Aggregate Effect of All Requests to Change Products on BPA's Peak Load Forecast

Assumptions and Methodology

The following three PUDs have expressed interest in changing their Contract High Water Mark (CHWM) Contract purchase obligation from Slice/Block to Load Following, effective October 1, 2025 through September 30, 2028: Clark, Emerald, and Snohomish. The remainder of this paper refers to the change in purchase obligation as a product change. Below is an analysis of the aggregate effect to BPA's peak load obligations if all three customers were to switch products. The aggregate change in BPA's monthly peak load obligations is evaluated for Fiscal Year (FY) 2026 consistent with the first year of delivery under the new products. Quantifying the aggregate change in BPA's monthly peak loads can be broken down into three discrete steps:

1. For customers requesting to change products, forecast the aggregate monthly peak loads based on their current products.
2. For the same subset of customers, forecast the aggregate monthly peak loads based on their requested product change.
3. Calculate the difference between the aggregate monthly peak loads based on their requested product change (2) and their current products (1).

The data sources and methodologies for the first two steps are summarized below. A fundamental assumption in this analysis is that no amount of the unsubscribed Slice is reallocated to any existing Slice/Block customer.

FY24 Slice Percentages				
Clark PUD	2.18%		Sum of 3 customers requesting to switch products	7.99%
Snohomish PUD	5.44%		Sum of all Slice/Block customers	19.74%
Emerald PUD	0.37%			

Peak Loads for Current Products

All customers requesting to change products are currently purchasing the Slice/Block product. BPA recognizes there may be multiple reasonable assumptions to make when forecasting its monthly peak loads for Slice. Consequently, results are presented for each of the following Slice assumptions:

- The BP-24 Final Proposal Loads and Resources Study (outyear) monthly 1-hour peak Slice load forecast for FY 2026 under P10 Firm System Output
- The BP-24 Final Proposal Loads and Resources Study (outyear) monthly 1-hour peak Slice load forecast for FY 2026 under P50 Median System Output
- The highest monthly usage based on the average of FY 2021 through FY 2023 Slice Right To Power data
- The highest theoretical monthly usage based on the average of FY 2021 through FY 2023 Slice Right To Power data assuming all three customers used Slice in the same manner as the Slice/Block customer that shaped its Slice product most aggressively in each month

The monthly load forecast for Block is based on the BP-24 Final Proposal Loads and Resources Study (outyear) forecast for FY 2026. The monthly Slice and Block loads are summed to calculate BPA's monthly peak load.

Peak Loads for Requested Products

Since every customer has requested the Load Following product the peak load amounts are calculated as the customer's FY 2026 monthly peak total retail load minus the customer's FY 2026 monthly dedicated resources.

The BP-24 Final Proposal Loads and Resources Study (outyear) monthly 1-hour peak total retail load forecast and customer's CHWM contract Exhibit A dedicated resource information serve as the data sources for this calculation.

Results

If BPA permitted all three customers to change their purchase obligation to load following, the aggregate effect on BPA's forecast of its total monthly peak loads is shown below. The results indicate under three of the Slice assumptions there is an increase in BPA's forecast of its total monthly peak loads that exceed 300 MW.

Aggregate effect of all requests to change products on BPA's 2026 Peak Load Forecast*												
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
P10 Firm System Output	**311**	**317**	**379**	**449**	**401**	**273**	**261**	**33**	**28**	**96**	**399**	**153**
P50 Median System Output	**244**	**319**	**274**	**264**	**303**	**59**	**40**	**(83)**	**(245)**	**(89)**	**237**	**101**
Historical Max Slice RTP	**196**	**295**	**317**	**288**	**244**	**211**	**128**	**5**	**(82)**	**28**	**166**	**62**
Theoretical Max Slice RTP	**112**	**(25)**	**(94)**	**(147)**	**(116)**	**15**	**187**	**(326)**	**(489)**	**(289)**	**(116)**	**(15)**

*Positive number indicates an increase to BPA's peak load obligation forecast

WRAP Consideration

While the Western Resource Adequacy Program (WRAP) was not envisioned at the time the Tiered Rate Methodology (TRM) was developed, today it is prudent to at least think about the effect product switching could have on other customers from a resource adequacy perspective. While the analysis performed as part of this evaluation is not consistent with WRAP methodologies, it can lend some strong data for thought. For loads the WRAP analysis looks at a P50 load forecast, if we use the P50 Median Firm System Output Slice Aggregate Peak Load Forecasts amounts presented above, we see a winter season peak change of 319 MW and a summer season peak change of 237 MW. On the resource side WRAP looks at the Qualifying Capacity Contribution (QCC) value of resources, as noted above the aggregated slice share of the three customers' requesting to change products is 7.99%. From WRAP estimates we have available at this time, this 7.99% would account for more than 1000 MW of QCC in each season becoming available for BPA, resulting in additional QCC surplus at Forward Showing. In the WRAP's Operations time frame BPA would have a higher Forward Showing Capacity Requirement coming in, would have a larger load also associated, but would also have the additional 7.99% of the resource available in its operational control. BPA would manage its resource fleet as needed without any currently identified negative issues.

Evaluation of Potential Charge for Product Switch from Slice/Block to Load Following

The TRM allowed for a one-time consideration of a product switch. At the outset of the Regional Dialogue there was concern that switching products could impose unfair cost shifts on other customers. Therefore, BPA retained the right to apply a special charge on customers whose product change would impose a greater burden of costs upon other, non-switching customers.

The principles of the TRM are designed to treat customers fairly regardless of the product choices they make and the resulting impact of those choices on BPA and other customers. Through the TRM's existing rate design, a product switch would already account for differing impacts associated with product choice. The three fundamental components to consider are: 1) allocation of costs and credits (*e.g.*, allocation of secondary energy revenue); 2) impact to BPA's balancing energy costs; and 3) use of and payment for capacity.

On the first factor, with the exception to timing complications caused by BPA's debt actions[1] and financial reserves, a Slice/Block to Load Following switch provides additional secondary energy to BPA's Trading Floor and is included in the forecast secondary sales revenues included in the Non-Slice customer charge. Examining this impact alone results in no change to the Non-Slice customer rate because the secondary energy credit included in the Non-Slice cost pool (numerator) would increase proportional to the increased non-Slice load obligation (denominator).

The timing complication associated with financial reserves arises from the risk adjustment mechanisms in BPA's Power rate schedules and general rate schedule provisions. The three risk adjustments are the Cost Recovery Adjustment Clause (CRAC), Reserves Distribution Clause (RDC), and Financial Reserves Policy Surcharge (FRP Surcharge.) Each of the risk adjustments is triggered within a fiscal year based on the previous fiscal years end of year financial reserves. If any of the risk adjustments are trigged by the EOY financial reserve levels, then any applicable charges (CRAC, FRP Surcharge) or credits (RDC) are applied to customers' power bills based on their Non-Slice loads within the current fiscal year. For example, if an RDC triggered within FY 2024 it would be based on FY 2023 EOY financial reserves and would be distributed to customers using their FY 2024 Non-Slice loads.

If BPA allows the three customers to switch from the Slice/Block product to the Load Following product, it seems reasonable that staff would propose in the BP-26 rate case to modify the FY 2026 risk adjustment mechanisms to carve out that portion of load that was served with Slice in FY 2025 to not be subject to a risk mechanism as a Non-Slice load in FY 2026. As a Slice customer the customer would have already experienced any financial impacts due to secondary sales based on its use of its Slice product within FY 2025 and the customer would also be subject to the FY 2025 Slice True-Up for all composite cost pool expenses and revenues. Modifying the risk mechanisms for FY 2026 ensures the product switching customers are not exposed to the same risk twice for their portion of load that was served by Slice.

With regard to the second factor (the impact to BPA's balancing energy costs), BPA's Load Shaping charges account for energy load shape differences among customers. If a customer's switch from Slice/Block to Load Following impacts the shape of the energy purchased from BPA, that customer would pay, or be credited, market-based rates for any deviation in that load shape from the shape of BPA's system. This increase or decrease in Load Shaping charges effectively accounts and compensates BPA (and thereby other customers) for resulting changes to BPA's balancing energy costs.

Lastly, the third factor, capacity (demand) must be considered – both use of and impact on BPA's demand charge revenue collection. Additional evaluation is needed for customers converting to Load Following because the product switch will impact both BPA's capacity obligation and demand charge revenue collection. If the use of Federal capacity and the corresponding demand charge revenue collection is roughly proportional to BPA's other non-Slice customers, then the product switch is determined to be without undue cost shift to other customers. In other words, if a customer is using capacity, that customer should pay its fair share for the use of that capacity relative to other customers that also use and pay for capacity. Some variances are expected. For example, a customer may have high or low Contract Demand Quantities based upon historical load shapes which impact that customer's forecast demand charge revenue collection. The methodology used to test capacity equity is described below.

[1] In BP24, three customers that converted from the Slice product to a non-Slice product beginning Fall 2023, were subject to a customer-specific monthly charge due to product switching. These customers received benefits associated with the Reserves Distribution Clause (RDC)) management actions in FY 2022 and 2023 through the Slice Product that would not otherwise have been captured in the Slice True-Up for those years, while Non-Slice customers received their share of FY 2022 and 2023 benefits and costs in the 2022 and 2023 RDC. Application of the BP24 product switching charge avoided having the former Slice customers receive RDC benefits twice. The FY23charge was $2,337,543 for Benton PUD, $1,654,609 for Grays Harbor PUD, and $481,189 for Pacific PUD.

Methodology and Assumptions

To assess the reasonableness of demand revenue collection post-product switch, BPA compared each product-switching customer to other customers currently taking the load following product, with similar load factors using customer data from the BP-24 Final Studies. A distribution of customers by load factor (averaged across all months) among current Load Following customers was developed. The imputed load factor on BPA of each customer requesting the product switch was then computed (also averaged across all months). For each customer, 20 customers were selected from the distribution of Load Following customers that were closest to the imputed load factor of each product-switching customer. These represent the three "cohorts" of customers with similar load factors relative to each product-switching customer. Then each of the product-switching customers' anticipated demand charge effective rates, in $/MWh, was compared to the average demand rate effective rates for each customers' applicable cohort.[2]

Results

On average using BP-24 rates, a Load Following customer pays $1.96/MWh through the demand charge, with an average load factor of about 74%. One product-switch customer, Snohomish PUD, has a demand charge effective rate below $1.96/MWh but above their respective cohorts' demand charge effective rate. This customer is within a reasonable range of their respective cohorts' demand charge effective rates. The remaining two customers are also expected to produce demand revenues that exceed the average of each respective cohort. Finally, the aggregate demand charge effective rate for all three product switching customers is $1.86/MWh, which is above the respective cohort's demand charge effective rate of $1.73/MWh. Therefore, BPA believes there is not a significant capacity-related cost shift to address based on product switching customers' expected demand charges.

	Product Switch Customer		Load Following Cohort	
	Average Load Factor	Demand Charge Effective Rate $/MWh	Average Demand Charge Effective Rate $/MWh	Difference $/MWh
Clark County PUD #1	74.2%	$2.34	$1.79	$0.55
Emerald PUD	68.5%	$3.40	$2.39	$1.00
Snohomish County PUD #1	79.3%	$1.55	$1.42	$0.13
Aggregate Product Switch Customers	76.6%	$1.86	$1.73	$0.13

Net Capacity Cost Analysis

The cost to serve the change in BPA's peak load obligations due to the three customers switching products was compared to the increased demand revenue these customers would pay to BPA as Load Following customers. The change in BPA's peak load obligations was calculated as: (i) the sum of each product switching customers' forecast peak loads less its dedicated resources; minus (ii) the sum of the customer's peak Slice Right to Power (using four Slice RTP assumptions) plus its aHLH Block amounts. This change in peak load obligations (also described in more detail in the first section of this paper) was multiplied by two capacity rates to develop a range of capacity costs due to the proposed product switches. The two capacity rates were from the BP-24 final

[2] To remove potential distortion in the shape of the demand rate across the year, the demand rate is de-shaped before computing the $/MWh rate of demand revenue collection for each customer, to remove potential shape bias.

proposal, the first rate is the embedded cost of capacity of the federal system ($5.92/kW/mo) and the second rate is the monthly average PF demand rate of $9.54/kW/mo. The eight different estimated capacity costs were offset by the forecast demand revenue the customers would pay as Load Following customers ($18.9 million). The resulting net capacity costs range between -$23 million and -$4.5 million. This means under these assumptions BPA would have more demand revenue than it is estimated it would cost to serve the change in peak load obligations.

using BP-24 Embedded Capacity Rate of $5.92/kW/mo			
	Capacity Cost of Change to Peak Load Obligation ($)	Forecast Demand Revenue ($)	Net Capacity Cost ($)
1937 Water Year (Critical) Slice	8,931,759	18,943,329	(10,011,570)
1958 Water Year (Average) Slice	(2,507,607)	18,943,329	(21,450,936)
Historical Max Slice RTP	6,662,155	18,943,329	(12,281,173)
Theoretical Max Slice RTP	2,506,617	18,943,329	(16,436,712)

using BP-24 Average Monthly Rate of $9.54/kW/mo			
	Capacity Cost of Change to Peak Load Obligation ($)	Forecast Demand Revenue ($)	Net Capacity Cost ($)
1937 Water Year (Critical) Slice	14,393,408	18,943,329	(4,549,921)
1958 Water Year (Average) Slice	(4,040,975)	18,943,329	(22,984,304)
Historical Max Slice RTP	10,735,974	18,943,329	(8,207,355)
Theoretical Max Slice RTP	4,039,379	18,943,329	(14,903,950)