BP-26 Rate Case Workshop

(Power Rates Topics Rescheduled from July 31)

August 9, 2024

Agenda

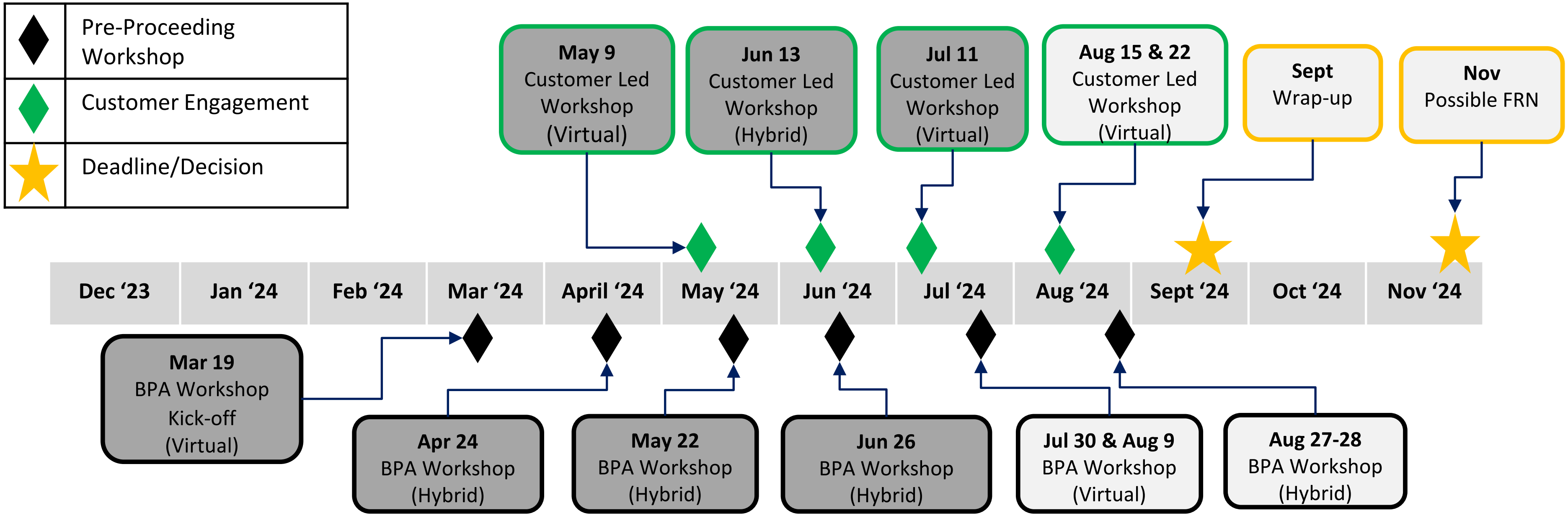
	BP/TC-26 Pre-Proceeding Workshop	
Time*	Topic	Presenter
9:00 – 9:10 a.m.	Introduction, Meeting Protocols, Comments and Agenda	Daniel Fisher
9:10 – 9:20 a.m.	Rates Analysis Model (RAM) Update	Stephanie Adams
9:20 – 9:30 a.m.	Energy Shaping Service (ESS)	Peter Stiffler, Daniel Fisher
9:30 – 9:40 a.m.	Rate Schedule Changes	Daniel Fisher
9:40 – 10:10 a.m.	Tier 2 Rates	Scott Reed
10:10 – 10:20 a.m.	**Break**	
10:20 – 11:20 a.m.	Power UnAuthorized Increase (UAI)	Leon Nguyen, Garth Beavon, Alec Horton
11:20 a.m. – 12:00 p.m.	Demand Rate	Garth Beavon

***** *Times are approximate***

Webex Format Update

- Given the serious nature of the disruptive and offensive behavior by a participant at the July 31 BP/TC-26 workshop, **effective immediately**, BPA will adjust its public stakeholder virtual engagement approach.
- The Webex format is moving to a “webinar” style.
  - Webex attendees can no longer mute/unmute themselves or enable their webcam.
- The all-chat feature is disabled. Attendees can only message panelists.
  - To participate, attendees must raise their hand (BPA will unmute you to enable your participation), or send a question to panelists in the chat.
- If you are Webex phone only: Hit *3 to request to be unmuted.
- Moderators will continue to address raised hands in the order received.
  - Please continue to state your name and affiliation.
- As necessary, BPA may evolve these procedures and take other measures at its discretion to prevent future disruptions.

Proposed BP/TC-26 Pre-Proceeding Workshop Schedule



Procedural schedule dates are draft only

Approach to Customer Engagement

- Most identified issues will be presented according to the following process at workshops (multiple steps might be addressed in a single workshop):

Phase One: Approach Development	Phase Two: Evaluation	Phase Three: Proposal Development
Step 1: Introduction & Education	**Step 3: Analyze the Issue**	**Step 5: Discuss Customer Feedback**
Step 2: Description of the Issue	**Step 4: Discuss Alternatives**	**Step 6: Staff Proposal**

Teams will follow the steps that may be covered in one workshop or more based on the complexity of the issue.

Customer Led Workshops

- Within one week after every workshop, customers can request a Customer Led workshop that would focus on topics presented in the previous workshop.
- Customers should provide the topic and estimated time needed for discussion with BPA SMEs.
- BPA will not create new content – this is an opportunity to ask further questions on materials previously presented.
- Opportunities for customers to present on topics of interest, where BPA will be in listening mode.

August 22 Customer Led Workshop

- BPA has reserved Aug. 22 for a customer led workshop for **Power Rates topics only**.
- Customers may request time to discuss a topic at the Aug. 22 Customer Led workshop **no later than August 15**.
  - Customers must provide the topic and estimated time needed for discussion.
  - BPA will not create new content – this is an opportunity to ask further questions on materials previously presented or for customers to provide a presentation or information related to a workshop topic.
- Customers must provide BPA with their presentation or notify BPA they intend to ask further questions on BPA materials **no later than Aug. 19**.
- If a customer does not provide a presentation or notice to BPA by Aug. 19, the customer will be removed from the agenda for the Aug. 22 Customer Led workshop.

Customer Comment Process

- Thank you to everyone who submitted comments on the June 26 workshop topics.
- BPA is using the same comment tracking and response process that was developed in BP/TC-24, which includes the following:
  - All customer comments will be posted to the BP-26 Rate Case website.
  - BPA will create a consolidated customer response (CCR) document for each workshop that will be posted/updated at the same time as other workshop materials.
  - The CCR is organized to address comments listed by the workshop date where the comments were received.
  - The CCR will provide direct responses or identify other forums or future BP/TC-26 workshops where BPA expects to provide a response.
    - To the extent possible, BPA will endeavor to provide responses prior to the next workshop in the Customer Comments section on the BP-26 website (updated CCR will be posted with workshop materials)
    - All comments will have a response

Rate Analysis Model Updates

BP-26 Rate Analysis Model (RAM) Updates

RAM utilizes energy allocation factors (EAFs) to assign costs and credits to rate pools. EAFs are calculated based on service from resource pools to rate pools & informed by section 7 of the NWPA or cost causation principles.

- **Shifted to a 3-year rate period, no change in methodology.**
- **NR load included in the forecast, 18 aMW/per year in BP-26.**
  - This obligation is still in the early stages of negotiation and could be revised.
- **Cost and Credit Allocation Refinements**
  - Transfer Services also referred to as “Third Party GTA Wheeling” are now being allocated 100% to the Priority Firm (7b) rate pool. This adjustment better aligns assignment of the cost to those receiving the service.
  - Secondary inventory is a result of excess energy from the Federal Based System (FBS). As a result, we changed the energy allocation factor (EAF) applied to the Net Secondary Revenue credit to be FBS only instead of using the FBS+NR EAF. This change ensures that 100% of the NSR credit follows the cost allocation applied to the FBS regardless of how much NR load is forecast to be served by BPA.
  - Like secondary inventory, Generation Inputs (GI) Revenue is derived by using capacity from the FBS. In addition, providing GI impacts BPA’s Net Secondary Revenue – all else equal, decreasing or increasing Net Secondary Revenue the more or less GI BPA provides from the FBS. Applying the same logic as we did the Net Secondary Revenue credit, we propose to use the FBS EAF for allocating the Generation Input Revenue.

BP-26 Rate Analysis Model (RAM) Updates

- **FPS Real Power Losses Capacity Credit included in revenue forecast.**
  - Beginning in 2024, BPA observed a significant increase in the number of customers settling losses financially; this includes payment for both energy and capacity. Given this change in trend, we propose to include a forecast of the revenue received from the capacity adder associated with Power providing Real Power Losses.
  - The energy revenue component has an equal and opposite cost impact, and thus is not explicitly modeled in RAM.
  - The structure for forecasting and recovering FPS Real Power Losses was developed in the BP-22 Rate Case; however, this is the first-time BPA is including a forecast of the revenue credit in the Rate Case.

BP-26 Rate Analysis Model (RAM) Updates

- **Firm Energy Serving Tier 2 and System Augmentation**
  - The introduction of NR load brought to light the need to add granularity to the order in which loads are served by specific resource pools starting with PF 7(b) Loads to ensure alignment with Section 7 of the NWPA.
  - The Priority Firm 7(b) Rate Pool is made up of both Public (Tier 1/Tier 2) and Exchange Loads. Per Section 7 of the NWPA system FBS resources are prioritized to serve the PF rate pool first followed by Exchange Resources and New Resources.
  - BP-26 RAM has been adjusted to ensure all PF loads, including both Tier 1 and Tier 2, receive priority to firm system resources before serving IP, NR or FPS loads.
    - If PF loads exceed the system resources, then the cost and MWh impact of system augmentation, regardless of its PF rate design categorization, will be added to the FBS.
  - After ensuring PF loads are met then all other loads are evaluated. If the remaining system resources are insufficient to serve IP, NR and SP loads then “Other” Non-FBS system augmentation will be forecast and the costs included in the New Resources cost pool.
  - All system augmentation will either be priced at its actual purchase cost or, for any unpurchased amounts, be based on the method used to value Tier 2/Firm Surplus.

Energy Shaping Service for NLSLs & NR Resource Flattening Service

Topics Addressed

Topic 1: NR Energy Shaping Service (ESS)

- Background
- Initial Intent
- Current ESS
- Problem Statement
- Example data
- Discussion

Topic 2: NR Resource Flattening Service

Topic 1: Background NR Energy Shaping Service

- There is a need for some capacity and shaping service for supporting non-federal resources in meeting NLSL load variability.

- BP-16 established a set of rates under the NR rate schedule to accomplish this.

- The current rate allows for energy purchases to meet NLSL variability, where the customer can over schedule in HLH and under schedule in LLH to bring enough power to meet the capacity need of the NLSL.

Initial Intent of the NR ESS

- Reserve capacity on the Federal System at the NR Demand Rate
- Use energy shaping service for energy deviations across the month at actual observed market prices

NR Energy Shaping Service

- The ESS allows for energy purchases to meet NLSL variability, where the customer can over schedule in HLH and under schedule in LLH to bring enough power to meet the capacity need of the NLSL.

- Three bands of compensation level for excess energy:
  - Error within 1.5% - 100% salvage value or no penalty relative to index price
  - Error between 1.5% and 7.5% - 94% salvage value or 6% penalty relative to index price
  - Error greater than 7.5% - 84% salvage value or 16% penalty relative to index price

Problem Statement

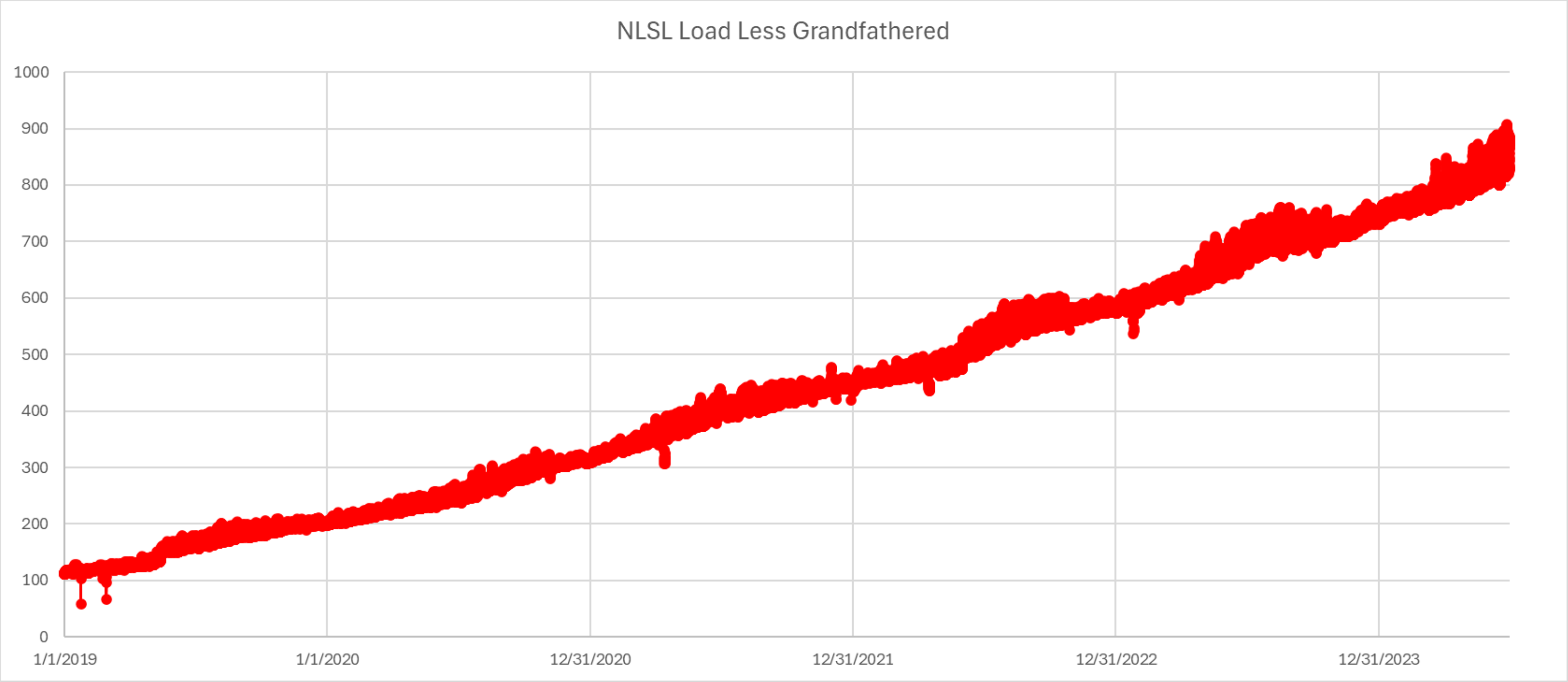
- Customers are using over-scheduling in HLH periods to 1) avoid paying for capacity at the demand rate, and 2) provide for scheduling “cushions” to avoid a Demand UAI penalty charge.

- This is not how we intended the service be used and the scheduling error is wreaking havoc on operations and independently contributing to significant forecasting error on the trading floor.

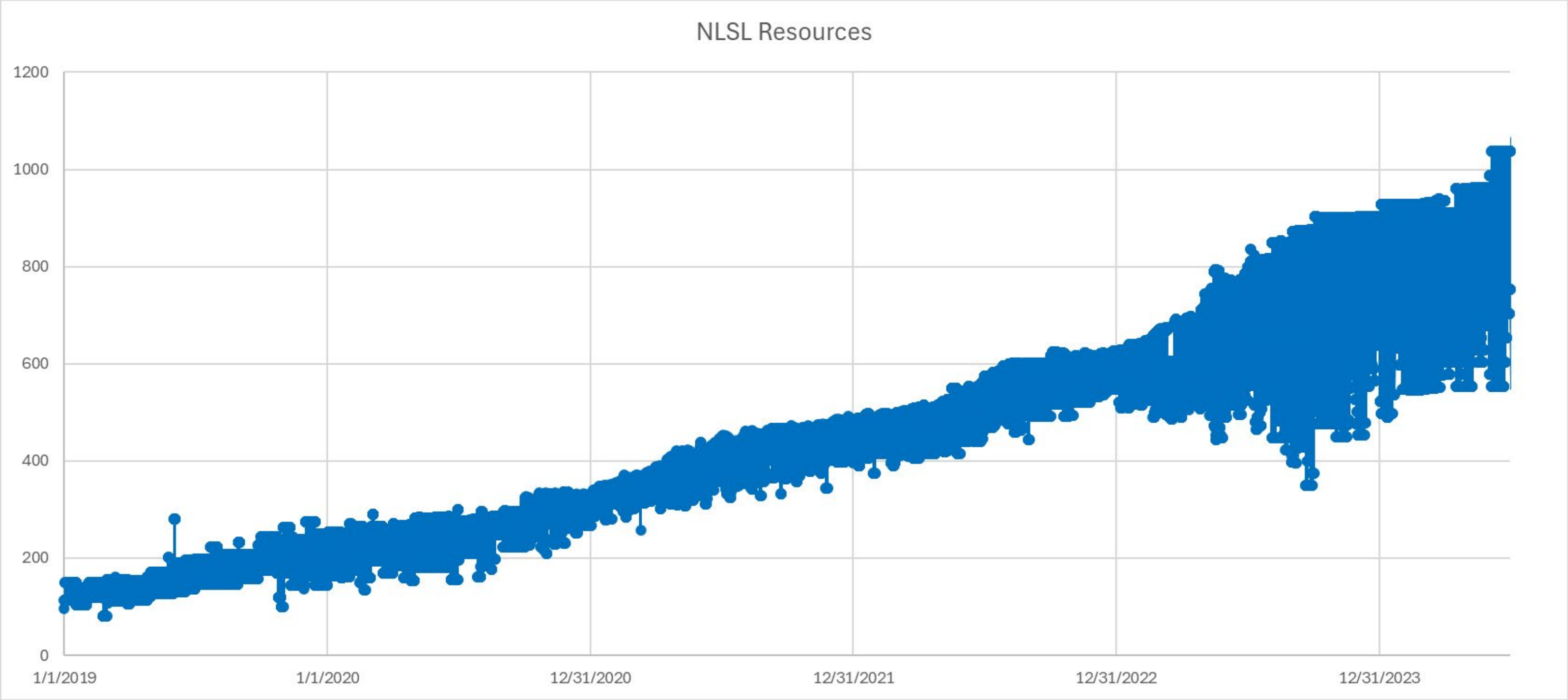
- These costs of load uncertainty are believed to be in excess of the current small haircut that the NLSL customer takes on energy brought to load.
  – Scheduling error shows up in the near-term load forecast for unscheduled load because schedules are subtracted from total load to get to the residual non-scheduled load.
  – Scheduling error often results in over-scheduling in LLH at the end of the month to make up for any energy shortfall for the month to avoid penalty charges for leaning on the federal system.

- Problem will get to unsustainable levels as NLSL loads grow.

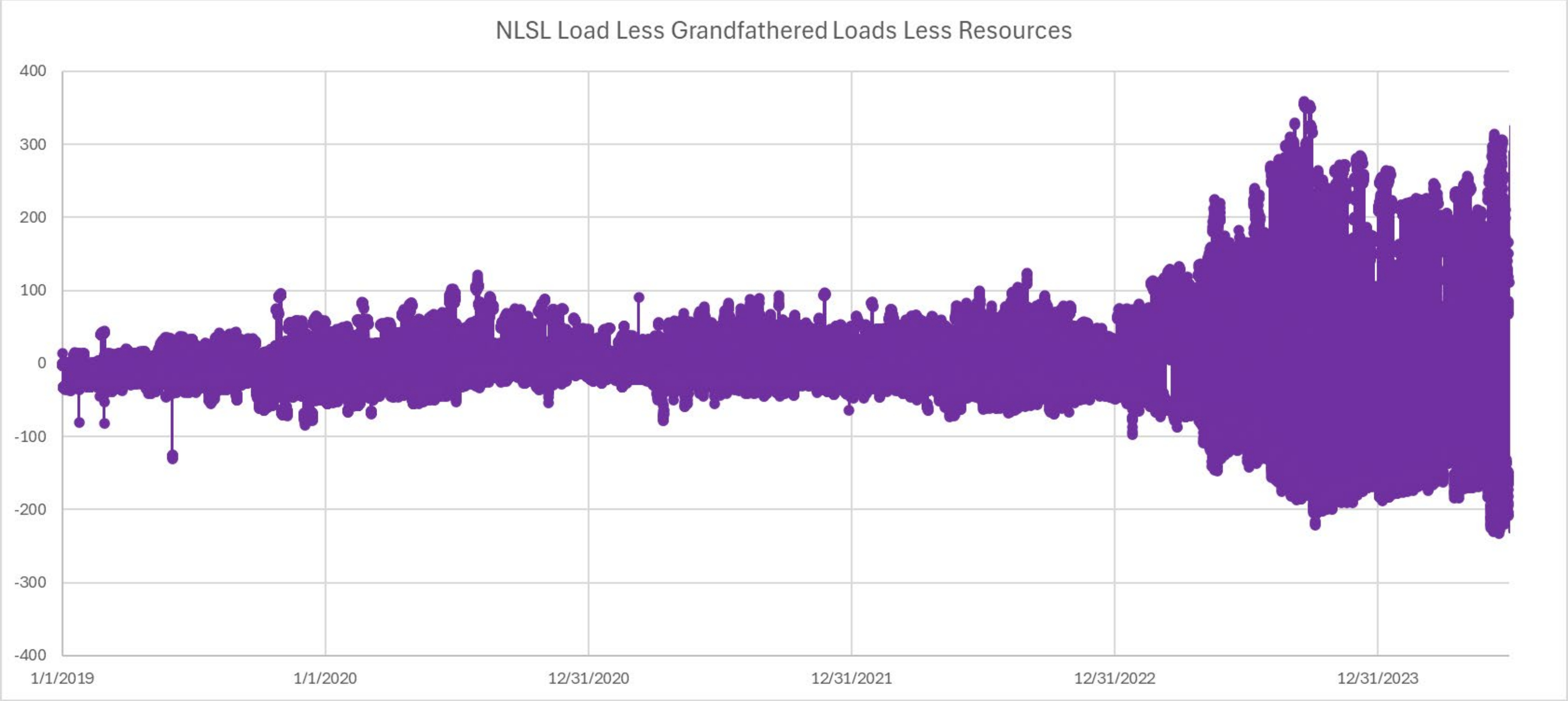
NLSL Loads


NLSL Load Less Grandfathered
1000
900
800
700
600
500
400
300
200
100
0
1/1/2019
1/1/2020
12/31/2020
12/31/2021
12/31/2022
12/31/2023

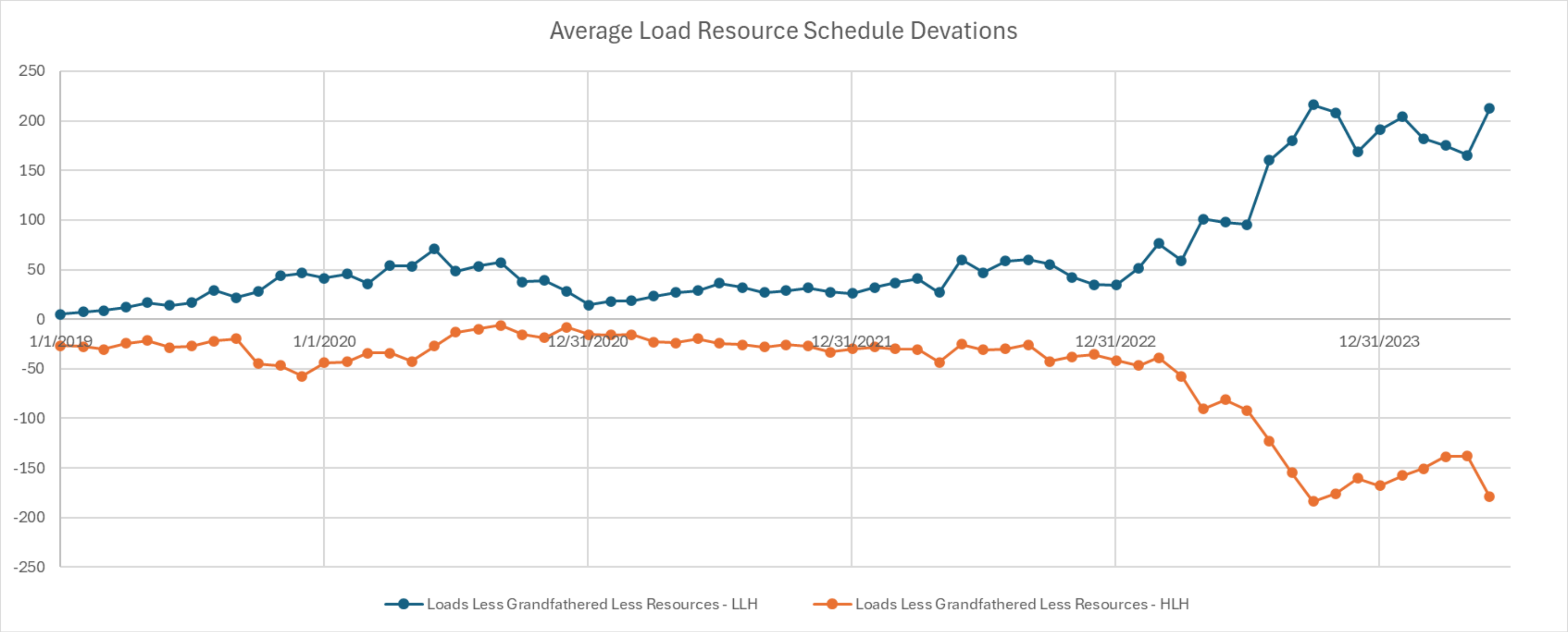
NLSL Resources



Net Load Variability



HLH/LLH Divergence



Discussion

- Open discussion
- Option: Change the NR Shaping service to much lower salvage values
  - Error within 1% - 94% salvage or 6% penalty relative to index price
  - Error between 1% and 5% - 84% salvage value or 16% penalty relative to index price
  - Error greater than 5% - 68% salvage value or 32% penalty relative to index price
- Alternatives?

Remember – original intent of the rate design is for these customers to pay for capacity, schedule as accurately as possible, and true-up to market on energy use relative to actual market prices observed during the period.

Rate Schedule Changes

NR Resource Flattening

Topic 2: NR Resource Flattening Service

- BPA's BP-24 Rate Schedules include the rate treatment that would have applied to a service that no one has requested that BPA provide – the NR Resource Flattening Service.

- The intent of the NR Resource Flatting Service was to aid customers in meeting their NR Load Obligations when a Load Following customer was trying to meet its obligations with a non-dispatchable Specified Resource.

- Given that no customers are taking this service, nor do we anticipate that any customers would be eligible for such a service in the BP-26 rate period, we will remove the language from the BP-26 rate schedules.

Questions?

Tier 2 Rates

Steps Being Covered

- Step 1: Introduction and education
- Step 2: Description of the issue
- Step 3: Data and/or analysis that supports the issue
- Step 4: Discussions on possible alternatives to solve issue

Steps 1 & 2: Introduction, Education and Description of Issue

Previous and Current Tier 2 Rates

BP-12 through BP-24 T2 rates in $/MWh:

Fiscal Year	Rate Case	Short Term	Load Growth	VR1-2014	VR1-2016
2012	BP-12	$46.48	N/A	N/A	N/A
2013	BP-12	$48.69	$48.63	N/A	N/A
2014	BP-14	$35.58	$35.58	N/A	N/A
2015	BP-14	$39.65	$41.62	$41.56	N/A
2016	BP-16	$29.72	$45.18	$44.72	$40.60
2017	BP-16	$32.01	$49.60	$49.08	$43.18
2018	BP-18	$27.20	$47.68	$51.40	$46.50
2019	BP-18	$24.97	$45.42	$53.02	$48.02
2020	BP-20	$30.32	N/A	N/A	N/A
2021	BP-20	$33.00	N/A	N/A	N/A
2022	BP-22	$34.39	$34.39	N/A	N/A
2023	BP-22	$32.99	$32.99	N/A	N/A
2024	BP-24	$63.83	$63.83	N/A	N/A
2024	BP-25	$60.25	$60.25	N/A	N/A

BP-24 Tier 2 Rates

- BP-24 Short Term and Load Growth rate components:

Fiscal Year	Forecast Power Price	Risk Adder	Losses	TSS	Overhead Adder	Short Term and Load Growth Rate	Short Term amounts	Load Growth amounts
	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	annual aMW	annual aMW
2024	$70.23	$0.00	$1.94	$0.11	$1.47	$63.83	195.88	14.02
2025	$62.59	$0.00	$1.83	$0.11	$1.45	$60.25	377.62	16.77

- In BP-24 BPA did not make any power purchases to support its sales at T2 rates; obligations at T2 rates were met with available Firm Surplus amounts (assuming critical water after meeting firm load obligations.)
  - Current T2 aMW estimates for FY 2026, 2027 and 2028 are significantly higher than the T2 amounts in BP-24.
  - T2 aMW amounts will be set November 1, 2026 for BP-26.

BP-24 Forecast Power Prices

- In BP-22, the forecast power prices (aka Remarketing Value) used to set the Short Term and Load Growth rates were based on:
    - Average ICE MID-C settlement prices that were pulled during two separate five-consecutive-business-day periods for a flat block of power in FY 2020 and FY 2021;
    - Plus $0.50/MWh.
- The $.50 adder was used to convert settlement prices to physical prices. It was based on the difference between:
    - previously made Tier 2 power purchases;
    - and ICE settlement prices on the date the Tier 2 power purchases were made for the same years of the power purchases
- In BP-24, the T2 rate was based on a settlement decision to average forecast power prices (ICE, Mid-C) with Bonneville's market price forecast (Aurora).

Steps 3 & 4: Analyze and Discuss the Issue

BP-26 Tier 2 Rate Proposals

- Staff proposes to use the same methodologies used in BP-22 to set BP-26 Tier 2 rates.
  - If Bonneville has Firm Surplus power to meet its entire Tier 2 obligation in a fiscal year, then that fiscal year's Tier 2 rate would be based on ICE settlement prices (pulled during the last full week of September 2026 and the last full week of March 2027) for a flat block of power in the same fiscal year, plus $0.50.
  - If Bonneville purchases an annual flat block of power to meet all or a portion of its Tier 2 obligation in a fiscal year, then that fiscal year's Tier 2 rate would be based on the purchase price for such power, even if some portion is supplied from the federal system.
- Staff proposes to use this methodology for Short Term and Load Growth rates. The Load Growth rate is proposed to be set equal to the Short Term rate.

Vintage Rate Terms

- Information customers should share with AE:
  - aMW amounts by Fiscal Year that the customer would like to buy at a Vintage rate (power the customer has otherwise elected to purchase from BPA at the Tier 2 Short Term rate.)
  - Type of acquisition (that meets the low carbon, specified resource requirements)
- Confidentiality Agreement :
  - A confidentiality and non-disclosure agreement is required for all interested, eligible parties that would like to participate in SOI negotiations.
  - Example here: Confidentiality Agreement Example
- Statement of Intent (SOI):
  - Ideally the customers will have at least one month to sign the SOI. The SOI is a binding agreement that obligates the customer to purchase power at the Vintage rate if BPA makes a purchase in accordance with the terms of the SOI.
  - Example here: SOI Example

Power Unauthorized Increase Charge (UAI)

Steps Being Covered

- Step 1: Introduction and education
- Step 2: Description of the issue
- Step 3: Data and/or analysis that supports the issue
- Step 4: Discussions on possible alternatives to solve issue

Topics

- UAI in BP-24 Recap
- UAI Background Education
- UAI Charges Over the Years
- BP-26 Proposed Alternatives
- Proposed UAI Waiver Language
- Next Steps
- Appendix

Steps 1 & 2: Introduction, Education and Description of Issue

UAI in BP-24 Rate Case

- Implemented the Energy Imbalance Market (EIM) Load Aggregation Point (LAP) price hourly average price for the calculation of UAI in Energy Charges.
- For BP-24, the Power UAI Charge is limited to the higher of $2,500/MWh or 125% of the California Independent System Operator’s Hard Energy Bid Cap.
- Bonneville will revisit this price cap and Power’s Unauthorized Increase Charge prior to the BP-26 rate proceedings.

UAI Background Education

- The UAI Charge is a penalty intended to deter customers from taking more power from Bonneville than they are contractually entitled to.

- Bonneville has a substantial economic and reliability interest in ensuring that customers are motivated at all times to guarantee the availability and delivery of their non-BPA resource amounts.

- If set too low, the UAI charge can be an attractive alternative price to the market price for power for some BPA customers. Therefore, BPA may face power demands far in excess of its contract obligations and its planned system capability. Such demands could result in a significant erosion of BPA’s financial position and inability to recover its costs and repay the US Treasury.

BP-24 UAI Demand and Energy Charges

The energy UAI charge applies when:

- the amount of measured energy exceeds the amount of energy the customer is contractually entitled to take during a diurnal period; and
- is billed at the greater of: (1) 150 mills/kWh; or (2) two times the highest hourly Energy Imbalance Market (EIM) Load Aggregation Point (LAP) price for firm power for the month in which the unauthorized increase occurs.

The demand UAI charge applies when:

- the amount of measured demand during a HLH billing hour exceeds the amount of demand the purchaser is contractually entitled to take during that hour; and
- is billed at 1.25 times the applicable monthly demand rate.

BP-24 UAI Demand Billing Determinants

The amount of measured demand that exceeds that of which a CHWM Contract customer is contractually entitled to take is further defined by purchase obligation types as follows:

- The Load Following customer’s demand UAI billing determinant is the shortfall of its dedicated resources delivered to load on the hour of its Customer System Peak (CSP)
- A Block customer or the Block portion of a Slice/Block customer’s demand UAI billing determinant is the single highest HLH demand in excess of the sum of its Tier 1 and Tier 2 HLH predetermined hourly schedule amounts
- The Slice portion of a Slice/Block customer’s demand UAI billing determinant is the hourly Slice power delivery amount greater than the Slice customer’s hourly Right to Power (RTP) for that same hour during the hour of the customer’s monthly peak HLH Slice RTP.

NR ESS, RSS/FORS, TCMS

BPA offers support services to its customers to help cover potential non-federal resource shortfalls and avoid UAIs.

- NR Energy Shaping Service (NR ESS) for Load Following customers using non-federal resources to serve an NLSL.
  - Customer requests and pays for capacity in advance of need
  - Monthly energy differences are trued-up after-the-fact at NR rates (shortfalls) or a day-ahead index price (excess power provided by the non-federal resources)
- Resource Support Services (RSS) including Forced Outage Reserve Service (FORS)
  - Customer pays for capacity in advance of need through its RSS and FORS monthly capacity fees
  - Except during a forced outage, energy differences are trued-up using forecast market prices (Load Shaping rates). During a forced outage event, energy is trued-up using an hourly index price for the first 24 hours and a day-ahead index price after the first 24 hours
- Transmission Curtailment Management Service (TCMS) for Load Following customers treats eligible transmission curtailments on non-federal resource schedules like generation imbalance.
  - No capacity fee, capacity is covered by deployed balancing reserves
  - Energy is trued-up using an hourly index price

Steps 3 & 4: Analyze and Discuss the Issue

UAI Demand Charges

- BPA staff still believe that the UAI should have some consideration for capacity costs, (i.e., demand).
  - Equity Concerns: If the demand component were removed entirely, staff would be concerned about equity across products (other products would have to pay for capacity that they would be entitled to take).
  - Counter to industry trend. It may not be wise to reduce BPA's capacity penalties at a time when capacity is becoming scarcer and an elevated strategic issue for many utilities.

- Capacity is expensive. The current rate is equivalent to 125% of one monthly debt payment a utility would pay to build new capacity. The financing assumed is also extraordinarily favorable – assumed to be financed over 30 years with BPA's credit rating at tax-exempt rates.

- Analogy: What would you charge someone that stayed in your house uninvited?
  - If the house was vacant at the time, maybe charging 125% of your monthly mortgage payment is too much.
  - If their unexpected arrival caused you to have to sleep outside in the rain, maybe 125% of your monthly mortgage payment isn't enough.

- Capacity penalties are tricky in that they are often too high until they aren't high enough.

Actual UAI Charges

Demand and Energy UAIs - Billed Revenue			
Fiscal Year	Slice and Block	Load Following	IP and NR
2012	351,377	300	0
2013	382,980	27,150	0
2014	208,746	17,526	0
2015	144,060	150	12,538
2016	118,475	17,701	71,715
2017	154,022	3,463	21,819
2018	142,609	1,500	8,781
2019	117,616	0	23,903
2020	69,422	40,519	3,552
2021	223,908	124,705	132,013
2022	104,486	33,593	303,246
2023	172,709	231,222	280,290
2024	287,035	587,146	534
Total	2,477,445	1,084,975	858,391
YTD actuals through June			

Demand and Energy UAIs - Billed Line Counts			
Fiscal Year	Slice and Block	Load Following	IP and NR
2012	84	1	0
2013	91	7	0
2014	82	4	0
2015	43	3	1
2016	57	1	30
2017	46	4	5
2018	41	3	1
2019	36	0	2
2020	19	28	1
2021	20	32	4
2022	25	9	4
2023	26	20	5
2024	20	19	2
Total	590	131	55

Demand UAIs are not billed as frequently as Energy UAIs, but when they are billed the amount paid for Demand UAI has always been larger than Energy UAIs.

- For BP-22 actuals, Demand UAIs line counts make up of 19% of billed UAI revenue line counts.
- On average a Demand UAI is $42K per bill line item and an Energy UAI is $7K per bill line item.

Alternative 1

Maintain current BP-24 UAI charges design:

- Energy charge: the greater of two times the highest hourly Energy Imbalance Market (EIM) Load Aggregation Point (LAP) price for firm power for the month *or* minimum of 150 mills/kWh.

- Demand charge: if the excess occurs during a HLH billing hour, a demand charge is billed at 1.25 times the applicable monthly demand rate.

- The combined Energy and Demand cost of the UAI is capped at $2,500/MWh.

Alternative 2

Continue with the current BP-24 UAI design penalty, but eliminate the cap of $2,500.

- The introduction of the cap was a product of the BP-24 settlement. Staff views the cap as a negotiated band-aid that treated the symptom and not the cause of customer concern.

- Staff understands the concerns with the level of the UAI as being not better tied to the time when the UAI event occurs as well as, potentially, applying a monthly demand rate to an event that may last only a single hour. When viewed on the margin, the effective $/MWh cost of the last unit of demand is expensive, but it's expensive for the last MWh regardless of it being a penalty or not.

Alternative 3

Calculate the energy component of the penalty based on the cost of energy during the hour in which the unauthorized increase occurred:

- Energy charge: the greater of two times the hourly Energy Imbalance Market (EIM) Load Aggregation Point (LAP) price for firm power for the hour in which the overage occurred or 150 mills/kWh.

- Demand charge: if the overage occurs during a HLH billing hour, a demand charge would be billed at 1.25 times the applicable monthly demand rate.

- No cap.

Alternative 4

Calculate the energy component of the penalty based on the cost of energy during the hour in which the unauthorized increase occurred:

- Energy charge: the greater of two times the hourly Energy Imbalance Market (EIM) Load Aggregation Point (LAP) price for firm power for the hour in which the overage occurred or 150 mills/kWh
- Demand charge: Applied Daily: 1.25 times the applicable monthly demand rate divided by 30 (Daily Demand rate) multiplied by the maximum hourly MW energy take during the day.
  - Demand rate will apply regardless of the diurnal period (LLH, HLH), and regardless of whether the shortfall occurs on the hour of the customer's CSP.
  - UAI Demand will be applied for each day in which a UAI occurs.

UAI Penalty Examples

1 MWh taken for 1 hour during LLH

Alternative	Energy Rate During Event	Highest Monthly Energy Charge	Monthly Demand Rate	UAI Energy Charge	UAI Demand Charge	Total Charge	$/MWh
Alt 1	$65	$248	$9,675	$496	$0	$496	$496
Alt 2	$65	$248	$9,675	$496	$0	$496	$496
Alt 3	$65	$248	$9,675	$150	$0	$150	$150
Alt 4	$65	$248	$9,675	$150	$403	$553	$553
LF	$65	$248	$9,675	-	-	$65	$65

1 MWh taken for 1 hour during HLH

Alternative	Energy Rate During Event	Highest Monthly Energy Charge	Monthly Demand Rate	UAI Energy Charge	UAI Demand Charge	Total Charge	$/MWh
Alt 1	$65	$248	$9,675	$496	$2,500	$2,500	$2,500
Alt 2	$65	$248	$9,675	$496	$12,094	$12,590	$12,590
Alt 3	$65	$248	$9,675	$150	$12,094	$12,244	$12,244
Alt 4	$65	$248	$9,675	$150	$403	$553	$553
LF	$65	$248	$9,675	-	-	$9,740	$9,740

UAI Penalty Examples

1 MWh taken for 8 hours during the LLH in a single day							
Alternative	Energy Rate During Event	Highest Monthly Energy Charge	Monthly Demand Rate	UAI Energy Charge	UAI Demand Charge	Total Charge	$/MWh
Alt 1	$65	$248	$9,675	$3,968	$0	$3,968	$496
Alt 2	$65	$248	$9,675	$3,968	$0	$3,968	$496
Alt 3	$65	$248	$9,675	$1,200	$0	$1,200	$150
Alt 4	$65	$248	$9,675	$1,200	$403	$1,603	$200
LF	$65	$248	$9,675	-	-	$520	$65

1 MWh taken for 8 hours during HLH in a single day							
Alternative	Energy Rate During Event	Highest Monthly Energy Charge	Monthly Demand Rate	UAI Energy Charge	UAI Demand Charge	Total Charge	$/MWh
Alt 1	$65	$248	$9,675	$3,968	$12,094	$16,062	$2,008
Alt 2	$65	$248	$9,675	$3,968	$12,094	$16,062	$2,008
Alt 3	$65	$248	$9,675	$1,200	$12,094	$13,294	$1,662
Alt 4	$65	$248	$9,675	$1,200	$403	$1,603	$200
LF	$65	$248	$9,675	-	-	$10,715	$1,339

Proposed UAI Waiver Language

- Under appropriate circumstances, BPA may, in its sole discretion, waive up to 80% of the penalty portion of the UAI Energy Charge, up to 100% of the UAI Demand Charge, or a combination of the two, to a Power customer on a non-discriminatory basis.

- A Power customer seeking a reduction or waiver must demonstrate good cause for relief, including demonstrating that the event that resulted in the UAI:

  - (1) was inadvertent or was the result of an equipment failure or outage that the Power customer could not have reasonably foreseen or avoided; and
  - (2) did not result in harm to BPA's power system or services, or to any other Power customer.

Next Steps

- Comments or questions? Email techforum@bpa.gov and copy your Account Executive

- Please provide comments by August 14.

Demand Rate

Steps Being Covered

- Step 1: Introduction and education
- Step 2: Description of the issue
- Step 3: Data and/or analysis that supports the issue
- Step 4: Discussions on possible alternatives to solve issue

Steps 1 & 2: Introduction, Education, and Description of Issue

Background on Demand Rates

- The Demand Rate applies to customers purchasing PF Load Following and Block with Shaping Capacity, and power sold at the IP and NR rates.
- The TRM states that the demand rate will be based on the annual fixed costs (capital and O&M) of the marginal capacity resource as determined in each 7(i) process.
- The TRM gives BPA discretion to determine the source data for the costs of the marginal capacity resource. Beginning in BP-24, BPA has used a Wartsila reciprocating generating plant for the marginal capacity resource.
- The Northwest Power and Conservation Council (NWPPC or the Council) models the Wartsila Reciprocating engine natural gas plant (18V50SG) as one of the Reference Plants for flexible capacity. It is modeled in the 2021 Northwest Power Plan.

Previous Demand Rates

- Average monthly PF/NR/IP demand rate in $/kW/mo:

BP-12	BP-14	BP-16	BP-18	BP-20	BP-22	BP-24
$9.62	$9.32	$9.88	$9.79	$10.29	$9.67	$9.54

- Revenues from demand rate are credited to the non-slice cost pool.

- Increasing the demand rate increases effective rates for low load factor customers (i.e., peaky Load Following customers) and decreases effective rates to high load factor customers (i.e., Block customers).

Demand Rate Inputs

Input	Source
Heat Rate Btu/kWh	NWPPC microfin model*
All-in Capital Costs $/kW	NWPPC microfin model* in 2016 dollars
Fixed O&M $/kW/yr	NWPPC microfin model* in 2016 dollars
Fixed Fuel Costs $/kW/yr	NWPPC microfin model*, average of the existing eastside and westside Pacific Northwest fixed fuel costs
Insurance Rate %	NWPPC 2021 Power Plan
Cost of Debt %	BPA's third-party tax-exempt 30-Year borrowing rate forecast
Inflation %	7 year average inflation rate based on Bureau of Economic Analysis' gross domestic product implicit price deflator
Monthly shape (convert annual rate to monthly rates)	HLH Load Shaping rates (based on Aurora market prices at average water)

Draft BP-26 Demand Rate

	A	B	C	D	E	F	G	H	I	J
1				**Calendar Year**	**Chained GDP IPD**		**Month**	**BP-26 Load Shaping Rate HLH $/MWh**	**Demand Shaping Factor**	**Monthly Demand Rate $/kW/mo**
2	Start Year of Operation (FY)	2026		2016	98.241		Oct	58.85	10.61%	$ 14.90
3	Cost of Debt	3.79%	/1	2017	100.000		Nov	45.52	8.21%	$ 11.53
4				2018	102.291		Dec	57.72	10.40%	$ 14.60
5	Inflation Rate	3.18%		2019	104.008		Jan	51.23	9.23%	$ 12.96
6	Insurance Rate	0.25%	/2	2020	105.381		Feb	52.54	9.47%	$ 13.30
7				2021	110.213		Mar	35.79	6.45%	$ 9.06
8	Debt Finance Period (years)	30	/2	2022	117.973		Apr	28.57	5.15%	$ 7.23
9	Plant Lifecycle (years)	30	/2	2023	122.273		May	14.72	2.65%	$ 3.72
10					103.18%	7-year Avg.	Jun	20.46	3.69%	$ 5.18
11	Lifetime Average Heat Rate Btu/kWh	8,797	/2				Jul	58.36	10.52%	$ 14.77
12				Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product (2017 Base year) - Last Revised July 25, 2024			Aug	62.56	11.28%	$ 15.84
13	Eastside Fixed Fuel $/kW/yr with 8797 Heat Rate 2016$	$ 16.67	/2				Sep	68.44	12.34%	$ 17.33
14	Westside Fixed Fuel $/kW/yr with 8797 Heat Rate 2016$	$ 22.68	/2				**Average $/kW/mo**			**$ 11.70**
15	Average Eastside and Westside 2016$	$ 19.67								
16										
17	All-in Capital Cost Recip $/kW 2026$	$ 1,797.60	/3	**End of Fiscal Year**	**Midyear Assessed Value**	**Debt Payment**	**Fixed O&M**	**Insurance**	**Fixed Fuel**	**Cash Expense Each Year**
18	Fixed O&M $/kW/yr 2026$	6.83	/4	2026	$ 1,767.64	$101.32	$ 6.83	$ 4.42	$ 26.90	$ 139.47
19	Fixed Fuel $/kW/yr 2026$	26.90		2027	$ 1,707.72	$101.32	$ 7.05	$ 4.27	$ 27.75	$ 140.39
20				2028	$ 1,647.80	$101.32	$ 7.27	$ 4.12	$ 28.64	$ 141.35
21						**Rate Period Average Expense $/kW/year**				**$ 140.40**

Steps 3 & 4: Analyze and Discuss the Issue

BP-26 Demand Rate Proposal

- BPA's model, updated for the BP-26 Rate Case, is showing a 23% increase in the Demand Rate when compared to the BP-24 Demand Rate ($9.54 kW/mo in BP-24; $11.70 kW/mo in BP-26).

- Should BPA limit the increase in the Demand Rate to a 10% increase for the BP-26 Rate Period? If BPA did this, the BP-26 Demand rate would be $10.49 kW/mo ($9.54 * 110%).

- Under the Tiered Rate Methodology, the Demand Rate was intended to be a long run price signal that incented energy and resource decisions; it was not intended to change quickly under the influence of volatile inputs.

- TRM Section 5.3.6: "The shape of the Demand Rate may be subject to a dampening methodology proposed in each 7(i) Process if there proves to be significant volatility in the shape of the Demand Rate from Rate Period to Rate Period."

- Customers may wish to see the logic of a dampening methodology applied here, where the average monthly Demand Rate is projected to increase by 23% during a rate period and monthly Demand Rates are projected to change by 63% (in April) to -6% (in May). (Monthly Demand Rates are given a market shape)

Demand Rate Proposal Comparison

Demand Rate Summary:	BP-24 Final Wartsila - Gas Recip	BP-26 Workshop Wartsila - Gas Recip
Inflation %	2.28%	3.18%
Cost of Debt %	3.06%	3.79%
All-in Capital Cost $/kW	$ 1,575	$ 1,799
Debt Payment $/kW/yr	$ 81	$ 101
Fixed O&M $/kW/yr	$ 6	$ 7
Insurance $/kW/yr	$ 4	$ 4
Fixed Fuel $/kW/yr	$ 24	$ 28
Demand Rate $/kW/yr	$ 115	$ 140
Monthly Average $/kW/mo	**$ 9.54**	**$ 11.70**

23% increase

Meeting Wrap-up

- Please send any feedback, with the topic you are addressing, by Friday, August 23 to BPA's Tech Forum at techforum@bpa.gov, with a cc to your Power Account Executive.
- If you would like to have a customer led workshop on August 22, please send us the topic that you would like to discuss, and how much time you will need, by August 15 to BPA's Tech Forum at techforum@bpa.gov, with a cc to your Power and Transmission Account Executive.
- The next workshop will be on August 27-28, and it will be hybrid.

Appendix

BP-26 and TC-26 Workshops: Proposed Dates for Topics

Date	Rate/Tariff Topics
August 27 & 28 (Tue-Wed)	**Transmission Rates** • Energy Storage Devices • GI Withdrawal Penalties • Gen Inputs **Power Rates** • Revenue Requirements (Power and Transmission) • Risk (Power and Transmission) • Western Resource Adequacy Program (WRAP) – Follow up • Transfer Service Update • Generation Input Variable Cost Plan Update • Gas Forecast **Tariff** • GI Reform – LGIA (Option to Build) • Tariff clean-up – ministerial edits to Attachments L and R • Redline draft proposed tariff

BP-26 and TC-26 Workshops: Proposed Dates for Topics

Date	Rate/Tariff Topics
September 25 (Wed)	**Transmission Rates** • Utility Deliver Segment • Non-EIM Balancing **Power Rates** **Tariff** • GI Reform – LGIA • Network Loss Factors (if needed)