BP-26 Rate Case and TC-26 Tariff Proceeding Workshop

July 30-31, 2024

Agenda July 30 (Day 1)

	BP/TC-26 Pre-Proceeding Workshop	
Time*	Topic	Presenter
9:00 – 9:10 a.m.	Introduction, Meeting Protocols, Comments and Agenda	Brian McConnell
9:10 – 9:30 a.m.	Network Loss Factors	Colleen McDonnell, Jonathan Young
9:30 – 9:40 a.m.	ROFR Queue Management	Nadine Hanhan
9:40 – 10:25 a.m.	Transmission Line Ratings	Ashley Donahoo, Gage Marek
10:25 – 10:35 a.m.	**Break**	
10:35 – 11:35 a.m.	GI Reforms – LGIA	Kim Gilliland
11:40 a.m. to 12:40 p.m.	**Lunch**	
12:45 – 1:15 p.m.	EIM Charge Codes	Bill Hendricks
1:15 – 1:45 p.m.	Persistent Deviation Penalty	Bill Hendricks, Frank Puyleart
1:45 – 2: 15 p.m.	New Technology Pilot	Ross Ponder, Eric King
	Closing comments	

**** Times are approximate***

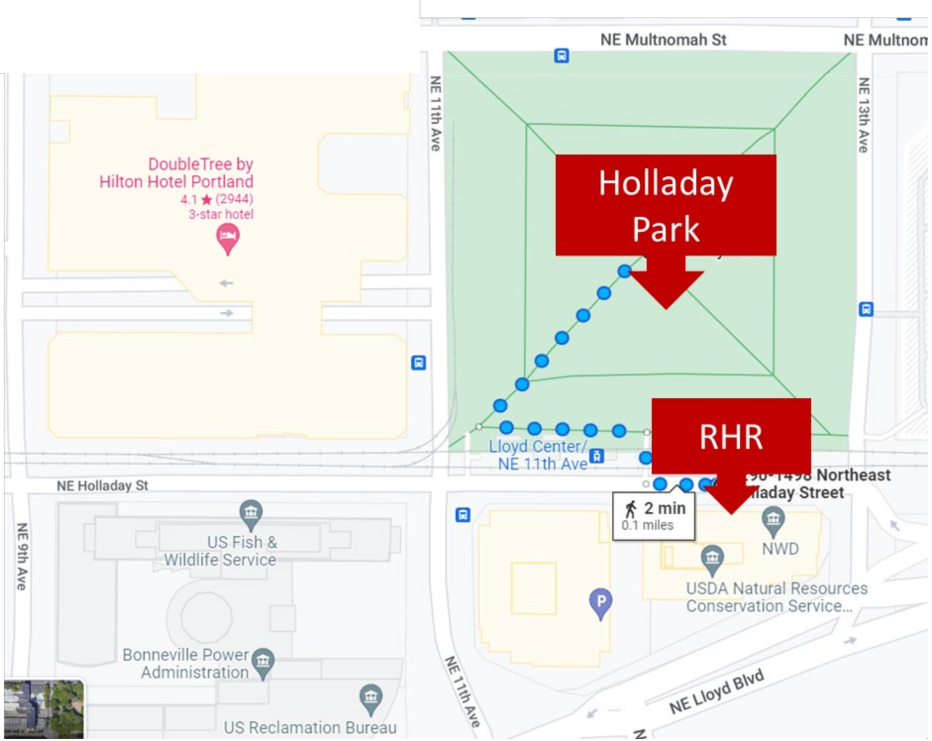
Agenda July 31 (Day 2)

	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***

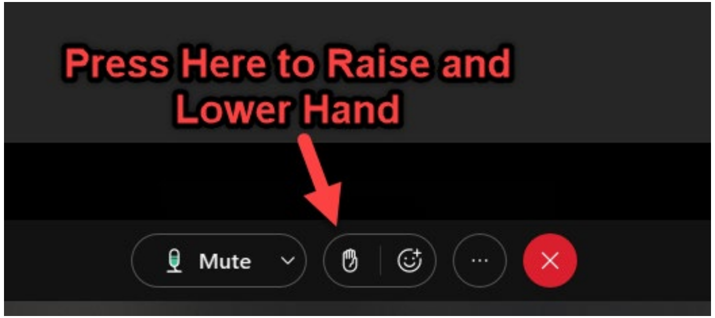
Safety Moment

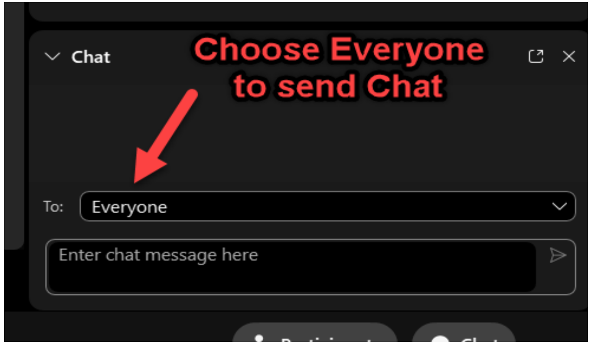
- The Rates Hearing Room has two exits.
- In the event an alarm sounds, please meet at Holladay Park across the street.



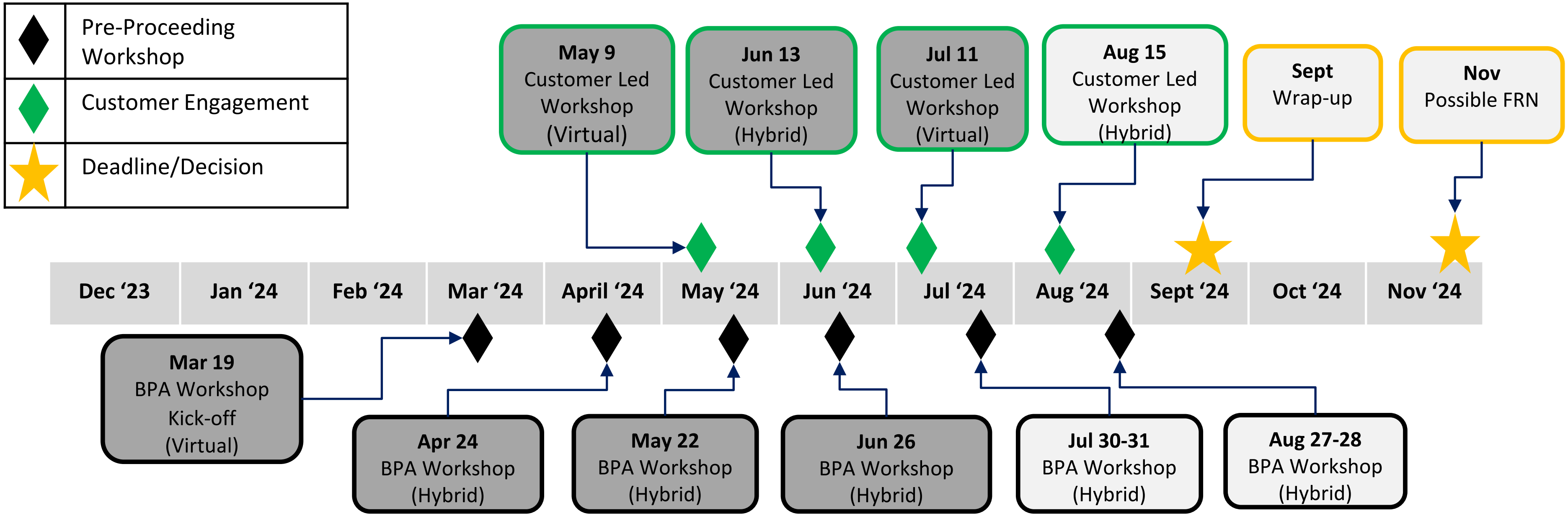
WebEx Meeting Participation and Asking Questions

- After you join the WebEx, you will be automatically muted.
- Please identify your company in your display name on WebEx.
- **To be recognized for asking a question:**
  1. *Use the "Raise your Hand" option to signal you have a question*
  2. *Or use the Chat option to send a question request to "Everyone"*
- Once recognized, unmute yourself and state your name and company before commenting/asking your question – participants in the RHR are also asked to do this.
- When finished speaking please remember to **re-mute** and/or **lower your hand**.





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 15th Customer Led Workshop

- Customers may request time to discuss a topic at the August 15 Customer Led workshop **no later than August 7**.
  - 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 August 12**.
- If a customer does not provide a presentation or notice to BPA by August 12, the customer will be removed from the agenda for the August 15 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

BP-26 and TC-26 Workshop

July 30, 2024
(Day 1)

Network Loss Factors

Regulatory

- Sections 15.7 and 28.5 of BPA's Tariff requires point-to-point (PTP) and network integration transmission service (NT) customers to replace the real power losses associated with transmission service as calculated by BPA.
  - BPA calculates the real power losses a customer owes using the loss factors specified in Schedule 11 of its Tariff.
- Schedule 11 of BPA's Tariff includes loss factors for the Network and Southern Intertie segments.
- FERC requires a transmission provider to specify the loss factor for transmission service in its Tariff, which BPA does, but does not specify what the loss factor should be.

Background

- TC-22
  - Staff proposed to update the network loss factor from an annual average to monthly averages.
  - Final ROD adopted an alternate proposal of two-season loss factors and directed staff to *propose* monthly loss factors in TC-24.
- TC-24
  - Settlement reached with parties, which included maintaining the two-season loss factors and updating the values based on the latest loss factor study.

- In general, customers and parties have supported updating the loss factors to reflect the latest changes on the system, however, there has been varying positions on the granularity of the loss factors (monthly vs. two-season vs. annual).

Staff Leaning – Maintain Two-Season Loss Factors

Maintain the two-season loss factor granularity and update the values to reflect the latest loss factor study results: **1.97% (Summer)** and **1.76% (Non-Summer)**.

- Two-season loss factor granularity has been in place since TC-22.
- Customers have previously expressed more support for two-season vs monthly loss factor granularity.
- Customers have expressed concerns with the complexity and administrative burden of monthly loss factors.
- Offers stability – the loss factors adopted in TC-26 will likely be in place for three years.
- Although losses would likely be over/under collected during certain months, overall difference in losses returned (MWHs) between two-season and monthly would likely be minimal.
  - BPA will continue to complete the loss factor study, share study results and discuss loss factors before proposing updated loss factors in future tariff proceedings.
  - BPA will continue to compare the loss factor granularity differences and may reevaluate the loss factor granularity in future tariff proceedings.

Summary of TC-26 Loss Factor Study: Methodology

- Step 1: Power flow analysis using 2026 WECC seasonal base cases to determine the amount of real power losses by season.
- Step 2: Create seasonal curves (winter, spring, summer).
- Step 3: Perform statistical analysis by month.
  - Average the seasonal curves to create a single curve for the BPA system.
  - The single curve was used to calculate monthly loss factors by dividing the monthly average real power losses by the monthly average Total Transmission System Load (TTSL).
  - The two-season loss factors are calculated by averaging the monthly loss factors included in the summer season (June, July and August) and non-summer season (all other months).

Summary of TC-26 Loss Factor Study: Results

Monthly Loss Factors		
Month	**Average Hour (MW)**	**Loss Factor (%)**
January =	23725.305	1.54%
February =	23469.047	1.53%
March =	21145.718	1.92%
April =	18437.973	1.87%
May =	19809.756	1.90%
June =	21566.904	1.94%
July =	22520.921	2.01%
August =	21982.362	1.97%
September =	18932.479	1.88%
October =	17531.028	1.86%
November =	20630.032	1.91%
December =	22842.869	1.45%

Two-Season Loss Factors	
Season	**Loss Factor (%)**
Summer =	1.97%
Non-Summer =	1.76%

Summer = June, July, August
Non-Summer = all other months

Annual Average Loss Factor = 1.82%

Summary of TC-26 Loss Factor Study: Data Details

- Changes in load and generation patterns:
  - Load growth in the Tri-Cities and Umatilla areas.
  - Generation at Mid-C and McNary/John Day serving larger loads more locally, which translates to lower losses.

More Info and Next Steps

- The TC-26 Loss Factor Study Summary data (.xlsx) is posted with the meeting material on the BP-26 Rate Case webpage.
- We encourage customers to submit feedback on the staff leaning and will plan a follow-up workshop in September, if necessary.
  - Please submit any comments to techforum@bpa.gov with a copy to your Account Executive.
  - Comments are due by August 14.
- If we don't receive any comments, we will proceed with proposing the updated two-season loss factors in the TC-26 initial proposal.

ROFR Queue Management

July 30, 2024

Review of May Workshop (Steps 1 – 4)

- Issue: Should BPA change its approach to offering rollover rights based on the requested 5-year term of service or modify Section 2.2 of BPA’s Tariff?
  - BPA currently offers rollover rights to customers who have requested at least 5 years of service.
  - Pro forma offers rollover rights to customers who execute a contract for 5 years of service.
- Staff Leaning: Tariff change to harmonize BPA’s practices with its Tariff
  - Aligns BPA’s Tariff with current practices.
  - Allows BPA to continue providing for new transmission service needs for the region.
  - Allows BPA to continue current planning process, avoiding disruption to studies, accounting for lengthy project timelines, maintaining the business cases for projects, and has a low administrative burden.
  - Prevents significant harm and provides significant benefit.

Proposed revision to Section 2.2(a)

Section 2.2(a) of Bonneville's Tariff

Existing firm service customers (wholesale requirements and transmission-only, with a requested contract term of five years or more other than customers that have signed a Precedent Transmission Service Agreement under sections 19.10 or 32.6), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed.

Steps 5 and 6 – Customer Feedback and Staff Proposal

- Step 5 – Customer feedback: All comments supported Staff Alternative 2 (Tariff Change)
  - “Commenting Parties support Alternative 2.” – NIPPC
  - “City Light supports BPA’s Alternative 2 to change the Tariff to harmonize BPA’s practices fully with the Tariff.”
  - “Snohomish supports BPA’s “Alternative 2” proposal to change the language of Section 2.2(a) of BPA’s Tariff to align with BPA’s existing process to offer ROFR to customers who *request* at least five years of service.”
- Step 6 – Staff Proposal: BPA Staff will proceed with its proposal to change the Tariff as described on May 22.

Transmission Line Ratings
FERC Order 881

Background

- FERC issued Order 881 on December 16, 2021, proposing reforms to both the *pro forma* Open Access Transmission Tariff (OATT) and FERC's regulations under the Federal Power Act to improve the accuracy and transparency of transmission line ratings.
- Specifically, the Order calls for:
  - proposing transmission providers to implement ambient adjusted ratings (AARs) on the transmission lines over which they provide transmission service;
  - Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least hourly;
  - transmission owners to share transmission line ratings and transmission line rating methodologies with their respective transmission provider(s) and, in RTOs/ISOs, with their respective market monitor(s).

The Order goes into effect July 2025

Overview of FERC Order 881

- **Requires implementation of Seasonal Ratings**
  - Must have at least 4 seasons
  - Must be re-evaluated annually
  - Must be based on historic temperatures
  - Used for longer range transmission availability studies >10 days out
- **Requires implementation of Emergency Ratings**
  - Emergency ratings to apply to a “finite period of operation” opposed to continuous operation
  - Used for post contingency operation of the power system
  - Emergency ratings are adjusted for ambient temperatures
- **Requires implementation of Ambient Adjusted Ratings**
  - AARs to be used for providing near-term (10 days out) transmission service
  - Must have day and night ratings
  - Must be updated at least each hour
  - Rating database must be created by Regional Transmission Organizations (RTO) and Independent System Operators (ISO) to which Transmission Owners (TO) will submit AARs
  - TOs must share ratings and methodologies with their transmission providers and/or market monitors
  - Transmission Providers must maintain a database of TO’s ratings and methodologies on the Open Access Same-Time Information System (OASIS) site or equivalent
  - Must have “reasonable confidence” in the forecasted ratings

Tariff Principles

- Considering the Tariff principles in evaluating alternatives for this issue.

- Alignment with the *pro forma* tariff
- Meeting the criteria for BPA to consider a deviation from the *pro forma* tariff.

1. Implement BPA's statutory and legal obligations, authorities, or responsibilities;
2. **Maintain the reliable and efficient operations of the federal system;**
3. Prevent significant harm or provide significant benefit to BPA's mission or the region, including BPA's customers and stakeholders; and
4. Align with industry best practice when the FERC *pro forma* tariff is lagging behind industry best practice, including instances of BPA setting the industry best practice.

May BP/TC-26 Workshop

- May 22nd Workshop Presentation:
  - Presented BPA's proposal to adopt a modified version of the *pro forma* Attachment M into BPA's Tariff (to become "Attachment S")
  - Sought customer comments and feedback on BPA's proposal

Customers' Comments

NIPPC and Renewable NW Joint Comments

- *BPA staff...proposes that BPA will not comply with Order 881's requirement to calculate and post separate daytime and nighttime transmission line ratings. BPA has a framework to determine the circumstances in which it will propose tariff provisions that deviate from the FERC pro forma Open Access Transmission Tariff ("OATT"). BPA staff, however, has not presented any analysis that explains to customers why it is appropriate for BPA to deviate from FERC's Order 881 on this issue. FERC conducted a rulemaking process and upon full consideration of the record, FERC determined the requirements of Order 881 were necessary to ensure accurate line ratings and avoid rates that are unjust and unreasonable. Based on the information presented to date, it is not clear why BPA staff has come to a different conclusion than FERC on the usefulness of separate daytime and nighttime transmission line ratings.*

Day vs Night Ratings

- Why are we deviating from *pro forma?*
  - **Tariff Principle: Maintain the reliable and efficient operation of the federal system**
    - The order only requires removing solar heating, however wind speeds are also lower at night which provides less cooling.
    - If solar heating was removed without reducing wind speed, there are higher risks for public safety and our equipment.
    - It's difficult to quickly assess wind speed across a large service territory because it's highly variable and localized.
    - EPRI report "Ambient Adjusted Ratings Application Guide" (https://www.epri.com/research/products/000000003002021564):
      - Risks related to AARs are particularly high during night periods.
      - Wind speeds are statistically more likely to be low at night.
      - During the night period, there is no solar heating but is counteracted by lower wind speeds that provide limited cooling.
  - BPA will be using ambient adjusted ratings in real-time at all times of the day.

NIPPC and Renewable NW Joint Comments

- *Commenting Parties also note that BPA's neighboring transmission systems will be complying with Order 881 and posting daytime and nighttime Ambient Adjusted Ratings for their transmission facilities connecting to BPA's network. Commenting Parties request further explanation from BPA staff about whether its proposal to deviate from the language of Order 881 will create any unnecessary seams with its adjoining transmission providers. At this time, Commenting Parties do not have a formal recommendation as to BPA's proposed deviations from Order 881, but simply seek to better understand BPA's reasoning for proposing them.*

Seams

- BPA is providing ratings and TTCs every hour totaling the 240 hours matching what each utility is required to when following FERC Order 881.
  - The Order does not require for every entity to use the same set of assumptions.
  - Each utility today uses different assumptions for their ratings, which will continue after the Order is in effect.
- BPA is providing data to ensure entities can operate their system. The assumptions for our data is seasonal, however in real-time BPA is using ambient adjusted ratings.

NIPPC and Renewable NW Joint Comments

- *Staff also seeks to insert additional language to the definition of "Ambient-Adjusted Rating" proposed by FERC. On the one hand, it seems reasonable that BPA would "evaluat(e) the need to curtail paths or develop(e) Operating Plans to prevent/mitigate an (sic) System Operating Limit (SOL) exceedance on the network." On the other hand, that additional language does not seem to be appropriate within the definition of an Ambient Adjusted Rating. Rather, it seems to be an ongoing action that BPA would take to ensure the reliability of its system and not limited to any requirement to develop or post ambient adjusted line ratings. Moreover, BPA has not provided any analysis under its OATT deviation framework that explains how this additional language meets that standard.*

Proposed red-line to AAR definition

- Attachment M Definitions:
  - "Transmission Line Rating" means the maximum transfer capability of a transmission line, computed in accordance with a written Transmission Line Rating methodology and consistent with Good Utility Practice, considering the technical limitations on conductors and relevant transmission equipment (such as thermal flow limits), as well as technical limitations of the Transmission System (such as system voltage and stability limits). Relevant transmission equipment may include, but is not limited to, circuit breakers, line traps, and transformers.
  - Ambient-Adjusted Rating (AAR) means a Transmission Line Rating:

To be deleted

- Evaluating the need to curtail paths or developing Operating Plans to prevent/mitigate an System Operating Limit (SOL) exceedance on the network.

- BPA's original goal was to provide transparency on how we are proposing to use ambient adjusted ratings.
- However, we acknowledge that it doesn't belong in the definitions section and the Transmission Provider Obligation covers our intention (relevant excerpts on next slide).
- BPA is recommending to remove the once proposed red language.

Proposed Adoption

- Attachment M – Transmission Line Ratings
  - Obligations of Transmission Provider:
    - The Transmission Provider must use AARs as the relevant Transmission Line Ratings when determining where to make flow-based curtailments (under section 13.6) Firm Point-to-Point Transmission Service or when determining whether to curtail and/or interrupt (under section 14.7) Non-Firm Point-to-Point Transmission if such curtailment and/or interruption is both necessary because of issues related to flow limits on transmission lines and anticipated to occur (start and end) within 10 days of such determination.
    - For determining whether to curtail or interrupt Point-to-Point Transmission Service in other situations, the Transmission Provider must use Seasonal Line Ratings as the relevant Transmission Line Ratings.
    - The Transmission Provider must use AARs as the relevant Transmission Line Ratings when determining whether to make flow-based curtailments (under section 33) or redispatch (under sections 30.5 and/or 33) Network Integration Transmission Service or secondary service if such curtailment or redispatch is both necessary because of issues related to flow limits on transmission lines and anticipated to occur (start and end) within 10 days of such determination. For determining the necessity of curtailment or redispatch of Network Integration Transmission Service or secondary service in other situations, the Transmission Provider must use Seasonal Line Ratings as the relevant Transmission Line Ratings.

Portland General Electric comments

- *Portland General Electric Company ("PGE") hereby respectfully submits that Bonneville Power Administration ("BPA") should provide TTC values in compliance with FERC Order No. 881 ("Order") for jointly owned transmission paths where BPA is the path operator...On May 22, BPA explained that it does not plan on providing TTC values that are compliant with Order 881, which would put BPA's path ratings out of line with the rest of the Northwest. PGE requests that BPA provide forecasted hourly AARs for the required (and now industry standard) 240 hours into the future.*

- *As the path operator, BPA calculates the TTC for the jointly owned paths and provides PGE its share of the TTC for All Lines in Service (ALIS) and outage conditions as part of the operating agreements for such paths. BPA's disposition towards complying with the 240 hours of hourly Ambient Adjusted TTC Ratings will impact PGE's ability to provide its transmission customers the hourly transmission capacity of its share of the jointly owned transmission scheduling paths operated by BPA.*

Update TTCs using AARs

- Why are we deviating from *pro forma*?
  - **Tariff Principle: Maintain the reliable and efficient operation of the federal system**
    - Accuracy in AAR utilization requires accurate temperature, load, and generation forecasts.
    - Performing contingency analysis ensures the system is set-up reliably before going into real-time.
    - BPA is not confident in our ability to provide customers the same reliability we do today by incorporating AARs with the existing technology and forecasts.
    - Focusing on the ratings of the elements that make-up the path, does not account for all aspects that can affect a Path TTC.
    - Daily reservations are the least type of tag utilized on BPA's system. BPA's customers rely on long-term firm. BPA will continue to sell unlimited hourly non-firm on internal paths.
  - BPA will not use ambient adjusted ratings to update Total Transfer Capabilities. However, BPA will be providing ratings and TTCs for the 240 hours into the future.

Seattle City Light comments

- *City Light supports BPA's overall approach to implementation of FERC Order 881. City Light suggests that there would be value in BPA developing explanatory material supporting BPA's decision to not follow the pro forma language.*

Reasoning

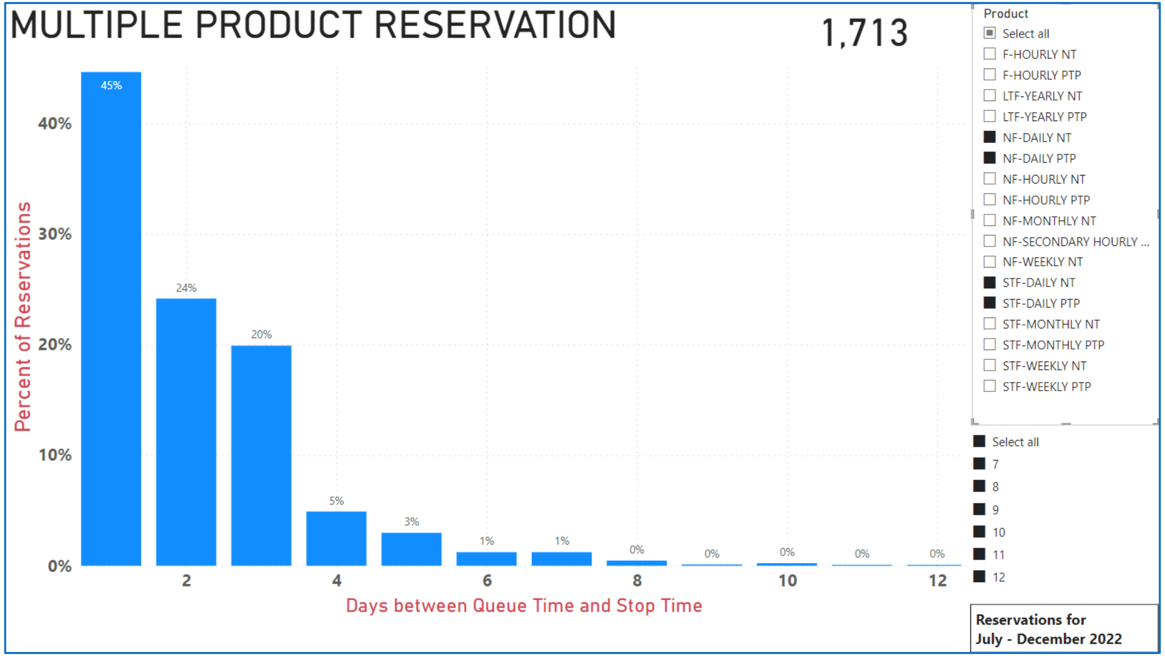
- BPA's primary concern is being able to maintain the reliable and efficient operations of the federal system.
- BPA cannot analyze day vs night rating benefits before July 2025, leaning on EPRI study shows it's not reliable to only assess solar heating.
- Only using ambient adjusted ratings to update TTCs voids the ability to reliably set-up TTC paths.
  - Load
  - Generation
  - Contingency Analysis
- BPA will be providing ratings and TTCs 240 hours in the future as the Order states.

Next Steps

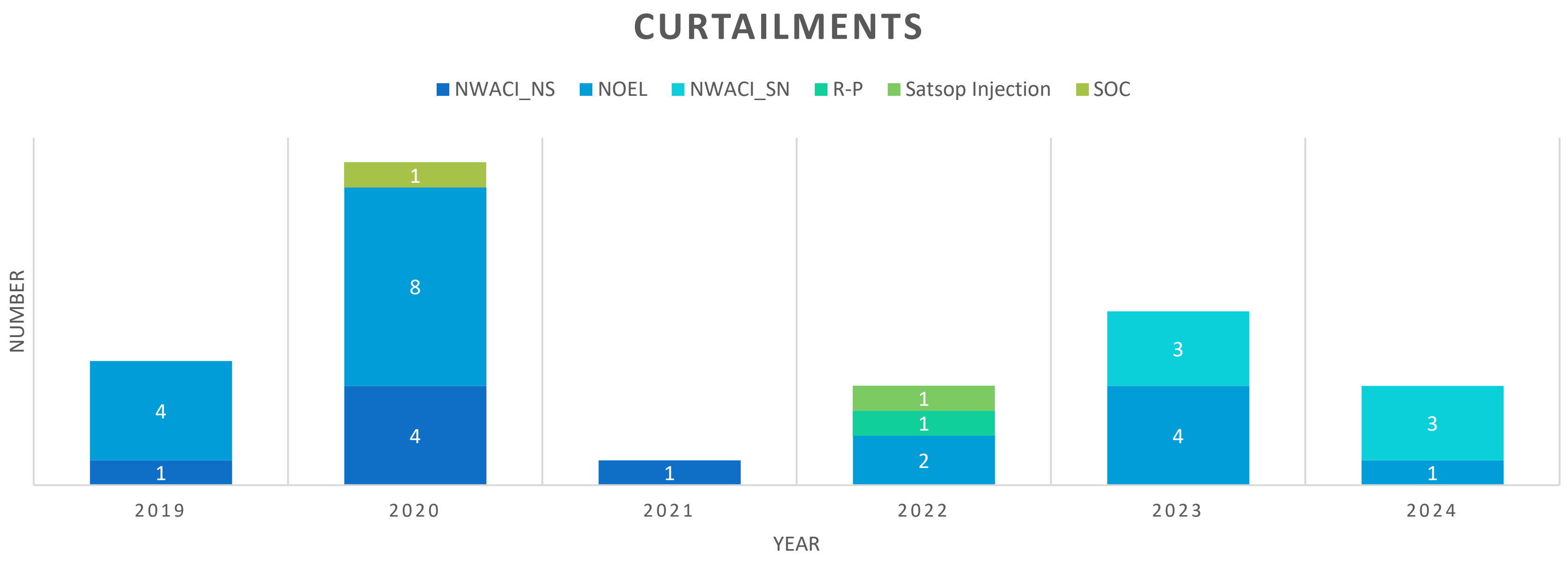
- BPA will collect comments on staff's proposal
  - The proposed Attachment S is posted with the meeting materials on the BP-26 Rate Case webpage.
  - Please send all feedback to techforum@bpa.gov with a copy to your Account Executive.
  - Comments are due by August 14.

Q&A

Appendix – actual utilization



Appendix – Curtailment Data



BPA has curtailed 34 different times since 2019, on 6 paths

Review BPA’s proposal for new Attachment

Proposed Adoption

- Attachment M – Transmission Line Ratings
  - Definitions:
    - "Transmission Line Rating" means the maximum transfer capability of a transmission line, computed in accordance with a written Transmission Line Rating methodology and consistent with Good Utility Practice, considering the technical limitations on conductors and relevant transmission equipment (such as thermal flow limits), as well as technical limitations of the Transmission System (such as system voltage and stability limits). Relevant transmission equipment may include, but is not limited to, circuit breakers, line traps, and transformers.
    - Ambient-Adjusted Rating (AAR) means a Transmission Line Rating:
      - Applies to a time period of not greater than one hour.
      - Reflects an up to date forecast of ambient air temperature across the time period to which the rating applies.
      - Reflects the absence of solar heating during nighttime periods, where the local sunrise/sunset times used to determine daytime and nighttime periods are updated at least monthly, if not more frequently
      - Is calculated at least each hour, if not more frequently.
      - Evaluating the need to curtail paths or developing Operating Plans to prevent/mitigate an System Operating Limit (SOL) exceedance on the network.

BPA is proposing to delete this bullet point

BPA is proposing to delete this bullet point

Proposed Adoption

- Attachment M – Transmission Line Ratings
  - Definitions:
    - "Seasonal Line Rating" means a Transmission Line Rating that:
      - Applies to a specified season, where seasons are defined by the Transmission Provider to include not fewer than four seasons in each year, and to reasonably reflect portions of the year where expected high temperatures are relatively consistent.
      - Reflects an up-to-date forecast ambient air temperature across the relevant season over which the rating applies.
      - Is calculated annually, if not more frequently, for each season in the future for which Transmission Service can be requested.

Proposed Adoption

- Attachment M – Transmission Line Ratings
  - Definitions:

BPA is proposing to delete this definition

(4) "Near Term Transmission Service" means Transmission Service which ends not more than 10 days after the Transmission Service request date. When the description of obligations below refers to either a request for information about the availability of potential Transmission Service (including, but not limited to, a request for ATC), or to the posting of ATC or other information related to potential service, the date that the information is requested or posted will serve as the Transmission Service request date.
"Near-Term Transmission Service" includes any Point-To-Point Transmission Service, Network Resource designations, or secondary service where the start and end date of the designation or request is within the next 10 days.

Proposed Adoption

- Attachment M – Transmission Line Ratings
  - Definitions:
    - "Emergency Rating" means a Transmission Line Rating that reflects operation for a specified, finite period, rather than reflecting continuous operation. An Emergency Rating may assume an acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

Proposed Adoption

- Attachment M – Transmission Line Ratings
  - System Reliability
    - If the Transmission Provider reasonably determines, consistent with Good Utility Practice, that the temporary use of a Transmission Line Rating different than would otherwise be required by this Attachment is necessary to ensure the safety and reliability of the Transmission System, then the Transmission Provider may use such an alternate rating. The Transmission Provider must document in its database of Transmission Line Ratings and Transmission Line Rating methodologies on OASIS or another password-protected website, as required by this Attachment, the use of an alternate Transmission Line Rating under this paragraph, including the nature of and basis for the alternate rating, the date and time that the alternate rating was initiated, and (if applicable) the date and time that the alternate rating was withdrawn and the standard rating became effective again.

Proposed Adoption

- Attachment M – Transmission Line Ratings
  - Obligations of Transmission Provider:
    - The Transmission Provider must use AARs as the relevant Transmission Line Ratings when performing any of the following functions: (1) evaluating requests for Near-Term Transmission Service; (2) responding to requests for information on the availability of potential Near-Term Transmission Service (including requests for ATC or other information related to potential service); or (3) posting ATC or other information related to Near-Term Transmission Service to the Transmission Provider's OASIS site or another password-protected website.

BPA is proposing to delete this section

Proposed Adoption

- Attachment M – Transmission Line Ratings
  - Obligations of Transmission Provider:
    - The Transmission Provider must use AARs as the relevant Transmission Line Ratings when determining where to make flow-based curtailments (under section 13.6) Firm Point-to-Point Transmission Service or when determining whether to curtail and/or interrupt (under section 14.7) Non-Firm Point-to-Point Transmission if such curtailment and/or interruption is both necessary because of issues related to flow limits on transmission lines and anticipated to occur (start and end) within 10 days of such determination.
    - For determining whether to curtail or interrupt Point-to-Point Transmission Service in other situations, the Transmission Provider must use Seasonal Line Ratings as the relevant Transmission Line Ratings.
    - The Transmission Provider must use AARs as the relevant Transmission Line Ratings when determining whether to make flow-based curtailments (under section 33) or redispatch (under sections 30.5 and/or 33) Network Integration Transmission Service or secondary service if such curtailment or redispatch is both necessary because of issues related to flow limits on transmission lines and anticipated to occur (start and end) within 10 days of such determination. For determining the necessity of curtailment or redispatch of Network Integration Transmission Service or secondary service in other situations, the Transmission Provider must use Seasonal Line Ratings as the relevant Transmission Line Ratings.

Proposed Adoption

- Attachment M – Transmission Line Ratings
  - Obligations of Transmission Provider (cont'd):
    - The Transmission Provider must use Seasonal Line Ratings as the relevant Transmission Line Ratings when evaluating requests for and whether to curtail, interrupt, or redispatch any Transmission Service not otherwise covered above in this section (including, but not limited to, requests for non-Near-Term Transmission Service or requests to designate or change the designation of Network Resources or Network Load), when developing any ATC or other information posted or provided to potential customers related to such services. The Transmission Provider must use Seasonal Line Ratings as a recourse rating in the event that an AAR otherwise required to be used under this Attachment is unavailable.
    - The Transmission Provider must use uniquely determined Emergency Ratings for contingency analysis in the operations horizon and in post-contingency simulations of constraints. Such uniquely determined Emergency Ratings must also include separate AAR calculations for each Emergency Rating duration used.
    - In developing forecasts of ambient air temperature for AARs and Seasonal Line Ratings, the Transmission Provider must develop such forecasts consistent with Good Utility Practice and on a non-discriminatory basis.
    - Postings to OASIS or another password-protected website: The Transmission Provider must maintain on the password-protected section of its OASIS page or on another password-protected website a database of Transmission Line Ratings and Transmission Line Rating methodologies . The database must include a full record of all Transmission Line Ratings, both as used in real-time operations, and as used for all future periods for which Transmission Service is offered. Any postings of temporary alternate Transmission Line Ratings or exceptions used under the System Reliability section above or the Exceptions section below, respectively, are considered part of the database. The database must include records of which Transmission Line Ratings and Transmission Line Rating methodologies were in effect at which times over at least the previous five years, including records of which temporary alternate Transmission Line Ratings or exceptions were in effect at which times during the previous five years. Each record in the database must indicate which transmission line the record applies to, and the date and time the record was entered into the database. The database must be maintained such that users can view, download, and query data in standard formats, using standard protocols

Proposed Adoption

- Attachment M – Transmission Line Ratings
  - Sharing with Transmission Providers: The Transmission Provider must share, upon request by any Transmission Provider and in a timely manner, the following information:
    1) Transmission Line Ratings for each period for which Transmission Line Ratings are calculated, with updated ratings shared each time Transmission Line Ratings are calculated, and
    2) Written Line Rating methodologies used to calculate the Transmission Line Ratings in (1) above.

Exceptions: Where the Transmission Provider determines, consistent with Good Utility Practice, that the Transmission Line Rating of a transmission line is not affected by ambient air temperature or solar heating, the Transmission Provider may use a Transmission Line Rating for that transmission line that is not an AAR or Seasonal Line Rating. Examples of such a transmission line may include (but are not limited to): (1) a transmission line for which the technical transfer capability of the limiting conductors and/or limiting transmission equipment is not dependent on ambient air temperature or solar heating; or (2) a transmission line whose transfer capability is limited by a Transmission System limit (such as a system voltage or stability limit) which is not dependent on ambient air temperature or solar heating. The Transmission Provider must document in its database of Transmission Line Ratings and Transmission Line Rating methodologies on OASIS or another password-protected website any exceptions to the requirements contained in this Attachment initiated under this paragraph, including the nature of and basis for each exception, the date(s) and time(s) that the exception was initiated, and (if applicable) the date(s) and time(s) that each exception was withdrawn and the standard rating became effective again. If the technical basis for an exception under this paragraph changes, then the Transmission Provider must update the relevant Transmission Line Rating(s) in a timely manner. The Transmission Provider must reevaluate any exceptions taken under this paragraph at least every five years.

GI Reform
Large Generator Interconnection Agreement (LGIA)

Steps 3 – 6

GI Reform - Large Generator Interconnection Agreement (LGIA)

Why is BPA Reviewing the LGIA
Step 1 (Intro & Education) and Step 2 (Description of Issue)

- In TC-25, BPA changed the Standard Large Generator Interconnection Procedures (LGIP), Attachment L of BPA's Open Access Transmission Tariff, which necessitates revisions to the LGIA template in Attachment L.
  - BPA delayed revising the template during the proceeding due to time constraints.

- The Objective of this effort is to align BPA' LGIA template with TC-25 reforms and FERC's recent changes to the *pro forma* LGIA made in Order Nos. 2023 and 2023-A.
  - BPA reviewed the current LGIA template for consistency with BPA's TC-25 reforms and FERC's changes to the *pro forma* LGIA made in Orders 2023 and 2023-A.

GI Reform - Large Generator Interconnection Agreement (LGIA)

Summary of BPA's Review of the LGIA
Step 3 (Analyze the Issue) and Step 4 (Discuss Alternatives)

- BPA posted a summary document and a redline of the proposed changes to the LGIA on July 22, 2024
- BPA identified:
  - Modifications to LGIA to adopt FERC's changes to the *pro forma* LGIA made in Order Nos. 2023/2023-A
  - Deviations from pro forma changes to LGIA adopted in Orders 2023 and 2023-A: modifications or retentions of existing language in BPA's LGIA to align with TC-25 Reforms
  - Ministerial changes due to formatting, grammar, numbering, punctuation, consistent use of defined terms, usage of acronyms, etc.
  - FERC Order 2023/2023A *pro forma* language changes to defer~~red~~ to the next tariff proceeding
  - Articles in LGIA still under review
- Articles in the summary document can be listed in more than one category if multiple edits are proposed in the same section

GI Reform - Large Generator Interconnection Agreement (LGIA)

Modifications to BPA's LGIA to align with pro forma (language adopted in Order 2023 and 2023-A)

Proposed language aligns with both *pro forma* changes and reforms adopted in TC-25

- Examples (refer to the summary document for all proposed edits in this category):
  - Article 1 - Deleted definitions of Interconnection Feasibility and System Impact Study, as they are no longer part of the interconnection study process
  - Article 8.4 and 9.6.4.4 – added "contains" language to account for hybrid generating facilities

GI Reform - Large Generator Interconnection Agreement (LGIA)

Deviations from pro forma changes to LGIA adopted in Orders 2023 and 2023-A: modifications or retentions of existing language in BPA's LGIA to align with TC-25 Reforms

Proposed language deviates from *pro forma* to address differences between BPA's TC-25 reforms and Order 2023/2023-A *pro forma*

- Examples (refer to the summary document for all Articles and Appendices in this category):
  - Adopting new definitions or language from Order Nos. 2023/2023-A but using additional language consistent with TC-25 Tariff:
    - Article 1, definition of "Balancing Authority", "Balancing Authority Area", "Control Area"
    - Article 24.3, Updated Information Submission by Interconnection Customer
  - Deleting language retained in *pro forma* LGIA to be consistent with language BPA deleted in the LGIP as part of the TC-25 reforms
    - Article 1, definition of "Optional Interconnection Study" and "Optional Interconnection Study Agreement"

GI Reform - Large Generator Interconnection Agreement (LGIA)

Deviations from pro forma changes to LGIA adopted in Orders 2023 and 2023-A: modifications or retentions of existing language in BPA's LGIA to align with TC-25 Reforms (cont'd)

- Examples (refer to the summary document for all Articles and Appendices in this category):
  - Propose retention of existing language in BPA's LGIA to align with TC-25 reforms and not adding additional language FERC adopted
    - Article 1, definition of "LGIA Deposit"
    - Article 11.5, Provision of Security
  - Proposing a new deviation from *pro forma* to correct language regarding cost responsibility for studies and upgrades associated with transmission delivery consistent with TC-25 Tariff
    - Article 4.1.2.2, Transmission Delivery Service Implications

Ministerial Changes to LGIA

Proposed changes necessary to address formatting, grammar, punctuation, numbering, use of acronyms, and/or definitions

- Example (refer to the summary document for all proposed edits in this category):
  - Replacing “NERC” and “Applicable Reliability Council” with the new defined term “Electric Reliability Organization” throughout the LGIA

Adoption of *Pro Forma* LGIA Language Deferred

- BPA proposes to defer changes to the following articles in the LGIA as explained below:
  - Articles related to Proportional Impact Method: Article 1, definitions of "Proportional Impact Method", "Substation Network Upgrades", "System Network Upgrades", and language in Appendix A, Network Upgrades. BPA agreed to consider implementation of a Distribution Factor Method (DFAX) for network cost allocation after the Transition Period (under Section 5.a of Attachment 1 to the TC-25 Settlement Agreement)
    - As part of this evaluation, BPA will evaluate implementing a proportional impact methodology for network cost allocation and will share this evaluation and any proposed changes to impacted language in the LGIP and LGIA in pre-proceeding workshops prior to the next tariff proceeding
  - Articles 9.7.3, Ride Through Capability and Performance, 17.2, Violation of Operating Assumption for Generating Facilities, and Appendix H, Operating Assumptions for Generating Facility: BPA did not consider reforms related to ride through requirements and operating assumptions in the TC-25 reforms
    - BPA will evaluate those changes to the LGIP and LGIA adopted in Orders 2023 and 2023-A and share any proposals in pre-proceeding workshops prior to a future tariff proceeding

Articles in LGIA Under Review

BPA is still reviewing the following language and may share proposed language in August or September TC-26 workshops.

- Articles 1, definition of “Withdrawal Penalty”
  - May include language in the LGIA related to Withdrawal Penalties depending on proposal for Withdrawal Penalties for BP-26
- Article 1, definition of “Stand Alone Network Upgrade” and Article 5.1.3, Option to Build
  - BPA is evaluating whether the changes to this article made in Orders 2023 and 2023-A are consistent with the TC-25 reforms and BPA’s legal and statutory obligations as a federal agency
  - BPA will provide an update in the August workshop on its evaluation of these articles

NIPPC and Renewable NW Joint Comment

Please provide an update on BPA's timeline to implement the reforms of FERC Order 845 allowing customers to self-build interconnection facilities. NIPPC and RNW note that BPA has already adopted the Order 845 self-build option in its tariff, but has yet to implement that functionality for transmission customers.

- BPA intends to provide an update on our option to build implementation efforts at the August workshop

Next Steps

- BPA will collect comments on this proposal
  - Please send all feedback to techforum@bpa.gov with a copy to your Account Executive.
  - Comments are due by August 14.
  - Comments will be addressed at the September workshop.
- You can provide feedback on the proposed LGIA changes by inserting comments in the LGIA Redline PDF document or by providing written comments.
- In written comments, please include reference to the article you are commenting on, any alternate proposed language, and the reasoning for the proposed change.
- We plan to provide an update on the Articles still under evaluation at the August workshop.

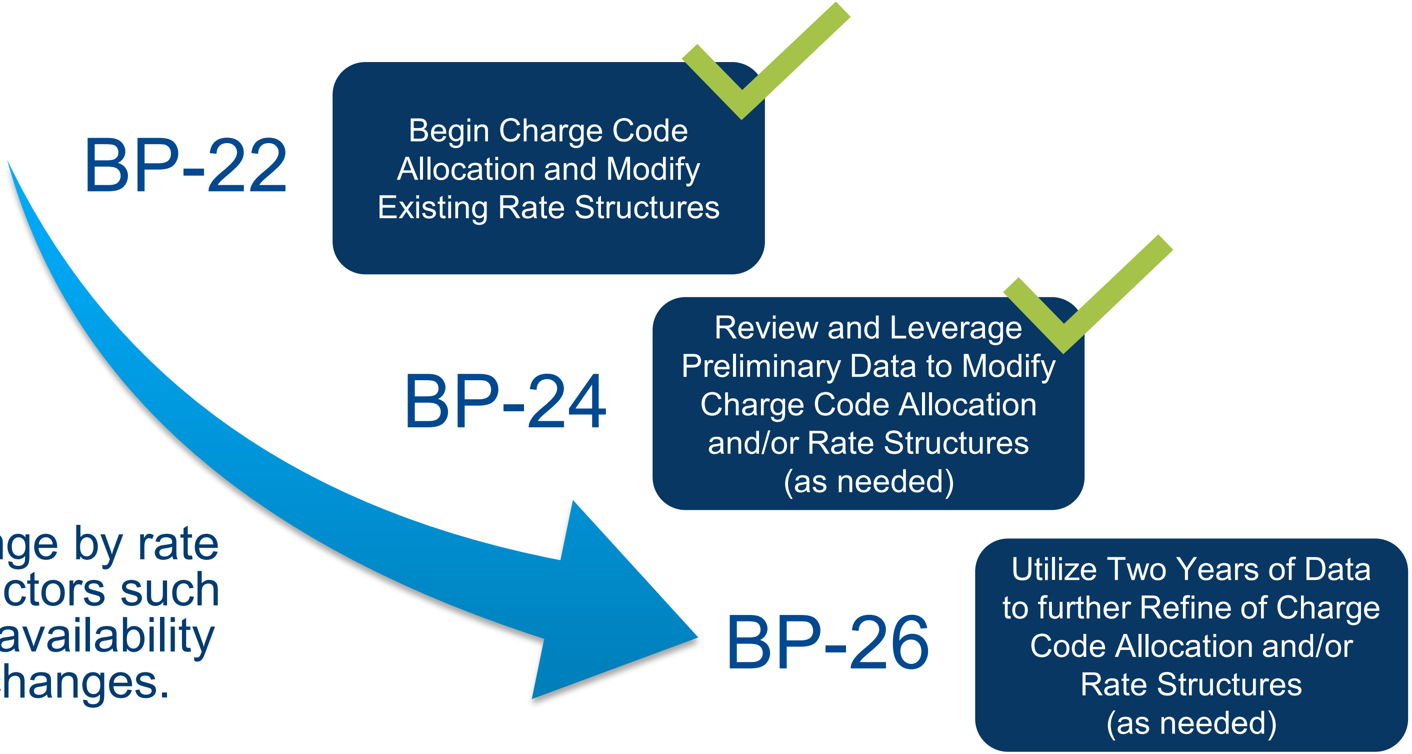
EIM Charge Code Allocation

July 30, 2024

Context

- In the EIM, BPA will receive charges and credits from the CAISO. BPA will need to, in turn, recover these charges or distribute these credits through sub-allocating them to customers or rolling them into rates.
- There is no *pro forma* method for allocating the various charge codes.
- While most EIM entities have followed similar cost allocation methodologies, that is not always the case.
- While FERC-approved methods are considered as a starting point, there may be rationale to modify methods to align with cost-causation.

Phased In Approach



Subject to change by rate period, given factors such as information availability and market changes.

Sub-Allocated Charge Codes

- Base Codes – No Changes
- Neutrality Codes – No Changes
- Over/Under Scheduling Codes – No Changes
- Flex Ramping Codes – No Changes
- Real-Time Bid Cost Recovery
  - These codes were not expected to produce significant charges, but the data indicates that enough charges are accumulating to justify action.
  - These charges are proposed to be sub-allocated using the Measured Demand method, which is in line with other entities.

Real-Time Bid Cost Recovery

- Bid Cost Recovery is the process by which CAISO ensures scheduling coordinators can recover Bid Costs for real-time Energy that CAISO dispatches in the EIM.
- Real-time Energy Bid Costs are used as inputs to calculate a resource's net difference between Real-Time Market (RTM) costs and revenues in the Pre-calculation RTM Net Amount configuration.
  - If the difference between the total costs and the market revenues is positive, then the net amount represents a Shortfall. If the difference is negative, then the net amount represents a Surplus.
- Non-Participating Resources get a Bid Cost Recovery Settlement during certain instances related to the occurrence of a Flex Ramp Movement Settlement (7070) charge.
- To be eligible for a Bid Cost Recovery Settlement a Non-Participating Resource cannot change their schedule post T-40.
- BPA has automated manual dispatch which has minimized Non-Participating Resource Bid Cost Recovery settlements.

- 66780 - Real Time Bid Cost Recovery EIM Allocation - Estimated annual charges of $362k
- 66200 - RTM Bid Cost Recovery EIM Settlement - Estimated annual credits of $19k

Real-Time Bid Cost Recovery

Proposing to sub-allocate the real-time bid cost recovery charge codes from the EIM, adding in the following language:

- Any charges or payments to the BPA EIM Entity pursuant to Section 29.11(f) of the MO Tariff for EIM real-time bid cost recovery shall be allocated to Transmission Customers based on EIM Measured Demand.

Questions

Persistent Deviation Language

July 30, 2024

Problem

- While Persistent Deviation Penalty Charges are being assessed correctly, the rate language is causing confusion regarding how those charges are assessed.

Current Language

- The rate schedule specifies that the penalty rate will be the greater of
  - 125% of either BPA's highest incremental cost that occurs during that day or the highest RTD LMP at the closest point of interconnection during the period of penalty for service; or
  - 100 mills per kilowatt-hour
- The rate schedule also specifies that if BPA assesses a Persistent Deviation Penalty charge, then base imbalance charges will not be assessed

Why this is Causing Confusion

- If BPA assesses a Persistent Deviation Penalty Charge, the hourly penalty amount is calculated as discussed on the previous slide, but the base imbalances charges are netted from the total amount
- The base imbalance charges appear as a separate line item on a customer's bill

Examples

Example 1		Calculations	Current Language	Actual Bill
Imbalance (MWh)		50		
LMP ($/MWh)		82		
IIE/UIE ($)		4,100	0	4,100
Persistent Deviation	125% of LMP	5,125	5,125	1,025
	$100/MWh	5,000		

Example 2		Calculations	Current Language	Actual Bill
Imbalance (MWh)		50		
LMP ($/MWh)		70		
IIE/UIE ($)		3,500	0	3,500
Persistent Deviation	125% of LMP	4,375	5,000	1,500
	$100/MWh	5,000		

Proposed Language

- The rate schedule language for calculating the charge and the “greater of” language will remain unchanged
- Instead of stating that base charges will not be assessed, it will specify that they will be netted from the penalty amount to isolate each charge individually

Questions

Proposed Edits to the New Technology Pilot Language

New Technologies

- BP-26 is a three-year rate period, during which BPA could see new types of technology being deployed in the BPA BAA.
- BPA has been contacted by several customers interested in new technologies, such as:
  - Wave generation
  - Fuel cells
  - New combinations of existing technologies
- These proposed projects are in the BPA BAA, but are not owned or operated by BPA.

Issues Raised by New Technologies

Current ACS designs and definitions (including the current New Technology Pilot) do not cover these types of new technologies.

- The goal of the New Technology Pilot was to reduce projects’ balancing reserve capacity burden placed on the BPA BAA.
  - An example is a solar project coupled with a co-located battery, where the battery is used to smooth the operational variability of the solar project.
- As new technologies emerge, they may not fit the definition of existing Balancing Capacity Services (e.g. VERBS, DERBS).
- This creates a need to update the New Technology Pilot language under which BPA could recover the cost of the Balancing Capacity needed to stand ready to cover variability in the operation of these new technology projects.

Proposed Language Purpose

- BPA is proposing to edit the New Technology Pilot in BP-26.
- The intent of the new language is to enable BPA to determine the Balancing Capacity needs of emerging new technologies and recover the cost of providing that service.

New Language

G. New Generation Technology Pilot Program

- ~~A customer and~~ BPA ~~may~~ will ~~jointly~~ develop a pilot program at the individual generation project level in order to integrate new ~~uses of~~ technology, such as fuel cells, or to integrate new uses of technology, such as a solar project coupled with a co-located energy storage device (ESD). The goal of the pilot is to determine the balancing reserve capacity a new technology needs, or, for a generator co-located with an ESD, to reduce the project's balancing reserve capacity burden placed on the BPA BAA. In place of any normally applicable RFR, VERBS or DERBS rates, BPA will instead directly assign the cost of balancing reserve capacity to the pilot project customer in accordance with the following reserve capacity rate components:

(Note: These are the existing rates in the New Generation Technology Pilot. Rates will be updated in BP-26)

- (a) Regulating INC Reserves $0.261 per kilowatt-day
- (b) Non-Regulating INC Reserves $0.168 per kilowatt-day
- (c) DEC Balancing Reserves $0.012 per kilowatt-day

These rates are applied to the balancing reserve capacity BPA determines is needed for the pilot (not the installed nameplate of the project).~~, and for~~ For the co-located generator and ESD, the total rate shall not exceed the total cost of the normally applicable RFR, VERBS, or DERBS rates. On a monthly basis, BPA shall revisit the amount of balancing reserves required for the project based on actual operational data for that project. All other rates required for the project shall apply.

A customer participating in a pilot program may still be subject to any applicable Intentional Deviation or Persistent Deviation penalties if operation of the project is not consistent with the pilot program expectations, such as the pilot adding to, rather than reducing, the Station Control Error of the project.

Effects of Proposed Language

- Establish at an early stage that emerging technologies will be subject to the same principles of cost causation and cost allocation as other customers.
- Ensures customer are charged for the services they use.
- The proposed language creates a more technology inclusive policy, allowing us to continue the current service to reduce ACS rates for new uses of technology while incentivizing projects that reduce the Balancing Capacity need.

Questions?

Meeting Wrap-up

- Please send any feedback, with your topic you are addressing by Wed., August 14 to BPA's Tech Forum at techforum@bpa.gov, with a cc to your Power and/or Transmission Account Executive.
- If you would like to have a customer led workshop on August 15, please send us the topic that you would like to discuss, and how much time you will need, by August 7 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.

BP-26 and TC-26 Workshop

July 31, 2024
(Day 2)

Agenda July 31 (Day 2)

	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***

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

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 Addressed

Topic 1: NR Energy Shaping Service (ESS)

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

Topic 2: NR Resource Flattening Service

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

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

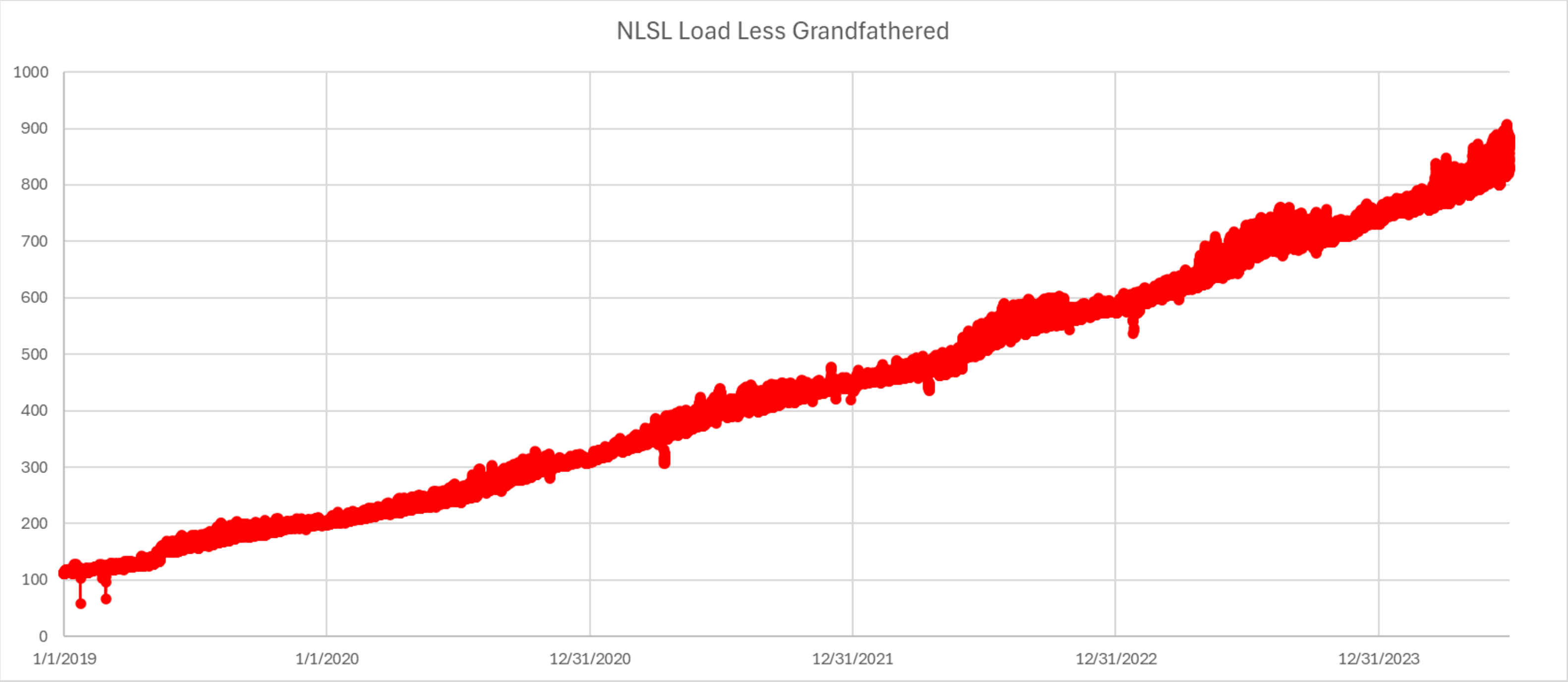
NR Energy Shaping Service

- 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

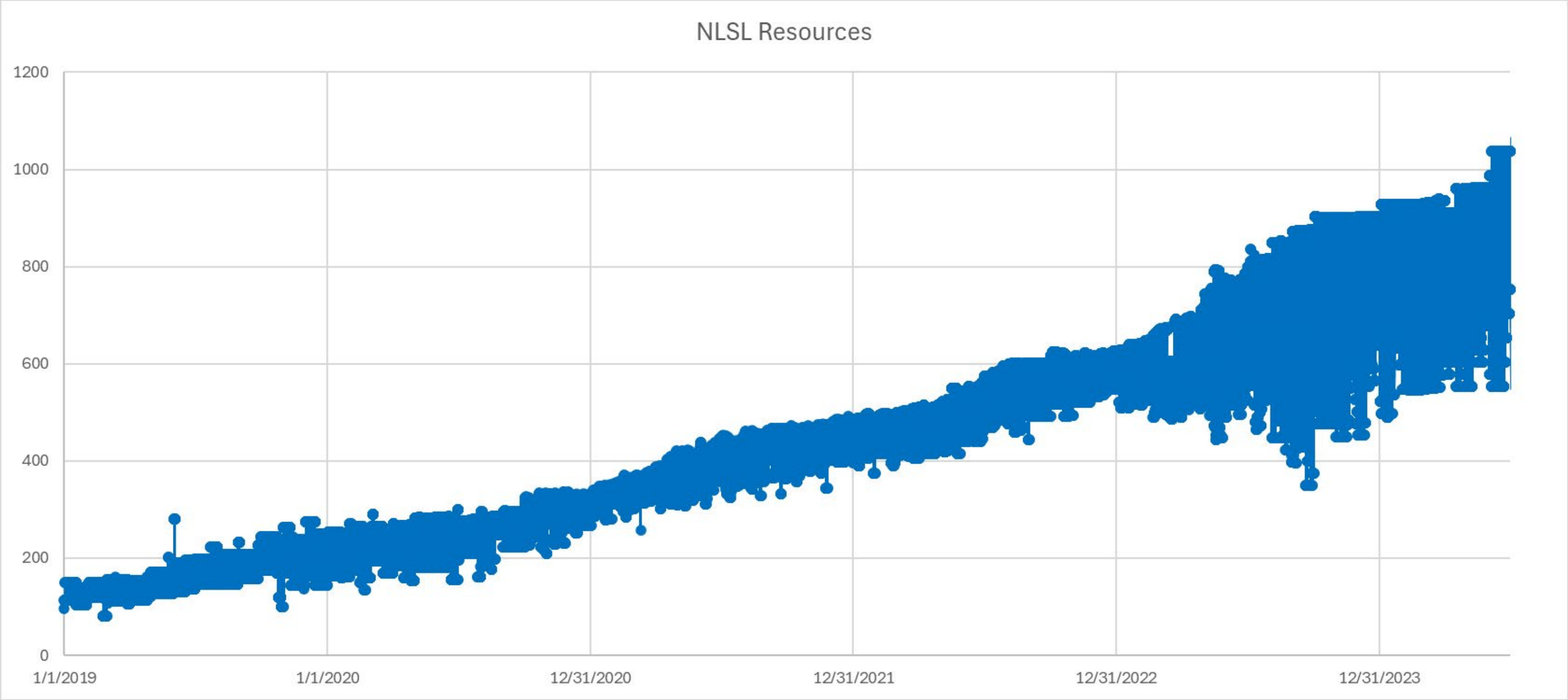
Problem Statement

- 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.
  - 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.

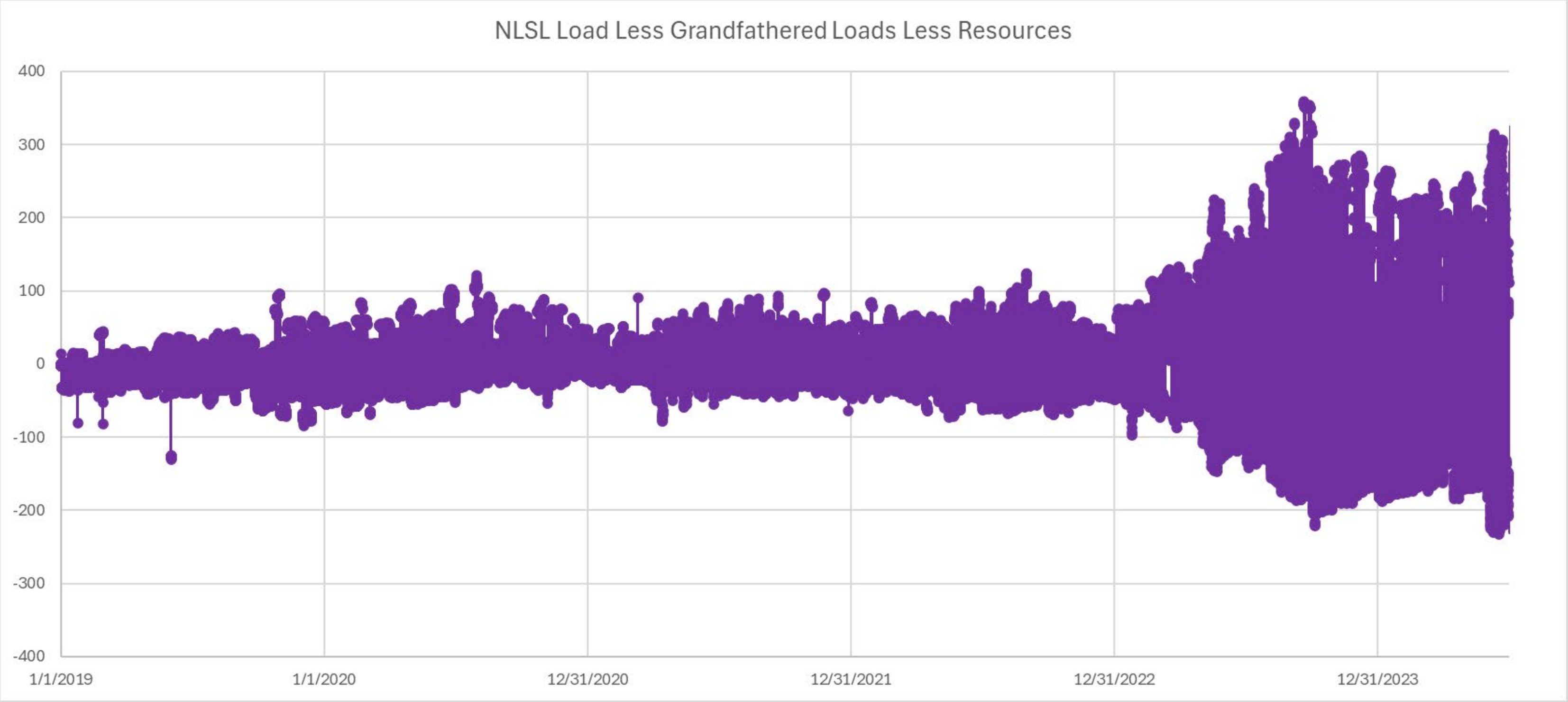
NLSL Loads


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

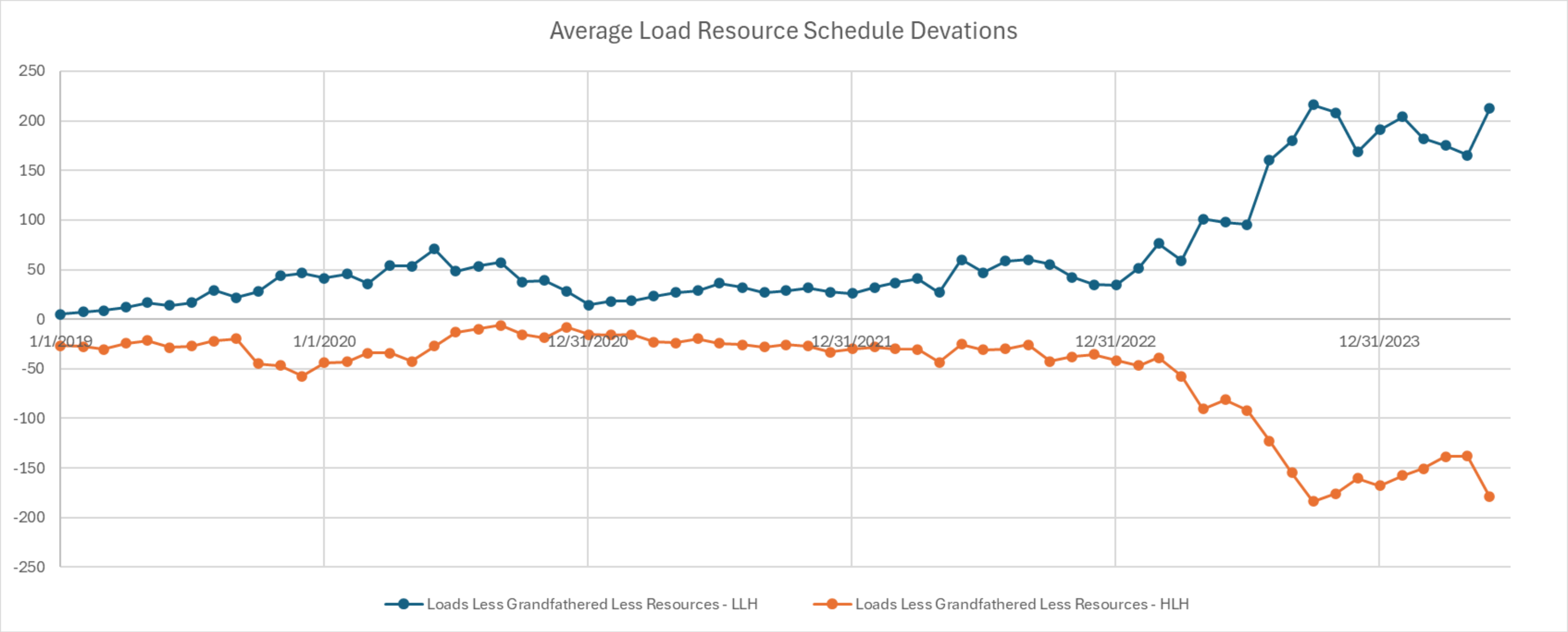
NLSL Resources



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

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

- Please provide comments by August 14.

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 80% of the penalty portion of the UAI Energy Charge, 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

Next Steps

- Comments or questions? Email techforum@bpa.gov and copy your Account Executive
- Please provide comments by August 14.

Meeting Wrap-up

- Please send any feedback with the topic you are addressing by August 14 to BPA's Tech Forum at techforum@bpa.gov, with a cc to your Power and/or Transmission Account Executive.
- If you would like to have a customer led workshop on August 15, please send us the topic that you would like to discuss, and how much time you will need, by August 7 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 • Non-EIM Balancing • 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 **Power Rates** **Tariff** • GI Reform – LGIA • Network Loss Factors (if needed)