2029 Public Rate Design Methodology (PRDM)
PRDM-26 Proceeding

ADMINISTRATOR'S DRAFT RECORD OF DECISION

PRDM-26-A-01

April 2025

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COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
ACS	Ancillary and Control Area Services
AF	Advance Funding
AFUDC	Allowance for Funds Used During Construction
AGC	automatic generation control
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
BPAP	Bonneville Power Administration Power
BPAT	Bonneville Power Administration Transmission
Bps	basis points
Btu	British thermal unit
CAISO	California Independent System Operator
CIP	Capital Improvement Plan
CIR	Capital Investment Review
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CNR	Calibrated Net Revenue
COB	California-Oregon border
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission
Corps	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council (see also "NPCC")
COVID-19	coronavirus disease 2019
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRFM	Columbia River Fish Mitigation
CRITFC	Columbia River Inter-Tribal Fish Commission
CSP	Customer System Peak
CT	combustion turbine
CWIP	Construction Work in Progress
CY	calendar year (January through December)
DD	Dividend Distribution
DDC	Dividend Distribution Clause
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service

DNR	Designated Network Resource
DOE	Department of Energy
DOI	Department of Interior
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EE	Energy Efficiency
EESC	EIM Entity Scheduling Coordinator
EIM	Energy imbalance market
EIS	environmental impact statement
EN	Energy Northwest, Inc.
ESA	Endangered Species Act
ESS	Energy Shaping Service
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FERC	Federal Energy Regulatory Commission
FMM-IIE	Fifteen Minute Market – Instructed Imbalance Energy
FOIA	Freedom of Information Act
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FRP	Financial Reserves Policy
F&W	Fish & Wildlife
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
GDP	Gross Domestic Product
GI	generation imbalance
GMS	Grandfathered Generation Management Service
GSP	Generation System Peak
GSR	Generation Supplied Reactive
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	Heavy Load Hour(s)
HYDSIM	Hydrosystem Simulator (computer model)
IE	Eastern Intertie
IIE	Instructed Imbalance Energy
IM	Montana Intertie
inc	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power
IPR	Integrated Program Review
IR	Integration of Resources

IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRPL	Incremental Rate Pressure Limiter
IS	Southern Intertie
JOE	Joint Operating Entity
kcfs	thousand cubic feet per second
kW	kilowatt
kWh	kilowatthour
LAP	Load Aggregation Point
LDD	Low Density Discount
LGIA	Large Generator Interconnection Agreement
LLH	Light Load Hour(s)
LMP	Locational Marginal Price
LPP	Large Project Program
LT	long term
LTF	Long-term Firm
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenue
MO	market operator
MRNR	Minimum Required Net Revenue
MW	megawatt
MWh	megawatthour
NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon border
NORM	Non-Operating Risk Model (computer model)
NWPA	Northwest Power Act/Pacific Northwest Electric Power Planning and Conservation Act
NWPP	Northwest Power Pool
NP-15	North of Path 15
NPCC	Northwest Power and Conservation Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service
NRU	Northwest Requirements Utilities
NT	Network Integration
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation

OATT	Open Access Transmission Tariff
O&M	operations and maintenance
OATI	Open Access Technology International, Inc.
ODE	Over Delivery Event
OS	oversupply
OY	operating year (August through July)
P10	tenth percentile of a given dataset
PDCI	Pacific DC Intertie
PF	Priority Firm Power
PFp	Priority Firm Public
PFx	Priority Firm Exchange
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POR	point of receipt
PPC	Public Power Council
PRSC	Participating Resource Scheduling Coordinator
PS	Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point-to-Point
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
RCD	Regional Cooperation Debt
RD	Regional Dialogue
RDC	Reserves Distribution Clause
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
REP	Residential Exchange Program
REPSIA	REP Settlement Implementation Agreement
RevSim	Revenue Simulation Model
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement
RRHL	Regional Residual Hydro Load
RRS	Resource Remarketing Service
RSC	Resource Shaping Charge
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTD-IIE	Real-Time Dispatch – Instructed Imbalance Energy
RTIEO	Real-Time Imbalance Energy Offset

SCD	Scheduling, System Control, and Dispatch Service
SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
SMCR	Settlements, Metering, and Client Relations
SP-15	South of Path 15
T1SFCO	Tier 1 System Firm Critical Output
TC	Tariff Terms and Conditions
TCMS	Transmission Curtailment Management Service
TDG	Total Dissolved Gas
TGT	Townsend-Garrison Transmission
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
TRAM	Transmission Risk Analysis Model
Transmission System Act	Federal Columbia River Transmission System Act
Treaty	Columbia River Treaty
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
UDE	Under Delivery Event
UFE	unaccounted for energy
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
UIE	Uninstructed Imbalance Energy
ULS	Unanticipated Load Service
USFWS	U.S. Fish & Wildlife Service
VER	Variable Energy Resource
VERBS	Variable Energy Resource Balancing Service
VOR	Value of Reserves
VR1-2014	First Vintage Rate of the BP-14 rate period (PF Tier 2 rate)
VR1-2016	First Vintage Rate of the BP-16 rate period (PF Tier 2 rate)
WECC	Western Electricity Coordinating Council
WPP	Western Power Pool
WRAP	Western Resource Adequacy Program
WSPP	Western Systems Power Pool

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PARTY ABBREVIATIONS

AC Avista Corporation
AWEC Alliance of Western Energy Consumers
GC Grant County Public Utility District No. 2
ID Idaho Conservation League, Great Old Broads for Wilderness, and Idaho Rivers United
JP01 Joint Party 1*
JP02 Joint Party 2**
NL New Large Single Load Group
NR Northwest Requirements Utilities
NW Northwest Irrigation Utilities
PC PacifiCorp
PN Pacific Northwest Generating Cooperative
PP Public Power Council
PS Puget Sound Energy, Inc.
RN Renewable Northwest
SE City of Seattle
SN Snohomish County Public Utility District No. 1
TA City of Tacoma
WG Western Public Agencies Group***

* Northwest Requirements Utilities, Public Power Council, Snohomish Pub. Util. District, Clatskanie Public Utility District, Tacoma Power, Grant Public Utility District, and the members of Western Public Agencies Group.

** Eugene Water and Power Board, Clark County Public Utility District, Lewis County Public Utility District, Franklin County Public Utility District, and Idaho Fall Power.

*** The Western Public Agencies Group ("WPAG") petition for leave to intervene states that each of the utilities that comprise WPAG individually file the petition requesting leave to intervene. These utilities are Eugene Water & Electric Board, Benton Rural Electric Association, Umatilla Electric Cooperative, the cities of Port Angeles, Ellensburg and Milton, Washington, the towns of Eatonville and Steilacoom, Washington, Elmhurst Mutual Power and Light Company, Lakeview Light and Power Company, Ohop Mutual Light Company, Parkland Light and Water Company, Public Utility Districts No. 1 of Clallam, Clark, Cowlitz, Grays Harbor, Jefferson, Kittitas, Lewis, Mason, and Skamania Counties, Washington, Public Utility District No. 3 of Mason County, Washington, and Public Utility District No. 2 of Pacific County, Washington.

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1.0 INTRODUCTION AND BACKGROUND

1.1 Introduction

This Draft Record of Decision (ROD) contains the draft decisions of the Administrator of the Bonneville Power Administration (BPA) based on the record compiled in this proceeding (PRDM-26) with respect to the development of the 2029 Public Rate Design Methodology (PRDM). The purpose of the PRDM–26 proceeding is to develop and review the terms of the rate design methodology applicable to Priority Firm Public (PFp) rates for the period following the expiration of the Tiered Rate Methodology (TRM) (*i.e.*, beginning October 1, 2028). This rate methodology is called the Public Rate Design Methodology (PRDM). As explained in this Draft ROD, the PRDM is a rate design methodology that will be used by BPA to establish the Section 7(b) power rate applicable to the general requirements of public bodies, cooperatives, and federal agencies (collectively Public Customers) beginning on October 1, 2028. *See* 16 U.S.C. § 839e(b)(1).

The PRDM was evaluated and developed in a formal administrative proceeding (PRDM-26) conducted under Section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act (NWPA) or Act). 16 U.S.C. § 839e(i). The PRDM-26 proceeding included an evidentiary hearing, submission of written briefs by the parties, and publication of this Draft ROD. This Draft ROD provides background information, addresses the issues raised in the parties' briefs, and summarizes BPA's assessment of the potential environmental effects of implementation of the PRDM consistent with the National Environment Policy Act (NEPA).

1.2 Background

1.2.1 BPA and Its Statutory Mission

BPA is a self-financing power marketing agency within the United States Department of Energy. Congress established BPA in the Bonneville Project Act of 1937, 16 U.S.C. §832, *et seq*., to market power from the Bonneville Dam and to construct powerlines for the transmission of this power to load centers. As other federal dams and transmission lines were built in the Pacific Northwest, these generation and transmission facilities became known as the Federal Columbia River Power System (FCRPS). Today, BPA markets power from 31 federal hydroelectric projects, operated by the U.S. Army Corps of Engineers and the Interior Department's Bureau of Reclamation, one nonfederal nuclear plant and several small nonfederal powerplants.

BPA supplies about 32 percent of the power consumed in the Pacific Northwest Region.[1] BPA's customers include public and private utilities, tribal entities, industries, marketers, and other federal agencies. BPA's largest class of customers are non-profit public utilities

[1] *See* BPA, BPA Fact Sheet FY 2023, *available at* https://www.bpa.gov/-/media/Aep/about/publications/general-documents/bpa-facts.pdf.

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made up of public bodies and cooperatives, and collectively referred to as Public Customers. Pursuant to Section 5(b) of the Northwest Power Act, BPA is required to sell power to Public Customers to meet their energy requirements "net" of their own non-federal resources. 16 U.S.C. § 839c(b)(1). BPA has entered multiple versions of the Section 5(b) contracts since passage of the Northwest Power Act in 1980. The most recent version of the Section 5(b) contract is colloquially referred to as the "Regional Dialogue" (RD) contract. It expires on September 30, 2028. Through the RD contract, BPA delivers firm power to 134 local non-profit utilities, which in turn provide retail power service to roughly 3 million people located in Oregon, Idaho, Washington, California, Nevada, Montana, Wyoming, and Utah.[2]

BPA recovers the costs of all its operations, and performs a myriad of other statutory duties, through the rates it charges its customers. *See* 16 U.S.C. § 839e(a)(1).

1.2.2 Power Rates

1.2.2.1 Overview of Power Rates

BPA's power rates are set pursuant to a series of rate directives contained in the Northwest Power Act, 16 U.S.C. § 839e, *et seq.*, Federal Columbia River Transmission System Act, 16 U.S.C. § 838, *et seq*., and the Flood Control Act of 1944, 16 U.S.C. § 825 *et seq.* Congress granted BPA broad ratemaking discretion in Section 7(e) of the Northwest Power Act to design rates to recover BPA's total system costs. *See e.g.,* 16 U.S.C. § 839e(e) (preserving the Administrator's discretion to design "rate forms").

When setting rates, BPA must conduct an administrative hearing as required by Section 7(i) of the Northwest Power Act. 16 U.S.C. § 839e(i). Upon completion of the administrative hearing, BPA files its rates with the Federal Energy Regulatory Commission (FERC) for review, pursuant to Section 7(a)(2) of the Northwest Power Act. 16 U.S.C. § 839e(a)(2). FERC's review of BPA's power rates is limited to a finding that the rates are sufficient to repay the federal investment in the FCRPS, are based on the Administrator's total system costs, and, for transmission rates, equitably allocate the costs of the federal transmission system between federal and non-federal power utilizing the system. 16 U.S.C. § 839e(a)(2). BPA's power rates become final and reviewable in court after FERC grants final approval of those rates. 16 U.S.C. § 839e(a)(2).

The overarching purpose and objective of BPA's rates is to recover, in accordance with sound business principles, the costs associated with the production, acquisition, conservation, and transmission of electric power. This includes the amortization of the federal investment in the FCRPS (and amortized irrigation costs from appropriations required to be paid by power revenues) over a reasonable period of years, as well as other costs and expenses incurred by the Administrator under the Northwest Power Act and other provisions of law. *See* 16 U.S.C. § 839e(a)(1).

[2] *See id*.

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1.2.2.2 Rate Pools and the Section 7(b) Rate

Section 7 of the Northwest Power Act, 16 U.S.C. § 839e, provides unique guidance on how power rates must be set. These "directives" provide broad guidance on grouping resources and other costs into different "pools" of costs, referred to as "rate pools" in BPA ratemaking. BPA's power-related costs are allocated to two primary rate pools: the Section 7(b) rate pool and the Section 7(f) rate pool. 16 U.S.C. § 839e(b), (f). For purposes of the PRDM, only the Section 7(b) rate pool is relevant.[3] The Section 7(b) rate pool recovers the resource and other net costs needed to supply firm power to serve BPA's Public Customers' "general requirements" load.[4] *Id.* at (b)(1). The term "general requirements" means the Public Customers' firm power purchases under Section 5(b) of the Act, less power needed to serve their New Large Single Loads (NLSL).[5] *Id.* at (b)(4).

Ultimately, the costs and credits allocated to the Section 7(b) rate pool are subject to a hierarchical ordering of resources (Federal Base System,[6] exchange resources, and other resources) and then application of special rate directives under the Act. A Cost of Service Analysis (COSA) is used to meet the hierarchical ordering of resources established in the Act, which dictates that 7(b) loads have access to the least-cost resources first. Then, several rate directives are implemented to reallocate costs in a manner consistent with other provisions of the Act. The two most significant directives are the Section 7(b)(2) "Rate Test" and the 7(c)(1)-(3) "Industrial Margin." *See* 16 U.S.C. §§ 839e(b)(1)-(4) and 16 U.S.C. §§ 839e(c)(1)-(3). The Section 7(b)(2) rate test is a form of cost protection that is intended to reflect the preference status of BPA's Public Customers. Section 7(c) then directs BPA to preserve a proportional relationship between 7(b) rates and 7(c) rates charged to Direct Service Industry industrial loads, which results in adjustments to the final costs and credits allocated to the 7(b) rate pool.

After these steps are completed, a total net cost that must be recovered from the 7(b) rate pool is known. Section 7(e) of the Act, 16 U.S.C. §§ 839e(e), provides BPA discretion in the design of rates to recover this amount from its Public Customers for their "general requirements" load. *See* 16 U.S.C. §§ 839e(b)(1)-(4). This rate is called the "Priority Firm

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[3] The Section 7(f) rate pool recovers the resource and other costs associated with serving the net requirement service to Investor-Owned Utilities (IOUs) and to serve PF Customers' New Large Single Loads (NLSLs). *See* 16 U.S.C. § 839e(f).

[4] The Section 7(b)(1) rate pool also includes the residential and farm loads and the cost of exchange resources for utilities participating in the Residential Exchange Program. *See* 16 U.S.C. § 839c(c)(1)-(7); 16 U.S.C. § 839e(b)(1). BPA sets a separate rate to engage in the energy-neutral exchange required by Section 5(c) of the Northwest Power Act. This other rate is referred to as the PF Exchange rate and will be discussed in greater detail in Draft ROD Section 9.1.5.

[5] A New Large Single Load is a statutory term that refers to a load that grows by greater than 9.9aMW over 12 consecutive months. 16 U.S.C. § 839a(13). If a load becomes an NLSL, it is served at the Section 7(f) rate, not the Section 7(b) rate. 16 U.S.C. § 839e(b)(4), (f).

[6] The Federal Base System, or FBS, is a statutory term referring to the resources of the FCRPS (*e.g.,* hydroelectric dams), resources acquired by the Administrator under long-term contracts as of December 1980, and such other resources acquired by the Administrator to replace lost capability from the foregoing. 16 U.S.C. § 839a(10).

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Public" or "PFp" rate. As explained herein, the PRDM governs the rate design of these net costs.

1.2.2.3 The West Coast Energy Crisis

The Act permits BPA to establish more than one PFp power rate for recovering the costs of supplying power to meet the general requirements of Public Customers. *See* 16 U.S.C. § 839e(b)(1) ("The Administrator shall establish a rate or rates…"). Nevertheless, from the 1980s through the mid-2000s, BPA designed the PFp rate as a single set of energy and demand rates to recover the costs of meeting the Public Customers' collective "general requirements" as a group. Fisher *et al.*, PRDM-26-E-BPA-02, at 4. This approach to ratemaking was informally called the "buy and meld" approach because BPA *bought* power to meet the collective load needs of its customers and would *meld* the cost of that power with its low-cost Federal Base System resources. *Id.* The "buy and meld" approach is one way BPA can recover its costs consistent with its statutory obligations under Section 7. *Id.*

The West Coast Energy crisis of 2000-2001, however, identified some of the shortcomings of the "buy and meld" approach to ratemaking.[7] *Id.* During this period, BPA saw its Public Customer loads increase substantially above the agency's original rate case projections.[8] *Id.* BPA, in turn, had to acquire large sums of additional power at high market prices. *Id.* These high-cost acquisitions were melded with the low-cost existing Federal Base System resources in the Section 7(b) rate pool, increasing the PFp rates for all Public Customers regardless of whether those Public Customers' loads contributed to the need for the large acquisitions. *Id.*

Following the experience in the West Coast Energy crisis, Public Customers and BPA started discussions to determine whether BPA should move away from the "buy and meld" approach to the Section 7(b) PFp rate. The reasons for exploring these changes were multifaceted but generally centered on achieving three policy objectives. *Id.*

First, both BPA and Public Customers wanted greater rate certainty. *Id.* at 5. Central to achieving this objective was finding a way to preserve, in ratemaking, the value of the existing low-cost Federal Base System resources. *Id.* In general, the costs of BPA's existing resources are cheaper than acquiring new resources.[9] *Id.* Many customers wanted BPA to take steps to preserve the value of the Federal Base System resources by preventing or

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[7] The West Coast Energy crisis generally refers to the wholesale market price volatility that originated from energy shortages primarily in the California energy market in 2000-2001. While the history of this crisis is "long, detailed, and tortured. . . ," *Bonneville Power Admin. v. FERC*, 422 F.3d 908, 911 (9th Cir. 2005), in general, spot market energy prices in California increased to historic levels, precipitating cascading price hikes in wholesale markets across the West Coast. *See also Pub. Utils. Comm'n of State of Cal. v. FERC*, 462 F.3d 1027, 1036–44 (9th Cir. 2006) (detailing background on the West Coast Energy crisis).

[8] *See Golden Nw. Aluminum v. Bonneville Power Admin.*, 501 F.3d 1037, 1044 (9th Cir. 2007) (noting BPA needed to acquire over 3300 average megawatts (aMW) of additional power to meet its contractual obligations.).

[9] BPA's rates are, in general, lower than market prices. However, because BPA's rates recover its costs, there are times when the PFp rate is higher than spot prices. *See* Fisher *et al.*, PRDM-26-E-BPA-02, at 5.

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limiting new acquisition costs from being melded with existing low-cost federal resources. *Id.*

Second, there was a general consensus that more needed to be done to incentivize Public Customers to build their own resources. *Id.* Under the "buy and meld" approach to ratemaking, Public Customers had little motivation to build their own resources to meet their future load growth needs. *Id.* Customers with growing loads had a choice: take the risk of building their own resources (and bear all that cost alone) or have BPA serve their load growth and spread the risk and cost of any BPA resource acquisition across *all* Public Customers through the PFp rate. *Id.* Finding a way to incentivize future resource development by creating economic signals through ratemaking was, then, another objective that could be achieved through a redesigned PFp rate. *Id.*

Third, BPA wanted to enhance its financial stability and assurance of recovering its costs for the long term. *Id.* The "buy and meld" approach to ratemaking created risk for BPA that, over time, low-cost federal system resources would be diluted with higher cost, new acquisitions. *Id.* These increased costs would be passed on to Public Customers through a higher PFp rate. *Id.* Customers have a right at the end of each Section 5(b) contract to choose another supplier for their power. *See id.*; *see also* 16 U.S.C. § 839c(b)(1). Consequently, protecting the existing federal system from unlimited acquisition costs preserves the low-cost value of these resources, increasing the likelihood that regional customers will continue to purchase power from BPA, ensuring BPA recovers its costs and repays the U.S. Treasury. Fisher *et al.*, PRDM-26-E-BPA-02, at 5-6.

1.2.3 Tiered Rates and the Tiered Rates Methodology

1.2.3.1 Origins of the Tiered Rates Construct

With the above-noted objectives in mind, BPA and Public Customers commenced discussions in the early-2000s to explore different rate design approaches for the PFp rate. Those discussions led to the concept of "tiering" the PFp rate by creating sub-cost pools within the Section 7(b) rate pool. *Id.* at 6. These separate sub-cost pools would allow BPA to isolate resource costs, which would then be collected by charging multiple PFp rates to Public Customers. *Id.* The resulting PFp rates would recover only specified resource costs assigned to that rate. *Id.* These rates were called "tiered" rates because the PFp rate was divided into two primary tiers. *Id.* The first "tier" recovered the costs of BPA's existing system; the second "tier" recovered the costs of resource acquisitions. *Id.* In this way, "tiered rates" moved BPA away from the general "buy and meld" paradigm, to a more precise allocation that better aligned resource costs to customer choices and load needs. *Id.*

The tiered rates concept was codified in a rate methodology called the TRM. The TRM laid out the methodology to charge for general requirements power through Tier 1 Rates that would recover the costs of BPA's existing Federal Base System resources, and Tier 2 Rates that would recover the costs of future acquisitions to meet general requirements load growth. *Id.* While divided up into two separate rates, both Tier 1 and Tier 2 rates are, in

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statutory parlance, PFp rates set pursuant to Section 7(b) of the Northwest Power Act. 16 U.S.C. § 839e(b)(1), (4).

1.2.3.2 Tiered Rates and Other Power Rates

As described above, the TRM and tiered rates create a pre-defined suballocation of cost and credits *within* the Section 7(b) rate charged to Public Customers. Fisher *et al.*, PRDM-26-E-BPA-02, at 9. From a sequencing point of view, the TRM does not become operative until all costs and credits have been allocated to the PFp rate by the mandatory rate directives of Section 7. *Id.* at 9-10; *see also* 16 U.S.C. § 839e(b)(1). After that allocation, the TRM divides up those costs between the Tier 1 and Tier 2 Rates per its terms. Fisher *et al.*, PRDM-26-E-BPA-02, at 10. In this way, the TRM can be thought of as an inter-cost pool methodology applying to Public Customers paying the Section 7(b) rate. *Id.* The TRM does not address, nor purports to affect, any other rate or rate pool. *Id.* Thus, for instance, the TRM and tiered rates do not impact the PF Exchange rate used in the Residential Exchange Program, the Direct Service Industrial rates under Section 7(c), or any of the services BPA sells under Section 7(f) rates. *Id.*

1.2.3.3 Development of the TRM in a Section 7(i) Proceeding

Nothing in BPA's statutes requires it to develop a rate methodology to develop tiered rates.[10] BPA could have developed tiered rates through its ratemaking discretion afforded by Section 7(b) as well as the Administrator's broad rate design discretion discussed in Section 7(e), in the Section 7(i) rate case. *See* 16 U.S.C. § 839e(b)(1), (e), (i); *see also* Fisher *et al.*, PRDM-26-E-BPA-02, at 8. The issue with this approach, however, was that the Administrator's decision on those allocations would only be effective for a single rate period. Fisher *et al.*, PRDM-26-E-BPA-02, at 8. A subsequent Administrator could revisit those allocations in a future Section 7(i), disrupting the certainty and stability objectives BPA and Public Customers were trying to achieve. *Id.*

The TRM was the answer to this consistency issue. The TRM is not a rate; it is a rate methodology. *Id.* Its function is to define BPA's rate design approach for the PFp rates in future Section 7(i) proceedings for the duration of the RD contract. *Id.* BPA was bound by both the methodology itself (which says it applies until September of 2028) and BPA's RD Contract (which commits BPA to use the TRM when setting rates). *Id.* Thus, when BPA sets the Section 7(b) rate for its PF Public Customers in future Section 7(i) rate cases, both BPA and the PF Public Customers can have certainty as to the rules around the allocation of costs and credits for the Tier 1 and Tier 2 Rates. *Id.*

Even though the TRM is not a rate, BPA used the procedural requirements of Section 7(i) to establish its terms.[11] At the completion of the Section 7(i) hearing, BPA issued a record of

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[10] In contrast, BPA is required to develop a rate methodology for determining the "average system cost of resources" for utilities participating in the exchange called for in Section 5(c) of the Northwest Power Act. *See* 16 U.S.C. § 839c(c)(7).

[11] *See 2012 Tiered Rate Methodology Proceeding; Public Hearings and Opportunities for Public Review and Comment*, 73 Fed. Reg. 24,961 (May 6, 2008).

decision on the terms of the TRM in November 2008.[12] Because the TRM was a new and untested rate design, BPA filed the TRM with FERC and sought a declaratory order from the Commission on noting that the TRM "would not prevent BPA from recovering its costs consistent with its statutory obligations." Fisher *et al.*, PRDM-26-E-BPA-02, at 24. FERC agreed and issued the declaratory order in June 2010.[13] In requesting this order, BPA was clear that FERC did not have jurisdiction to actually approve/disapprove the TRM, and was seeking only a "check in" with FERC before implementing the TRM in rates. Fisher *et al.*, PRDM-26-E-BPA-02, at 24.

1.2.4 Implementation of the TRM (2011-2028)

The TRM went into effect in October, 2011.[14] Since then, the TRM has been a resounding success in providing certainty, predictability, and stability in the development of the PFp rate through Tier 1 and Tier 2 rates. Though portions of the TRM were initially challenged in the Ninth Circuit, with the Court dismissing some challenges, and affirming BPA on others,[15] no further substantive disagreements among Public Customers and BPA have occurred during the TRM's implementation. This stability occurred even with a range of load changes, customers switching product elections, market conditions, and even BPA joining a new market (the Western Energy Imbalance Market). *Id.*

Similarly, FERC has reviewed seven sets of rates established by BPA under the TRM and approved each without reservation.[16] The TRM has proven to be an efficient and effective means of ensuring BPA recovers its costs consistent with the criteria set forth in Section 7 of the Northwest Power Act. BPA is now in the process of completing the BP-26 rate proceeding to set rates for the BP-26 rate period (FY 2026-2028) and, with it, the final rate period under the TRM. The TRM expires at the end of the BP-26 rate period, on September 30, 2028, concurrent with the end of the RD Contract.

It is against the above backdrop that BPA and Public Customers commenced discussions in 2024 to build on the success of the TRM and develop a new methodology that would carry forward the "tiered rates" construct into the next generation of Section 5(b) power supply contracts. That process, which led to the Public Rate Design Methodology (PRDM) and this proceeding, is described next.

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[12] Administrator's Record of Decision, TRM-12-A-01 (Nov. 2008).
[13] *U.S. Dep't of Energy -- Bonneville Power Admin.*, 131 FERC ¶ 61,244 (2010).
[14] Fisher *et al.*, PRDM-26-E-BPA-02, at 2.
[15] *See Indus. Customers of Nw. Utils. v. Bonneville Power Admin.*, 388 F. App'x 586, 590 (9th Cir. 2010) (dismissing for lack of jurisdiction a challenge to the TRM ROD); *Clatskanie People's Util. Dist. v. Bonneville Power Admin.*, 493 F. App'x 880, 883 (9th Cir. 2012) (dismissing for lack of jurisdiction a challenge to the TRM ROD).
[16] The TRM was used to set PFp rates in BP-12 (FY 2012-2013), BP-14 (FY 2014-2015), BP-16 (FY 2016-2017), BP-18 (FY 2018-2019), BP-20 (FY 2020-2021), BP-22 (BP-2022-2023), BP-24 (FY 2024-2025), and BP-26 (FY 2026-2028).

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1.3 Procedural History of the PRDM-26 Proceeding

1.3.1 Overview: PRDM and Provider of Choice Contracts

The purpose of the PRDM–26 proceeding is to develop the rate design methodology for the period following the expiration of the TRM (*i.e.,* beginning October 1, 2028). As noted, this rate methodology is called the Public Rate Design Methodology (PRDM). Concurrent with the PRDM–26 proceeding, BPA is also negotiating the Section 5(b) contract for the supply of firm power for BPA's customers' requirements for the period covering October 1, 2028–September 30, 2044. The new Section 5(b) contract is colloquially referred to as the ''Provider of Choice'' contract. The Provider of Choice contract and the PRDM are designed to work in tandem. Customers that elect to purchase their Section 5(b) power under a Provider of Choice contract will also agree to have their PFp power rate set pursuant to the PRDM. Fisher *et al.*, PRDM-26-E-BPA-02, at 27.

1.3.2 Workshops Prior to the PRDM-26 Proceeding

The PRDM was the product of months of collaborative negotiations, workshops, and workgroups with customers and other stakeholders. *Id.* at 16. The development process for the PRDM began in January 2024, when BPA commenced a series of workshops and workgroups to describe the terms of the TRM and discuss possible revisions to those terms. *Id.* Those workshops and workgroups continued through the summer of 2024. All told, BPA held 16 public workshops and workgroups where BPA engaged with customers and stakeholders on the terms and concepts in the PRDM.[17] *Id.* Specifically, BPA held public workshops and workgroups on January 9, January 24, February 21, March 7, March 19, April 23, April 29, May 23, May 28, June 11, June 21, July 9, July 22, August 1, August 14, and October 8.

After the extensive customer and stakeholder engagement process described above, BPA converted the ideas and concepts from those meetings into methodological language. *Id.* at 17. Using the TRM as the base, BPA crafted the terms of the PRDM. *Id.* BPA provided an initial redline of the PRDM as compared to the TRM to participants on August 1, 2024. *Id.* Informal public comments on this "rough draft" PRDM were due about a week later. *Id.* Thereafter, on August 14, 2024, BPA published a proposed draft ("Draft 1") of the PRDM and requested additional public comment. *Id.* Comments were due September 30, 2024. *Id.* Based on those comments, BPA made a variety of revisions to the PRDM proposed in this proceeding and presented those changes to stakeholders on October 8, 2024. *Id.* at 17-20.

1.3.3 PRDM-26 Proceeding

On November 13, 2024, BPA formally commenced the PRDM-26 proceeding pursuant to Section 7(i) of the Northwest Power Act with the issuance of a Federal Register Notice. *See*

[17] The testimony of Fisher *et al.*, PRDM-26-E-BPA-02, at 16, mentioned only 12 such meetings. A subsequent review of the applicable calendars showed there were, in fact, 16, when including public workgroup sessions.

Fiscal Year (FY) 2029 Public Rate Design Methodology; Public Hearing and Opportunities for Public Review and Comment, 89 Fed. Reg. 89,633, PRDM-26-FR-BPA-01 (Nov. 13, 2024) ("PRDM-26 FRN"). The PRDM-26 proceeding was subject to BPA's Rules of Procedure. *Id.*[18]

On November 15, 2024, BPA published its Initial Proposal for the PRDM. *Id.* BPA's Initial Proposal included 10 exhibits: the Draft PRDM supported by nine pieces of testimony. *See generally* PRDM-26-E-BPA-01 through PRDM-26-E-BPA-10. Sixteen parties intervened in the PRDM-26 proceeding. *See* Third Amended Order Adopting Service List, PRDM-26-HOO-13 (Mar. 6, 2025). Parties to the PRDM-26 proceeding were provided the full procedural and legal rights afforded by Section 7(i) and BPA's Rules of Procedure, including a prehearing conference, the presentation of direct cases, discovery, clarification, rebuttal, cross examination, briefing, oral argument, and briefs on exception. *See* Order Adopting Procedural Schedule, PRDM-26-HOO-04 (Dec. 4, 2024).

Parties' direct cases were due on January 15, 2025. *Id.* Four parties filed direct cases responding to BPA's Initial Proposal.[19] BPA staff filed its rebuttal to these direct cases on February 14, 2025.[20] Bleifuss *et al.*, PRDM-26-E-BPA-11. Attached to its rebuttal, BPA Staff included a redline version of the PRDM that adopted many of the Parties' suggestions and made other revisions. *Id.,* Attachment 1: PRDM Redlines from Initial Proposal, PRDM-26-E-BPA-11-AT01.[21]

In its rebuttal testimony, among other issues, BPA Staff identified a mismatch in the allocation of certain costs and revenues in the PRDM. Bleifuss *et al.*, PRDM-26-E-BPA-11, at 34-37. BPA Staff proposed supplemental changes to the PRDM to address these issues. *Id.* Because these changes were first identified in BPA Staff's rebuttal, BPA modified the procedural schedule in the PRDM-26 proceeding to permit parties to submit supplemental testimony in response to BPA's proposed changes. *See id.* at 37; Unopposed Motion to Amend Procedural Schedule and Request for Special Rules, PRDM-26-M-BPA-04. Parties had until February 20, 2025, to submit supplemental testimony. Amended Order Adopting

[18] The Rules of Procedure are posted on BPA's website at https://www.bpa.gov/energy-and-services/rate-and-tariffproceedings/rules-of-procedurerevision-process; *see also* Final Rules of Procedure, 83 Fed. Reg. 39,993 (Aug. 13, 2018).
[19] Joint Party 01 (JP01), which was composed of Northwest Requirements Utilities, Public Power Council, Snohomish Pub. Util. District, Clatskanie Public Utility District, Tacoma Power, Grant Public Utility District, and the members of Western Public Agencies Group (WPAG)) filed testimony under Traetow *et al.,* PRDM-26-E-JP01-01. Joint Party 2 (JP02), composed of Eugene Water and Power Board, Clark County Public Utility District, Lewis County Public Utility District, Franklin County Public Utility District, and Idaho Fall Power, filed testimony under Bush *et al.*, PRDM-26-E-JP02-01. Pacific Northwest Generating Cooperative (PNGC) filed testimony under Erben, PRDM-26-E-PN-01. Alliance of Western Energy Consumers (AWEC) filed testimony under Safford & Weber, PRDM-26-E-AW-01.
[20] No party besides BPA filed rebuttal.
[21] Attached to this Draft ROD as Attachment 1 is this same version of the PRDM without any redlines. In preparing the PRDM for this document, BPA made a few minor typographical corrections, none of which were substantive. Unless otherwise noted, all references to the "PRDM" throughout this ROD is to the version of the PRDM attached herein.

Procedural Schedule, PRDM-26-HOO-09 (Feb. 17, 2025). No party filed supplemental testimony.

No party requested cross examination. Order Cancelling Cross-Examination and Order on Procedures to Admit Evidence, PRDM-26-HOO-11 (Feb. 25, 2025).

Parties' initial briefs were due March 3, 2025. Amended Order Adopting Procedural Schedule, PRDM-26-HOO-09. Five parties filed briefs.[22] No party requested oral argument. Order Cancelling Oral Argument, PRDM-26-HOO-12 (Mar. 6, 2025).

1.3.4 Waiver of Issues by Failure to Raise in Briefs

Pursuant to Section 1010.17(f) of the Rules of Procedure, arguments not raised in parties' briefs are deemed to be waived. Under this provision, a party's brief must specifically address the legal or factual dispute at issue. Blanket statements that seek to preserve every issue raised in testimony will not preserve any matter at issue.

Sections 1010.17(b) and (c) of the Rules of Procedure set forth the requirements applicable to initial briefs and briefs on exceptions. Pursuant to Section 1010.17(c) of the Rules of Procedure, a party that raises an issue in its initial brief need not reassert that issue in its brief on exceptions to avoid waiving the issue; all arguments raised by a party in its initial brief are deemed to have been raised in the party's brief on exceptions.

1.4 Legal Guidelines Governing Establishment of PRDM

1.4.1 Tiered Rates and BPA's Statutory Rate Directives

The PRDM, like the TRM, is not a rate; it is a rate methodology. As such, BPA is not establishing any rates through the PRDM, but a methodology for establishing future rates. At the time BPA sets those rates in future Section 7(i) rate cases, BPA will show compliance with the myriads of rate directives and statutory requirements that govern the recovery of its costs. *See generally* 16 U.S.C. § 839e *et seq.* The first set of rates to be set under the PRDM will be in the next BPA rate case (BP-29).

Because the PRDM's terms will govern future cost allocation decisions in BPA rate cases, BPA considers the PRDM a form of ratemaking. For that reason, BPA has developed its terms consistent with the Section 7(i) rate procedures. Specifically, the PRDM's terms will be used to sub-allocate the costs assigned to the Section 7(b) rate pool to create multiple PFp rates charged to Public Customers. Those costs will be sub-allocated to the Tier 1 and Tier 2 rates as described in the PRDM. Because the PRDM is applicable only to the costs and credits that have been allocated by BPA's statutory directives to the Section 7(b) rate, the PRDM—like the TRM—will not affect any other rate, rate directive, or cost recovery requirement in BPA statutes. *See* PRDM § 1.3. BPA included a diagram in the PRDM to

[22] *See generally,* JP01 Br., PRDM-26-B-JP01-01; JP02 Br., PRDM-26-B-JP02-01, PNGC Br., PRDM-26-B-PN-01; AWEC Br., PRDM-26-B-AW-01; Renewable Northwest (RNW) Br., PRDM-26-B-RN-01.

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show where, in the sequencing of ratemaking, the PRDM resides. Fisher *et al.*, PRDM-26-E-BPA-02, at 10; *see also* PRDM § 2.2, Figure 2-1 (Soup-to-Nuts Power Cost Allocation).

1.4.2 Statutory Authority for Tiered Rates

BPA's statutory authority to develop the PRDM and engage in this sub-allocation comes from three primary sources. First, Section 7(b) of the Northwest Power Act acknowledges that BPA may establish more than one Section 7(b) rate to meet the "general requirements" of Public Customers. Specifically:

> The Administrator shall establish a **rate or rates** of general application for electric power sold to meet the general requirements of public body, cooperative, and Federal agency customers within the Pacific Northwest, and loads of electric utilities under section 839c(c) of this title. Such **rate or rates** shall recover the costs of that portion of the Federal base system resources needed to supply such loads until such sales exceed the Federal base system resources. Thereafter, such **rate or rates** shall recover the cost of additional electric power as needed to supply such loads, first from the electric power acquired by the Administrator under section 839c(c) of this title and then from other resources.

16 U.S.C. § 839e(b)(1) (emphasis added).

Second, Section 7(e) of the Northwest Power Act grants to BPA broad ratemaking and rate design discretion. It provides that "[n]othing in this chapter prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal rates, or other rate forms." 16 U.S.C. § 839e(e). The Court has found that this provision affords BPA wide latitude in developing rate and rate designs to recover its costs. *See City of Seattle v. Johnson*, 813 F.2d 1364, 1367 (9th Cir. 1987) (noting "the statute does not require BPA to impose any particular type of rate on its customers. Rather it restricts BPA only to 'sound business principles' in setting rates to meet its revenue requirements.").

Third, and more broadly, is the general rate directives in Section 7 of the Northwest Power Act to recover BPA's costs. As noted above, BPA is generally tasked with establishing rates "in accordance with sound business principles." 16 U.S.C. § 839e(a)(1). The Court has recognized that the Administrator has a broad mandate to operate with a business-oriented philosophy. *Ass'n of Pub. Agency Customers, Inc. v. Bonneville Power Admin.*, 126 F.3d 1158, 1171 (9th Cir. 1997). Additionally, the Court has affirmed BPA's ability to set different types of rates in a wide range of situations. *See, e.g., Pub. Power Council, Inc. v. Bonneville Power Admin.*, 442 F.3d 1204, 1210-11 (9th Cir. 2006) (upholding BPA's decision absent evidence that it failed to proceed in accordance with sound business principles); *Indus. Customers of Nw. Utilities v. Bonneville Power Admin.*, 388 F. App'x 586, 589 (9th Cir. 2010) (upholding the establishment of the TRM because BPA did not act arbitrarily or capriciously); *Atl. Richfield Co. v. Bonneville Power Admin.*, 818 F.2d 701, 705 (9th Cir. 1987) (BPA's rate determination upheld as a "reasonable decision in light of economic realities"); *Cent. Lincoln Peoples' Util.*

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Dist. v. Johnson, 735 F.2d 1101, 1120-29 (9th Cir. 1984) (upholding various rate features because they complied with the Northwest Power Act and were adequately supported by the administrative record).

1.5 Related Processes and Scope of PRDM-26

1.5.1 Provider of Choice Policy and Contract

As noted above, concurrent with the PRDM-26 proceeding, BPA is in the process of negotiating new long-term power sales agreements with Public Customers for their Section 5(b) net requirements. *See* 16 U.S.C. § 839c(b)(1); *see also* PRDM-26 FRN at 89,634. Those agreements, known as Provider of Choice Contracts, will govern BPA's power sales to Public Customers beginning October 1, 2028, through September 30, 2044. *Id.*

BPA and regional stakeholders have been engaged in discussions on the policies and objectives of the Provider of Choice Contract for over five years. Those discussions began in late 2019 and ultimately led to a Provider of Choice Concept paper issued on July 14, 2022. Thereafter, BPA held public workshops with stakeholders to discuss the objectives and goals of the Provider of Choice Contracts. Those discussions led to BPA issuing the Provider of Choice Policy and Record of Decision (ROD) in March 2024. In the Provider of Choice Policy and ROD, BPA more formally identified its policy and objectives for the next Section 5(b) contract. Following issuance of the Provider of Choice Policy and ROD, BPA commenced a series of public workshops to negotiate the terms, conditions, and features of the Provider of Choice Contract.

On March 12, 2025, BPA published the Draft Provider of Choice Contract Template for public comment. Comments on that template were due April 9, 2025. The development of the Provider of Choice Contract is ongoing.

The Provider of Choice Contract and the PRDM are designed to work in tandem. PRDM-26 FRN at 89,634. Customers that elect to purchase their Section 5(b) power under a Provider of Choice Contract will also agree to have their PFp power rate set pursuant to the PRDM. *Id.* While the Provider of Choice Contract process and the PRDM are related, they are being decided in separate processes. In particular, the terms and conditions of the Public Customer power supply and product choice are decided by and through the contract development process. *Id.* The Provider of Choice Contract negotiation is being conducted in an open public workshop process, where BPA and stakeholders engage in informal comments and discussions. *Id.* That process has a schedule separate from PRDM-26 and will conclude with a final contract template and a record of decision.[23]

By contrast, the PRDM is being established pursuant to Section 7(i) of the Northwest Power Act, along with all the attendant procedural and record requirements. For this reason, the Federal Register Notice for the PRDM-26 proceeding expressly excluded arguments and

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[23] The schedule for the Provider of Choice process is available at https://www.bpa.gov/energy-and-services/power/provider-of-choice.

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evidence from the administrative record that addressed the issues related to the Provider of Choice Contract. PRDM-26 FRN at 89,635.

1.5.2 Energy Market Development

BPA has long been a participant in local and regional energy markets. Recently, BPA has issued a draft policy describing its proposed intent to join a "day-ahead" energy market.[24] BPA's energy market decisions are not decided in the PRDM, nor are those decisions likely to affect the terms of the PRDM. Nonetheless, the PRDM contains provisions that enable BPA to modify the PRDM if changes to its terms are necessary for energy market participation. *See* PRDM § 9.3.1.

1.5.3 Western Resource Adequacy Program

The Pacific Northwest does not currently have a method by which the region coordinates to ensure the adequacy of resources and/or transmission used by entities serving load within and across balancing authority areas.[25] The Western Resource Adequacy Program (WRAP) was created to fill this gap by developing a standard, uniform resource adequacy planning methodology for program participants within the WRAP footprint. The objective of this effort is to ensure the WRAP footprint has sufficient generating capacity to adequately serve load under a variety of possible scenarios, and that participants are acquiring firm transmission rights to deliver that generation to load. The WRAP is intended to implement programmatic mechanisms—the Forward Showing Program and the Operations Program—to assure adequate capacity is available for its participants. Implementation of WRAP requirements was proposed to occur through multiple phases.

On December 16, 2022, BPA issued a Closeout letter informing the region of its intent to join the WRAP's binding program.[26] The PRDM, as a rate methodology, does not impact BPA's participation in the WRAP. Whether BPA acquires resources compliant with the WRAP's requirements is not decided in the PRDM.

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[24] *See* Bonneville Power Administration, Day-Ahead Market Draft Policy (Mar. 6, 2025), *available* at https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.
[25] *See* Closeout Letter from Administrator John Hairston, at 5 (Dec. 16, 2022), *available at* https://www.bpa.gov/-/media/Aep/projects/resource-adequacy/wrap-final-closeout-letter.pdf.
[26] *Id.*

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2 PRDM: PRIMARY ELEMENTS

2.1 Introduction

The PRDM maintains many of the key features of the TRM. Fisher *et al.*, PRDM-26-E-BPA-02, at 14. Importantly, the TRM's most essential function—tiering the Section 7(b) rate into sub-cost pools to preserve the value of the low-cost existing federal system from higher-cost new resource acquisitions—is retained in the PRDM. *Id.* Many of the terms and concepts used in the TRM are retained in the PRDM. At the same time, the PRDM is a new methodology. The PRDM removes certain features of the TRM and adds provisions to reflect the new balance of interests and objectives BPA and parties to the PRDM-26 proceeding intended to achieve.

This chapter of the Draft ROD provides an overview of the key elements that comprise the PRDM. Because many of those features are derived from the TRM, this chapter begins with an overview of the TRM's components and then explains which of those features are retained in the PRDM. This portion of the Draft ROD also describes features of the TRM that are not retained in the PRDM (to the extent not discussed in other chapters of this ROD).

2.2 Primary Elements of the TRM

2.2.1 Overview of TRM Elements

The TRM is comprised of five primary features. Fisher *et al.*, PRDM-26-E-BPA-02, at 10.

First, the TRM establishes the sub-cost pools for the Section 7(b) rate. *Id.* These sub-cost pools are divided into two major sub-cost pools: Tier 1 and Tier 2 Cost Pools. *Id.* Each of these cost pools is further broken down. *Id.* The Tier 1 Cost Pool consists of the Composite Cost Pool, Slice Cost Pool, and Non-Slice Cost Pool. *Id.* The Tier 2 Cost Pool consists of a cost pool for each Tier 2 Rate. *Id.* The TRM outlines the types of costs that could/would be allocated to each of these pools and describes a series of principles BPA would follow when determining what to do with new or other costs and credits not otherwise identified. *Id.* A series of tables attached to the TRM identifies which costs and credits map to each cost pool.

Second, the TRM describes how BPA calculates the amount of power that it would sell to its Public Customers at the Tier 1 Rates. *Id.* Under the TRM, the amount of power sold at Tier 1 Rates adjusts with the expected firm output of the existing federal resources (Tier 1 System). *Id.* at 10-11. Thus, as the forecasted output of the Tier 1 System grows or shrinks, so too does the amount of power sold at Tier 1 Rates. *Id.* at 11. The process for calculating these changes and the Public Customers' respective share of the resulting system is described in the TRM. *Id.* The TRM also addresses resource acquisitions for power sold at the Tier 1 or Tier 2 Rates. *Id.*

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Third, the TRM describes in detail the rates that would be used to recover the costs from the sub-cost pools mentioned above. *Id.* This was generally divided into Tier 1 Rates and Tier 2 Rates. *Id.* Tier 1 Rates are comprised of three primary charges: Customer Charges, Load Shaping Charges, and Demand Charges. *Id.* The Tier 2 Rates include a Tier 2 Load Growth Rate and a Tier 2 Short-Term Rate. *Id.* A Tier 2 Vintage Rate is also discussed, though its availability depends on customers requesting and BPA offering this rate. *Id.*

Fourth, the TRM discusses a number of other rate features and adjustments that relate to serving a customer's general requirements. *Id.* Among other provisions, such as the Shared Rate Plan (that no utility elected), these include a service for managing Public Customers' resources (Resource Support and Shaping Services), as well as rates for unanticipated load, risk mitigation, and provisions relating to the Low Density Discount and Irrigation Rate Mitigation. *Id.*

Fifth, the TRM describes how and when the TRM may be changed or adjusted under certain circumstances.

2.2.2 TRM Cost Pools and Power Products

2.2.2.1 Overview of Tier 1 and Tier 2 Cost Pools and Power Products

The TRM subdivided the Section 7(b) costs and revenues into two primary cost pools: Tier 1 and Tier 2. The costs and revenues allocated to the Tier 1 cost pool are further subdivided into three sub-cost pools: Composite Cost Pool, Non-Slice Cost Pool, and Slice Cost Pool. *Id.* at 11-12. The Tier 2 cost pools, as its name suggests, addressed costs for sales at Tier 2 Rates, which are applicable to a customer's Above-Rate Period High Water Mark (RHWM) Load supplied by BPA. *Id.* at 12

The Composite Cost Pool, Non-Slice Cost Pool, and Slice Cost Pool are each designed to recover costs and return credits associated with and applicable to different power products that BPA offers. *Id.* at 12. This means that the costs and credits that are allocated to each of these cost pools depend on the characteristics of the power product the customer is buying from BPA. *Id.*

The term "power products" is a BPA colloquialism that refers to the different ways BPA supplies the firm power needs of its customers under Section 5(b). *Id.* Under RD, these products generally come in three forms. *Id.*

<u>*Load Following*</u>

The most basic is the Load Following product. *Id.* This product supplies all of the power needs of customers that elect this service (to the extent not met by the customers' own resources). *Id.* Under Load Following, BPA supplies power in the shape of the customer's load (*i.e.*, BPA "follows the load"). *Id.* Thus, as a particular Load Following customer's load increases or decreases, BPA matches those changes with its resources. Under Load Following, BPA has the planning obligation to meet the customer's peak load needs.

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Block

Additionally, BPA sells a product called the "Block" product. *Id.* The Block product is a planned fixed amount of power supplied by BPA to the customer. *Id.* The amount of power is calculated based on a forecast of the customer's net requirement—that is, a forecast of the customer's total load minus its own non-federal resources. BPA's supply obligation in this instance is only the amount of power in the Block. Any deviations by the customer's actual load needs from the fixed Block amount is on the customer to manage. *Id.* at 12-13. The Block can be "shaped" across the year to be higher in some months and lower in others to more closely match the load needs of a customer. *Id.* at 13. Under the Block product, the customer takes on the planning obligation to meet the customer's peak load needs. *Id.* (While BPA also offered a Block product with shaping capacity that was intended to provide the customer peak load service while still leaving the net obligation on the customer, no customer elected to purchase this product during the RD Contract period.) *Id.*

Slice/Block

Finally, there is a product called "Slice/Block." *Id.* Slice or Slice of the System is an unfixed amount of power supplied by BPA to the customer that varies as a percent of the actual Tier 1 System output. *Id.* A Slice customer's percentage is calculated based on a forecast of the customer's net requirement compared to the expected firm capability of the Tier 1 System output. *Id.* Generally speaking, BPA's supply obligation in this instance is a customer's Slice percentage of the actual Tier 1 System output. The obligation is on the customer to supply the difference between deviations of actual load needs and the combination of the Slice portion of the Tier 1 System output plus the customer's Block amount. The Slice product was also paired with a sale of Block power—hence the name Slice/Block product. The Slice portion of the product accounts for about 50 percent of the customers' forecast net requirement and is a percentage of power provided in a simulated shape that is representative of the actual Tier 1 System output. The Block portion is a predetermined fixed amount as described above and accounts for roughly the other 50 percent of a Slice/Block customer's forecast net requirement. *Id.* The calibration of the Slice percentage to provide roughly 50 percent of a customer's load (under critical water conditions) occurred at the beginning of RD, and the Block amount fluctuated each year with changes in the customer's anticipated load as well as changes in the forecasted Tier 1 System Firm Critical Output (which is a forecast of federal generation, less certain off-the-top obligations, under critical hydroelectric conditions).

2.2.2.2 Connecting Tier 1 Cost Pools to Power Products.

The sub-Tier 1 cost pools tie to the power products BPA sells under the RD Contract as follows: Load Following, Block, and Slice products all pay rates that recover the cost of the Composite Cost Pool. *Id.* at 13. Load Following and Block product customers pay for their respective proportional share of the Non-Slice Cost Pool. *Id.* at 13-14. Slice Product customers collectively pay for the entirety of the Slice Cost Pool. *Id.* at 14.

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2.2.3 TRM High Water Marks: CHWM and RHWM

To structure tiered rates, BPA determined an amount of the customer's load to be charged at a Tier 1 rate and for load served by BPA above that amount at a Tier 2 rate. *Id.* at 7. For that calculation, BPA developed the "high-water mark" concept. *Id.* The TRM, in conjunction with the Section 5(b) RD Contracts, sets the base amount of power each Public Customer would be eligible to purchase at the Tier 1 Rate. *Id.* This base amount of power is governed by the Public Customer's Contract High Watermark (CHWM), which is used to set the Public Customer's RHWM that establishes the highest amount of power they can purchase at the Tier 1 Rate during a specific Rate Period. *Id.*

If a Public Customer's general requirements load was forecast to grow above its RHWM, then that amount of load was classified as "Above-Rate Period Highwater Mark Load" or Above-RHWM Load and charged at Tier 2 Rates if the customer elected to put that load on BPA. *Id.* Tier 2 Rates were, in general, sold at market-based rates so that Tier 2 loads would bear the incremental cost of additional resources used to meet load growth. Although still an average-cost concept, these rates are sometimes referred to as "marginal" rates as shorthand for rates set at BPA's incremental cost of serving that load. *Id.* In this way, BPA was able to suballocate the resource costs assigned to its PFp rate between its existing resources costs (Tier 1 Rates for RHWM Load) and its effective marginal cost of acquisitions (Tier 2 Rates for Above-RHWM Load), thereby supporting the objectives described earlier. *Id.*

2.3 Primary Elements of PRDM

2.3.1 Overview of PRDM Elements

The primary features of the PRDM are largely the same as those of the TRM. *Id.* at 20.

First, the PRDM retains the TRM's two main sub-cost pools for the Section 7(b) rate: the Tier 1 Rate cost pool and the Tier 2 Rate cost pool. *Id.* The Tier 1 Rate cost pool in the PRDM will also be comprised of the same three main sub-cost pools from the TRM: Composite Cost Pool, Slice Cost Pool, and Non-Slice Cost Pool. *Id.* The PRDM also maintains a Tier 2 Cost Pool for each Tier 2 Rate Alternative. *Id.* The PRDM also explains how costs and credits for different services are allocated to and among these cost pools. *Id.* Like the TRM, the PRDM includes a series of tables that identify which costs and credits go to which cost pool. *Id.* The PRDM also identifies the principles BPA will use when allocating new costs or credits to these cost pools in future Section 7(i) processes. *Id.* at 20-21. Most of these principles are from the TRM, though some are new. *Id.* at 21.

Second, the PRDM retains the TRM's approach to identifying the resource costs that will be recovered in the Tier 1 Rate. *Id.* The resources that make up the Tier 1 System (called Tier 1 System Resources) will be identified in a table. *Id.* Resources may be added to the table as needed to meet the Tier 1 system loads. *Id.* Once added, a Tier 1 System Resource will stay a Tier 1 System Resource. *Id.* Acquisitions for other purposes, such as Tier 2 or

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other loads, will also be separately identified in other tables with a specific purpose identified. *Id.* Resources other than the Tier 1 System Resources can be repurposed in each 7(i) Process. *Id.* In this way, the PRDM will allow BPA to identify and track the resources BPA acquires to meet different load needs. *Id.*

Third, the PRDM describes how BPA will calculate the Tier 1 and the Tier 2 Rates from the cost pools mentioned above. *Id.* Tier 1 Rates will be comprised of the following four Core Rate Design charges: Tier 1 Energy Charges; Marginal Energy True-up; Demand Charge; and the Peak Load Variance Charge. *Id.* The Tier 1 Rates will also be subject to three Core Rate Design Rate Impact Credits: the Rate Impact Credit for Capacity (RICc), the Rate Impact Credit (or charge) for Mitigation (RICm), and the Rate Impact Credit for a Joint Operating Entity (JOE) (RICj). *Id.* Other charges or credits may apply depending on the circumstances.

Tier 2 Rates will be comprised of the Tier 2 Long-Term Rate, the Tier 2 Short-Term Rate, and potentially one or more Tier 2 Vintage Rates. *Id.* These rates correspond to the Public Customers' service elections for their Above-CHWM Load under the Provider of Choice Contract. *Id.*

Fourth, the PRDM includes a number of rate features and adjustments that relate to serving a customer's general requirements. *Id.* at 21-22. Among other provisions, these include services to help manage the customer's non-federal resources to serve its load (Resource Support Services), capacity credits for non-federal resources, risk mitigation, and provisions relating to Unanticipated Load Service (ULS), the Low Density Discount, and the Irrigation Rate Discount. *Id.* at 22. The PRDM also makes clear that its terms do not address the development of the PF Exchange rate or Sections 7(b)(2) or 7(b)(3) (with the caveat that the PF Exchange rate does not apply to Public Customers with a CHWM Contract). *Id*.

Fifth, and finally, the PRDM contains provisions addressing how the PRDM's terms may be modified or adjusted, and how disputes over its terms will be resolved. *Id.* 22.

2.3.2 PRDM Compared to TRM

2.3.2.1 Primary Differences of PRDM

Throughout the remainder of this Draft ROD, BPA explains the operation and function of the PRDM. In these chapters and sections, where relevant, BPA also discusses the relative differences between the TRM and PRDM. In this chapter, BPA provides a high-level overview of the structural and general changes between TRM and PRDM. It should be noted that BPA's descriptions of the PRDM's term throughout this Draft ROD are provided in a narrative form to promote understanding and explain the PRDM's development. These descriptions, however, should not be taken as modifying or overriding the PRDM's plain meaning.

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First, the PRDM attempts to simplify many of the provisions of the TRM. *Id.* at 22. These general improvements can be seen throughout the PRDM and are designed to make the PRDM easier to implement. *Id.*

Second, the PRDM uses a different approach to calculating power rates. *Id.* The TRM used a combination of energy charges and customer charges to allocate the costs of the Tier 1 system to Public Customers. *Id.* A customer charge is, in general, an allocation of cost to a customer based on a fixed percentage or formula. *Id.* It is not calculated based on a customer's forecast need and does not change based on the customer's actual energy usage. *Id.* During the development of the PRDM, it was found that many customers had difficulty comparing BPA's sales under the TRM to other resource alternatives because of the complexity of converting the TRM's charges to market-equivalent energy rates. *Id.* at 22-23. BPA simplified this approach by calculating all the power rates in the PRDM in terms of energy (mills per kilowatthour or mills/kWh) or capacity (dollars per kilowatt or $/kW) rates and removed the TRM's dollars per percentage point rates. *Id.* at 23. This aligns the PRDM with more industry standard units of measurement. *Id.*

Third, the PRDM substantially revised several charges. *Id.* The marginal energy true up under the TRM (called the Load Shaping Charge True-Up under the TRM) applied to Load Following customers only. *Id.* Under the PRDM, the marginal energy true-up (called the Marginal Energy True-Up under the PRDM) will apply to Load Following, Block, and Slice customers. *Id.* Additionally, the Demand Charge billing determinant was revised. *Id.* For one, BPA removed the Contract Demand Quantities (CDQs). *Id.* Also, the average HLH energy component was removed and replaced with average monthly energy. *Id.* The PRDM also adds a new charge to address the cost of holding capacity to meet peak capacity needs—the Peak Load Variance Charge. *Id.*

Fourth, the PRDM is written as an evergreen methodology, meaning the PRDM does not have a date-specific expiration. *Id.* So long as BPA develops contracts that rely on the terms of the PRDM, it will remain in effect. *Id.*

2.3.2.2 Notable Deletions

While the PRDM retains most of the features and components of the TRM, certain parts of the TRM were not continued forward into the PRDM. Deletions specific to certain sections in the PRDM that are relevant to understanding that section or were contested will be discussed in later parts of this Draft ROD. Here, BPA takes note of major deletions not mentioned elsewhere.

FERC Review and Declaratory Order (Section 11 of TRM)

As noted above in Section 1.2.3.3 of this Draft ROD, BPA filed the TRM with FERC and sought a declaratory order from the Commission noting that the TRM would not prevent BPA from recovering its costs. The Commission issued that order in June 2010.[27] The TRM

[27] *U.S. Dep't of Energy – Bonneville Power Admin.*, 131 FERC ¶ 61,244 (June 17, 2010).

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included certain terms and provisions relating to the filing of the TRM with FERC including contingencies in the event FERC did not grant the requested declaratory order. This "check-in" with FERC was believed important at the time because the TRM was an "untested concept." Fisher *et al.*, PRDM-26-E-BPA-02, at 24.

For the PRDM, the factual context is very different. *Id.* at 25. BPA has been operating under the TRM for over 13 years. *Id.* During this time, BPA has shown it can fully recover its costs under a tiered rates construct. *Id.* FERC has also reviewed and approved power rates set under the TRM seven times. *Id.* Additionally, as BPA explained earlier, the PRDM's essential elements are largely the same as the TRM's. *Id.* Thus, FERC's familiarity with tiered rates can be transferred to the PRDM. *Id.* Finally, the proven track record of the TRM to recover BPA's costs indicates that FERC is unlikely to have any concerns with BPA proposing to use a similar methodology for future rates. *Id.* Given this different context, BPA concluded that filing the PRDM with the FERC for a "check-in" was unnecessary, and did not include provisions in the PRDM requiring such a filing.

Eligibility to Purchase at Tier 1 Rates (TRM Section 4)

Section 4 of the TRM (Eligibility to Purchase at Tier 1 Rates) was intended to describe the functions and processes needed to develop a customer's High Water Mark (HWM). *Id.* To that end, this part of the TRM describes the methodology for calculating the various iterations of the HWM (Transition High Water Mark, Contract High Water Mark, and Rate Period High Water Mark). *Id.* Section 4 of the TRM also described how the HWM could be adjusted, and the process BPA would engage in each rate period to determine each customer's RHWM Load and Above-RHWM Load for the rate period. *Id.* Importantly, the process for determining RHWM and Above-RHWM Loads occurred in a process conducted outside of the Section 7(i) Process.

The PRDM need not retain these features because BPA has provided other forums and means for making these calculations. *Id.* Specifically, the Provider of Choice Policy and ROD provided a detailed overview of how customers' CHWM would be calculated. *Id.* at 25-26. Additionally, BPA is planning to develop a process to determine each customer's individual CHWM and Above-CHWM Load. *Id.* at 26. Given these other processes and activities, BPA did not find it necessary to reiterate or outline those processes as a component of the PRDM. *Id* Ultimately, how a customer's general requirements load is divvied up between CHWM and Above-CHWM Loads is a power contract and supply question, not a rate question. *Id.* While BPA included those terms before in the TRM, nothing requires BPA to make these calculations as part of the TRM or in setting power rates. *Id.* Indeed, even under TRM, the entirety of the HWM calculation process occurred outside of the Section 7(i) Process. *Id* BPA has provided the terms for determining the CHWM through the Provider of Choice Policy and related processes; including such provisions in the PRDM is not required. *Id.*

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2.3.3 PRDM High Water Mark: CHWM

The PRDM, in conjunction with the Provider of Choice Contract, will differentiate a customer's general requirements load into "high-water marks" much like the TRM and the RD Contracts. *Id.* at 14-15. Thus, Public Customers' general requirements will continue to be broken up into two variants—CHWM Load and Above-CHWM Load. *Id.* at 15. One difference, however, is unlike the TRM, the PRDM will not be using "Rate Period High Water Marks." *Id.* Instead, the PRDM will be using CHWMs that do not change each Rate Period based on the expected output of the existing federal system. *Id.* Load within a customer's CHWM will be supplied at the Tier 1 Rate. *Id.* Load above the customer's CWHM is called Above-CHWM Load and will be supplied power at the Tier 2 Rate if served by BPA. *Id.* The Provider of Choice Contract and related processes will establish each customer's CHWM. For customers with Above-CHWM Load, the Provider of Choice Contract will provide various elections for either the customer or BPA to serve such load. *Id.*

2.3.4 PRDM and Provider of Choice Contracts

The PRDM is the rate methodology applicable to the Section 7(b) rate that BPA will charge for the general requirements of Public Customers beginning October 1, 2028. *Id.* at 27. The Provider of Choice Contract is the power supply contract that BPA is statutorily required to offer to Public Customers under Section 5(b) of the Act. *Id.* As noted above, the Provider of Choice Contract will govern power sales beginning October 1, 2028. *Id.* Additionally, the Provider of Choice Contract and related processes will determine what portion of the customers' general requirements is CHWM Load and what portion is Above-CHWM Load. *Id.* Those calculations will be an input into the PRDM for purposes of calculating the Tier 1 and Tier 2 Rates. *Id.*

The PRDM uses certain terms and ideas that point back to the Provider of Choice Policy and Contract. *Id.* Many of these terms are defined in the Definitions Appendix of the PRDM. *Id.* The Provider of Choice Contract negotiation process is ongoing and is expected to continue into 2025. *Id.* While the PRDM definitions were designed to be compatible with the Provider of Choice Contract, it is entirely possible that as the contract negotiations end, new definitions may need to be added or existing definitions modified in the PRDM to ensure the PRDM and Provider of Choice Contracts are consistent and operate correctly. *Id.* Updates to definitions that occurred during the 7(i) Process are accounted for in the PRDM. To the extent a definition needs to be updated after this proceeding, such change would occur in a future Section 7(i) pursuant to the terms of the PRDM. *Id.*; *see also* PRDM § 9.1.

2.4 General Responses to PRDM

Five parties filed briefs in the PRDM proceeding. *See generally,* JP01 Br., PRDM-26-B-JP01-01; JP02 Br., PRDM-26-B-JP02-01; AWEC Br., PRDM-26-B-AW-01; RNW Br., PRDM-26-B-RN-01; PNGC Br., PRDM-26-B-PN-01.

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Overall, parties in the PRDM proceeding supported the PRDM provided with BPA Staff's rebuttal testimony. *See* JP01 Br., PRDM-26-B-JP01-01, at 3; AWEC Br., PRDM-26-B-AW-01, at 1-2. JP01, which "represents roughly 97% of BPA's Tier 1 load" views the PRDM "as a grand compromise between BPA and its diversely situated customer base for how BPA will establish power rates during the term of the Provider of Choice Contracts." JP01 Br., PRDM-26-B-JP01-01, at 3-4. JP01 noted that, while "[e]ach utility and trade group represented by this Initial Brief has different views about the PRDM and considers some aspects to be more favorable to their utility or membership than others . . . overall, [they] agree that the PRDM is a negotiated package that represents a lot of work and compromises on all sides . . . ." *Id.* at 4. For that reason, JP01 recommends that BPA "(1) adopt the PRDM as revised in PRDM-26-E-BPA-11-AT01; and (2) faithfully adhere to the words and original intent of the PRDM, as revised, in BPA's interpretation and implementation of the PRDM during the term of the Provider of Choice Contracts." *Id.* AWEC provided similar supportive feedback. In its brief, AWEC contends that "the PRDM as set forth in PRDM-26-E-BPA-11-AT01 appropriately preserves the give-and-take of the negotiated package, and therefore should be adopted." AWEC Br., PRDM-26-B-AW-01, at 1-2.

JP01 also agreed that the PRDM proposed by BPA Staff was "largely consistent with the goals that were set out in the public process for developing a revised tiered rate methodology that aligns with the Provider of Choice Policy and Record of Decision." JP01 Br., PRDM-26-B-JP01-01, at 4. JP01 agreed that the PRDM established appropriate price signals through the design of the Tier 1 and Tier 2 rates, and that this design "equitably balance[s] a broad range of customer interests while respecting the co-principles of cost causation and avoiding rate shock for some customers." *Id.* at 4-5. JP01 notes that "[t]he best way for BPA to honor this fragile and hard-won equilibrium, as well as the underlying collaboration and compromise it took to get there, is to adopt the PRDM as revised in PRDM-26-E-BPA-11-AT01 and then implement and interpret it during the term of the Provider of Choice Contract as written." *Id.* at 5.

A number of parties raised concerns in their briefs about various features of the PRDM. *See, e.g.,* JP02 Br., PRDM-26-B-JP02-01; RNW Br., PRDM-26-B-RN-01; PNGC Br., PRDM-26-B-PN-01. These concerns, however, go to the functionality of specific features of the PRDM or ask BPA to consider broader policy goals or objectives. No party requested BPA reject the PRDM outright. In addition, no party to this proceeding disputes BPA's authority to adopt tiered rates or to codify its rate design within a rate methodology.

The balance of this Draft ROD addresses the major provisions of the PRDM and responds to parties' specific comments, concerns, and suggestions.

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2.5 Issues

Issue 2.5.1
Whether the PRDM contains appropriate incentives for non-federal resource development.

Party's Position

Renewable Northwest (RNW) urges BPA to adopt policies in the PRDM that encourage non-federal resource development. RNW Br., PRDM-26-B-RN-01, at 2. RNW contends that BPA would not adopt policies that would make it the only power supplier for its customers, and similarly, BPA should not offer products that would unwittingly trend in that direction. *Id.* To support non-federal investment, RNW argues the PRDM should maintain product parity, and urges BPA to engage in future discussions on implementation decisions openly with customers. *Id.* at 3, 4-5.

BPA Staff's Position

The PRDM contains appropriate price signals for capacity and energy. PRDM §§ 4.1.2, 4.2, 4.3. In fact, one of the primary principles of the PRDM is to incentivize customers to develop their own resources for load growth. Fisher *et al.*, PRDM-26-E-BPA-02, at 15. RNW's other concerns with transparency and follow-on processes were raised for the first time in its brief.

Evaluation of Positions

RNW raises in its briefs several concerns that it "invites" BPA to address as it makes decisions on the PRDM. RNW Br., PRDM-26-B-RN-01, at 2. In general, RNW does not want BPA to adopt policies through the PRDM that would render it "the only power supplier for its Preference Customers" or that support product offerings that would "unwittingly trend in that direction." *Id.* This, in RNW's view, would impact the incentive of customers to acquire non-federal generation to meet regional carbon and other needs. *Id.* at 1, 2, 4, 5.

The specific concerns RNW raises fall into two broad categories. The first category addresses specific features of the PRDM—the development of the Rate Impact Credit Capacity (RICc) and the pricing of the Resource Support Service. *Id.* at 2-3, 4. BPA will address those issues in the portions of this Draft ROD that discusses those features of the PRDM. *See* Issue 5.4.1.2.1; Issue 7.4.1.

The second category of issues addresses a number of non-specific PRDM issues that go to the general policy goal of avoiding disincentives to future non-federal generation development. *Id.* at 3, 4-5. BPA addresses those issues here.

First, RNW "applauds" BPA staff for its focus on parity between the product offerings and for working diligently to avoid lopsided outcomes that might dramatically impact the agency's planning needs and/or use of the federal system. *Id.* at 3. RNW notes that if all Public Customers elect the load-following product, "all customers" would be harmed by the

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loss of the flexibility made available by Slice and Block. *Id.* RNW further notes that product parity was discussed at length throughout the PRDM process in regard to WRAP compliance and Day-Ahead-Market (DAM) optionality. *Id.* RNW notes that "key policy implementation details" have yet to be determined and could still impact non-federal development. *Id.* For these reasons, RNW urges BPA to "strive for transparent, holistic discussions with all stakeholders during any subsequent policy decisions to ensure product parity is maintained." *Id.*

BPA appreciates the theme of RNW's comments and notes that many of the product issues RNW describes are being addressed in other applicable forums, such as the Provider of Choice, WRAP, and DAM processes. As BPA understands RNW's brief on this issue, it does not appear to be asserting that the PRDM is defective, but more generally is asking for BPA to maintain its commitment to open public processes that consider issues that cross into multiple work streams. BPA agrees that transparency is an important feature of any public process, particularly those that have issues that overlap with other processes.

As to the specific issues of WRAP and DAM, BPA notes that the PRDM neither takes a position on either process, nor governs future decisions resulting from those processes. The WRAP is not mentioned in the PRDM in any way. While DAM is mentioned, it is merely classified as an "unintended consequence" under the PRDM change procedures in Section 9. *See* PRDM § 9.3.1; *see also* Bleifuss *et al.*, PRDM-26-E-BPA-11, at 16-19.

Second, and relatedly, RNW urges BPA to adopt policies that "continue to incentivize" the development of non-federal generation. RNW Br., PRDM-26-B-RN-01, at 1. RNW recognizes that the PRDM is a product of compromise, and RNW "commends" BPA's efforts to keep Public Customers at the negotiating table. *Id.* at 4-5. RNW notes, though, that given the scale and scope of "decisions remaining to be addressed," RNW is concerned that "incentives to non-federal development may still be impacted." *Id.* at 5. RNW urges BPA to discuss subsequent implementation decisions openly with all stakeholders. *Id.* RNW notes it has a particular interest in how BPA meets its "statutory requirements" under the PRDM. *Id.* RNW then discusses BPA's "net requirements" calculation and what kind of flexibility will be provided to "add or remove" resources, and how the Marginal Energy True Up tool will work. *Id.* RNW requests BPA to provide notice to all customers of these aspects of the PRDM, even though they deal only with Public Customers. *Id.*

As noted above, BPA agrees that transparency and open public processes will continue to be part of BPA's future objectives. RNW will have opportunities in future processes to express its views on the areas that it identifies, including the basic requirements for determining net requirements and the terms for adding or removing dedicated resources. BPA also points to the Staff position that incentivizing non-federal development remained one of the key principles behind the development of the PRDM. *See* Fisher *et al.*, PRDM-26-E-BPA-02, at 15. To that end, the PRDM was designed to include appropriate price signals for both energy and capacity. *See, e.g.,* PRDM §§ 4.1.2, 4.2, 4.3.

BPA notes, however, that RNW's specific concerns with the calculation of a customer's net requirements and the terms for adding or removing a resource from a customer's net

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requirements calculation are not PRDM issues. As explained earlier in this decision document, the PRDM addresses the *sub*-cost allocation of costs and credits within the Section 7(b) rate pool among customers that pay the PF rate. *See* Section 1.4 of this ROD. The PRDM's terms do not touch any other BPA statutory obligations, including any aspect of BPA's supply obligations under Section 5(b). 16 U.S.C. § 839c(b)(1). Section 5(b) contains BPA's power supply obligations and, as explained in Section 1.5 of this ROD, those issues are being addressed in the Provider of Choice processes. The Provider of Choice Contracts are input to the PRDM—not the other way around. *See* Fisher *et al.*, PRDM-26-E-BPA-02, at 27. As explained by BPA Staff:

> The PRDM is the rate methodology applicable to the Section 7(b) rate that BPA will charge for the general requirements of PF Public Customers beginning October 1, 2028. The Provider of Choice Contract is the power supply contract that BPA is statutorily required to offer to PF Public Customers under Section 5(b) of the [Northwest Power] Act. As noted above, the Provider of Choice Contract will govern power supply sales beginning October 1, 2028. Additionally, the Provider of Choice Contract and related processes will determine what portion of the customers' general requirements is CHWM Load and what portion is Above-CHWM Load. Those calculations will be an input into the PRDM for purposes of calculating the Tier 1 and Tier 2 Rates.

Id.

Similarly, the PRDM does not dictate nor otherwise address the provisions of the Section 5(b) power supply contract, which would necessarily include terms for adding or removing resources. Since these issues are not being addressed in the PRDM, RNW's comments regarding "outstanding PRDM decisions" are misdirected at the PRDM and should be made in the appropriate forums where BPA's obligation to supply customers power under Section 5(b) is being determined (*i.e.,* the applicable Provider of Choice processes).

<u>Draft Decision</u>

The PRDM contains appropriate provisions that properly incentivize non-federal resource development. BPA intends to engage in future processes that affect non-federal resource development in an open and transparent manner. Issues with BPA's net requirements calculation or the addition/removal of resources from a customer's Section 5(b) contract are not being decided in the PRDM.

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3 BACKGROUND, PURPOSE, AND COST ALLOCATION (PRDM CHAPTERS 1 AND 2)

3.1 Background and Purpose (PRDM Chapter 1)

3.1.1 Overview

Chapter 1 of the PRDM is intended to frame the PRDM in its statutory context as well as describe its relationship with other features of BPA ratemaking. *See* PRDM § 1; *see also* Stiffler *et al.*, PRDM-26-E-BPA-03, at 1. It begins by describing the nature of the rates to which the PRDM applies, namely the rates set by Section 7(b) of the Northwest Power Act. PRDM § 1. Chapter 1 then describes the general legal underpinnings of tiered rates. The general principles behind Tier 1 and Tier 2 Rates are also discussed. *Id.* Chapter 1 also includes specific terms about the Rate Periods applicable to the PRDM and the duration and scope of the PRDM. *Id.*

3.1.2 Future Power Rates and Rate Period

Section 1.1 of the PRDM makes clear that the PRDM does not establish any rates. Instead, BPA's determination of specific rate levels "will be made" consistent with the terms of the PRDM in future Section 7(i) Processes. PRDM § 1.1. This section of the PRDM also states that rates set pursuant to the PRDM must be "no longer than" two years. PRDM § 1.1. Rates set for a year, for instance, would meet this condition. Stiffler *et al.*, PRDM-26-E-BPA-03, at 2.

3.1.3 Duration of PRDM

The PRDM is proposed to stay in effect until "all contracts that sell power at rates set pursuant to the PRDM have expired." PRDM § 1.2. The intent of this language is to allow the PRDM to continue to be available as the applicable rate methodology until there are no contracts that use its terms. Stiffler *et al.*, PRDM-26-E-BPA-03, at 2-3. This is a change from the TRM, which had a stated expiration date. *Id.* at 3. To be clear, this language does not make the PRDM apply to future agreements. *Id.* Instead, the intent was to allow the PRDM's terms to be available for future contracts if that is what BPA and its customers decide to use for future agreements. *Id.* For example, if, at the end of the Provider of Choice Contracts, BPA and customers decided to retain the PRDM for the next round of power sales contracts, they need only say in such contracts that rates for sales of power under those agreements will be set pursuant to the PRDM. *Id.* That would meet the terms of Section 1.2. If BPA and customers do not decide to use the PRDM for the rates for those future power sales contracts, then once the Provider of Choice Contracts expire, the PRDM would be sunset as *no* contracts would be active that "sell power at rates set pursuant to the PRDM . . . ." *Id.*

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3.1.4 Scope of PRDM

Section 1.3 of the PRDM reaffirms the limited scope of the PRDM's terms. As noted earlier, BPA is not required by statute to develop the PRDM. Section 7 of the Northwest Power Act, 16 U.S.C. § 839e, provides the various rate directives BPA must follow when setting rates for its different customer classes. These rate directives require BPA to allocate costs and credits to various rate pools. The PRDM does not disrupt or otherwise affect those allocations. Indeed, the PRDM applies after BPA has complied with its statutory rate directives and has allocated all its costs to the appropriate rate pools. *See* PRDM § 2.2, Figure 2-1. It is only *within* the Section 7(b) rate pool, and even then, only the Public Customer portion of that rate pool, that the terms of the PRDM become operative. Stiffler *et al.*, PRDM-26-E-BPA-03, at 3.

Even so, there are various times where the PRDM mentions other rate pools for context or to explain the interaction between the PRDM and these rate pools. *Id.* at 3-4. Because of those references, it may appear as if the PRDM is affecting other rate pools. *Id.* at 4. To dispel this confusion, Section 1.3 of the PRDM was included to specifically acknowledge that the PRDM "does not address the cost allocation or rate design of any other rate." PRDM § 1.3. To the extent the PRDM does refer to other rate pools, such "statements should be understood in the context of the sequential process." *Id.*

3.2 Cost Allocation (PRDM Chapter 2)

3.2.1 Overview

Chapter 2 of the PRDM provides for a set of over-arching cost allocation principles intended to guide the implementation of the PRDM. Stiffler *et al.*, PRDM-26-E-BPA-03, at 4. It describes the basis of allocation of costs and credits between the Composite, Non-Slice, Slice, and Tier 2 Cost Pools, prescribes how new costs and credits should be allocated, discusses the implementation of the secondary energy credit in rates, addresses the treatment of certain interest items on reserves carried for risk, identifies certain methods for allocating stranded Tier 2 Costs, and includes a detailed treatment of true-ups to ensure products are charged Tier 1 Rates up to Contract High Water Marks (CHWMs), as well as true-ups inherent to the Slice product. *Id.*

The PRDM covers the rate design applicable to Public Customers with CHWM Contracts and is developed in accordance with BPA's statutory authority under Section 7(b) and Section 7(e) of the Northwest Power Act. *See* 16 U.S.C. § 839e(b), (e). However, to ensure that this design does not violate other provisions of the Act, the PRDM includes an allocation proof in Section 2.2.1 to demonstrate that the net revenues collected from Public Customers are consistent with the other rate directives contained in the Northwest Power Act. *See* PRDM § 2.2.1; *see also* Stiffler *et al.*, PRDM-26-E-BPA-03, at 4.

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3.2.2 Cost Allocation Principles

The PRDM includes a series of cost allocation principles to provide guidance to BPA for future decisions and allocations under the PRDM. *See* PRDM § 2.1. These principles are designed to provide assurance to stakeholders and guidance to BPA regarding the implementation of the PRDM when faced with new costs, credits, or other changed situations. *See* Stiffler *et al.*, PRDM-26-E-BPA-03, at 5. These principles will provide guidance for most foreseeable new circumstances. *Id.* This list served BPA and the customers well under the TRM and should provide some assurance of its completeness, with Chapter 9 of the PRDM providing procedures for revisions and dispute resolution. *Id.* These principles largely follow those adopted under the TRM, though some were modified to reflect current issues. *See id.* at 5-6.

3.2.3 Cost Pools under the PRDM

PRDM Sections 2.2.1.1 through 2.2.1.4 describe the "cost pools" in use within the PRDM. As noted above, there are four primary cost pools in the PRDM: Composite Cost Pool, Non-Slice Cost Pool; Slice Cost Pool; and Tier 2 Cost Pools. The Composite Cost Pool collects costs and credits revenues that are allocated to Priority Firm Public (PF) rates and applicable to all Tier 1 loads, irrespective of product selection. Stiffler *et al.*, PRDM-26-E-BPA-03, at 7. The Non-Slice Cost Pool collects costs and credits revenues that accrue to only the Load Following and Block products, such as balancing purchase costs and secondary sales revenues. *Id.* The Slice Cost Pool collects for costs and any revenues accruing to the Slice product specifically, such as special or extraordinary implementation costs for systems specific to the Slice product. *Id.* Finally, the Tier 2 Pools collect all Tier 2 Costs accruing to one of several Tier 2 Alternatives as sold to customers with Above CHWM Load served by BPA at a Tier 2 Rate. *Id.*

3.2.4 Allocation of Costs to the Cost Pools

PRDM Sections 2.3 through 2.6 discuss particular allocations of costs and credits among the cost pools described above. The allocation of New Expenses and New Credits is addressed in Section 2.3. Section 2.4 lays out the treatment for secondary energy credits. Section 2.5 changes the practice under the TRM of separating reserves held for risk between those accruing to the Composite Cost Pool versus the Non-Slice Cost Pool. Starting with the PRDM, all interest accruing to reserves for risk will accrue to the Non-Slice Cost Pool. Stiffler *et al.*, PRDM-26-E-BPA-03, at 8. Section 2.6 lists the steps BPA would first take before proposing to allocate costs incurred for Tier 2 to the Tier 1 Cost Pool. *Id.* at 9.

3.2.5 Slice Related Adjustments

3.2.5.1 Slice True-Up

The Slice product is responsible for recovering actual costs net of actual revenues allocated to either the Composite or Slice Cost Pools in the 7(i) Process. *Id.* at 9. Because the

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Composite and Slice Rates were based upon a forecast at the time of the Final Proposal in the applicable 7(i) Process, there is a need to true-up the Slice charges to actuals. *Id.* The Slice True-up discussed in Section 2.7 performs this task. *Id.*

3.2.5.2 Composite and Slice Cost Pools True-Up Charge

The Composite and Slice True-Up Charges are made up of two components: the first component is the calculation of the True-Up billing determinant, and the second component is the True Up Rate. *Id.* at 10. For both Composite and Slice True-Up Charge, the product of these two values gives the amount to be either credited (if rate case forecasts were higher than actuals) or charged (if rate case forecasts were less than actual costs). *Id.* The billing determinant calculation adjusts the Slice energy amounts by the actual amount of unused CHWM after the Marginal Energy True-Up calculation for the Load Following, Block, and Slice Products has been completed. *Id.* In this way, the billing determinants for Composite and Slice True-Up Charges are adjusted to actual loads effectively served at Tier 1 Rates. *Id.* The rate calculations itemize and sum the difference between forecast and actuals for every cost and credit item in each of the Composite and Slice Cost Pools to arrive at separate aggregate deviations for the Composite and Slice Cost Pools. *Id.* These separate aggregations are then each divided by the actual load effectively served at Tier 1 Rates. *Id.* That is, aggregations of these deviations for each of the Composite and Slice Cost Pools are each divided by the sum of CHWMs less unused CHWM after application of the Marginal Energy True-Up for the Load Following, Block, and Slice Products. *Id.* These form the Slice True-Up rates for Composite and Slice Cost Pools. *Id.*

3.2.6 Cost Review Process

Section 2.9 of the PRDM commits BPA to conduct a Cost Review Public Process. The Cost Review Public Process is a process that allows customers to gain visibility into BPA's forecast programmatic costs prior to setting rates and financial performance during the rate period. *Id.* at 11. BPA uses a variety of processes to provide this information currently, including Integrated Program Review (IPR) and the Quarterly Business Reviews (QBRs). *Id.* For the post-2028 period, BPA retains the discretion to continue to use these forums, or adopt new processes, to provide the required information to customers. *Id.*

3.3 Issues

<u>Issue 3.3.1</u>
Whether BPA should commit in the Final Record of Decision to a comprehensive review of BPA's risk mitigation and risk management policies prior to the BP-29 rate period.

<u>Parties' Positions</u>

JP01 argued in its direct testimony for changes to PRDM Cost Allocation Principle 8 that would require BPA to credit power rates with the actual, realized, secondary revenues from the Federal Base System. JP01 Br., PRDM-26-B-JP01-01, at 5-6. JP01 notes that BPA Staff's

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rebuttal acknowledged the merit of JP01's position but contends that such issue should be addressed in a comprehensive review of BPA's financial policies. *Id.* at 6. In its Initial Brief, JP01 agrees with BPA Staff's view, and requests that BPA commit in the ROD to a process to review its financial policies before BP-29. *Id.* AWEC supports JP01's proposal. AWEC Br., PRDM-26-B-AW-01, at 2.

<u>BPA Staff's Position</u>

BPA Staff understands the basis for JP01's concerns with secondary revenue, but do not think addressing those concerns through adjustment to Cost Allocation Principle 8 in the PRDM is the proper course of action. Bleifuss *et al.*, PRDM-26-E-BPA-11, at 6-10. BPA agrees that further conversations should occur on the treatment of secondary revenue but believes those conversations should occur outside of the PRDM in an open, collaborative forum. *Id.* at 10.

<u>Evaluation of Positions</u>

As noted above, Section 2.1 of the PRDM includes a list of cost allocation principles which will be "used for allocating costs that are not specifically addressed in the PRDM." PRDM § 2.1. These principles are "designed to provide assurance to stakeholders and guidance to BPA regarding the implementation of the PRDM when faced with new costs, credits, or other changed situations." Stiffler *et al.*, PRDM-26-E-BPA-03, at 5.

Cost Allocation Principle 8 (Principle 8) is one of these principles. PRDM § 2.1(8). Principle 8 has its antecedents in the TRM and, thus, is not a new principle. Bleifuss *et al.*, PRDM-26-E-BPA-11, at 7. Its overall purpose, as evident from its language ("will continue to . . ."), was to express a practice that had been a part of BPA ratemaking for many decades—namely, to credit to the Section 7(b) rate the forecast net secondary revenues from surplus sales originating from the Federal Base System. *Id.* It was not a new idea but a recognition of a long-standing ratemaking approach that ensured forecast net secondary revenues were allocated to PF rates commensurate with other costs and credits directly attributable to the Federal Base System. *Id.* This principle also parrots what BPA's statutes already generally required, as seen by the reference to "pursuant to Northwest Power Act Section 7(g) . . . ." PRDM § 2.1(8)(a). The inclusion of "forecast" was also intentional because it ensures that this principle operates in the context of ratemaking, which uses projections and estimates to establish rates. *Id.*; *see also* Bleifuss *et al.*, PRDM-26-E-BPA-11, at 7.

In its direct case, JP01 requested changes to Principle 8 that would have required BPA to not only base the tiered rates on the forecast revenues of secondary, but also to commit to return to power rates as a credit the actual revenues of secondary sales. Traetow *et al*., PRDM-26-E-JP01-01, at 5. BPA Staff in its rebuttal opposed this change because it implicated broader financial policies and, therefore, was outside of the scope of the PRDM. Bleifuss *et al.*, PRDM-26-E-BPA-11, at 6-7. Staff also clarified the importance of Principle 8 focusing on *net* secondary revenues to reflect the relation between secondary revenues and the cost of power purchases, and that BPA does not currently separate its net secondary revenue performance from its overall financial performance. *Id.* at 7-8. At the same time, BPA Staff acknowledged that the concerns and questions behind JP01's proposal had "merit" and BPA Staff committed to address this issue in another forum. *Id.* at 10.

In their briefs, JP01 and AWEC agree with BPA Staff's proposal and request BPA to make a commitment in this Draft ROD to conduct a process to revisit its financial policies comprehensively and, in particular, to address the treatment of actual net secondary revenue in a separate process prior to the BP-29 rate case. JP01 Br., PRDM-26-B-JP01-01, at 5-6; AWEC Br., PRDM-26-B-AW-01, at 2.

BPA agrees to make this commitment. As such, prior to the BP-29 rate proceeding, BPA commits to commence a public process wherein BPA will take a comprehensive look at its risk package and, as part of that review, consider the treatment of actual net secondary revenue.

Draft Decision

Prior to the BP-29 rate proceeding, BPA commits to commence a public process wherein BPA will take a comprehensive look at BPA's risk package and, as part of that review, consider the treatment of actual net secondary revenue.

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4 RESOURCES AND AUGMENTATION (PRDM Chapter 3)

4.1 Overview

Chapter 3 of the PRDM defines the categories that BPA will use to map its resources for purposes of allocating costs and setting tiered rates for Public Customers purchasing power under a CHWM Contract. Bellcoff *et al.*, PRDM-26-E-BPA-04, at 1. Such resource mapping will be updated in each 7(i) Process. *Id.* The resource categories will be used to set Tier 1 and Tier 2 Rates as well as provide information used to differentiate the resource costs and benefits allocated to either the Composite or Non-Slice Cost Pools. *Id.* Chapter 3 also lists the Designated System Obligations and BPA's notification commitments for updating that list. *Id.* Designated System Obligations are used to calculate the costs allocated to the Composite Cost Pool and various Slice-related measurements, specifically Modeled CHWM Augmentation, the Firm Slice Amount, and the simulated Slice capability. *Id.* at 1-2.

4.2 Tier 1 System Resources

PRDM Section 3.1 defines the Tier 1 System Resources. Tier 1 System Resources are a defined list of resources, such as Grand Coulee and Bonneville hydro projects, that BPA will use for setting the Tier 1 Rates and establishing the amount of power provided through the Slice product. *Id.* at 2. The list of Tier 1 System Resources will be updated in each 7(i) Process. *Id.* The list of resources will be updated to include any additions, including market purchases, that BPA determines are needed to meet its CHWM obligations. *Id.* There are no subtractions from the list because once a resource is characterized as a Tier 1 System Resource it will remain a Tier 1 System Resource. *Id.* While Chapter 3 includes tables that designate specific resources to specific rate pools, this should be understood as a ratemaking construct, and not a physical allocation of power. *Id.* These resource cost allocations are also assumed to occur after cost allocation as directed by BPA statutes. *Id.* The Tier 1 System Resources are identified in PRDM Table 3-1.

4.3 System Obligations

PRDM Section 3.2.1 discusses system obligations. In general terms, Designated System Obligations are BPA's obligations that should impact all Public Customers taking power under CHWM Contract in a similar way regardless of the power product elected—Slice, Block, or Load Following. *Id.* at 3. Designated System Obligations are a use of the Tier 1 System Resources capability and, in general, reduce/change the remaining capability (capacity, energy, or both) of the Tier 1 System Resources after those obligations have been met. *Id.* 3-4. Designated System Obligations are considered firm obligations of the system regardless of weather, water, or economic conditions. These obligations may involve energy, capacity, or a combination of the two. *Id.* at 3. Section 3.2 of the PRDM discusses how Designated System Obligations can change, including how these obligations increase or decrease. *Id.* The Designated System Obligations are identified in PRDM Table 3-2.

4.4 Acquisitions

BPA is required by statute to acquire sufficient resources to meet its contractual obligations. 16 U.S.C. § 839d(a)(2)(A). Thus, if BPA's existing resources are not capable of meeting all of BPA's expected load (on a forecast basis), BPA acquires additional resources. The cost of those resources must be recovered in BPA's rates pursuant to statutory rate directives. *See* 16 U.S.C. § 839e *et seq.* The PRDM includes terms that describe the interplay between BPA's general obligation to acquire resources to meet its supply obligations, with the cost pools and tiered rates construct. Specifically, the PRDM describes the treatment of five categories of power acquisitions: augmentation, balancing purchases, Tier 1 Non-Slice Capacity acquisitions, Tier 2 acquisitions, and all other resource acquisitions. PRDM §§ 3.3-7. Each is described below.

4.4.1 Augmentation

Augmentation refers to the expected annual average amount of additional firm power BPA would need to balance loads and resources, assuming BPA's load obligations and firm generation produced by its resources were flat across a future year in a prospective rate period. PRDM § 3.3; *see also* Bellcoff *et al.*, PRDM-26-E-BPA-04, at 5-6. BPA's loads are not flat throughout the year, and neither is the firm capability of its resources. Bellcoff *et al.*, PRDM-26-E-BPA-04, at 6. Thus "augmentation" is largely a categorization and measurement term used in product design and ratemaking to sort BPA's forecast power acquisition costs equitably, transparently, and consistently. *Id.*

PRDM Section 3.3 describes two types of augmentation: CHWM Modeled Augmentation and Rate Period Augmentation. *Id.* CHWM Modeled Augmentation is used to support equitable Slice and Non-Slice Product design. *See id.* at 6-8.

Rate Period Augmentation is the forecast average annual amount of power needed to be in load and resource balance after considering all of BPA's resources (*see* PRDM Tables 3-1, 3-3, 3-4, and 3-5) and obligations (*e.g.*, Designated System Obligations, Table 3-2, and power needed to serve loads under Section 5 of the Northwest Power Act). *Id.* at 8. In simple terms, Rate Period Augmentation is a traditional forecast measurement of the amount of power BPA expects to need to achieve load and resource balance on an average annual basis during the rate period. *Id.*

4.4.2 Balancing Purchases

Balancing Power Purchases are distinct from Rate Period Augmentation in that they are power purchases forecast in a 7(i) Process to be made by BPA for periods within a year during which BPA's resource capability is insufficient to meet BPA's Non-Slice obligations for that period. *Id.* at 11; *see also* PRDM § 3.4. Such Balancing Power Purchases will not be included when calculating Rate Period Augmentation. Bellcoff *et al.*, PRDM-26-E-BPA-04, at 11. BPA's Balancing Power Purchase costs may include procured contract purchases as

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well as a forecast of future procurements. *Id.* These purchases are necessary because loads are not flat during the year. *Id.* BPA may need more energy in some months when compared to other months. Balancing Purchases address these within-year variations. *Id.*

4.4.3 Tier 1 Non-Slice Capacity Acquisitions

Tier 1 Non-Slice Capacity Acquisitions are purchases of capacity that BPA makes with the purpose of serving its Load Following and the Block with Shaping Capacity load obligations served at Tier 1 Rates. *Id.* at 12; *see also* PRDM § 3.5. These purchases are distinct from Augmentation and Balancing Purchases. Bellcoff *et al.*, PRDM-26-E-BPA-04, at 13-14. PRDM Table 3-3 identifies resources in this category.

4.4.4 Tier 2 Acquisitions

Tier 2 Acquisitions are purchases of energy, capacity, or a combination of both made for the purpose of serving BPA's load obligations at Tier 2 Rates. *Id.* at 14; *see also* PRDM § 3.6. As loads grow above a customer's CHWM, customers have the option to place that Above-CHWM Load obligation on BPA to be served at Tier 2 Rates. Bellcoff *et al.*, PRDM-26-E-BPA-04, at 14. Eventually these loads could extend beyond the firm capability of the existing federal system, which will require that BPA acquire additional resources to meet these Above-CHWM Load obligations. *Id.* at 14-15. These costs will then be allocated to the applicable Tier 2 Cost Pools and collected from BPA's Tier 2 Rates. *Id.* at 15. PRDM Table 3-4 identifies resources in this category.

4.4.5 All other Resource Acquisitions

BPA has load obligations that are not associated with Public Customer loads with CHWM Contracts. *Id.*; *see also* PRDM § 3.7. These load obligations may include, but are not limited to, Public Customer load obligations not served under a CHWM Contract, load obligations served at Industrial Firm Power rates, and load obligations served at New Resource Firm Power rates. Bellcoff *et al.*, PRDM-26-E-BPA-04, at 15. To the extent BPA forecasts or makes a resource acquisition for the purpose of serving these other load obligations, BPA will list that resource in PRDM Tables 3-5, which identifies resources in this category, as updated in each 7(i) Process. *Id.*

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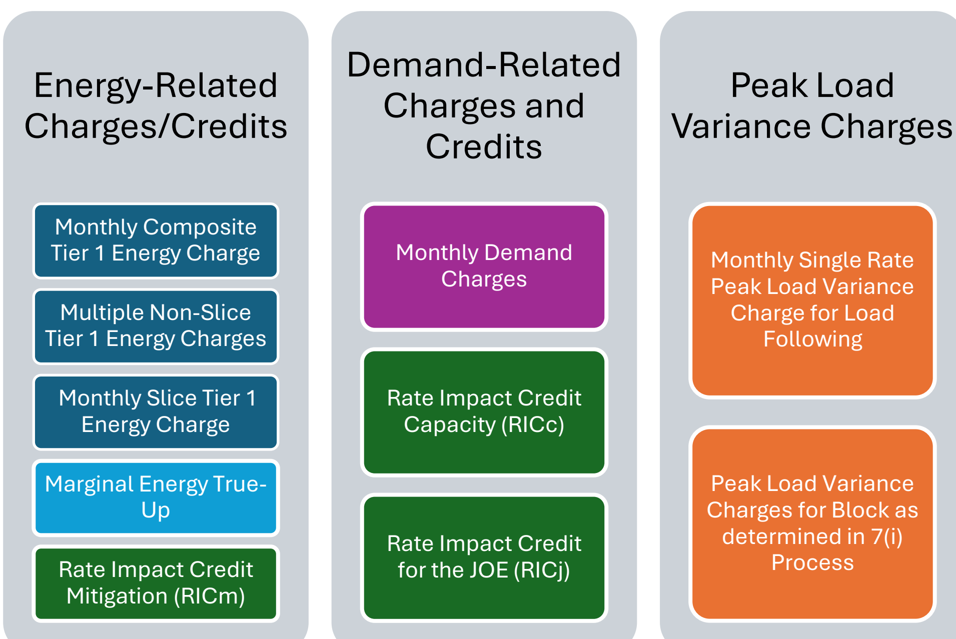
5 TIER 1 RATE DESIGN (PRDM CHAPTER 4)

5.1 Overview

Chapter 4 of the PRDM describes the four Core Rate Design charges and three credits that make up the Tier 1 Rate design. Reed *et al.*, PRDM-26-E-BPA-05, at 1. The four Core Rate Design charges that comprise the Tier 1 Rate design are: 1) Tier 1 Energy Charges, 2) Tier 1 Marginal Energy True-Up, 3) Tier 1 Demand Charges, and 4) Tier 1 Peak Load Variance Charges. *Id.* The Tier 1 Rate design also includes three Core Rate Design Rate Impact Credits: 1) the Rate Impact Credit for Capacity (RICc), 2) the Rate Impact Credit for Mitigation (RICm), and 3) the Rate Impact Credit for the Joint Operating Entity (JOE) (RICj). *Id.* These defined Core Rate Design elements of the Tier 1 Rate design are centrally important to the PRDM in that these elements: 1) recover the bulk of BPA's Power Revenue Requirement; 2) have the largest and most direct impact on customers in terms of costs, risks, and actionable price signals and 3) define the boundaries for what types of new charges and credits can be proposed in a 7(i) Process without triggering the PRDM revision process as described in PRDM Chapter 9. *Id.* at 1-2.

It should be noted that a single Core Rate Design charge can consist of multiple charges as defined in the PRDM or left for each 7(i) Process to define. *Id.* at 2. Also, simply because something is labeled a "charge" doesn't necessarily mean that this is money paid to BPA. *Id.* Charges can be negative and thus would result in a credit to a customer and a debit to BPA. *Id.*

The Core Rate Design elements fall into the following categories:



Together, the Core Rate Design charges and credits work to balance BPA's intent to send clear price signals that incentivize efficient consumption of finite resources, equitably allocate the value of the federal power system, convey cost-based capacity value inherent to the existing federal system, and transition from one rate design to another in a stable and predictable fashion. *Id.* at 4.

5.2 PRDM Tier 1 Core Rate Design Compared to TRM

The PRDM's Tier 1 Core Rate Design has many features that reflect the approach used in the TRM. Thus, for instance, both the TRM and PRDM charge for energy and capacity, and both convey a cost-based capacity value inherent to the existing federal system while offering some form of mitigation for rate design impacts from one methodology to another. *Id.* While the Core Rate Design elements of PRDM rely on a similar set of building blocks as the core elements of TRM, the Core Rate Design elements used in setting the Tier 1 rates in PRDM are different. *Id.* The core elements of the TRM included the Composite, Non-Slice, and Slice charges based on a percentage of firm federal system use, Load Shaping Charges for deviations in energy use from the shape of the firm federal system, and Demand Charges applied to a fractional portion of peak use above average HLH energy consumption. *Id.*

Under the PRDM, the Tier 1 Energy Charges include: Tier 1 Composite, Tier 1 Non-Slice, and Tier 1 Slice Energy Charges based on time-of-use energy consumption and denominated in kilowatthours, rather than a percentage of the firm federal system; the Tier 1 Marginal Energy True-up Charge to ensure a customer gets full access to the value of its CHWM and no more value than its load would support; a Tier 1 Peak Load Variance Charge used to collect the cost of holding capacity to meet load variability; and Tier 1 Demand Charges applied to the full amount of peak use above average monthly energy consumption. *Id.* at 4-5. The PRDM also establishes three Tier 1 rate mitigation credits: one to mitigate the move to charging for demand use based upon the entire difference in peak less average consumption at the long-run marginal cost of capacity, a second to re-calibrate the rate impact of the core design changes made in the PRDM relative to the TRM to be no more than a 2 percent impact at the start of the implementation of the PRDM, and third to mitigate the rate impacts attributed solely to changes to the Tier 1 Demand Charge calculations particular to the JOE from moving from the TRM to the PRDM. *Id.* at 5. The second and third mitigation credits will be phased out over time, while the first will apply—with potential recalculation—for the duration of the PRDM. *Id.*

5.3 Tier 1 Core Rate Design Components

5.3.1 Tier 1 Energy Charge (PRDM Section 4.1)

The Tier 1 Composite, Tier 1 Non-Slice, and Tier 1 Slice Energy Charges are the primary Tier 1 Energy Charges that collect the costs allocated to each of the respective cost pools as applied to Tier 1 Energy Billing Determinants. *Id.* The billing determinants for each are product-specific and are measurements of energy consumed (scheduled, measured, and

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take-or-pay) up to a customer's maximum Tier 1 purchase amount, *i.e.,* the customer's CHWM. *Id.* The Tier 1 Composite Energy Charges are applicable to Slice, Block, and Load Following Products offered to PF Public Customers with CHWM Contracts. *Id.* The Tier 1 Non-Slice Energy Charges are applicable to Block and Load Following Products. *Id.* The Tier 1 Slice Energy Charges are applicable to the Slice Product. *Id.* To aid in understandability, clarity, and intuitiveness, the Tier 1 Composite Energy Charges will be combined with the Tier 1 Non-Slice Energy Charges. Bleifuss *et al.,* PRDM-26-E-BPA-11, at 35.

The Tier 1 Energy Charges recover the remainder of BPA's Revenue Requirement associated with the cost to provide Tier 1 energy from the federal system that is not otherwise collected through the Tier 1 Demand Charge and Tier 1 Peak Load Variance Charge. Reed *et al.*, PRDM-26-E-BPA-05, at 6. And, as stated above, the Tier 1 Composite Energy Charges recover the net costs allocated to the Composite Cost Pool. *Id.* The Tier 1 Non-Slice Energy Charges recover the net costs allocated to the Non-Slice Cost Pool. *Id.* The Tier 1 Slice Energy Charges recover the net costs allocated to the Slice Cost Pool. *Id.; see also* PRDM Figure 2-1, Soup-to-Nuts Power Cost Allocation, for a comprehensive view of how BPA recovers its Revenue Requirement.

5.3.2 Tier 1 Marginal Energy True-Up Charge (PRDM Section 4.2)

The Tier 1 Marginal Energy True-Up Charge is a Tier 1 Energy Charge, or credit, applied at the end of the year to true-up differences between forecast and actual energy needs. Reed *et al.*, PRDM-26-E-BPA-05, at 7. Its purpose is to ensure a customer gets full access to the value of its CHWM and no more value than its load would support. *Id.* Absent the Tier 1 Marginal Energy True-Up Charge, a customer could end up paying Tier 1 Rates for power that, under a perfect forecast, should have been at rates applicable to Above-CHWM Load. *Id.* The Tier 1 Marginal Energy True-Up Charge also protects against the converse outcome and ensures that a customer does not pay rates applicable to Above-CHWM Load for power that, under a perfect forecast, should have been purchased at Tier 1 Rates. *Id.* It accomplishes this result by measuring the difference between a customer's forecast load and its actual load and compares that to its CHWM and Above-CHWM Load. *Id.* Any differences in need of true-up are charged, or credited, the difference between the rate the customer paid and the rate they should have paid as determined in each 7(i) Process.

In terms of cost recovery, because the need for the Tier 1 Marginal Energy True-Up Charge is the result of forecast error, it will always have a cost recovery expectation of zero. *Id.* The financial impact of the Tier 1 Marginal Energy True-Up Charge on BPA will be managed through BPA's financial reserves, risk adjustments, and the Slice True-Up. *Id.*

Mechanically, the Tier 1 Marginal Energy True-Up Charge is settled annually, at the end of the fiscal year. *Id.* at 8. If the charge is a credit, BPA will pay any amounts owed to the customer in a single bill credit in the first month following the determination of the final Tier 1 Marginal Energy True-Up Charge. *Id.* If the charge is a debit, it will be applied as a three-month charge spread equally across the three months following the month the final

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Tier 1 Marginal Energy True-Up Charge is determined by BPA. *Id.* Neither the credit nor the charge includes interest. This is consistent with how the Load Shaping Charge True-Up Adjustment works under TRM. *Id.*

5.3.3 Tier 1 Demand Charge (PRDM Section 4.3)

5.3.3.1 Overview

The Tier 1 Demand Charge collects revenue on a per-unit basis for the actual capacity used by a Load Following customer and the contractual capacity reserved by a Block customer. *Id.* This charge is aimed both at cost recovery and sending marginal price signals to incentivize economical use of the federal system's capability. *Id.* Because capacity use is not tiered like energy use, the Tier 1 Demand Charge is designed to recover the cost of growing capacity use from the customers causing that increased capacity draw from the federal system. *Id.* The Tier 1 Demand Charge does so by charging a long-run marginal cost for incremental capacity use. *Id.* By providing the necessary marginal price signal, the Tier 1 Demand Charge incentivizes economical behavior and encourages non-federal resource development to expand capacity infrastructure in the Northwest. *Id.* The Tier 1 Demand Charge is billed with a non-coincidental billing determinant to allow transparent and actionable price signal responses by customers as well as collect a relatively more conservative stream of revenue proportionate to capacity use. *Id.* This approach addresses inherent risk propositions between Load Following and Block Products. *Id.* at 8-9.

Unlike the Tier 1 Energy Charges that are designed to recover the costs allocated to each respective cost pool, the Tier 1 Demand Charge is not designed to recover the cost of a specific cost pool. *Id.* at 10. Rather, the size of the Tier 1 Demand Charge is calculated by multiplying the Tier 1 Demand Charge Billing Determinants by the long-run marginal cost of capacity. *Id.* The Tier 1 Demand Charge revenue is credited to the Non-Slice Cost Pool and effectively offsets the cost of the capacity that would otherwise be included in the Non-Slice Cost Pool and allocated to Tier 1 Energy Charges. *Id.*

5.3.3.2 Tier 1 Demand Billing Determinant

The Tier 1 Demand Charge uses a customer's non-coincidental peak for its billing determinant. *Id.* at 8. There are two primary ways of billing customers for generation-related demand: coincidental system peak (also called generation system peak) or non-coincidental system peak (also called customer system peak). *Id.* at 9. The difference between these methods goes to the timing and the measurement of that demand. *Id.*

Billing on the coincidental system peak means measuring a customer's demand at the same moment in time that *BPA's* generation system is peaking. *Id.* Thus, for instance, if BPA's generation fleet experienced its highest demand on July 8, 2024, at 2 p.m., the customer's Demand billing determinant would be whatever demand the customer was placing on BPA at that same moment in time. *Id.* This is called a coincidental billing determinant because it measures the customer's demand that occurred "coincident" with BPA's generation system peak. *Id.* Billing customers for demand on a coincidental billing determinant generally results in overall lower demand charges because customer specific peak usage will occur at times different from BPA's system peak. BPA used this method of measuring and billing demand prior to the adoption of the TRM. *Id.*

Billing on the non-coincidental system peak means measuring a customer's demand at the time of the *customer's* peak usage. *Id.* That is, the customer is billed for demand based on its highest power usage placed on BPA. *Id.* Returning to our example, assume that the customer's peak usage did not occur at the same time as BPA's generation system peak (July 8, 2024, at 2 p.m.), but occurred a week later on July 15, 2024, at 9 p.m. *Id.* In this instance, the customer would be charged for the demand it placed on BPA at the customer's peak usage (*e.g.,* its demand on July 15, 2024, at 9 p.m.). *Id.* at 9-10. This billing determinant is called a non-coincidental billing determinant because it measures the customer's demand at a time that is "not coincident" with BPA's generation system peak. *Id.* at 10. Billing on the customer's non-coincidental peak generally results in larger Demand Charge Billing Determinant (and thus higher overall demand charges to customers). *Id.*

The PRDM uses non-coincidental peak for the billing determinant of the Tier 1 Demand Charge for several reasons. First, it increases the probability that a customer could successfully respond to the price signal as it is easier for a customer to predict its own peak needs as compared to trying to predict when the coincidental peak needs of the federal system will occur. *Id.* By charging demand at the customer level, it creates a more transparent and an easier-to-predict price signal that can be directly mitigated by the investment in non-federal resources and conservation or demand-response programs at the customer level. *Id.* at 11.

Additionally, billing on non-coincidental peak was a chosen tradeoff between better cost causation, which ties closer to demand use during the coincidental peak, and a stronger economic incentive to invest in peak demand reductions. *Id.* at 10. That is, by charging demand based on a customer's non-coincidental peak usage, it ensures a more conservative, *e.g.*, larger, revenue stream sourced from Load Following customers because it does not factor in BPA's aggregate load diversity benefits that reduce its overall capacity obligations for Load Following customers. *Id.* at 11. This more conservative design was selected to balance the inherent risk propositions underlying the Load Following and Block Products. *Id.* Said differently, the load service for Load Following and Block Products may place different risks on BPA, yet the PRDM explicitly prohibits disaggregating this risk across these products prior to September 30, 2041, at which point any such disaggregation of risk would be decided through a 7(i) Process. *Id.* Therefore, instead of attempting to disaggregate this risk, the PRDM selected a larger billing determinant for measuring capacity use for Load Following customers to offset some of the additional risks BPA takes on with fully following a load (Load Following) relative to a planned product (Block). *Id.* at 11-12.

5.3.3.3 PRDM Tier 1 Demand Charge Compared to TRM

The PRDM Tier 1 Demand Charge is built similarly to the demand charge used under the TRM with three important differences. Two are mentioned in this section. The third warrants its own section and will be discussed in Section 5.3.3.4 of this ROD.

The first major difference is the billing determinant. Reed *et al.*, PRDM-26-E-BPA-05, at 12. Specifically, the Tier 1 Demand Charge Billing Determinant has changed from peak minus average Heavy Load Hour energy (in TRM), to peak minus average monthly energy (in PRDM). *Id.*

The second major difference relates to the removal of Contract Demand Quantities (CDQs). *Id.* at 13. The TRM's Tier 1 Demand Charge Billing Determinant included a fixed reduction within the calculation called a CDQ. *Id.* The CDQ was used for three rate mitigation purposes, the same as the PRDM's RICc, RICm and RICj, but did so in a single value. *Id.* The three purposes are to: 1) account that existing capacity use should not be charged at the marginal cost of capacity, 2) limit overall rate impacts caused by changing BPA's core rate design, and, as explained more fully below, 3) remove the impact of billing the JOE on a single peak as compared to billing each JOE member separately. *Id.* The purpose of the CDQ was reasonable and prudent but its implementation left room for improvement in the PRDM. *Id.* Therefore, rather than combining these three purposes into a single adjuster and implementing it through a reduction in the Tier 1 Demand Charge Billing Determinant, the PRDM separated these purposes, addressed them explicitly, and implemented them as their own standalone adjustments. *Id.* The PRDM's implementation adds transparency to the purpose of these adjustments and leaves a pure Tier 1 Demand Charge Billing Determinant that should serve its intended purpose of sending appropriate price signals. *Id.*

5.3.3.4 Tier 1 Demand Charges for a Joint Operating Entity (JOE)

The third major difference between demand charges under the TRM and the PRDM relates to the treatment of a JOE buying power from BPA. A JOE is an entity that is lawfully organized under state law as a public body or cooperative prior to the date of the enactment of Section 5(b)(7) of the Act and is formed by and whose members or participants are two or more public bodies or cooperatives, each of which was a customer of the BPA on or before January 1, 1999. The statutory requirements for selling to a JOE are set forth in Section 5(b)(7) (16 U.S.C. § 839c(b)(7)) of the Act. If these conditions are met, BPA is authorized to sell power to a JOE for service to meet its members' requirements. Reed *et al.*, PRDM-26-E-BPA-05, at 13-14.

TRM Treatment

Under the TRM, and only for the purpose of calculating the demand charge, the JOE was treated as a single customer, with a combined, aggregate non-coincidental peak across its member utilities for demand. *Id.* at 14. This was not the case for any other rate design element under the TRM. *Id.* This meant BPA billed the JOE based on the JOE's collective peak, rather than the peak of each of its individual members. *Id.* To use a simple example that ignores the imperfectly offsetting impacts of the CDQs, assume the JOE has three members, and these members have the following loads over a three-hour period (see Table 1).

Table 1

Member	Hour 1	Hour 2	Hour 3	Non-Coincidental Member Peak
Member A	45 MW	50 MW	55 MW	55 MW
Member B	50 MW	40 MW	35 MW	50 MW
Member C	60 MW	80 MW	75 MW	80 MW
Total	155 MW	170 MW	165 MW	**185 MW**
Coincidental Member Peak		**170 MW**		

Collectively, the JOE's peak (the highest demand in an hour) occurred at Hour 2, at 170 MW. Individually, though, the JOE's member's peak occurred at different times. *Id.* Member A's peak was at Hour 3 (55 MW); Member B's peak occurred at Hour 1 (50 MW), and Member C's peak was at Hour 2 (80 MW). *Id.* Had BPA assessed the JOE a Tier 1 Demand Charge based on its member's individual peak demand, the Tier 1 Demand Charges would have been higher (185 MW as opposed to 170 MW). *Id.* Using the JOE's peak as opposed to its members' peak allowed the JOE to receive a lower Tier 1 Demand Charge because its members' peak demand did not occur at the same time. *Id.* at 14-15. Under the TRM, this favorable billing treatment was imperfectly offset by a reduction in the JOE's CDQ. *Id.* at 15.

PRDM Treatment

Consistent with the removal of the CDQ, the PRDM removes the exception under TRM that allowed JOEs to pool member system peaks for a single, coincident Tier 1 Demand Charge billing determinant for the JOE. *Id.* Thus, returning to our example above, the PRDM will bill the JOE for demand based on the members' peak (185 MW) rather than the JOE's peak (170 MW). *Id.* The reasons for removing this treatment are multi-faceted, and will be discussed in greater detail in the Issues section below, but a key consideration in this change is that the JOE's aggregation of its members' load results in no appreciable operational reduction in the capacity BPA must hold for load service that can be attributed to the nature of a JOE or its business relationship to individual members. *Id.* Absent an appreciable operational reduction in capacity attributed to the nature of a JOE, this exception would represent a cost shift from the JOE to other BPA customers. *Id.* In simple terms, from a planning standpoint, BPA must set aside the same quantity of capacity for

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load service to the JOE members' demand whether the JOE exists or not. *Id.* BPA recognized that this is a change from TRM, and thus, proposed a specific rate credit for the JOE to partially mitigate this transition to PRDM. *See* PRDM § 4.5.3; Reed *et al.*, PRDM-26-E-BPA-05, at 22.

5.3.3.5 Issues

The Pacific Northwest Generating Cooperative (PNGC) is the only JOE currently purchasing power from BPA under Section 5(b)(7) of the Northwest Power Act. PNGC is comprised of twenty-five utilities, located throughout the Pacific Northwest region. *See* Bleifuss *et al.*, PRDM-26-E-BPA-11, at 27. PNGC opposes the PRDM's method for calculating demand charges for a JOE. *See* PNGC Br., PRDM-26-B-PN-01, at 1-13. This section addresses PNGC's issues related to the PRDM's treatment of a JOE for purposes of calculating the demand charge. Issue 5.4.3.2.1, below, addresses PNGC's concerns with the Rate Impact Credit for the JOE (RICj) that the PRDM includes to mitigate the transition from the TRM to PRDM.

Issue 5.3.3.5.1
Whether BPA is required by the Northwest Power Act to aggregate the load of a JOE's members for purposes of assessing demand charges under the PRDM.

Party's Positions

PNGC contends that "federal law as well as BPA's implementation and practices" support PNGC's position that a JOE is a statutory preference customer with "unique rights to aggregate loads and resources of its individual JOE members . . . ." PNGC Br., PRDM-26-B-PN-01, at 2. PNGC requests BPA to "affirm its legal rights to aggregate loads and resources of its members." *Id.* at 7.[28]

BPA Staff's Position

This is a legal issue, which BPA Staff did not address. *See* Bleifuss *et al.*, PRDM-26-E-BPA-11, at 22 (noting they "will not opine on the legal merits of this portion of PNGC's argument.").

Evaluation of Positions

As described in detail above in Section 5.3.3.4 of this Draft ROD, under the PRDM, the demand charges for a JOE will be assessed based on each individual member's demand on BPA, rather than the collective aggregated demand of the entire JOE. BPA chose this

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[28] Throughout its initial brief, PNGC requests the "Hearing officer acknowledge BPA's statutory duty . . . ." *E.g.*, PNGC Br., PRDM-26-B-PN-01, at 7. BPA has taken these references to mean the Administrator. *See* Rules of Procedure, § 1010.17(b)("The purpose of an initial brief is to identify separately each legal, factual, and policy issue to be resolved **by the Administrator** and present all arguments in support of a Party's position on each of these issues.") (Emphasis added).

approach because the cost of serving a JOE's member's demand is not reduced simply because the member's power sales agreement is being administered by a JOE. *Id.*

PNGC contends that BPA is required by law to aggregate a JOE's demand and bill them for demand as a "single preference power customer." PNGC Br., PRDM-26-B-PN-01, at 4. PNGC claims this treatment is afforded to it as a consequence of its "statutory status as a [JOE] under federal law, 16 U.S.C. § 839c(b)(7) . . . ." *Id.* at 1. PNGC argues that BPA's decision in the PRDM to charge demand to PNGC based on each members' demand (rather than the aggregated demand of PNGC) is "contrary to the statutory goals of aggregation that the JOE was created for in the first place." *Id.* PNGC maintains that "federal law as well as BPA's implementation and practices, all support PNGC's position that a JOE is a statutory preference power customer of BPA with purposefully unique rights to aggregate loads and resources of its individual JOE members, who themselves are long-standing preference power customers of BPA." *Id.* at 2. PNGC comments that there "have been no changes of law that would justify the divergent course of action and treatment of a JOE that BPA staff have proposed in this proceeding." *Id.* at 7.

BPA disagrees that, as a matter of law, BPA must treat a JOE's members' load (and hence PNGC) as an aggregate load for purposes of developing rates and demand charges in the PRDM. The basis for PNGC's argument is Section 5(b)(7) of the Northwest Power Act. It reads as follows:

> (A). DEFINITION OF A JOINT OPERATING ENTITY—In this section, the term 'joint operating entity' means an entity that is lawfully organized under State law as a public body or cooperative prior to the date of enactment of this paragraph, and is formed by and whose members or participants are two or more public bodies or cooperatives, each of which was a customer of the Bonneville Power Administration on or before January 1, 1999.
>
> (B). SALE—Pursuant to paragraph (1), the Administrator shall sell, at wholesale to a joint operating entity, electric power solely for the purpose of meeting the regional firm power consumer loads of regional public bodies and cooperatives that are members of or participants in the joint operating entity.
>
> (C). NO RESALE—A public body or cooperative to which a joint operating entity sells electric power under subparagraph (B) shall not resell that power except to retail customers of the public body or cooperative or to another regional member or participant of the same joint operating entity, or except as otherwise permitted by law.

16 U.S.C. § 839c(b)(7)(A)-(C).

For purposes of this discussion, the only operative term is subsection (B). There, Congress provided that BPA "shall sell" wholesale power to a JOE "solely for the purpose of meeting the regional firm power consumer loads" of the members of a JOE. 16 U.S.C.

§ 839c(b)(7)(B). In simple terms, Section 5(b)(7)(B) directs BPA to *sell power* to a JOE to meet "the regional firm power consumer loads" of a JOE's members. Importantly, Section 5(b)(7) is entirely silent on how BPA must set rates for service to a JOE.

To determine what rate applies, BPA must look at other statutory provisions. Section 5(a) of the Northwest Power Act says that sales of power under Section 5(b) (inclusive of sales to a JOE under Section 5(b)(7)) are at "rates established pursuant to section [7]." 16 U.S.C. § 839c(a). Turning to Section 7—the rates provision of the Northwest Power Act—there are no special rate provisions or directives that apply to power sold to a JOE. *See* 16 U.S.C. § 839e(a) *et seq*. Section 7(b) provides that BPA must establish a "rate or rates of general application for electric power to meet the general requirements" of BPA's public customers and that those rates must "recover the costs of that portion of the Federal base system resources needed to supply such loads . . . ." 16 U.S.C. § 839e(b)(1). Beyond requiring BPA to set rates for the "general requirements" of its customers, which would include the JOE, BPA is given no special instruction in Section 7(b) on how to develop its rates—Tier 1 Demand Rates or *any* other rates—for a JOE.

Given that there are no specific rate directives applicable to sales of power to a JOE, BPA's determination of the appropriate rate treatment for such sales is governed by the directives in Section 7(b) and the rate design discretion afforded BPA in Section 7(e). *See* 16 U.S.C. § 839e(e). Section 7(e) provides that "[n]othing in this chapter prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal rates, or other rate forms." *Id.* The Courts have viewed Section 7(e) as giving BPA a wide degree of flexibility to establish rates and rate forms. *City of Seattle v. Johnson,* 813 F.2d 1364, 1367 (9th Cir. 1987) (noting BPA's ratemaking discretion is only limited by "sound business principles."). This discretion extends specifically to the design of demand charges. *Cent. Lincoln Peoples' Util. Dist. v. Johnson,* 735 F.2d 1101, 1124 (9th Cir. 1984) (affirming BPA decision to include Saturday as peak for demand charge and noting that section 7(e) "contains neither a blanket prohibition nor a blanket authorization for equalization of demand charges in all circumstances.").

In summary, and contrary to PNGC's claims, the Northwest Power Act does *not* direct that BPA "aggregate" a JOE's members' loads for purposes of establishing its rates under Section 7. BPA has discretion under Section 7 to determine the appropriate rate treatment for a JOE and its members, which, as explained in Issue 5.3.3.5.2, BPA has done in the PRDM. That discretion was in no way constrained by the addition of Section 5(b)(7) to the Northwest Power Act.

PNGC next argues that Section 5(b)(7) places on BPA the obligation to treat a JOE as "a single customer" that has "an obligation to meet the regional firm power needs of certain existing preference power customers of BPA existing as of January 1, 1999." PNGC Br., PRDM-26-B-PN-01, at 3. PNGC claims it is a "single preference power customer of BPA," acting on behalf of its preference distribution cooperative members. *Id.* at 4. PNGC warns that the "two should not be conflated nor should the importance of the 'single preference customer' be dismissed as unimportant." *Id.* PNGC contends it is a "generation and transmission (G&T) cooperative" and these entities "aggregate distribution cooperative members' retail load and serve those loads through least cost resource acquisitions and transmission services as one." *Id.* at 3.

The import of PNGC's description of itself as a "single customer" or "G&T" is not entirely clear to BPA. What PNGC appears to be claiming is that once an entity has been determined by the Administrator to be a JOE, BPA can no longer take into account the individual members' loads in determining its rates but must approach the JOE as if it is only one customer, with a single aggregated load.

If that is what PNGC is asserting, BPA cannot agree. The presence of a JOE does not change the nature of BPA's obligation to serve the individual members' loads of that JOE. Section 5(b)(7) makes clear that a JOE's right to BPA's power is derivative—not independent—from its members' rights to power from BPA. A JOE is not itself an entity eligible to request and receive a firm power sales contract pursuant to the Act without underlying members that were customers of BPA on or before January 1, 1999. Therefore, a JOE has no rights to BPA power that are different from its members' rights. This is clear from the language of Section 5(b)(7)(B): "the Administrator shall sell, at wholesale to a joint operating entity, electric power solely for the purpose of meeting the regional firm power consumer loads of regional public bodies and cooperatives that are members of or participants in the joint operating entity." 16 U.S.C. § 839c(b)(7). On this point, PNGC appears to agree: the JOE legislation "does not enable *more* sales than the individual preference customers could obtain on their own, nor does it permit sales to entities outside the established membership of the JOE." PNGC Br., PRDM-26-B-PN-01, at 3. In short, the statute does not contemplate BPA ignoring the existence of the members of a JOE once a JOE is formed. Far from it. Section 5(b)(7)(B) fully appreciates that a JOE is entitled to no greater rights than would otherwise be afforded to each individual member. In the same way, BPA is not affording to a JOE under the PRDM any greater rate treatment under Section 7 than if its members contracted directly with BPA. If a JOE's members had individual contracts with BPA, they would be charged for demand the same way under the PRDM.

Moving beyond the plain language of Section 5(b)(7) and Section 7, PNGC contends that BPA's treatment of a JOE in the PRDM violates the purpose of the JOE provision. Specifically, PNGC argues that "aggregation and co-optimization of loads and resources is the reason JOEs like PNGC exist and may be developed in the future." *Id.* at 2. PNGC claims that Section 5(b)(7) was intended to give them the "unique rights" to aggregate their load and receive a load diversity benefit and the treatment provided in the PRDM "weaken[s] the ability of a JOE to fulfill its mission . . . ." *Id.* at 2, 4, 7. PNGC asserts that not allowing PNGC to aggregate its load "prevents PNGC and its members[] from fulfilling Congress' intent for a JOE like PNGC, . . ." *id*. at 4, and "cause[s] financial harm to PNGC's members . . . in contravention of the JOE statute." *Id.* at 6.

PNGC's conclusions are unsupported by law. Nothing in the statutory language and its plain meaning supports this interpretation. There is no mention of aggregation, co-optimization, or rate treatment in the JOE language. Thus, PNGC's argument fails based on the language itself.

Indeed, the legislative history of Section 5(b)(7) confirms that this provision was never intended to give a JOE a rate benefit. The House Report on the JOE legislation makes clear that the purpose of Section 5(b)(7) was to provide *administrative* and *operational* efficiencies when purchasing power from BPA. H.R. Rep. No. 106-820 (Sept. 6, 2000) ("The purpose is to provide administrative and operational efficiencies for the power purchasers and for the BPA."). To that end, the benefits of a JOE come in the form of contract administration benefits: reduced scheduling costs, fewer staff because of consolidated billing, and general efficiencies through "economies of scale." Hearing Before the Subcommittee on Energy and Power of the Committee on Commerce, House of Representatives, Serial No. 106-106, at 91-93 (Mar. 30, 2000) (statement of PNGC CEO, David Piper).

The legislative history is also clear that a JOE was *not* to be given unique rights or special treatment in rates. During hearings on the JOE legislation, PNGC's CEO[29] expressly *denied* the bill would provide a JOE any rate advantage, noting "each BPA customer is separately metered and is billed based on its load during the hour of the BPA system peak. As a consequence, S.1937 [the JOE bill] does not provide an ability to capture additional 'diversity' benefits because the power usage and consequent charges do not change as a result of operating under a single contract." *Id.* at 92 (statement of PNGC CEO, David Piper).

The statement from PNGC's CEO comports with the general theme of the testimony and comments made during the hearing on the JOE bill, which universally emphasize that the JOE legislation would not result in "costs shifts" to other BPA customers and was a narrowly tailored piece of legislation designed to deal with a specific contracting issue. *Id.* at 12 ("This legislation is very, very narrow in scope.") (statement of Rep. Peter DiFazio), 35 (a JOE may "reduce. . . overhead", but would not "increase[ ] costs for BPA's other regional customers.") (statement of Allen Burns, BPA VP of Requirements Marketing), 117-18 (Oregon Utility Resource Coordination Association stating that a JOE would not impact other customer groups' supply or cost), 119-20 (a JOE would provide "administrative savings" and not harm other customers; it may also provide a "diversity benefit" but this depends on "the design of BPA rates.") (statement of Idaho Energy Authority), 160 (JOE legislation would be unlikely and is not intended to result in "cost shifts" among customers) (statement of Northwest Power Planning and Conservation Council), 183-84 (a JOE would make scheduling and billing easier, and allow centralized contracting; JOE legislation "does **not** provide the ability to capture additional 'diversity' benefits in terms of combining individual system loads for the purpose of purchasing less power from the agency. The power usage and consequent charges do not change as a result of operating under a single contract.") (statement of PNGC CEO, David Piper) (emphasis added).

[29] PNGC was the primary sponsor and proponent of the JOE bill.

The PRDM's treatment of a JOE for demand charges expressly *avoids* cost shifts among BPA's customers and, consequently, is directly in line with the plain meaning of the statute and the function of a JOE as described by the sponsors and proponents of the JOE legislation. *See* Bleifuss *et al.*, PRDM-26-E-BPA-11, at 28 ("Simply put, the presence of the JOE does not reduce the costs BPA incurs to serve the JOE's individual members and changing the billing determinant for demand to assume it does results in a cost shift from PNGC to other customers.").

PNGC also makes passing claims that BPA has previously accepted PNGC's position that Section 5(b)(7) *legally* required aggregating PNGC's load for purposes of demand. PNGC Br., PRDM-26-B-PN-01, at 2 ("BPA's implementation and practices[] all support PNGC's position that a JOE is a statutory preference power customer of BPA with purposefully unique rights to aggregate loads and resources of its individual JOE members . . . ."); *id.* at 4 (noting the PRDM's approach "ignores current and past practice implemented by BPA, and is completely unnecessary.").

That is incorrect. While BPA's current treatment for PNGC under the TRM is to aggregate its load for purposes of the demand charge, that treatment occurred "as a result of compromise and negotiation—not because BPA thought it had to comply with statute." Bleifuss *et al.*, PRDM-26-E-BPA-11, at 23. Indeed, originally under the TRM, BPA intended to treat the "individual utilities in a JOE separately for all aspects of the TRM," which would have included demand charges. Reed *et al.*, PRDM-26-E-BPA-05, at 16 (*citing* Cherry *et al*., TRM-12-E-BPA-10, at 3 9 (July 2008)). That is, BPA initially intended to do under the TRM exactly what BPA is proposing to do under the PRDM: charge a JOE based on its members' individual demand. Ultimately, the decision to aggregate a JOE's demand signals under the TRM came with other counterbalances (such as an aggregate CDQ for a JOE that is smaller than the sum of each member's CDQ), which, on the whole, were "intended to place the JOE in roughly the same position as other customers." Reed *et al.*, PRDM-26-E-BPA-05, at 16.

The PRDM is a new methodology, and with that new methodology, BPA has an opportunity to design the appropriate rate treatment for customers charged under its terms. Nothing in the Northwest Power Act precludes BPA from considering the individual members of a JOE for purposes of the demand charge rate under that methodology. The issue here involves how to recover the costs of providing service to BPA's customers, which is not addressed by Section 5(b)(7). To this point, PNGC ultimately agrees with BPA, admitting that "[i]n the context of PRDM, the issue of aggregation of loads and resources becomes one of rate design and cost allocation." PNGC Br., PRDM-26-B-PN-01, at 4. BPA agrees. BPA addresses below whether the treatment proposed in the PRDM is reasonable as a matter of rate design and cost allocation. Here, though, there can be little question that the PRDM approach is not faulty as a matter of law, and PNGC's contention to the contrary is incorrect.

Draft Decision

Both the JOE statutory language and legislative history support BPA's interpretation. BPA is not required by the Northwest Power Act to aggregate the load of a JOE's members for purposes of assessing demand charges under the PRDM. BPA may use its rate discretion to determine the appropriate treatment for a JOE under the PRDM.

Issue 5.3.3.5.2
Whether the PRDM's approach to charging a JOE demand charges based on its individual members' demand is consistent with sound business principles.

Party's Positions

PNGC contends BPA's proposal in the PRDM to charge a JOE based on its individual members' loads is "inequitable" and "unnecessary." PNGC Br., PRDM-26-B-PN-01, at 1, 4. PNGC argues that aggregating PNGC's member's loads does not cost more to BPA to serve, and that disaggregating PNGC's load provides "no direct financial benefit to BPA." *Id.* 6-7. PNGC claims that BPA's proposal is not consistent with cost causation or ratemaking principles. *Id.* at 4-5. PNGC also raises a number of policy arguments, among which PNGC contends that maintaining the current aggregation of PNGC's loads will promote resource development and reduce BPA's need to acquire resources to meet its customers' loads. *Id.* at 5-6, 7.

BPA Staff's Position

There is no operational reduction in the capacity BPA must hold for load served through a JOE. Reed *et al.*, PRDM-26-E-BPA-05, at 15. Thus, BPA's proposal for charging demand based on PNGC's members' loads is consistent with cost causation and sound business principles. Bleifuss *et al.*, PRDM-26-E-BPA-11, at 27-28. The presence of a JOE does not reduce the costs BPA incurs to serve a JOE's individual members and changing the billing determinant for demand to assume it does results in a cost shift from PNGC to other customers. *Id.* at 28.

Evaluation of Positions

As noted above in Issue 5.3.3.5.1, there is no legal requirement that BPA aggregate the load of a JOE when determining how to develop demand charges in the PRDM pursuant to Section 7 of the Northwest Power Act. BPA's discretion to design rates for demand in the PRDM is, then, guided by Section 7(e), which is only limited by "sound business principles." *City of Seattle v. Johnson,* 813 F.2d 1364, 1367 (9th Cir. 1987) (noting BPA's ratemaking discretion is only limited by "sound business principles.").

Following these principles, BPA designed the PRDM to apply demand charges to a JOE coincident with each of its members' peaks. Returning to the hypothetical example provided in Section 5.3.3.4 of this Draft ROD, BPA's proposal is to charge a JOE based on the collective total of its individual members' peaks (185 MW) rather than a lower netted aggregated total of a JOE as single entity (170 MW).

PNGC argues that BPA's proposal is "inequitable" and "unnecessary." PNGC Br., PRDM-26-B-PN-01, at 1, 4. PNGC claims that BPA's proposal is "subjective and discriminatory" and serves "only to harm PNGC" and provides "no direct financial benefit to BPA." PNGC Br., PRDM-26-B-PN-01, at 6-7. PNGC argues that, while BPA claims PNGC's aggregation saves BPA no money, the "converse to this argument" is also true, namely, that PNGC does not impose incremental cost upon BPA through the aggregation of its members' load. *Id.* at 4.

PNGC's argument fails to address the facts established in the record that BPA's costs of serving a JOE's members are **not** reduced simply because they are all served through a single contract. As BPA explained in its direct case, there is "no appreciable operational reduction in the capacity BPA must hold for load service that can be attributed to the nature of a JOE or its business relationship to individual members." Reed *et al.*, PRDM-26-E-BPA-05, at 15. That is, "[f]rom a planning standpoint, BPA must set aside the same quantity of capacity for load service to the JOE members" regardless of whether a JOE exists or not. *Id.*

With this understanding of BPA's power service obligation, BPA's reasoning for its demand charges in the PRDM becomes clear. The PRDM's demand charge is designed to recover the cost of meeting the demand for all its customers, including each individual member or participant that is served through a JOE. To apply a different cost recovery mechanism (the Demand Billing Determinant) for a JOE, when BPA's costs are in no way reduced by a customer joining a JOE, would create an inequitable cost shift from utilities that are part of a JOE to utilities that are not. This treatment is in no way "discriminatory" because it is the same treatment provided to every other customer under the PRDM. Reed *et al.*, PRDM-26-E-BPA-05, at 8 ("The Tier 1 Demand Charge is billed with a non-coincidental billing determinant to allow transparent and actionable price signal responses by customers as well as collect a relatively more conservative stream of revenue proportionate to capacity use."). All other customers under the PRDM will be charged based on each individual utility's peak demand in a month. *Id.* at 11 ("This charge [*i.e.,* demand charge] is evaluated for each customer on an individual, non-coincidental basis."). This method of billing is called "non-coincidental peak" billing because it charges based on the *utility's* peak usage during a month rather than *BPA's* peak usage. *See id.* at 9 (describing difference between coincidental and non-coincidental peaks). BPA chose the "non-coincidental" billing practice because it was a "chosen tradeoff between better cost causation, which ties closer to demand use during the coincidental peak, and a stronger economic incentive to make an investment to reduce peak demand." *Id.* at 10.

Assessing demand based on a JOE's non-coincidental peak rather than its individual members' non-coincidental peak would create a fiction that the cost of serving a JOE's member is in some way reduced by joining a JOE. As BPA Staff explained in the record, no such cost reduction occurs. *Id.* at 15. Perpetuating this fiction in the PRDM would distort price signals, as members of a JOE would be shielded from paying demand charges commensurate with the costs of the service BPA is providing them. These costs must ultimately be recovered from other customers, which means PNGC's proposal would "impose a direct cost shift among customers with no causation associated with it." *Id.*

PNGC nonetheless contends that allowing them to aggregate their load for purposes of demand charges does not result in a windfall to their members. PNGC Br., PRDM-26-B-PN-01, at 2. In fact, PNGC seems to assert that BPA is taking away a benefit that PNGC believes it is providing BPA and its customers today. PNGC asserts BPA is seeking to "absorb and redistribute the diversity benefit of a subset of customers legally working together as one to the system as a whole, without acknowledging the risks and investments that PNGC members have undertaken . . . ." *Id.* 4-5. PNGC claims BPA is attempting to "allocate the load diversity benefit associated with the aggregated JOE members to all BPA customers rather than allowing JOE members to maintain them to be distributed among themselves." *Id.* at 5; *see also id.* at 7 ("BPA is seeking instead to ensure that the JOE does not benefit from load aggregation as it does today and is choosing instead to socialize the load diversity benefit of JOE members to all BPA preference customers and thus creating a cost shift to PNGC members.").

PNGC's argument is both incorrect and, importantly, unsupported by the record. Nothing in the record establishes that serving a JOE's members under a single contract results in a load "diversity benefit" that reduces BPA's costs of serving the collective needs of a JOE's members. BPA's witnesses in the case addressed this point directly. BPA Staff explained that PNGC's comparison of itself to a regular utility with an aggregated and diverse retail load base was unfounded. For one, PNGC has no "retail load." Bleifuss *et al.*, PRDM-26-E-BPA-11, at 27. This is even stated in PNGC's power sales contract with BPA: "PNGC does not directly serve retail load." *Id.* at 27, *citing* PNGC's Regional Dialogue Contract § 2.79. PNGC's *members* have retail customers, but those retail customers are the responsibility of the individual members. *Id.* The aggregation that PNGC provides is at the wholesale contract level and, as such, its aggregation is a "contractual aggregation, or aggregation on paper." *Id.*

This "paper aggregation" does not reduce BPA's cost of serving PNGC's members, and it is difficult to see how PNGC could conclude otherwise. Holding a contract for service to multiple independent utilities located throughout the Pacific Northwest does not result in reduced costs or loads on BPA. As Staff explained:

> As we understand the facts, by the time the PRDM becomes operative (October 2028), PNGC is expected to hold a contract with BPA for service to 25 utilities, each with its own unique load profile and characteristics. These utilities will be geographically separated into six states (Oregon, Washington, Idaho, Montana, Nevada, Utah), and separated by as much as 700 miles (compare Orcas Power and Light Cooperative (near Bellingham, Washington) to Raft River Rural Electric Cooperative (Utah). The utilities' topography will also be very different, with some located on islands in the Pacific Ocean, while others are situated in the high desert. Their weather will be different, their geography

> will be different, their retail consumers will be different, and, ultimately, their peak loads will be different. These unique attributes are not changed because PNGC holds their contract or because they receive one bill. **<u>BPA must prepare to meet each of these customers' requirements, and the fact they are members of a JOE does not reduce BPA's costs or responsibilities.</u>**

Bleifuss *et al.*, PRDM-26-E-BPA-11, at 27-28 (emphasis added, internal citation omitted).

PNGC contends that Staff's proposal "defies traditional cost causation principles that underlie sound ratemaking principles . . . ." PNGC Br., PRDM-26-B-PN-01, at 4. To the contrary, BPA's proposal directly links to cost causation and sound ratemaking principles by charging PNGC what it costs BPA to serve its members' loads, as it does for every other Public Customer. Indeed, ultimately what PNGC is asking for under the PRDM is a special rate treatment that does not apply to any other customer and that does not reflect the costs of serving its members' loads. Bleifuss *et al.*, PRDM-26-E-BPA-11, at 28. BPA does not agree it is reasonable or consistent with sound business principles to give PNGC a reduced billing determinant based on a "paper" diversity benefit that neither reduces the capacity obligations put on BPA by PNGC member loads nor results from any PNGC-specific action taken. *Id.* Simply put, the presence of a JOE does not reduce the costs BPA incurs to serve a JOE's individual members and changing the Demand Billing Determinant to assume it does results in a cost shift from PNGC to other customers. *Id.*

This last point must be emphasized. If BPA were to acquiesce to PNGC's request and charge it *less* for the demand, the result would be a "cost shift" among BPA's customers. BPA does not operate for profit. All of its costs must be recovered in its rates. *See* 16 U.S.C. § 839e(a)(1). If a cost is not recovered from one customer or class of customers, it must be recovered from another. A "cost shift" would occur under PNGC's request because the dollars not collected from PNGC and its members' demand charge would be recovered from the rates assessed to other Public Customers. Reed *et al.*, PRDM-26-E-BPA-05, at 24. BPA's rates are a zero-sum game; if one customer's rate goes down, another customer's rate must go up.

PNGC next raises a number of policy arguments in support of its position. PNGC claims that by allowing PNGC to aggregate its load, it will enable PNGC to acquire more non-federal resources, which will reduce the costs of BPA's Tier 2 rates. PNGC Br., PRDM-26-B-PN-01, at 5. According to PNGC, investing in new resources will result in a "benefit to all BPA customers" because it "decrease[s] BPA's obligations to serve all of preference customers future load growth, thereby reducing risk to both BPA and other preference customers." *Id.* at 11. PNGC provides an example of how it recently procured a resource to serve its member's Tier 2 load and that this acquisition was a "direct benefit" for all BPA preference customers, as it alleviated the need for BPA to acquire resources in BP-26 to meet preference load, thereby resulting in an overall lower cost of Tier 2 power than would have been the case absent action by PNGC. *Id.* at 5.

BPA agrees that customers should develop, own, operate, or purchase non-federal resources to meet their future needs during the period of the Provider of Choice power sales contract and the PRDM. Indeed, creating these incentives, i.e., price signals and/or tiered rates that recover costs that may be higher than another tiered rate, was one of the primary principles underlying the PRDM's terms. *See* Fisher *et al.*, PRDM-26-E-BPA-02, at 15 ("The PRDM is built from the same principles and objectives that underlie the TRM. As we noted above, those . . . incentivize customers to develop their own resources for load growth . . . ."). Ensuring that those incentives apply equally to all customers in a fair and reasonable manner is also important. Under BPA's proposal, customers will have an incentive to acquire resources of their own to avoid demand charges or to invest in demand-side infrastructure to reduce their exposure to demand costs. *See* Reed *et al.*, PRDM-26-E-BPA-05, at 11 ("One [of the policy goals of the Demand Charge Billing Determinant] is to establish a transparent and easier to predict price signal that can be directly mitigated by the investment in non-federal resources and/or conservation programs at the customer level."). Those policy goals would be undermined if PNGC's approach were adopted.

PNGC also contends that by allowing it to aggregate its load for purposes of the demand charge, PNGC lowers BPA's overall power obligation through resource development. PNGC contends that resource development is a "heavy lift" for small preference customers of BPA to do alone and, "to be successful, requires the aggregation of loads and resources that only a JOE can provide under the Northwest Power Act." PNGC Br., PRDM-26-B-PN-01, at 5-6. PNGC also claims that there is "no need to implement rate designs and policies that financially harm and handicap PNGC by trying to disallow the ability of a JOE to efficiently optimize loads [and] resources among our JOE members." *Id.* at 7; *see also id.* at 6.

BPA does not see how charging PNGC the true costs for demand harms PNGC's ability to acquire resources to meet its customers' growing loads. All customers will have a choice on how they serve load growth. The point of the demand charges in the PRDM is to provide a "pure Tier 1 Demand Charge Billing Determinant that should serve its intended purpose of sending appropriate price signals." Reed *et al.*, PRDM-26-E-BPA-05, at 13. BPA does not agree that to encourage non-federal investment BPA must redesign its demand rates in such a way that costs must be shifted from PNGC to other customers. Bleifuss *et al.*, PRDM-26-E-BPA-11, at 28. In fact, the converse—providing for a fictional diversity benefit—would *reduce* the incentive for PNGC to invest in demand side management, or other non-federal resources, relative to other customers, because it would receive a demand *subsidy* relative to other customers.

PNGC also raises some broad purpose arguments, claiming that unless BPA provides it with the demand charge treatment it requests, its "mission" or reason for its "existence" is called into question. PNGC Br., PRDM-26-B-PN-01, at 2, 7, 11. PNGC argues that the proposed approach in the PRDM "would severely constrain PNGC's ability to co-optimize loads and resources of its members by eliminating the aggregation of JOE loads for BPA billing purposes under the next Power Sales Agreement (Provider of Choice Power Sales Contract). *Id.* at 6.

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While BPA cannot speak to the business case for joining or not joining PNGC, BPA notes that nothing in the PRDM precludes PNGC as a JOE from retaining the congressionally-expected benefits of economies of scale, administrative efficiencies, and optimization of non-federal resources. As BPA explained in its testimony, the PRDM does not fundamentally change PNGC's incentives to "optimize[] member loads at scale." Bleifuss *et al.*, PRDM-26-E-BPA-11, at 29. Said another way, a capacity asset has the same value to PNGC and its members under PRDM that it did under TRM. *Id.* PNGC has provided no material on the record to the contrary. *Id.*

Finally, PNGC contends that BPA has made its proposal without any support from other preference customers. PNGC Br., PRDM-26-B-PN-01, at 4. The implication here is that BPA's proposal is not supported among the broader Public Customer community, and its actions here are "unilateral." *Id.*

The record in this case refutes PNGC's assertion. The overwhelming majority of Public Customers support the PRDM as designed. *See* Section 2.4 of this Draft ROD. To that point, no party has joined PNGC in its request for special rate treatment under the demand rate. While certainly not dispositive, these facts strongly suggest that BPA has struck the proper balance in the PRDM, and that its proposal is largely supported by the other Public Customers (particularly those that would be on the receiving end of the cost shift PNGC seeks).

In summary, the PRDM's approach to charging demand for a JOE properly aligns costs and benefits, consistent with cost causation and general ratemaking principles. Membership in a JOE does not reduce BPA's costs of serving a JOE's members. In that context, it is appropriate to charge a JOE for demand in the same manner as BPA would any other customer: namely, based on the individual member-utility's demand. The PRDM's demand charge paradigm correctly assigns costs and benefits consistent with usage, supports the policy objective of sending appropriate price signals at the utility level, and allows PNGC and its members to realize the full value of any capacity-reducing initiatives it chooses to invest in any of its members' service territories. This design is rooted in the long-standing principles of costs following benefits and sending appropriate price signals, and is consistent with sound business principles.

Draft Decision

The PRDM's approach to charging a JOE demand charges based on its individual members' demand is consistent with sound business principles.

Issue 5.3.3.5.3

Whether BPA's decision to not continue the TRM's demand charge treatment for a JOE in the PRDM is reasonable.

Parties' Positions

PNGC asserts that BPA is undoing the "balance struck in the current TRM" and BPA is "tak[ing] away one of the solutions for regional load growth that only JOE aggregation can bring." PNGC Br., PRDM-26-B-PN-01, at 11. PNGC also argues that BPA, on its own accord and without support from other preference customers, "unilaterally redefine[s]" the JOE treatment from the TRM. *Id.* at 4. PNGC contends that "BPA alone seeks to change what BPA describes as a negotiated balancing of interests in the Regional Dialogue contract." *Id.* at 7. PNGC also argues BPA's change is "inequitable." PNGC Br., PRDM-26-B-PN-01, at 1, 2.

BPA Staff's Position

The balance struck in the TRM for a JOE was the result of compromise and other "counterbalances" which, on the whole, were intended to place a JOE in the same place as other customers. Reed *et al.*, PRDM-26-E-BPA-05, at 16. Under the PRDM, those counterbalances (*e.g.,* CDQs) are removed, the rates are redesigned, and new price signals and approaches to rates are established. *Id.* Given these differences, a change to a JOE's demand charge treatment is warranted. *Id.* In addition, the TRM treated JOE members as individual utilities in all but one instance. Bleifuss *et al.*, PRDM-26-E-BPA-11, at 25-26. Thus, BPA's proposed change is not a stark change from past precedent, but "simply extends th[e] current practice to the demand rate." *Id.* at 26. Finally, BPA is proposing a special rate credit—the Rate Impact Credit JOE (RICj)—to assist the JOE's transition from TRM to PRDM. Reed *et al.*, PRDM-26-E-BPA-05, at 16.

Evaluation of Positions

PNGC argues that BPA should retain the TRM's treatment for assessing demand charges for a JOE in the PRDM. PNGC requests BPA to "at a minimum" not reverse its existing implementation and practices that aggregate a JOE member's load to optimize its own demand. PNGC Br., PRDM-26-B-PN-01, at 8. PNGC requests the Administrator to reverse BPA's Staff's proposal and revert back to "the current treatment under the TRM." *Id.* PNGC notes that BPA is undoing the "balance struck in the current TRM . . ." and BPA is "tak[ing] away one of the solutions for regional load growth that only JOE aggregation can bring." *Id.* at 11. PNGC argues that the potential for a JOE to be a regional partner with BPA and other preference customers creates an opportunity to solve BPA's dilemma of a finite system resource size, regional decarbonization goals, and relentless challenges to continued use of hydroelectric resources. *Id.*

BPA has already explained in detail above that there is no legal requirement that the PRDM aggregate a JOE's load for purposes of ratemaking. Additionally, BPA has laid out its rate rationale and cost-causation basis for calculating the demand charge for a JOE based on its

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individual member utility's peak. Here, BPA explains why it has decided to move away from the TRM treatment—which allowed PNGC to aggregate its demand—and move towards a more uniform approach to charging demand for all customers.

By way of background, in the TRM, BPA originally intended to apply *all charges,* including the demand charge, to a JOE based on its individual members' peak demand. Reed *et al.*, PRDM-26-E-BPA-05, at 16. Indeed, in the original TRM proceeding, BPA made it clear that "a JOE . . . should not be afforded any additional rights under the TRM by virtue of being a JOE as compared to the rights of its members individually." *Id.* at 26, *citing* Fisher *et al.*, TRM-12-E-BPA-19, at 5 (Aug. 2008). In fact, for all other charges and credits under the TRM, a JOE is treated as separate individual utilities. Bleifuss *et al.*, PRDM-26-E-BPA-11, at 24. As noted by Staff, "for every aspect of the TRM *except* demand charges, BPA treats each of PNGC's members as individual utilities and bills PNGC as if they were such." *Id.* Demand charges for a JOE under TRM are, then, an exception to the general rule of charging a JOE for its individual utility members.

Even with the demand charge, it was never BPA's intent under the TRM to allow a JOE to avoid demand charges and shift costs onto other customers through its "paper diversity." *See* Issues 5.3.3.5.1 and 5.3.3.5.2. The TRM's allowance for a JOE to aggregate its load, and receive a lower demand charge, came with other offsetting conditions that, "on the whole, were intended to place a JOE in roughly the same position as other customers." Reed *et al.*, PRDM-26-E-BPA-05, at 16. One specific offset was that the JOE received a lower CDQ, which in turn meant that more of its demand was subject to the demand charge. *Id.* at 13 ("[T]he CDQ for the JOE was sized smaller than the sum of the CDQ had each member been billed on its individual peak load."). The combination of an aggregated demand signal and a smaller CDQ was no guarantee of a rate benefit to PNGC. *Id.* at 26 ("The net impact of the TRM's demand billing and reduced CDQ could have been positive or negative in any given year.").

As it turned out, the CDQ did not perfectly offset the cost to BPA of providing the JOE a lower Demand Billing Determinant, resulting in a cost shift from PNGC to other customers. *See also id.* at 24 ("This decade of experience shows this particularity of the TRM design resulted in a cost shift from the JOE to other customers."). This was not the intent of the TRM, but nonetheless, was a byproduct of the "general compromise on issues to reach the final TRM." *Id.* at 24.

With the elimination of CDQs under the PRDM, and the redesign of the underlying energy and capacity rates, BPA must also re-evaluate how a JOE is treated for purposes of demand under the PRDM. *Id.* at 16. The "compromise and negotiation" of the TRM is gone. In its place are the "goals, price signals, and other objectives" of a new methodology for tiered rates. *Id.* The PRDM Tier 1 demand charge is "fundamentally different" than the TRM demand charge. *Id.* at 12. Its billing determinant is different, *id.,* and the way BPA mitigates for existing capacity costs is different. *Id.* at 13 (noting BPA is removing CDQs). With these differences comes a new balance of costs, equities, and objectives. And, significantly, most parties have agreed that the PRDM "strikes an appropriate overall balance that will result in fair cost allocations to customers." Safford & Weber, PRDM-26-E-AW-01, at 3; *see also* Section 2.4 of this Draft ROD, General Responses to PRDM.

In sum, BPA has logical, reasonable, and sound reasons to move away from the treatment adopted in the TRM relating to a JOE and demand charges. As BPA explained above in the previous issue, sound ratemaking and cost-causation reasons support this change in the PRDM. Further, this change is a logical extension of the way a JOE is charged or paid credits for all other features of the TRM. As BPA Staff explained: "BPA's current practice under Regional Dialogue is to charge PNGC for its individual member[s'] loads in multiple ways, and the PRDM proposal simply extends that current practice to the demand rate." Bleifuss *et al.*, PRDM-26-E-BPA-11, at 26.

PNGC calls this change "inequitable." PNGC Br., PRDM-26-B-PN-01, at 1, 2. For the reasons described above, it is not. Nevertheless, as a matter of "equity and mitigating rate shock," BPA has proposed a special credit to help PNGC transition from the treatment afforded under the TRM to the PRDM. Reed *et al.*, PRDM-26-E-BPA-05, at 32. This special rate credit, the Rate Impact Credit JOE or RICj, is applicable only to PNGC and provides it with $8 million of rate mitigation over the Provider of Choice Contract period. *Id.* at 22, 31. The RICj and its features are discussed in more detail in Issue 5.4.3.2.1 below.

<u>Draft Decision</u>

BPA's decision to not continue the demand charge treatment for a JOE from the TRM into the PRDM is reasonable considering the objectives, pricing policies, and goals of the PRDM.

5.3.4 Tier 1 Peak Load Variance Charge (PRDM Section 4.4)

5.3.4.1 Overview

The Tier 1 Peak Load Variance Charge is the charge for customers taking the Peak Load Variance Service (PLVS). Reed *et al.*, PRDM-26-E-BPA-05, at 16-17. Tier 1 PLVS is a capacity-based service that formalizes long-held operational planning actions that ensure an adequate amount of capacity is planned for and standing ready when loads exceed expected peak values. *Id.* at 17. PLVS is coincidental in nature, and accounts for diversity across loads. *Id.* The costs recovered through the Tier 1 Peak Load Variance Charge are calculated using BPA's embedded cost of capacity. *Id.* This charge effectively unbundles the cost of this capacity for transparency purposes and enables similar services to be offered to eligible customers taking the Block with Shaping Capacity Product. *Id.*

The Tier 1 Peak Load Variance Charge (PLVC) recovers BPA's capacity costs associated with holding and planning for capacity needs when its load obligations can increase relative to its expected load obligations. *Id.* BPA uses a P10 load planning standard when calculating the Tier 1 Peak Load Variance Charge. *Id.* P10 is a statistical term that BPA uses as a planning standard, where the P stands for percentile, and the 10 stands for the tenth. It means that 90 percent of the peak load estimates are lower than this value and 10 percent are higher than this value. *Id.* The Tier 1 Peak Load Variance Charge would recover the cost of holding capacity between BPA's expected peak load obligation (P50) and a P10 peak load event. *Id.* P50 is the expected coincidental peak, and P10 is a lower probability, but possible coincidental peak. *Id.*

5.3.4.2 Issues

<u>Issue 5.3.4.2.1</u>
Whether BPA should establish the billing determinant for the Block PLVS in the PRDM.

<u>Parties' Position</u>

JP02 contends BPA should determine the PLVS Billing Determinant for the Block Product in the final PRDM so that "customers can make an informed decision" on product selection. JP02 Br., PRDM-26-B-JP02-01, at 1. JP02 further contends that the appropriate billing determinant that BPA should use for the Block PLVS is accredited Qualified Capacity Contribution (QCC) rather than PLVS nameplate. *Id.* at 3.

<u>BPA Staff's Position</u>

The PRDM states that the "PLVC rate design applicable to the Block Product will be established in each 7(i) Process." PRDM § 4.4. That includes the billing determinant for the PLVC, which "will be established in each 7(i) Process . . . ." *Id.*

<u>Evaluation of Positions</u>

<u>PLVS for Load Following and Block</u>

As explained above in Section 5.3.4.1 of this Draft ROD, and Reed *et al*., PRDM-26-E-BPA-05, at 17, PLVS is a capacity-based service that transparently formalizes long-held operational planning actions that ensure capacity is planned for and standing ready when loads exceed expected peak values. Bleifuss *et al.*, PRDM-26-E-BPA-11, at 20. PLVS specifically targets the quantity of capacity to meet planning reserve margins above the expected load (sometimes referred to as average load or 50th percentile load). *Id.* In the development of the PRDM, this planning reserve margin was discussed colloquially as "P10" (or "10th percentile") coincidental-peak load value on a peak load probability distribution. *Id.* The charge for providing PLVS is called Peak Load Variance Charge (PLVC).

As JP02 notes, PLVS is an "intrinsic" part of the Load Following product and can be "added" on to Block with Shaping as a separate option. Bush *et al.*, PRDM-26-E-JP02-01, at 3; *see also* PRDM § 4.4. The PRDM outlines the basic contours of the PLVC rate design and billing determinants for the Load Following Product. *See id.* The reason this level of detail is included in the PRDM is because of the nature of the Load Following Product service. With Load Following, BPA "supplies all of the power needs of customers that elect this service (to the extent not met by the customers' own resources)." Fisher *et al.*, PRDM-26-E-BPA-02, at 12. In simple terms, "BPA meets or 'follows' the customers' load" meaning "as the customer's load increases or decreases, BPA matches those changes with its resources." *Id.* Importantly, under the Load Following Product, "BPA has the planning obligation to meet the customer's peak load needs." *Id.* As such, no matter what future industry standard terms may be created to impose duties on BPA to meet its customer's peak loads, BPA must bear that cost through its Load Following obligations. Because BPA holds this risk, BPA is able to describe in detail the rate design that it would apply to recover BPA's costs of serving the customer's peak loads.

In contrast, the PRDM does not establish either the rate design or the billing determinant of the PLVC for the Block Product. Instead, the PRDM says the PLVC for the Block Product will be "established in each 7(i) Process." PRDM § 4.4. The reason the PRDM does not lock down the billing determinant or other features of PLVC for the Block Product is because of the nature of the Block Product, which requires that the customer (not BPA), take on the planning obligation to meet the customer's peak load needs. *See* Fisher *et al.*, PRDM-26-E-BPA-02, at 13. Additionally, important features of the PLVS as applicable to the Block Product are not yet known. *See* Bleifuss *et al.*, PRDM-26-E-BPA-11, at 20. Specifically, future regional planning standards and requirements are still in development, and it is unknown at this time how those standards will impact or interact with the Block Product. *Id.* at 21.

Because the PLVS is not the same for Load Following and Block customers, it follows that their rate treatment in the PRDM need not be the same either. Load Following and Block are different products with different obligations on BPA and the customer. The PRDM specifically recognizes these differences, noting that the billing determinant established for PLVC in a 7(i) Process may be different between Load Following and Block if the "planning, access to and use of PLVS capacity is determined to be materially different across the products . . . ." PRDM § 4.4. BPA left the development of PLVC for the Block with Shaping product open in order to design "the cost of PLVC [to] be set commensurate with the service provided." *Id.*

<u>JP02's Arguments</u>

JP02 argues in its brief that BPA should "at least in broad terms" say what billing determinant will be used to price the PLVS for Block customers. JP02 Br., PRDM-26-B-JP02-01, at 1. JP02 asserts that its direct case established that the "level of service provided under the Load Following PLVS" is "fundamentally differ[ent]" than the level of service provided under the Block PLVS. *Id.* As such, JP02 argues that the "pricing of the Block PLVS should reflect the reduced level of service it receives." *Id.* at 1-2. JP02 argues BPA has not explained what billing determinant it plans to use. *Id.* 2. JP02 further contends before requesting customers to commit to Block with PLVS they need to "have a clearer understanding that the pricing will accurately reflect the reduced level of service Block PLVS receives." *Id.*

BPA declines to establish the billing determinant for PLVC for Block with Shaping in the PRDM. The current PRDM language makes clear that the billing determinant for PLVC for

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Block will be determined in a future 7(i) Process and that at that time "the cost of PLVC will be set commensurate with the service provided." PRDM § 4.4. In this way, BPA is ensuring that the rate established for the PLVC will be based on the best available information and designed to recover BPA's costs. This flexibility is particularly useful given the different obligations at issue here. As noted above, and by JP02, PLVS for a Load Following or Block customer is not the same. There are different limitations and different obligations. BPA is not prepared to lock down the billing determinant and other rate design features of PLVS for Block until it has more information about the nature of that service and how it will be used.

JP02 argues that it cannot make an informed decision on the Block Product until it knows BPA's billing determinants for the PLVC. JP02 Br., PRDM-26-B-JP02-01, at 2. BPA disagrees that the PRDM can, or should, attempt to resolve uncertainty driven by processes outside the scope of the PRDM that can, and likely will, change through time. JP02's proposed solution highlights the importance of this point in that it depends on a term called "Qualified Capacity Contribution" or "QCC," which is a definition specific to the still developing WRAP. *Id.* at 2. The PRDM addresses cost allocation and is designed to be adaptive and support equitable cost allocation solutions to all future uncertainties, PLVS for the Block Product and otherwise. Generally, the PRDM achieves this adaptive and equitable end through its cost allocation principles as laid out in PRDM Section 2.1 and, specific to the rate design applicable to the PLVS, provides further cost allocation requirements as laid out in PRDM Section 4.4.

Locking down rate terms on a service BPA has never sold (*e.g.,* Block with PLVS), whose contours have yet to be determined, and anchoring it further on present expectations of a still developing resource adequacy program, removes the very flexibility BPA needs to reach an equitable cost allocation outcome for the full term of the PRDM. *See* Bleifuss *et al.*, PRDM-26-E-BPA-11, at 21. BPA believes the more prudent course is to leave the pricing for Block with PLVS until the rate case, wherein the service will be priced and its usage known.

Further, BPA notes that JP02's concern that it is signing up for a product before knowing its pricing should be largely addressed by the latest draft of the Provider of Choice Contract, which contains an option for the customer to drop PLVS once it sees BPA's approach to PLVC pricing without counting that as a product change election.[30]

JP02 contends that BPA did not actually "rebut" any of its arguments from its direct case. JP02 Br., PRDM-26-B-JP02-01, at 2. BPA responds that JP02 did not raise any arguments to rebut. JP02's direct case discussed the "uncertainty" facing Block PLVS customers due to the "overall direction of the Block PLVC cost." Bush *et al.*, PRDM-26-E-JP02-01, at 4. JP02's

[30] *See* Provider of Choice Draft Master Contract Template, § 11.4.2, *available at* https://www.bpa.gov/energy-and-services/power/provider-of-choice ("By February 1, 2028, «Customer Name» may notify BPA that it elects to stop taking the Flat Monthly Block purchase obligation with PNR Shaping Capacity with PLVS. Upon such notice, «Customer Name» shall by default receive the Flat Monthly Block purchase obligation with PNR Shaping Capacity. Such election will not constitute a change in purchase obligation in accordance with section 11.1 of this Agreement.").

testimony then describes various limitations with the PLVS *product*, and the *potential* impact these limitations could have on the WRAP critical capacity methodology. *Id.* at 4-6. JP02 then engages in various musings about whether a customer would choose Load Following over Block because of these differences. *Id.* at 6-7. JP02 then discusses an example of how capacity "derated" by a yet-to-be-determined WRAP methodology could impact the value of the PLVS to a Block customer. *Id.* 7-9. Once done with that example, JP02 asks whether BPA should try to solve this issue. *Id.* at 9-10. JP02's witnesses also note, "No, BPA is not obligated to provide a solution to this issue." *Id.* Further, JP02 admits that BPA "can fulfill its legal obligations to customers by providing the Load Following product." *Id.* at 10. JP02 notes that its "intent" was to "make BPA aware of the issue, to create a record for future decisions, and hopefully generate opportunities to address this through product design changes." *Id.*

Further, JP02 notes that "[w]hile we believe that there are possible rate treatments available, the PRDM structure is supported by a large coalition of public power, and we do not wish to introduce new elements. We would prefer to remedy this gap through product design." *Id.* JP02 then provides its "preference" for more certainty on the billing determinant and some suggestions on what this may look like. *Id.* at 11-13. In any event, BPA Staff read JP02's testimony as providing suggestions to BPA for a PLVC billing determinant *if* BPA chose to adopt a billing determinant in the PRDM.

In sum, JP02 did not raise arguments against the PRDM or claim that the proposal was objectionable in any way. JP02 presented its arguments in the form of suggestions for BPA to consider, and making its preferences known, but also looking to product development to work out their issues. In light of the ambivalence in JP02's testimony, BPA Staff decided to leave these issues to a future 7(i) Process, and hence *not* take a position on the billing determinant, as well as not strenuously "rebut" JP02's various musings and preferences. *See* Bleifuss *et al.*, PRDM-26-E-BPA-11, at 20-21.

Now, in its brief, JP02 asserts BPA "should" commit to a specific billing determinant and lock in the Block PLVS based on "QCC accreditation" rather than "nameplate capacity" in the PRDM. JP02 Br., PRDM-26-B-JP02-01, at 2. BPA declines to do so and finds that it did not need to rebut JP02's arguments on the record to reach that conclusion. JP02 presented its testimony as a preference not as a requirement of the PRDM. Thus, its present representation of its testimony as requiring BPA make this change is misleading and specious. As JP02's own testimony states:

> While we believe that there are possible rate treatments available, the PRDM structure is supported by a large coalition of public power, and we do not wish to introduce new elements. We would prefer to remedy this gap through product design.
>
> * * * *

> We are interested in discussing several alternatives in the contract and product development processes that could improve Block PLVS viability and have asked BPA for additional time to collaborate on mutually beneficial solutions. We believe that product development rather than rate treatment is a better solution to these issues going forward. However, we also believe there are valid reasons BPA might use an alternate billing determinant than nameplate for Block PLVS, discussed below.

Bush *et al.*, PRDM-26-E-JP02-01, at 10. JP02 did not assert the position it is now taking, and its claim that BPA did not rebut its "arguments" is unsupportable.

In any event, the PRDM does provide important guidance for JP02 to make an informed decision. In addition to the PRDM's cost allocation principles that "will be used for allocating costs that are not specifically addressed in the PRDM" (PRDM § 2.1), the PRDM already locks down the PLVS rate treatment in two substantive ways that provide customers with meaningful assurances with how BPA will approach the PLVS rate design in the applicable 7(i) Process when the contours and usage of the services is known. The first is that it will be cost based and that "costs recovered through the PLVC will be established using BPA's embedded cost of Supplemental Operating Reserves, or its successor, adjusted to reflect the Tier 1 System Resources only, and shaped into months using each Rate Period's monthly Tier 1 Demand Rates." PRDM § 4.4. This is a particularly important anchor that all customers can use to ensure that the PLVC rate design, as adopted through a 7(i) Process, will result in a cost recovery that is no higher nor lower than the cost of providing the service as measured with BPA's embedded cost of capacity. Notably, and rightfully, not included in this description is an adjustment to BPA's cost of providing the service for perceived and external-to-the-PRDM impacts on the realized value of the service. JP02's proposal could result in just that; that is, JP02's proposal could forever lock into the PRDM an unjustified discount or premium to BPA's embedded cost of providing the service for reasons that do not impact BPA's cost of providing the service. It is not the PRDM's place to subsidize or inequitably charge a service based on factors external to its scope.

The second way the PRDM meaningfully locks down the rate design for PLVS is through its statement that "the cost of PLVC will be set commensurate with the service provided." *Id.* To the extent there are differences between the cost of providing the Load Following and Block Product versions of PLVS—a potential outcome identified in the PRDM—the PRDM requires that those differences be considered and reflected in the cost of the applicable PLVS. *Id.* The PRDM's intended outcome is clear and absolute: the PLVC will be "set commensurate with the service provided." *Id.* The PRDM affords BPA the ability to meet this required outcome by providing flexibility on the path taken, inclusive of contract terms, to reach that end. JP02's proposal to lock down the billing determinant for Block PLVS now in the PRDM is premature as it myopically focuses on the perceived value of PLVS rather than on the cost of providing the service. The better path is the one adopted in the PRDM: hold off on making billing determinant decisions until a later 7(i) Process, and devise the rate at that time so that its costs are "set commensurate with the service provided." *Id.*

<u>Draft Decision</u>

BPA will not establish the billing determinant for the Block PLVS in the PRDM.

5.4 Tier 1 Credits (PRDM Section 4.5)

5.4.1 Rate Impact Credit Capacity (RICc)

5.4.1.1 Overview

The RICc is a rate credit that conveys the value of the embedded cost of capacity inherent to the existing federal system to each preference customer for its expected capacity use at the onset of the Provider of Choice CHWM Contracts. Reed *et al.*, PRDM-26-E-BPA-05, at 18. It is akin to a proxy for tiering capacity through a monetized value. *Id.* Through the RICc, the PRDM effectively allows the rate design to charge a fixed portion of a customer's capacity requirement (*i.e.,* expected use at the onset of the contract period) at an embedded cost-based rate, and charge the remainder, including future load growth, at a long-run marginal cost-based rate. *Id.*

BPA included the RICc in the PRDM for two primary reasons. *Id.* at 20. First, BPA believed it important and consistent with the tiering of energy costs to not impose a marginal cost for every unit of capacity at the outset of the PRDM. *Id.* To date, no capacity has been purchased to meet BPA's Tier 1 load obligations and thus all capacity is being provided by the existing federal system. *Id.* Further, the RICc allows BPA to send a long-run marginal price signal for every unit of capacity while also only charging an embedded cost of capacity for existing capacity needs. *Id.* This means BPA can meet two objectives in that it can provide an unfettered marginal capacity price signal to incentivize conservation and non-federal resources development while also only charging embedded cost for existing capacity needs. *Id.*

The second reason is to declutter the price signal associated with the Demand Charge. *Id.* When the monetized value of capacity at cost was placed inside the Demand Charge itself under TRM, the resulting price was convoluted from actual load movements. *Id.* In some extreme cases, some customers received a price of zero for this charge, despite real—and in some cases growing—peak loads. *Id.* Conveying, and isolating, the monetized value of capacity at cost outside the Tier 1 Demand Charge under PRDM lends greater transparency to both the Tier 1 Demand Charge and its price signals, as well as the value associated with federal capacity allocated through the RICc. *Id.* Customers' actions, as well as exogenous factors such as weather, will be directly translatable through the demand charge—both actions that increase a customer's peak, and actions that are taken to reduce it. *Id.* at 20-21. Keeping the Tier 1 Demand Charge and RICc separate allows a more direct understanding of the charges and price signals for customers as well as for BPA's internal systems and processes that manage rates and bills. *Id.* at 21.

5.4.1.2 Issues

Issue 5.4.1.2.1
Whether BPA's proposal for the RICc and demand charges inhibit non-federal capacity investments because of artificially depressed federal pricing.

Parties' Positions

RNW argues that the PRDM should include features that incentivize the development of non-federal generation. RNW Br., PRDM-26-B-RN-01, at 1. RNW contends the PRDM's terms on demand pricing are "flawed" because they artificially depress federal pricing. *Id.* at 2. RNW asks BPA to remove the demand price "governor" from the PRDM. *Id.* at 3.

BPA Staff's Position

The PRDM's pricing on capacity is reasonable and sends a long-run marginal price signal that incentivizes economic behavior and encourages non-federal resource development to expand capacity infrastructure in the Northwest. Reed *et al.,* PRDM-26-E-BPA-05, at 8. The RICc and demand charge are appropriately designed to send a long-run marginal price signal for every unit of capacity while also only charging an embedded cost of capacity for existing capacity needs. *Id.* at 20.

Evaluation of Positions

RNW argues BPA should not adopt policies in the PRDM that render BPA the only power supplier for Public Customers. RNW Br., PRDM-26-B-RN-01, at 2. RNW contends BPA's demand pricing in the PRDM is "flawed" because it "artificially depresse[s]" federal pricing. *Id.* RNW argues that while BPA is "technically" committed to include marginal capacity costs, the PRDM provides for a RICc and a rate "governor" limiting volatility in the demand rate. *Id.* at 2-3. These features, according to RNW, "essentially ensure[] Preference Customers will enjoy reduced capacity costs akin to locking in an embedded capacity cost component throughout the entire POC contract period." *Id.* at 3. RNW asserts that artificially low demand costs "clearly disincentivize[s] non-federal investments," which in turn could "drastically alter Bonneville's role in the region from being a provider of choice to the only realistic provider of capacity." *Id.* RNW requests BPA "at a minimum" remove the rate governor to avoid potential price distortion. *Id.*

RNW is incorrect about the RICc and how it relates to the long-run marginal price signal sent through the PRDM's Demand Charge. As noted above, the TRM's Demand Charge included a CDQ adjustment to the Demand Charge Billing Determinant to remove the marginal price signal for existing capacity use (as well as having two other purposes). *See* Reed *et al.,* PRDM-26-E-BPA-05, at 13. The PRDM, however, removes the CDQ from the Demand Billing Determinant entirely and replaced it with the independently applied RICc—*e.g.*, the PRDM decluttered the price signal associated with the Demand Charge. *Id.* at 13, 18.

When the monetized value of capacity at cost was placed inside the Demand Charge itself under TRM, the resulting price was convoluted from actual load movements. *Id.* at 20. In some extreme cases, some customers received a price of zero for this charge, despite real—and in some cases growing—peak loads. *Id.* Conveying and isolating the monetized value of capacity at cost outside the Tier 1 Demand Charge under PRDM lends greater transparency to both the Tier 1 Demand Charge and its price signals, as well as the value associated with federal capacity allocated through the RICc. *Id.* Customers' actions, as well as exogenous factors such as weather, will be directly translatable through the Demand Charge—both actions that increase a customer's peak, and actions that are taken to reduce it. *Id.* at 20-21. Keeping the Tier 1 Demand Charge and RICc separate allows a more direct understanding of the charges and price signals for customers as well as for BPA's internal systems and processes that manage rates and bills. *Id.* at 21.

In summary, the PRDM does not do what RNW claims. Rather, the PRDM allows BPA to meet two objectives in that it can provide an unfettered marginal capacity price signal to incentivize conservation and non-federal resource development while also only charging embedded cost for existing capacity needs. *Id.* at 20. Contrary to RNW's argument, every unit of capacity used is charged—and every unit of capacity not used is credited—to the customer at the long-run marginal cost of capacity. Because the megawatt size of the RICc is fixed and locked down for the term of the PRDM, it remains completely independent of increases and decreases in a customer's Demand Charge Billing Determinant over the term of the PRDM. PRDM § 4.5.1.

With regard to the Tier 1 Demand Rate Adjustment Cap, referred to as a "governor" by RNW, RNW misidentifies its purpose and overestimates its impact. As a reminder, the Tier 1 Demand Rate is intended to be a long-run marginal price signal. Reed *et al.,* PRDM-26-E-BPA-05, at 8. Economically, the intent of using the long-run marginal price signal (rather than a more volatile short-run marginal price signal) is to produce a stable, dependable, and reasonably predictable signal to encourage non-federal investments with long investment horizons. Allowing the price signal to whipsaw up and down based on short-term or transient observations is neither the Tier 1 Demand Rate's intent nor would it instill confidence in customers contemplating the rate of return associated with a long-term investment in a demand response asset or capacity-serving non-federal resource. In fact, it would likely have the opposite effect in that a less predictable price signal, as proposed by RNW, would add additional uncertainty and risk to any investment.

Historically, BPA's long-run marginal price signal has been quite stable with only one occurrence over the last 17 years of BPA needing to implement a similar dampening provision in the TRM. Like the PRDM's proposed Tier 1 Demand Rate Adjustment Cap, the TRM includes a provision that allows BPA to dampen significant volatility in the calculation of the Tier 1 rate. TRM, BP-12-A-03, at 77. The context of its one-time use highlights the prudency of including a stabilizing provision to a long-run marginal price signal that can be impacted by short-term events. Specifically, the TRM's stabilizing provision was needed when the long-run capacity cost methodology started picking up relatively sudden increases in borrowing costs that were the direct result of the Federal Reserve's policies to

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combat "transitory" inflation caused in part by the COVID-19 pandemic. Capturing transitory, sudden, and abrupt changes such as those observed through the COVID-19 pandemic serve no purpose in a long-run price signal other than to needlessly confuse and conflate the long-run intent of the price signal. As this historical example demonstrates, it is best for the long-run marginal cost price signal to include some sort of stabilizing provision to manage abrupt shifts, be they long- or short-term, so that the price signal can best match the time horizon of the investments it is trying to incentivize and not suddenly make or break a 15-to-20-year investment in a single two-year rate period.

Further, what RNW appears to overlook is that the Tier 1 Demand Rate Adjustment Cap is bidirectional, meaning it can just as likely slow a sudden decrease in the long-run cost of capacity that would otherwise significantly decrease, in a single rate period, the value of a non-federal resource investment. Not unexpectedly, customers are more likely to make non-federal investments if the projected value of a non-federal investment is more predictable and dependable, which is exactly what the Tier 1 Demand Rate Adjustment Cap is attempting to achieve while also allowing changes of up to 10 percent in a month, up or down, each and every two-year rate period. *See* PRDM § 4.3.5.

Draft Decision

BPA's proposal for the RICc and demand charges do not inhibit non-federal capacity investments.

5.4.2 Rate Impact Credit, Mitigation (RICm)

The RICm is a mitigation credit that tempers the immediate impact of rate-design changes from the TRM to the PRDM, and gradually exposes all customers to the new methodology in a predictable, steady fashion. Reed *et al.*, PRDM-26-E-BPA-05, at 21. This credit aligns with generally accepted ratemaking principles of minimizing rate-shock and promoting rate stability over time. *Id.* The RICm tempers effective rate impacts due to design changes from the TRM to PRDM, including the Tier 1 Energy Charge, Tier 1 Demand Charge, and Tier 1 Peak Load Variance Charge for Load Following, and for Block customers who are eligible for, and elect, PLVS for the BP-29 rate period. *Id.* The RICm does not include the impacts to rate levels from other methodology changes (*e.g.,* Irrigation Rate Discount and Load Density Discount), nor any changes affecting rate levels (*e.g.*, rate changes attributed to a changing Revenue Requirement or changing loads), policy or product design changes, and changes to Tier 1 eligibility. *Id.* The RICm is a customer-specific mills-per-kilowatthour adjustment that limits positive and negative rate impacts within prescribed limits and has a prescribed transition schedule to reduce these credits and charges over time. *Id.*

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5.4.3 Rate Impact Credit, JOE (RICj)

5.4.3.1 Overview

The RICj is a credit specific to the only JOE that purchased power from BPA under the TRM (*i.e.*, PNGC). Reed *et al.*, PRDM-26-E-BPA-05, at 22. It tempers the impact of rate design changes from the TRM to the PRDM, specific to the removal of the aggregated demand signal mentioned previously. *Id.* This credit aligns with generally accepted ratemaking principles of minimizing rate-shock and promoting rate stability over time. *Id.* The RICj tempers rate changes that result from the TRM to PRDM with respect to removing the TRM's aggregated demand signal for the JOE, and does not include the impacts to rate levels from other design changes, non-Core Rate Design aspects (*e.g.*, IRD and LDD), nor any changes affecting rate levels (*e.g.*, rate changes attributed to a changing Revenue Requirement or changing loads). *Id.* at 22-23. The RICj is a specific mills per kilowatthour credit applicable to the only JOE that purchased power from BPA under the TRM, and only if that JOE elects to purchase the Load Following Product. *Id.* at 23. The RICj has a prescribed schedule (see PRDM Table 4-1), which begins at $1 million in FY 2028 and reduces to zero by 2044. *See* PRDM at § 4.5.3, Table 4-1. The RICj was sized to roughly reflect the original assumed cost benefit to the JOE (based on its membership at the time) under the TRM, along with considerations of equity and rate shock. Reed *et al.*, PRDM-26-E-BPA-05, at 24-25.

5.4.3.2 Issues

<u>Issue 5.4.3.2.1</u>
Whether BPA should modify the RICj as requested by PNGC.

<u>Parties' Positions</u>

PNGC contends that if BPA does not revise the PRDM's treatment for demand charges applicable to a JOE, then BPA should, as an alternative, modify BPA's RICj proposal. Specifically, PNGC requests the RICj be modified so that it remains in effect "throughout the entire period of the PRDM's applicability." PNGC Br., PRDM-26-B-PN-01, at 8, 9-10. PNGC contends maintaining the RICj through the entire Provider of Choice period is "more equitable" and keeps PNGC financially whole from today's practice while not imposing incremental costs on other customers. *Id.* at 9. PNGC also opposes the taper off feature of the RICj. *Id.* at 11. PNGC proposes BPA fix the RICj at $1 million a year for the duration of the Provider of Choice Contract, with no reduction over time. *Id.* at 12-13. This would result in $16 million in credits to PNGC over this period. *Id.* at 13.

<u>BPA Staff's Position</u>

The RICj appropriately tempers rate changes that result from transitioning the JOE from the TRM to the PRDM. Reed *et al.*, PRDM-26-E-BPA-05, at 22. The RICj provides PNGC mitigation payments of $8 million over 16 years and is correctly sized to mitigate the transition of the JOE from TRM to PRDM. *Id.* at 24-25, 26. The taper-off feature of the RICj is important because it sunsets the cost shift among customers and places PNGC and its members "in the same place as every other customer under the PRDM" by the end of the Provider of Choice Contract period. Bleifuss *et al.*, PRDM-26-E-BPA-11, at 32.

<u>Evaluation of Positions</u>

PNGC "agrees" with BPA Staff's decision to develop a billing credit for PNGC to address the financial hardship for the JOE and its members. PNGC Br., PRDM-26-B-PN-01, at 8. PNGC, however, objects to BPA Staff's proposed RICj, noting it is "insufficient to mitigate the harm that results." *Id.* at 11. PNGC's objections to the RICj fall into three general categories: 1) the amount of the RICj mitigation; 2) the duration of the RICj mitigation; and 3) the permanence of the RICj mitigation. *Id.* at 9-13.

<u>RICj Mitigation Amount</u>

PNGC objects to the amount of mitigation BPA proposes to provide through the RICj. PNGC contends that billing credits under the PRDM are intended to mitigate the financial impacts to a specific customer or customer group resulting from the transition from TRM to PRDM ratemaking policy. *Id.* at 10. PNGC argues, however, that the RICj only "partially mitigates" the financial harm resulting from BPA's proposed changes that eliminate the load diversity benefit JOE members realize under the TRM's treatment of demand. *Id.* PNGC asserts that BPA Staff has estimated the current benefit to PNGC in the range of $1 million a year. *Id.* at 9. PNGC provides a table in which it suggests BPA hold the $1 million constant for the duration of the Provider of Choice Contract, resulting in $16 million of rate mitigation for PNGC. *Id.* at 13.

BPA disagrees that any adjustment to the amount of RICj is warranted. It is important to note here that BPA does not have any obligation to develop a RICj or provide *any* rate mitigation to PNGC. As BPA staff explained, "in transitioning to the PRDM, the RICj is not required." Reed *et al.*, PRDM-26-E-BPA-05, at 26. The inclusion of the RICj was introduced as a "reasonable compromise . . . that . . . balances the need to ensure the ratemaking policy goals and incentives for demand under the PRDM are met but does so in a manner that avoids rate shock to the JOE." *Id.* To that point, the RICj is not "intended to" fully mitigate the PNGC's transition from TRM to PRDM. *Id.* This is because "the intent of the TRM was not to provide the JOE a guaranteed rate benefit." *Id.*; *see also* Issue 5.3.3.5.3 (noting the counteracting features of CDQs on the demand charge provided to PNGC). Thus, the RICj should be understood as a product of "equity" and mitigating "rate-shock," *see* Reed *et al.*, PRDM-26-E-BPA-05, at 24, and not as a means to compensate PNGC for any alleged harm or to make it "financially whole." *See* PNGC Br., PRDM-26-B-PN-01, at 9, 12.

The RICj mitigation payment itself is based on logic and analysis. It has its origins in the value BPA Staff estimated PNGC received when the TRM was first developed. Reed *et al.*, PRDM-26-E-BPA-05, at 24. Specifically, the RICj was "sized to roughly reflect the original assumed cost benefit to the JOE (based on its membership at the time) under the TRM,

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along with considerations of equity and rate shock." *Id.* BPA Staff considered this value in its testimony. *Id.* at 24-25. Using the configuration of PNGC's membership and loads at the time the TRM was developed (circa 2008), BPA Staff estimated the value to PNGC of the TRM's treatment for demand was around $1 million. *Id.* at 25. This value, to be clear, was not *required* to be provided to PNGC under the TRM. Properly understood, this benefit should be viewed as "incidental rather than intentional . . . ." Bleifuss *et al.*, PRDM-26-E-BPA-11, at 31. From this incidental value, BPA Staff developed a straight line schedule of credits, starting with $1 million in 2028 and tapering down to zero in 2044. *Id.* at 32. In total, PNGC will receive $8 million under the RICj. *Id.* at 22, 31.

The idea behind the RICj, then, is this: the RICj is built from—for lack of a better phrase—the value BPA knew or should have known it was giving PNGC (the only JOE) as the cost of the "compromise" for the TRM. *Id.* at 32. That compromise is over, and BPA and the region are now embarking on a new methodology with new rates under the PRDM. *Id.* As a matter of equity and mitigating rate shock, BPA has designed the RICj to start at the same level as that original TRM compromise ($1 million) but then taper it off over the ensuing 16 years to $0 to transition PNGC over to the PRDM. In this way, the RICj was appropriately "tailor[ed]" to transition the JOE from the TRM to the PRDM. Reed *et al.*, PRDM-26-E-BPA-05, at 26.

PNGC proposes a different schedule of payments, one that effectively doubles the mitigation proposed by BPA Staff's RICj proposal. PNGC Br., PRDM-26-B-PN-01, at 13. The basis for PNGC's request, however, is non-existent. It simply appears to be BPA Staff's proposal with no taper, in essence doubling BPA Staff's proposal. Bleifuss *et al.*, PRDM-26-E-BPA-11, at 33. Given that PNGC has not provided any analysis or support to expand the RICj beyond BPA Staff's proposal, and given that the TRM was not intended to assure PNGC of any such benefit, BPA finds the amount of RICj as proposed by BPA Staff to strike the appropriate balance of mitigating rate shock and equitably transitioning PNGC from TRM to PRDM.

<u>*RICj Mitigation Duration*</u>

PNGC also argues that the RICj should not have a taper off feature and urges BPA to maintain the RICj for the entirety of the Provider of Choice Contract period. PNGC Br., PRDM-26-B-PN-01, at 8, 9. While claiming that the financial harm to its members is "very real," PNGC offers no record evidence to support its claim for a continuation of the $1 million for the entire duration of the Provider of Choice Contract. *Id.* at 10. PNGC contends that the sunset feature of the RICj "effectively terminate[s] the benefits of demand diversity that PNGC currently experiences under [the] TRM." *Id.* at 11. PNGC also contends that a higher RICj would not have a "material impact on the remaining set of BPA preference customers" but "would have a material impact on PNGC members and the rural communities PNGC serves." *Id.* at 12.

As discussed in detail above, BPA finds PNGC is not entitled to a diversity benefit on behalf of its members' loads. *See* Issues 5.3.3.5.1 through 5.3.3.5.3. Thus, PNGC's claims that BPA

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must fully "mitigate" the cost of transitioning PNGC from the TRM demand charge treatment to the PRDM demand charge treatment cannot stand.

Additionally, the taper-off feature of the RICj is an important part of the balance that holds together the compromise behind the PRDM. Bleifuss *et al.*, PRDM-26-E-BPA-11, at 32. That balance is not lessened because PNGC does not consider the RICj a "material" cost in BPA rates. The principle of paying PNGC a special RICj credit, which must be recovered from all other customers, remains controversial. By proposing the RICj, BPA is, in part, perpetuating in the PRDM for another 16 years the unintentional cost shift originating from the TRM. *Id.* However, this outcome is largely palatable because it is not forever. *Id.* The RICj has a beginning and an end, and by the end of the Provider of Choice Contract, "PNGC (and its members) will be in the same place as every other customer under the PRDM." *Id.* This aligns BPA's proposal for the RICj with the original intent behind the TRM's treatment of the JOE, which was to "place the JOE in roughly the same position as other customers." Reed *et al.*, PRDM-26-E-BPA-05 at 16. On the other hand, expanding the RICj as suggested by PNGC, exacerbates the cost shift and threatens to upend the "hard-won equilibrium" that is the PRDM. *See* JP01 Br., PRDM-26-B-JP01-01, at 5.

<u>RICj Mitigation Permanence</u>

Finally, PNGC "objects strongly" to BPA staff's "supposition that this change should be permanent and precedential." PNGC Br., PRDM-26-B-PN-01, at 9. PNGC claims there is "no plausible reason to unduly discriminate against a JOE in perpetuity." *Id.* PNGC contends that the PRDM will "expire . . . on September 30, 2044," and decisions the Administrator makes under the PRDM framework should not bind or restrict future Administrators. *Id.* PNGC also argues that it does "not accept that this decision should stand forever" because "[n]o one can predict what the landscape will be 15-20 years from now." *Id.* at 11. PNGC asserts that "[t]he world will be redefined by future generations when it is their turn to do so and it is not reasonable to bind future Administrators at this time, nor to seek to establish a perpetuity not clearly established or expressed by Congress." *Id.*

PNGC's arguments are incorrect. First, the PRDM does *not* expire on September 30, 2044; it has no express expiration date. *See* PRDM § 1.2; Stiffler *et al.*, PRDM-26-E-BPA-03, at 2-3 ("Our intent with this language is to allow the PRDM to continue to be available as the applicable rate methodology until there are no contracts that use its terms. This is a change from the TRM, which had a stated expiration date.") (emphasis omitted). Thus, the decision BPA makes in this decision document, as reflected in the PRDM, will be in effect until modified consistent with the terms of Chapter 9 of the PRDM. While this decision may not be in effect "forever," it will be the approach BPA takes until the PRDM no longer guides BPA's rates.

Second, and more importantly, the eventual elimination of the RICj produces certainty regarding how to address the JOE issue in the future. PNGC's proposal—which is to continue to provide a credit to PNGC at the end of the Provider of Choice Contract—perpetuates the issue forward to future generations, leaving it to them to figure out whether and how to continue a subsidy to a subset of BPA customers. Thus, at the end of the Provider of Choice Contract, the "cost shift" issue that exists today under the TRM and the RD contract could continue into the next iteration of rates and agreements. Bleifuss *et al.*, PRDM-26-E-BPA-11, at 33. The same equity questions of moving PNGC and its membership to a level playing field with other customers would again be debated. *Id.*

BPA's approach, in contrast, sunsets the RICj in 16 years, after which "PNGC (and its members) will be in the same place as every other customer under the PRDM." *Id.* at 32. BPA finds two sets of long-term contracts and rates with implicit (TRM) and now explicit (PRDM) costs shifts are enough, and a hard sunset of this issue as proposed in the RICj is reasonable and a sound business decision. *Id.*

Finally, PNGC notes that the future is uncertain and that it is not reasonable to bind future generations to the decisions being made here. PNGC Br., PRDM-26-B-PN-01, at 11. BPA agrees that the future is uncertain. As such, it makes sound business sense to ensure future generations have *flexibility* to address that uncertainty, particularly when it comes to ratemaking. The best way to mitigate that uncertainty is not to burden future rate analysts and policy makers with old debates or hobble them with a methodology riddled with exceptions, rate credits, and other mitigation features that mute price signals and insulate customers from the true costs of the services they are purchasing. The better approach is the one BPA has taken here: to deal with the hard issues now and propose a solution that resolves the issue in a fair and equitable manner, while not perpetuating it into future rates. BPA's design of the RICj does just that.

Draft Decision

BPA will not modify the RICj.

5.5 Other Tier 1 Charges (PRDM Section 4.6)

The PRDM defines the Core Rate Design charges that cannot be changed without pursuing a successful change to the PRDM as governed by Chapter 9 of the PRDM. Reed *et al.*, PRDM-26-E-BPA-05, at 27. Outside these Core Rate Design charges and credits, Section 4.6 of the PRDM makes clear that BPA can and will propose other adjustments, charges, and special rate provisions in each 7(i) Process as needed, without it being considered a change to the PRDM. *Id.*

5.6 Disaggregation of Risk Within Tier 1 Non-Slice Products (PRDM Section 4.7)

PRDM Section 4.7 was designed to memorialize the agreement to not further sub-allocate costs associated with risk prior to September 30, 2041; at which time any such sub allocation of risk in Tier 1 Rates would be decided through a 7(i) Process. The phrase "disaggregation of risks within the Tier 1 Non-Slice Products" refers conceptually to the possibility that the revenue BPA collects from rates charged to Load Following and Block

Products may contribute to, and draw upon, BPA's financial reserves unequally over time. *Id.* at 27-28.

BPA developed the PRDM as a package that attempts to address all risks in a reasonable and equitable way. *Id.* at 30. BPA believes that the PRDM's terms do this well, and that is why the PRDM does not propose to disaggregate risk within the Non-Slice cost pool. *Id.* At the same time, there are differing views among customers about the equity of not sub-allocating risk within a cost pool. In view of these differing opinions, BPA included in the PRDM this section to permit this issue to be revisited in 2041, where new information may make disaggregating risk within a cost pool more apparent. *Id.*

5.7 Cashflow Consideration (PRDM Section 4.8)

Several of BPA's Core Rate Design elements have pricing structures that are not flat throughout a year. *Id.* at 31. There are higher-priced periods of time and lower-priced periods of time. *Id.* This section acknowledges that this structure may impose cashflow challenges for particular customers. *Id.* As such, Section 4.8 of the PRDM enables BPA and customers to evaluate, on a case-by-case basis, modifications to particular customer bills that could mitigate these cash flow challenges. *Id.* To be clear, the total amount collected from the customer over a given year would be the same on a net present value basis. *Id.* The considerations here simply address the timing of those payments.

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6 TIER 2 RATE DESIGN (PRDM CHAPTER 5)

6.1 Overview

Chapter 5 of the PRDM provides guidance on the establishment of Tier 2 Rates, which are to be implemented in each 7(i) Process consistent with the principles outlined in Chapter 2 of the PRDM. Fisher & Reed, PRDM-26-E-BPA-06, at 1. Chapter 5's sections include: an overview of the Tier 2 construct and general pricing philosophy of setting Tier 2 Rates; an overview of how Tier 2 energy amounts are set and an operational exception provided to certain customers; the cost basis and components that will be used in each 7(i) Process to set Tier 2 Rates; the rate treatment applied when a customer has a Tier 2 purchase obligation but no load to support such purchase; and additional rate considerations and associated processes for both the Tier 2 Long-Term and Tier 2 Vintage Rate Alternatives. *Id.* at 1-2.

6.2 Tier 2 Rate and Above-CHWM Load

As noted earlier, Tier 2 Rates apply to power sold to meet a customer's Above-CHWM load. A customer's Above-CHWM Load is calculated in the Above-CHWM Process and any such Above-CHWM Load is then used in conjunction with the customer's contractual elections to determine the amount of that Above-CHWM Load that will be served at BPA's Tier 2 Rates. *Id.* at 2. The Above-CHWM Process is not dictated by the PRDM and is completed outside and before setting the Tier 2 Rates in each 7(i) Process. *Id.* The PRDM does, however, specify an operational convenience provided to certain customers that allows up to 0.999 average megawatts (aMW) of otherwise Above-CHWM Load to be served through the Core Rate Design as described in Chapter 4 of the PRDM. *Id.* This operational convenience is provided to Load Following customers that would have otherwise had a portion of their Above-CHWM Load served under the Flexible Tier 2 Path. *Id.* If the JOE meets the eligibility criteria, then the 0.999 aMW operational convenience is applied to the JOE and not each member, given that the purpose of the operational convenience is inherently provided by being a JOE with its ability to operationally manage its members' Above-CHWM Loads as a single entity. *Id.*

6.3 Cost Basis for Tier 2 Rates (PRDM Section 5.2)

The PRDM states that the allocation of Tier 2 Costs and the design of Tier 2 Rates will ensure, "to the maximum extent practical," that the Tier 2 Rates will recover the fully allocated cost of BPA's service to planned Above-CHWM Load. PRDM § 5.0. It also states the corollary, that "Tier 1 System Resources will not be used in a manner that subsidizes the allocated costs of Tier 2 Rate service." *Id.* With one exception,[31] the PRDM specifies that

[31] The PRDM carves out one situation where BPA will set the Tier 2 Rates using the costs allocated to Tier 1 Rates. This situation is applicable to the Tier 2 Long-Term Rate only, and occurs when BPA's Tier 2 Long-Term

Tier 2 Rates will be based on BPA's marginal cost of serving Above-CHWM Load at a Tier 2 Rate, including the cost of any services that BPA provides because of selling power at Tier 2 Rates. Fisher & Reed, PRDM-26-E-BPA-06, at 4. This cost may be based upon the actual or projected cost of specific resources acquired to serve the load or another market-based value (*e.g.,* forecast, actual, or index market value). *Id.* This value could include value for capacity, energy, and other relevant value-based attributes and services. *Id.* Outside of this direction, PRDM Chapter 5 does not specify how Tier 2 Rates will be calculated, but rather, directs those calculations to be defined in each 7(i) Process. *Id.* This gives better certainty that Tier 1 Rates will not bear costs associated with serving loads at Tier 2 Rates. *Id.* This flexibility also allows BPA to set Tier 2 Rates appropriately as markets, conditions, costs and tools change over time. *Id.* In summary, Chapter 5 balances a need for certainty with the flexibility necessary to achieve cost separation between Tier 1 and Tier 2 Rates. *Id.*

6.4 Remarketing of Tier 2 Amounts (PRDM Section 5.3)

Tier 2 purchases are take-or-pay commitments to purchase a fixed amount of power at its associated Tier 2 Rate. *Id.* at 6. For Tier 2 Long-Term and Tier 2 Short-Term customers, these purchase amounts are forecast-based commitments made on a rate-period basis, which may differ from actual loads. *Id.* For any Tier 2 Vintage offerings, the purchase amounts will be made on forecasts well in advance of expected delivery and could also be larger than the then-current load needs of the customer given the expected and planned uneven shape of resource acquisitions. *Id.* Section 5.3 of the PRDM acknowledges that a difference may occur between a customer's planned Tier 2 purchase obligations and its actual loads or an updated forecast from the time in which Above CHWM Loads are determined. *Id.* To manage this difference, Section 5.3 establishes a rate provision for BPA to credit those customers for any unused portion its Tier 2 purchase obligation amount. *Id.* Said differently, this section allows BPA to credit a customer for its unused Tier 2 purchase amounts at whatever remaining marketable, or salvage value, exists, plus any costs associated with those remarketing activities. *Id.*

6.5 Forms of Tier 2 Rates

There are three categories of Tier 2 Rates: Tier 2 Short-Term Rate; Tier 2 Long-Term Rate; and Tier 2 Vintage Rate(s). *Id.* at 3. Each category is described in the Provider of Choice Policy and is applicable to a customer based upon contract-defined customer elections and load forecasts relative to the customer's CHWM prior to each 7(i) Process. *Id.* The Tier 2 Vintage Rate category may have no rates associated with it (in the event no vintage

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load obligation has otherwise unmet power needs—i.e., BPA has not already acquired the full amount of resources with the purpose of meeting its Tier 2 Long-Term load obligation—and BPA has Forecast Firm Inventory available. In this limited situation, BPA would set the Tier 2 Long-Term Rate with the costs included in the Tier 2 Long-Term Cost Pool plus the otherwise unmet power need at a cost equivalent to BPA's Non-Slice Tier 1 Rates. *See* Fisher & Reed, PRDM-26-E-BPA-06, at 4.

purchase has been offered, or any offer not elected), or several different rates associated with it (in the event multiple vintage purchases have been offered and elected). *Id.*

6.5.1 Tier 2 Long-Term Alternative (PRDM Section 5.4)

The Tier 2 Long-Term Alternative is a contract election that customers can elect to have BPA serve a portion, or all, of their Above-CHWM Loads at the BPA's Tier 2 Long-Term Rate. *Id.* at 6. Customers can elect to take this Tier 2 Alternative one time and within 60 calendar days after CHWMs are established. *Id.* The Provider of Choice Policy describes some limited options to cap or reduce the first election—sometimes with and sometimes without fees and other charges. *Id.* Generally, the Long-Term Tier 2 Alternative will function as a pooled election to manage multiple customers' Above-CHWM Load under a single portfolio of resources with the cost of those resources melded and collected from all customers that elected this Tier 2 Rate Alternative. *Id.* at 6-7.

6.5.2 Tier 2 Vintage Alternative (PRDM Section 5.5)

BPA's Tier 2 Vintage Alternative is a contract election that is only available if certain conditions are met. *Id.* at 8. The initiating condition is that BPA intends to make a Request for Offer to acquire the output of one or more physical resources for a period that extends beyond a three-year period. *Id.* Once that initiating condition occurs, customers elect an associated Tier 2 Vintage Alternative, and a purchase is made, BPA would then use the costs of that purchase, plus other costs that may be needed to support that sale, to calculate the associated Tier 2 Vintage Rate. *Id.* BPA intends to establish a formula and other special rate provisions at the time the rate is set to account for the lumpy and often not perfectly timed or predicable nature of developing and acquiring the output of a physical resource. *Id.* at 8-9.

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7 SUPPORT SERVICES (PRDM CHAPTER 6)

7.1 Overview

The purpose of Chapter 6 of the PRDM is to establish the principles and rate treatment upon which the charges and credits for each service will be built. Reed & Fisher, PRDM-26-E-BPA-07, at 1. This chapter also specifies that those charges and credits will be established in each 7(i) Process. *Id.* Lastly, the PRDM establishes how the revenue and the resulting obligation of providing Support Services will impact the Composite Cost Pool, the Non-Slice Cost Pool, and the list of Designated System Obligations. *Id.*

7.2 Support Service Pricing Principles (PRDM Section 6.1)

The Support Services' principles establish several key links: a link in the provision of capacity-based services to the marginal cost of capacity, such as the Marginal Capacity Resource used to set the Demand Rate specified in Tier 1 Rate Design; a link to the embedded cost of capacity used for required capacity-based services applied to existing non-federal resources; a link in the provision of energy-based services to market-based pricing; a link in the provision of other service-related costs to opportunity and like-based costs; and alignment of the associated revenues with corresponding Cost Pools based on the principles of cost-causation established in PRDM Chapter 2. *Id.* at 5. The PRDM also includes Appendix D, Support Services Framework, to aid clarity in the different Support Services BPA may provide and the pricing construct attached to each. *Id.*; *see also* PRDM, Appendix D, Figure D-1.

7.3 Treatment for Specific Types of Service (PRDM Sections 6.2-6.5)

The PRDM recognizes that there are several different permutations of Load Following customer resources, each with unique considerations under Support Services. Reed & Fisher, PRDM-26-E-BPA-07, at 6. These permutations are based on contractual status (*e.g.*, an Existing Resource or a resource serving Above-CHWM Load), resource characteristics that include the resource's relative dispatchability, and the nature of the resource's fuel supply. *Id.* Dispatchability refers to the ability of a resource to respond to changes in load. *Id.* Variability refers to whether the fuel supply, or source of energy, of the resource is controllable or not—such as wind, solar, or wave action. *Id.* Given the multitude of ways a non-federal resource of a Load Following customer could ultimately impact BPA's net load obligation, the PRDM establishes how BPA will approach Resource Support Services (RSS) for different types of Load Following customers' non-federal resources. *See* PRDM §§ 6.2-6.5.

7.4 Issues

Issue 7.4.1
Whether the PRDM's RSS pricing principles disincentivize the integration of non-federal generation.

Parties' Positions

RNW contends that the PRDM's RSS pricing principles disincentivize the integration of non-federal generation. RNW Br., PRDM-26-B-RN-01, at 4. RNW contends that pricing RSS at marginal costs continues a past practice of discouraging the integration of non-federal resources. *Id.*

BPA Staff's Position

The Support Services pricing principles, which include RSS, are appropriate and leave future 7(i) Processes to develop appropriate rates. *See* PRDM §6.1. Pricing Support Services at the marginal cost of providing such services results in an economically efficient price signal to invest in cost effective non-federal resources. Marginal cost pricing does not constitute an "inflated" cost, nor does it "disincentivize" the integration of non-federal resources. *See, generally,* Reed & Fisher, PRDM-26-E-BPA-07, at 2.

Evaluation of Positions

RNW argues BPA should not adopt policies in the PRDM that render BPA the only power supplier for Public Customers. RNW Br., PRDM-26-B-RN-01, at 1, 2. RNW argues that BPA Staff's proposal for pricing RSS at "marginal cost of capacity" may continue to disincentivize the integration of non-federal generation. *Id.* at 4. RNW claims that BPA's "inflated" RSS pricing under the Regional Dialogue "discouraged" customers from integrating non-federal resources. *Id.* RNW contends it was "hopeful" that the PRDM would result in lower RSS pricing policies, but the PRDM has deferred those decisions to future 7(i) Processes. *Id.* RNW is concerned that nothing in the PRDM limits BPA's discretion in such future processes from increasing RSS charges, and thus, "nothing precludes the agency from continuing to discourage non-federal resource development with cost-prohibitive RSS requirements." *Id.* RNW recommends the Administrator "consider providing general policy direction in the PRDM ROD to avoid any such result." *Id.*

Marginal cost pricing principles, as used in the TRM and as continued in the PRDM, encourage economically efficient investments in capacity and appropriately incentivize economical use of the federal system's capability. Reed *et al.*, PRDM-26-E-BPA-05, at 8. As such, their application would neither render BPA the only power supplier for Public Customers, nor would their application disincentivize the development of non-federal generation. To the contrary, marginal cost pricing principles for Support Services, such as RSS, combined with a customer's choice for how it will serve its Above-CHWM Load ensures that BPA's customers consider not only the marginal *energy* cost of serving its

Above-CHWM Load with non-federal resources but also the associated marginal *capacity* cost of serving its Above-CHWM Load.

RNW argues nonetheless that the higher BPA's Support Service costs, the fewer non-federal resources will be developed. RNW Br., PRDM-26-B-RN-01, at 4. In fact, the opposite is true: the higher BPA's Support Service costs are the more likely a customer will want to avoid paying BPA's rate and procure its own non-federal *capacity* resource to serve its Above-CHWM Load *capacity* needs, such as appending battery technology to a solar facility. The battery, in this example, is in direct competition with BPA's Support Services and thus the lower BPA's Support Services costs the less likely the customer would choose to invest in the battery.

To be clear, BPA is not proposing to artificially increase Support Service costs for the purpose of incentivizing non-federal resource investment. That is not BPA's proposal, nor would such a practice be consistent with the PRDM's intent. Fisher *et al.*, PRDM-26-E-BPA-02, at 15 (describing principles underlying the PRDM). The intent of the PRDM's Support Service pricing principles is to level the playing field for non-federal capacity investments—to offer a federal option at the marginal cost of providing the capacity associated with the customer's Above-RHWM Load needs while also providing the customer the option to procure some, or all, of the required load service capacity on its own. *See* Reed & Fisher, PRDM-26-E-BPA-07, at 2 (noting that Support Services "will be priced at the marginal cost of capacity" and that this "is an important feature of the PRDM in that it makes clear BPA will not undermine its Tier 1 Rate Design by providing capacity to . . . [c]ustomers through Support Services at a cost lower than the marginal price signal used in its Core Rate Design."). This provides customers an economically efficient and non-punitive option that both holds other customers harmless from the choice to place this increased capacity obligation on BPA, while also giving the customer greater flexibility in the type of non-federal resources it chooses to serve its Above-CHWM Load.

For example, the PRDM's Support Service pricing principles allow a customer to partially meet its Above-RHWM Load requirement with non-federal resources and leave the remainder to BPA, at the marginal cost. This allows customers to procure from the more plentiful and readily available energy-only non-federal resources available to it without having to take on the added complication and presently sparce availability of non-federal capacity options.

Also missing from RNW's argument is any acknowledgment of the inextricable link between the marginal capacity price signal sent to load, through the Tier 1 Demand Rate, and the marginal capacity price signal sent to a resource through RSS. Setting aside operational differences that may require capacity with more or less costly operational capabilities, the two represent different sides of the same capacity coin and must be crafted and considered together. *See id*. at 5. RNW appears to argue that the price signal proposed to be sent to load is too low while simultaneously arguing that the price signal proposed to be sent to a resource is too high. *Compare* RNW Br., PRDM-26-B-RN-01, at 4 (arguing that RSS capacity costs are too high), *with id.* at 2-3 (arguing that the PRDM produces “[a]rtificially low demand costs . . . .”). Given that both are addressing the marginal cost of capacity, both cannot be true as argued by RNW. The PRDM is consistent in its application and provides for an economically efficient price signal to invest in cost effective non-federal resources. That capacity price signal is agnostic as to its source—whether it be capacity to reduce or serve load or capacity to shore up a non-federal resource serving a customer’s Above-CHWM Load.

Draft Decision

The PRDM’s Resource Support Service pricing principles are reasonable and do not disincentivize the integration of non-federal generation.

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8 RISK MITIGATION (PRDM CHAPTER 7)

8.1 Overview

Risk mitigation in the context of the PRDM refers to systematic rate design and rate-setting strategies used to reduce the likelihood of financial losses and/or inequity in planned outcomes. Mandell *et al.*, PRDM-26-E-BPA-08, at 1. "Risk" itself refers to the possibility that future outcomes differ from forecast outcomes, which could have negative and/or disparate impacts on BPA and its customers. *Id.*

In the context of BPA ratemaking and the PRDM, risk mitigation generally refers to rate design and rate-setting decisions that affect the probability or impact of unintended financial consequences. *Id.* Risk mitigation matters in the PRDM because financial and other business outcomes may not occur as planned. *Id.* Actual costs and revenues will differ from forecasts used to set rates. *Id.* Risk mitigation is used to minimize the probability or impact of these unintended outcomes. *Id.* at 1-2. The PRDM does not limit the risk mitigation policies BPA may adopt, or the risk mitigation mechanisms BPA may adopt in a rate proceeding. *Id.* at 2; *see also* PRDM § 7. The PRDM guides the allocation of costs associated with risk mitigation between Tier 1 and Tier 2 Rates only. Mandell *et al.*, PRDM-26-E-BPA-08, at 2.

Risk associated with Tier 1 and Tier 2 rates will be assessed in each Section 7(i) Process, consistent with BPA's then-current agency financial risk standard(s), as set out in BPA's then-current financial plan and policies. *Id.* at 3; *see also* PRDM §§ 7.1, 7.2. If, after assessing and mitigating risks for each Tier 2 Cost Pool and for Tier 1 Cost Pools, BPA finds that Power function risks have not been adequately mitigated pursuant to BPA's risk standards, then BPA will allocate the remaining risk and any additional mitigation between the tiers in the applicable 7(i) Process, consistent with the PRDM. Mandell *et al.*, PRDM-26-E-BPA-08, at 3.; PRDM § 7.3.

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9 OTHER RATE DESIGN (PRDM CHAPTER 8)

9.1 Other Rate Design

9.1.1 Overview

PRDM Chapter 8 is intended to address various topics that were not specifically part of the Core Rate Design. This includes the rules and structure of the power rate discounts for rural areas and agriculture. PRDM § 8; *see also* Beavon *et al.*, PRDM-26-E-BPA-09, at 1.

9.1.2 Rates for Unanticipated Load (PRDM Section 8.1)

This PRDM section describes how BPA will develop rates in a 7(i) Process for service to unanticipated loads. PRDM § 8.1. Unanticipated loads are PF Public Customer loads that BPA is obligated to serve under the Northwest Power Act, but for which BPA has not received the notice to serve required by the CHWM Contract or Wholesale Power Rate Schedules and General Rate Schedule Provisions (GRSPs) in order for a customer to receive service at Tier 1 or Tier 2 Rates. Beavon & Fisher, PRDM-26-E-BPA-09, at 2; PRDM § 8.1. The actual rate design for Unanticipated Load Service (ULS) will be determined in the applicable 7(i) proceeding. Beavon & Fisher, PRDM-26-E-BPA-09, at 2. However, the PRDM does describe the pricing basis for ULS—namely that the price for ULS will reflect the cost of power and service. *Id.*; PRDM § 8.1.

9.1.3 Low Density Discount (PRDM Section 8.2)

This PRDM section summarizes the Low Density Discount (LDD), which is a discount program under Section 7(d)(1) for customers with low system density. *See* 16 U.S.C. § 839e(d)(1); Beavon & Fisher, PRDM-26-E-BPA-09, at 2; PRDM § 8.2. Currently, the LDD applies to both PF Preference and New Resource Rates. Beavon *et al.*, PRDM-26-E-BPA-09, at 2. The PRDM will make several changes to the LDD program by: establishing a discount program to achieve a specified program cost at the beginning of the contract period in FY 2029; changing the formula for calculating the effective LDD percentage to exclude PF loads beyond a customer's CHWM; and calculating the LDD benefit for Slice customers using the customer's Tier 1 charges without a conversion as if the customer were a Load Following customer. Beavon & Fisher, PRDM-26-E-BPA-09, at 3. BPA retains the right to change the LDD in a future 7(i) Process. *Id.*

The LDD Percentage Discounts will be set at values in the BP-29 Rate Period that, when applied to forecasts of qualifying customers, will result in an LDD program cost between $42 million and $44 million. *Id.* at 3-4. This range was selected so that the LDD program at the beginning of the BP-29 Rate Period would be comparable to the program costs prior to the effective date of the PRDM. *Id.* at 4. BPA retains the right to modify the LDD Percentage Discount Table—an example of which is included in Appendix C of the PRDM—in a future 7(i) proceeding. *Id.*; *see* PRDM § 8.2.

Importantly, with the PRDM, the LDD will now apply to "Tier 1 Composite Energy Charge, the Tier 1 Non-Slice Energy Charge, the Tier 1 Slice Energy Charge, the Tier 1 Demand Charge, and the Tier 1 Peak Load Variance Charge." PRDM § 8.2. The LDD will not apply to purchases of power for Above-CHWM Load. *Id.*; Beavon & Fisher, PRDM-26-BPA-E-09, at 4-5. This change results from customer desires to see LDD program costs controlled. Beavon & Fisher, PRDM-26-E-BPA-09, at 5. Additionally, BPA will change the calculation of LDD benefits for qualifying Slice customers by directly applying the LDD rate to the charges billed to the Slice/Block customer. *Id.*

9.1.4 Irrigation Rate Discount (PRDM Section 8.3)

This PRDM section summarizes the Irrigation Rate Discount (IRD), which is a discount to BPA's wholesale power rate for eligible irrigation load served by a customer. Beavon & Fisher, PRDM-26-E-BPA-09, at 5; PRDM § 8.3. In the PRDM, the IRD will be set at a fixed percentage discount to Tier 1 rates that will result in a program cost of approximately $22 million in FY 2029, the same cost to the IRD program under the TRM. Beavon & Fisher, PRDM-26-E-BPA-09, at 6. The current IRD percentage discount is 37.06 percent, and BPA estimates that under the PRDM the discount will be between 30 and 35 percent when calculated in the BP-29 Rate Period. *Id.* This number, once calculated in the BP-29 rate proceeding, will stay the same in each future rate period. *Id.* In each future Rate Period, a new mills per kilowatthour discount will be derived by applying the IRD discount percentage to the applicable Tier 1 Rates, adjusted for any applicable LDD, of eligible irrigation loads. *Id.*

To qualify for the IRD, a customer serving irrigation load must meet one of the following criteria: either the customer participated in the IRD program in FY 2028, or "[a]t least 75 percent of the customer's Total Retail Load must be placed on BPA starting October 1, 2028, and the customer's irrigation rate schedule sales, May through September in FY 2018-2022, divided by its TRL for FY 2018-2022, is at least 5 percent; or, if less than 5 percent, the average kilowatthour usage for May through September in FY 2018-2022 (25 months/5 years) is 7,500,000 kilowatthours (kWh) or more." *Id.* at 7-8. For Slice/Block customers, the rate adjustment is applied to the lesser of the customer's monthly block purchased at Tier 1 Rates or the qualifying irrigation kilowatthour specified in its contract. *Id.* at 8.

9.1.5 Section 7(b)(2) Rate Test (PRDM Section 8.4)

As noted in Section 3.1.4 of this Draft ROD, the PRDM does not address the calculation of any other rates besides the PFp rate (and certain services related thereto). *See also* PRDM § 1.3. To confirm that the scope of the PRDM is limited, this section reaffirms that the terms of the PRDM do not impact certain other rates and rate directives. One area expressly excluded from the PRDM is the Residential Exchange Program (REP). Beavon & Fisher, PRDM-26-E-BPA-09, at 8-9. The REP is the colloquial name of the statutory purchase and exchange sale called for in Section 5(c) of the Northwest Power Act, 16. U.S.C. § 839c(c). Basically, any utility in the region may sell power to BPA at their average system cost (ASC) in an amount equal to their residential and farm load. Beavon & Fisher, PRDM-26-E-

BPA-09, at 8. BPA buys this power and sells back an equivalent amount of power at BPA's cost of power, modified by certain rate adjustments. *Id.* The rate for BPA's power under the REP is the PF Exchange Rate. *Id.* In practice, no power moves, and the two simultaneous sales net out to a payment from BPA to the utility participating in the REP. *Id.*

For the post-Regional Dialogue period (2028-2044), customers that choose to sign a Provider of Choice Contract and pay rates pursuant to the PRDM must agree to waive their participation in the REP. As such, the PRDM acknowledges that no PF Exchange rate will be designed for those customers. PRDM § 8.4.1. Customers that do not sign a Provider of Choice Contract are not required to waive their participation in the REP, and consequently, the PRDM assures those customers that BPA will perform its statutory duties and develop an applicable PF Exchange rate. PRDM § 8.4.2.

The REP is also subject to a complicated rate test set forth in Section 7(b)(2) of the Act. *See* 16 U.S.C. § 839e(b)(2). Because this rate test has been "the source of much controversy in past rate cases," BPA included an express disclaimer in the PRDM to make clear that it does not impact the implementation of the rate test. Beavon & Fisher, PRDM-26-E-BPA-09, at 9; PRDM § 8.4.3.

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10 REVISIONS PROCESS AND DISPUTES (PRDM CHAPTER 9)

10.1 Overview

Chapter 9 of the PRDM describes 1) the criteria and processes that apply when BPA (or a customer) seeks to revise the terms of the PRDM, and 2) dispute resolution processes for determining whether an action by BPA violates or is otherwise inconsistent with the PRDM. Fisher & Beavon, PRDM-26-E-BPA-10, at 1. The PRDM is intended to maintain long-term certainty and predictability from Rate Period to Rate Period by being employed in future Rate Periods for at least the life of the Provider of Choice Contract. *Id.* at 1-2. The PRDM reflects a balanced compromise on issues relating to how BPA will develop the Section 7(b) rates among a diverse set of customers and interests. *Id.* at 2. While it is expected that the PRDM will be implementable without issue, there is always the chance that future circumstances present an opportunity for improvement or cause a provision of the PRDM to no longer operate properly. *Id.* Additionally, there may be actions outside of BPA's control—such as a Court decision—that require BPA to make adjustments to ensure it recovers its total costs. *Id.* Therefore, the PRDM includes revision processes tailored to the *type* of revision being considered. *Id.*

10.2 PRDM Revision Processes and Dispute Resolution Compared to TRM

PRDM Chapter 9 was built largely from the revision process and dispute resolution used by the TRM. *Id.* at 3. The PRDM keeps the primary categories used by the TRM to describe different types of changes and how those changes are proposed. Specifically, the PRDM retains three types of revisions under the categories of 1) improvements and enhancements, 2) unintended consequences, and 3) cost recovery or court ruling. *Id.* The PRDM also retains a distinction between dispute resolution 1) within a 7(i) Process, or 2) outside a 7(i) Process, regarding whether BPA has violated the PRDM. *Id.*

Chapter 9 combines the material from two chapters in the TRM. *Id.* at 3-4. The TRM divided material into criteria and conditions for revising the TRM (TRM Chapter 12), and processes for making those revisions (TRM Chapter 13). *Id.* Chapter 9 of the PRDM combines these concepts into a single chapter to make the connections between the criteria and processes clearer. *Id.* at 4.

The PRDM's Mini-Trial process is different from the TRM's Mini-Trial, despite retaining the term for familiarity. *Id.* at 12. The TRM included a larger role for the 7(i) Process Hearing Officer. *Id.* Ultimately, the Administrator was still able to disagree with the Hearing Officer and choose not to adopt the Hearing Officer's decision. *Id.* But the inclusion of the Hearing Officer process, and tracing out all potential BPA responses, added unnecessary complexity,

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without added value. *Id.* Instead, the PRDM recognizes that early, direct access to the decision-maker provides the most value. *Id.* at 13.

The TRM also potentially limited customers from fully exercising their procedural rights within the 7(i) Process. *Id.* If the Hearing Officer agreed with BPA's position, and the Administrator agreed with the Hearing Officer, then the decision was conclusive for the 7(i) Process. *Id.* In contrast, the PRDM allows parties to continue making their case even after an unfavorable decision in the Mini-Trial. *Id.*

10.3 Components

10.3.1 Customer Count and General Provisions

As discussed below, different processes require different levels of customer support or opposition. Chapter 9 measures customer support using a House and Senate approach. *Id.* at 4. Support is measured by *both* utility count *and* load. *Id.* More specifically, support or opposition is measured as a group totaling 1) at least 70 percent of customers (utility count) and 2) at least 50 percent of the sum of the CHWMs. *Id.*

The terms "Customer" and "Customer Group" have a specific meaning within Chapter 9. *Id.* For purposes of Chapter 9, a "Customer" is a utility that has a CHWM Contract, and a "Customer Group" is a group of Customers that are made up of 45 percent or more of all Customers (by utility count). *Id.* A Customer Group, rather than a single Customer, may propose a revision for "improvement or enhancement" or "unintended consequences." *Id.* However, such proposals are subject to House and Senate requirements discussed below. *Id.* For purposes of the Customer Group count, and for measuring House and Senate support, a JOE will have votes equal to the number of its members. *Id.* Thus, for instance, if the JOE has 15 members, the JOE's vote will be considered to be worth 15 by utility count. *Id.*

PRDM Section 9.1 makes clear that the PRDM may only be revised within a Section 7(i) Process. *Id.* at 5. This means that, while Chapter 9 sets up procedural barriers to introducing certain revision proposals into a 7(i) Process, the BPA Administrator will only decide whether to adopt the proposal after reviewing the full record developed by BPA and parties over the course of the 7(i) Process. *Id.*

Section 9.1 of the PRDM also identifies certain provisions that are so core to the balance struck in the PRDM that they cannot be revised as an "improvement or enhancement" or "unintended consequence," but only to ensure cost recover or comply with Court ruling. *Id.* On the other extreme, Section 9.1 also identifies actions that are explicitly not considered a revision to the PRDM, and therefore can be proposed in a 7(i) Process regardless of customer support. *Id.*

10.3.2 Improvements and Enhancements (PRDM Section 9.2)

If a proposal to revise the PRDM is not needed to ensure cost recovery or comply with a court ruling, and is not in response to unintended consequences, then the proposal is considered an improvement or enhancement of the PRDM. *Id.* at 5-6. While there is a path for such revisions, given the PRDM's interest in maintaining long-term certainty and predictability, such proposals cannot be made unless a House and Senate of Customers approve it being introduced in a 7(i) Process. *Id.* at 6. Notably, even after achieving this level of customer support, Customers in the minority that oppose the revision would still have the 7(i) Process to present evidence and arguments. *Id.* The BPA Administrator would only decide whether to adopt the proposal in the Final ROD after reviewing the full record developed in the 7(i) Process. *Id.*

10.3.3 Revisions for Unintended Consequences (PRDM Section 9.3)

These types of revisions apply to proposals to address or avoid unintended consequences that are putting at risk the policies and goals underlying the PRDM. *Id.* Compared to improvement proposals, there is a lower bar for unintended consequence proposals being considered in a 7(i) Process. *Id.* Here, a House and Senate of Customers that *oppose* the proposal can veto the proposal and prohibit it from being presented in the 7(i) Process. *Id.* This means the proposed revisions will move forward and be proposed in a 7(i) Process unless a House and Senate of Customers express disapproval of the proposal. *Id.* Again, the 7(i) Process will allow the issue to be discussed in a robust process by parties in support and opposition. *Id.* At the same time, given the PRDM's interest in maintaining long-term certainty and predictability, a House and Senate of Customers that prefer the status quo could constrain BPA and prevent the issue from entering the 7(i) Process. *Id.*

Importantly, there is a different process for a revision to address an unintended consequence that "affects others." *Id.* at 7. The PRDM only applies to sub-allocating costs within the Public Customer cost pool. *Id.* The PRDM is a balanced package that provides long-term certainty and predictability on issues among Public Customers. *Id.* The PRDM does not dictate ratemaking regarding other cost pools. *Id.* Therefore, if an unintended consequence impacts others beyond Public Customers with CHWM Contracts, Public Customers with a CHWM Contract should not be able to prevent BPA from considering the issue in a 7(i) Process. *Id.* The PRDM cannot prevent those others—*e.g.*, Public Customers without a CHWM Contract, investor-owned utility customers purchasing power at 7(f) rates or participating in the REP under Section 5(c), or direct service industry customers that purchase power under Section 7(c)—who are impacted from presenting evidence and arguments. *Id.* If a PRDM revision to address an unintended consequence affects others, it can be proposed in a 7(i) Process, regardless of opposition from Public Customers with CHWM Contracts. *Id.* Customers will of course be able to present their evidence and arguments in the 7(i) Process. *Id.*

BPA is considering whether to participate in a day-ahead market. *Id.* BPA Staff has been closely involved in the development of both the California Independent System Operator's

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(CAISO) Extended Day-Ahead Market (EDAM) and the Southwest Power Pool's (SPP) Markets+. *Id.* Given significant unknowns, it is not clear that any revisions to the PRDM would be necessary or desirable. *Id.*

However, if there were a package of proposed revisions to accommodate participation in a day-ahead market, the PRDM avoids conflict over whether the individual revisions within the package were "improvements" or "revisions for unintended consequences," and therefore what process would apply. *Id.* at 8. As a default assumption, BPA expects proposals to revise the PRDM related to day-ahead market participation to fall under Section 9.3.2 (Unintended Consequences that do not affect others). Bleifuss *et al.,* PRDM-26-E-BPA-11, at 18. This means that a House and Senate of customers would need to *oppose* the revisions to prevent them from being introduced into a 7(i) Process. Fisher & Beavon, PRDM-26-E-BPA-10, at 8.

There are two caveats to this default assumption. First, BPA must be able to propose revisions that are necessary for BPA to ensure cost recovery or respond to a court ruling, regardless of customer support or opposition. *Id.* Therefore, proposals for such revisions related to day-ahead market participation would still follow the procedures for recovery/response proposals. *Id.* Second, there is a theoretical possibility that a proposed revision to accommodate day-ahead market participation would also be a proposed revision "to address unintended consequences that affect others or general programs or policies" under Section 9.3.3 of the PRDM. Bleifuss *et al.,* PRDM-26-E-BPA-11, at 18. BPA does not have any specific potential revisions in mind, but as discussed above, the PRDM does not preclude others from presenting evidence and arguments in a rate case. *Id.* at 18-19. Therefore, proposals for such revisions related to day-ahead market participation would still follow the procedures for unintended consequences that affect others.

10.3.4 Revisions to PRDM to Ensure Cost Recovery or Comply with Court Ruling (PRDM Section 9.4)

BPA is able to propose PRDM revisions to ensure cost recovery or to comply with court rulings. Fisher & Beavon, PRDM-26-E-BPA-10 at 8. BPA must retain the ability to respond to such issues. *Id.* While parties will be able to support or oppose the proposal in the 7(i) Process, Customer opposition cannot prevent the proposal from coming into the 7(i) Process. *Id.* However, given the PRDM's interest in long-term certainty and predictability, BPA will seek to limit the number and scope of such revisions, and to the extent practicable, take certain preliminary steps outlined in PRDM Section 9.4.2.1. *Id.* at 8-9.

Further, BPA proposals could be subject to a Mini-Trial process. *Id.* at 9. The Mini-Trial element adds a procedural structure to allow customers to weigh in on whether BPA's proposal is appropriately narrow in scope. *Id.* That is, a cost recovery issue or court ruling might require some sort of PRDM revision in response, but the existence of such an issue does not give BPA free reign to propose *any* PRDM revision. *Id.* Customers may also

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disagree with whether any PRDM revision is actually necessary. *Id.* Ultimately, BPA must be able to respond to cost recovery issues and court rulings as it deems necessary.

The Mini-Trial process allows customers to have direct access to the Administrator at a meaningful time that can often lead to early resolution of issues. *Id.* Customers, with House and Senate support, may petition for a Mini-Trial regarding whether BPA's proposal is necessary and/or reasonably proportionate to ensure cost recovery or to respond to a court ruling. *Id.* In addition to the show of opposition, the process provides Customers an opportunity to file written statements and make oral presentations directly to the Administrator. *Id.* This process comes early in the 7(i) Process, giving BPA sufficient time to change course in response to Customers' arguments, and allows early direct interaction with the Administrator in addition to the more formal 7(i) Process of submitting written data requests, testimony, and briefs. *Id.*

10.3.5 Disputes Alleging Irreconcilable Conflict with the PRDM (PRDM Section 9.5)

Irreconcilable conflicts involve allegations that BPA is violating the terms of the PRDM. *Id.* at 10. That is, BPA's position is in irreconcilable conflict with the terms of the PRDM. *Id.* The definition originates from the TRM and is a high bar. *Id.* As the name suggests, the allegation must be that BPA's position is either contrary to a clear and unambiguous requirement or prohibition, or cannot be reconciled with *any* reasonable interpretation of the PRDM. *Id.* Under the PRDM, different processes apply to disputes that occur *within* or *outside* a Section 7(i) Process.

10.3.5.1 Disputes over Irreconcilable Conflict within a Section 7(i) Process

Within a Section 7(i) Process, Customers have the full 7(i) Process to present evidence and arguments for why the PRDM requires BPA to deviate from its position. *Id.* The Administrator will make a decision based on the full record, and customers will be able to challenge that final action. *Id.*

A House and Senate of Customers can also petition for a Mini-Trial under Section 9.4.2.2. The Mini-Trial element is an additional layer of process available to hopefully resolve conflicts early on and at the lowest level possible. *Id.* At the end of a Mini-Trial over irreconcilable conflict within a 7(i) Process, the Administrator is not limited to making a thumbs-up/thumbs-down determination on whether BPA's position is in irreconcilable conflict with the PRDM. *Id.* Consistent with the various processes discussed above, BPA could also propose to revise the PRDM, such that the BPA position would no longer be in irreconcilable conflict with the PRDM. *Id.* at 10-11.

Notably, the PRDM states that, if BPA's position is in irreconcilable conflict with the PRDM, but BPA is now proposing to revise the PRDM to ensure cost recovery or respond to a court ruling, the Administrator's decision will "to the extent practicable" be accompanied by the report in Section 9.4.2.1. *Id.* at 11; PRDM § 9.6. Section 9.4.2.1 lays out steps BPA should take before proposing a revision for cost recovery, but recognizes that such criteria cannot frustrate BPA's ability to recover costs. Fisher & Beavon, PRDM-26-E-BPA-10, at 11. In the Mini-Trial scenario, BPA likely did not follow these steps before the 7(i) Process began because it did not think its position was in irreconcilable conflict with the PRDM. *Id.* BPA will still issue the report in Section 9.4.2.1, but given the practical reality of being in a 7(i) Process and needing to set rates to recover costs, it may not be practicable for BPA to meet all criteria in Section 9.4.2.1. *Id.*

10.3.5.2 Disputes over Irreconcilable Conflict outside a Section 7(i) Process (PRDM Section 9.5.3)

As the name suggests, the PRDM is a methodology applicable to setting rates, and therefore BPA expects that nearly all issues with the PRDM would take place within the 7(i) Process. *Id.* All PRDM revisions must also be made through a 7(i) Process. *Id.* Nonetheless, there could be allegations that a BPA action is in irreconcilable conflict with the PRDM. *Id.* The PRDM leverages the same Mini-Trial structure to resolve conflicts at the lowest level possible before relying on the ability to bring Ninth Circuit Court litigation, and provides an opportunity to speak directly to the Administrator. *Id.*; *see also* PRDM §§ 9.5.3, 9.6.

10.3.6 Mini-Trial Before the Administrator (PRDM Section 9.6)

As discussed above, the Mini-Trial provides an additional process, including the opportunity to speak directly to the Administrator, in order to resolve conflicts at the lowest level possible. Fisher & Beavon, PRDM-26-E-BPA-10, at 12. It does not refer to a binding quasi-judicial determination. *Id.* The Mini-Trial is an additional process within the 7(i) Process, and the Administrator retains the ability to reach a different final decision at the conclusion of the 7(i) Process in the Administrator's ROD. *Id.* Outside a 7(i) Process, the Mini-Trial provides an opportunity to attempt to resolve conflict without resorting to Ninth Circuit Court litigation. *Id.*

Mini-Trial decisions are not final decisions. *Id.* at 13. Within a 7(i) Process, the Administrator may make a different decision in the Final ROD after considering all the evidence in the record. *Id.* Outside a 7(i) Process, BPA will take all practicable steps to revoke a BPA final decision that is in irreconcilable conflict, but those steps may involve additional public processes resulting in additional final decisions. *Id.* at 13-14.

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11 PARTICIPANT COMMENTS

BPA distinguished between ‘‘participants in’’ and ‘‘parties to’’ the PRDM proceeding. PRDM-26 FRN at 89,636. Separate from the formal PRDM-26 hearing process, BPA accepts written comments, views, opinions, and information on the PRDM from participants who have not intervened in the PRDM proceeding and been granted ‘‘party’’ status by the Hearing Officer. *Id.* To be included in the record and considered by the Administrator, such written comments by participants were due to BPA by January 30, 2025. *Id.*

No participant comments were submitted for the PRDM.

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12 NATIONAL ENVIRONMENTAL POLICY ACT ANALYSIS

BPA is in the process of assessing the potential environmental effects of the proposed implementation of the PRDM. The PRDM-26 proceeding (PRDM-26) was initiated to develop and review the terms of the rate design methodology applicable to Priority Firm public power rate following the expiration of the current TRM. BPA would use the PRDM rate design methodology to establish power rates applicable to Public Customers beginning on October 1, 2028.

The National Environmental Policy Act (NEPA) process is conducted separately from the formal rate design methodology process. All public comments concerning NEPA compliance or the proposal's potential environmental effects that were received during the participant comment period for the PRDM-26 proceeding have been provided to BPA's NEPA compliance staff for consideration in the NEPA process being conducted for this proposal.

As BPA noted in the Federal Register notice for the PRDM-26 proposal, 89 Fed. Reg. 89,633 (Nov. 13, 2024), the proposed PRDM-26 rate design methodology would solely involve changes to BPA's rate methodology. The PRDM would not establish any rates, but rather a method for establishing future rates. The rate structure process would allow BPA to meet its financial obligations and other costs and expenses, while using existing generation sources operating within normal limits. As such, the PRDM proposal appears to be the type of action typically excluded from further NEPA review pursuant to U.S. Department of Energy NEPA regulations, which apply to BPA.

Specifically, it appears this rate proposal falls within Categorical Exclusion B4.3, found at 10 C.F.R. § 1021, subpt. D, B4.3, which categorically excludes from further NEPA review "[r]ate changes for electric power, power transmission, and other products or services provided by a Power Marketing Administration that are based on a change in revenue requirements if the operations of generation projects would remain within normal operating limits." Nonetheless, BPA continues to assess the proposal and will complete and document its NEPA process concerning the proposal when it issues its Final ROD for the PRDM-26 proceeding.

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