11.1 Timeline

Figure 4 contains the proposed timeline for the Provider of Choice process, illustrating major work streams and milestones associated with the policy and ROD. Much remains to unfold in the process, issues will evolve, and the timeline will adapt as needed to accommodate the conversation. The proposed schedule is expected to provide sufficient time to resolve policy and contract issues while affording customers time to plan for service post-2028.

Figure 4. Provider of Choice Timeline - Overview



Bonneville acknowledges that some customers have expressed that 2025 is too late to offer and execute the agreements, noting that they feel a need to understand the future contracts before planning, developing or acquiring resources. Other customers have expressed support for 2025. It is important to acknowledge that the level of detail-oriented contract development needed in this type of process typically takes a year and up to a year and a half. To tighten the contract development timeline, the region would also have to come to quick alignment on the overarching policy. Conversely, the policy development phase would shorten the contract negotiation phase.

Bonneville anticipates that most of the policy decisions made as part of the Provider of Choice policy and its accompanying ROD will be reflected in the new long-term contracts and rates processes. Bonneville recognizes that these processes are inextricably linked; the contract and rate mechanisms must be developed close in time with the policy decisions in the Provider of Choice Policy ROD to achieve the goals of the Provider of Choice process.

Provider of Choice Policy Development

Building on the April and May 2022 Provider of Choice public workshops, Bonneville will host a series of public workshops throughout calendar years 2022 and 2023 to more fully explore and refine policy elements discussed in this concept paper. These educational, analytical and policy-focused workshops will be opportunities to discuss the key issues surrounding product and service offerings. Bonneville looks forward to constructive regional engagement in these sessions to help shape its Provider of Choice Policy.

Bonneville’s approach to policy workshops seeks to touch on foundational issues first. This includes system size, augmentation, CHWM calculation and capacity. With many policy underpinnings aligned in these areas, the remaining issues are likely to fall into place with more ease. Finally, while Bonneville will often hold discussions on discrete policy issues, it will publish one policy and one ROD that cover the Provider of Choice package as a whole.

Contract Development

Contract development and negotiation will be initiated in early calendar year 2024 and conclude in the summer of 2025. Once negotiated, Bonneville will prepare and offer customer-specific agreements with the goal of having the contracts fully executed by the end of calendar year 2025.

System Readiness & Other Post-2028 Processes

Once policy development processes are underway, early planning will be initiated to support a smooth transition in power delivery. As early as calendar year 2024, Bonneville will start to identify business process modifications and work streams impacted by Provider of Choice policies, and undertake steps to develop and modify business systems as part of a multi-year implementation period. The years prior to 2028 will also afford time and space for other Post-2028 Initiative processes, including REP, rates and conservation, to continue. Power deliveries under the new agreements will commence October 1, 2028.

APPENDIX – ABBREVIATIONS/ACRONYMS

Abbreviation/Acronym	Definition
2012 REP Settlement	2012 Residential Exchange Program Settlement Agreement
Above-RHWM	Above-Rate Period High Water Mark
aMW	average megawatt
ARTS	Agreement Regarding Transfer Service
ASC	Average System Cost
CAISO	California Independent System Operator
CDQ	Contract Demand Quantity
CETA	The State of Washington’s Clean Energy Transformation Act
CHWM	Contract High Water Mark
Council	Northwest Power And Conservation Council
court	Ninth Circuit Court of Appeals
DSI	direct service industry
ECA	Energy Conservation Agreement
EDAM	Extended Day-Ahead Market (CAISO initiative)
EI	Energy Efficiency Incentive
FBS	Federal Base System
FCRPS	Federal Columbia River Power System
FERC	Federal Energy Regulatory Commission
FY	fiscal year
G&A	General & Administrative
GRSP	General Rate Schedule Provision
HLH	heavy load hour
IOU	investor-owned utility
IP	Industrial Firm Power
IPR	Integrated Program Review
IRD	Irrigation Rate Discount
kW or kWh	kilowatt, kilowatt hour
LDD	Low Density Discount
LLH	light load hour
MW	Megawatt
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NLSL	New Large Single Load
NR	New Resource
NRU	Northwest Requirements Utilities
NT	Network Transmission
OATT	Open Access Transmission Tariff
P10	monthly 10 th percentiles
P35	monthly 35 th percentiles
PF	Priority Firm
PNGC	PNGC Power
PPC	Public Power Council
QBR	Quarterly Business Review

Abbreviation/Acronym	Definition
POD	point of delivery
REC	renewable energy credit
REP	Residential Exchange Program
ROD	record of decision
RHWM	Rate Period High Water Mark
RSO	Requirements Slice Output
RSS	Resource Support Services
RTO	regional transmission operator
SNEER Exception	Small Non-dispatchable New Resource Treated Equivalently to an Existing Resource Exception
SPP	Southwest Power Pool
T1SFCO	Tier 1 System Firm Critical Output
TOCA	Tier 1 Cost Allocator
Treaty	Columbia River Treaty
TRM	Tiered Rate Methodology
WPAG	Washington Public Agencies Group
WRAP	Western Resource Adequacy Program