Western Resource Adequacy Program

RAPC Meeting

February 13th, 2025; 10am-12pm PPT

Participant	Name	Participant	Name
APS	Mike Eugenis, Kent Walter, **Tyler Moore**	PacifiCorp	**Ben Faulkinberry**, Nadia Wer
Avista	**Kevin Holland** (Ken Santman Alternate)	PGE	Pam Sporborg, **Teyent Gossa, Tiffany Emerson**
BPA	Suzanne Cooper**, Steve Bellcoff**	Powerex	**Mike Goodenough**
Calpine	**Bill Goddard**	PSE	**Phil Haines**, Tricia Fischer
Chelan	Mike Bradshaw, **Brandon Carnahan**	PNM	**John Mayhew**, **Tom Duane**
Clatskanie	**Chris Roden**	SRP	**Grant Smedley**, **Michael Reynolds**
EWEB	**Jon Hart, Megan Capper**	SCL	**Mara Kontos**
Grant	**Rich Flanigan**, Lisa Stites	Shell	
Idaho	**Ben Brandt, Camille Christen**	Snohomish PUD	Joe Fina
NorthWestern	**Joe Stimatz**, **Tom Michelotti** (Quinn McCarthy Alternate)	**Tacoma**	Ray Johnson, **Leah Marquez-Glynn**
NV Energy	**Lindsey Schlekeway**, David Rubin	**TEA**	**Ed Mount**, **Colin Cameron**

Meeting Objectives

1. Provide the RAPC with updates on project progress
2. Seek RAPC input on progress and any administrative actions
3. Consider Endorsement of 2024-NTFP-4 (BPM 103 fixes)

Meeting Agenda

Call to Order			
10:00	– **Attendance** – **Anti-trust Statement** – **Approved Agenda** *WPP proposed a change to the agenda to discuss a COSR update into the open agenda. SRP motions to approve the change, with no opposition and the agenda is approved.* – **Approved Minutes from last meeting** *Grant motions to approve, TEA seconds the motion and the minutes from the last meeting are approved.*	APPROVE	Chair
PA/PO Report			
10:07	– **PA/PO Update:** *<u>Froward Showing Group (SPP): Update on transition to EDST and summer 25 forward showing submittal:</u>* *The transition from the Excel workbook to EDST has been smooth, with the first submittal being the most complex. New features, like document upload and linking, have functioned well. SPP has received positive feedback and identified a few non-critical defects, with workarounds in place while coordinating with IT for resolution.*	Inform	WPP/SPP

	SPP has been prioritizing improvements and enhancements and will coordinate with WPP to bundle these items for future releases. *Key Benefits of EDST:* ○ ***Automation****: Increased automation of validations has reduced human error and saved time on manual validations, allowing for more in-depth review of participant submissions and smoother coordination on deficiency corrections.* ○ ***Submittal Process:*** *Though time-consuming for first-time users, participants generally appreciated the tool, and ongoing improvements are being made.* ○ ***Advanced Assessment Results:*** *EDST enables posting of seasonal and monthly QCC results, participant load forecast P50s, and clear assignment of subregions and subregion PRMs, reducing confusion from past workbook methods.* *SPP will send out a slide with these improvements and will coordinate with WPP to do so.*		
Ongoing Business			
10:15	– Workgroup Updates: – *Forward Showing Workgroup – Maya M.* • *FS Summer 2025* ○ *Cure Period ending 02.28.2025 at 5:00pm (PPT)* ○ *Have met with most participants, very productive and thank you all for meeting with us* • *FS Winter 2025-2026 Submittal* ○ *EDST: Winter 25-26 grids open for editing 02/17/2025 (6 week ahead of the deadline)* ○ *FS Submittal due by 03/31/2025 at 5:00pm (PPT)* • *Advanced Assessment Summer 2027 & Winter 2027-2028* ○ *Participant data to be submitted by 03/03/2025 (03/01/2025 falls on a Saturday)* • *Advanced Assessment Winter 2026-2027 Draft Results* ○ *Presented draft results to the FS WG last week* ○ *Will get finalized results by the end of March* ○ *Comments, questions need to be reviewed and resolved by 03/03/2025* • *Reminders: Attestation and JCAF signatures are required to be deemed complete* *There was a question on whether clear written documentation on how to input data into EDST to avoid errors. WPP will update user manuals and ensure clear documentation on data input procedures to minimize errors.* – Operations Workgroup – *Maya M.* • *Ops Client updates:* ○ *2024-NTFP-01 changes in testing and planned to be effective on 03.16.2025: CR, DR, VH (still in development)* • *Input Data File Specification document:* ○ *V1.0 Cleaned up version shared with Ops WG Group this week - Only 1 additional requirement: ATFED Information requirements* ○ *V2.0 Granular Data File Specifications –* • *Language being drafted*	Discuss	WPP/SPP/ Chair

	• *Reminders:* o *Daylight Savings Time change: 03.09.2025* *<u>Questions and Commentary:</u>* *WPP clarified that changes from NTFP-1 will not follow the same timeline and will serve as supplementary information alongside participant submissions.* *WPP/SPP aims to have systems ready to receive data by summer, but this does not guarantee all participants will be prepared to submit by that time. Individual discussions will be held to determine appropriate timelines.* *WPP referenced a previous conversation about providing a detailed data specification for next steps. They are working on this document and will share it once ready.* *No set timeline or specific request has been defined yet. The focus is on flexibility, using existing data sharing methods initially, and transitioning to more granular data over time. This approach is intended to improve data quality and support QA/QC efforts, without imposing significant burdens on participants.* *WPP will commit to have something to you by early next week to move this process forward.* – Storage Hydro User group – *Steve B.* *Nothing new to report. Our next meeting will be on February 26th.*		
10:35	– Change Control Process Update *PRC will review a draft schedule at their next meeting on February 19th. The schedule will include three lanes: one long-term and two short-term concepts. A consideration the PRC will need to keep in mind is to minimize sponsor overlap and concepts that affect the same WRAP occurring at the same time, to ensure appropriate resources are given to each concept. The PRC will be able to discuss the current priority order and make an appropriate changes so this process is successful.* *Following the meeting, the timeline will be incorporated into a draft workplan, which will outline the history of prioritization and all submitted CRFs. This document will be sent out for public comment by March 15th for a one-month period.* *2024-NTFP-2: This update addresses changes from the tariff and revised transition plan, requiring modifications to all BPMs to align with these changes. The document is currently with the COSR for comment, after which it will be sent to the PRC for endorsement and then to RAPC on February 27th.*	Inform	WPP
10:40	– Endorsement of 2024-NTFP-4 (BPM 103 Load Forecast Fixes) *This NTFP addresses the correction of the load change methodology. It ensures that any changes in load (up or down) are incorporated into the calculation of the peak load p50 forecast, rather than being applied directly to the result as they currently are. This change is significant for*	APPROVE	RAPC

	all participants, especially when a participant transfers its entire load to another, as seen in Snohomish's request for BPA to represent their load in the program. *<u>Timeline</u>:* o *02.13.25: RAPC endorsement* o *02.27.25: COST Oppose (unlikely)* *03.06.25: Final to Board of Directors for Approval.* **Endorsement:** Bonneville motions to endorse NTFP-04, TEA seconds the motion, and NTFP-04 is endorsed by the RAPC. **Discussion:** None		
10:43	– Settlements Update *WPP has hired external contractors to ensure timely completion of the project. A development team has already dedicated 600 hours since the beginning of the year.* *The goal is to have an automated process by the end of Q1, which will include creating the settlement spreadsheet and processing inputs. While the API won't be ready by then, the system will allow participants to view calculated settlement prices and a fully populated spreadsheet.* *After March, the focus will shift to developing the API. The aim is to be ready for summer, as it's important for participants to access settlement prices.* *Significant progress is being made, and a substantive interface will be ready for interaction. WPP will collaborate with participants to gather input and feedback on the API design. A rough outline of the API is available, and additional features will be included.* *The objective is to provide clear visibility into settlement prices, with the spreadsheet allowing participants to track prices every hour. The inclusion of energy delivery information in the file specification is to anticipate future requirements during development.* *Participant Question: WPP was asked if there is a timeline for the project's expectations.* *WPP confirmed they have a project schedule in place and are working to ensure readiness, whether transactions occur or not. Discussed the timeline with the Operations Workgroup and are focusing on internal development first. A participant engagement plan and training will be rolled out, with full documentation and interaction starting in March.*	Inform	WPP
10:46	– COSR Data Slide Update *WPP is working with WIEB to schedule a meeting for COSR/RAPC, but there have been scheduling conflicts. It is important to ensure commissioner attendance and avoid last-minute arrangements. The meeting is not yet on the calendar, but WPP will confirm the date once finalized and ensure good attendance. WPP will review the slides and make the updates that were discussed.*		
New Business			

10:49	– None	Discuss	WPP
External Affairs			
	[None]		
Good of the Order			
	– Participant topics requests for next meeting	Discuss	Chair
Closed RAPC			
Upcoming			
	– Next meeting: February 27th	Inform	WPP
Meeting Adjourned ta 10:49am PPT			

Current Participants: APS, Avista; BPA; Calpine; Chelan; Clatskanie; EWEB; Grant; Idaho Power; NorthWestern; NV Energy; PacifiCorp; PGE; Powerex; PNM; PSE; SRP; SCL; Shell; Snohomish PUD; Tacoma Power, The Energy Authority

WPP forums will not foster or allow communications or practices that violate antitrust laws. Please avoid discussion of topics that would result in anti-competitive behavior, including but not limited to: availability of or terms of services and sales, design of products, price setting, or any other activity that might unreasonably restrain competition.

CRF#: N/A NTFP Confirmed: 1/15/25	# 2024-NTFP-2	Lead Sponsor: **WPP**

BPM Updates to reflect Revised Transition Proposal (2024-EP-1)

Public Comment		Revision	COSR Comment		PRC Endorse	RAPC Endorse	COSR Oppose?	Final to BOD
1/15/25	1/29/25	2/5/25	3/5/25	2/14/25	2/19/25	2/27/25	3/6/25	3/6/25
No Comments			-					

Target Board Approval: 3/13/25

2024-CRF-6	**2024-NTFP-4**	Lead Sponsor: **SnoPUD**
NTFP Confirmed: 12/18/24		Co-Sponsors: **BPA** **TEA** **WPP**

BPM 103 P50 Peak Load Forecast Methodology Fix to enable Participant-to-Participant Load Transfer

Public Comment		Revision	COSR Comment		PRC Endorse	RAPC Endorse	COSR Oppose?	Final to BOD
12/18/24	1/9/25	1/14/25	1/14/25	1/28/25	2/5/25	2/13/25	2/27/25	3/6/25
1 Comment			No Comment					

Target Board Approval: 3/13/25

WRAP

Western Resource Adequacy Program

Non-Task Force Proposal

Non-Task Force Proposal	
Name: 2024-NTFP-004	Date of PRC Confirmation: 12/18/24

Lead Sponsor Information	
Name: Garrison Marr	Organization: Snohomish County PUD
Title: Senior Manager, Power Supply	Phone Number: 425-309-6923
Email: GBMarr@snopud.com	Date of Submission: 12/11/24
Co-Sponsors' Information (optional)	
Name: Steve Bellcoff	Organization: Bonneville Power Administration
Phone Number: 360-901-5208	Email: srbellcoff@bpa.gov
Name: Ed Mount	Organization: The Energy Authority
Phone Number: N/A	Email: emount@teainc.org
Name: Rebecca Sexton	Organization: Western Power Pool
Phone Number: 253-279-3002	Email: rebecca.sexton@westernpowerpool.org

WRAP
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Type of Change Requested
Check one*: ☐ Correction *(i.e., revising erroneous language or language that needs clean-up for grammatical errors or inconsistency across governing documents - no changes to intent or policy)* ☐ Clarification *(i.e., revising language to better represent existing intent, no changes to functionality or policy)* ☒ Enhancement *(i.e., revising language to expand upon existing intent or functionality)* ☐ New Protocol, Business Practice, Criteria, Tariff *(i.e., new language to accommodate new functionality or policy not existing today)* ☐ Change *(i.e., a change in the existing policy – will replace an existing language)* ☐ Other *(i.e., changes that do not fall into the categories listed above)*

I. Needs and Benefits

a. Description of the Issue

The Winter and the Summer P50 Peak Load Forecast Methodologies in BPM 103 fail to adequately capture discrete load additions or subtractions of loads in the medium term (as those changes gradually become part of the five years of historical load data used to calculate the monthly P50 Peak Load Forecasts). These discrete load changes could be additions and subtractions, in scenarios where load is existing or new, meaning historical load data exists or does not, respectively. Clear direction and a robust policy for discrete load changes is important for all Participants experiencing discrete load changes, but is of particular consequence when one Participant transfers the responsibility for its load and resources in its entirety to another Participant, as is anticipated by Snohomish PUD's transition in BPA service contracts, resulting in BPA representation of Snohomish's load in October 2025.

b. Realized Benefits

The BPM 103 P50 Peak Load Forecast methodology incorrectly captures load changes by only amending the result rather than the underlying data. It is critical that this methodology is fixed.

II. Solution

a. Proposed Solution:

Load Changes when Historical Load Data is Available. As currently described in BPM 103 the P50 Peak Load Forecast methodologies for both Summer and Winter begin by determining the peak load for each month of the Season for the last available five Seasons using the Historical Load Data submitted as part of the Advanced Assessment. Note that

Historical Load Data is defined in BPM 101 Advanced Assessment as: “Load data from one or more Years prior to the current Year, such as the previous 10 Years. Historical Load Data is expected to consist of 8,760 hours (or 8784 hours for a leap Year) of data for a Year”. Tariff Section 16.1.1 allows for the P50 Peak Load Forecast in the Business Practice Manuals to include “a base monthly peak derived from a recent historic period that recognizes additions and removals of load during the historic period”. In the scenario where a load change (addition or subtraction) has historical load data available (as would be the case with a Participant-to-Participant load transfer, or a Participant assuming responsibility for a load that has been operational prior to the Participant assuming said responsibility), the affected Participant(s) is(are) responsible for adjusting the peak load for each Month of the Season for any of the last available five Seasons that do not capture the load change, and then calculating the monthly P50 Peak Load Forecasts, until the load change is automatically captured fully.

- In the case where one Participant (A) completely assumes the load responsibilities for another Participant (B) in October 2025, Participant A will complete the Forward Showing for Winter 2025/26 on March 31, 2025, using load data that combines Participant A’s and B’s historical loads. Participant B will not complete a Forward Showing for Winter 2025/26 (but will participate in Summer 2025 as normal).

- In the case where a Participant assumes responsibility for a discrete load (e.g. a paper mill) that has operated previously, the Participant will add this historical load data from the discrete load to their historical load data for every hour.

Load Changes when Historical Load Data is Unavailable. In the scenario where a load change does not have historical load data available (e.g. a new large load such as a data center or manufacturing facility) the affected Participant will generate synthetic load data and adjust monthly P50 Peak Loads for any of the last available five Seasons that do not capture the load change, and then calculate the monthly P50 Peak Load Forecasts, until the load change is automatically captured fully in historical load data.

b. Specific Document and Language:
   - Business Practice Manual (BPM 103) Participant Forward Showing Capacity Requirement

c. Suggestion for Language Update
   - See Document BPM 103 Redlines CRF-2024-006

III. Implementation Plan and Feasibility

a. Resource, Cost Assessment & Feasibility Review - TBD

b. Proposed Implementation Timeline - TBD

WESTERN POWERPOOL

Western Resource Adequacy Program

103 Participant Forward Showing Capacity Requirements

100 – Forward Showing

Revision History

Manual Number	Version	Description	Revised by	Date
103	0.1	RAPC Glance Version	Michael O'Brien	5/28/2024
103	0.2	Public Comment Version	Michael O'Brien	5/30/2024
103	0.3	RAPC & PRC Discussion	Michael O'Brien	8/28/2024
103	0.4	RAPC Endorsement	Michael O'Brien	9/4/2024
103	0.5	Board Consideration	Michael O'Brien	9/12/2024
103	1.0	Board Approve	Rebecca Sexton	9/19/2024
103	1.1	2024-NTFP-4 Redlines		

Table of Contents

103 Participant Forward Showing Capacity Requirement

1. Introduction

The Forward Showing (FS) Capacity Requirement is the minimum quantity of capacity a Participant is required to demonstrate for a Month of a Binding Season. Business Practice Manual (BPM) 103 describes the process for determining the components of the FS Capacity Requirement (the FS Planning Reserve Margin [FSPRM] calculations can be found in *BPM 102 Reliability Metrics*). BPM 103 also includes directions for a Participant seeking to exclude load from its FS Capacity Requirement, along with a discussion of the effect of using another Subregion's lower FSPRM on a Participant's FS Capacity Requirement, and considerations for load aggregation and disaggregation.

1.1. Intended Audience

BPM 103 is intended for WRAP Participants and other interested individuals or entities. BPM 103 will be particularly useful for those responsible for their Participant organization's FS Submittal as it pertains to meeting the FS Capacity Requirement, as this BPM provides an overview of the Monthly P50 Peak Load Forecast, load growth and load change considerations, and the Contingency Reserve Adjustment.

1.2. What You Will Find in This Manual

BPM 103 has the following sections: FS Capacity Requirement; P50 Peak Load Forecast; Load Growth Factor; Contingency Reserve Adjustment; Excluding Load; Submitting Loads from Multiple ; Load Aggregation/Disaggregation; and LOLE Study Load Forecast and Load Growth Rate. BPM 103 also includes Appendix A - P50 Peak Load Forecast Modifications and Appendix B - Load Exclusion.

1.3. Purpose

BPM 103 provides an overview of the components of the monthly FS Capacity Requirements calculations, including the Monthly P50 Peak Load Forecast methodology.

1.4. Definitions

All capitalized terms that are not defined in BPM 103 have their meaning set forth in the Tariff. Any capitalized terms not found in the Tariff that are specific to BPM 103 are defined here, including by reference to another BPM where such term is defined.

Contingency Reserve Adjustment: An adjustment to the FS Capacity Requirement to account for changes in Contingency Reserve requirements resulting from a Participant's contractual purchases and sales that include the Contingency Reserve as a specific part of the contract. The Contingency Reserve Adjustment has two components: Contingency Reserve Adjustment - Generation and Contingency Reserve Adjustment - Load.

Contingency Reserve Adjustment - Generation: The component of the Contingency Reserve Adjustment that accounts for differences between the system average Contingency Reserve requirement assumed in the LOLE Study and a Participant's actual purchases and sales.

Contingency Reserve Adjustment - Load: The component of the Contingency Reserve Adjustment that accounts for a Participant's specific Contingency Reserve purchases and sales.

Forward Showing (FS) Capacity Requirement Unadjusted: The FS Capacity Requirement Unadjusted takes into account the monthly P50 Peak Load Forecast and the monthly FSPRM. The FS Capacity Requirement Unadjusted does not take into account the Contingency Reserve Adjustment.

Historical Load Data: As defined in *BPM 101 Advance Assessment*.

Load Forecast Ratio: The Load Forecast ratio for each Month of a Binding Season is the ratio of the monthly average of the peak loads of a Month for the last five years to the maximum of the monthly average of the peak loads of the months of a Binding Season for the last five years.

Load Growth Factor: A program-wide load growth factor applied to P50 Peak Load Forecasts that may take into account location, weather, Participant type, and Participant customer composition (balance between retail, commercial, and industrial) among other factors.

LOLE Study: As defined in *BPM 102 FS Reliability Metrics*.

Regional P50 Peak Load Forecast: As defined in *BPM 102 FS Reliability Metrics*.

Seasonal Peak Months: The Winter Season months of December, January, and February.

2. Demand Response Utilization

A Participant has two options when choosing how to use Demand Response to affect its Monthly FS Capacity Requirements in its FS Submittal (see *BPM 108 FS Submittal Procedure*).

- A Participant may leave the effects of its historically deployed Demand Response included in its Historical Load Data (see *BPM 101 Advance Assessment*). This will have the effect of reducing the amount of load in the LOLE Study (see *BPM 102*

FS Reliability Metrics), reducing maximum loads in the P50 Peak Load Forecast (see Section 4) ultimately leading to lower Monthly FS Capacity Requirements.

- If a Participant removes the effects of historically deployed Demand Response from its Historical Load Data, the Participant may choose to utilize Demand Response as a Qualifying Resource (see attestation in *BPM 108 FS Submittal Procedure*). As described in *BPM 105 Qualifying Resources*, a Demand Response program registered as a Qualifying Resource will require a Capability Test to confirm the claimed capability and duration of load reduction, along with a more frequent Operational Test at a portion of the program's claimed capability and duration.

3. FS Capacity Requirement

The FS Capacity Requirement is the minimum quantity of capacity a Participant is required to demonstrate for each Month of a Binding Season in its FS Submittal (see *BPM 108 FS Submittal Process*). As shown in Equation 1, a Participant's FS Capacity Requirement begins with the Participant's monthly P50 Peak Load Forecast (see Section 4), which is multiplied by one plus the applicable Monthly FS Planning Reserve Margin (FSRPM - see *BPM 102 FS Reliability Metrics*) for a Month (the net result is known as the FS Capacity Requirement Unadjusted). The Contingency Reserve Adjustment (see Section 6) is then added to the FS Capacity Requirement Unadjusted to arrive at a Participant's monthly FS Capacity Requirement.

Equation 1 – FS Capacity Requirement

$$\boldsymbol{FS\ Capacity\ Requirement = FS\ Capacity\ Requirement\ Unadjusted + Contingency\ Reserve\ Adjustment}$$

where

$$\boldsymbol{FS}\ Capacity\ Requirement\ Unadjusted = (P50\ Peak\ Load\ Forecast) * (1 + \ FSPRM)$$

and

$$\boldsymbol{Contingency\ Reserve}\ Adjustment = Contingency\ Reserve\ Adjustment\_Generation + Contigency\ Reserve\ Adjustment\_Load$$

4. P50 Peak Load Forecast

A Participant's monthly P50 Peak Load Forecast for the Binding Season is calculated to determine a Participant's FS Capacity Requirement Unadjusted. The monthly P50 Peak Load Forecast will be calculated using the following methodologies for the Winter Seasons (Section 4.1) and Summer Seasons (Section 4.2).

4.1. Winter P50 Peak Load Forecast

Example monthly P50 Peak Load Forecasts for a Winter Season is shown in Table 1 and referred to in the methodological steps below.

	Month	Season	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2023/2024 Monthly P50 Peak Load Forecast - unadjusted	2023/2024 Monthly P50 Peak Load Forecast - adjusted for load growth
	November	Winter	2098	1998	1899	1958	2468	1998	2042
Seasonal	December	Winter	2060	2206	2241	2202	2273	2448	2502
Peak	January	Winter	2363	2381	2239	2521	2302	2448	2502
Months	February	Winter	2448	2072	2213	2476	2477	2448	2502
	March	Winter	2070	2253	2047	1959	1806	2047	2093
		Maximum	2448	2381	2241	2521	2477		

Table 1 - Example Winter Season P50 Peak Load Forecast

1. Determine the peak load for each Month of the Winter Season for the last available five seasons using the Historical Load Data submitted as part of the Advance Assessment (see *BPM 101 Advance Assessment*). These are the load values populating the light blue section of Table 1 (e.g. November peak load from 2019/2020 is 1899 MW).
2. Calculate the maximum peak load for each of the last available five seasons. For example, the maximum peak load for 2020/2021 is 2521 MW.
3. The Monthly P50 Peak Load Forecast for the Seasonal Peak Months is the median of step 2 which in Table 1 is 2448 MW.
4. The Monthly P50 Peak Load Forecasts for November and March are the median of the respective load values from step 1, which in Table 1 are respectively 1998 MW and 2047 MW.

An example spreadsheet showing steps 1 through 4 is posted on the WPP website.

5. Per the Tariff, a Participant can modify the results of Step 1 to capture load changes (including Load Transfers) during the forecast window and ensure the results of Step 3 and Step 4 are correct. If historical load data is available the affected Participants are responsible for adjusting any monthly peak loads for in Step 1 that do not capture the load change. If historical load data is unavailable (e.g. a new data center) the affected Participant is responsible for generating synthetic load data and adjusting any monthly peak loads in Step 1 that do not capture the load change. Amending the results of Step 1 will be necessary until the peak load for each Month of the Winter Season for the last available five season automatically fully capture the impacts of the load change through the Historical Load Data

submitted as part of the Advance Assessment. A Participant will need to attest to the accuracy of any modification (see Appendix A - P50 Peak Load Forecast Modifications Senior Official Attestation). Additions and removals of load are separate and distinct from Load Growth Factors discussed in Section 5 and are intended to capture significant one-time changes such as the addition or loss of a large industrial customer.

6. Per the Tariff, a specified Load Growth Factor will then be applied to the results of step 5 (see Section 5) for each year following the last year in the Historical Load data. For example, the Monthly P50 Peak Load Forecast – unadjusted is multiplied by the Load Growth Factor once for 2022/2023 and again to arrive at the 2023/2024 Monthly P50 Peak Load Forecast – adjusted for load growth value in the last column in Table 2).

4.2. Summer P50 Peak Load Forecast

The monthly P50 Peak Load Forecast for the Summer Seasons utilizes a Load Forecast Ratio to reflect the potential for a Participant to experience peaks in different months of the Summer Season from year to year. An example monthly P50 Peak Load Forecast for a Summer Season is shown in Table 2 and referred to in the methodological steps below.

Month	Season	2018	2019	2020	2021	2022	Monthly Average of Peak Loads	Maximum Monthly Average of Peak Loads	Median of Maximum of Peak Loads for the last five Seasons	Load Forecast Ratio	2024 Monthly P50 Peak Load Forecast - unadjusted	2024 Monthly P50 Peak Load Forecast - adjusted for load growth
June	Summer	3071	3571	1903	2496	1957	2600	2960	3571	0.88	3136	3206
July	Summer	3672	1761	2434	3219	3715	2960			1.00	3571	3650
August	Summer	2049	2929	2661	2939	2347	2585			0.87	3119	3188
September	Summer	2308	1698	1880	1664	2443	1999			0.68	2411	2465
	Maximum	3672	3571	2661	3219	3715						

Table 2 - Example Summer Season P50 Peak Load Forecast

1. Determine the peak load for each Month of the Summer Season for the last available five seasons using the Historical Load Data submitted as part of the Advance Assessment (see BPM 101 Advance Assessment). These are the load values populating the light blue section of Table 2 (e.g. June peak load from 2020 is 1903 MW).
2. Calculate the maximum peak load for each of the last available five seasons. For example, the maximum peak load for 2021 in the yellow section of Table 2 is 3219 MW.
3. Calculate the median of step 2, which in Table 2 is 3571 MW.
4. Calculate the Load Forecast Ratio.

4.1. For each of the last available five Summer Seasons calculate the average of the five peak loads for each Month. For example, in August in Table 2 the average of the peak loads is 2585 MW.
4.2. Identify the maximum load value from step 4.1. In the example shown in Table 2 this is the July average of 2960 MW.
4.3. The Load Forecast Ratio for each Month of the Summer Season is the result of step 4.1 divided by the MW value identified in step 4.2. In the example shown in Table 2, this is 1.00 for July (and will always by 1.00 for the maximum Summer month) and 0.68 for September.

5. Multiply the Load Forecast Ratios for each Month of the Summer Season from step 4.3 by the result of step 3. These are the Monthly P50 Peak Load Forecast values unadjusted for load growth or load additions/removals (seen in red in Table 2). In the example shown in Table 2 the Monthly P50 Peak Load Forecast - unadjusted value for September is 2411 MW (0.68 multiplied by 3571 MW).

An example spreadsheet showing steps 1 through 5 is posted on the WPP website.

6. Per the Tariff, a Participant can modify the results of Step 1 to capture load changes (including Load Transfers) during the forecast window and ensure the results of Step 5 are correct. If historical load data is available the affected Participants are responsible for adjusting any monthly peak loads for in Step 1 that do not capture the load change. If historical load data is unavailable (e.g. a new data center) the affected Participant is responsible for generating synthetic load data and adjusting any monthly peak loads in Step 1 that do not capture the load change. Amending the results of Step 1 will be necessary until the peak load for each Month of the Summer Season for the last available five season automatically fully capture the impacts of the load change through the Historical Load Data submitted as part of the Advance Assessment. A Participant will need to attest to the accuracy of any modification (see Appendix A - P50 Peak Load Forecast Modifications Senior Official Attestation). Additions and removals of load are separate and distinct from Load Growth Factors discussed in Section 5 and are intended to capture significant one-time changes such as the addition or loss of a large industrial customer.
7. Per the Tariff, a specified Load Growth Factor will then be applied to the results of step 6 (see Section 5) for each year following the last year in the Historical Load Data. For example, the Monthly P50 Peak Load Forecast – unadjusted is multiplied by the Load Growth Factor once for 2023 and again to arrive at the 2024 Monthly P50 Peak Load Forecast – adjusted for load growth value in the last column in Table 2).

5. Load Growth Factor

A Participant will have the option of using either a WPP-established WRAP-wide growth rate(s) (Section 5.1) or developing its own alternative growth rate (Section 5.2). Load growth is separate and distinct from the additions and removals of load discussed in Section 4.1 step 5 and Section 4.2 step 6.

5.1. Established Growth Rate

A WRAP-wide established growth rate (or set of established growth rates) may account for location, weather, Participant type, Participant customer composition (balance between retail, commercial, and industrial). The established growth rate is currently set at 1.1%. Changes to the established growth rate for the P50 Peak Load Forecast in BPM 103 will be reviewed, endorsed, and approved as described in the *BPM 300's Stakeholder Engagement* series.

5.2. Participant Alternative Growth Rate

If a Participant believes the established growth rate discussed in Section 5.1 does not accurately represent its anticipated loads in the Binding Season, the Participant may request an alternative growth rate that will be validated by the Program Administrator and Program Operator (using the form found on WPP website). The Program Administrator will consider the data presented in support of the Participant's request for an alternative growth rate, which could potentially relate to weather, economic growth, or climate. As part of the request, the Participant will demonstrate that the alternative growth rate (applied to each year following the last year in the Historical Load Data) results in a P50 Peak Load Forecast that is (in total) 5% higher or lower than the P50 Peak Load Forecast calculated using the growth rate in Section 5.1 in the Month of the Binding Season with the highest P50 Peak Load Forecast. For example, the Participant with data from Table 1 would provide an alternative load growth factor that, when applied for two years of growth, results in a P50 Peak Load value of greater than 2,627MW or less than 2,377MW for December, January, or February, and would provide supporting information for said load growth factor.

6. Contingency Reserve Adjustment

As discussed in *BPM 102 FS Reliability Metrics*, the LOLE Study and resulting monthly FSPRMs ensure Contingency Reserve is maintained by assuming a proxy Contingency Reserve requirement of six percent (6%) of the Regional P50 Peak Load Forecast across the WRAP Region. However, as the BAL-002-WECC-3 standard requires a reserve equal to three percent (3%) of hourly integrated load and three percent (3%) of hourly integrated generation, the individual Participants' Contingency Reserve requirements (and therefore FS Capacity Requirements) will be different depending on the load and generation profiles specific to them. For instance, some Participants may utilize contracted capacity to meet their FS Capacity Requirement where the seller, through a contractual arrangement, is responsible for carrying the Contingency Reserve obligation of contracted capacity, or some Participants may purchase Contingency Reserve to cover some or all of their Contingency Reserve requirements. These are categorized as Contingency Reserve adjustments and the intent is to ensure that the portion of the FSPRM attributable to Contingency Reserve is included in the FS Capacity Requirement of the LRE with the actual responsibility, whether that responsibility is driven by a BAL-002 WECC-3 compliance obligation or through a contractual arrangement. The FS Capacity Requirements Unadjusted are therefore adjusted for a Participant's Contingency Reserve requirements (plus or minus). A Participant's Contingency Reserve Adjustment has two components: Contingency Reserve Adjustment-Generation and Contingency Reserve Adjustment-Load.

6.1. Contingency Reserve Adjustment-Generation

A Participant's sale or purchase of capacity where there is an accompanying contractual transfer of obligation for Contingency Reserve may impact the amount of Contingency Reserve needed in the Participant's FS Submittal.

Participants selling capacity that is utilized to meet another Participant's FS Capacity Requirement will get a positive value for the Contingency Reserve Adjustment-Generation, meaning the Participant will demonstrate additional capacity to cover Contingency Reserve for the generating resources serving the export contracts. Participants meeting some or all of the FS Capacity Requirement with contracts where the seller carries the Contingency Reserve obligation will have a negative Contingency Reserve Adjustment-Generation, meaning the Participant demonstrated less capacity, as the seller is carrying the Contingency Reserve for the resources serving the contract(s).

Exceptions to the aforementioned are possible when contractual arrangements dictate alternative treatment as indicated in the workbook.

6.2. Contingency Reserve Adjustment-Load

For a Participant with Contingency Reserve contracts, the Participant's Contingency Reserve Adjustment-Load is the net of the Participant's sales of such contracts less purchases for each Month of a Binding Season.

If a Participant is a net seller of Contingency Reserve contracts to a Participant assumed to have a Contingency Reserve obligation on its WRAP load, it will carry additional Contingency Reserve to cover such contracts (with a positive Contingency Reserve Adjustment-Load). If a Participant is a net purchaser of Contingency Reserve contracts, it will carry fewer Contingency Reserve (having contracted away the obligation), resulting in a negative Contingency Reserve Adjustment-Load.

7. Excluding Load

As described in *BPM 108 FS Submittal Process*, a Participant will include all loads in its FS Demonstration for which it is responsible: i.e. all loads within the Western Interconnect (that are not participating in another resource adequacy program or represented by another WRAP LRE) for which the Participant has an obligation to forward procure capacity to meet any portion of the load or for which the Participant is the exclusive wholesale electricity provider to a load serving entity.

A Participant may seek to exclude loads from WRAP participation. This is distinct from a Participant modifying its P50 Peak Load Forecast to account for additions and removal of load. This is distinct from a Participant modifying its P50 Peak Load Forecast to account for additions and removal of load. As part of its FS Demonstration, the Participant will attest that the Participant is not the exclusive wholesale provider for the load (see Appendix B - Load Exclusion). As part of its FS Demonstration, the Participant will also provide documentation of notice to the end-use customer of the Participant's intent to exclude the load from WRAP in the form provided on the WPP website and acknowledged via signature by a senior official of the end-use customer. Excluded load may not be included in the Operations Program. Excluded load must be separately metered, such that the excluded load may be removed from load forecasting information to be provided in the Operations Program, as further discussed in *BPM 202 Participant Sharing Calculation Inputs*, and from the Historical Load Data utilized in Section 4. Loads may not be partially excluded.

8. Submitting Loads from Multiple Subregions

As described in *BPM 108 FS Submittal Process*, a Participant responsible for loads in two Subregions seeking to submit a single workbook using one monthly FSPRM may do so if the Participant can demonstrate NERC Priority 6 or NERC Priority 7 firm point-to-point (PTP) transmission service or network integration transmission service (NITS) from the load in the Subregion with the utilized monthly FSPRM to the load in the Subregion with the higher monthly FSPRM (see *BPM 108* for additional information). When submitting a single FS Submittal for loads in multiple Subregions, the Participant will use historical load data including all loads when calculating the FS Capacity Requirement for that Month according to Sections 2 through 7 of this BPM. Subregion loads will be combined on a coincident peak basis to determine monthly P50 Peak Loads when submitting a single FS Submittal.

9. Load Aggregation/Disaggregation

10. As described in *BPM 108 FS Submittal Process,* all loads submitted by a Participant within a single FS Submittal must be able to be served interchangeably by all Qualifying Resources and Qualifying Contracts in that same FS Demonstration, without the expectation that additional transmission rights will be required to deliver resources to load. In accordance with this, a Participant may be required to submit separate FS Demonstrations, even as to loads residing in the same Subregion, if the Program Administrator determines it is not practicable to treat such loads as if they can share in load and resource diversity for reasons that may diminish the integrity of WRAP reliability metrics, including but not limited to, if loads and resources are not operated collectively. LOLE Study Load Forecast and Load Growth Rate

A LOLE Study (see *BPM 102 FS Reliability Metrics*) is undertaken as part of the Advance Assessment (see *BPM 101 Advance Assessment*) to determine a Binding Season's monthly FSPRMs. The Regional P50 Peak Load Forecasts for the Binding Seasons in the LOLE Study are calculated using the same Participant P50 Peak Load Forecast methodologies outlined in Section 4. An LOLE Study-specific program-wide load growth rate is then applied to the results. The current Load Growth Factor for the LOLE Study is set to 1.1%. Changes to the established growth rate for the LOLE Study in BPM 103 will be reviewed, endorsed, and approved as described in the *BPM 300's Stakeholder Engagement* series.

Appendix A - P50 Peak Load Forecast Modifications Senior Official Attestation

I, the undersigned, who as [title], serves as a senior official of [Participant], hereby attest that the peak loads for each month of the Season for the last available five seasons have been modified accurately to the best of my knowledge and belief following due inquiry to account for discrete additions and removals of load planned to take place by the corresponding Months of the Binding Season, not to include speculative or estimated load growth, to ensure accurate Monthly P50 Load Forecast values included with this attestation. Also included with this attestation is a narrative description of the loads added and/or removed from the Monthly P50 Load Forecast, including their magnitude and applicable Months.

Appendix B - Load Exclusion Senior Official Attestation

I, the undersigned, who as [title], serves as a senior official of [Participant], hereby request that the [load identifier from FS Submittal] be excluded from [Participant's] P50 Load Forecast calculation. I attest that [Participant] is not the exclusive wholesale electricity provider for this load.

RAPC PA/PO Update – EDST

Technical Aspect

1. Overall the transition from the Excel workbook to EDST has been quite smooth, especially considering that the first submittal is easily the heaviest lift
2. Some features like Document upload/linking and Facility linking for hybrid/collocated resources are new to EDST with the WRAP FS release, and overall we are happy with how those are functioning
3. We appreciate all feedback that has been received from WRAP users
4. A few defects have been identified, but none that we view as critical
    a. We have found workarounds in place and are coordinating with IT to hopefully resolve these in an upcoming minor release
5. We have been tracking and prioritizing improvement/enhancement items, and the next step is for SPP to coordinate with WPP to "bundle" items for a future major release

Validation Aspect

1. Automation:
    a. More validations are now automated which allows for less human error
    b. This has helped SPP and WPP spend less time manually validating each Participants FS Submittal
    c. In turn, for manual validations this has also allowed us to spend more time thoroughly looking through a Participants FS Submittal.
    d. It has helped us to have more time coordinating with both WPP and Participants on how to cure deficiencies that were identified during the validation process
2. Submittal Process:
    a. Although time consuming for the first time, most Participants have appreciated the EDST tool as far as using it from an FS submittal perspective
    b. We have received both positive and constructive feedback on how to continue to make the tool better
3. Advance Assessment Results:
    a. EDST has allowed us to start posting both seasonal and monthly QCC results and Participants Load Forecast/P50's
    b. We are now able to assign each Participant a particular Subregion and Subregion PRM avoiding confusion with different workbook versions that we had used in the past