Public Rate Design Methodology (PRDM)

Workshop #6

Chapters 9 & 10, Risk Mitigation and Other Rate Design

Continuation of Chapter 5 Core Design Discussion

Meeting 9 a.m. – 4 p.m.

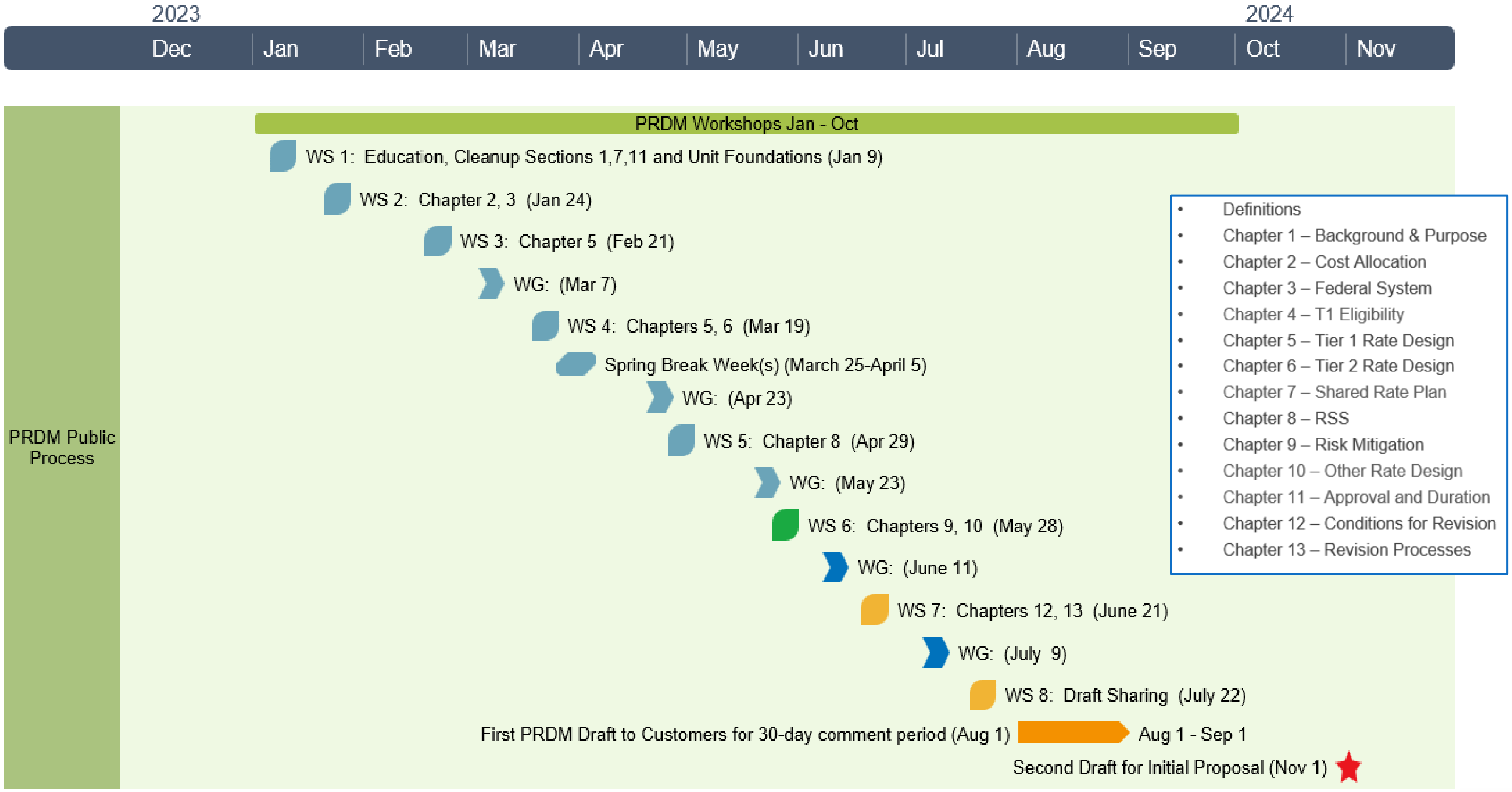
May 28, 2024

RATE METHODOLOGY POST 2028

Agenda

Time Start	Time End	Topic	Presenter(s)
9 a.m.	9:15	Welcome, Introduction, Agenda, and Housekeeping	Scott Reed
9:15	10:30	Workgroup report out and discussion	Scott Reed
10:30	10:40	**BREAK**	
10:40	12:00	Chapter 9 Risk Mitigation	Mitch Green, Neal Gschwend, Daniel Fisher
12:00	1:00	**LUNCH BREAK**	
1:00	2:30	Chapter 10, Other Rate Design (LDD, IRD)	Garth Beavon, Pontip Kruse, Mike Normandeau
2:30	2:40	**BREAK**	
2:40	3:45	Core design elements and rates discussion	Daniel Fisher, Garth Beavon, Scott Reed, Peter Stiffler
3:45	4:00	Conclusion and next steps	Scott Reed
Note: times are approximate			

Timeline


2023
2024
Dec
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
PRDM Public Process
PRDM Workshops Jan - Oct
WS 1: Education, Cleanup Sections 1,7,11 and Unit Foundations (Jan 9)
WS 2: Chapter 2, 3 (Jan 24)
WS 3: Chapter 5 (Feb 21)
WG: (Mar 7)
WS 4: Chapters 5, 6 (Mar 19)
Spring Break Week(s) (March 25-April 5)
WG: (Apr 23)
WS 5: Chapter 8 (Apr 29)
WG: (May 23)
WS 6: Chapters 9, 10 (May 28)
WG: (June 11)
WS 7: Chapters 12, 13 (June 21)
WG: (July 9)
WS 8: Draft Sharing (July 22)
First PRDM Draft to Customers for 30-day comment period (Aug 1)
Aug 1 - Sep 1
Second Draft for Initial Proposal (Nov 1)
• Definitions
• Chapter 1 – Background & Purpose
• Chapter 2 – Cost Allocation
• Chapter 3 – Federal System
• Chapter 4 – T1 Eligibility
• Chapter 5 – Tier 1 Rate Design
• Chapter 6 – Tier 2 Rate Design
• Chapter 7 – Shared Rate Plan
• Chapter 8 – RSS
• Chapter 9 – Risk Mitigation
• Chapter 10 – Other Rate Design
• Chapter 11 – Approval and Duration
• Chapter 12 – Conditions for Revision
• Chapter 13 – Revision Processes

Housekeeping

- Model and data inputs and updates – inputs have been scrubbed and updated with preliminary RIC:
  - Fixes: NSLSs, Load forecasts, LDD/IRD updates for some customers
  - Updates: RICc added, all load following added
- Coalescing around Alternative #1 – summarize customer feedback

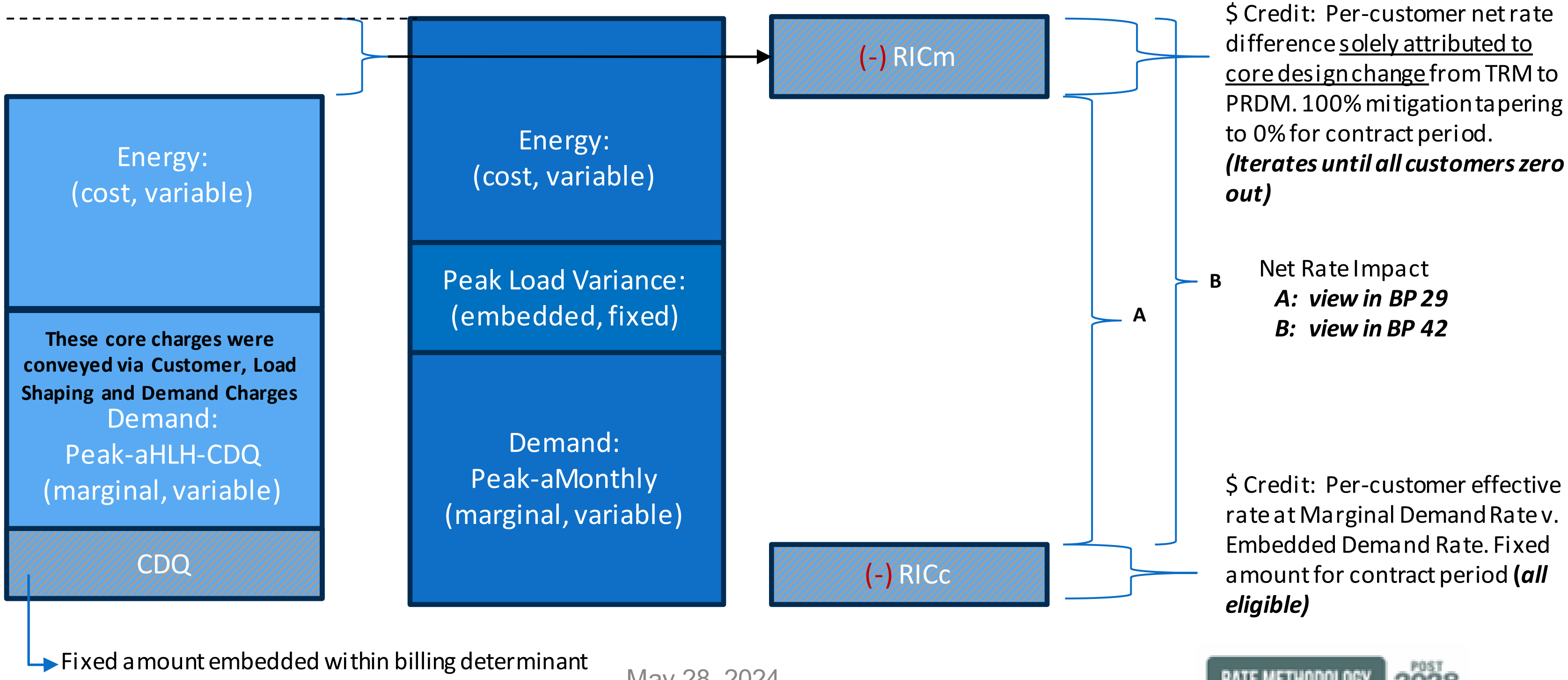
Workgroup Report Out

- Summary
  - Attendance
  - Topics
    - RDC Proposal
    - RICc – capacity credit
    - RICm – rate design change mitigation (TRM design to PRDM design)
    - Peak Load Variance Charge (PLVC)
    - RICc and JOE
- Summarize discussion & feedback

Core designs before and after

TRM Core Design
Regional Dialogue (2012-2028)

PRDM Core Design
Provider of Choice (2029-2044)



RICc

RIC*c* – the *capacity* RIC that balances the rate design to Bonneville's embedded cost of capacity and is applicable for the term of the contract.

- This is a "capacity credit" that extends to customers the value of the embedded cost of capacity of the federal generation system. The RICc would be set by customer using BP-29 data and would remain static throughout the duration of the contract with the exception of certain annexations and formation of new publics.
- The RICc would be a $/MWh credit for Bonneville's embedded cost of capacity.
- The embedded cost of the federal system capacity ($5.92 kW/mo) is lower than our current marginal demand rate ($9.54 kW/mo). <u>The RICc would be calculated as the difference in the forecast Tier 1 effective rate for a customer resulting from the use of a marginal demand rate rather than embedded demand rate</u>.
- Each customer's RICc will be calculated based on BP-29 forecast billing. The RICc somewhat captures value in the TRM's Contract Demand Quantity (CDQ) as that sunsets, and helps mitigate the change of the billing determinant from aHLH to average monthly power use. It can be thought of as a proxy for "tiering capacity" via a monetized value.

RICm

RIC*m* – the *mitigation* RIC that tempers any remaining rate impact of the PRDM core charges relative to the TRM and is phased out over the term of the contract.

- Aimed at tempering rate changes that result from the TRM-to-PRDM core design change – and will not include the impact of other mitigation choices (IRD and LDD) nor any non-rate design impacts.
- RICm is a per-customer $/MWh credit needed to mitigate the PRDM to TRM positive rate change to be zero in BP29. Our intent is that no customer will experience an immediate rate increase flowing from the change in the core design from TRM to PRDM.
- It would be calculated in combination with the RICc, so that the rate impact would be zero after the combination of both the RICm and RICc are applied.
- This amount would be phased out across the contract duration in six equal proportions. During the first rate period under POC, the RICm would completely mitigate the rate design change. During the final rate period, the RICm will have completely sunset, leaving a pure rate design.
- The cost of the RICc and the RICm would be charged to the Composite Cost Pool (similar to the IRD and the LDD, which reflects a shared allocation of the benefits and costs of power service). This would be a change from TRM, where the CDQ affected the Non-Slice Cost Pool only.

Alternative RICc

RICc *alternative* concept – embedded cost and a coincidence factor

- This alternative RICc construct was created to try to be responsive to requests from some stakeholders that are concerned with tail and other-related risk sharing among non-Slice products. **Bonneville staff does not recommend this approach but is open to it.**
- We believe that if the future exploration of tail and other operational-related risks could lead to the creation of additional core charges or a material shift in risk sharing across non-slice products, then that future opener needs to be considered and traded for concessions in other core charges. We believe this is a "or" situation and not an "and" situation.
  - No load diversity factored in RICc and no potential future tail-event surcharge. **OR**
  - Diversity adjusted RICc and the potential of a different risk sharing across non-Slice products, such as a future tail-event surcharge applicable to only certain product choices.
- Alternative RIC*c* would be designed to capture a diversity benefit not otherwise captured in a Customer System Peak (CSP) based billing determinant. This would effectively increase the size of a customers RICc for the term of the contract.
- Our approach could take the shape of using a coincidence factor (GSP/∑CSP) multiplied by the embedded cost to determine a diversity-adjusted embedded rate (e.g., $5.92 * 0.80 = $4.73 kW/mo.) that would be leveraged for the RICc calculation mentioned previously.

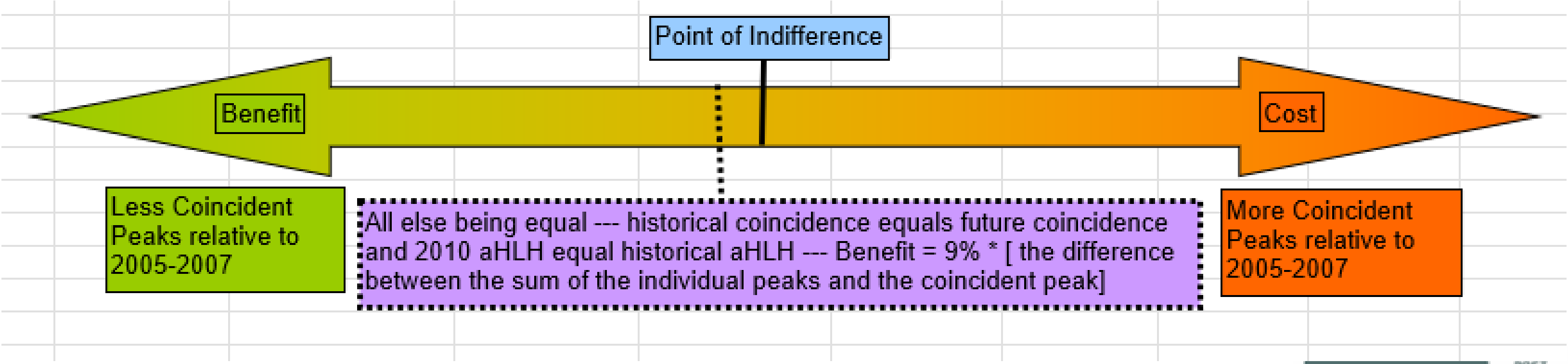
RICc and Joint Operating Entity (JOE)

- JOE members' Contract Demand Quantity (CDQ)'s today are 'tuned down' to reflect a planned diversified demand signal. CDQ's are going away, and we need to consider how best to approach the RICc for JOE members.

- Proposal:
  - Each JOE member would be billed on their own CSP and the full RICc would be applied for each JOE's individual member consistent across all customers. These would remain intact and consistent for POC contract duration.
    - Unlike CDQs, no need to recalculate PNGC's RICc any time a customer joins or leaves PNGC.
    - Increases likelihood that Demand Side Management decided at the local level would provide 1:1 economic benefit to that utility.
    - Removes PNGC member risk of not being able to predict PNGC's peak (the same rational for moving from GSP to CSP for all other utilities).
    - Removes diversity risk for PNGC members (see next slide) – as full RICc provided regardless of changes in PNGC member actual peak diversity.
    - Aligns with the greater PRDM package in that load diversity is either applied to all utilities or no utilities as a function of other rate design choices (see previous Alternative RICc slide).

JOE’s CDQ Math – Dusting Off 2008 Analysis

If nothing changed from the historical year to the 2010 year to the year that you bill, the JOE would see a slightly decreased billing determinant as a result of moving to a JOE coincident billing factor. This is simply due to the nature of the CDQ methodology and how it puts 9% of the historical peak on the margin. Putting 9% of a 100 MW load on the margin and then doing it again for another 100 MW load is effectively like putting a 200 MW load 9% on the margin. However, the JOEs peak load is only 190 MW and the methodology puts 9% of that peak on the margin. The **expected** benefit to the JOE then becomes 9% times the difference between the sum of the individual peaks (200 in this example) and the coincident peak (190 in this example). Benefit could be calculated as (190 - 200) * 9% = -0.9. The actual benefit would be different and could either be a better or worse depending on the actual coincidence factor relative to the historical coincidence factor.



Demand Rate & RICc

- Marginal prices in PRDM effectively do two things: allocate revenue-requirement across customers and send price signals to incent conservation and non-federal resource development. Both aims are held in balance, along with our interest in rate stability over time.
- RICc will be based on our planned, demand rate – and we have a choice to make there.
- Marginal rates apply to demand charges for LF and planned products. Here are our proposed approaches in PRDM:
  - Alternative 1: PRDM Fixed marginal price on par with today's pricing logic until capacity-based acquisition is made, with up only changes to that new marginal rate restricted by a governor.
  - Alternative 2: Marginal price to be determined each rate period, on par with today's pricing logic, with a governor restricting rate increases in PRDM. Workgroup seemed to be leaning in this direction with a fixed PRDM-defined seasonal shape.
  - Alternative 3: Upper-end marginal demand rate fixed for the term of the PRDM.
    - Ensures RICc is calibrated consistent with the PRDM's intent.
    - Sends a stronger and consistent price signal for capacity during the term of the PRDM.
    - Would make all capacity-based services more expensive – for example, RSS and ESS.

Capacity and Pricing Structure Summary to Date

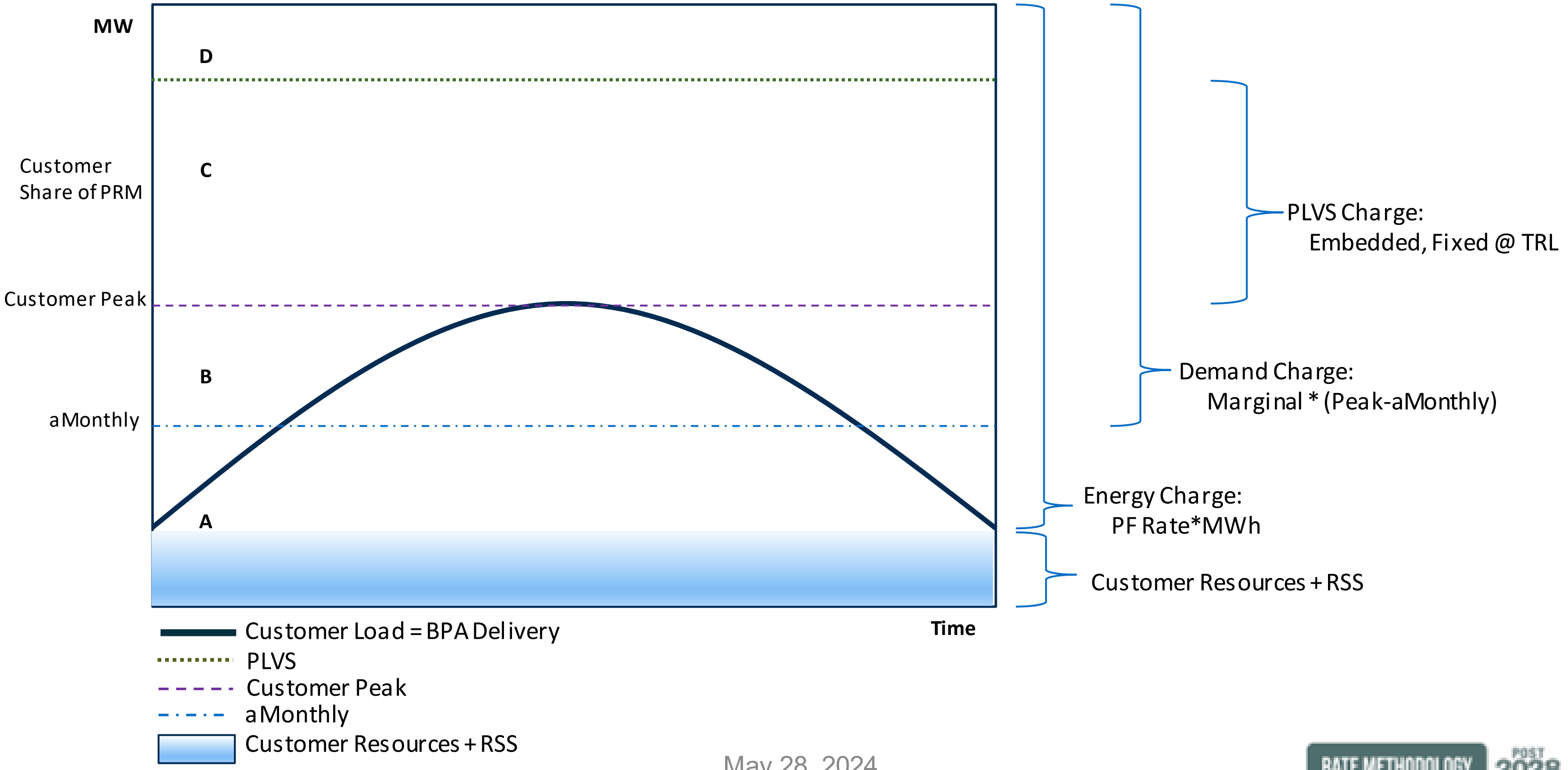
PRDM Capacity Structure as of May 10 (in development)

		A Power (capacity & energy)		B Shaping Capacity		C Peak Capacity		D Unplanned Capacity	
		LF	BWS	LF	BWS	LF	BWS	LF	BWS
Element	*Planned*					PLVS		n/a	
	Actual	Power + RICc		Actual Demand	Contract Demand	Demand + Energy	Energy	Demand + Energy	n/a
Determinant	*Planned*					Fixed PLVS		n/a	
	Actual	MWh		MW		MW & MWh	MWh	MW & MWh	n/a
Rate	*Planned*					Embedded		n/a	
	Actual	Tier 1 shaped to Mkt Forecast		Marginal		Marginal Capacity + Market Forecast Energy	Actual Market Energy	Marginal Capacity + Mkt Forecast Energy	n/a
Access		restricted to actual load	restricted to contract amount	"	"	restricted to actual load	restricted to defined amounts and events	restricted to actual load	n/a
NF Resources		contract amounts applies to load + RSS	unrestricted	"	"	"	"	"	"

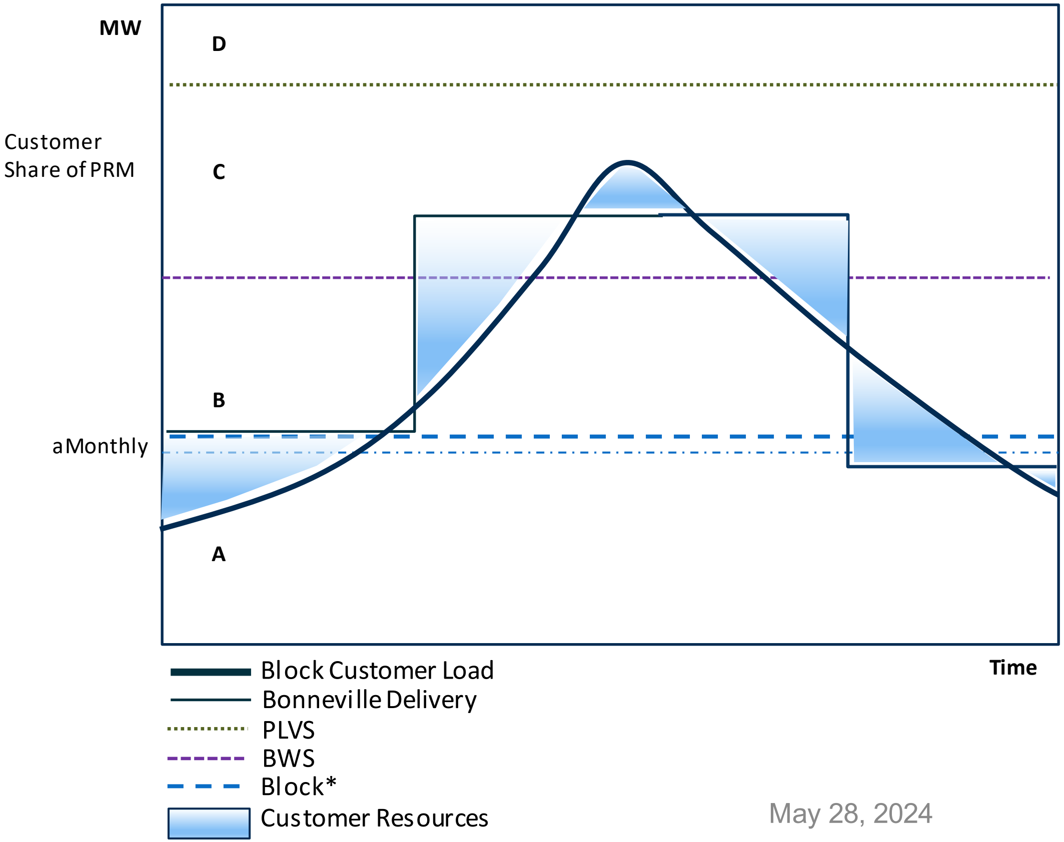
PRDM Pricing Structure as of May 10 (in development)

	A LF	A BWS	B LF	B BWS	C LF	C BWS	D LF	D BWS
Energy	Tier1 to CHWM, then T2		T1/T2	Market	T1/T2	Market	T1/T2	Market
Demand	Marginal	n/a	Marginal		Marginal		Marginal	
PLVC	n/a		n/a		Embedded @ PRM * TRL	Embedded @ PRM *T1	n/a	
RICc	Fixed (contract duration) - effective rate delta between design w/marginal v. embedded rate							
RICm	100% to 0% across contract duration in 6 increments - iterative impact including RICc							

Load Following Product Profile with Charges



Block Variant Product Profile with Charges



Customer Resources

Fixed PLVS Charge: Embedded @ T1

Demand Charge*:
Marginal x i. Block-aMonthly
ii. (Block+BWS)-aMonthly
iii. (Block+BWS+PLVS)-aMonthly

Energy Charge: PF Rate x MWh

** Flat blocks will have no demand billing determinant, whereas shaped blocks will*

*** Shaping rules, ramp rates, product design and implementation will not be in PRDM – to be developed in product design and contract processes*

Chapter 9, Risk Mitigation

Mitch Green, Neal Gschwend, Daniel Fisher

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Risk in the PRDM

- The risk section of the TRM is very light and leaves risk mitigation to each 7(i).
- We continue to believe this is the correct approach for the PRDM as locking down risk treatment would in and of itself create risk.
- As explained on the "alternative RICc" slide of this PowerPoint, the workgroup has been exploring potentially putting some additional non-Slice PF product guidance on risk in the PRDM. Bonneville staff would prefer to handle this broadly through the RICc alternatives, but we remain open to other proposals – particularly if they are "tweaks" or other principle-based additions to clarify our future intent.
- While the PRDM will not lock down how Bonneville will manage its future risk, we believe there is an opportunity to use the PRDM to build on and solidify past successes – specifically, trading more conservative base rates for certainty around how mid-rate period downward rate adjustment would operate.

Risk Mitigation Principles in the TRM

Identify and design risk mitigation measures at each 7(i) process that address risks specific for each rate tier

Avoid risk mechanism spillover between cost pools and products

Provide for aggregate risk mitigation if necessary

Consistency with Financial Plan

Potential Changes to Risk Mitigation Approach

While Bonneville intends to keep changes to its risk policies tied to its Financial Plan, here is a sample of our current thinking on approaches that we could consider including in PRDM (i.e., one of these):

- Reduced reliance on net secondary credit (i.e., <100% of expected NSR)
- Phase-out of Treasury Note for TPP support
- Additional PNRR

In exchange for certainty around how mid-rate period rate adjustments would function.

Risk Mitigation Principles in PRDM

Retained from TRM:

- Broad principles from TRM that seek to align risk with cost causation between rate tiers, products, and cost pools
- Flexibility to update risk framework (e.g., FRP & SCFP) with Financial Plan, as determined through each 7(i) Process

Potential New Approach for PRDM:

- Add language that specifies additional risk mitigation paired with clarity on how the RDC process functions

Example: *In response to [additional risk mitigation applicable to non-Slice PF Public rates]*, any mid-rate-period downward rate adjustments applicable to the Tier 1 PF Public rates would be formulaic**, automatic, and flow back to Bonneville's PF Public Tier 1 rates in the next fiscal year consistent with the PF Public Tier 1 rate's proportional load share of Bonneville's risk provisions.*

*Specific language to follow decision on which variety of additional risk mitigation we can agree upon.

**Such formula would consider Bonneville's leverage policy as captured in its Financial Plan.

Chapter 10, Other Rate Design

Garth Beavon, Pontip Kruse, Mike Normandeau

Irrigation Rate Discount (IRD) and Low Density Discount (LDD)

1. History
2. Regional Dialogue (RD) and Tier Rate Methodology (TRM)
3. Proposal for PRDM
4. PoC ROD

Agriculture’s Importance to PNW’s Economy

Irrigation Method Reduces Water Needed for Potato Growth - Spud Smart

History:

- 1942-1996, Irrigation Discount
- 1997-2001, Summer Seasonal Product
- 2002-2011, Irrigation Rate Mitigation Product
- 2012-2028, Irrigation Rate Discount
- Discount is not required by BPA statute

IRD – RD/TRM

30 customers

BP-24 ~$21 million/year

IRD is about 1% ($0.35/MWh) of PF revenue requirement

IRD – RD/TRM

Load eligibility 3-year average irrigation load

Eligible kWh amounts set for term of contract

Discount rate ($/MWh) determined each rate case

Discount applied to May-Sept power bills

End of season true-up

Cost-effective conservation

Eligibility in RD/TRM – one of the following:

Summer Seasonal Product participant (FY 1997-2001)

Irrigation Rate Mitigation Product participant (FY 2007-2011)

75% of total retail load from BPA and May-Sept sales are 5% or higher. If sales are less than 5%, the 3-year average load is 7,500 MWh or more

IRD - PoC/PRDM

Load eligibility 5-year average of irrigation load

Eligible kWh amounts set for term of contract

Discount ($/MWh) determined each rate case

Discount applied to May-Sept power bills

Overall program cost approximate to RD, TBD in 7(i) process

End of season true-up

Cost-effective conservation

Eligibility in PoC/PRDM- one of the following:

Regional Dialogue IRMP (FY 2012-2028)

75% of total retail load served by BPA by October 1, 2028, and May-Sept sales are 5% or higher. If sales are less than 5%, the 5-year irrigation average load is 7,500 MWh or more

Customers Lacking Historical Monthly Irrigation Data

5-year average (FY 2018 – FY 2022) of May-August irrigation load.
(Additionally, September data to establish shape)

Bonneville will, working with the Customer, use the most reasonable substitute data. Information already possessed by the Customer is the starting point.

The IRD Rate

Discount is fixed, adopted from TRM

BP- 24, **37.06%**

→

Used, each rate case, to derive a $/MWh rate discount

→

BP-24 IRD is

$11.57/MWh

The IRD Rate

Proposed methodology is dynamic

→

Increasing the $ discount when the cost of power increases

→

Decreasing the $ discount when the cost of power decreases

The IRD Rate

Program costs Similar to RD

(~$22 Million/yr)

→

Assuming an increase of 5-10% eligible irrigation loads

→

Discount fixed for term of the contract **~30%-35%** (TBD)

IRD – PoC/PRDM

Change in total IRD Program Cost ($ 000s)						
		Eligible Irrigation Load (aMW)				
Assumed Cost of Energy Block ($/MWh):	$ 31.22	BP24	BP24 + 5%	BP24 + 10%	BP24 + 15%	BP24 + 20%
		214.80	225.53	236.27	247.01	257.75
Current (BP24) Prog Cost ($ 000s):	$ 21,777	Eligible Irrigation Load (MWh)				
$/MWh Discount:	% Discount:	**1,881,605**	1,975,685	2,069,765	2,163,845	2,257,925
$ 9.37	30.00%	$ (4,154)	$ (3,273)	$ (2,392)	$ (1,511)	$ (630)
$ 9.68	31.00%	$ (3,567)	$ (2,657)	$ (1,746)	$ (835)	$ 75
$ 9.99	32.00%	$ (2,980)	$ (2,040)	$ (1,100)	$ (160)	$ 780
$ 10.30	33.00%	$ (2,392)	$ (1,423)	$ (454)	$ 516	$ 1,485
$ 10.61	34.00%	$ (1,805)	$ (806)	$ 193	$ 1,191	$ 2,190
$ 10.93	35.00%	$ (1,217)	$ (189)	$ 839	$ 1,867	$ 2,895
$ 11.24	36.00%	$ (630)	$ 427	$ 1,485	$ 2,542	$ 3,600
$ 11.57	**37.06%**	$ (0)	$ 1,081	$ 2,170	$ 3,258	$ 4,347

Initial assessment indicates that eligible irrigation loads will rise by about 15% between RD and PoC (using the new reference irrigation years). New customer entrants may result in a somewhat higher increase.

To avoid a change in the total IRD program costs, the discount rate would need to be reduced from the current rate of 37.06%.

Questions

LOW DENSITY DISCOUNT

(LDD)

LDD History

Section 7(d)(1) of the Northwest Power Act

Avoid adverse impacts on retail rates of customers with low system densities

Program changes are made in Section 7(i) rate proceedings

LDD – RD/TRM

FY 2023

53 Customers

FY 2023

~$40 Million/year

Increase average effective PF rate

~ 2% ($0.69/MWh)

LDD - RD/TRM

Applicable to LF, Slice/Block and Block

Eligible discount will not exceed 7%

Applicable discount* for Above-RHWM load

Adjustment for Very Low Density

Phase-in adjustment

Annual eligibility determination

*Applicable discount can exceed 7%

LDD - RD/TRM: Eligibility Criteria

Serve as an electric utility offering power for resale to retail consumers

Pass the benefits to its eligible consumers within BPA's service territory

Average retail rate exceeds BPA's average PF rate by 25 percent

Kilowatt-hour to investment ratio (K/I) must be less than 100

Consumer per Pole Miles (C/M) ratio must be less than 12

LDD - RD/TRM: Determine Eligible Percentage

Kilowatt-hour to investment ratio (K/I) must be less than 100

Consumer per Pole Miles (C/M) ratio must be less than 12

Sum of the corresponding discount for K/I and C/M = Eligible Percentage

Table B
LDD Eligible Discount percentage

Percentage Discount	Applicable Range for kWh/Investment (K/I) Ratio	Applicable Range for Consumers/Mile (C/M) Ratio
0.0%	35.0 < X	12.0 < X
0.5%	31.5 < X ≤ 35.0	10.8 < X ≤ 12.0
1.0%	28.0 < X ≤ 31.5	9.6 < X ≤ 10.8
1.5%	24.5 < X ≤ 28.0	8.4 < X ≤ 9.6
2.0%	21.0 < X ≤ 24.5	7.2 < X ≤ 8.4
2.5%	17.5 < X ≤ 21.0	6.0 < X ≤ 7.2
3.0%	14.0 < X ≤ 17.5	4.8 < X ≤ 6.0
3.5%	10.5 < X ≤ 14.0	3.6 < X ≤ 4.8
4.0%	7.0 < X ≤ 10.5	2.4 < X ≤ 3.6
4.5%	3.5 < X ≤ 7.0	1.2 < X ≤ 2.4
5.0%	X ≤ 3.5	X ≤ 1.2

LDD - RD/TRM

Eligible Discount

vs

Applicable Discount

$$applicableLDD = eligibleLDD \times \max\left(\frac{adjTRL}{RHWM}, 1.0\right)$$

where:

$applicableLDD$ = LDD percentage to be applied to a customer's bill

$eligibleLDD$ = LDD percentage indicated by the customer's eligibility factors

$adjTRL$ = customer's Total Retail Load less output of Existing Resources and NLSLs

$RHWM$ = customer's Rate Period High Water Mark

LDD - RD/TRM

Applicable Discount Calculation Example

Eligible Percent = 7%, RHWM = 5.881 aMW,
Above-RHWM 2.204 aMW, Adjusted TRL= 8.085 aMW

BP-24 RHWM	AdjTRL aMW FY2024	LDD adjTRL/RHWM FY2024	FINAL eligible LDD FY2024	FINAL Applicable LDD FY2024
5.881	8.085	1.37477	7.0%	9.623%

LDD – PoC/PRDM

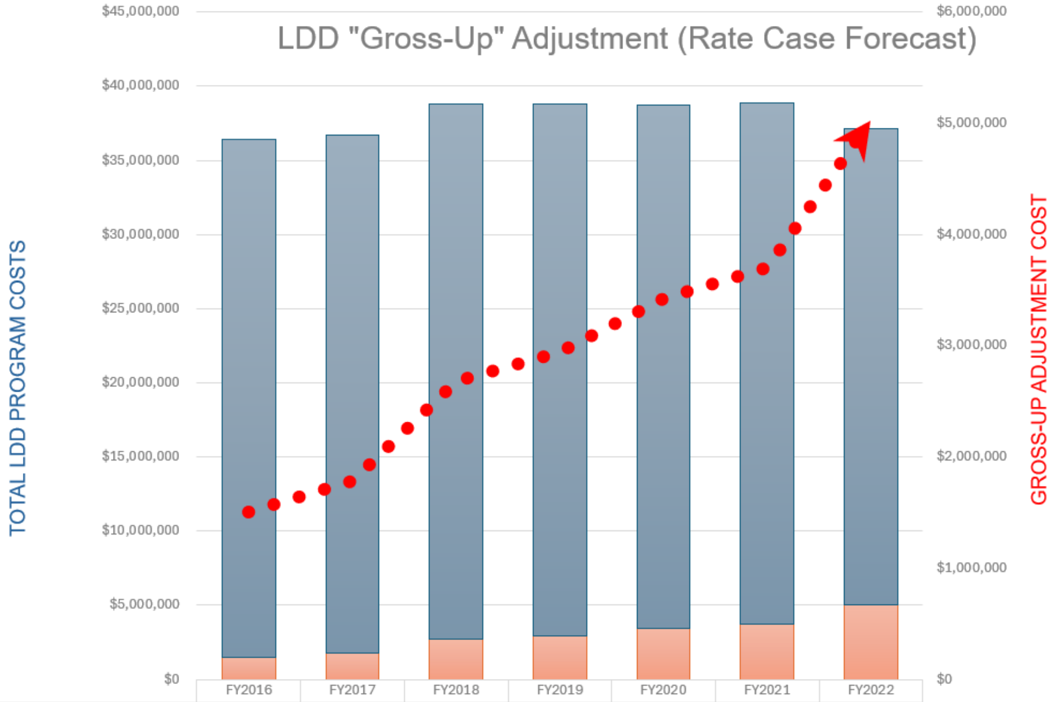
- Applicable to LF, Slice/Block, and Block
- Five eligibility criteria
- Max eligible discount 7%
- Adjustment for Very Low Density
- Phase-in adjustment
- Treatment for Joint Operating Entity

LDD - PoC/PRDM

Eligibility determination period → Final PoC Policy Rate Period

Eliminate Applicable Percentage → Eligible Percentage Applies to T1 only

LDD – PoC/PRDM



	FY2016	FY2017	FY2018	FY2019	FY2020	FY2021	FY2022
Eligible LDD	$34,904,083	$34,915,101	$36,113,332	$35,870,803	$35,275,616	$35,195,551	$32,093,971
Gross-Up to "Applicable LDD"	$1,503,323	$1,781,060	$2,679,074	$2,939,569	$3,420,174	$3,705,953	$5,026,404
Gross-Up to "Applicable LDD"	$1,503,323	$1,781,060	$2,679,074	$2,939,569	$3,420,174	$3,705,953	$5,026,404

Customers are, with a few exceptions, not “outgrowing the program,” even as their Above-RHWM loads grow.

The costs attributable to the “Gross-Up” adjustment are expected to continue to grow.

LDD - PoC/PRDM

Discussion: Eligible Percentage Applies T1 only

- Intent is to remove Above CHWM costs from Tier 1 cost pool
- Applicable LDD costs are due to Above RHWM load
- How best to mitigate impact transitioning from RD to POC contract?
  - Increase eligible % cap
  - Adjust K/I and C/M table
  - Other options

LDD – PoC ROD Discussion

Should Bonneville increase the 12 consumers per pole mile (C/M) ratio threshold for eligibility?

Should Bonneville evaluate how underground distribution lines are accounted for in the C/M ratio?

Cost of Rate Discounts - $0.02 per $1

BP-22 rate period (Oct. 1, 2021, through Sept. 30, 2023)
Updated 7/1/2021

How BPA spends a dollar of its power revenues

O&M (26 cents)
Operation and maintenance costs at the hydro projects and Columbia Generating Station.

Debt (23 cents)
Principal and interest on federal and nonfederal debt.

Fish & Wildlife (16 cents, plus the impact of lost power generation)
Principal and interest on debt, expense and people costs total 16 cents. But the full impact is 24 cents due to the cost of lost power generation that results from spill and other operational requirements to support fish and wildlife.

Residential Exchange (9 cents)
Payments to consumers served by higher-cost investor- and consumer-owned utilities.

Conservation (7 cents)
Principal and interest on debt, expense costs, people and Energy Efficiency Incentive.

BPA people (5 cents)
Salaries, benefits and supplies for power and corporate employees not supporting conservation and fish and wildlife.

Transmission (5 cents)
Resource integration costs and cost to deliver secondary energy to customers.

Power purchases (4 cents)
System augmentation, balancing purchases, renewable purchases, long-term contracts and risk mitigation.

Transfer (3 cents)
Cost to deliver power to customers not directly connected to BPA's transmission system.

Rate discounts (2 cents)
Discount provided to customers with low system densities and to customers with eligible irrigation load.

Questions

Conclusion & Next Steps

June and July Schedule

Workgroup #4 6/11

June 21, Workshop #7

- Chapter 12: Conditions for Revision
- Chapter 13: Revision Processes

Workgroup #5 7/9

July 22, Workshop #8

- PRDM Draft Document Review

2029 PRDM

- Definitions
- Chapter 1 – Background & Purpose
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Parking Lot

Issue	Action	Note
Environmental Attributes T1, T2	New section in Chapter 2	
WRAP and PRM-Related Services	Contract negotiations and Chapter 5 through Peak Load Variance Charge	
Battery Treatment	Contract negotiations, maybe PRDM, likely future 7(i) process	
Risk framework (e.g., RDC & Secondary energy credits)	Chapter 2, Chapter 9, or potential future 7(i) process	
Designated System Obligations	Chapter 3	
Vintage Tier 2 not flat block	Contract negotiations and potential PRDM	
Resource Acquisition Strategy and Execution	Resource Program and Operations	
New Resources Rate Design	Contract negotiations and applicable 7(i) process	