BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-125:
Service Area and Territory (Electric Power and Water) SRP

Service Territory

As a community-based not-for-profit water and energy company, SRP provides reliable, affordable water and power to more than 2 million people living in central Arizona.

Enter your address to see the SRP services available at your location

SRP delivers affordable water and power to more than 2 million customers living in and around the Valley. Our service territory is broad and covers much of central Arizona. Some addresses receive only one of our services while others are provided both water and power.

Feedback

Find address or place

Esri, TomTom, Garmin, FAO, NOAA, USGS, Bureau of Land Management, EPA, NPS, USFWS

Powered by Esri

Search for an address to learn more about the location and its surrounding area.

If you don't know the address, use one of these search methods:

Click the search box and type in an address or choose **Use current location.**

Be sure to click within the map.

Feedback

RELATED TOPICS

About Salt River Project | SRP

SRP is a community-based, not-for-profit organization providing affordable water and power to more than 2 million people in central Arizona. Read more here.

[History of Salt River Project | SRP]

Since 1903, Salt River Project has helped shape our state. Learn about our history of service to the people who call Arizona home.

[Future plan for energy | SRP]

Ensuring that the Valley's energy future remains reliable requires energy experts and communities working together. Learn about SRP's energy plan for the future.

Feedback

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-26-21
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-126:
Xcel, List of Towns Receiving Electric Service in Colorado

COLORADO COMMUNITIES SERVED BY XCEL ENERGY

INFORMATION SHEET
COLORADO

Xcel Energy®

🔥 = Gas only 🔌 = Electricity only 🔥🔌 = Gas and Electricity

A
Alamosa 🔥🔌
Alma 🔌
Antonito 🔥🔌
Arvada 🔥🔌
Aspen Park 🔥
Atwood 🔥🔌
Ault 🔌
Aurora 🔥🔌
Avon 🔥
Avondale 🔥

B
Barnesville 🔌
Battlement Mesa 🔌
Beaver Creek 🔥
Bellvue 🔥🔌
Bergen Park 🔥🔌
Berthoud 🔥🔌
Berthoud Falls 🔌
Black Hawk 🔥🔌
Blanca 🔌
Blue River 🔌
Bonanza 🔌
Boone 🔥
Boulder 🔥🔌
Bountiful 🔌
Bow Mar 🔥🔌
Bracewell 🔌
Breckenridge 🔥🔌
Briggsdale 🔌
Brighton 🔥
Broomfield 🔥🔌
Brush 🔥🔌

C
Campion 🔥🔌
Canfield 🔥🔌
Canon 🔌
Canyon Creek 🔌
Capulin 🔥
Carbondale 🔌
Castle Pines 🔌
Centennial 🔌
Center 🔌
Central City 🔥🔌
Chama 🔌
Cherry Hills Village 🔥🔌
Clifton 🔥🔌
Climax 🔥🔌
Cody Park 🔥🔌
Columbine Valley 🔥🔌
Commerce City 🔥🔌
Conejos 🔥🔌
Conifer 🔥
Copper Mountain 🔥
Cornish 🔌
Crisman 🔌

D
De Beque 🔥🔌
Del Norte 🔥🔌
Denver 🔥🔌
Dillon 🔥🔌
Downieville 🔥🔌
Dumont 🔥🔌

E
Eastlake 🔥🔌
Eaton 🔌
Edgewater 🔥🔌
Eldora 🔌
Eldorado Springs 🔌
Empire 🔥🔌
Englewood 🔥🔌
Erie 🔥🔌
Estes Park 🔥
Evans 🔌
Evergreen 🔥🔌

F
Fairplay 🔌
Farmers Spur 🔌
Federal Heights 🔥🔌
Fort Collins 🔥🔌
Fort Garland 🔌
Fort Lupton 🔥
Fort Morgan 🔥🔌
Fosston 🔌
Foxfield 🔌
Fraser 🔥
Frisco 🔥🔌
Fruita 🔥🔌
Fruitvale 🔥🔌

G
Galeton 🔌
Garden City 🔌
Garfield 🔌
Georgetown 🔥🔌
Gilcrest 🔌
Gill 🔌
Gilman 🔌
Glendale 🔥🔌
Glenwood Springs 🔌
Gold Hill 🔌
Golden 🔥🔌
Granby 🔥
Grand Junction 🔥🔌
Grand Lake 🔥
Greeley 🔌
Greenwood Village 🔥🔌
Guadalupe 🔥🔌

H
Hideaway Park 🔥
Highlands Ranch 🔥🔌
Hillrose 🔌
Homelake 🔌
Hooper 🔌
Horca 🔌
Hot Sulphur Springs 🔥
Hygiene 🔥

I
Idaho Springs 🔥🔌
Idledale 🔥🔌
Indian Hills 🔥🔌

J
Jamestown 🔌
Johnstown 🔥🔌

K
Kelim 🔥🔌
Kersey 🔌
Keystone 🔥
Kittredge 🔥🔌
Kremmling 🔥
Kuner 🔌

COLORADO COMMUNITIES SERVED BY XCEL ENERGY

🔥 = Gas only 🔌 = Electricity only 🔥🔌 = Gas and Electricity

L
La Jara 🔥🔌
Laporte 🔥🔌
La Salle 🔌
La Valley 🔌
Lafayette 🔥🔌
Lakeside 🔥🔌
Lakewood 🔥🔌
Las Mesitas 🔌
Lawson 🔥🔌
Leadville 🔥🔌
Leyden 🔌
Littleton 🔥🔌
Lobatos 🔌
Lochbuie 🔥
Log Lane Village 🔥🔌
Lone Tree 🔌
Longmont 🔥🔌
Lookout Mountain 🔌
Louisville 🔥🔌
Louviers 🔥
Loveland 🔥🔌
Lucerne 🔌
Lyons 🔥🔌

M
Magnolia 🔌
Malta 🔌
Manassa 🔥🔌
Marshall 🔌
Marshdale 🔌
Maysville 🔌
Mead 🔥
Merino 🔥🔌
Milliken 🔥🔌
Minturn 🔥🔌
Moffat 🔌
Mogote 🔌
Monarch 🔌
Monte Vista 🔥🔌
Montezuma 🔌
Morrison 🔥🔌
Mosca 🔌
Mountain View 🔥🔌
Mount Vernon 🔥🔌

N
Nederland 🔥🔌
New Castle 🔥🔌
Niwot 🔥🔌
North Avondale 🔥
Northglenn 🔥🔌
Nunn 🔌

O
Orchard Mesa 🔥🔌
Ortiz 🔌

P
Paisaje 🔌
Palisade 🔥🔌
Parachute 🔥🔌
Parker 🔥
Parshall 🔥
Peaceful Valley 🔌
Peckham 🔌
Peetz 🔌
Pierce 🔌
Platoro 🔌
Platteville 🔌
Poncha Springs 🔌
Pueblo 🔥
Purcell 🔌

R
Raymer 🔌
Raymond 🔌
Red Cliff 🔥🔌
Redlands 🔌
Richfield 🔥🔌
Rifle 🔥🔌
Riverside 🔌
Romeo 🔥🔌
Rulison 🔌
Russell Gulch 🔥🔌

S
Saguache 🔥🔌
Salida 🔌
Salina 🔌
San Antonio 🔌
San Francisco 🔌
San Luis 🔌
San Pablo 🔌
San Pedro 🔌
Sanford 🔥🔌
Sargent 🔥🔌
Sedalia 🔥
Severance 🔥🔌
Sheridan 🔥🔌
Silt 🔥🔌
Silver Plume 🔌
Silverthorne 🔥🔌
Smeltertown 🔌
Snyder 🔌
Springdale 🔌
Sprucedale 🔌
Sterling 🔥🔌
Sterling Ranch 🔥🔌
Stoneham 🔌
Stringtown 🔌
Sugarloaf 🔌
Summitville 🔥🔌
Sunshine 🔌
Superior 🔥🔌

T
Tabernash 🔥
Thornton 🔥🔌
Timnath 🔥🔌
Tiny Town 🔌

V
Vail 🔥
Valmont 🔌
Vineland 🔥

W
Wah Keeney Park 🔥🔌
Wallstreet 🔌
Ward 🔌
Watkins 🔌
Weldona 🔥🔌
Wellington 🔌
West Vail 🔥
Westminster 🔥🔌
Wheat Ridge 🔥🔌
Wiggins 🔥
Willard 🔌
Windsor 🔥🔌
Winter Park 🔥

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-26-21
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

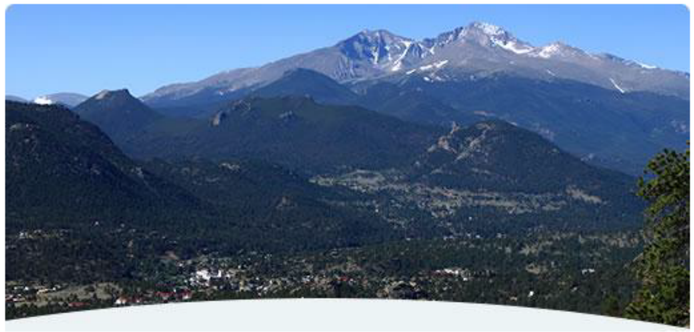
Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-127:
Who we serve - Platte River Power Authority

Our communities

Platte River Power Authority is a Colorado political subdivision established to provide wholesale electric generation and transmission to the utilities of its owner communities – Estes Park, Fort Collins, Longmont and Loveland.



Town of Estes Park

Estimated population*: 6,426
Utility: Estes Park Power and Communications, established in 1945
Source to Switch

City of Fort Collins

Estimated population*: 170,243
Utility: Fort Collins Utilities, established in 1938
Source to Switch

EN

City of Longmont

Estimated population*: 97,261
Utility: Longmont Power & Communications, established in 1912
Source to Switch

City of Loveland

Estimated population*: 78,877
Utility: Loveland Water and Power, established in 1925
Source to Switch

*Based on the U.S. Census Bureau

Accessibility Notice:
Per the Americans with Disabilities Act (ADA), Platte River Power Authority will provide reasonable accommodation to qualified individuals with a disability who need assistance. Please email us at communications@prpa.org or call 970-226-4000. "Walk-in" requests for auxiliary aids and services may be honored to the extent possible but can be unavailable if advance notice is not provided.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-26-21
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-128:
Order No. 24-073 OR PUC on Pac 2023 IRP

ORDER NO. 24-073

ENTERED Mar 19 2024

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 82

In the Matter of PACIFICORP, dba PACIFIC POWER, 2023 Integrated Resource Plan.	ORDER

DISPOSITION: STAFF'S RECOMMENDATION ADOPTED.

In this order, we adopt the recommendations made by Staff of the Oregon Public Utility Commission to acknowledge in part and not acknowledge in part PacifiCorp, dba Pacific Power's Integrated Resource Plan (IRP). We do not acknowledge PacifiCorp's Clean Energy Plan (CEP). We also adopt Staff's 21 recommendations, which set firm direction for what we require to be provided with PacifiCorp's 2025 IRP.

While we understand that development of PacifiCorp's 2025 IRP is a multi-stakeholder, multi-state process in which the company might reasonably seek our flexibility in setting requirements for the analysis, we are reacting to the rigidity PacifiCorp has displayed in responding to Oregon Staff and stakeholders' reasonable requests for adjustments and additional analysis during our review of its filed IRP and CEP, and even in its forthcoming IRP Update. We expect PacifiCorp to embrace the letter and spirit of the Staff recommendations that we adopt here, to follow them assiduously in developing its 2025 IRP, and to return to us for clarification if there is any doubt about what we require. With the urgency of reliability, cost control, and House Bill (HB) 2021 compliance challenges upon us, we would rather review any emerging questions or uncertainty about our direction before an IRP is locked down rather than find the IRP deficient and the company unwilling to adjust until the next cycle.

I. INTRODUCTION

The purpose of the IRP review process is to provide the utility with the input of the Commission, Commission Staff, and stakeholders on the reasonableness of the plan presented. Our acknowledgment decision provides PacifiCorp with guidance to consider in taking resource actions that, ultimately, rest with the company.[1]

We take seriously our role in informing PacifiCorp's direction, but also reinforce that we do not control PacifiCorp's resource decisions and that any risks associated with carrying out even acknowledged actions rest with the company.

Our goal in an IRP proceeding is to acknowledge that a utility's action plan and preferred portfolio represent the least-cost, least-risk strategy for meeting customer needs, based on the best data available at the time and using the best available tools to analyze and review that data. In this particular IRP proceeding, we are asked to review a plan and portfolio that PacifiCorp had already abandoned by suspending the 2022 All-Source RFP, and that was further impacted by the stay of the federal Ozone Transport Rule. We are left without a plan that reflects PacifiCorp's reality, and without any willingness by PacifiCorp to adjust its action plan to reflect that reality. Therefore, we have no basis on which to acknowledge the majority of PacifiCorp's IRP, nor can we acknowledge its CEP without the foundation of a viable IRP action plan. We expect that, in 2025, we will be given a plan that follows Staff's recommendations and reflects both updated operating circumstances and an action plan that the company can stand behind. Recognizing that circumstances are rapidly evolving, that plan may describe action items and the key factors that would instigate a change in course. We also invite the company to present an IRP Update with revised actions that can serve as the foundation for a refiled CEP, which we will consider for acknowledgment and as a demonstration of continual progress.

II. IRP AND CEP PROCESS

A. Overall Purpose of the IRP

The IRP is a road map for providing reliable and least-cost, least-risk electric service to the utility's customers, consistent with state and federal energy policies, while addressing and planning for uncertainties.[2] The primary outcome of the process is the "selection of a

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[1] *See In the Matter of the Investigation into Least-Cost Planning for Resource Acquisitions by Energy Utilities in Oregon*, Docket No. UM 180, Order No. 89-507 at 6 (Apr. 20, 1989) (explaining, "The Commission does not intend to usurp the role of utility decision-maker. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy while having the benefit of the information and opinion contributed by the public and the Commission* * *.").

[2] *In the Matter of Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002 at Appendix A, Guidelines 1-13 (Jan. 8, 2007) corrected by Order No. 07-047 (Feb. 9, 2007); *In the Matter of Investigation into* the *Treatment of CO_2 Risk in the Integrated Resource Planning Process*, Docket No. UM 1302, Order No. 08-339 (June 30, 2008) (refining Guideline 8 addressing environmental costs.).

portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[3]

Our IRP guidelines provide procedural and substantive requirements for utilities to meet in developing their IRPs.[4] Consistent with our guidelines, which require modeling of at least a 20-year time horizon, a utility's IRP must include the following key components:

- Identification of capacity and energy needs to bridge the gap between expected loads and resources;
- Identification and estimated costs of all supply-side and demand-side resource options;
- Construction of a representative set of resource portfolios;
- Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;
- Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers; and
- Creation of a two- to four-year Action Plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.

In reviewing an IRP, we assess reasonableness based on the information available at the time. Our decision to acknowledge or not acknowledge an action item does not constitute ratemaking. Acknowledgment, or non-acknowledgment, of an IRP is a relevant but not exclusive consideration in our examination of whether the costs associated with a utility's resource investment should be recovered in customer rates. The question of whether a specific utility investment or procurement decision was prudent and reasonable will be examined in the subsequent rate proceeding.

B. Overall Purpose of the CEP

The Commission is tasked with ensuring progress towards, and evaluating compliance with, the emissions reductions targets required by HB 2021. Oregon electric companies subject to HB 2021 must file clean energy plans (CEPs), which we are charged with evaluating for acknowledgment pursuant to ORS 469A.415(6).[5] CEPs must meet statutory requirements set forth in ORS 469A.415, and also must demonstrate continual

[3] Order No. 07-002 at Appendix A, Guideline 1.
[4] Order No. 07-002 and Order No. 07-047 (adopting 13 IRP Guidelines); Order No. 08-339 (June 30, 2008) (refming Guideline 8 addressing environmental costs).
[5] ORS 469A.410(1) lists the required greenhouse gas emission reductions; the Commission's required evaluation is described in ORS 469A.415(4)(e) and (6).

progress towards meeting the HB 2021 targets in a way that results in "an affordable, reliable and clean electric system."[6]

Oregon electric companies subject to HB 2021's requirements must submit a CEP to the Commission concurrent with the development of each IRP.[7] CEPs "must be based on or included in an [IRP] filing," and must be filed concurrently with the IRP.[8]

Each CEP must:

(1) incorporate the clean energy targets articulated in ORS 469A.410;

(2) "[i]nclude annual goals set by the electric company for actions that make progress towards meeting the clean energy targets * * * including acquisition of nonemitting generation resources, energy efficiency measures and acquisition and use of demand response resources;"

(3) "[i]nclude a risk-based examination of resiliency opportunities that includes costs, consequences, outcomes and benefits based on reasonable and prudent industry resiliency standards;"

(4) "[e]xamine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy;"

(5) "[d]emonstrate the electric company is making continual progress within the planning period towards meeting the clean energy targets * * * including demonstrating a projected reduction of annual greenhouse gas emissions;" and

(6) "[r]esult in an affordable, reliable[,] and clean electric system."[9]

The actions and investments proposed in a CEP can include "the development or acquisition of clean energy resources, acquisition of energy efficiency and demand response * * * development of new transmission * * * retirement of existing generating facilities, changes in system operation and any other necessary action."[10]

The CEP must also "present annual goals for actions that balance expected costs and associated risks and uncertainties for the utility and its customers, including a demonstration of making continual progress towards meeting the clean energy targets, the

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[6] ORS 469A.415(4)(f).
[7] ORS 469A.415(1).
[8] ORS 469A.415(3).
[9] ORS 469A.415(4)(a) - (f).
[10] ORS 469A.415(5).

pace of greenhouse gas emissions reductions, and community impacts and benefits."[11] The CEP must be "written in language that is as clear and simple as possible, with the goal that it may be understood by non-expert members of the public."[12]

III. PACIFICORP'S 2023 IRP AND CEP

After PacifiCorp filed its amended IRP and CEP in May 2023, we adopted a procedural schedule. This schedule allowed numerous opportunities for submission of written comments from Staff and intervenors, as well as opportunities to obtain feedback from PacifiCorp. On January 24, 2024, Staff filed its Round 2 Comments and Recommendations, in which it recommended truncating the schedule and bringing PacifiCorp's IRP to the February 20 regular public meeting for decision. Due to changed circumstances, including suspension of PacifiCorp's 2022 All-Source RFP and stay of the federal Ozone Transport Rule, Staff recommended only partial acknowledgment of the IRP and that instead of finishing the established procedural schedule, stakeholder and Staff attention should instead turn to the IRP update, to be filed in April 2024. On January 30, 2024, Staff filed a motion to modify the procedural schedule consistent with that recommendation, which was granted. After engagement with parties and Commissioner deliberation on February 20, we adopted the decision memorialized in this order at our March 5 regular public meeting.

C. PacifiCorp's Preferred Portfolio and Action Items

PacifiCorp states its preferred portfolio includes "substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, advanced nuclear, and non-emitting peaking resources."[13] Among other things, PacifiCorp states that it plans 1,792 MW of wind, and 495 MW of solar additions with 200 MW of battery storage capacity from the 2020 All-Source RFP, as well as resource selections from the 2022 All-Source RFP. It also includes 1500 MW of advanced nuclear resources, including the 500 MW Natrium demonstration project. PacifiCorp asks for acknowledgment of the preferred portfolio, as well as a variety of actions, specifically:

- Existing Resource Actions – PacifiCorp seeks to exit Colstrip Units 3 and 4, and Craig Unit 1. It seeks to convert Naughton Units 1 and 2 and Jim Bridger Units 1 and 2 to gas. Finally, it seeks acknowledgment of its compliance plans for Wyoming House Bill 200 (Carbon Capture, Utilization, and Storage); regional haze; and the Ozone Transport Rule.

[11] OAR 860-027-0400(5).
[12] *Id*.
[13] Amended IRP at 10 (May 31, 2023).

- New Resource Actions – PacifiCorp seeks acknowledgment of its customer preference RFP; its 2024 All-Source RFP; and its 2022 All-Source RFP (now suspended).
- Transmission Action Items – PacifiCorp seeks acknowledgment for three long transmission segments – Energy Gateway South, Segment F; Energy Gateway West, Segment D.1; and Boardway-to-Hemingway – and for local reinforcement projects. It also seeks acknowledgment of continued permitting activities for Gateway West Segments D.3 and E.
- Demand-Side Management (DSM) Actions – PacifiCorp seeks acknowledgment of its energy efficiency targets.
- Market Purchases – PacifiCorp seeks acknowledgment of its intent to acquire short-term firm market purchases for on-peak delivery from 2023-2025.
- Renewable Energy Credit (REC) Actions – PacifiCorp seeks acknowledgment of its intent to pursue unbundled REC RFPs and purchases to meet state compliance obligations and to sell RECs that are not required to meet state RPS obligations.

D. PacifiCorp's CEP

PacifiCorp's CEP first discusses its community engagement strategy, community benefit indicators and metrics, local resiliency, and community-based renewable energy. It then discusses the company's procurement strategy and the IRP's projection that the company will need to acquire over 30 GWs of new resources, including over 800 MW of small-scale renewables. PacifiCorp's CEP finally lays out two pathways for complying with HB 2021: Pathway 1 achieves compliance by allocating the company's gas resources in such a way that the amount allocated to Oregon is capped; Pathway 2 achieves compliance by assuming that new large commercial load is 100 percent served with non-emitting generation through voluntary renewable options.

E. Stakeholder Engagement

Numerous stakeholders filed comments and otherwise participated in this proceeding. Some of their recommendations were incorporated by Staff into their initial and supplemental Staff Reports. Participating stakeholders were: the Oregon Citizens' Utility Board; Energy Advocates; Columbia River Inter-Tribal Fish Commission; NewSun Energy LLC; Renewable Northwest; Swan Lake North Hydro, LLC and FFP Project 101, LLC; Alliance of Western Energy Consumers; Fervo Energy; Sierra Club; Cascade Policy Institute; and Community Advocates.

F. Staff Report

On February 7, 2024, Staff submitted an extensive Staff Report, in which it reiterated its recommendation for partial acknowledgment. That Staff Report is attached as Appendix A. In it, Staff recommends acknowledging eleven action plan items and the company's load forecast. It recommends not acknowledging nine action plan items, the preferred portfolio, and the company's long-term IRP/CEP strategy. It also makes thirteen recommendations that it asks the Commission to adopt and lists over 50 expectations that it intends to work with the company on for the IRP Update or 2025 IRP; it states that it does not seek the Commission impose those expectations.

Staff recommends this course of action because "the 2023 IRP/CEP would not be revised to reflect major events—like the suspended acquisition of over 1 GW of renewable and storage capacity by 2027"—and therefore "Staff and stakeholders lack the shared analytic foundation from which most of the important acknowledgment decisions could be made."[14] Staff's recommendations are also premised on the fact that "the IRP Update will be filed in April 2024, presenting an opportunity to address these issues in a prompt and efficient manner."[15]

On March 1, 2024, Staff filed a report containing an updated set of recommendations, responding to Commissioner deliberation in the February 20 public meeting, including some edited recommendations and a number of new ones. This report is attached as Appendix B and stands as Staff's final recommendations in this proceeding. It did not change Staff's acknowledgment recommendations but did provide specific expectations for PacifiCorp's 2025 IRP and the analyses that PacifiCorp is to provide with that document.

IV. DISCUSSION

We adopt the recommendations set forth in Staff's March 1 report. We acknowledge certain elements and action items in the IRP, but do not acknowledge many other action items. Moreover, we do not acknowledge PacifiCorp's preferred portfolio or the CEP. The plans and many of the action items simply no longer reflect PacifiCorp's reality; most significantly, when PacifiCorp suspended the 2022 All-Source RFP and declined to update its analysis or the further procurement actions set forth in its action plan, we were left with few reality-based actions to acknowledge. Also, when the decision not to take those actions fundamentally undermines a preferred portfolio that was already substantially altered by the federal Ozone Transport Rule, we find it curious that PacifiCorp continues to assert that we should acknowledge its IRP and CEP. In short,

[14] Staff Report at 4.
[15] *Id.*

when the IRP and CEP are superseded by events, and the company makes no effort or space to adjust and provide visibility into what actions it is actually planning to take, acknowledgment is not appropriate. Much in the way we would not acknowledge actions that PacifiCorp has already taken, we do not see a point in acknowledging actions that PacifiCorp has already abandoned.

In saying this, we recognize that not all of these changed circumstances are in the company's control—there are real changes in federal regulations, real operating circumstances and pressures affecting the company, and some inflexibility in PacifiCorp's six-state IRP structure. Nonetheless, we expect PacifiCorp to design its IRP process so that Oregon-specific analysis is upfront and visible to us in our review. If IRP timelines in other states do not allow for testing assumptions and making adjustments during review of the filed IRP and CEP, we expect the company to make an extra effort to ensure a full exploration of alternatives for Oregon.

As to the CEP specifically, the elements that made up the basic actions that would move the company toward the HB 2021 targets were removed at the company's discretion and there has been no engagement around how those can be revised. PacifiCorp chose to pull back on the actions on which the CEP relied as the foundation for movement toward the clean energy targets—movement toward resource acquisitions that would reduce emissions but also, importantly, reduce customers' exposure to electricity market price volatility, for instance.

Beyond the changed circumstances, we are concerned that the CEP was treated as a manual or outboard adjustment to the preferred portfolio development and analysis in the IRP. Without alternative portfolio testing that incorporates state policy requirements, we are unable to see alternatives to the company's allocation-only approach. Had PacifiCorp's plans stayed on track, this approach may have been acceptable for a first iteration given PacifiCorp's persuasive assertion that the IRP preferred portfolio with reallocation was least cost for HB 2021 compliance, and we are not concluding that an allocation approach is legally invalid. It may well be a viable pathway, but going forward, we expect the company to integrate the requirements of state policies into the IRP itself. We need modeling of state policy in order to be able to see, among other things, achievement of the small-scale resource requirement in context of other resources and as a relative cost driver. As we understand it, a key element of HB 2021 is to be able to use the planning process to see tradeoffs and alternative paradigms, and we conclude that adopting requirements for 2025 is necessary to be able to understand PacifiCorp's alternatives for progress to HB 2021 compliance.

To that end, we are approving Staff's clear recommendations laying out a roadmap for the company's next IRP and we emphasize the importance of the company following these recommendations in its 2025 IRP. At the same time, we invite the company to find a way to include in its 2024 IRP update some of the items that Staff is looking for and to update the CEP. We also voice our support for Staff continuing to pursue its non-binding "expectations;" it is not our intention to only support the items that have been formed into recommendations for our adoption.

We particularly want to call out Recommendations 15, 16, and 17 as difficult but important analyses. Stakeholders have worked with the company over successive IRP cycles to effectively model the comparative economics and flexibility of the many resource options, including careful analysis of when it is cost effective to retire a thermal facility. This rigor must continue as cost pressures mount. Recommendation 16, derived from CUB's comments, is a sound recommendation to incorporate actual carbon prices from California and Washington as PacifiCorp is modeling the cost of resources and the resulting dispatch. PacifiCorp has historically put a long-term price on carbon as a proxy for future regulatory requirements. HB 2021 requires a specific carbon budget and a carbon price, and without it, the CEP is not precise enough to establish compliance. Remedying this is especially important so that the CEP can test how much the portfolio as a whole will meet the Oregon requirements, how much will need to be solved with allocation, and what the cost will be. It will also help us determine whether the company is on a least-cost path to compliance. We also note that analysis of the federal loan program is a critical, near-term priority given capital constraints and rate pressure.

In general, we expect to see more cost information in the course of PacifiCorp's planning, both due to affordability concerns and because we need the company to be clearer about constraints that may be impacting their progress and how they are allocating their resources among their many priorities. The company should be transparent with stakeholders if the IRP Update or the 2025 IRP action plan are being driven by constraints that are not visible in the modeling The company needs to do more to communicating the many moving parts in the company's planning and procurement landscape.

We recognize that we committed in our order in docket UM 2273 to consider, alongside IRP and CEP review processes, whether utilities have demonstrated continual progress.[16] We are not doing so here simply because we expect, in a matter of weeks, to have a more realistic view of PacifiCorp's status with the IRP/CEP Update that are to be filed in April 2024. We will assess continual progress in connection with our review of the update. If we do not find that PacifiCorp has demonstrated "continual progress [toward the HB 2021 targets] and [that it] is taking actions as soon as practicable that facilitate

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[16] *In the Matter of Public Utility Commission of Oregon, Investigation of House Bill 2021 Implementation Issues*, Docket No. UM 2273, Order No. 23-465 (Dec. 4, 203).

rapid reduction of greenhouse gas emissions at reasonable costs to retail electricity consumers," we will consider in a holistic manner whether we need to take actions to fulfill our responsibility to ensure this progress.

V. ORDER

IT IS ORDERED that the Integrated Resource Plan filed by PacifiCorp, dba Pacific Power, is acknowledged in part to the extent and with the conditions contained in Staff's February 7, 2024, and March 1, 2024 reports attached as Appendix A and Appendix B.

Made, entered, and effective Mar 19 2024.

Megan W. Decker	**Letha Tawney**
Chair	Commissioner

ITEM NO. RA4

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: FEBRUARY 20, 2024

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** N/A

DATE: February 7, 2024

TO: Public Utility Commission

FROM: JP Batmale

THROUGH: Kim Herb **SIGNED**

SUBJECT: PACIFICORP:
Docket No. LC 82
Acknowledgement of 2023 Integrated Resource Plan and Clean Energy Plan.

STAFF RECOMMENDATION:

Acknowledge in part and not acknowledge in part PacifiCorp's (Company) 2023 Integrated Resource Plan (IRP), subject to the condition that the Company implements Staff's recommended conditions, including four recommended IRP analyses as part of the IRP Update. Decline to acknowledge the Clean Energy Plan (CEP) filed with the 2023 IRP. Direct the Company to revise and resubmit certain elements of the IRP, and to revise and resubmit the CEP, by the next IRP Update in April 2024, consistent with Staff's recommendations.

DISCUSSION:

Issue

Whether the Public Utility Commission of Oregon (PUC or Commission) should acknowledge PacifiCorp's IRP with or without conditions, acknowledge specific portions of the IRP, with or without conditions, or decline to acknowledge the IRP.

Whether the Commission should acknowledge PGE's CEP or decline to acknowledge the CEP and direct the Company to revise and resubmit certain portions of the plan. Whether the Commission should direct PGE to take any additional actions prior to filing its next IRP or IRP Update or CEP.

Applicable Law

The Commission adopted least-cost planning as the preferred approach to utility resource planning in 1989.[1] In 2007, the Commission updated its existing least-cost planning principles and established a comprehensive set of “IRP Guidelines” to govern the IRP process. The IRP Guidelines found in Order Nos. 07-002 (corrected by 07-047), and 08-339 clarify the procedural steps and substantive analysis required of Oregon’s regulated utilities before the Commission considers acknowledgement of a utility’s resource plan.[2] These orders are incorporated in OAR 860-027-0400(2), which requires any IRP to satisfy their requirements.

The IRP Guidelines and Commission rules require a utility to file an IRP with a planning horizon of at least 20 years within two years of its previous IRP acknowledgment order, or as otherwise directed by the Commission.[3] Further, the IRP must also include an “Action Plan” with resource activities that the utility intends to take over the next two to four years.[4] The utility’s IRP should satisfy the IRP Guidelines and Commission rules for its determination of future long-term resource needs, its analysis of the expected costs and associated risks of the alternatives reviewed to meet its future resource needs, and its near-term Action Plan to achieve the IRP goal of selecting the “portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.”[5] This is often referred to as the “least cost/least risk portfolio.”

The Commission reviews the utility’s plan for adherence to the procedural and substantive IRP Guidelines and generally acknowledges the overall plan if it is reasonably based on the information available at the time.[6] However, the Commission explains: “We may also decline to acknowledge specific action items if we question whether the utility’s proposed resource decision presents the least cost and risk option for its customers.”[7] The Commission may also provide direction on additional analysis or actions for the next IRP or IRP Update.[8]

[1] Order No. 89-507.
[2] Order Nos. 07-002 and 07-047. Additional refinements to the process have been adopted: See Order No. 08-339 (IRP Guideline 8 was later refined to specify how utilities should treat carbon dioxide (CO2) risk in their IRP analysis); Order No. 12-013 (guideline added directing utilities to evaluate their need and supply of flexible capacity in IRP filings).
[3] Order No. 07-002 (Guidelines 1(c) and 3(a)) and OAR 860-027-0400.
[4] Order No. 14-415 at 3.
[5] Order No. 07-002 at 1-2.
[6] *Id.* at 1.
[7] *Id.*
[8] OAR 860-027-0400(7), (10).

In 2021, the legislature passed Oregon House Bill (HB) 2021, codified as ORS 469A.400 to 469A.475, which requires the state's large investor-owned electric utilities (IOUs) and electricity service suppliers (ESSs) to decarbonize their retail electricity sales with consideration for direct benefits to local communities.

ORS 469A.415 requires large electric IOUs to, "develop a clean energy plan for meeting the clean energy targets set forth in ORS 469A.410 concurrent with the development of each integrated resource plan," and file the plan with the Commission and Oregon Department of Environmental Quality (DEQ).

ORS 469A.420 outlines the requirements and considerations for the Commission to acknowledge the CEP "…if the commission finds the plan to be in the public interest and consistent with the clean energy targets...."

In addition, ORS 469A.415(6) requires the Commission to ensure that the utilities demonstrate continual progress within the CEP planning period toward meeting the clean energy targets and are taking actions as soon as practicable to reduce emissions at reasonable cost to retail electricity consumers.

Additional requirements for the filing, review, and update of IRPs and CEPs are provided in OAR 860-027-0400.

Finally, PacifiCorp's previous IRP, LC 77, resulted in Order No. 22-178, which provided specific direction to the Company on analytic matters for this IRP.

<u>Analysis</u>

Background
PacifiCorp filed its 2023 Integrated Resource Plan and Clean Energy Plan (IRP/CEP or Plans) with PUC on May 31, 2023. PacifiCorp's filing shortly followed PGE's filing of the first IRP/CEP on March 31, 2023, both of which followed from the passage of HB 2021 and direction from Docket UM 2225.

Originally three rounds of comments had been planned in the lead up to a final Staff memo for an April 2024 Special Public Meeting to acknowledge PacifiCorp's 2023 IRP/CEP. Round 0 comments provided preliminary notes about improvements PacifiCorp could make in advance of participants' in-depth review of the IRP/CEP. Round 1 comments evaluated the reasonableness of the plan and explored acknowledgement considerations. Round 2 comments were meant to focus on Staff's draft recommendations for Commission acknowledgement of the IRP/CEP. The Company would respond with a final set of comments, typically including a final set of revisions to the IRP. Then in March a public meeting memo from Staff with final acknowledgement recommendations was to be published, giving stakeholders and the Company a final opportunity to make written comments to the Commission.

Round 1 comments by Staff and stakeholders reflected the fact that there had been material changes impacting the IRP/CEP analysis since the documents were filed in May 2023. These changes rendered moot most of the IRP's Action Plan and Preferred Portfolio. The changes also undermined PacifiCorp's CEP and plan to meet the HB 2021 targets. Of particular concern, PacifiCorp confirmed in response to an information request that the Company will not be able to procure the clean energy additions included in the Preferred Portfolio through 2028 given the suspension of the 2022 All-Source RFP.[9]

In PacifiCorp's December 2023 LC 82 Round 1 reply comments, PacifiCorp made it plain that changes would not be made to the 2023 IRP/CEP, despite Staff and stakeholders' requests. Instead, the Company pointed toward the IRP Update – planned for April 2024 – for any revisions of the Company's now obsolete IRP analysis. PacifiCorp reinforced this position several information request responses.

As the 2023 IRP/CEP would not be revised to reflect major events – like the suspended acquisition of over 1 GW of renewable and storage capacity by 2027 – Staff and stakeholders lacked the shared analytic foundation from which most of the important acknowledgement determinations could be made. Given this threshold issue, Staff saw little value in continuing multiple rounds of comments on the plan as filed. Staff's Round 2 comments included proposed <u>*final*</u> recommendations, rather than <u>*draft*</u> recommendations, and a request to shorten the procedural schedule and end LC 82 in February, rather than April.[10] A revised schedule consistent with Staff's request was adopted by the ALJ in a ruling on February 5, 2024.

Staff sees benefits to an abbreviated schedule, and non-acknowledgment as proposed by Staff followed by revision and resubmission of the CEP and additional actions for the IRP Update. The first, the Company's planned IRP Update will be filed in April 2024, presenting an opportunity to address these issues in a prompt and efficient manner. Second, by directing a revised and resubmitted CEP in mid-2024, the Commission can avoid an extensive delay in the acknowledgment of a CEP the Company to implement, given the looming emissions reductions targets in HB 2021, rather than stalling consideration of the CEP to 2025. Finally, the Commission could consider providing

[9] PacifiCorp response to OPUC Staff Information Request No. 243.

[10] LC 82, OPUC Staff Second Round Comments, January 24, 2024, pg. 4 and Staff procedural motion on January 30, 2024 to change the schedule.

direction to shape PacifiCorp's quickly moving small-scale renewable request for proposal (SSR RFP).

Staff's redacted Round 2 comments are included with this memo as Attachment A. The Round 2 comments provide more details to Staff's recommendations. The Round 2 comments also include more background information on the IRP itself and stakeholder comments than is contained in this memo. This public meeting memo includes no new analyses. It does, however, seek to reemphasize and clarify the positions taken by Staff in the Round 2 comments and address potential shortcomings in the SSR RFP currently under development.

Acknowledgement Recommendations for the IRP and CEP

Staff made thirteen acknowledgement recommendations in our Round 2 comments.[11] They spanned the IRP and CEP. Staff also listed over fifty expectations for the IRP Update or the 2025 IRP. These expectations amounted to issues that did not require Commissioner deliberation and would not require an order. Instead, Staff plans to work with PacifiCorp and stakeholders to meet these expectations.

The table below summarizes the recommendations from Staff's comments regarding the IRP.[12]

Table 1

	Acknowledge	Not Acknowledge
IRP	• Eleven Action Plan Items (1a, 1b, 1e, 1f, 3a-3c, 3e, 4a, 6a, 6b) • Load Forecast	• Nine Action Plan Items (1c, 1d, 1g, 1h, 2a – 2c, 3d, 5a) • Preferred Portfolio • Long-Term IRP/CEP Strategy

With regard to the CEP, Staff believes that the necessary changes to the Preferred Portfolio in the IRP Update will significantly impact PacifiCorp's Oregon-allocated GHG emissions and/or the allocation strategies needed for PacifiCorp to comply with HB 2021. Staff does not believe the CEP is consistent with the emissions reduction targets of HB 2021, given the present circumstances. Staff therefore recommends that PacifiCorp be directed to revise and resubmit the CEP so that the emission strategy and information on costs to Oregon ratepayers is consistent with the information in the IRP Update.

With regard to PacifiCorp's allocation approach to CEP compliance pathways, Staff stated previously that we find the approach of testing hypothetical allocations to be a reasonable approach to forecasting future Oregon-allocated emissions in years beyond

[11] LC 82, OPUC Staff Second Round Comments, January 24, 2024, Appendix A, pgs. 55-56.
[12] *Id.*, pg. 4.

the current allocation agreement. It would, however, generate more insight if PacifiCorp tested more options and was more transparent about those options and their tradeoffs. Additionally, Staff is clear in our Round 2 comments that the Company is not expected to make significant revisions in community-focused areas of the CEP as part of a revised filing; only the CEP Compliance pathways and demonstration of continual progress on emission reductions. With that said, Staff did include four CEP, community-focused recommendations:

> **Staff Recommendation 5.** Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.
>
> **Staff Recommendation 6.** Direct PacifiCorp to provide baseline metrics prior to filing its next IRP/CEP Update. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.
>
> **Staff Recommendation 7.** Direct PacifiCorp to proceed with the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG in Q1 2024.
>
> **Staff Recommendation 8.** Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.

Beyond these recommendations, to the extent that the CEP's community-based activities or strategies have changed since it was filed in May 2023, the Company should provide new information in the revised CEP filing. Otherwise, Staff expects PacifiCorp to leverage the CBIAG and 2025 IRP process to continue to improve the community-based elements of the CEP.

Minimum Changes Sought by Staff in the IRP Update and Revised CEP
Staff's Round 2 comments identified four analytic threshold issues that would need to be addressed in the IRP Update and reflected in the revised and resubmitted CEP for

Staff to consider recommending acknowledgment of the revised and resubmitted CEP.[13] These were in addition to the thirteen acknowledgement recommendations.

1. Align the updated Preferred Portfolio and Action Plan with PacifiCorp's updated plans in light of key developments since the filing of the IRP, including the suspension of the 2022 AS RFP and the stay of the Ozone Transport Rule.
2. Include Oregon's Small Scale Renewable requirement in the updated Preferred Portfolio.
3. Confirm that the updated Preferred Portfolio can support simultaneous compliance with the clean energy requirements and GHG targets in Oregon, Washington, and California.
4. Fix any confirmed analytical errors identified in this docket, including any errors in the calculation or application of granularity adjustments.

On January 31, 2024, PacifiCorp released a draft of the IRP Update. This draft outlined eight areas that PacifiCorp planned to revise with new information in the IRP Update. They are:

- System coincident peak load forecast,
- Natural gas and power market price updates,
- Stay of the ozone transport rule,
- Suspension of the 2022 all-source RFP,
- Natural gas generation and the use of either green hydrogen or green ammonia,
- Preference for peaking type resources,
- Demand-side management,
- Front office transactions,
- Contracted resources, and
- Transmission option updates.

It appears that PacifiCorp plans to update the Preferred Portfolio and Action Plan in the IRP Update, though these updates were not completed and included in the draft document. PacifiCorp makes no mention of Staff's other three recommendations. Further, the draft IRP Update outline included no mention of seeking acknowledgement of a revised Preferred Portfolio and Action Plan as part of the IRP Update. All of these things are crucial.

If Staff's additional analyses are not addressed as part of the April 2024 IRP Update, Staff is concerned that the basis from which to assess the acknowledgability of a revised and resubmitted CEP will be compromised and more time wasted. Thus, Staff

[13] *Id.,* pg. 3.

requests that the Commission order PacifiCorp to conduct Staff's recommended analyses within the IRP Update, in addition to all thirteen recommendations from Staff's Round 2 comments.

Timing of Resubmission of Revised CEP

Due to the circumstances surrounding this IRP and CEP, Staff finds that PacifiCorp should seek to resubmit its revised CEP with the IRP update. However, given that April is less than two months away, Staff is open to PacifiCorp filing a request in its reply comments for an extended CEP filing date of four to eight weeks.[14] Regardless of the timing, Staff plans to work quickly to review the CEP once it is filed.

SSR RFP

The 2023 IRP/CEP forecasted a need of approximately 490 MW of new, renewable capacity – all less than 20 MW in size – to meet HB 2021's 2030 SSR requirement. Because the Company believes acquiring this volume and type of capacity by 2030 may be difficult, PacifiCorp plans to move rapidly. On January 24, 2024, PacifiCorp held a bidders workshop for its SSR RFP. The workshop outlined the Company's initial approach to acquiring the SSR resources necessary to meet a key component of HB 2021. Per the bidders conference presentation, the RFP will be finalized and issued by March 29, 2024. Staff appreciates the Company's sense of urgency on this topic.

However, Staff is concerned about the strategic choices made by PacifiCorp in designing this RFP. First, the timing was such that the bidders conference was the same day as Staff's comments were due. Staff did include two SSR RFP recommendations that were not part of the RFP. They were:

> **Staff Recommendation 5.** Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.
>
> **Staff Recommendation 9.** The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and the CBRE Pilot be designed to promote resiliency-related factors.

Should the Commission choose to accept Staff recommendation we would hope to see the SSR RFP be updated accordingly.

[14] OAR 860-027-0400(9)(c).

Beyond this, the Company also appears to be establishing RFP parameters that limits the pool of potential resources, drives up SSR project costs borne by Oregon ratepayers, and/or limits insights into the community benefits of projects. Specifically:

- The RFP bars energy storage from being paired with eligible renewable systems.
- No RFP mechanism like non-price scoring or sensitivities to identify, track, and/or allow for project selection that accounts for community benefits.
- Premium peak hour pricing, like what was approved for Oregon PURPA projects, is not allowed. Only flat pricing and on-peak/off-peak.
- Requiring ODOE RPS certification, which includes WREGIS certification and metering.
- Requiring CAISO EIM visibility and dispatchability.

Staff has included two attachments associated with the SSR RFP. Attachment B is the bidders conference presentation and Attachment C Staff's response.

Time permitting at the Public Meeting, Staff suggests that it may be productive to discuss with PacifiCorp their SSR acquisition strategy. The SSR RFP represents one of the first actions by PacifiCorp to meet the HB 2021 targets. As such, a better understanding of PacifiCorp's strategy and approach to SSR acquisition could help all parties learn more about balancing tradeoffs around the economic and technical feasibility of HB 2021 actions.

PROPOSED COMMISSION MOTION:

Acknowledge in part and not acknowledge in part PacifiCorp's (Company) 2023 Integrated Resource Plan (IRP), subject to the condition that the Company implements Staff's recommended conditions, including four recommended IRP analyses as part of the IRP Update. Decline to acknowledge the Clean Energy Plan (CEP) filed with the 2023 IRP. Direct the Company to revise and resubmit certain elements of the IRP, and to revise and resubmit the CEP, by the next IRP Update in April 2024, consistent with Staff's recommendations.

LC 82

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

Docket No. LC 82

In the Matter of PACIFICORP, dba PACIFIC POWER, 2023 Integrated Resource Plan.	OPUC STAFF ROUND 2 COMMENTS AND RECOMMENDATIONS

Table of Contents

Executive Summary

In this second round of comments on the PacifiCorp (PAC or Company) Integrated Resource Plan (IRP) and Clean Energy Plan (CEP), the Oregon Public Utilities Commission (OPUC) Staff puts forth draft recommendations for acknowledgment and future expectations. Our recommendations and expectations cover this IRP, the planned IRP Update (April 2024), and the next IRP (April 2025). As detailed below – and throughout this document – Staff also puts forth a plan and rationale to revise the current IRP/CEP process to enable the Commission to consider the significant changes to the Preferred Portfolio and Action Plan that PacifiCorp plans to include in the IRP Update to be filed in April 2024.

Staff finds the 2023 IRP was an insightful first attempt at putting forth a comprehensive resource plan to meet HB 2021's decarbonization targets and community benefit goals while accomplishing traditional IRP analysis. PacifiCorp staff conducted more complex modeling than in any previous IRP and demonstrated a commendable level of engagement and candor with Staff and stakeholders. However, Staff has determined that a change of course in this IRP is necessary. This is spurred by two developments.

First, events outside the LC 82 process profoundly changed the relationship between this IRP/CEP's conclusions, action plan, and the market and policy realities faced by PacifiCorp. The two most notable of these events were the judgment against PacifiCorp in the wildfire lawsuits in August 2023 and the Tenth Circuit Court of Appeals' stay of the Ozone Transport Rule in July 2023. The combination of these two events, along with other events, led PacifiCorp to suspend its 2022 AS RFP in September 2023. As noted by many stakeholders in the first round of comments, the RFP suspension, which removed approximately 1.5 GW of new, non-emitting capacity by 2027 from the Preferred Portfolio, cast into doubt several important elements of the IRP/CEP. These included the Preferred Portfolio itself, many action plan items, and any understanding of the potential of forecasted emissions reductions to achieve CEP compliance. In short, the IRP/CEP map no longer matches the territory of operational and market realities. Thus, Staff and stakeholders argued in the first round of comments that additional analysis within this IRP/CEP was necessary in order for several elements to be acknowledged. Independent of these outside events, Staff and stakeholders also noted in Round 1 comments the need for improvements to the IRP/CEP to consider acknowledgement. These included:

- Including Oregon's Small Scale Renewable (SSR) requirement in the Preferred Portfolio in 2030 to capture the portfolio benefits of SSRs.
- Adding more energy efficiency (EE) in Oregon to reflect the higher value that EE brings to Oregon in the context of HB 2021.
- Utilizing more reasonable resource cost estimates.
- Addressing any identified errors with the granularity adjustments that PacifiCorp applied within its PLEXOS modeling.
- Analyzing the sufficiency of the Preferred Portfolio to enable simultaneous compliance with clean energy and GHG policies in Oregon, Washington, and California.
- Reoptimizing select portfolios for a clearer understanding of portfolio NPVRR and the ability to compare actions.

- Articulating more clearly the Oregon implication of coal-to-gas conversions vis-à-vis emissions, decarbonization efforts, and future MSP allocations.

While PacifiCorp has signaled an openness to eventually considering the improvements listed above, the Company was also clear that it would not conduct additional analysis to revise its filed IRP/CEP.[1] The Company has pushed all additional analysis or changes to this IRP/CEP to either the IRP Update or the next IRP.

While it would be unwieldy to constantly revise a filed IRP/CEP, additional analysis has been done in the past when staff or stakeholders indicate they cannot support acknowledgement without material revisions. Conducting additional analysis within the IRP/CEP timeframe to adjust to large-scale and material events impacting the Preferred Portfolio – or in response to stakeholder insights and requests – is reasonable. The IRP process is designed for rounds of comments to consider, discuss, and debate changes to achieve acknowledgement. Accordingly, the IRP/CEP is deemed reasonable to acknowledge at the end of the process, not upon filing.

Because PacifiCorp will not voluntarily make changes to this IRP/CEP, some of the most important issues before us lack a shared analytic foundation from which an acknowledgement determination can be made. As such, Staff does not see a path to recommending acknowledgment of PacifiCorp's current IRP/CEP. At the same time, Staff is concerned that non-acknowledgement and reconsideration at an undetermined future date could delay important activities that the Company must or should undertake to comply with HB 2021. Time is limited for the utility to adopt a CEP that can be acknowledged and successfully implemented before the first emissions reduction target in 2030. Given this tension and the indications from PacifiCorp that there will be significant changes to the Preferred Portfolio and Action Plan in the IRP Update to be filed in April 2024, Staff recommends that the schedule be updated to allow the Commission to consider the information in the forthcoming IRP Update. Staff also recommends that PacifiCorp be directed to address, within the IRP Update, a limited number of threshold issues that have been raised within this docket.

Specifically, Staff recommends that PacifiCorp be directed to, at a minimum:

- Align the updated Preferred Portfolio and Action Plan with PacifiCorp's updated plans in light of key developments since the filing of the IRP, including the suspension of the 2022 AS RFP and the stay of the Ozone Transport Rule.
- Include Oregon's Small Scale Renewable requirement in the updated Preferred Portfolio.
- Confirm that the updated Preferred Portfolio can support simultaneous compliance with the clean energy requirements and GHG targets in Oregon, Washington, and California.
- Fix any confirmed analytical errors identified in this docket, including any errors in the calculation or application of granularity adjustments.

With regard to the CEP, Staff believes that the changes to the Preferred Portfolio in the IRP Update may significantly impact PacifiCorp's Oregon-allocated GHG emissions and/or the allocation strategies

[1] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 96. "Pertaining to the 2022 AS RFP, PacifiCorp has no revised plan or substantive updates available at this time and is actively working to incorporate a number of updated assumptions as part of portfolio development for its 2023 IRP Update, anticipated to be filed April 1, 2024. The result will be comprehensive changes to the portfolio, and not just specific line items that could be modified in a few figures in the filed 2023 IRP."

needed for PacifiCorp to comply with HB 2021. Staff therefore recommends that PacifiCorp be directed to revise and resubmit the CEP so that the emission strategy and information on costs to Oregon ratepayers is consistent with the information in the IRP Update.

Staff also describes in these comments a number of issues regarding PacifiCorp's efforts to incorporate community impacts into planning decisions and presents a number of expectations regarding community engagement, community benefit indicators (CBIs), community-based renewable energy (CBREs), and resiliency. Staff views PacifiCorp's efforts on these fronts as important first steps upon which to build in future planning cycles. Staff does not expect the Company would make significant revisions in these areas prior to filing a revised CEP, but does expect the Company would update information in a revised CEP filing to the extent that their plans have changed.

To accommodate the timing of PacifiCorp's planned IRP Update filing, Staff proposes that the Commission take up these recommendations at the February 20, 2024, Public Meeting. This will allow Staff and stakeholders to focus the remaining efforts for this IRP/CEP on reviewing the April 2024 IRP Update and a revised and resubmitted CEP. Staff believes a revised CEP should be submitted with the IRP Update.

The table below summarizes those IRP items that Staff plans to recommend and not recommend for acknowledgement in LC 82:

Table 1: IRP Elements Recommended for Acknowledgement

	Acknowledge	Not Acknowledge
IRP	Eleven Action Plan Items (1a, 1b, 1e, 1f, 3a-3c, 3e, 4a, 6a, 6b) Load Forecast	Nine Action Plan Items (1c, 1d, 1g, 1h, 2a – 2c, 3d, 5a) Preferred Portfolio Long-Term IRP/CEP Strategy

Finally, Staff is incredibly grateful to the following stakeholders for their work in LC 82: Alliance of Western Energy Consumers (AWEC); Community Advocates; Columbia River Inter-Tribal Fish Commission (CRITFC); Oregon Citizens' Utility Board (CUB); Energy Advocates; Fervo; NewSun Energy LLC (NewSun); Renewable Northwest (RNW); Sierra Club; and Swan Lake and FFP Project 101. The comments and overall engagement throughout this IRP have deepened Staff's understanding of the issues surrounding HB 2021. They have also improved this IRP/CEP and future filings by PacifiCorp as they chart a pathway to a reliable, affordable, equitable and decarbonized system.

Key Challenges & Vulnerabilities

In Round 1 comments, Staff identified key challenges and key vulnerabilities to LC 82. The challenges represented issues within IRP and CEP that would require more explanation of the near-term resource strategy and general implementation. Staff's identified vulnerabilities represented more critical issues that called into question the ability to acknowledge a particular aspect of LC 82. While all of the identified topics from Round 1 are covered in these comments, we revisit the most pressing or unresolved items below.

Composition and Costs of Small-Scale Renewables and Community-Based Renewable Energy (Challenge)

In Reply comments, PacifiCorp addressed questions around costs and composition of SSRs. While the Company reasserted that SSRs remain uneconomic, the Company is clearly committed to trying to meet the 2030 SSR target in HB 2021.[2] Staff appreciates PacifiCorp's approach of letting the RFP run its course and then pivot to other methods of acquiring SSRs based on the RFP results.[3] Staff also appreciates PacifiCorp's thorough response on the potential barriers in Oregon rule to SSR procurement.[4] The Company's four suggestions provide a solid basis for fruitful public dialogue. Staff will not address each of the Company's suggestions in its comments, but would be open to participating or leading an informal public discussion on PacifiCorp's suggestions.

Both Staff and the Company see some overlap between CBRE and SSR projects.[5] However, PacifiCorp has modeled CBRE Projects and SSR projects separately, most notably with CBRE projects having a higher cost per MWh. PacifiCorp plans to acquire CBRE projects through a grant pilot program rather than an RFP.[6]

Staff would note the initial SSR RFP filing limits the range of projects from 3 MW to 20 MW. We think the bound at the low-end of the range may unnecessarily exclude potential CBRE projects that are smaller in nature. Staff will work to expand this range in the SSR RFP so that it can potentially capture these projects and establish two channels for acquiring this resource.

State Policy Compliance in IRP Portfolios (Vulnerability)

In Round 1 Comments, Staff raised a central concern to PacifiCorp's CEP compliance allocation methodology: would the Preferred Portfolio contain a sufficient amount of non-emitting resources in 2030 to simultaneously comply with the clean energy and GHG policies of Oregon, Washington, and California? Staff is concerned that if PacifiCorp continues to evaluate compliance with each state-level policy in separate analyses outside of the IRP, resources could be erroneously double-counted toward policy compliance in multiple states.

Staff requested that PacifiCorp demonstrate in this IRP that the Preferred Portfolio could simultaneously comply with clean energy and GHG policies in Oregon, Washington, and California and that, in future IRPs, the Company to constrain the Preferred Portfolio to ensure that simultaneous policy compliance is feasible.

PacifiCorp's Response Comments noted that, "there is no feasible single-pass modeling solution that guarantees Oregon compliance while simultaneously meeting all other portfolio requirements."[7] PacifiCorp also suggested that Staff's request to demonstrate simultaneous compliance of state-level policies would not be possible due to limitations of PLEXOS and the fact that resource allocations have not yet been determined.[8]

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[2] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 53.
[3] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 52.
[4] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 85.
[5] LC 82, PacifiCorp Clean Energy Plan, May 31, 2023, page 36.
[6] LC 82, PacifiCorp Clean Energy Plan, May 31, 2023, page 54.
[7] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 24.
[8] *Ibid*.

Yet elsewhere in PacifiCorp comments, the Company expresses openness to developing a more "unified" portfolio that integrates systemwide and state-level constraints.[9]

From Staff's perspective, ensuring that PacifiCorp can simultaneously comply with all state-level policies to which it is bound should be foundational to the Company's IRP process. Staff appreciates PacifiCorp's concern that a "single pass" modeling solution to this problem may not be available through the PLEXOS model. However, this limitation does not prevent PacifiCorp from demonstrating that simultaneous state-level policy compliance is feasible or ensuring that portfolios meet this requirement. PacifiCorp already uses multiple modeling passes to make adjustments to portfolios to respect other complicated constraints (e.g. the reliability and granularity adjustments). PacifiCorp could similarly adopt an iterative process within the IRP in the event that a portfolio was found not to comply with one or more state-level policies simultaneously.

Staff also appreciates PacifiCorp's concern that evaluating state-level policy compliance may require the Company to make assumptions regarding future allocation. However, Staff does not see this as an impediment to testing the <u>feasibility</u> of simultaneous policy compliance. PacifiCorp could, for example, demonstrate that there is <u>some</u> feasible allocation (i.e. all allocation factors fall between 0 and 1 and sum to 1) that achieves simultaneous policy compliance, without adopting that allocation strategy. Such an exercise could be used to test the limitations of what can be achieved through allocation and to identify if there are high-level constraints that could inform allocation discussions in MSP.

Because PacifiCorp would not or could not conduct this analysis – and given its centrality to the IRP and CEP – Staff conducted a high level and approximate exercise to make a "back of the envelope" determination of the non-emitting sufficiency of the Preferred Portfolio in 2030. Staff's simple analysis, which was based on public information from PacifiCorp's IRP and CEP workpapers, identified multiple energy allocation strategies for the Preferred Portfolio that would likely result in simultaneous policy compliance in Oregon, Washington, and California in 2030.

Further, the policy-feasible allocations that Staff tested also resulted in the majority of the load in Idaho, Utah, and Wyoming being met with non-emitting generation by 2030 under the Preferred Portfolio.

Staff's findings are in fact consistent with PacifiCorp's assertion that the proposed renewable additions originally proposed in this IRP are primarily being driven by economics, rather than policy compliance. Staff's analysis also bolstered Staff's view that it is reasonable for PacifiCorp to incorporate this type of analysis into future IRPs and IRP Updates.

Staff Expectations:

- In the next IRP, PacifiCorp should demonstrate that simultaneous compliance with all state-level policies is feasible with the Preferred Portfolio and with the Preferred Portfolio variants tested in the IRP.
- In the next CEP, PacifiCorp should transparently explore and describe constraints that HB 2021 compliance potentially places on allocation.

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[9] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 54.

CEP Compliance Pathways (Vulnerability)

Staff finds that considering the effect of allocation pathways in the CEP on HB 2021 compliance is an acceptable, flexible approach to beginning a conversation about HB 2021 compliance that reflects how DEQ conducts annual emissions compliance evaluation. However, Staff also recognizes that it represents a complete departure from the allocation methodology approved in the 2020 MSP. Staff agrees with CUB that this was done with limited discussion outside of MSP. CUB observed that, beyond comparing compliance costs across portfolios, PacifiCorp's approach to developing CEP pathways – along with changes in coal retirements and this IRP's quick pivot to coal-to-gas conversions – represent a fundamental break from the approach of the 2020 Multi-State Protocol (MSP) with no transparent discussion or analytic demonstration of how these changes to the allocation methodology are in the best interest of Oregon.[10] Further, AWEC speculated that PacifiCorp's proposed pathways most likely exceeded HB 2021's incremental cost cap, that neither pathway can be enforced or guaranteed, and that because both pathways do not reflect the current MSP allocation they should be prohibited.[11] Both RNW and the Energy Advocates generally objected to PacifiCorp's approach as just an allocation exercise with no meaningful emission reductions and little chance of being accomplished within the MSP framework.

The Company's response points out that CEP pathways are compliant with the 2020 MSP prior to its expiration at the end of 2024, and that no MSP has been agreed upon for the time period after 2024 when most CEP cost will be incurred. Further, PacifiCorp counters CUB that the CEP does include cost analysis. The CEP pathways also represent issues to be considered in the current MSP negotiations, not actual positions that must be taken. To this end, PacifiCorp notes that the pathways were not the primary means to achieve CEP compliance. Rather, the IRP's proposed system-wide, Preferred Portfolio would in fact achieve 98 percent of the Oregon CEP emission reduction targets by 2030.[12] Finally, PacifiCorp argues for a narrow interpretation of HB 2021's cost cap that should be applied once costs are incurred and to conduct such an analysis in a rate case.[13]

Staff agrees with PacifiCorp that the expiration of the 2020 MSP provides a level of flexibility in proposing CEP compliance pathways. Yet the analysis in this CEP – while instructive and insightful –falls short of providing actionable insights *and* a forum to discuss the tradeoffs for Oregonians around MSP allocation methodologies capable of meeting HB 2021's goals. In this sense Staff agrees with CUB: by limiting the CEP pathways to only "illustrate" what could eventually occur in MSP, the IRP/CEP falls short of providing an actionable "plan" around which to debate the costs and risks of various CEP Compliance Pathways. Finally, Staff agrees with the Company's assertion that UM 2273 will be the best place to address policy issues around HB 2021's cost cap, not this IRP/CEP.

Staff Expectations:

- PacifiCorp should utilize its 2025 IRP public input workshops to clarify with stakeholders the relationship between MSP, IRP "actions," Oregon's CEP requirements, and Oregon's DEQ compliance methodology and explore improvements such that HB 2021 targets and activities are informative to and reflected in MSP decisions. As part of this process, changes to MSP disclosure rules should be explored to increase transparency.

[10] LC 82, CUB Round 1 Comments, October 25, 2023, page 5.
[11] LC 82, AWEC Round 1 Comments, October 25, 2023, page 3-5.
[12] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 23.
[13] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 26.

- To improve an understanding of tradeoffs in the IRP Update and/or as part of the revised CE, the Company should report Oregon-allocated costs and GHG emissions for the top performing IRP portfolios (inclusive of Oregon's SSR requirement) under various allocation pathways and that PacifiCorp.

Coal-to-Gas Conversions (Vulnerability)

In Opening Comments (Round 1), Staff recognized that PacifiCorp's 2023 IRP makes a significant departure from its 2021 IRP in its plans to retire coal-fired generation resources. Specifically, while the 2021 IRP only included gas conversions of Jim Bridger Units 1 and 2, the current plan adds Jim Bridger Units 3 and 4 and Naughton Units 1 and 2 to the list.

PacifiCorp's analysis shows that the conversions are selected by its optimization model based on economics. Staff appreciated this analysis and sought more information from the Company to better understand the cost and risks associated with these conversions for Oregon customers as well as the consistency of these actions with HB 2021 emissions reduction targets. Staff appreciates PacifiCorp's responses to some of the questions posed by Staff, however, expresses disappointment that the Company did not answer most of the questions posed by Staff.

In response to Staff's question regarding the prominence of gas conversions in this plan compared to the 2021 IRP, PacifiCorp explains that the previously realized benefits from Bridger 1 and 2 conversions in the 2021 IRP portfolio analysis prompted the Company to explore this option for the other coal plants, and the conversions were endogenously selected within its optimization model. The Company also points out that gas conversions identified in the 2021 and 2023 IRP are a better outcome compared to a new gas plant selected in its 2019 IRP. Further, the Ozone Transport Rule limiting nitrous oxide emissions also favors gas conversions over coal. PacifiCorp also sees benefits in using the converted plants as a backup resource to be used in "limited circumstances" as it integrates clean energy resources into its system. The delay in the Natrium demonstration project has further necessitated the conversion of the Naughton Units 1 and 2.

PacifiCorp did not provide explanations in its Reply Comments to Staff's other requests in which Staff sought to understand if the Company has evaluated the risks of these converted units becoming stranded assets, or what factors could alter the decisions around future coal plant retirement and conversions. Staff had also asked for an analysis with a portfolio variant that does not allow any conversion beyond Jim Bridger 1 and 2, and to test this variant across various gas and CO_2 price options. Staff expected PacifiCorp to either include this portfolio in its CEP alongside other high-performing portfolio variants or introduce constraints related to HB 2021 in its IRP analysis. PacifiCorp indicated that more detailed analysis around coal retirement and conversion options will be provided in its 2023 IRP Update due to be filed in April 2023. Staff looks forward to receiving the updated analysis and expects PacifiCorp to include a detailed analysis of risk of regrets, potential changes in future retirement and conversion plan and the portfolio variant that Staff suggested.

CUB pointed out that coal to gas conversions nullify the agreement reached in the 2020 Multi-State Protocol regarding Oregon's exit from these coal plants, which was key to the determination of the 2020 MSP agreement. CUB had also expressed concerns with the implications of coal to gas conversion for decommissioning and cost allocation to Oregon customers. PAC is inclined to address MSP issues in the MSP process. PacifiCorp indicated that the main component of gas conversion costs is the cost of natural gas pipeline transport and therefore there is no significant impact on depreciation and decommissioning costs.

Energy Advocates commented that coal to gas conversion is not shown to be least cost least risk in the presence of HB 2021. PacifiCorp indicated that they provided economic analysis showing system benefits from conversion of all Bridger units and Naughton units (in both 2021 (JB1 and 2) and 2023 IRPs). Conversion should be consistent with HB 2021, since these plants would have lower emissions compared to before and will be operated with low-capacity factor but meet peak and reliability needs. In response to Energy Advocates' comments on whether the benefits from these conversions and costs will only be limited to Oregon customers, PacifiCorp replied that these plants will retire in 2037, before HB 2021's 2040 timeline, hence Oregon is not the only one sharing costs. Moreover, conversion costs are much lower than cost of new renewables.

Sierra Club had expressed concern around availability of firm gas capacity for the converted units. PacifiCorp did not disclose the pipeline information in its Reply Comments due to confidentiality agreements with third parties.

Staff believes that the Company's decision to continue to operate coal generation units as natural gas plants must be evaluated in the light of HB 2021. Staff understands that inter-state protocol and cost allocation concerns raised by CUB are vital and expects the Company to respond to those in the appropriate docket. Further, Staff understands that the conversions of Jim Bridger 1 and 2 was acknowledged in the 2021 IRP and the conversion plan for Naughton 1 and 2 is also well under way, and therefore these items are not appropriate action items for acknowledgement in this IRP.[14]

Staff Expectations:

- PacifiCorp should provide analysis around risk of regret for coal to gas conversions in its 2023 IRP Update.
- PacifiCorp remove Action Items 1c and 1d from the Action Plan because the Company has already taken these actions.

RFP Suspension

As previously noted in Staff's Round 1 comments, PacifiCorp recently suspended its 2022 All Source Request for Proposals (2022 AS RFP), which sought bids from resources capable of coming online by the end of 2026. The suspension raises concerns around the Company's ability to execute certain Action Plan items in the 2023 IRP and procure sufficient near-term resources to meet Oregon's HB 2021. RNW's Round 1 comment similarly noted the risk from this suspension and encouraged PacifiCorp to resume the RFP as soon possible or have the Commission to direct the Company to do so.[15]

PacifiCorp's Round 1 Response Comments did not provide much information to assuage 2022 AS RFP suspension concerns. The Company failed to address many of the questions raised by Staff and stakeholders. Despite stating previously in LC 82 that the greatest risk to the IRP was under procurement of resources, the Company now stated that it did not have any revised plan or substantive updates available that reflected the impacts of the RFP suspension.[16] However, the Company did state that it had

[14] PacifiCorp Response to Staff DR Nos. 222 and 223.
[15] LC 82, Renewable Northwest, Round 1 Comments, October 25, 2023, page 7.
[16] LC 82, PacifiCorp Reply Comments, page 96.

engaged in a bilateral effort to procure battery storage technology by June 1, 2026, and that in the IRP Update a new RFP may be put forth.

Given that the Preferred Portfolio included 2,531 MW of wind, 6,383 MW of solar, and 6,411 MW of battery capacity on the system by 2028, the impact of suspending a near-term RFP puts these builds at risk. In response to discovery, PacifiCorp confirmed that it is unable to procure the amount of wind and solar included in the Preferred Portfolio in years leading up to 2028.[17] Table 2 summarizes the difference in installed capacity between the Preferred Portfolio and the additions that may actually occur if PacifiCorp is unable to procure any additional new renewables, other than the bilateral storage mentioned above.

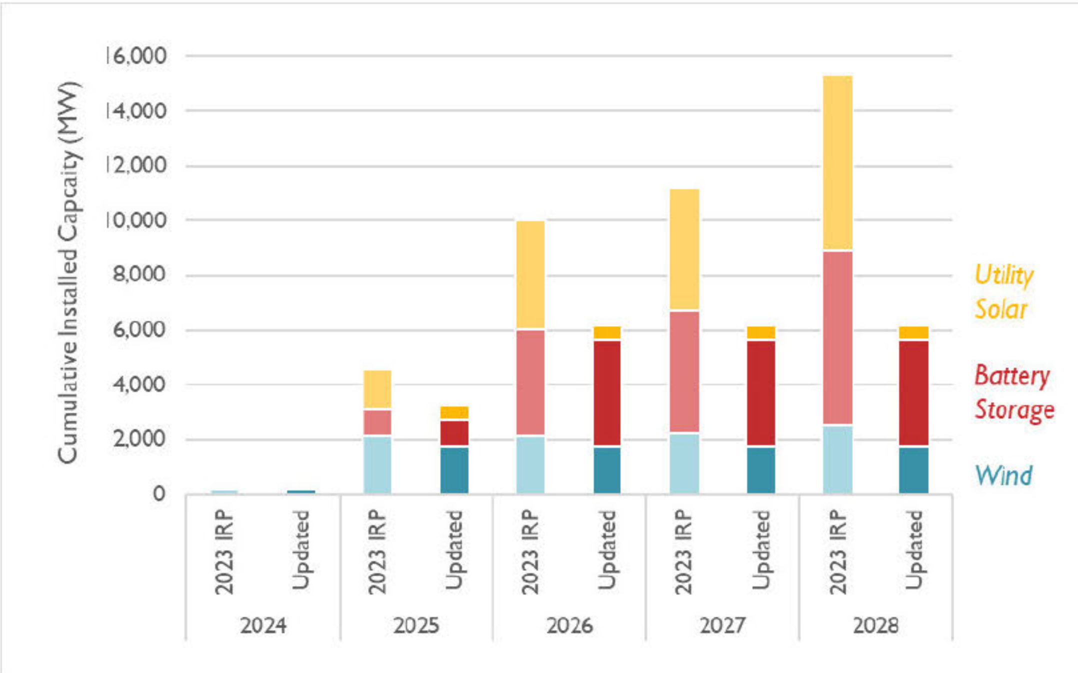
Table 2: Difference in Installed Capacity Between 2023 IRP Preferred Portfolio and Current Reality

Cumulative Installed Capacity Delta (MW)	2024	2025	2026	2027	2028
Renewable- Utility Solar	0	-974	-3,498	-3,981	-5,888
Renewable- Battery	0	0	0	-628	-2,528
Renewable- Wind	0	-339	-339	-439	-739
Total	**0**	**-1,313**	**-3,837**	**-5,048**	**-9,155**

The figure below demonstrates the impact that this delayed procurement could have on renewable resource builds over the next five years. The “2023 IRP” chart series on the left represents the data as presented in the Preferred Portfolio. The “Updated” chart series on the right represents capacity that PacifiCorp has currently indicated it can procure based on the 2020AS RFP and bilateral storage contracts. Solar is the resource that is most at risk due to the 2022AS RFP suspension, as the 2020AS RFP did not result in a large number of solar additions and PacifiCorp has not indicated any alternative procurement processes for solar.

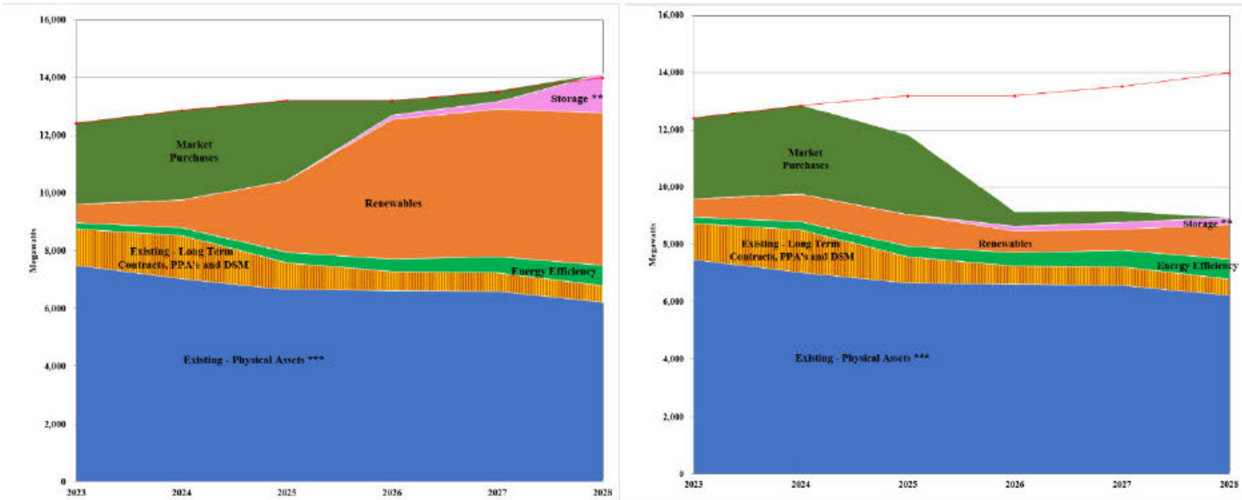
[17] PacifiCorp Response to Staff DR No. 243.

Figure 1. Difference in Installed Cumulative Capacity Between 2023 IRP Preferred Portfolio and Current Reality



This delay will also have a significant impact on the generation mix of the system. Figure 9.60 in the IRP shows the projected generation by resource type for the Preferred Portfolio. Over the next five years, PacifiCorp's Preferred Portfolio relied heavily on market purchases (also referred to as front office transactions or FOTs) and existing resources in the near-term while transitioning to rely more and more on new renewable resources. The left side of the figure below is a reproduction of Figure 9.60 as published in the IRP for years through 2028. The right side of the figure below demonstrates what the generation mix could look like if PacifiCorp does not procure new renewables and instead has a capacity mix that resembles the "Updated" chart series in Figure 9 above.

Figure 2. Reproduction of Figure 9.60 in IRP, with and without 2022AS RFP Suspension Impacts



Without the guarantee of additional solar, storage, and wind resources coming online over the next few years, PacifiCorp may end up relying more heavily on FOTs or delaying thermal resource retirements relative to the Preferred Portfolio. This could lead to decarbonization risks, which the Company has not adequately addressed in the current IRP.

As PacifiCorp will not remove the Action Plan items related to the 2022 <u>and</u> the proposed 2024 AS RFP from the filed IRP, nor update any analysis in this IRP/CEP to reflect the indefinite suspension of these procurements, the filed plans do not appear feasible. Staff finds little value in continuing to review this IRP/CEP. Too much is indeterminate and unknown. Further, as the CEP compliance pathways, and thus any determination of continual progress of emission reductions and compliance with the reduction targets, rests so squarely upon the IRP's Preferred Portfolio, without a revised analysis and procurement plan by PacifiCorp, Staff cannot determine the extent to which the CEP demonstrates compliance with the emissions reduction targets or can be substantiated to meet most if not all of the public interest factors detailed in HB 2021.[18]

Staff Recommendation 1. Do not acknowledge the IRP action plan elements 2b and 2c, the IRP's preferred portfolio, or the IRP's long-term plan.

Staff Recommendation 2. Direct PacifiCorp to seek acknowledgement of a revised Preferred Portfolio and Action Plan in the planned April 2024 IRP Update.

Staff Recommendation 3. Do not acknowledge the LC 82 CEP and direct PacifiCorp to revise and resubmit the CEP with its April 2024 IRP Update.

Action Plan Changes

PacifiCorp reply comments did not offer alternatives or revisions to the following Action Plan items that were impacted by events external to the IRP/CEP.

[18] See ORS 469A.420(2).

- Action Plan Item 1h: Per the non-confidential response to Sierra Club Information Request (IR) No. 37, the very near-term installation of the proposed selective, non-catalytic reduction (SNCR) installations at several coal plants is being paused and reevaluated due to the Federal Court stay of the Ozone Transport Rule.
- As noted previously all Action Plan Items Under Category 2 involve the acquisition of new resources either through the suspended 2022 AS RFP or through a proposed, new 2024 AS RFP. No alternatives or revisions to these activities were offered by the Company. Instead, PacifiCorp points to the potential for new procurements to be proposed with the April 2024 IRP Update.

Staff Recommendation 4. Do not acknowledge Action Plan items 1h and 2a.

CEP Comments

CEP acknowledgement hinges upon a finding that the CEP is, "in the public interest and consistent with the clean energy targets…" of HB 2021.[19] The recent order in UM 2273 provides an excellent overview of the public interest factors for valuating a CEP.[20] As noted above, given the Company's unwillingness to revise its analysis, Staff recommends not acknowledging the CEP. In the sections below, Staff details its determination that the community-focused elements of the LC 82 CEP appear reasonable with certain recommended changes, while the GHG emission reduction related portion of the CEP is not consistent with the clean energy targets nor does it appear to meet most if not all of the public interest factors detailed in HB 2021. For this reason, Staff does not recommend acknowledgement, but identifies portions of the CEP that may be included and/or improved in the revised and resubmitted CEP.

Community Benefits Indicators (CBI)

In Round 1 Comments Staff expressed concern that the interim CBIs provided no incremental information for evaluating the Company's IRP or CEP portfolios and did not materially affect its plans.[21] Staff requested that for the next IRP, the Company adopt CBIs representing the community impacts of energy efficiency, local non-GHG emissions from PacifiCorp facilities, and the Company's CBRE actions.[22]

The Energy Advocates recommend greater granularity for the Company's CBIs.[23] They also encourage the Company to include better measures of distributional justice when creating CBIs.[24] The Energy Advocates then state that the Company's CBIs do not offer any sense of how PacifiCorp brings economic benefits to communities,[25] a sentiment that is echoed by NewSun Energy.[26] The Community Advocates Cohort is discouraged by the lack of details in the Company's proposed CBIs and believes the Company's CO2 emissions CBI is not an indicator of community benefits.[27] Renewable Northwest (RNW) would like more detail about how the Company chose the 17 metrics that were included in the CEP.[28] RNW also recommends that the Company adopt additional environmental CBIs and believes that the language the Company uses when describing its resiliency CBIs expresses a hope instead of indicating that it is strongly committed to improvements or has any planned actions.[29] CRITFC supports past recommendations by the Energy Advocates to improve CBIs and wants better accounting for tribal needs in the Company's CEP.[30] In particular, CRITFC wants the CBI to incorporate tribal energy metrics and create metrics that target reducing peak loads, maximizing energy efficiency, strategically siting renewable resources, reducing reliance on Federal hydro resources, and minimizing the transmission and distribution system.[31]

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[19] ORS 469A.420(2).
[20] UM 2273, Investigation into HB 2021 Implementation Issues, Order No. 24-002, Jan. 5, 2024, starting on page 17.
[21] Staff's Round 1 Comments, page 19.
[22] Staff's Round 1 Comments, page 21.
[23] Energy Advocates' Round 1 Comments, page 7-8.
[24] Energy Advocates' Round 1 Comments, page 11.
[25] Energy Advocates' Round 1 Comments, page 12.
[26] NewSun Energy's Round 1 Comments, page 6.
[27] Community Advocates Cohort's Round 1 Comments.
[28] RNW's Round 1 Comments, page 65.
[29] RNW's Round 1 Comments, page 65.
[30] CRITFC's Round 1 Comments, page 4.
[31] CRITFC's Round 1 Comments, page 7.

PacifiCorp stated in Round 1 Response Comments that it intends its CBIs to be a holistic representation of all the Company's activities to increase community benefits and highlights that it has added two new draft CBIs through its stakeholder process.[32] The Company states that it intends to refine its approach to resiliency and that there is additional work necessary to develop its CBIs.[33] In response to Staff's suggestion to frame CBIs as a metric rather than a goal, the Company states that it would consider it, but anticipates that it may cause confusion.[34] The Company did not appear to directly respond to any other concerns raised by Staff or stakeholders regarding CBIs.

Staff finds that the Company failed to fully respond to Round 1 comments by both Staff and stakeholders. In particular, the Company failed to:

- Provide any timeline to refine CBIs or provide any detail about how they could be refined.
- Discuss how it is attempting to implement tribal concerns brought up by CRITFC or greater CBI granularity brought up by Energy Advocates and Staff into CBIs.
- Discuss whether or how it would incorporate additional environmental CBIs into its next CEP.
- Provide any explanation about how the 17 metrics were chosen, as requested by RNW.

Staff agrees with the Company that developing CBIs is an iterative process that should be done in consultation with local communities and tribal governments. Staff is worried by the Company's apparent lack of response to published concerns by stakeholders, lack of record keeping, and lack of target timeline to improve CBIs. Staff would note the importance of maximizing to the extent possible Oregon community benefits across such planning activities such as portfolio development[35] and resource selection.[36] As such, relying solely on measures of systemwide impacts provides very little value when evaluating whether the Company's IRP and CEP provide tangible benefits to Oregon communities. Staff's Round 1 comments to recommended that CBIs better addressing energy efficiency, local emissions, and CBRE impacts were meant to bridge this gap.

With the following draft recommendations and expectations, Staff recognizes that the CBIs in this CEP are interim, but also seeks to stress the importance of using CBIs to meaningfully inform utility decisions and to track progress over time. Staff expects that the further development of CBIs be done in coordination with local communities and tribal governments and describes additional recommendations and expectations regarding this coordination in the Community Engagement section.[37]

Staff believes that in order to have an effective set of CBIs, it is critical to provide baseline measures of community impact prior to the next IRP/CEP update, and to develop more CBIs that address local non-GHG emissions, energy efficiency, and CBRE actions.

Staff Recommendation 5. Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.

[32] LC 82, PacifiCorp Reply Comments, page 13.
[33] LC 82, PacifiCorp Reply Comments, page 16-17.
[34] LC 82, PacifiCorp Reply Comments, page 18.
[35] UM 2225, Order No. 23-060, February 23, 2023, Appendix A, page 5.
[36] UM 2273, Order No. 24-002, January 3, 2024, page 23.
[37] UM LC 80, Staff's Round 2 Comments, page 31.

Staff Recommendation 6. Direct PacifiCorp to provide baseline metrics prior to filing its next IRP/CEP Update. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.

Staff Expectations:
In the next IRP/CEP, Staff expects PacifiCorp to:

- Adopt CBIs representing the community impacts of energy efficiency, local non-GHG emissions from PacifiCorp facilities, and the Company's CBRE actions.
- Better inform CBIs and methods with input from stakeholders and community.
- Enhance tribal-focused CBIs.
- Use CBIs to better reflect the health impacts of EE.
- Provide portfolio analysis that allows more direct comparison of tradeoffs of different resource strategies e.g., more precisely capture the CBIs of portfolios.
- Enhance the ability of CBIs to better reflect the resiliency benefits of actions.
- Incorporate CBIs reflecting community-level impacts of non-GHG emissions, energy efficiency, and the Company's CBRE actions.

Community Based Renewable Energy (CBRE)

Staff found PacifiCorp's identified CBRE resources a reasonable starting point, but questioned whether more should be available based on a forecast of market activities not just existing programs. Staff also questioned whether net benefits were appropriately considered. Staff encouraged PacifiCorp to not limit CBRE potential to the activities and resources identified in the CEP and consider energy efficiency and flexible loads as potential valuable contributors. Lastly, Staff drew the connection between CBRE and SSR, and encouraged PacifiCorp to more aggressively pursue CBREs. Further, Staff encouraged PacifiCorp to pursue a CBRE strategy targeted at Oregon load pockets to avoid significant local transmission and distributions system upgrades.

RNW encouraged PacifiCorp to better quantify the benefits of CBRE and identify above market costs. Energy Advocates similarly encouraged PacifiCorp to consider broad benefits of CBRE, beyond a levelized cost of electricity analysis. RNW and Energy Advocates highlighted that PacifiCorp's CBRE potential relied on tallying existing programs which could be counted as CBRE. Both entities encouraged PacifiCorp to take initiative to identify additional CBRE resources. Energy Advocates highlighted that costs are likely inflated due to modeling not considering the IIJA and IRA. CUB raised government funding and questioned how funds may support CBRE development.

In response to Round 1 comments, PacifiCorp emphasized the Company's commitment to launching the CBRE Pilot proposal to external parties in the first quarter of 2024. The Company highlighted some of the ways in which the landscape of CBRE is quickly developing since the initial CEP filing. Of note, PacifiCorp anticipates a larger CBRE potential in Group B, siting 20 new projects in the pipeline. Initially, Group B included 3.5 MW of small-scale and community-focused renewable projects, primarily solar plus storage.

PacifiCorp commented on features of the Company's modeling that were raised by Staff and stakeholders. PacifiCorp clarified that the 10 percent adder was used to treat CBRE resources commensurately with energy efficiency. For the CBRE scenario, PacifiCorp clarified that the Company had to force the model to acquire CBRE resources as the model would not have otherwise done so for cost reasons. Finally, PacifiCorp emphasized the dynamic nature of the planning environment for CBRE and committed to ongoing refinement of CBRE Pilot Approach. In particular, the Company resolved to support projects that are "in-flight" via other co-funding mechanisms and programs. PacifiCorp contends that despite commitment to ongoing improvement, costs were not inflated in this first round of analysis even though large federal legislation, namely the Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA), were not included in initial analysis.

CBRE Resource Potential
Staff recommends that PacifiCorp consider more ambitious CBRE potential than the 95 MW identified, including 92 MW of which are in existing programs. The initial potential study tallied pending projects, and did not rely on forecasting sophistication of consumer adoption curves, historical cost declines, or enabling funding and programs. Staff appreciates PacifiCorp's acknowledgement that the 3.5 MW, Group B, potential is likely much greater due to new funding and programs. Due to rapid increases in renewable energy acquisition, Staff finds that 95 MW could significantly undercount the CBRE potential if effective program designs are deployed that recognize the benefits of CBRE, especially in the preferred portfolio.

Due to the magnitude of the 490 MW SSR requirement and the potential of CBRE resources to grow, Staff would like PacifiCorp to take a more aggressive approach than the "measured and incremental approach to investigating CBREs".[38] Staff encourages a sense of urgency and recommends PacifiCorp immediately publish the CBRE Grant Pilot Proposal to the CBIAG. Feedback should be solicited and processed quickly, such that PacifiCorp files the first round of the CBRE Grant Pilot for Staff approval by the end of Q2 2024. A quick feedback cycle is essential such that PacifiCorp may consider amending its CBRE potential based on feedback and results of an initial CBRE Grant Pilot.

Staff Recommendation 7. Direct PacifiCorp to pursue the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG in Q1 2024.

CBRE Activities
In the upcoming 2024 CEP update, Staff recommends PacifiCorp include an acquisition target of CBRE in its Action Plan. PacifiCorp's Round 1 comments identified a growing pool of known CBRE resources suggesting that 95 MW is likely a floor for a 2030 acquisition goal.[39] Many of PacifiCorp's CBRE actions are positive steps, but the current Action Plan, with no firm acquisition target, falls short of Staff's expectations. Staff appreciates that PacifiCorp continues to develop the CBRE Grant Pilot with stakeholders and is prioritizing "in-flight projects", such that the Company can accelerate how quickly those come online. Further, Staff expects PacifiCorp to be proactive beyond publishing a CBRE Grant Pilot. PacifiCorp should report regularly to the CBIAG on development activities, including on concrete actions PacifiCorp takes to reduce barriers, accelerate deployment, and expand CBRE potential.

Staff Expectation:
- Report regularly to the CBIAG on development including concrete and proactive activities PacifiCorp takes to reduce barriers, accelerate deployment, and expand CBRE potential.

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[38] LC 82, PacifiCorp Reply Comments, page 4.
[39] LC 82, PacifiCorp Reply Comments, page 92.

CBRE Inclusion in Preferred Portfolio

In Portland General Electric's (PGE) 2023 IRP/CEP, PGE clearly communicated the fixed cost minus the benefit streams of CBRE resources. PGE's modeling selected the entire 155 MW of CBRE potential for the resource's value within the balancing authority.[40] Acknowledging that PGE and PacifiCorp have different geographic and resource characteristics, PacifiCorp's load pockets are an example where prioritization for CBRE resources would maximize benefits to both individual communities and to all ratepayers.

Staff disagrees with PacifiCorp's blanket characterization that a commitment to pursuing CBRE resources would break from historical least-cost, least-risk paradigm. Much of the CBRE resources identified have complementary, non-ratepayer sources of funding to reduce costs and avoid separate SSR procurement. As PacifiCorp acknowledged, the IRA and IIJA incentives were not accounted for in CBRE analysis which both reduces the potential and inflates the cost. Further, as was raised by Energy Advocates and RNW, PacifiCorp did not provide a transparent accounting of the benefits of CBRE resources to the system, particularly with respect to investments that can be avoided as a result. Without this clear articulation of value and despite PacifiCorp's claims of "considerable favor to SSRs" in PLEXOS modeling, Staff is not persuaded that all CBRE resources are as uneconomic as the Company portrays.[41]

Also undermining PacifiCorp's argument that pursuing CBRE breaks from the least-cost, least-risk paradigm is the fact that the Company's potential study found 92 MW of CBRE in existing programs. Proper cost consideration should have included these resources in the IRP preferred portfolio. Staff expects PacifiCorp to include these CBRE resources in the 2024 IRP update preferred portfolio and to update the CBRE potential in the 2024 CEP update.

Staff requested PacifiCorp address CBRE's role in minimizing costs in Oregon's load pockets.[42] PacifiCorp acknowledged the request but failed to respond in a quantitative manner. Staff highlights that PacifiCorp is versed in the dynamics of storage as a tool to manage transmission constraints, as section 6 in Round 1 comments includes robust discussion of specific examples (storage in lieu of B2H) and general agreement that less transmission expense is a "chief advantage of SSR".[43] However, it is unclear whether the Company applied a commensurate benefit to small scale and customer sited renewables and storage.

Staff Expectations:

In the IRP/CEP update:

- Include at least 92 MW of CBRE in the preferred portfolio, depending on the current pipeline of existing programs.

By the next IRP/CEP:

- Highlight and communicate the relative benefits of CBRE in load pockets.

[40] See Docket No. LC 80, *Portland General Electric 2023 Integrated Resource Plan and Clean Energy Plan,* Figure 77. Net cost of a microgrid CBRE, page 251, https://edocs.puc.state.or.us/efdocs/HAA/lc80haa8431.pdf.

[41] Id., page 84.

[42] Staff Round 1 Comments, DR No. 16, page 25, https://edocs.puc.state.or.us/efdocs/HAC/lc82hac144131.pdf.

[43] LC 82, PacifiCorp Reply Comments, page 53, https://edocs.puc.state.or.us/efdocs/HAC/lc82hac1546.pdf.

- Quantify the costs and benefits of CBRE for meeting HB 2021 guidance to "[e]xamine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy."[44]
- Identify one or more new, specific CBRE resource opportunities in Oregon and report on findings regarding specific costs and benefits.

CBRE Program Design

Staff encourages PacifiCorp to consider CBRE program designs that scale quickly and provide meaningful capacity distributed across the geographically diverse territory and specifically to load pockets. Staff highlights Green Mountain Power's (GMP) residential storage programs that have 1.1 percent of customers enrolled today and are poised to double annual customer acquisition rates.[45] A similar program growing at the same, per capita rate as GMP's could add 200 MW of distributed storage capacity to PacifiCorp's Oregon territory by 2030.[46] GMP's rate-based cost to operate the programs is reduced by the benefit of a 30 percent federal tax credit, monthly customer participation fees, and GMP's ongoing economic dispatch of the aggregated capacity. Over the system's lifetime, GMP identifies a positive lifetime net-present value of $2,749, despite the upfront, fixed cost of $22,000.[47]

Staff highlights Green Mountain Power as an example of a program design that delivers resilience, helps increase renewables adoptions, and scales quickly. Staff encourages PacifiCorp to be more expansive in its consideration of CBRE resources and consider additional energy efficiency and demand response capacity. For example, many buildings and communities across the state lack basic weatherization and existing programs are not scaled up to meet the need. In one example, the Northwest Energy Efficiency Alliance's 2016-2017 Residential Building Stock Analysis showed that 11 percent of Oregon's single family homes have uninsulated walls.[48] Efficient buildings that can maintain comfort during severe heat and cold events deliver not just energy savings but are better able to participate in demand response programs and deliver capacity savings.

Staff Expectation:

- Engage the CBIAG on potential program designs that can scale quickly to meet community and system needs.

Community Engagement

In Order No. 22-390, the Commission adopted expectations for PacifiCorp and PGE to furnish details on community engagement.[49] PacifiCorp used its existing IRP public input process, DSP efforts, and CETA Washington Equity Advisory Group as the basis of its CEP engagement efforts. The Company's

[44] ORS 469A.415(4)(d).

[45] Howland, Ethan, *Vermont PUC lifts caps on Green Mountain Power battery storage programs with Tesla, others,* Utility Dive, Aug. 29, 2023, https://www.utilitydive.com/news/vermont-puc-green-mountain-power-gmp-battery-storage-programs-tesla/692052/.

[46] Ibid. GMP anticipates growth of 474 residential battery installs per 100,000 customers. At 10 kW capacity per install, PacifiCorp's 610,000 customers could accumulate 200 MW of capacity by 2030.

[47] Ibid.

[48] *Residential Building Stock Assessment II Single Family Report,* Northwest Energy Efficiency Alliance, April 2019, neea.org/img/uploads/Residential-Building-Stock-Assessment-II-Single-Family-Homes-Report-2016-2017.pdf.

[49] *In the Matter of Near-term Guidance on Roadmap Acknowledgement and Community Lens Analysis the First Clean Energy Plans*, Docket No. UM 2225, Order No. 22-390, Appendix A at page 54 (October 25, 2022) *corrected,* Order No. 22-470 (December 5, 2022).

engagement efforts consist of customer surveys, sharing the Company's planning decisions at public "stakeholder engagement venue" meetings, and a Feedback Tracker to document the Company's response meeting questions and comments. The engagement venues include, among others, a CEP Engagement Series, the Community Benefits and Impacts Advisory Group (CBIAG), and the Oregon Tribal Nations Clean Energy Engagement Series.

Staff Round 1 Comments asserted that PacifiCorp had not successfully articulated the Company's path from engagement and input to planning and action. While the CEP discussed tribal engagement opportunities, Staff found the CEP lacked detail on whether the Company had successfully incorporated Tribal perspectives into the Company's decision making and engagement strategy. Additionally, it was not clear that the Company's plan included the perspectives of environmental justice communities. To this extent, Staff suggested improvements including reevaluating the Feedback Tracker to include a clear description of why feedback was or was not included in IRP/CEP.[50] Going forward, Staff also recommended a dedicated stakeholder and cross-utility community engagement working group similar to that put forward in LC 80.[51]

In Opening Comments, the consensus among CUB, RNW, Energy Advocates, and Community Advocates, was that PacifiCorp had not meaningfully considered input from environmental justice communities. Energy Advocates and Community Advocates further noted that PacifiCorp had not measured the effectiveness of their engagement strategy. CRITFC advanced that there is no indication from the CEP or IRP that PacifiCorp has consulted with affected Tribes prior to making decisions, particularly around hydropower reliance.

In Reply Comments, PacifiCorp did not oppose working with PGE to create a common community engagement strategy group along the lines of Staff's suggestion.[52] PacifiCorp committed to timely updating the Feedback Tracker following public workshops,[53] but did not address Staff's additional suggestions to improve the Feedback Tracker. PacifiCorp stated the Company continues to pursue a dialogue with its sovereign tribal partners across its six-state service area and intends to hire a tribal-affairs representative. The Company further commented that it was developing a Tribal CBI focused on TE. PacifiCorp linked components of its DSP/Clean Energy survey to outreach and accessibility practices. Regarding environmental justice, the Company referenced an educational component at CBIAG meetings.

On December 19, 2023, following Round 1 Reply Comments, PacifiCorp met with Staff informally to explain how the Company had used the community engagement process to develop its Interim CBIs. PacifiCorp explained that, due to time constraints, the Interim CBIs presented in the CEP did not originate with the CBIAG. Instead, PacifiCorp selected CBIs previously developed through Washingtons' Clean Energy Transformation Act (CETA) engagement process. According to PacifiCorp, CBIAG members had approved of the Washington CBIs and also suggested additional CBIs; however, PacifiCorp stated at the meeting with Staff that it could not provide Staff with documentation of this approval or the

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[50] *In the Matter of Near-term Guidance on Roadmap Acknowledgement and Community Lens Analysis the First Clean Energy Plans*, Docket No. UM 2225, Order No. 22-390, Appendix A at page 54 (Oct. 25, 2022) *corrected,* Order No. 22-470 (Dec. 5, 2022).

[51] *See In the Matter of Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan*, Docket No. LC 80, Staff Round 2 Comments and Recommendations at pages 29-30 (October 24, 2023).

[52] LC 82, PacifiCorp Reply Comments, December 1, 2023, pages 10, 11.

[53] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 11.

proposed CBIs from CBIAG members[54] beyond the map showing the Company had opposed CBIs proposed by Joint Advocates that were not in line with the Washington CBIs.[55] Going forward, Company representatives committed to:

- Working with the CBIAG to evolve CBIs to be Oregon specific and reflective of CBIAG member feedback;
- Leveraging other efforts to inform and bolster CBIs, including through a 2023 survey and by developing channels to streamline community input from adjacent initiatives to CBIAG members; and
- Making changes to how the Company received and documented input to ensure CBIAG member feedback and knowledge was captured and could be referenced at a later date.[56]

After review of Stakeholder and PacifiCorp comments, Staff has identified the following key adjustments to the Company's platforms and methods that can improve community engagement in future CEP/ IRP processes.

Accountability and Transparency

PacifiCorp's CEP includes available venues for public input, yet the Company's community engagement strategy could be improved and ultimately more effective through better documentation of stakeholder input. This CEP did not provide a clear roadmap of how or why PacifiCorp used stakeholder input to inform the Company's IRP and CEP. Going forward, this documentation can help close the gaps between the Company's interpretation of effective engagement and stakeholders' priorities and expectations. Accordingly, Staff reiterates the need for Feedback Tracker improvements and looks forward to working with PacifiCorp and stakeholders to implement these improvements. Staff also recommends the utility conduct a participant survey on the engagement process before the next IRP/CEP filing. The survey should allow PacifiCorp to measure the effectiveness of the Company's engagement strategy efforts. Additionally, Staff expects PacifiCorp's CBIAG and CBI activities to better capture and document how Environmental Justice community priorities are addressed. Finally, as introduced in Round 1 Comments, Staff believes it is a priority to develop clear, actionable expectations for engagement in future IRP/CEP development and review. Consistent with LC 80, Staff recommends the establishment of a working group that can operate in coordination with the broader investigation into the Commission's planning and procurement policies in 2024.

Cross-venue Engagement Planning

Staff recognizes that stakeholder engagement addressing critical issues, such as wildfire risk, transportation electrification (TE), and energy affordability is occurring in separate dockets and venues outside of the CEP process. As discussed at the informal December 19 meeting with PacifiCorp, Staff is encouraged by the Company's work to streamline input channels. In the next CEP, Staff expects PacifiCorp to better articulate how it is leveraging stakeholder input and deliverables in these adjacent dockets and venues to inform CBIs, CBREs, and portfolio decisions.

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[54] Staff and PacifiCorp meeting held December 19, 2023.
[55] PacifiCorp response to Staff DR 35 Attachment.
[56] Staff and PacifiCorp meeting held December 19, 2023.

Tribal Engagement
In Opening Comments, Staff recognized that engagement with Tribal Nations requires intentional recognition and a focused approach that the utility and industry as a whole is working to better understand and practice. Staff appreciates PacifiCorp's introduction of a Tribal TE CBI. Going forward, Staff expects the Company to provide updates to the CBIAG and Staff on the Tribal CBI development and strategy to actively increase Tribal Nation priorities in planning conversations and resource decision-making.

Notably, in December 2023, the U.S. Government reached a settlement agreement to support the Columbia Basin Restoration Initiative (CBRI) in partnership with the Six Sovereigns.[57] This comprehensive agreement leveraged the collective knowledge and priorities of Tribal Nations, Oregon and Washington states, federal agencies, and interest groups. The CBRI anticipates changes to the energy system as part of the work to restore fisheries while supporting decarbonization and resilient communities. For these reasons, Staff views the CBRI as an opportunity for PacifiCorp to improve its engagement strategy with Tribal Nations impacted by the construction and operation of the Columbia River Federal dams.

Staff Recommendation 8. Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.

Staff Expectations:
- Staff expects PacifiCorp's CBIAG and CBI activities to better capture and document Environmental Justice community priorities.
- In the next CEP, Staff expects PacifiCorp to better articulate how it is leveraging stakeholder input and deliverables in related dockets and venues to inform CBIs, CBREs, and portfolio decisions.
- PacifiCorp should include the following additions and enhancements to the Feedback Tracker:
  - Organization/entity attribution or affiliation.
  - Flag for whether and where PacifiCorp incorporated the feedback into specific utility planning, actions, resource selection, and project prioritization.
  - Clear description of why feedback was or was not included.
- Staff encourages PacifiCorp to report on its Tribal engagement strategy by December 31 of each year to the CBIAG. The review should include successes, opportunities for improvement, feedback received, a discussion of Tribal CBIs and CEP/DSP project development, and any work to involve Tribal Nations in planning and resource decision-making.
- PacifiCorp should conduct a participant survey on the engagement process before the next IRP/CEP filing. The survey should allow PacifiCorp to measure the effectiveness of the Company's engagement strategy efforts.

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[57] *See* Northwest Power and Conservation Council memorandum, *Report on the US Government Commitments: Power Related Topics*, January 3, 2024, https://www.nwcouncil.org/fs/18579/2024_01_p2.pdf. The Six Sovereigns include the Nez Perce Tribe, Confederated Tribes and Bands of the Yakama Nation, the Confederated Tribes of the Warm Springs Reservation of Oregon, the Confederated Tribes of the Umatilla Indian Reservation, and the States of Oregon and Washington.

Resiliency Analysis Framework

PacifiCorp's CEP outlines the beginnings of the Company's Resiliency Analysis Framework. The Resiliency Analysis Framework combines census tract level community[58] and utility[59] resilience scores into a composite community-resilience score. The Company plans to use the community-resilience score to identify census tracts for additional analysis and project prioritization.[60] After identifying threats, probabilities, and consequences, PacifiCorp plans to use a risk-spend efficiency (RSE) or cost-benefit analysis (CBA) to account for the costs at specific project locations. The Company's goal is to include resilience risk scores in project and program prioritization, including when assessing the IRP, CBRE, and SSR.[61]

In Opening Comments, Staff requested an update on the Resiliency Analysis Framework timeline, which includes PAC's plan to incorporate community-utility resilience scores and risk drivers into CEP program planning by Q1 2024.[62] By extension, Staff asked how the Company planned to use the Resiliency Analysis Framework in the IRP, CEP, and/or DSP. Staff also asked for additional information on the resiliency scoring metrics.

Energy Advocates and CRITFC argued that PacifiCorp should improve community resiliency and consider how SAIDI/SAIFI/CAIDI data can be connected with information about lived experiences and community resources that can be used during an outage. Energy Advocates added that PacifiCorp should clearly define resiliency in the CEP and improve the readability of the CEP to include important definitions for SAIDI, SAIFI, and CAIDI. CRITFC discussed the link between healthy salmon ecosystems, utility resource planning to meet HB 2021 requirements, and tribal community resiliency.

In Round 1 Reply Comments, PacifiCorp did not directly respond to requests for information about resiliency planning and community data points. Instead, PacifiCorp stated that much of Staff and stakeholders' comments, questions, and concerns would be addressed in the next CEP.[63] PacifiCorp's future planning approach will, "evolve as [the Company] gain[s] experience and receive[s]additional stakeholder input."[64] PacifiCorp explains that it is still evaluating how to include additional community input.

[58] To develop the community resilience score, PacifiCorp assigns social vulnerability and community resilience scores to census tracts using FEMA National Risk Index (NRI) values. PacifiCorp response to Staff DR No. 97.

[59] To develop the utility resilience score, PacifiCorp applies System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI) including major events to calculate the annual number of customers and minutes interrupted at each transformer in each census tract. PacifiCorp response to Staff DR No. 97.

[60] For example, PacifiCorp explains that by sorting the largest census tract CAIDI values first, and then sorting by the lower NRI values the Company can identify customers experiencing longer system outages with lower community resilience or higher social vulnerability. PacifiCorp response to Staff DR No. 99.

[61] LC 82 PacifiCorp 2023 CEP, Resiliency, May 31, 2023, page 29.

[62] *See* LC 82 PacifiCorp 2023 CEP, Resiliency, May 31, 2023, page 32; *see also* PacifiCorp response to Staff DR No. 30.

[63] *See* LC 82, PacifiCorp Reply Comments, December 1, 2023, page 48 (In Round 1 comments Staff requested an updated Table 9 timeline. PacifiCorp acknowledged Staff's request in its Round 1 Reply Comments but did not provide an updated Table 9 timeline.); *see also* LC 82, PacifiCorp Round 1 Reply Comments, December 1, 2023, page 49 ("PacifiCorp is also evaluating how to apply its resilience analysis to DSP and CEP programs and will provide additional information in its upcoming CEP consistent with Staff recommendations. … PacifiCorp is currently developing a preliminary resilience cost-benefit analysis and will include this framework in its upcoming CEP.").

[64] LC 82, PacifiCorp Reply Comments, December 1, 2023, page 48.

PacifiCorp did not address Staff's questions on how the Company's wildfire plan was incorporated into the CEP resiliency analysis beyond directing Staff to review the Company's Wildfire Mitigation Plan. PacifiCorp disagreed with Staff's assessment about its use of the terms "resiliency" and "reliability", but states it will be clearer in the next CEP. In response to Stakeholder requests, PacifiCorp has provided definitions of SAIDI, SAIFI, and CAIDI.

Staff also understands that PacifiCorp is currently evaluating the geographic scope of the Resiliency Analysis Framework to develop more granular resilience scores.[65] Of note, PacifiCorp's current methodology to calculate SAIDI/SAIFI/CAIDI scores at the census tract level results in higher values than under the traditional use, which applies these metrics to the state or utility level.[66] As stated in Staff Round 1 Comments, Staff is still interested in understanding how these census-level SAIDI/SAIFI/CAIDI data has been successfully used in the past for resiliency-related planning. Staff expects the Resiliency Analysis Framework to consider direct benefits to Oregon communities. Nevertheless, Staff is concerned that limiting the scope of resilience metrics to transformer outages within Oregon census tracts, as discussed in step two of the Resiliency Analysis Framework, may result in unnecessary grid-hardening at the expense of PacifiCorp's Oregon ratepayers or overlook cross-state resiliency issues such as wildfire, extreme weather, and load pockets.[67] Given the nascent state of the Resiliency Analysis Framework, Staff sees an opportunity to open discussions with the Company and Stakeholders on the appropriate geographic scope of the Resiliency Analysis Framework.

PacifiCorp states it accounts for non-energy related resilience assets and services in the NRI values.[68] As noted in Round 1 comments, the NRI values use well known indices and Staff continues to find them helpful. That said, Staff would like further insight on how the Company plans to consider these assets and services to meet its goal to prioritize enhancing community resilience over acquiring additional capacity[69] and avoid extraneous utility projects and their associated costs. Staff also expects further discussions between the Company, the CBIAG, Tribes, and Stakeholders on how NRI values can be tailored or supplemented to reflect specific community concerns and assets and leverage existing Company resilience plans, such as the wildfire mitigation plan in Docket No. UM 2207.

Staff understands that resiliency analysis is an evolving field and expects that PacifiCorp will significantly improve upon its Resiliency Analysis Framework in the next CEP. In the meantime, Staff recommends that PacifiCorp incorporate resiliency-related factors into the Q1 2024 SSR RFP and the CBRE Grant Pilot so that these efforts can bring tangible community benefits to their system.

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[65] *See e.g.*, PacifiCorp response to Staff DR No. 96.

[66] LC 82, PacifiCorp 2023 CEP, CBI, May 31, 2023, page 20.

[67] *See e.g., In the Matter of Investigation into House Bill 2021 Implementation Issues*, Docket No. UM 2273, Order No. 24-002 at page 25 (January 5, 2024) ("Grid-connected facilities located outside Oregon contribute to reliable service for Oregon electricity customers and to reducing GHG emissions on the grid, and facilities located inside Oregon do not serve Oregon customers exclusively. There may be resiliency benefits to in-state resources and resource strategies that are worthwhile to consider, but those must be based on reliability and resiliency analysis or related valuation methodologies, not assumed based solely on geographic location or the presence of specific electricity market transaction receipts.").

[68] LC 82, PacifiCorp response to Staff DR Nos. 102, 104.

[69] LC 82 PacifiCorp 2023 CEP, CBRE, May 31, 2023, page 45; *see also* PacifiCorp response to Staff DR 109.

Figure 3: SSR RFP Procurement Timeline[70]

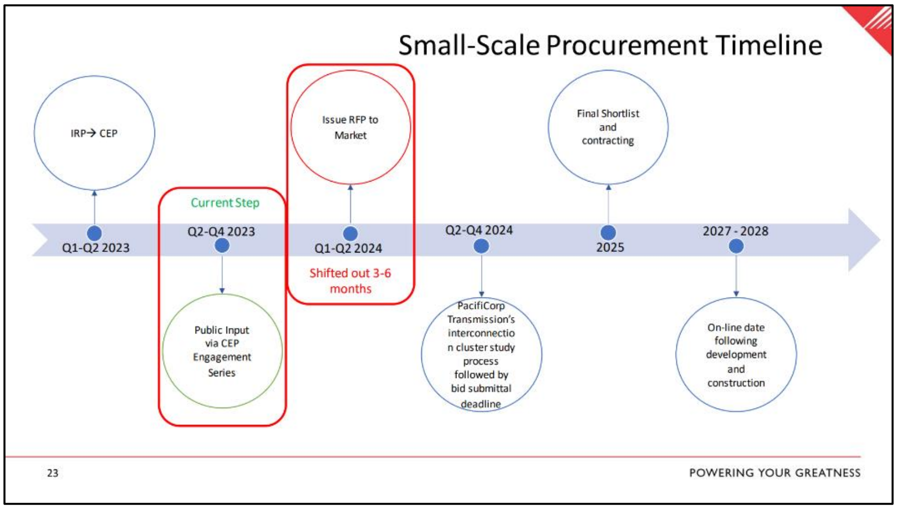
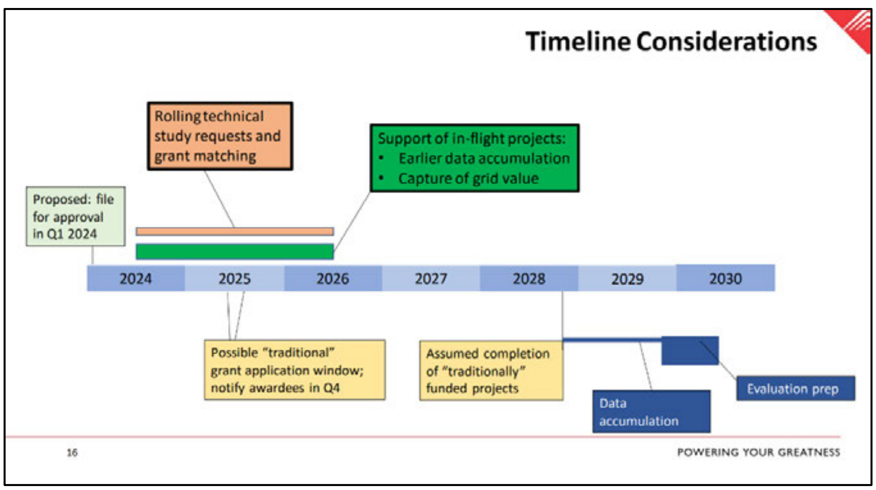


Figure 4: Timeline Considerations for the CBRE Pilot[71]



PacifiCorp's community-utility resilience score accounts for time and duration of outages through SAIDI/SAIFI/CAIDI metrics. It is not clear to Staff what additional information Stakeholders need regarding SAIDI/SAIFI/CAIDI methodologies and definitions. Prior to the next CEP filing, Staff expects PacifiCorp work with Stakeholders to identify gaps in Resiliency Analysis Framework comprehension and the vulnerabilities and complexities of these data sets as a measure of community level impacts.

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70 PacifiCorp CEP Engagement Series, 4th meeting, slide 23 (August 25, 2023) available at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/cep/CEP_Engagement_Series_August_Meeting.pdf.

71 PacifiCorp CEP Engagement Series, 4th meeting, slide 16 (August 25, 2023) available at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/cep/CEP_Engagement_Series_August_Meeting.pdf.

Staff Recommendation 9. The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and the CBRE Pilot be designed to promote resiliency-related factors.

Staff Expectations:

- PacifiCorp should specify how it intends to incorporate CBIAG feedback and other community input into the community-utility resilience scores and risk drivers by March 1, 2024.
- By the next IRP, PacifiCorp should explain how it will use the Resiliency Analysis Framework in IRP and CEP resource planning, project prioritization, and portfolio selection considering HB 2021's requirement that resiliency planning consider costs, consequences, outcomes and benefits.
- Prior to the next CEP, Staff expects the Company to open discussions with stakeholders on the appropriate geographic scope of the Resiliency Analysis Framework; work with Stakeholders to identify gaps in comprehension of the Resiliency Analysis Framework; and identify the vulnerabilities and complexities of SAIDI/SAIFI/CAIDI data sets and NRI values as a measure of community level impacts. The Company is encouraged to discuss how it can incorporate the lived experiences of communities into the community-resiliency score. The results of these discussions should be included in the next CEP.
- By the next CEP, PacifiCorp should be able to articulate further discussions between the Company, the CBIAG, Tribes, and Stakeholders on how NRI values can be tailored or supplemented to reflect specific community concerns and assets and leverage existing Company resilience plans, such as the wildfire mitigation plan in Docket No. UM 2207.
- At a CBIAG meeting before the next CEP and prior to any CBRE Grant Pilot project selection, provide details for how a completed Resiliency Analysis Framework will be used to impact project selection. Staff expects to work with PacifiCorp in helping to craft this presentation and what will be covered.

Acquisition of Federal Incentives

One of the specifically enumerated, HB 2021 public interest factors for weighing CEP acknowledgement is the extent to which the availability of federal incentives were considered.[72] In Round 1 comments Staff joined Sierra Club and CUB in calling for PacifiCorp to fully incorporate the financing opportunities and tax credits made available through the Interest Reduction Act (IRA) more fully into its IRP/CEP analysis. This included rerunning variant portfolios. Specifically: apply a 30 percent reduction to transmission network upgrade costs for low cost, renewable projects in select cluster study areas; and, assuming low cost federal financing and loan guarantees be used for targeted early plant retirements. Suggestions also included regular reporting to the Commission on progress pursuing federal incentives, exploring how Justice 40 incentives could be used for CBREs, and applying tax bonus credits to eligible "energy communities" in Oregon.

PacifiCorp responded that it used the available IRA information at the time of filing and continues to examine evolving legislation for use in future analysis where appropriate. Further, the Company stated that the PLEXOS model did account for federal incentives, as appropriate. The Company also shared that it was actively pursuing EIR programs, financing it can qualify for, and applying for grants and that it will communicate the details of IRA financing and other incentives as they become known. Finally, the Company stated that a variant study can be reported once the IRA financing details are better known.

[72] ORS 469A.420(2).

Staff appreciates all of the work done by PacifiCorp, stakeholders, and especially Sierra Club, to highlight the enormous cost-saving opportunities available through the federal government's IRA initiatives. However, this funding is limited to $2 Billion, expires in September 2026, and utilizes a first-come, first-served competitive application process. In short, time is of the essence if PacifiCorp wants to secure low-cost financing for planned investments to replace aging infrastructure.

Staff Expectations:

- The IRP Update includes two variant portfolios that directly reflect Sierra Club's suggested analysis around reduced upgrade costs and early retirements using the EIR program.
- PacifiCorp details in the IRP Update the timeline for submitting an EIR application and the scope of the projects it is seeking to be financed through the U.S. Department of Energy Loan Program Office's EIR program.
- PacifiCorp provides a brief update at every IRP public input meeting and every CBIAG meeting leading up to the 2025 IRP that details the Company's activities to apply for federal incentives and detailing any funding secured.

IRP Comments

In this section, Staff will not revisit all topics raised in our Round 1 comments on the IRP aspects of LC 82. Rather we have sought to prioritize those items which have the greatest bearing on acknowledgement/non-acknowledgement or are most critical for improvement in the next IRP/CEP.

Preferred Portfolio Modeling Process

Staff, RNW, and Sierra Club included an extensive number of comments on portfolio modeling for both improved development and selection. Most notable were the comments on the granularity adjustment, reliability adjustment, the inclusion of CEP resource additions (i.e., Oregon SSRs and higher levels of EE in Oregon), and the re-optimization of variant portfolios.

In developing the second round of comments, Staff's team explored the extent to which the processes around the granularity adjustment, the reliability adjustment, and portfolio reoptimization may have led to suboptimal portfolio development and selection.

Granularity Adjustment

In Round 1 comments, Sierra Club raised potential issues with PacifiCorp's application of granularity adjustments in their capacity expansion runs. PacifiCorp did not address Sierra Club's methodological questions about why the granularity adjustments did not seem to make sense and instead stated that there are "no logical alternatives" to the granularity adjustments, because they were "dictated by model math."[73] The Company's responses to earlier discovery from Sierra Club were similarly unclear.[74]

Staff engaged Synapse to further investigate the development and application of granularity adjustments. Synapse examined the workpaper that the Company used to develop the granularity adjustments,[75] and it identifies a potential errors and omissions in the calculations. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]. [BEGIN HIGHLY CONFDENTIAL]** [redacted] **[END HIGHLY CONFDENTIAL]**. Thus the Company may be adding erroneous adjustment factors to its capacity expansion modeling, which should be corrected. While the mistake does not appear to systematically favor **[BEGIN CONFIDENTIAL]** [redacted]

[73] LC 82, PacifiCorp Round 1 Reply Comments, page 39.

[74] Sierra Club Round 1 Comments, page 41.

[75] [redacted]

[redacted] **[END CONFIDENTIAL].**

[BEGIN HIGHLY CONFDENTIAL] [redacted] **[END HIGHLY CONFDENTIAL]. [BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**[76] The inclusion of this adjustment introduces further subjectivity into the LT modeling and highlights the broader shortcomings of PacifiCorp's modeling approach.

[BEGIN HIGHLY CONFDENTIAL]

[redacted]

[END HIGHLY CONFDENTIAL]

The impact of the granularity adjustments, even with the limit of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, significantly changes the resource fixed prices. Figure 6 shows the capacity-weighted average fixed cost and granularity adjustments for each category of units. The granularity adjustments reduce fixed prices enough that they could have affected capacity expansion decisions in the model.

Ideally, PacifiCorp should improve the temporal granularity of LT modeling in future IRP proceedings so that granularity adjustments are no longer necessary. If this is not possible, the Company should at minimum revisit its methodology and correct its workpapers if necessary. It should also clearly explain

[76] PacifiCorp response to OPUC DR No. 240.

its methodology for this adjustment, including clarifying whether it uses the same set of granularity adjustments in each LT model run or whether it adjusts them iteratively. Importantly, PacifiCorp should be able to justify why its results, both with and without the price cap, are reasonable.

[BEGIN HIGHLY CONFDENTIAL]
[redacted]
[END HIGHLY CONFDENTIAL]

Reliability Adjustment
In Round 1 Comments, Sierra Club also raised concerns with the magnitude and potential subjectivity of the reliability adjustments that PacifiCorp made to optimized portfolios to meet reliability-based constraints. Sierra Club confirmed through discovery that PacifiCorp chooses which reliability adjustments to make based on the duration and timing of the shortage, the maximum size of the shortage in megawatts, and the location of the shortage.[77] However, the details of the Company's process are not transparent, including which resources it considers eligible for reliability adjustments and how it values eligible resources. As with the granularity adjustments, the Company stated in its Reply Comments that the reliability adjustments were "dictated by model math."[78] This explanation is even less satisfactory for the reliability adjustments than the granularity adjustments; while it is true that the model determines which hours have unserved energy, the decision about which manual adjustment to make in order to address this problem is at least partially subjective (as illustrated by the alternative portfolio of adjustments that Sierra Club developed for one of the variants in its Round 1 Comments).

[77] PacifiCorp response to Sierra Club DR No. 27.
[78] LC 82, PacifiCorp Reply Comments, page 39.

Staff engaged Synapse to further investigate the Company's reliability adjustments. Synapse confirmed Sierra Club's findings and similarly expressed concern regarding the magnitude of and lack of transparency in PacifiCorp's reliability adjustments.

Table 3 and Table 4 below quantify the reliability adjustments that PacifiCorp made in its preferred portfolio. The reliability adjustments more than triple the capacity of non-emitting peakers added during the study period, increase the amount of new batteries by 70 percent, and increase the amount of new solar by 26 percent. PacifiCorp shifted wind builds earlier, increasing the amount of new capacity by 129 percent between 2023 and 2030, but slightly decreasing the amount added over the entire study period.

In discovery, PacifiCorp stated that only non-emitting resources are eligible for reliability adjustments.[79] However, this is not quite accurate. The Company also manually adjusted the conversion and retirement dates for a number of its thermal resources. In the preferred portfolio, these adjustments took place in two stages. PacifiCorp started with a "Base" scenario, and then it hard-coded coal retirement dates and re-ran PLEXOS to produce a "Base Limited" scenario,[80] which it identified as the "initial" run used to create the preferred portfolio.[81] It then added further adjustments to produce the "reliable" portfolio. Table 3 cTable1ompares coal retirement and conversion dates across these three model runs. The large number of changes further underscores the extent to which PacifiCorp produced the preferred portfolio through manual adjustments, rather than configuring PLEXOS in a way that would allow it to optimize builds and retirements.

Table 3: Reliability Adjustments in Preferred Portfolio 2023-2030

	Builds in Initial Portfolio (MW)	**Builds in Reliable Portfolio (MW)**	**Difference in Cumulative Builds/Retirements (MW)**	**Percent difference in Cumulative Builds/Retirements**
Coal to Gas	375	1,770	1,394	371%
Coal – SNCR	(1,380)	-	1,380	-100%
Gas – EOL	247	247	-	0%
Nuclear	500	500	-	0%
Non-emitting peaker	-	606	606	Inf.
Battery	4,359	7,560	3,201	73%
Battery – LDES	482	-	(482)	-100%
Wind	1,934	4,431	2,497	129%
Solar	6,063	6,583	520	9%

Source: "(P)-LT-6529-23I.LT.Initial Run.20.PA0-.EP.MM.Base Limited.xlsx" and "(P)-LT-13338-23I.LT.Reliable.20.PA1-.EP.MM.PP-D3 29 v109.9.xlsx"

[79] PacifiCorp response to OPUC DR No. 233.
[80] PacifiCorp response to Sierra Club DR No. 40.
[81] PacifiCorp response to Sierra Club DR No. 25.

Table 4: Reliability Adjustments in Preferred Portfolio 2023-2042

	Builds in Initial Portfolio (MW)	Builds in Reliable Portfolio (MW)	Difference in Cumulative Builds/Retirements (MW)	Percent difference in Cumulative Builds/Retirements
Coal to Gas	(349)	0	349	-100%
Coal – SNCR	(2,335)	(2,335)	(0)	0%
Gas – EOL	(652)	(595)	57	-9%
Nuclear	1,500	1,500	-	0%
Non-emitting peaker	289	1,240	951	329%
Battery	4,643	7,910	3,267	70%
Battery – LDES	-	350	350	Inf.
Wind	9,251	9,113	(138)	-1%
Solar	6,246	7,855	1,609	26%

Source: "(P)-LT-6529-23I.LT.Initial Run.20.PA0-.EP.MM.Base Limited.xlsx" and "(P)-LT-13338-23I.LT.Reliable.20.PA1-.EP.MM.PP-D3 29 v109.9.xlsx"

Table1 5: Manual Changes to Coal Retirement and Conversion Dates in the IRP Preferred Portfolio

<table>
<tr><th></th><th>Base</th><th>Base Limited</th><th>Reliable</th></tr>
<tr><td>Craig 1</td><td colspan="3">Retires 2026</td></tr>
<tr><td>Craig 2</td><td colspan="3">Retires 2029</td></tr>
<tr><td>Dave Johnston 1 and 2</td><td colspan="3">Retires 2029</td></tr>
<tr><td>Dave Johnston 3</td><td colspan="3">Retires 2028</td></tr>
<tr><td>Dave Johston 4</td><td>Gas conversion, retires 2040</td><td colspan="2">Retires 2040</td></tr>
<tr><td>Hayden 1</td><td colspan="3">Retires 2029</td></tr>
<tr><td>Hayden 2</td><td colspan="3">Retires 2028</td></tr>
<tr><td>Jim Bridger 1</td><td>Converts 2024, retires 2031</td><td>Converts 2024, retires 2031</td><td>Converts 2024, retires 2038</td></tr>
<tr><td>Jim Bridger 2</td><td>Converts 2024, retires 2030</td><td>Converts 2024, retires 2030</td><td>Converts 2024, retires 2038</td></tr>
<tr><td>Jim Bridger 3</td><td>Retires 2026</td><td>Unclear from workpaper</td><td>Converts 2030, retires 2038</td></tr>
<tr><td>Jim Bridger 4</td><td>Retires 2032</td><td>Unclear from workpaper</td><td>Converts 2030, retires 2038</td></tr>
<tr><td>Hunter 1</td><td>Retires 2031</td><td>SNCR, retires 2031</td><td>SNCR, retires 2032</td></tr>
<tr><td>Hunter 2</td><td>Retires 2031</td><td>SNCR, retires 2032</td><td>SNCR, retires 2033</td></tr>
<tr><td>Hunter 3</td><td>Retires 2030</td><td>SNCR, retires 2030</td><td>SNCR, retires 2033</td></tr>
<tr><td>Huntington 1</td><td>Retires 2030</td><td>SNCR, retires 2030</td><td>SNCR, retires 2033</td></tr>
<tr><td>Huntington 2</td><td>Retires 2026</td><td>SNCR, retires 2028</td><td>SNCR, retires 2033</td></tr>
<tr><td>Naughton 1</td><td>Converts 2026, retires 2032-2033</td><td>Converts 2026, retires 2032</td><td>Converts 2026, retires 2037</td></tr>
<tr><td>Naughton 2</td><td colspan="3">Converts 2026, retires 2037</td></tr>
<tr><td>Wyodak</td><td>Converts 2027, retires 2040</td><td colspan="2">SNCR, retires 2040</td></tr>
</table>

Source: "(P)-LT-6529-23I.LT.Initial Run.20.PA0-.EP.MM.Base Limited.xlsx," "(P)-LT-13338-23I.LT.Reliable.20.PA1-.EP.MM.PP-D3 29 v109.9.xls," "(P)-LT-6530-23I.LT.Initial Run.20.PA0-.EP.MM.Base.xlsx," and Sierra Club Round 1 Comments at page 19.

Staff shares Sierra Club's concerns about both transparency surrounding PacifiCorp's process for making reliability adjustments and the magnitude of the adjustments. The reliability adjustments substantially change the resources in the preferred portfolio, calling into doubt the extent to which PacifiCorp's capacity expansion is economically optimized.

Portfolio Reoptimization

Sierra Club's Round 1 comments also raised concerns regarding the inconsistency of PacifiCorp's practice of re-optimizing portfolio variants. Because re-optimization generally finds the lowest cost way to meet a portfolio's constraints, failure to re-optimize a portfolio could lead to an over-estimation of the costs associated with the specific resource variation being examined by that portfolio. This may lead some portfolio variants to appear artificially more expensive than others. In response to this concern, PacifiCorp noted that they have limited time to conduct re-optimization and must prioritize. Additionally, the variant portfolios identified by Sierra Club for re-optimization were generally meant to test through a counterfactual portfolio, a choice within or not included in the Preferred Portfolio (i.e., P-17's exploration of Colstrip's early retirement).

PacifiCorp's decision to not-reoptimize the PLEXOS LT model for variants P13, P18, and P19 causes the resulting portfolios to retain excess capacity that ratepayers do not necessarily need for a reliable system. For example, the resource builds, conversions, and retirements are identical between the Preferred Portfolio and P13– Max DSM, despite this variant installing an additional ~4,000 MW of DSM capacity over the time frame.

Regardless of the ostensible "purpose" of a variant portfolio, this approach fails to allow Staff and stakeholders to properly compare the preferred portfolio to other variants due to the overbuilt nature of the selected variants. As stated above, P18 results in PacifiCorp having an additional 2,000 MW of capacity starting in 2029, and P19 results in additional 500 MW of capacity starting in 2028. Even though PLEXOS ST captures any cost savings associated with dispatch, it is important for PLEXOS LT to be re-optimized as well to give the opportunity for additional cluster resource and DSM capacity to displace other new resource builds and/or identify earlier retirement dates for existing plants. Without re-optimizing PLEXOS LT, stakeholders are unable to easily tease out which resources would be displaced and how that would impact GHG and PVRR outcomes.

In discovery, PacifiCorp stated that three of the variant studies (P13, P18, and P19) were conducted with the understanding that additional resources would likely result in higher cost PVRR outcomes, and that the purpose of these variants is to assess the magnitude of the impact for determining possible least-regret paths to consider for the preferred portfolio.[82] While the results as presented in this IRP may still be of interest to the Company, PacifiCorp should not be doing this in lieu of re-optimization.

For example, the Max DSM variant as modeled is not currently providing much value for comparison to the preferred portfolio due to the magnitude of the incremental installed capacity that has been required (~4,000 MW) and the magnitude of the PVRR delta ($3 billion). The benefits of pursuing

[82] PacifiCorp response to Sierra Club DR No. 43.

ambitious energy efficiency and demand response are to reduce system load, peak demand, and firm capacity reserve requirement, thus avoiding investments in generation and capacity resources and transmission and distribution infrastructure. By not allowing re-optimization of this portfolio, PacifiCorp fails to allow for a significant portion of DSM benefits to be realized in the PVRR result. This variant design also fails to account for the potential of DSM to reduce the SSR and CBRE requirements, further reducing portfolio costs.

In future studies, PacifiCorp should re-optimize all future variant portfolios that add incremental capacity to the preferred portfolio. This will allow the Commission and stakeholders to assess all variant portfolios on an equal playing field. If a variant does not result in the addition or subtraction capacity from the portfolio and can be fully evaluated using PLEXOS ST only, re-optimization may not be necessary. If there is a scenario where PacifiCorp would legitimately be expected to maintain a system with more resources than needed to cost-effectively meet customer needs (e.g. P21), or if there is a legitimate reason the Company could not change its resource plans in time (e.g. P17), then studies without re-optimization could be used. If the Company is still interested in assessing the magnitude of incremental costs from hard-coded resources without re-optimization, this should be done outside of the variant case analysis.

Table 6 below summarizes PacifiCorp's variant portfolios and how they were modeled.

Table 6: Variant Portfolios

Scenario Name	Re-optimized builds?	If no, why not?	Future Recommendation
P01-JB3-4 GC	Yes		
P02-JB3-4 EOL	Yes		
P03-Hunter3-SCR	Yes		
P04-Huntington RET28	Yes		
P05-No NUC	Yes		
P06-No Forward Tech	Used P05		
P07-D3-D2 32	Yes		
P08-No D3-D2	Yes		
P09-No WY OTR	No	Used to evaluate the impact on P-MM if Wyoming's OTR was not enforced.	
P10-Offshore Wind	Yes		
P11-Max NG	Yes		
P12-RET Coal 30/33 NG 40	Yes		
P13-Max DSM	No	Used to evaluate the impact on P-MM if all DSM was selected.	Re-optimize capacity mix.
P14-All GW	Yes		
P15-No GWS	Yes		

Scenario Name	Re-optimized builds?	If no, why not?	Future Recommendation
P16-No B2H	Yes		
P17-Col3-4 RET25	**No**	Used to evaluate if earlier retirement of Colstrip 4 would result in energy or capacity shortfalls.	
P18-Cluster East	**No**	Used to evaluate the economic impact of adding the next best cluster resource to P-MM.	Re-optimize capacity mix.
P19-Cluster West	**No**	Used to evaluate the economic impact of adding the next best cluster resource to P-MM.	Re-optimize capacity mix.
P20-JB3-4 CCUS	Used P02		
P21-DJ2 CCUS	**No**	Used to evaluate the impact of installing CCUS at DJ2.	
P22-DJ4 CCUS	**No**	Used to evaluate the impact of installing CCUS at DJ2.	
P23-RET Coal 30/33	Used P12		
P24-Gas 40-year Life	**Yes**		

Staff Recommendation 10. Direct PacifiCorp to fix any confirmed analytical errors in the calculation or application of granularity adjustments.

Staff Expectations:
Before the next IRP, PacifiCorp should:

- Work with interested participants from the IRP Public Input process to develop and publicly produce a granularity adjustment methodology.
- Increase transparency around reliability adjustments by stating which resources will be eligible to be included as reliability adjustments in the next IRP and how each one will be valued. Further, it should clarify its modeling approach around how to limit the magnitude of the reliability adjustments that it must make.
- Solicit suggestions through the IRP Public Input process and as part of the Draft IRP of variant portfolios.

As part of the next IRP, PacifiCorp should:

- Adjust its modeling approach to better capture resource adequacy needs and the capacity contributions of resource options to reduce the need for and magnitude of reliability adjustments to portfolios.
- Reoptimize variant portfolios that add resources to the preferred portfolio unless there is a clearly explained reason to study an un-optimized portfolio of resources.

Coal Strategy

In its Round 1 Comments, Sierra Club raised concerns about the coal prices that PacifiCorp used in its modeling, which may have erroneously delayed the economic retirement date for Jim Bridger 3 and 4.[83] These units, which are co-owned by PacifiCorp (67 percent) and Idaho Power Company (33 percent) **[BEGIN HIGHLY** [redacted] **[END HIGHLY CONFIDENTIAL]. [BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**[86]

Fuel costs influence unit economics, so it is important for PacifiCorp to represent them correctly within PLEXOS so that the model is able to determine economic retirement and/or conversion dates. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted]

	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]

Sources: [redacted] **[END HIGHLY CONFIDENTIAL].**

[BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL].**

PacifiCorp's Round 1 Response Comments suggested that the Company accounted for the full cost of coal in the IRP, but represented some of the costs as fixed, rather than modeling all coal costs as variable.[88] **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL].**

83 Sierra Club Round 1 Comments, page 44.

84 [redacted]

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88 LC 82, PacifiCorp Reply Comments, page 82: "PacifiCorp did incorporate significant fixed costs for coal supply to Jim Bridger units 3 & 4."

However, PacifiCorp added the fixed costs for coal supply at Jim Bridger in post-processing rather than modeling them within PLEXOS.[89] As a result, PLEXOS sees only the variable portion of the coal cost (blue line in [redacted] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Unrealistic coal prices within PLEXOS may make Jim Bridger 3 and 4 appear more economic than they are in actuality, which could result in PLEXOS selecting a delayed economic retirement date. In the future, PacifiCorp should correct its PLEXOS modeling so that the full cost of coal at Jim Bridger is represented within the model.

[BEGIN HIGHLY CONFIDENTIAL]

[redacted]

[END HIGHLY CONFIDENTIAL]

Sources: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.
[BEGIN HIGHLY CONFIDENTIAL] [redacted] **[END HIGHLY CONFIDENTIAL]**.

Hunter and Huntington

Two of PacifiCorp's coal plants, Hunter and Huntington, are located in Utah and have experienced the impact of disruptions to the Utah coal market for reasons such as the Lila Canyon mine fire and unfavorable coal mining conditions. While it can be hard to fully predict future disruptions to coal markets and resulting impact on fuel prices, it is important to incorporate as much up-to-date information as possible in order to ensure model results are reasonably similar to reality. Synapse, on behalf of Staff, reviewed federal Department of Energy EIA 923 fuel receipts data for 2023 and determined that PacifiCorp paid between $1.79 and $4.19 per MMBTU for coal at Hunter. At Huntington, Synapse determined that PacifiCorp paid between $2.18 and $2.54/MMBTU.

[89] PacifiCorp response to Staff DR No. 228.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]			[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[END CONFIDENTIAL].

On April 3, 2023, PacifiCorp filed its Transition Adjustment Mechanism in Docket No. UE 420 to update its net power costs for 2024. In Witness Owen's testimony, he states that "the significant production shortfall due to the Lila Canyon mine fire negatively affected all large coal consumers including PacifiCorp. Unfortunately, this negative impact is expected to continue into the foreseeable future."[92] If this is PacifiCorp's current position, then the 2023 IRP Update should incorporate the lasting impacts of unfavorable market conditions into its coal price forecast for these Utah plants.

[90] Confidential Attachment OPUC 229, "HTR-HTG Coal Update_2022 12 21 CONF".

[91] US Bureau of Land Management. 2022. *The Bureau of Land Management issues decision on Lila Canyon Mine.* Available at: https://www.blm.gov/press-release/bureau-land-management-issues-decision-lila-canyon-mine.

[92] *In the Matter of PacifiCorp's 2024 Transition Adjustment Mechanism*, Docket UE 420, Exhibit PacifiCorp/200, Owen/4.

Staff Expectation:
In the next IRP PacifiCorp should:

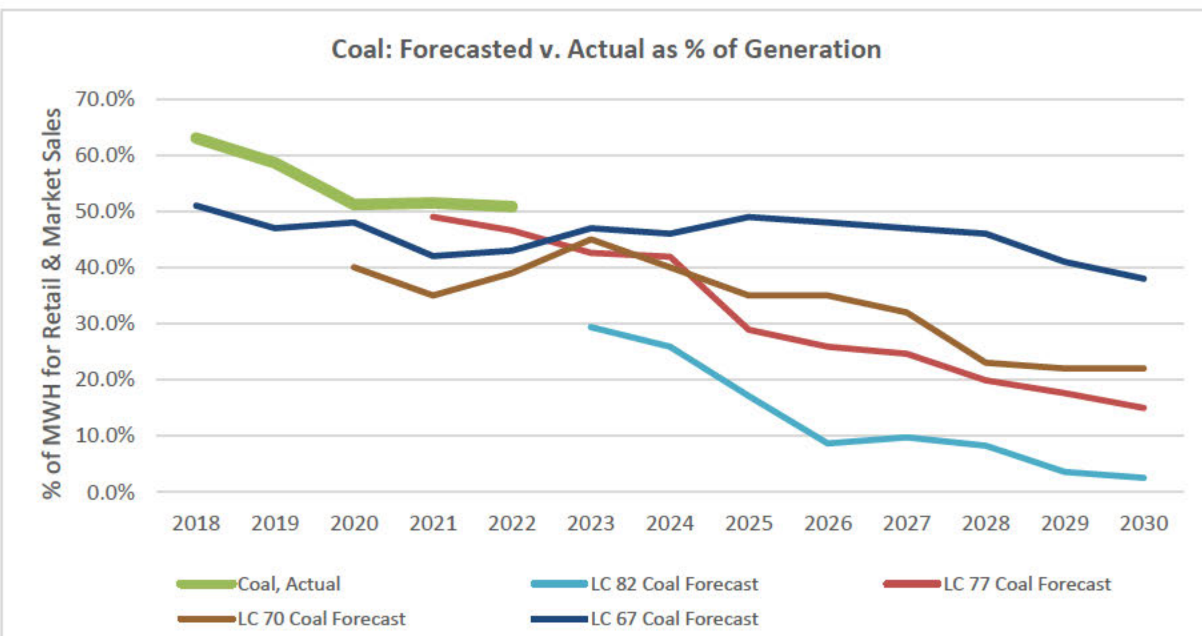
- Utilize coal prices for Jim Bridger that are reflective of actual costs from the Long-Term Fuel supply contract.
- Provide a full update on Utah coal supply issues.

Carbon Price Path

At the LC 82 Special Public Meeting on December 12, 2023, Bob Jenks of CUB raised an interesting point regarding PacifiCorp's use of carbon pricing. He noted that PacifiCorp's IRPs generally begin to apply a price to carbon two years after the IRP. This has the effect of reducing forecasted emissions in the IRP, especially from coal plants, as PacifiCorp's models internalized this carbon price into simulated, future operations. CUB suggested that because a true carbon price has never actually internalized into operations, real-life emissions are systematically higher than IRP modeled GHG emissions. CUB also noted in its Round 1 comments that an effective GHG price could be developed by forecasting, "...the annual cost of carbon from wildfires (prevention and insurance), divide that by its carbon emissions, and allocate the costs of emissions directly to the emissions themselves." [93]

Staff conducted a brief analysis forecasted to actuals in an attempt to substantiate CUB's comments regarding the disconnect between planning that uses a carbon price and actual coal operations.

Figure 8: 3Comparison of Forecasted v. Actual Coal Use as Percent of Generation



Staff's simple analysis would seem to corroborate CUB's concerns regarding the realism of PacifiCorp's modeled coal dispatch in the IRP. Staff raised a similar concern in UM 2225 in discussing the role of

[93] CUB Round 1 Comments, October 25, 2023, page 8.

operational changes in achieving GHG reductions and the Commission adopted the following expectation:

> *For the first CEP and associated IRP, if the Preferred Portfolio relies on operational changes relative to expected economic dispatch to reduce GHG emissions, including, but not limited to, application of operating or emissions constraints, inclusion of a GHG emissions cost in dispatch decisions, or out-of-state sales of fossil fuel generation, the utility should:*
>
> - *Quantify the impacts of those operational changes relative to expected economic dispatch in terms of generation (curtailed, reduced, or sold) and GHG emissions (avoided); and*
> - *Describe how the utility intends to implement those operational changes (e.g. through the development of operating or emissions limits, application of GHG emissions penalties, or execution of contracts with out-of-state entities), to the extent that they impact forecasted GHG emissions in the Action Plan window.* [94]

Accordingly, if the GHG emissions reductions in the CEP depend on the reduction in coal generation that results from applying carbon prices to dispatch, Staff would expect PacifiCorp to quantify those impacts in terms of both generation and GHG emissions, relative to an assumption of economic dispatch without carbon prices.

Importantly, PacifiCorp removes all coal from Oregon rates prior to 2030 per SB 1547 and so Staff expects this issue may only affect the Oregon-allocated GHG emissions in the 2020s. Nevertheless, PacifiCorp's use of GHG prices in modeling operations could be resulting in an unrealistic trajectory of GHG emissions reductions and the lack of an operationalized carbon price could therefore affect PacifiCorp's ability to demonstrate continual progress in the 2020s.

Staff fully supports PacifiCorp's use of GHG prices in portfolio design to capture the risk of future GHG policies. However, Staff is concerned that including GHG prices in the dispatch simulation that informs the Company's Oregon-allocated GHG emissions could be resulting in an unrealistic GHG reduction trajectory.

Staff Expectation:
In the next IRP/CEP PacifiCorp should:

- Recreate the chart above for (a) coal and (b) Oregon allocated GHG emissions comparing past IRP forecasts to actuals.
- Provide a sensitivity that calculates Oregon-allocated GHG emissions under the assumption of no carbon prices operationalized in dispatch. This sensitivity should still be based on the Preferred Portfolio, which considers a carbon price in investment decisions.
- Propose a PacifiCorp specific carbon price that layers atop the medium carbon price the Company's annual cost from wildfires as described by CUB.

[94] Order No. 22-446, Appendix A at page 21.

Candidate Resource Costs

In Round 1 comments, stakeholders raised concerns that PacifiCorp incorporated unreasonable price escalations for renewable resources. RNW's Round 1 Comments raised concerns on the cost assumptions PacifiCorp applied to its clean energy and energy efficient technologies, which include solar, wind (land-based and offshore), and storage resources.[95]

PacifiCorp sourced its cost data from WSP, an engineering and professional services firm, and later made some adjustments to the cost data to align with its view of future renewable resources market conditions.[96] WSP had relied primarily on the 2022 NREL ATB study to formulate renewable cost forecasts. The IRP states that PacifiCorp's cost-escalation curve differs from the NREL ATB forecast to account for observed market conditions, such as supply chain issues and long construction lead times.[97] RNW found that the company's ambiguous modifications to WSP's renewable resource cost estimates results in cost escalations that are 15-50 percent higher through the years 2023-2030.[98] PacifiCorp's sources or methodology behind large price escalations remain unclear. PacifiCorp has not clearly explained its resource cost modifications besides the "recent tighter trade tariff and inflation" observed in 2022.[99]

Staff agrees with RNW that the long duration of these high prices assumptions are concerning and not well proven. Manual adjustment of cost assumptions most likely affects resource selection and the preferred portfolio's economics.[100, 101] Due to the high capital cost forecast for renewable resources in PacifiCorp's IRP, the model selects over a GW of nuclear and non-emitting peaking resources through the years of cost escalations.[102]

While it is reasonable to assume cost escalations due to recent market conditions, PacifiCorp's estimates are far above the consensus. Compared to other studies that have adjusted for the recent market changes in renewable energy, PacifiCorp's adjustments have overstated the effects of inflation. Recently published studies have shown that cost increases may not be as persistent as PacifiCorp assumes. Lazard's most recent Levelized Cost of Energy Analysis from 2023 provides recent capital cost comparisons for renewable energy technologies based on a detailed analysis of observed new renewable builds across best-in-class renewables companies. This source provides a thoroughly vetted set of actual costs from newly installed projects.[103] Lazard's report states that "Even in the face of inflation and supply chain challenges, the LCOE of best-in-class onshore wind and utility-scale solar has declined at the low-end of our cost range, the reasons for which could catalyze ongoing consolidation across the sector—although the average LCOE has increased for the first time in the history of our studies."[104]

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[95] Renewable Northwest, Round 1 Comments, page 31.

[96] *Ibid.*

[97] *Ibid.*

[98] Renewable Northwest, Round 1 Comments, page 31.

[99] LC 82, PacifiCorp Reply Comments, page 47.

[100] Renewable Northwest, Round 1 Comments, page 32.

[101] *Id,* page 32.

[102] *Id,* page 32.

[103] https://www.lazard.com/media/2ozoovyg/lazards-lcoeplus-april-2023.pdf.

[104] Lazard. Levelized Cost of Energy Analysis-version 16.0. April 2023. Available at: https://www.lazard.com/media/2ozoovyg/lazards-lcoeplus-april-2023.pdf.

Regulators in other states are also assessing the reasonableness of using NREL ATB studies for the purposes of resource planning.[105] One South Carolina study found that relying on NREL ATB was reasonable and anticipates, "…a gradual decline in real-dollar costs due to industry learning curves and economies of scale, especially as renewable adoption accelerates. Therefore, we encourage Santee Cooper to remain open to upward adjustments in future procurement targets to capitalize on these anticipated cost reductions."[106] Staff finds this sentiment to be similarly relevant to PacifiCorp's resource cost methodology and would also encourage the Company to reassess overly conservative costs and monitor the market for anticipated cost reductions.

For example, PacifiCorp estimates a 34 percent increase in the cost for solar starting in 2023 and persisting for five years after, until cost declines in 2029. This results in a projected cost of $1,533/kW for a 200MW PV installation in Utah for 2023 through 2028.[107]

PacifiCorp's capital cost forecast for land-based and offshore wind is also unsupported by the 2023 NREL ATB and Lazard. For 2023 through 2028, PacifiCorp assumes roughly $2,000/kW for land-based wind and $5,900/kW for offshore wind. According to Lazard's 2023 Levelized Cost of Energy Analysis, capital costs for land-based and offshore wind reaches a high of $1,700/kW and $5,000/kW, respectively. [108]

Finally, PacifiCorp's resource storage assumptions are also significantly higher than NREL's projections. PacifiCorp's battery storage capital costs estimates are $454 and $477/kWh in 2022 and 2023 respectively, with no projected cost declines until 2029.[109] NREL 2023 study estimates capital cost of approximately $470/kW but assumes step cost decline afterwards with capital cost reaching a low $320/kW in 2032.

Staff, through its consultant, Synapse, conducted a high-level analysis to estimate the difference in the Preferred Portfolio's build costs if the utility had instead relied on NREL's 2023 ATB. This analysis relies on the current levels of near-term renewable builds presented in the 2023 IRP Preferred Portfolio and does not attempt to re-optimize the renewable builds based on these lower costs. This analysis reflects the situation where PacifiCorp conducts resource planning using elevated prices, and is able to procure renewable resources for lower cost in actuality.

Additionally, we highlight here that if PacifiCorp had incorporated supply-side costs for renewables that were more in line with PGE, CPUC, and NREL ATB, it is likely that PLEXOS LT would select more of these resources ***instead of*** higher-cost alternatives, such as nuclear, non-emitting peakers, and fossil units. It is important to note that the build costs shown in the PLEXOS LT outputs are shown pre-tax credits and without annualization, rate of return, or depreciation. This means that the final impact on the Preferred Portfolio revenue requirement will be different than the total cost delta presented below.

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105 See South Carolina Public Service Commission, Report by PA Consulting *Independent Review of Santee Cooper's 2023 Integrated Resource Plan*. December 2023.
106 *Ibid.*
107 PacifiCorp file "(P)-Figure 7.3-7.5 History of IRP Renewables Cost Curves 2023 0119.xlsx".
108 https://www.lazard.com/media/2ozoovyg/lazards-lcoeplus-april-2023.pdf.
109 Renewable Northwest, Round 1 Comments, page 38.

Table 9: Renewable Build Costs Summary Results

Category	Resource Type	NPV (2023-2030) ($M)	2023	2024	2025	2026	2027	2028	2029	2030
Capacity (MW)	Solar	n/a	-	-	1,069	2,524	483	1,907	-	-
2023 IRP Build Costs ($)	Solar	$7,037	-	-	$1,687	$4,020	$790	$2,946	-	-
ATB Build Costs ($M)	Solar	$6,034	-	-	$1,474	$3,440	$650	$2,530	-	-
Delta ($M)	Solar	$1,003	-	-	$213	$580	$140	$416	-	-
Capacity (MW)	Wind	n/a	-	43	296	-	100	300	1,900	-
2023 IRP Build Costs ($M)	Wind	$3,317	-	$85	$644	-	$212	$613	$3,394	-
ATB Build Costs ($M)	Wind	$2,427	-	$59	$405	-	$138	$414	$2,631	-
Delta ($M)	Wind	$890	-	$26	$240	-	$75	$199	$763	-
Capacity (MW)	BESS	n/a	-	-	754	2,929	628	1,900	1,149	-
2023 IRP Build Costs ($M)	BESS	$9,594	-	-	$1,364	$5,300	$1,136	$3,416	$2,009	-
ATB Build Costs ($M)	BESS	$8,590	-	-	$1,240	$4,767	$1,010	$3,018	$1,800	-
Delta ($M)	BESS	$1,004	-	-	$124	$533	$126	$398	$209	-
Total Delta ($M)	All	**$2,897**								

Staff Expectation:

- As part of the IRP update and future IRP processes, PacifiCorp should update its renewable cost assumptions based on more recently available information.

Natrium and Non-Emitting Peaking Resources

In Opening Comments, Staff raised concerns about the permitting timeline and fuel availability of nuclear resources in the Company's preferred portfolio.[110] Staff concerns about reactor fueling risks and permitting were shared in comments from the Sierra Club,[111] NewSun,[112] and Renewable Northwest.[113] As an example RNW documented the lengthy six-year timeline to final approval by the NRC of the only other small modular reactor (SMR) design to date, developed by TerraPower competitor NuScale Power Company.[114] RNW follows this discussion with a request for the Company to identify offramps that would provide adequate lead time for replacement of the Natrium facility with clean energy resources with comparable attributes, a request that Staff finds to be reasonable.

[110] LC 82 – Staff's Round 1 Comments, page 44.
[111] LC 82 – Sierra Club's Round 1 Comments, page 58.
[112] LC 82 – NewSun Energy's Round 1 Comments, page 5.
[113] LC 82 – Renewable Northwest's Round 1 Comments, page 21-22.
[114] Id.

In PacifiCorp's December reply comments, the Company stated that its consideration of nuclear resources in the 2023 IRP are consistent with Oregon IRP Guidelines 1(a), 1(b), and 1(c), and therefore those resources are limited to years outside of the action plan and CEP planning windows and require continued evaluation of their potential.[115] The Company further stated that it "cannot provide meaningful tracking and reporting" on the Natrium facility's NRC Construction Permit Application due to there being no commercial agreement with the facility's developer, TerraPower. The Company did provide that a construction permit (CP) is targeted for submission to the Nuclear Regulatory Commission (NRC) by Q1 2024, stating a generic timeframe for issuance of the CP by the NRC is 36 months.[116] Staff, assuming a similar 36-month timeline for issuance of the separate operating license (OL) for the Natrium facility from the NRC, contemplates substantial risk in selecting this resource in the preferred portfolio for inclusion in the year 2030. Staff finds comments from the Sierra Club, NewSun, and RNW regarding fueling cost and risk, permitting timeline risks, and the lack of adequate alternatives should permitting issues arise, to be compelling.

The Company's timelines for the availability of non-emitting peaking resources and nuclear resources have both been modelled for portfolio consideration in the year 2030 or beyond, intentionally outside of the action plan window and the current CEP compliance window.[117] As the Company states that it anticipates that non-emitting peaking resources will improve in performance and cost-effectiveness, Staff believes that the Company should also prepare for the possibility that both non-emitting peaking resources and nuclear resources may potentially fail to materially improve in those regards before the year 2030.[118]

In short, Staff finds that the overly optimistic timeline for both the Natrium nuclear technology and any potential non-emitting peaking technology - given both what is known and unknown - requires planning more reflective of implementation risks. Staff is not opposed to either technology per se and believes they may both be necessary to achieve HB 2021's 2040 target and for the broader region to decarbonize. However, we agree with RNW's observation that the 2021 IRP selection of Natrium in 2028, which was due in part to overly optimistic assumptions, impacted both the action plan and the scope of the subsequent RFP (UM 2193).[119] Staff finds that PacifiCorp appears to be repeating the same process in LC 82 with these long lead time resources. An additional implication of this approach in LC 82 is that it puts Oregon's decarbonization efforts at risk.

Per a December filing, NRC has scheduled a readiness assessment meeting for the TerraPower permit application on January 10, 2024.[120] The process to conduct the assessment will take four weeks and 45 calendar days, following which NRC staff will issue a public report on their findings. The approximate date for the publication of this report will be approximately around March 20, 2024. At the point of the NRC report's publication, the Company should have a clear understanding if the Natrium project is on track to begin construction under the very tight timelines found in LC 82.

In variant portfolio P06 – No Forward Tech, PacifiCorp explored the risk of neither the nuclear facility ***nor*** the non-emitting peaker being operational by the end of 2030. This portfolio showed no impact to

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[115] LC 82 – PacifiCorp Reply Comments, page 94-95.
[116] PacifiCorp response to Staff DR No. 118.
[117] LC 82 – PacifiCorp Round Reply Comments, page 93-95.
[118] LC 82, PacifiCorp Reply Comments, page 93.
[119] Renewable Northwest, Opening Comments, page 20.
[120] *See Filing in NRC Docket 99902087, "Preapplication Construction Permit Readiness Assessment Plan," December 20, 2023.*

the timing of the planned retirements of approximately 2.5 GW of coal generation capacity between 2028 and 2032. Instead this variant portfolio showed more some additional solar and wind but most notably an additional 1.2 GW of batteries by 2033. This portfolio had some of the highest emissions compared to all other portfolios.[121]

As RNW notes, the Company's plan to replace SMRs should they not be viable is to largely replace them with non-emitting peakers.[122] The Company states that non-emitting peakers' limited presence in the 2023 IRP preferred portfolio supports the Company's position that the risks associated with these resources are reasonable.[123] Given the potential for neither to emerge and both the higher cost and higher emissions associated with this outcome – as evidenced by P-06 – the Preferred Portfolio's reliance on emergent nuclear and non-emitting peaking resources may prove to be an outsized risk.

Staff would note that in LC 80 the procurement of long lead time (LLT) resources posed a similar set of risks and procurement challenges for PGE. Given the uncertainty around timelines for both nuclear and non-emitting peaking resources, Staff believes that the Company should issue a request for information (RFI) for LLT resources. The RFI should be used to inform placement of LLT emergent resources in a preferred portfolio more realistically by accurately comparing them against more traditional, matured, resources. To gain a more accurate view of the entire resource landscape, the Company's RFI could also study advanced geothermal, pumped hydro storage, transmission costs associated with offshore wind, and any other resources identified by the Company or stakeholders. The Company might even coordinate with PGE in developing this RFI for a streamlined approach.

Staff Recommendation 11. Direct PacifiCorp to update Action Plan Item 1g to reflect actual events since the IRP/CEP was filed in May 2023.

Staff Expectations:

- Inform the Commission in the IRP Update whether the TerraPower permit application passed the U.S. NRC's readiness assessment for Natrium's construction permit and the estimated timeline for the project following that decision.
- In the next IRP, utilize a ten-year buffer between the date of the issuance of the Natrium CP and when that resource may appear in the Company's preferred portfolio.
- In the next CEP, more directly address the high-level planning questions from Order No. 22-446 regarding the critical junctures, dependencies, and barriers to nuclear and any non-emitting peaking technology as part of a preferred portfolio.

Small Scale Renewables

In Opening Comments, Staff expressed an interest in exploring options to facilitate the development and acquisition of small scale renewables (SSRs) in a cost-effective manner, highlighting the RPS certification process in particular.[124]

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[121] LC 82, PacifiCorp 2023 IRP, page 268, Table 9.14.
[122] Renewable Northwest, Opening Comments, page 22.
[123] LC 82, PacifiCorp Reply Comments, page 93.
[124] LC 82 – Staff's Opening Comments, page 46.

Staff greatly appreciates the Company's efforts to offer regulatory recommendations toward easing the acquisition of SSRs in its reply comments. Regarding the Company's recommendation that the OPUC amend or waive OAR 860-091-0030(1), Staff finds that this may be an unnecessary solution to a barrier that remains, in Staff's view, to be largely informational. The Company specifically cites an additional ODOE regulation, OAR 330-160-0035(2), that "may require…an explanation of the relationship between the applicant and the WREGIS account holder."[125] Staff does not understand how this requirement, nor RPS certification as a whole, are meaningful barriers to potential SSR project financing.

Staff agrees with the Company's recommendation that incentives might be refined or updated to better reflect system SSR needs through updated PURPA policies in the OPUC's UM 2000 proceeding.[126] Should these policies be updated to better reflect SSR acquisition costs, Staff would urge the Company to utilize PURPA policies to the greatest extent possible to streamline its SSR acquisition process, and additionally facilitate modelling of SSR acquisition in portfolio modelling as the SSR mandate will remain an ongoing compliance obligation. The ability to model SSR acquisition costs reliably and accurately will facilitate the modelling of marginal SSR needs and associated costs when system capacity acquisitions are made.

Resource Adequacy Modeling, Front Office Transactions, and WRAP

In Opening Comments, Staff found that the Company's current resource adequacy and capacity valuation approaches are lacking necessary sophistication and should be updated with both more data and methodologies that better conform to best practices. Staff recommended that the Company incorporate WRAP into its next IRP, update its resource capacity contribution methodology, add more weather data, and perform a Loss of Load Expectation (LOLE) analysis on the preferred portfolio.[2]

RNW has a host of recommendations for the Company to modernize its reliability and resource adequacy modeling that are largely in line with Staff's opening comments. Among them, RNW recommends that the Company move beyond its current capacity factor method to something an Effective Load Carrying Capability (ELCC) method or something similar, such as the "Global Slicing Block" that is available in PLEXOS.[3] RNW also believes that the Company's 13 percent Planning Reserve Margin is unfounded.[4] Of greater concern to them, RNW finds that the Company's deterministic look at Loss-of-load-probability (LOLP) modeling is lacking and recommends that the Company incorporate stochastic parameters for weather risk factors that correlate with supply and demand.[5] Given that the Western Resource Adequacy Program (WRAP) may become binding as early as 2026, RNW also advocates that the integrate WRAP into the IRP process.[6]

The Company responded to comments made by both Staff and RNW in its Round 1 Reply Comments. Staff recommended that the Company update its capacity valuation methodology to incorporate multiple years of weather data, calculate and report the LOLE of the preferred portfolio in each year and explain why the Company chose to plan to its current level of reliability.
PacifiCorp agrees with Staff and RNW that incorporating stochastic conditions is a necessary part of identifying supply and demand risks and notes that neither wind nor solar nor energy efficiency savings were modeled stochastically in the 2023 IRP. The Company also agrees that the value of stochastic analysis is higher when multiple years of data are used but also notes that incorporating this is a significant undertaking. The Company states that it looks forward to further improvements to the LOLP and that it is always open to improvements in its RA modeling.[7] In response to Staff's and RNW's

[125] LC 82 – PacifiCorp Reply Comments, page 85.
[126] Id, page 86.

comments on WRAP, the Company states that it is actively evaluating the WRAP program and considering how to implement it in the IRP as early as 2026.[8] The Company did not appear to directly respond to RNW's recommendation to conduct an ELCC style analysis.

Staff recognizes that updating LOLP, capacity valuation, and RA modeling is a large undertaking that may take many months. While Staff continues to advocate for the use of more years of weather, load and generation data, Staff is supportive of these things being included in the Company's next IRP. Staff also agrees with RNW's comments advocating for stochastic modeling of supply and demand variable in LOLP analysis and recommends that wind and solar resources be modeled stochastically using observed weather and load correlation. Staff also agrees with RNW that switching to an ELCC style analysis of capacity valuation is a necessary modeling improvement that should be integrated into the next IRP. Staff reiterates its past recommendation that the Company model and report the LOLE of the preferred portfolio in a future IRP.

Staff continues to recommend that PacifiCorp consider WRAP participation, including potential future obligations and benefits, in the next IRP. Staff notes that another Oregon-regulated utility, Idaho Power, has chosen to model the benefits of WRAP in its current IRP, LC 84, and assumes that WRAP's operational program would provide some system capacity benefit starting in 2027.[127] While Idaho Power presents this merely as a first attempt at modeling WRAP benefits, Staff feels it necessary to point out that one of the Company's Oregon peer utilities has already begun incorporating WRAP into its IRP.

Front Office Transactions

Staff is concerned by the Company's reliance on FOTs in its IRP.[128] PacifiCorp's IRP allows for a certain amount of market purchases to contribute to system capacity needs. These purchases are referred to as Front Office Transactions (FOTs) and they have limits as shown in Table 5.8 in the IRP and reproduced below as Table 10.

Table 10: Reproduction of Table 5.8 of IRP[129]

Market Hub	Availability Limit (MW)				
	2023 IRP			2021 IRP	
	Short-term (2023-2027)	Long-term (2028-2042) Summer	Long-term (2028-2042) Winter	Summer	Winter
Mid-Columbia (Mid-C)	1979	500	350	500	350
California Oregon Border (COB)	424	0	250	0	250
Nevada Oregon Border (NOB)	200	0	100	0	100
4 Corners (4C)	398	0	0	0	0
Mona	325	0	300	0	300
Total	**3326**	**500**	**1000**	**500**	**1000**

In the IRP, FOTs are modeled as short-term purchases that can be made with little or no notice. However, this may be an oversimplification. Staff also notes that in order to demonstrate compliance with WRAP, an entity has to secure resources and contracts with a lead time of multiple months,

[127] LC 84, Idaho Power IRP Initial Filing, page 8.
[128] LC 82, PacifiCorp 2023 IRP, page 33, Action item 5a.
[129] 2023 IRP at 126.

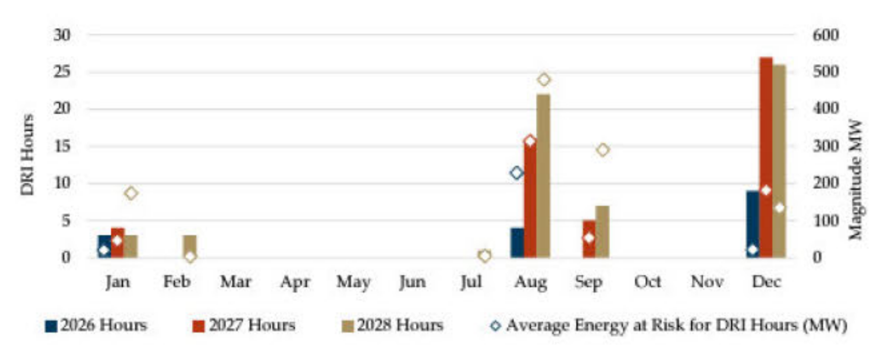
meaning that the Company's choice to rely on short-term purchases may lead to the Company being out of compliance with WRAP's forward showing requirements. Further, given the suspension of the Company's RFP, UM 2193,[130] Staff anticipates that the Company will need to rely further on FOTs to offset resources that may come on later than what was expected at the beginning of LC 82.

In other proceedings, the Company has noted that the volume of transaction in regional wholesale markets has been steadily declining in recent years.[131] The Company models a constant level of FOT availability at its main five market hubs through 2027, which is incongruous with its operational realities of the last few years. Staff worries that the failure to align its action plan assumptions with the operational realities it uses as evidence in its power cost dockets could lead to a situation in which it neither has resources available to meet its load nor a viable counterparty to buy energy in a peak load hour.

Renewable Northwest also expressed concern with PacifiCorp's assumptions regarding future reliance on regional markets. RNW notes that near-term reliance on market purchases for capacity in this IRP is high. In addition, RNW notes that the Load and Resource Balance table in the IRP includes market purchases well above the stated FOT limits in Table 5.8. RNW notes, "regional markets are likely to experience increasing uncertainty in both depth and availability due to environmental policies and regional market initiatives, which increases the importance of hedging against the continued risk of high market reliance in the future." RNW recommends that PacifiCorp work with other regional planning organizations such as the Western Power Pool (WPP) to develop "a detailed, quantitative analysis on the likelihood of regional markets to provide reliable power at non cost-prohibitive prices." Staff acknowledged that a regional study could provide value in long-term planning, but notes that there are currently multiple organizations that already look at resource adequacy to assess whether there is a surplus of energy available in the region. For example, WECC releases frequent studies of regional capacity availability. The 2023 WECC Western Assessment of Resource Adequacy (WARA) finds that total planned resources in the WECC are not adequate to prevent substantial "Demand at Risk" hours in 2026-2028.[132] Demand at risk hours are defined as the number of hours in a year that are at risk for loss of load exceeding the one-day-in-ten-year outage threshold. As Figure 9 below shows, in August 2028, the WARA finds on average about 500 MW of Demand at Risk over 25 hours.[133] We note, however, that shortage predictions five years out can often change, as both demand and supply side resources respond in advance to potential shortfalls with incremental development activity.

Figure 9: Mid-term DRI Hours and Magnitude for the Western Interconnection

[130] See the Company's September 29, 2023 filing in UM 2193.
[131] See UE 420, PAC/400, Mitchell/59 here.
[132] WECC. 2023 Western Assessment of Resource Adequacy, page 17.
[133] WECC. 2023 Western Assessment of Resource Adequacy, page 16.



The WARA finds that a significant increase in Demand at Risk hours in December can be attributed to increased load forecasts in the Northwest, while there are relatively few utility-scale resource additions planned in the Northwest. The WARA concludes that load serving entities may need to delay resource retirements if they cannot mitigate these risky hours in the next two years. However, we note that WARA may have less visibility into local small-scale supply and demand resource activity that could reduce the at-risk hours in those out years.

Notably, PacifiCorp's IRP relies on 944 MW of summer market purchases in 2027 and 493 MW in 2028.[134] Given WECC's showing of regional resource adequacy risk during August in those years (red bars in Figure 4 above), the expectation of nearly 1 GW of market energy being available for purchase during summer peak hours seems potentially risky. Further, PacifiCorp has suspended the 2022AS RFP that would have brought resources online from 2025 through 2027, further increasing the region's resource adequacy risk.

These findings are concerning and indicate that PacifiCorp should look seriously at reducing market reliance in the near term, whether through longer-term contracts or resource procurements. If PacifiCorp continues to plan its system around procuring capacity from the market that may not be available and is forced to delay fossil retirements as a result, the Company could be at risk for failing to meeting its HB 2021 Oregon emissions reductions targets and much higher power costs. To address this, PacifiCorp should consider actions to reducing near-term market reliance in the next IRP.

Staff also expects PacifiCorp to consider how WRAP participation might affect the Company's reliance on FOTs in the next IRP. The WRAP forward showing program will require PacifiCorp to secure enough resources to meet their obligations seven months in advance. Staff's understanding is that this requirement may limit FOTs to transactions that can be secured on that timeline. Staff also expects that information from the WRAP program may bring additional transparency into the depth of regional markets during constrained periods and that this information could help to inform future assumptions regarding FOT availability.

Staff Expectations:

By the next IRP, PacifiCorp should:

- Include more years of weather data in its resource adequacy modeling.
- Change its capacity valuation to an ELCC or ELCC-adjacent methodology that has weather-correlated stochastic modeling.

[134] LC 82, PacifiCorp 2023 IRP, page 325.

- Calculate and report the LOLE of the Preferred Portfolio in each year.
- Model the benefits of WRAP to the Company's system and compliance hurdles in addition to any requirements that arise from the ongoing resource adequacy rulemaking in AR 660.
- Account for the benefits of WRAP in future IRPs if it plans to continue as a WRAP participant.
- Update FOT availability assumptions based on insights from regional analysis and the WRAP program.
- Restrict the modeling of FOTs to contracts that can be obtained seven months ahead of need.

Transmission

Transmission & Storage

In Round 1 Comments, Energy Advocates recommends, "PacifiCorp should expand future CEP/IRP's to look beyond storage co-location near generation sites and to identify substations and transmission lines that can use storage to flatten load peaks and avoid congestion and costly transmission and distribution upgrades."

In Reply Comments, PacifiCorp responded that the 2023 IRP allows standalone storage to be selected at generator and load locations, in addition to co-location near generation sites. PacifiCorp states, "Additionally, storage options that were not part of a cluster study were considered unconstrained by transmission requirements, such that any amount could be placed anywhere on the system."[135]

PacifiCorp also notes that "[t]he specific substation and transmission would be identified in the request for proposals process after the 2023 IRP."[136] We note, however, that PacifiCorp should reconcile this statement with its unambiguous indication in the IRP itself that battery storage resource options are limited to co-location at generation sites.[137]

PacifiCorp's explanation partially addresses Energy Advocates' recommendation, although it does not directly explain how PacifiCorp considers the ability of storage to avoid transmission and distribution upgrades. PacifiCorp applies a Transmission and Distribution deferral credit to DSM resources in the IRP; however, it does not appear that PacifiCorp has used a T&D deferral value for storage in PLEXOS IRP modeling.

In evaluating PacifiCorp's consideration of T&D deferral value, it may be valuable to consider transmission deferral separately from distribution deferral. Regarding transmission, the PLEXOS modeling logic should be able to assess the potential for storage to reduce or defer the need for endogenously selected transmission resources. The model can generally make economic decisions about whether to upgrade the system with storage or to select a major new transmission investment.[138] However, there may be some transmission deferral value that is not considered in the IRP PLEXOS modeling. For transmission system investments that cannot be selected by the model, and are instead hard-coded, the model will not be able to see any opportunities to defer these resources by acquiring storage.

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[135] LC 82, PacifiCorp Reply Comments, page 73.
[136] LC 82, PacifiCorp Reply Comments, page 72.
[137] LC 82, PacifiCorp 2023 IRP, Chapter 8, page 233: "Batteries are assumed to **always** be co-located with other resources, enabling them to shift energy…". Emphasis added.
[138] PacifiCorp response to OPUC DR 190.

The IRP generally states that transmission resources are available for endogenous selection.[139,140] However, further clarification from PacifiCorp to verify whether this applies to all or only some planned transmission resources that could be deferred by storage would be valuable. There may be some transmission expenses that can be deferred by strategically located storage but are not included in the PLEXOS model. If these costs are significant, then applying a transmission deferral credit to storage resources in the IRP could be appropriate.

Staff Expectation:

- In the next IRP, develop a transmission deferral credit for storage resources.

Demand Side Management

Staff's Round 1 Comments supported PacifiCorp's plan to include near-term cost-effective EE in the Company's preferred portfolio. The long-term EE modeling however, appeared insufficient. Staff's analysis found that PacifiCorp had not included available and low-cost EE in the preferred portfolio after 2025.[141] Accordingly, Staff requested that PacifiCorp allow optimization of EE in the CEP to inform whether EE could reduce HB 2021 costs allocated to the CEP portfolio. Staff also requested PacifiCorp reoptimize the Max DSM scenario. Additionally, Staff found opportunities to improve PacifiCorp's avoided costs, such as including avoided planning reserve margin costs and considering HB 2021's emissions constraints.[142] Finally, Staff found PacifiCorp's short-term DR acquisition strategy reasonable but recommended additional measures to reduce NPVRR.

In Round 1 Comments CRITFC, CUB, Energy Advocates, and Sierra Club saw room for additional DSM measures in the preferred portfolio. By extension, they questioned whether PacifiCorp's long-term planning recognized the full implications of HB 2021. CRITFC, CUB, and Energy Advocates voiced concerns that the existing cost-effectiveness tests overlooked EE's non-energy values of improved community resiliency and reduced environmental and ratepayer burdens.

In Round 1 Reply Comments PacifiCorp did not allow the Max DSM Scenario to reoptimize the resource selections around the additional EE. PacifiCorp also declined to reoptimize EE in the CEP. According to PacifiCorp, this request was unnecessary because the model had selected an average of 91 percent of potential EE between 2023 to 2030, with few remaining potential EE measures to meet system needs. PacifiCorp further argued there is no statutory or regulatory mechanism requiring the Company to optimize EE for CEP requirements. Similarly, PacifiCorp argued it lacked Commission guidance to include HB 2021's constraints in avoided cost data. PacifiCorp stated that the Company's method is like the traditional concept of "capacity cost" with the added component of renewable energy compliance. PacifiCorp's standard renewable avoided costs reflect the cost of a renewable wind proxy starting in 2026; prices after that date would not include a forward market component. PacifiCorp further explained that calculating the avoided planning reserve margin cost was difficult due to the addition of

139 LC 82, PacifiCorp 2023 IRP, page 221.
140 LC 82, PacifiCorp 2023 IRP, page 213.
141 LC 82, Staff Round 1 Comments, October 15, 2023, page 58, Figure 12.
142 For example, in using the existing avoided cost method, Staff found the Company overlooked the need to purchase non-emitting resources rather than the least-cost market resources. These comments mirrored Staff's comments to PGE in LC 80. *See In the Matter of Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan*, Docket No. LC 80, Staff Corrected Opening Comments at pages 27-30 (July 27, 2023).

variable energy resources. Finally, PacifiCorp provided an update on its electrification modeling and agreed to consider DR measures encouraged by Stakeholders.

Staff's review of OPUC DR 80-1 found that the preferred portfolio selected only 80 percent of available EE between 2023 and 2030, which contradicts PacifiCorp's claim of 91 percent.[143] In either case, the model selected EE *without considering HB 2021,* which suggests that the model would select more EE once HB 2021 strategy is considered. Staff requests that the 2024 IRP Update address the discrepancy in EE acquisition and ensure that the model considers HB 2021 compliance in the preferred portfolio.

Further, PacifiCorp's 2023 IRP analysis relied on an Energy Trust potential study which used avoided costs from the 2019 IRP.[144] If the Company's long-term planning were to indicate that greater amounts of efficiency at higher avoided costs would benefit the system, Energy Trust could perform a new potential estimate that would likely result in a higher amount of available efficiency in Oregon. Therefore, Staff concludes that PacifiCorp's least cost, preferred portfolio likely includes more EE from the previously identified potential, plus additional new23 potential that may have been screened out of Energy Trust's potential study.

Given the impactful new requirements of HB 2021, the value of efficiency in Oregon should diverge substantially from the value of efficiency to some other states on PacifiCorp's system. Under Senate Bill 1547 (2016) and codified in ORS 757.054(3)(a), investor-owned utilities are required by law to acquire all cost-effective energy efficiency and demand response prior to acquiring new generating resources.[145] To meet this requirement, new approaches to avoided costs must be explored and Staff expects PacifiCorp to help update the accounting in UM 1893 to reflect current state policy. Staff expects that Oregon-specific avoided cost analysis will be included in PacifiCorp's IRP Update and future IRPs. The acquisition of higher-value Oregon EE in light of HB 2021 requirements, should be part of PacifiCorp's preferred portfolio in both IRP and CEP planning, not relegated to one or the other.

Staff will consider approaches to avoided cost valuation from other regions, such as the method used by New England energy efficiency program administrators.[146] PacifiCorp's current IRP modeling approach for calculating avoided energy costs has similarities with the New England AESC modeling construct and could be improved to better represent Oregon-specific benefits.
Staff reiterates prior recommendations from Round 1 Comments regarding demand response resources. Staff recommends acknowledgement of DR acquisition to 2026, but encourages the Company to consider additional classes of DR as part of the least cost, least risk portfolio in future analysis. Staff again cites the Northwest Power and Conservation Council's 2021 Power Plan recommendations for utilities to pursue frequently deployable, low-cost measures with minimal customer impact, including time-of-use rates and demand voltage reduction.[147] PacifiCorp did not respond to this request in Round

[143] See PacifiCorp response to Staff DR No. 80-1.
[144] Under OAR 860-030-011(2), utilities must provide energy efficiency avoided cost data based on the utility's most recently acknowledged IRP or update, or from the energy utility's most recent general rate case that has been resolved by a final order of the Commission.
[145] ORS 757.054(3)(a), https://oregon.public.law/statutes/ors_757.054.
[146] For every planning period (3 years), the efficiency program administrators sponsor an avoided energy supply components (AESC) study to determine the value of energy efficiency and other demand-side measures. Avoided costs are calculated for each New England state under a hypothetical future in which New England program administrators do not install any new demand side measures in future years.
[147] See 2021 Northwest Power Plan, page 47. https://www.nwcouncil.org/fs/17680/2021powerplan_2022-3.pdf.

1 Reply Comments. Staff expects future IRP analyses will consider these two resources to help manage power costs and reduce emissions.

Staff Recommendation 12. Acknowledge Action Item 4a to acquire cost-effective energy efficiency and demand response resources.

Staff Recommendation 13. Acknowledge updated avoided costs from the 2023 IRP planning and direct PacifiCorp to work with Staff and Stakeholders to update avoided costs for use in UM 1893 considering HB 2021 constraints.

Staff Expectations:

- In the IRP update, PacifiCorp should address the discrepancy in EE acquisition and ensure that HB 2021 compliance is considered in the preferred portfolio.
- In the next IRP, PacifiCorp should model a counterfactual case in which utilities install no new energy efficiency in Oregon in 2025 or later years.
- In the next IRP, PacifiCorp should include the HB 2021 emissions requirement and SSR/CBRE requirement based on the load forecast without new EE.
- In the next IRP, analyze the role of frequently deployable, low-cost DR measures with minimal customer impact, including but not limited to time-of-use rates and demand voltage reduction.

Conclusion

Despite the good work and hard effort of PacifiCorp staff, the decisions to both suspend the 2022 AS RFP **and** push all necessary revisions of LC 82 analysis to the IRP Update mean Staff and stakeholders lack the shared analytic understanding for making many of the needed acknowledgement recommendations required of this IRP/CEP. Until additional analysis is done, and the Preferred Portfolio is revised, many aspects of this IRP and the CEP cannot be acknowledged.

Staff proposes to truncate the LC 82 review process. Staff will file a motion to update the schedule so as to bring the recommendations from these comments forward for acknowledgement at the public meeting on February 20, 2024. Staff will seek a Commission order on those items that it believes can be acknowledged **and** on minimum analytic requirements for the IRP Update. Further, we recommend that the CEP be revised and resubmitted, per Staff's suggestions, with the IRP Update so that it has the potential to be acknowledged.

Dated at Salem, Oregon, this January 24th, 2024.

JP Batmale

JP Batmale
Administrator
Energy Resources and Planning Division

Appendix A: Summary of Recommendations

<u>RFP Suspension</u>
Staff Recommendation 1. Do not acknowledge the IRP action plan elements 2b and 2c, the IRP's preferred portfolio, or the IRP's long-term plan**.**

Staff Recommendation 2. Direct PacifiCorp to seek acknowledgement of a revised Preferred Portfolio and Action Plan in the planned April 2024 IRP Update.

Staff Recommendation 3. Do not acknowledge the LC 82 CEP and direct PacifiCorp to revise and resubmit the CEP with its April 2024 IRP Update.

<u>Action Plan Changes</u>
Staff Recommendation 4. Do not acknowledge Action Plan items 1h and 2a.

CEP Comments:
<u>Community Benefit Indicators</u>
Staff Recommendation 5. Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.

Staff Recommendation 6. Direct PacifiCorp to provide baseline metrics prior to filing its next IRP/CEP Update. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.

<u>CBRE Resource Potential</u>
Staff Recommendation 7. Direct PacifiCorp to proceed with the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG in Q1 2024.

<u>Community Engagement</u>
Staff Recommendation 8. Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.

<u>Resiliency Analysis Framework</u>
Staff Recommendation 9. The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and the CBRE Pilot be designed to promote resiliency-related factors.

IRP Comments:
<u>Preferred Portfolio Modeling Process</u>

Staff Recommendation 10. Direct PacifiCorp to fix any confirmed analytical errors in the calculation or application of granularity adjustments.

Natrium and Non-Emitting Peaking Resources

Staff Recommendation 11. Direct PacifiCorp to update Action Plan Item 1g to reflect actual events since the IRP/CEP was filed in May 2023.

Demand Side Resources

Staff Recommendation 12. Acknowledge Action Item 4a to acquire cost-effective energy efficiency and demand response resources.

Staff Recommendation 13. Acknowledge updated avoided costs from the 2023 IRP planning and direct PacifiCorp to work with Staff and Stakeholders to update avoided costs for use in UM 1893 considering HB 2021 constraints.

Appendix B: Staff Expectations

State Policy Compliance in IRP Portfolios

- In the next IRP, PacifiCorp should demonstrate that simultaneous compliance with all state-level policies is feasible with the Preferred Portfolio and with the Preferred Portfolio variants tested in the IRP.
- In the next CEP, PacifiCorp should transparently explore and describe constraints that HB 2021 compliance potentially places on allocation.

CEP Compliance Pathways

- PacifiCorp should utilize its 2025 IRP public input workshops to clarify with stakeholders the relationship between MSP, IRP "actions", Oregon's CEP requirements, and Oregon's DEQ compliance methodology and explore improvements such that HB 2021 targets and activities are informative to and reflected in MSP decisions. As part of this process, changes to MSP disclosure rules should be explored to increase transparency.
- To improve an understanding of tradeoffs in the IRP Update and/or as part of the revised CE, the Company should report Oregon-allocated costs and GHG emissions for the top performing IRP portfolios (inclusive of Oregon's SSR requirement) under various allocation pathways and that PacifiCorp.

Coal-to-Gas Conversions

- PacifiCorp should provide analysis around risk of regret for coal to gas conversions in its 2023 IRP Update.
- PacifiCorp remove Action Items 1c and 1d from the action plan because the Company has already taken these actions.

CEP Comments:

Community Benefit Indicators

- In the next IRP/CEP, Staff expects PacifiCorp to:
    - Adopt CBIs representing the community impacts of energy efficiency, local non-GHG emissions from PacifiCorp facilities, and the Company's CBRE actions.
    - Better inform CBIs and methods with input from stakeholders and community.
    - Enhance tribal-focused CBIs.
    - Use CBIs to better reflect the health impacts of EE.
    - Provide portfolio analysis that allows more direct comparison of tradeoffs of different resource strategies e.g., more precisely capture the CBIs of portfolios.
    - Enhance the ability of CBIs to better reflect the resiliency benefits of actions.
    - Incorporate CBIs reflecting community-level impacts of non-GHG emissions, energy efficiency, and the Company's CBRE actions.

CBRE Activities

- Report regularly to the CBIAG on development including concrete and proactive activities PacifiCorp takes to reduce barriers, accelerate deployment, and expand CBRE potential.

CBRE Inclusion in Preferred Portfolio

- In the IRP/CEP update:
  - Include at least 92 MW of CBRE in the preferred portfolio, depending on the current pipeline of existing programs.

- By the next IRP/CEP:
  - Highlight and communicate the relative benefits of CBRE in load pockets.
  - Quantify the costs and benefits of CBRE for meeting HB 2021 guidance to "[e]xamine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy."[148]
  - Identify one or more new, specific CBRE resource opportunities in Oregon and report on findings regarding specific costs and benefits.

CBRE Program Design

- Engage the CBIAG on potential program designs that can scale quickly to meet community and system needs.

Community Engagement

- Staff expects PacifiCorp's CBIAG and CBI activities to better capture and document Environmental Justice community priorities.
- In the next CEP, Staff expects PacifiCorp to better articulate how it is leveraging stakeholder input and deliverables in related dockets and venues to inform CBIs, CBREs, and portfolio decisions.
- PacifiCorp should include the following additions and enhancements to the Feedback Tracker:
  - Organization/entity attribution or affiliation.
  - Flag for whether and where PacifiCorp incorporated the feedback into specific utility planning, actions, resource selection, and project prioritization.
  - Clear description of why feedback was or was not included.
- Staff encourages PacifiCorp to report on its Tribal engagement strategy by December 31 of each year to the CBIAG. The review should include successes, opportunities for improvement, feedback received, a discussion of Tribal CBIs and CEP/DSP project development, and any work to involve Tribal Nations in planning and resource decision-making.
- PacifiCorp to conduct a participant survey on the engagement process before the next IRP/CEP filing. The survey should allow PacifiCorp to measure the effectiveness of the Company's engagement strategy efforts.

Resiliency Analysis Framework

- PacifiCorp should specify how it intends to incorporate CBIAG feedback and other community input into the community-utility resilience scores and risk drivers by March 1, 2024.
- By the next IRP, PacifiCorp should explain how it will use the Resiliency Analysis Framework in IRP and CEP resource planning, project prioritization, and portfolio selection considering HB 2021's requirement that resiliency planning consider costs, consequences, outcomes and benefits.
- Prior to the next CEP, Staff expects the Company to open discussions with stakeholders on the appropriate geographic scope of the Resiliency Analysis Framework; work with Stakeholders to

[148] ORS 469A.415(4)(d).

identify gaps in comprehension of the Resiliency Analysis Framework; and identify the vulnerabilities and complexities of SAIDI/SAIFI/CAIDI data sets and NRI values as a measure of community level impacts. The Company is encouraged to discuss how it can incorporate the lived experiences of communities into the community-resiliency score. The results of these discussions should be included in the next CEP.

- By next CEP, PacifiCorp should be able to articulate further discussions between the Company, the CBIAG, Tribes, and Stakeholders on how NRI values can be tailored or supplemented to reflect specific community concerns and assets and leverage existing Company resilience plans, such as the wildfire mitigation plan in Docket No. UM 2207.
- At a CBIAG meeting before the next CEP and prior to any CBRE Grant Pilot project selection, provide details for how a completed Resiliency Analysis Framework will be used to impact project selection. Staff expects to work with PacifiCorp in helping to craft this presentation and what will be covered.

<u>Acquisition of Federal Incentives</u>

- The IRP Update includes two variant portfolios that directly reflects Sierra Club's suggested analysis around reduced upgrade costs and early retirements using the EIR program.
- PacifiCorp details in the IRP Update the timeline for submitting an EIR application and the scope of the projects it is seeking to be financed through the U.S. Department of Energy Loan Program Office's EIR program.
- PacifiCorp provides a brief update at every IRP public input meeting and every CBIAG meeting leading up to the 2025 IRP that details the Company's activities to apply for federal incentives and detailing any funding secured.

IRP Comments:

<u>Preferred Portfolio Modeling Process</u>

Before the next IRP PacifiCorp should:

- Work with interested participants from the IRP Public Input process to develop and publicly produce a granularity adjustment methodology.
- Increase transparency around reliability adjustments by stating which resources will be eligible to be included as reliability adjustments in the next IRP and how each one will be valued. Further, it should clarify its modeling approach around how to limit the magnitude of the reliability adjustments that it must make.
- Solicit suggestions through the IRP Public Input process and as part of the Draft IRP of variant portfolios.

As part of the next IRP PacifiCorp should:

- Adjust its modeling approach to better capture resource adequacy needs and the capacity contributions of resource options to reduce the need for and magnitude of reliability adjustments to portfolios.
- Reoptimize variant portfolios that add resources to the preferred portfolio unless there is a clearly explained reason to study an un-optimized portfolio of resources.

<u>Coal Strategy</u>

In the next IRP, PacifiCorp should:

- Utilize coal prices for Jim Bridger that are reflective of actual costs from the Long-Term Fuel supply contract.
- Provide a full update on Utah coal supply issues.

Carbon Price Path

In the next IRP/CEP, PacifiCorp should:

- Recreate the chart above for (a) coal and (b) Oregon allocated GHG emissions comparing past IRP forecasts to actuals.
- Provide a sensitivity that calculates Oregon-allocated GHG emissions under the assumption of no carbon prices operationalized in dispatch. This sensitivity should still be based on the Preferred Portfolio, which considers a carbon price in investment decisions.
- Propose a PacifiCorp specific carbon price that layers atop the medium carbon price the Company's annual cost from wildfires as described by CUB.

Candiate Resource Costs

- As part of the IRP update and future IRP processes, PacifiCorp should update its renewable cost assumptions based on more recently available information.

Natrium and Non-Emitting Peaking Resources

- Inform the Commission in the IRP Update whether the TerraPower permit application passed the U.S. NRC's readiness assessment for Natrium's construction permit and the estimated timeline for the project following that decision.
- In the next IRP, utilize a ten-year buffer between the date of the issuance of the Natrium CP and when that resource may appear in the Company's preferred portfolio.
- In the next CEP, more directly address the high-level planning questions from Order No. 22-446 regarding the critical junctures, dependencies, and barriers to nuclear and any non-emitting peaking technology as part of a preferred portfolio.

Resource Adequacy Modeling, Front Office Transactions, and WRAP

By the next IRP, PacifiCorp should:

- Include more years of weather data in its resource adequacy modeling.
- Change its capacity valuation to an ELCC or ELCC-adjacent methodology that has weather-correlated stochastic modeling.
- Calculate and report the LOLE of the Preferred Portfolio in each year.
- Model the benefits of WRAP to the Company's system and compliance hurdles in addition to any requirements that arise from the ongoing resource adequacy rulemaking in AR 660.
- Account for the benefits of WRAP in future IRPs if it plans to continue as a WRAP participant.
- Update FOT availability assumptions based on insights from regional analysis and the WRAP program.
- Restrict the modeling of FOTs to contracts that can be obtained seven months ahead of need.

Transmission

- In the next IRP, develop a transmission deferral credit for storage resources.

Demand Side Resources

- In the IRP update, PacifiCorp should address the discrepancy in EE acquisition and ensure that HB 2021 compliance is considered in the preferred portfolio.
- In the next IRP, PacifiCorp should model a counterfactual case in which utilities install no new energy efficiency in Oregon in 2025 or later years.
- In the next IRP, PacifiCorp should include the HB 2021 emissions requirement and SSR/CBRE requirement based on the load forecast without new EE.
- In the next IRP, analyze the role of frequently deployable, low-cost DR measures with minimal customer impact, including but not limited to time-of-use rates and demand voltage reduction.

PacifiCorp
2024 Oregon Small-Scale Renewable Request for Proposal

Pre-Issuance Bidder Workshop

January 24, 2024





PACIFICORP

POWERING YOUR GREATNESS

2024 Oregon Small-Scale Renewable RFP

Logistics

Workshop Date and Time

- Wednesday, January 24, 2024
- 2:00 – 4:00 PM (Pacific Standard Time)

Location

- Microsoft Teams meeting
- Join on your computer or mobile app
- Click here to join the meeting
- Or call in (audio only)
- tel:+15632755003,,979257373# United States, Davenport
- Phone Conference ID: 979 257 373#

2024 Oregon Small-Scale Renewable RFP

Agenda

- Purpose/Resource Types
- Eligibility Requirements
- Contract Considerations
- Interconnection and Transmission Requirements
- Proposed RFP Schedule
- Evaluation and Selection Methodology
- Role of Independent Evaluator (IE)
- Next Steps
- Questions and Comments

2024 Oregon Small-Scale Renewable RFP

<u>Purpose of Request for Proposal (RFP)</u>

- To enable PacifiCorp to obtain, by 2030, approximately 490 megawatts (MW) of additional electrical capacity from small-scale renewable energy projects.
- The RFP supports PacifiCorp compliance with Oregon House Bill 2021 (OR HB2021) Section 37 and furthers PacifiCorp's Clean Energy Plan goals.

Energy sources accepted into the 2024 Oregon Small-Scale Renewable RFP must

- **Have a nameplate capacity of at least 3 MW but no greater than 20 MW *and***
- **Generate electricity utilizing one of the following sources:**
    - Wind energy
    - Solar photovoltaic and solar thermal energy
    - Wave, tidal and ocean thermal energy
    - Geothermal energy
    - Hydroelectric energy
    - Biomass that generates thermal energy for a secondary purpose
        - Biomass energy sources larger than 20 MW will be accepted, but only the first 20 MW of the energy source counts toward OR HB2021 requirement.
    - Energy sources listed above will be accepted to the 2024 Oregon Small-Scale Renewable RFP only if they meet the Renewable Portfolio Standard (RPS) criteria outlined in ORS 469A.025.

Note: Information in this presentation is subject to further change until RFP is issued.

2024 Oregon Small-Scale Renewable RFP

Minimum Resource Eligibility Requirements

- Eligible technologies consistent with ORS 469A.025.
- Eligible resources cannot be behind-the-meter, energy storage, microgrids or demand response technologies.
- Minimum 3 MW (ensures Energy Imbalance Market (EIM) eligibility); maximum 20[1] MW (supports Oregon HB2021 compliance).
- Possess Oregon Department of Energy Renewable Portfolio Standard (RPS) certification at time of commercial operation for contract effectiveness.
- Off-system bids not accepted; projects must be planned to interconnect to PacifiCorp transmission or distribution system in Oregon, Washington, California, Idaho, Utah or Wyoming.
- Completed interconnection study, confirming ability to interconnect to PacifiCorp's transmission or distribution system.
    - https://www.oasis.oati.com/ppw/index.html; https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Transmission_Wall_Map,_E-Size.pdf
- Site control required.
- Commercial Operation Date (COD) by December 31, 2028.
- Comply with co-location/proximity criteria based on Oregon OAR 860-089-0100, applied to a 20 MW threshold level.
- Bids for new and existing resources will be accepted provided the existing resources are not obligated in a contract effective as of the COD date above.
- Bid fee will be required for each bid proposal. Details provided at RFP issuance.
- All PPA bids must be fixed-price for the full term.

[1] As previously noted, Biomass resources larger than 20 MW *will* be considered, but only the first 20 MW will count toward OR HB2021 capacity requirement.

2024 Oregon Small-Scale Renewable RFP

Minimum Eligibility Criteria

1. Receipt of bid by deadline
2. Receipt of bid fee by deadline
3. Completed provided Bid Summary and Pricing Input Sheet, without modification
4. Capacity interconnected to PacifiCorp's transmission or distribution system
5. Completed PacifiCorp Transmission Interconnection Study or signed PacifiCorp Transmission Interconnection Study Agreement
6. Interconnection study results and/or executed Large Generator Interconnection Agreement (LGIA) consistent with and supports bid
7. Demonstrated ability to achieve COD deadline
8. Execute Confidentiality Agreement and allow appropriate disclosures to agents, contractors, regulators, etc.
9. No attempts to influence PacifiCorp
10. Entire bid held firm through Q2 2025
11. No commitments of all or part of bid to another entity
12. Must disclose real parties of interest
13. Compliance with Prohibited Vendors List (see pro forma PPA)
14. Bidder's credit information
15. Ability to meet credit security requirements
16. Non-modifiable standard pro-forma contract
17. Bidder not in bankruptcy proceedings
18. Proposal cover letter signed by authorized officer
19. Renewable Portfolio Standard (RPS) certification from Oregon Department of Energy
20. Performance report and model output including hourly output values; bid resource assumption (12X24 or 8760) includes all planned outages and losses, including planned and maintenance outages and curtailment due to protected species such as bats; third-party provided performance report preferred
21. Adherence to all applicable permits prior to and after construction. If applicable, Seller will also agree to Eagle Take Permit or alternative mitigation measures
22. Ownership of, leasehold interest in, or right to develop site, or valid title to property
    https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20230823_OATTMaster.pdf
23. Oregon bidder agrees to the contractor labor standards attestation in OR HB2021, Section 26
    https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
24. Compliance with OR HB2021 reporting requirements, including contractor diversity reporting requirement
    https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled

2024 Oregon Small-Scale Renewable RFP

Key Contract Considerations

- **Contract form**. PacifiCorp's pro forma power purchase agreement (PPA) will be provided.
  - Standard-form power purchase agreement (PPA). **The PPA will be standard for all bidders with no individual form modifications permitted.**
  - Seller develops, operates and owns resource; PacifiCorp buys the output for a specific term.
- **Ownership.** PacifiCorp takes ownership of all capacity, energy and associated environmental attributes after delivery to PacifiCorp.
- **Contract pricing**. Fixed pricing for term of contract (flat or on-peak/off-peak).
- **Credit requirements.** Letter of credit or approved parental guarantee will be required.
  - **Project development security**. Seller security is required to support delay damages and/or default damages for failure to reach commercial operation date (COD).
  - **Default security.** Seller security is required to support default damages in the event of breach of contract.
- **Commercial Operation Date delay.** Seller will have up to 365 days to cure a delay in scheduled commercial operation date; delay damages will be assessed.
- **Post-execution Condition Precedent.** Agreement language will ensure PacifiCorp's ability to obtain designated network resource (DNR) transmission service at no additional cost.
- **Annual Performance Guarantee.** Agreement will require annual resource mechanical availability guarantee and threshold percentage.
- **Benchmarks.** To support 2030 OR HB 2021 compliance PacifiCorp may offer benchmark bids.
  - PacifiCorp develops, constructs, owns and operates a bid project.
  - Benchmark bids will be evaluated using methodology consistent with market bid evaluation.

2024 Oregon Small-Scale Renewable RFP

Interconnection and Transmission

On-system resources (Off-system resources not accepted)

- PacifiCorp Transmission interconnection studies and agreements should be consistent with the bid proposal's technology, size and commercial operation date. If studies and agreements are not consistent with the proposal, bidder will provide documentation from PacifiCorp Transmission that a material modification to their interconnection documentation is not required.
- Bidders are financially responsible to PacifiCorp Transmission for all interconnection costs as identified in their generator interconnection agreement.
- After a PPA is executed, PacifiCorp's merchant function is responsible for requesting and arranging transmission from the Point of Interconnection (POI) to load.

Acceptable Documentation of Interconnection

- Completed PacifiCorp Transmission Interconnection Study (system impact study and/or facilities study) or signed PacifiCorp Transmission Interconnection Agreement is due when bid is submitted.
- An *Informational* Interconnection Study is NOT sufficient interconnection documentation to be considered eligible for the 2024 SSR RFP.

Questions

- For questions regarding PacifiCorp Transmission's interconnection study process, please visit the PacifiCorp Transmission website and contact Generation Interconnection at: www.pacificorp.com/transmission/transmission-services.html

2024 Oregon Small-Scale Renewable RFP

Equity Questionnaire

Facility proximity to community
Census track in which facility is located
Distance from facility to nearest residential home
Number of residential homes within 1 mile of facility
Number of residential homes within 6 miles of facility
How does this resource serve or otherwise impact vulnerable populations?
Is your facility located in a community afflicted with poverty or high unemployment or that suffers from high emission levels?
Distance to nearest existing generation sources by fuel source within 6 miles of proposed facility;
Will the proposed facility replace/supplant identified generation sources?
If "yes," provide estimated reduction in air pollutants/toxics in the community over life of the project/contract due to the facility (when/how much megawatt-hour ("MWh")/year), and avoided emissions released into the community (within 6 miles of the project).

Population characteristics of community where facility is proposed
To be completed based on census track in which facility is located
Race and ethnicity
White (%)
Black or African American (%)
Amercan Indian and Alaska Native (%)
Asian (%)
Native Hawaiian and Other Pacific Islander (%)
Two or More Races (%)
Hispanic or Latino (%)
Population 25 years and over with no high school diploma
Unaffordable housing
Population five years and older that speak English less than "very well" and "not at all"
Population with income 185% below poverty
Population 16 years and older unemployed

Facility Job Creation
Total hires (number of jobs)
Will there be an apprenticeship or training program?
Will there be a project labor agreement (PLA)?
Will Bidder have a plan for outreach, recruitment and retention of women, minority individuals, veterans and people with disabilities to perform work under the contract?
Projected local hires from nearby communities (number of jobs)
Expected total employment (hires) of fossil fuel construction workers (number of jobs)
Duration of work (months of construction / years of operation)
Total Recordable Incident (TRI) of Bidder
Industry Average TRI for type of business (OSHA)
Bidder agrees to use Veriforce, or equivalent, to report safety
Estimate projected economic benefits to the local economy (direct and indirect) (annual $ from payroll taxes, property taxes, other taxes, services)
Minority-owned businesses (percentage of contractors and subcontractors)
Woman-owned businesses (percentage of contractors and subcontractors)
Service-disabled veteran-owned businesses (percentage of contractors and subcontractors)
LGBT firms (percentage of contractors and subcontractors)
What percent of total work hours does Bidder target to be performed by women, minority individuals, veterans and people with disabilities?

Local Impacts
Is Facility a distributed energy resource?
Duration of construction
Source of water used during construction
Source of water used during operations
Is water a permitted or public source
Site disturbance - amount of disturbed soil during construction
Tree and pollinator seed re-planting after construction

Note: Above questionnaire was requested in the 2022AS RFP.

2024 Oregon Small-Scale Renewable RFP

Proposed RFP Schedule

Event	Date
Pre-issuance bidder workshop	1/24/2024
Independent Evaluator (IE) hired	2/16/2024
RFP issued to market and publicized	3/29/2024
PacifiCorp OATT[1] cluster study window open	4/1/2024
PacifiCorp OATT[1] cluster study window closed	5/16/2024
Bidder workshop No. 1	6/27/2024
Bidder workshop No. 2	TBD (September 2024)
Last day for bidder questions to PacifiCorp and IE	11/1/2024
Cluster study results posted to OASIS	~11/12/2024
Benchmark bid submissions due	11/15/2024
Benchmark final bid financial analysis provided to IE	12/20/2024
Market bid submissions due	12/23/2024
Bid eligibility screening complete	1/17/2025
Market bid evaluations complete	2/14/2025
IE final report	3/17/2025
Potential 2025 SSR RFP	3/28/2025
Contracts finalized and executed	TBD (June 2025)
Guaranteed commercial operations date (COD)	12/31/2028

[1] PacifiCorp's Open Access Transmission Tariff (OATT)

2024 Oregon Small-Scale Renewable RFP

Price Proposal – Bidder Inputs

Each Proposal is required to include a completed Bidder Inputs form, which provides PacifiCorp a "numbers based" overview of the bid offering:

Price Proposal - Bidder Inputs (Required for Bid Submittal)	**Location**
➢ Bid Summary ▪ Type of Bid: PPA or Benchmark ▪ Project Specifics (Generator Type, location, capacity, annual degradation) ▪ Bidder Contact Information ➢ PacifiCorp Interconnection/Transmission Information ▪ Queue Number or Cluster Study ▪ Cost of Interconnection Facilities and Network Upgrades ➢ Purchase Power Agreement Terms ▪ Start/End Dates ▪ $/MWh Price[1] (Flat or On- and Off-Peak Pricing) ➢ Benchmark Terms ▪ Date Operational ▪ Initial Capital Cost (Detail on Tab 3) ▪ ITC/PTC Qualification Questions	Tab 1
Expected First-Year Generation Inclusive of Degradation – 50th Percentile Estimate ➢ 8,760 hourly generation profile, OR ➢ 12 month by 24-hour generation profile ("12X24")	 Tab 2a, or Tab 2b
Benchmark Pricing (Not Applicable to Market Bids)	Tab 3
Benchmark Additional Information (Annual Operating and Capital Costs)	Tab 4

[1] Bid prices include direct interconnection costs. PacifiCorp includes network upgrade costs from PacifiCorp Transmission interconnection studies in the financial valuation model.

2024 Oregon Small-Scale Renewable RFP

Evaluation and Ranking of Bids

- Objective is to acquire 490,000 kilowatts (490 MW) of new capacity from small-scale renewable energy projects at the lowest cost to Oregon customers
- Acceptable Bid Criteria:
  - Power purchase agreement and benchmark bids
  - Fixed pricing for Term of PPA (flat or on-peak/off-peak)
- Bids will be ranked based on the LOWEST Real Levelized Cost per Kilowatt of installed Capacity

Cost to PacifiCorp of Bid
PPA Cost or Revenue Requirement of Benchmark Bid
(Present Value)
+
Network Upgrade Cost
(Present Value)

−

Value of Generation Based on Oregon Avoided Costs. Includes Value of Capacity Contribution.
(Present Value)

=

Net Cost / (Benefit) of Installed Capacity
(Present Value)

Net Cost / (Benefit) of Installed Capacity
(Present Value)

÷

Installed Capacity (kW)
over PPA Term or Asset Life.
(Real[1] Present Value)

=

Cost / (Benefit) Per Kilowatt-Year
(Real Levelized)

[1]Discussion of Real Levelized valuation methodology will be provided in June bidder workshop.

2024 Oregon Small-Scale Renewable RFP

Role of the Independent Evaluator (IE)

PacifiCorp is seeking the services of an Independent Evaluator to provide independent validation that:

- PacifiCorp's screening of eligible bidders based on published minimum eligibility requirements was consistently applied to all submitted market and benchmark bids; and
- PacifiCorp's cost valuation of all submitted market and benchmark bids was consistently applied.

2024 Oregon Small-Scale Renewable RFP

Next Steps

1. Questions or comments regarding this pre-issuance bidder conference should be sent to the following mailbox, even if an answer was provided verbally in today's meeting, to ensure all bidders receive responses: **2024SSR_RFP@pacificorp.com.**
2. Responses to questions (Q&As) received will be posted anonymously on PacifiCorp's 2024 Small-Scale RFP website.
3. 2024 Small-Scale RFP information will be provided it is developed and Q&As will be posted to: www.pacificorp.com/suppliers/rfps/2024-small-scale-renewable-rfp.html.

2024 Oregon Small-Scale Renewable RFP

Supporting Materials

2024 Oregon Small-Scale Renewable RFP

PacifiCorp Transmission OASIS Interconnection Requests

Information on new generator interconnection requests and general interconnection and cluster study information please visit:
https://www.oasis.oati.com/ppw/index.html

Question & Comments

To: PacifiCorp SSR RFP Team (2024SSR_RFP@pacificorp.com)
Subject: Oregon PUC Staff Initial Comments on SSR RFP

PUC Staff appreciates PacifiCorp releasing a draft of the Small Scale Renewable request for proposal (SSR RFP) for comments and the speed with which the Company is pursuing these resources. Staff's comments are organized around two themes. First, PacifiCorp's chosen SSR project characteristics are too narrow, leaving value on the table, driving up project costs, and failing to leverage the RFP as a market discovery mechanism. Second, Staff has suggestions for the structure of the RFP itself, based on our experience, that should help the Company meet its goals and the goals of the state while also assisting potential bidders.

Project Characteristics

Issue: Energy storage ineligibility
Staff position: Energy storage paired with renewable energy projects should be eligible.
Staff rationale:

- Allowing for the pairing of energy storage with renewables and dispatched as a single project enhances capacity value of SSR projects to system peak. Barring energy storage from SSRs appears to make projects less economic than other renewable systems and potentially drives up total costs of CEP compliance for Oregon ratepayers.
    - Energy storage allows for renewable projects to be dispatched in a way that better aligns with system need and to offset fossil fuel use (i.e., summer peak, after 6pm).
- PAC has outstanding capacity need that SSR projects with energy storage can help meet. Evidence:
    - Per the 2023 IRP, the Company has a 2028 summer capacity deficit over 6,000 MW.[1]
    - Per the Draft IRP Update, peak capacity will grow at an average annual rate of 1.7%.[2]
    - Company is seeking 100s of MW of energy storage by 2026 through bilateral contracts in wake of UM 2193 RFP suspension.

Given the outstanding capacity need, Staff questions why PacifiCorp would limit dispatchable load.

- PacifiCorp staff stated on the January 24, 2024 conference call that the Company had determined that the economics of SSR projects with energy storage would be uncompetitive. There is no data to substantiate this argument. Further, the purpose of an RFP is to discover what is available in the market. If project bids are uneconomic due to inclusion of energy storage that should be apparent in their RFP score.
    - Based on PacifiCorp's evaluation and ranking of bids, projects paired with storage will most likely provide more value and thus provide a higher benefit to ratepayers.
- CAISO and WREGIS allow for renewable projects to be paired with energy storage and to be dispatched as a single system.
- ODOE certifies RPS projects paired with energy storage.

[1] LC 82, PacifiCorp IRP, May 31, 2023, pgs. 165 – 172, specifically Table 6.11 and Figure 6.4.
[2] LC 82, Draft IRP Update, January 31, 2024, pg. 2.

Issue: 3 MW floor
Staff position: Allow for project sizes down to 25 kW.
Staff rationale:
- 25 kW is smallest size for Community Solar Program. A lower bid threshold allows for projects such as those waitlisted in the CSP to participate in the SSR RFP.
- Based on the size of PacifiCorp's CSP queue there are clearly many projects less than 3 MW in size that could submit viable bids.
- Function of an RFP is to discover what is available in the market. If project bids are uneconomic due to their smaller size, that will be apparent in the RFP scoring.
- WREGIS allows for renewable projects of any size to be registered.

Issue: CAISO EIM eligibility
Staff position: Should be optional for projects, not a requirement.
Staff rationale:
- Eliminates the potential for smaller projects.
- Imposes unnecessary costs on all projects.
- Reinforces need to allow batteries to be paired with projects as it would increase value of projects to ratepayers.

Issue: Required ODOE RPS Certification at time of commercial operation date (COD)
Staff position: Should be required only after COD and should be optional for projects, not a requirement.
Staff rationale:
- Timing is off. ODOE does not issue RPS certifications until after COD.
- Project does not need ODOE certification to be considered renewable energy resource. Just needs to be one of the technologies listed in ORS 469A.025. Imposes unnecessary costs on all projects.
- ODOE RPS certification requires WREGIS issuing a generating unit id. This requires equipment that is expensive for smaller projects. It also requires more time and raises project costs.
    - The largest benefit to registering with WREGIS is the ability to generate RECs. As HB 2021 does not require REC retirement to demonstrate emission reductions – and as PacifiCorp will have over 50 million RECs in excess of its Oregon RPS needs by 2030[3] – Staff finds little to no value in requiring PAC SSRs to be WREGIS certified, even if the ODOE RPS verification is waived.

Issue: Contract pricing limited to flat or on-peak/off-peak.
Staff position: Contract pricing should include flat, on-peak/off-peak, or premium peak hours
Staff rationale:
- Projects with associated storage should have a contract pricing structure which incentivizes and rewards its dispatchable nature. More targeted hours will maximize the capacity value derived from these projects at little to no cost to the project.
- Hour derivation could be based on projected market prices or utility capacity needs.
- Structure could follow UM 1729 Solar+Storage rate with minor modifications.

[3] LC 82, PacifiCorp IRP, May 31, 2023, pg. 321, Figure 9.59.

RFP Structure Issue

Issue: Lack of non-price scoring.
Staff position: Include non-price scoring that captures information about benefits to Oregon communities.
Staff rationale:

- Staff appreciates the inclusion of the Equity Questionnaire from the 2022 AS RFP. However, the equity questionnaire is not mandatory in the SSR RFP and answers do not impact project selection.
- Elements should be improved *(see below)* and converted into non-price scoring or sensitivity that captures community benefits.
- The Commission stated that it will want information about direct benefits to communities in Oregon.[4] In fact, capturing more information about benefits and impacts to Oregon communities was identified as a necessary first step in impacting near-term decisions around utility procurement.[5]
- PacifiCorp and Oregon PUC staff agree that many projects could easily qualify as both SSR and as Community Based Renewable Energy (CBRE) projects, under HB 2021.

Issue: Equity questionnaire
Staff position: Equity questionnaire needs more explicit linkages to PacifiCorp's CBIs and reflect input from the Company's CBIAG.
Staff rationale:

- Staff appreciates the inclusion of the 2022 AS RFP Equity Questionnaire. However, the equity questionnaire does not necessarily reflect the Company's evolving CBIs from LC 82 and input from community members in both LC 82 and in the CBIAG.
- Some portion of the equity questionnaire should become the non-price scoring element to the RFP. *(See above.)*
  - These can reflect the Company's evolving CBIs and/or attempt to capture insights into elements like positive impacts to community resiliency or the offsetting of fossil fuels.
  - HB 2021 requires consideration of community benefits in meeting the emissions reduction targets, vis-à-vis offsetting fossil fuels, increasing community resiliency, and even economic development.[6]

Issue: Lack of locational value in evaluating and ranking of bids.
Staff position: PacifiCorp's evaluation and ranking of bids needs to explicitly take into account the locational value of capacity and energy from proposed SSR projects when assessing bids.
Staff rationale:

- Given that PacifiCorp has multiple load pockets across its system (e.g., five in Oregon) and uneven growth across its system (e.g., northeast Oregon load will grow incredibly fast over the next five years), the methodology to determine net cost/benefit of installed capacity needs to explicitly account for locational value.

[4] UM 2273, Order No. 24-002, January 3, 2024, pg. 23
[5] *Ibid.* Pg. 24-25.
[6] ORS 469A.400(2)(a),(b) and 469A.415(4)(d)

- This will encourage the selection of bids with the lowest realized cost to Oregon ratepayers while better capturing the value to the PacifiCorp system.

Issue: No contract negotiations or redlines
Staff position: Redlines should be allowed.
Staff rationale:
- In UM 2274, contract redlines will be used by IE to illuminate bid nuances and pricing so as to make project selection more transparent and so the IE can comment around tradeoffs or irregularities in ISL or FSL project selection. [7]
- Contract redlines allows for projects with more unique attributes to potentially offer lower cost bids and provide necessary flexibility.

Issue: IE Scope
Staff position: Include information that compares and contrasts IE scope and staff interaction in the SSR RFP to UM 2193.
Staff rationale:
- Staff appreciates the inclusion of an IE for this RFP but needs a clearer understanding of the IE's scope and ability to interact independently with stakeholders, and how similar the role will be to an IE selected for a procurement under Oregon's competitive bidding rules.
- Will the IE be responsible for responding to bidder questions?
- Will the IE be responsible for establishing the scoring rules, as well as scoring all, or a subset of bids?
- Will the IE be working for/reporting to PAC or OPUC staff?

Issue: Separation of PacifiCorp RFP and Benchmark staff in establishing scoring system, reviewing bids and contract negotiations.
Staff position: The final RFP needs to clearly state how PacifiCorp RFP and Benchmark staff will be entirely screened from one another throughout this RFP process. This includes naming all employees working as part of the RFP team or the Benchmark team, including their roles and associated dates of their work; ensuring Benchmark staff have had no access to 3rd party project information during this RFP and for at least two years after bids are submitted; and developing and enforcing separation protocols to ensure no confidentiality breech or anti-competitive use of confidential data.
Staff rationale:
- If PacifiCorp's SSR benchmark project development team has any access to RFP bidder information they will have an unfair advantage in their bids.
- All other RFPs require a separation of staff.
- It is standard practice in Oregon to name utility staff on RFP and Benchmark teams so the IE, Staff, and/or stakeholders can verify that a separation between RFP and Benchmark teams was maintained.
- Bidders who receive confidential utility information are embargoed from using it for two to five years after an RFP. The same should be true for utility staff.

[7] UM 2274, Order No 24-011 at 1.

In closing, an RFP functions as a market discovery mechanism. In Staff's experience, an RFP with too many restrictions on project eligibility limits the Company's and stakeholder's insights into available, competitive options. And for this RFP, Staff finds no downside to removing many restrictions (e.g., energy storage, RPS certification, size limit, two-types of pricing, etc.,) if project selection still rests mainly on price and the determination of value as proposed in the RFP's evaluation and ranking methodology. If acquiring 490 MW by 2030 is truly an "all hands on deck" moment, restricting participation – as this RFP currently does – would appear to be counterproductive.

Further, HB 2021's direction to consider community benefits by understanding what they are necessitates some evaluation of a bid's community benefits and impacts. However, the equity questionnaire does not reflect recent developments and is not mandatory. Without some sort of non-price scoring or sensitivity that attempts to capture/understand community benefits we lose a unique opportunity in this RFP to understand and learn while also undermining a key rationale for including SSRs in HB 2021.

Finally, Staff encourages the utility to adopt the changes proposed above and to make any additional improvements necessary to clarify the community benefits and impacts of SSR procurement and ensure a fair, competitive process that reflects HB 2021's evolving approach to the public interest, especially with regards to technical and economic feasibility. Such efforts will be necessary for the Commission to evaluate the prudence of any acquisition and to evaluate the steps PacifiCorp is making to demonstrate continual progress towards the HB 2021 reduction targets at reasonable costs to customers.

ITEM NO. RA1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: MARCH 5, 2024

REGULAR __X__ CONSENT ____ EFFECTIVE DATE ____N/A____

DATE: March 1, 2024

TO: Public Utility Commission

FROM: JP Batmale

SUBJECT: PACIFICORP:
(Docket No. LC 82)
Acknowledgement of 2023 Integrated Resource Plan and Clean Energy Plan.

STAFF RECOMMENDATION:

Acknowledge in part and not acknowledge in part PacifiCorp's (Company) 2023 Integrated Resource Plan (IRP). Decline to acknowledge the Clean Energy Plan (CEP) filed with the 2023 IRP. Adopt Staff's recommendations for additional direction to PacifiCorp as outlined in this memo.

DISCUSSION:

Issue

Whether the Public Utility Commission of Oregon (PUC or Commission) should acknowledge PacifiCorp's IRP with or without conditions, acknowledge specific portions of the IRP, with or without conditions, or decline to acknowledge the IRP.

Whether the Commission should acknowledge PacifiCorp's CEP or decline to acknowledge the CEP.

Whether the Commission should adopt Staff's recommendations for additional direction to PacifiCorp.

Applicable Law

See Staff's February 20, 2024 public meeting memo for a full description of the Applicable Law to this docket.

Analysis

Purpose of Memo
The memo provides a final set of Staff recommendations to aid in Commissioner deliberation at the March 5, 2024 public meeting. These final recommendations are informed by the February 20, 2024 public meeting, the discussion of the Commissioners in that meeting, and subsequent review of the issues. For more background information behind these recommendations, please see Staff's previous public meeting memo, filed February 7, 2024, and associated comments from Stakeholders and PacifiCorp.

The approach guiding Staff's final suggested recommendations for Commissioner consideration are as follows:

- Elements of the IRP can be acknowledged in part.
- Based on Staff's interpretation of statute, the CEP cannot be acknowledged – in whole or in part – due to the CEP's failure to meet the standard in ORS 469A.420 to be in the public interest and consistent with the emissions reduction targets.
- Based on comments made by PacifiCorp at the February 20, 2024 public meeting, the April 2024 IRP/CEP Update is not a viable vehicle for any substantial new or revised analysis.
- All recommendations for any new or revised IRP/CEP analysis should focus on the 2025 IRP/CEP, which PacifiCorp plans to file in April 2025, and are based on an expectation that that IRP/CEP will be timely filed.
- Recommendations for the 2025 IRP/CEP should be kept to a minimum. The focus is on identifying the least number of analytic improvements or qualitative additions necessary to develop an IRP/CEP that leads to an acknowledgeable CEP.
- Additional recommendations are not new to this proceeding, but instead are drawn from previously stated expectations or stakeholder comments. Staff will continue to work with the Company and Stakeholders in the lead up to the 2025 IRP/CEP to implement the expectations identified in Staff's Round 2 comments.

Staff's final, suggested recommendations for Commissioner consideration are organized into two parts:

1. **Original Recommendations**: These come from Staff's Round 2 Comments. They are also included as Attachment A to Staff's February 20, 2024 public meeting memo. The recommendations include suggested strike throughs.

2. **Additional Recommendations**: There are three sources for these new recommendations. The first is Staff's stated expectations. The second is utility and stakeholder final comments and/or suggestions at the February 20, 2024 Public Meeting. The final source is the PacifiCorp IRP/CEP.

Original Recommendations
Table 1 below details Staff's original thirteen recommendations and includes Staff's suggested redlines as of the date of this memo.

Table 1, Revised Original Recommendations from Staff

Recommendation Description	Suggested Commissioner Action on March 5
# 1: Do not acknowledge the IRP action plan elements 2b and 2c, the IRP's preferred portfolio, or the IRP's long-term plan.	Retain in full.
~~#2: Direct PacifiCorp to seek acknowledgement of a revised Preferred Portfolio and Action Plan in the planned April 2024 IRP Update.~~	Remove in full
#3: Do not acknowledge the LC 82 CEP ~~and direct PacifiCorp to revise and resubmit the CEP with its April 2024 IRP Update~~.	Change.
#4: Do not acknowledge Action Plan item~~s 1h and~~ 2a.	Change.
#5: Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.	Retain in full.
#6: Direct PacifiCorp to provide specific baseline metrics ~~prior to filing its next~~ in the 2025 IRP/CEP to allow for measured progress towards CBI goals. ~~If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.~~	Change.

Recommendation Description	Suggested Commissioner Action on March 5
#7: Direct PacifiCorp to proceed with the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG and environmental justice groups.~~in Q1 2024~~	Change.
#8: Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, environmental justice groups, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.	Change.
#9: The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and the CBRE Pilot be designed to promote resiliency-related factors.	Retain in full.
~~#10: Direct PacifiCorp to fix any confirmed analytical errors in the calculation or application of granularity adjustments.~~	Remove in full. *Staff will have more specific directions in next table.*
#10 (Formerly #11): ~~Direct PacifiCorp to update Action Plan Item 1g (Natrium) to reflect actual events since the IRP/CEP was filed in May 2023.~~ In the 2025 IRP/CEP, direct PacifiCorp to update Natrium assumptions to reflect actual events.	Revise.
#11 (Formerly #12): Acknowledge Action Item 4a to acquire cost-effective energy efficiency and demand response resources.	Retain in full.
#12 (Formerly #13): Acknowledge updated avoided costs from the 2023 IRP planning and direct PacifiCorp to work with Staff and Stakeholders to update avoided costs for use in UM 1893 considering HB 2021 constraints.	Retain in full.

Additional Recommendations

Table 2 below details additional recommendations Staff believes the Commissioners should consider in the acknowledgement order. Recommendations number 13 and 14 are recommendations that should have been included with the original thirteen but were not due to a Staff oversight. We apologize for the error and seek to correct that by including those recommendations below.

The other seven remaining recommendations are all forward looking. They are designed to help the PacifiCorp IRP team by providing clear expectations for the 2025 IRP/CEP.

The table below also includes the source of the recommendation and a short summary of the rationale behind the recommendation's inclusion. While the text may not exactly match a recommendation attributed to a stakeholder, Staff sought to capture the essence of the recommendation. Finally, many stakeholders made outstanding contributions to this IRP/CEP in written and verbal comments, which Staff greatly appreciates. Staff apologizes in advance for any potential oversights in recognizing the contribution of a stakeholder organization toward these additional recommendations.

Table 2, Additional Recommendations

New Recommendation Description	Source and Rationale
#13: Do Not Acknowledge Action Items 1c and 1d from the action plan because the Company has already taken these actions.	**Source**: Staff expectations. **Rationale**: Should have been included in original recommendation. Do not acknowledge action items already undertaken and not already acknowledged.
#14: Acknowledge Action Plan Items 3a through 3e, 5a, 6a, and 6b.	**Source**: PacifiCorp IRP Action Plan. **Rationale**: Should have been included in original recommendation.

New Recommendation Description	Source and Rationale
# 15: In the 2025 IRP/CEP model, PacifiCorp must: (1) demonstrate that simultaneous compliance with all state-level policies is feasible with the least-cost, least-risk Preferred Portfolio and with the Preferred Portfolio variants tested in the IRP under multiple allocation paradigms; (2) include expected CBREs in the Preferred Portfolio and ensure that the Preferred Portfolio meets Oregon's Small Scale Renewable Requirement; (3) adopt best practices in resource adequacy modeling, including consideration of load and resource performance under multiple weather years and calculation of loss of load expectation and capacity contributions using probabilistic analysis.	**Source**: Staff's expectations; CUB, Sierra Club, and RNW comments. **Rationale:** An optimized preferred portfolio that reflects law and best practices.
#16: In the 2025 IRP/CEP, PacifiCorp shall include an analysis of forecasted costs and annual emissions of the Preferred Portfolio using only actual carbon prices in effect in 2025 through the 20-year planning horizon.	**Source**: CUB comments. **Rationale**: Better forecast of actual emissions. Provides insight into the potential continuation of historical underperformance of the fleet's emission reductions relative to IRP forecasts.
#17: In the 2025 IRP/CEP, PacifiCorp shall calculate and report the costs and GHG emissions associated with each portfolio assuming that GHG prices are not reflected in dispatch decisions but still included in investment and retirement decisions.	**Source**: Staff expectations. **Rationale**: Improve understanding of tradeoffs in CEP construction.
#18: In the 2025 IRP/CEP PacifiCorp shall provide an explanation of renewable cost assumptions and a comparison to recent pricing information from such organizations as National Renewable Energy Lab and Lazard.	**Source:** RNW comments **Rationale:** Improve transparency of resource costs in portfolio development.

New Recommendation Description	Source and Rationale
#19: In the 2025 IRP/CEP, PacifiCorp shall confirm that coal generator cost assumptions reasonably reflect the structure and terms of any associated fuel supply agreements or fuel supply plans. Categorize variable costs that affect dispatch as variable costs in the model with as much accuracy as reasonably possible.	**Source:** Sierra Club **Rationale:** Improved transparency in pricing of coal resources.
#20: In the 2025 IRP/CEP PacifiCorp shall report on steps that the Company took to reduce the magnitude of reliability and granularity adjustments, how the Company engaged with stakeholders on adjustments, and describe the methodology and report the resulting reliability and granularity adjustments by resource. Include any supporting work papers demonstrating the granularity/reliability adjustments in the Data Disk.	**Source:** Sierra Club, RNW, and Staff **Rationale:** Improve modeling and portfolio transparency.
#21: In the 2025 IRP/CEP PacifiCorp shall provide an update on PacifiCorp's efforts to secure Energy Infrastructure Reinvestment (EIR) financing from the DOE Loan Program Office. Assume EIR financing through the DOE Loan Program Office in the Preferred Portfolio or include a variant portfolio that optimizes resource additions and retirements under the assumption of EIR financing.	**Source:** Sierra Club **Rationale:** Very low-cost financing for renewables should be pursued. Future resources – for either the System or for Oregon ratepayers – will be less costly due to EIR financing.

Conclusion

The twenty-two final proposed recommendations above are designed to aid in Commissioner deliberation at the March 5, 2024 public meeting. The memo includes updated recommendations from Staff's previous memo ***and*** updated recommendations based on various sources and in response to learnings from the February 20, 2024 public meeting.

PROPOSED COMMISSION MOTION:

Acknowledge in part and not acknowledge in part PacifiCorp's 2023 IRP, per Staff's recommendations. Decline to acknowledge PacifiCorp's CEP. Adopt Staff's recommendations for additional direction to PacifiCorp as outlined in this memo.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-26-21
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-129:
Utah PSC on Pac 2023 IRP

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

PacifiCorp's 2023 Integrated Resource Plan	DOCKET NO. 23-035-10 ORDER

ISSUED: April 17, 2024

SHORT TITLE

PacifiCorp's 2023 Integrated Resource Plan

SYNOPSIS

We acknowledge that PacifiCorp's 2023 Integrated Resource Plan ("2023 IRP") substantially complies with the IRP Standards and Guidelines, with certain important exceptions. Most notably, PacifiCorp's inconsistent and disparate evaluation of the Natrium Demonstration Project ("Natrium"), non-emitting (hydrogen) resource technologies, Carbon Capture, Usage, and Storage ("CCUS") technologies, and new natural gas resources produced a preferred portfolio that likely does not identify the least-cost, least-risk resources. Consequently, we decline to acknowledge the portfolio selection process, the P-MM Preferred Portfolio, and the Action Plan.

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I. INTRODUCTION AND PROCEDURAL HISTORY

On May 31, 2023,[1] PacifiCorp filed with the Public Service Commission (PSC) its seventeenth Integrated Resource Plan ("2023 IRP"), pursuant to the IRP Standards and Guidelines ("Guidelines") adopted in Docket No. 90-2035-01.[2] PacifiCorp requests the PSC acknowledge the 2023 IRP in accordance with PSC rules and fully support the 2023 IRP conclusions, including the proposed action plan ("Action Plan").

The Division of Public Utilities (DPU) and the Office of Consumer Services (OCS) participated in the docket and the following parties intervened: the Utah Association of Energy Users (UAE), Utah Clean Energy (UCE), Western Resource Advocates (WRA), the Interwest Energy Alliance ("Interwest"), Sierra Club, Fervo Energy Company, and Utah Citizens Advocating Renewable Energy.

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[1] On March 28, 2023, the PSC granted PacifiCorp's Request for a two-month extension and preliminary comment phase to file its final 2023 IRP due to changed model inputs that were driven by then-recent material changes, including the Ozone Transport Rule (the "OTR"), the Inflation Reduction Act ("IRA"), resource interconnection rules, the Oregon Clean Energy Plan, and Washington's Clean Energy Transformation Act. According to PacifiCorp, the changes required additional time to implement the accuracy of the model's outputs and did not allow stakeholders to review the model's results, including the Preferred Portfolio, before the 2023 IRP March 31, 2023 deadline. The PSC authorized a preliminary IRP and comment phase to accommodate the filing of a preliminary 2023 IRP on March 31, 2023 (PacifiCorp's submission was filed after business hours on Friday, March 31, 2023 and therefore it was submitted April 3, 2023), comments on the preliminary IRP by April 30, 2023, and the final 2023 IRP filing by May 31, 2023.

[2] *See In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp*, (Report and Order on Standards and Guidelines, issued June 18, 1992), Docket No. 90-2035-01. Future references to Guidelines contained in that order will be referred to by the Guideline number. For example, "Guideline 3" will refer to Guideline 3 from page 19 of that order, without referencing the 1992 order each time the Guideline is referred to in this order.

By December 12, 2023, the following parties filed comments: DPU, OCS, UAE, WRA, Interwest, Sierra Club, and UCE. On January 31, 2024, PacifiCorp, DPU, UCE, and WRA filed reply comments.

A. Summary of the 2023 Integrated Resource Plan

The 2023 IRP presents PacifiCorp's plan to supply energy and capacity to provide for and manage the growing electricity demand in its six-state service territory over the next 20 years. The report identifies PacifiCorp's preferred least-cost, least-risk plan ("Preferred Portfolio") to invest in a portfolio of power plants, transmission facilities, firm power purchases, and demand side management (DSM) resources, including energy efficiency and direct load control. The 2023 IRP identifies the type, timing, and magnitude of resource additions and provides a short-term Action Plan.

The 2023 IRP includes modeling advancements such as a Targeted Portfolio Reliability Analysis that allows the assessment of the reliability of resource portfolios by performing subsequent modeling of renewable resources that are selected in the portfolios that can identify capacity shortfalls. It also includes supplemental studies such as, among others, an energy storage potential evaluation that provides details on energy storage grid services and how they can be configured and sited to maximize benefits.

PacifiCorp selected its Preferred Portfolio,[3] which it asserts is the least-cost plan, adjusting for risk and uncertainty. To serve system-wide peak hour demand over the next 20 years, the Preferred Portfolio identifies cumulative supply additions (both long- and short-term resources) of 1,240 MW of non-emitting peaker resources, 9,113 MW of new wind resources, 7,855 MW of new utility solar resources, approximately 8,260 MW of battery storage, inclusive of 350 MW of long duration battery storage, 4,953 MW of incremental energy efficiency, 929 MW of new direct load control resources, 35 MW of pumped hydro storage, 1,500 MW of nuclear, and, through the 20-year horizon, approximately 390 MW of summer and winter firm power purchases, also referred to as front office transactions (FOT).[4]

The 2023 IRP Preferred Portfolio includes the end-of-life retirement of 1,141 MW of existing coal resources, the retirement of 2,335 MW of coal-fueled capacity with selective noncatalytic reduction retrofits, the transition of 1,770 MW of coal resources to other types of fuel, the end-of-life retirement of 595 MW of natural gas resources, the retirement of 23 MW of non-thermal resources, and the expiration of 22 MW of other resources.

The Preferred Portfolio and Action Plan include the retirement of co-owned coal units, the conversion of several coal units to natural gas, the closure of the Naughton South Ash pond, the development of Natrium, new resource acquisitions

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[3] *See* 2023 IRP, Volume I, at 307-324.
[4] *See id.*, Table 9.31 at 325.

through the 2022 and 2024 All Source Requests for Proposals, as well as continuing development and construction of the Boardman-to-Hemingway 500 kV transmission line, among other action items.[5]

Planned investment in the Preferred Portfolio differs from PacifiCorp's Fall 2022 Business Plan ("Business Plan") primarily due to reductions or delays in the 2020 All Source Request for Proposals wind, solar, and battery storage resources in the Business Plan.[6] The Preferred Portfolio also reflects lower reliance on FOTs. In addition, CO2 emissions over the study period decreased by 9 million tons relative to the Business Plan.[7]

B. The IRP Process and Standard of Evaluation

Utah Code Ann. § 54-1-10 requires the PSC to "engage in long-range planning regarding public utility regulatory policy in order to facilitate the well-planned development and conservation of utility resources." The PSC relies in part on PacifiCorp's IRP process to fulfill this planning requirement to meet the electrical needs of PacifiCorp's Utah service territory. In 1992, the PSC developed and approved the Guidelines that govern the IRP process.[8] PSC acknowledgment of an IRP means it substantially complies with these Guidelines. Such acknowledgment, however, does not constitute PSC approval of any specific PacifiCorp resource acquisition decision or

[5] *See id.*, at 27-33.
[6] *See id.*, at 335-336.
[7] *See id*.
[8] Information on historic PacifiCorp Integrated Resource Plans can be found at the following link: https://psc.utah.gov/electric/historic-integrated-resource-plans/.

strategy for meeting its obligation to serve. Resource approval and cost recovery are addressed in dockets separate from the IRP.

II. SUMMARY OF ISSUES ADDRESSED IN COMMENTS

As discussed in more detail below, several parties urge us not to acknowledge this IRP. Many express serious concerns regarding the limited time afforded for their review, evaluation, and meaningful input. The challenges PacifiCorp has faced meeting IRP schedule deadlines are evident in the fact it has requested substantial extensions in each of the last three IRP cycles. Parties contend there was no opportunity for their review and feedback on modeling results and the P-MM Preferred Portfolio before the preliminary 2023 IRP was filed. Consequently, some dispute that the P-MM Preferred Portfolio represents the least-cost, least-risk resource portfolio. Additionally, many parties expressed concern over the suspension of the 2022 All Source Request for Proposals (the "2022 AS RFP") and its impact on the Action Plan. Finally, several parties, including the DPU and OCS, challenged various specific modeling inputs, assumptions, and studies, asserting:

a) inconsistent or insufficient analysis, or disparate treatment, of resources;

b) insufficient analysis of federal and state incentives and potential savings opportunities from the IRA and the Energy Infrastructure Reinvestment ("EIR") program;

c) insufficient discussion and analysis of regional transmission planning;

d) inadequate modeling and evaluation of advanced transmission technologies, grid-enhancing technologies ("GET"), and other alternatives to new transmission construction; and,

e) inadequate transparency and discussion related to PacifiCorp's reliability and granularity adjustments.

III. PARTIES' POSITIONS ON ACKNOWLEDGMENT OF THE 2023 IRP

Parties' Comments

DPU, OCS, and UAE recommend the PSC not acknowledge the 2023 IRP. DPU argues 1) its submission was two months late with the last of the supporting documents filed on June 20, 2023;[9] 2) Natrium was included in the Preferred Portfolio without sufficient analysis of costs, timing, and risks to customers in light of the large costs and schedule overruns of other nuclear projects in the country; 3) the 2022 AS RFP was suspended without explaining its impact on the Action Plan;[10] 4) the assumption that non-emitting peaker plant technology will be commercially available by 2030 is inappropriate given the technology is unproven and its operating costs are unknown; and 5) some resources and technologies, like nuclear and non-emitting

[9] DPU Comments, at 2 and 4, filed December 12, 2023 ("DPU Comments"). DPU comments this is the third straight instance the IRP was filed two or more months after the March 31 deadline.

[10] DPU explains the assumptions that served as model inputs may change significantly by the time PacifiCorp performs more modeling, reiterating that "[t]hrough the end of 2026, the 2023 IRP Preferred Portfolio includes an additional 745 MW of wind and an additional 600 MW solar co-located with storage, for which the 2022 AS RFP [was] … soliciting and evaluating resources to fulfill." *Id.*, at 15 (quoting the IRP, at 35).

peakers, are unjustifiably favored and others, like new natural gas resources and CCUS technologies, are unjustifiably excluded.[11]

OCS argues PacifiCorp failed to meet Guidelines 3, 4.b., 4.e., 4.g., and 4.h. OCS states PacifiCorp did not provide any modeling results to stakeholders for review and feedback until after it had filed the preliminary IRP.[12] Additionally, OCS joins DPU in asserting natural-gas-fired resources were not evaluated on a comparable and consistent basis relative to unproven technologies like Natrium and non-emitting hydrogen peakers. OCS also objects that an appropriate customer rates impact analysis was not provided. Finally, OCS notes the suspension of the 2022 AS RFP may negatively impact system reliability within the next four years, leading OCS to challenge whether the Action Plan reflects least-cost, least-risk resources.

UAE comments PacifiCorp withheld the results of any modeling runs, including the Preferred Portfolio, from stakeholders before filing its preliminary 2023 IRP, contrary to Guideline 3. UAE believes PacifiCorp's actions prevented UAE's reasonable and meaningful participation in the selection of the Preferred Portfolio.[13]

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[11] DPU notes that the CCUS technology was the top-performing variant case using medium gas/medium CO2 assumptions, with a present-value revenue requirement ("PVRR") of $507m under the P-MM Preferred Portfolio. It was also a top performer under various other scenarios. Regarding new gas resources, DPU explains PacifiCorp assumed a 10-year cost recovery period rather than a typical 40-year period (DPU Comments, at 24). This unusual assumption was made without stakeholder input and, to DPU's knowledge, was first announced after PacifiCorp submitted the preliminary IRP.

[12] OCS Comments, at 1-2, filed December 12, 2023 ("OCS Comments").

[13] UAE Comments, at 3, filed December 12, 2023 ("UAE Comments").

UAE also expresses concern about the inclusion of Natrium in the Preferred Portfolio. UAE explains the lack of information about Natrium's cost and performance assumptions impeded any independent evaluation. UAE states PacifiCorp in effect forced the model to select Natrium. This modeling approach cannot be viewed as providing consistent and comparable treatment of competing resources.[14]

UCE recommends the PSC acknowledge the 2023 IRP and explains UCE is encouraged by PacifiCorp's planned increases in wind, solar, and storage resources in the 2023 IRP.[15]

WRA takes no position regarding the acknowledgment of the 2023 IRP. But it joins other parties in asserting that time constraints negatively impacted the accuracy of the modeling and the opportunity for public input. WRA explains that the preliminary 2023 IRP, the final 2023 IRP, and the accompanying supporting workpapers include significant errors — far more than is typical. In WRA's view, many portfolio results don't make sense.[16] These discrepancies, according to WRA,

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[14] *Id.,* at 9.
[15] UCE Comments, at 3, filed December 12, 2023 ("UCE Comments").
[16] As an example, WRA described that several portfolios show inexplicable disparities particularly in early years where system resources should be more or less identical including a comparison of portfolio variant P05-No Nuclear and P06-No Forward Technology. WRA explains that given nuclear and non-emitting peakers are not selected in either portfolio until 2030, the expectation was that the portfolios would differ only in future years but that there were large discrepancies in market purchases appearing in the first three years of the modeling period, despite no difference in system need or expansion options in those early years. WRA Comments, at 11, filed December 12, 2023 ("WRA Comments").

undermine its confidence in the results and support its view the IRP was filed before it was ready for stakeholder analysis.

Interwest recommends either the PSC decline to acknowledge the 2023 IRP or conditionally acknowledge certain parts thereof and the Action Plan.[17] Interwest states the 2022 AS RFP's suspension casts extreme uncertainty over the Action Plan. Interwest calls for increased scrutiny of Natrium and non-emitting peaker resource technologies in the Preferred Portfolio, as they "do not reflect the least cost/least risk" resources".[18] Interwest also recommends the PSC direct PacifiCorp to resume the 2022 AS RFP as soon as possible.

Sierra Club recommends the PSC acknowledge the planned new renewable resources in the 2023 IRP but argues the Plan's coal retirement timelines, gas conversions, and nuclear additions "are extremely risky for ratepayers" and do not warrant acknowledgement.[19] Sierra Club also expresses concern about the suspension of the 2022 AS RFP.[20]

PacifiCorp's Reply

PacifiCorp asserts its 2023 IRP and Action Plan comply with the Guidelines and were developed after substantial stakeholder input. PacifiCorp asserts it held eleven public-input meetings and six state-specific input meetings.[21] The 2023 IRP public-

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[17] Interwest Comments, at 3, filed December 12, 2023 ("Interwest Comments").
[18] *Id.*, at 6.
[19] Sierra Club Comments, at 3, filed December 12, 2023 ("Sierra Club Comments").
[20] *Id.*
[21] PacifiCorp Reply Comments at 12, filed January 31, 2024 ("PacifiCorp Reply Comments").

input process materials covered inputs, assumptions, risks, modeling techniques, and analytical results. PacifiCorp states it considered and implemented the PSC's direction in developing the 2023 IRP. It further asserts the Preferred Portfolio is supported by a detailed analysis of: 1) key inputs and assumptions to inform the modeling and portfolio-development process; 2) a wide range of resource portfolios; 3) a targeted reliability analysis to ensure portfolios have sufficient flexible capacity to meet reliability requirements; 4) evaluation of the resource portfolios to measure comparative costs, risks, reliability, and emission levels; and 5) development of a near-term resource Action Plan required to deliver resources in the Preferred Portfolio.[22]

PacifiCorp asserts the 2023 IRP benefited from various modeling advancements[23] and that through an extensive IRP process PacifiCorp was able to develop a Preferred Portfolio that meets its long-term goals of providing reliable and affordable service to its customers.

IV. DISCUSSION, FINDINGS, AND CONCLUSIONS

A. SUSPENSION OF THE 2022 ALL SOURCE RFP

OCS, DPU, Interwest, and Sierra Club assert the suspension of the 2022 AS RFP in September 2023 is problematic and, according to OCS, violated Guideline 4.e. OCS explains, and DPU agrees, the 2022 AS RFP suspension directly impacts the

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[22] *Id.*, at 4.
[23] See 2023 IRP, Volume I, at 18-19.

assumptions and selection of resources in the 2023 IRP because the types of resources that were expected to emerge from the 2022 AS RFP may no longer be available and may not be ready for commercial operation by the date required. According to OCS, this could result in increased exposure to market price risks, especially in the event of extreme weather like the September 2022 western heatwave.[24]

DPU and Interwest assert the suspension of the 2022 AS RFP raises serious doubts as to whether the 2023 Action Plan can be implemented.[25] Likewise, Sierra Club states it is highly concerned over PacifiCorp's decision to pause the 2022 AS RFP, especially after the 2023 IRP shows an even greater need for new renewable resources than was forecast in the 2021 IRP.[26]

PacifiCorp responds it suspended the 2022 AS RFP in September 2023, after it had filed the 2023 IRP.[27] It explains its decision was based on a stay of the U.S. Environmental Protection Agency's ("EPA") proposed OTR; ongoing EPA rulemaking on greenhouse gas emissions; wildfire risk and associated liability; and, evolving extreme weather risks.[28] It argues that it complied with Guideline 4.e. and that IRP acknowledgment means not that the Action Plan or Preferred Portfolio selections are

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[24] OCS Comments, at 4.
[25] DPU Comments, at 14; and Interwest Comments, at 5-6.
[26] Sierra Club Comments, at 3.
[27] PacifiCorp Reply Comments, at 16.
[28] The OCS argues that all of these factors were known and included in the final 2023 IRP when it was filed on May 31, 2023; and therefore, was surprised PacifiCorp named the same factors as the reason for suspending the 2022 AS RFP in September 2023.

valid into perpetuity but rather, that the IRP and resulting Action Plan are appropriate given the conditions at the time of filing.

We conclude PacifiCorp's decision to pause the 2022 AS RFP substantially impacts the Action Plan and greatly reduces its value and trustworthiness. The PSC recognizes at least some of the reasons PacifiCorp offers for pausing the RFP were known to PacifiCorp at the time it filed its final 2023 IRP in May 2023. Nevertheless, while certain parties recommend the PSC direct PacifiCorp to reinstate the 2022 AS RFP, such proposals are outside the scope of this docket.

B. MODELING ISSUES, ASSUMPTIONS, AND RESOURCE SELECTIONS

1. Consistent and Comparable Treatment of Resources

a. *Natrium*

DPU, OCS, UAE, and Interwest argue that PacifiCorp either forces the selection of Natrium in the Preferred Portfolio or inputs favorable assumptions to ensure the model always selects Natrium. For example, UAE notes that unlike every other generation resource considered in Table 7.1 of Chapter 7 of the 2023 IRP (showing costs and performance information for all supply-side resources), Natrium is not included.[29] Rather, PacifiCorp's cost and performance assumptions for Natrium are unknown to stakeholders. According to UAE, this allows the assumed costs of Natrium to "move" in the model such that they purportedly always provide benefits to

[29] UAE Comments, at 7.

customers.[30] UAE contends this also ensures that Natrium is always selected by the model.[31] PacifiCorp justifies this treatment by stating that it is in commercial discussions with TerraPower and will not move forward unless there are benefits for customers. UAE concludes Natrium's treatment in the model is not consistent and comparable with the treatment of other resources.

DPU states PacifiCorp has never responded to requests for 1) Natrium's costs and performance factors and 2) a timeline with major milestones that shows a path to achieving an online service date of 2030.[32] DPU also contends that since no details are available to stakeholders, it is impossible to evaluate Natrium on a comparable and consistent basis with other resources. DPU concludes that until an agreement is finalized, federal funding is certain, and a timeline is provided, Natrium is a speculative resource that should not be in the Preferred Portfolio.[33]

PacifiCorp responds that its selection of Natrium in the P-MM Preferred Portfolio was based on substantial grants from the Department of Energy (DOE), Natrium's development by TerraPower, the alternative path analysis, the OTR and other federal regulatory requirements, and the obligation to provide least-cost, least-risk portfolios.[34] It explains TerraPower bears all development risks and asserts it has not signed any agreements with TerraPower. It reiterates it will only move forward if

[30] *Id.*, at 9.
[31] *Id.*
[32] DPU Comments, at 21.
[33] *Id.*, at 19.
[34] PacifiCorp Reply Comments, at 35.

Natrium brings value to customers. PacifiCorp indicates the risks associated with Natrium are mitigated because Natrium alternatives require much shorter lead-times than nuclear projects and ample opportunities to meet future electric demand will emerge, before it commits to Natrium.[35] PacifiCorp also reiterates the potential realization of Natrium does not fall within the two- to four-year Action Plan window and explains that Natrium was intentionally limited to years outside of the Action Plan.[36]

b. *Non-Emitting Peaker Plants*

DPU, OCS, and Interwest contend that PacifiCorp favors non-emitting peaker resources (turbines running on 100 percent hydrogen) by assuming they will be available and commercially viable by 2030 even though no such utility scale technology is currently operating. Both DPU and Interwest note the production and transportation plans for hydrogen for utility-scale energy generation are also currently only in the design phase.[37] They explain that while hydrogen could be delivered using a pipeline network from a centralized remote facility, these pipelines do not currently exist. Given these facts, the parties question the selection of the resource for the P-MM Preferred Portfolio.[38] DPU comments it is impossible to

[35] *Id.*, at 36.
[36] *Id.*, at 37.
[37] DPU comments, at 3 and 22.
[38] In response to a data request, PacifiCorp responded that its modeling of this technology assumes 1) the expense of the needed pipeline, as well as 2) its ability to procure hydrogen at market prices based on forward price curves and projections showing low hydrogen production costs and federal tax credits for 100 percent hydrogen. DPU Comments, at 22-23.

analyze PacifiCorp's cost information since such plants are not commercially operating, and DPU has no way to test any data supporting PacifiCorp's assumptions.[39] DPU adds that the timelines PacifiCorp uses for availability of non-emitting peakers may also be optimistic, and argues that assuming a specific date for this non-emitting resource is speculative.

Interwest criticizes non-emitting peaking resources' selection in the Preferred Portfolio stating that a 20 percent hydrogen blending ratio is inadequate to achieve emission performance requirements because it achieves only a marginal decrease of 6-7 percent in carbon emissions at the gas generating unit.[40] Additionally, there is evidence a sustained green hydrogen supply-chain does not exist.

In response, PacifiCorp states that its main goal is selecting a Preferred Portfolio with the best combination of expected costs and associated risks and uncertainties.[41] Thus, in creating a 20-year plan, it does not limit resources to only those currently estimated to be commercially viable within the planning horizon. Rather, it considers associated risks when it includes resource options. PacifiCorp believes non-emitting peakers, like nuclear, will achieve wider commercial use outside of the two- to four-year Action Plan window and restricts their selection on that basis. PacifiCorp also explains that the alternative path analysis indicates ample

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[39] *Id.*, at 22.
[40] Interwest Comments, at 11.
[41] PacifiCorp Reply Comments, at 41.

opportunity for adjustment to these proxy resource selections based on future analysis.

c. *CCUS Technology*

DPU contends PacifiCorp's planning is biased against CCUS technologies. For example, DPU states that variant P20 JB3-4 CCUS ("P20") (which includes CCUS technology), was the top-performing variant case using the medium gas/medium CO2 assumptions, with a PVRR of $507 million *under* the P-MM Preferred Portfolio variant (using short-term ("ST") value).[42] Variant P20 was also the top performer under a risk-adjusted cost metric and was third in the CO2 emissions category.[43] It was also the top ST cost performer under both the medium gas/zero CO2 scenario and the high gas/high CO2 scenario, and was the top emission performer under both of these scenarios.[44]

PacifiCorp responds that CCUS technologies have shown significant cost uncertainty and only two major utility-scale CCUS retrofit projects are commercially operating.[45] PacifiCorp conceded the P20 variant was the top performer under both ST and risk-adjusted evaluations, but explained it did not choose it for the Preferred Portfolio because 1) the CCUS assumptions are not based on bids or proposals from CCUS technology companies but are proxy assumptions for project-specific costs and

[42] DPU Comments, at 24.
[43] *Id.*
[44] *Id.*
[45] PacifiCorp Reply Comments, at 39.

operational characteristics; 2) the scale of the proposed CCUS technology has never been demonstrated on a coal plant operating commercially anywhere in the world; 3) while feasibility studies for amine-based CCUS at Jim Bridger ("JB") units 3 and 4 have been done, PacifiCorp currently does not have evaluation or equivalent cost data to that of a front-end engineering and design study; 4) the updated fueling strategy to source coal for JB exclusively from the Powder River Basin has not been previously attempted by PacifiCorp; and 5) other limitations, challenges, and risks. In response to a question about whether these risks were analyzed by its model, PacifiCorp indicated its rejection of the P20 variant in the Preferred Portfolio was more of a judgment call.[46]

d. *New Natural Gas Plants*

According to DPU and OCS, PacifiCorp's planning is also biased against generating facilities fueled by natural gas and coal. For example, DPU states PacifiCorp informed stakeholders for the first time in the April 13, 2023 public input meeting that in most scenarios, the recovery period for the costs of new gas resources is assumed to be 10 years to account for PacifiCorp's perceived risks in investments in new carbon emitting resources.[47] DPU requested results from a portfolio variant assuming instead a 40-year cost recovery horizon as realistically in line with new natural gas resources and PacifiCorp responded by producing variant

[46] DPU Comments, at 24-25.
[47] *Id.*, at 30.

"P24-Gas 40-year Life" ("P24"). PacifiCorp describes it as a variant of the P-MM Preferred Portfolio that changes the technical life assumption for proxy gas resources from 10 years in the base study to 40 years. According to PacifiCorp, this change produced different results. First, the model selected gas units as replacements for any coal retirements, instead of the nuclear or non-emitting peaking options in the P-MM Preferred Portfolio.[48] Second, the "cost of gas pipelines led the model to keep" the Hunter 2 and 3 coal plants running through 2042.[49] Third, the model selected significantly less early DSM.[50] DPU criticizes PacifiCorp's arbitrary decision to change the expected life of new natural gas plants arguing several natural gas plants are currently in different stages of development across the country.[51] DPU also notes the PSC declined to acknowledge the 2021 IRP for a similar reason — PacifiCorp's unilateral decision to force the model to exclude new natural gas plants altogether. DPU explains the decision to constrain the life of a new natural gas plant resulted in an inappropriate Preferred Portfolio. PacifiCorp responds that for the first time, it allowed the model to endogenously select natural gas conversions for a broader set

[48] *Id.*, at 26-27.
[49] *Id.*
[50] *Id.*, at 27 (DPU referencing the 2023 IRP, Volume I, at 305).
[51] DPU presents a map showing natural gas plants that were announced, in early development, in advanced development and under construction in 2023 which DPU states illustrates that many utilities do not attribute the same risks to natural gas plants that PacifiCorp does. DPU Comments, at 29 (Figure 5 – Planned New Natural Gas Plant (S&P)).

of units. According to PacifiCorp, this enhancement expands opportunities for natural-gas-fired operation compared to prior IRPs.[52]

DPU also challenges the final step PacifiCorp used to select the Preferred Portfolio. After all of the variants were run through the model, PacifiCorp explains its decision to select the P-MM variant as the Preferred Portfolio was driven by "consideration of current policies in motion and unmodeled risks for which ongoing trends recommend the adoption and development of tax-supported renewable projects … ."[53] In response to a request for calculations or other supporting data for these subjective criteria, PacifiCorp stated there were no records or calculations to review.

e. *We Find and Conclude PacifiCorp Failed to Treat Resources on a Consistent and Comparable Basis*.

Guideline 4.b. requires "[a]n evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis." In addition, 4.b.iii. states "resource assessments should include: life expectancy of the resources… ."

We find, based on the evidence, that PacifiCorp overlooked the negative attributes of Natrium in its analysis and withheld confidential costs and performance information that were necessary to compare Natrium on a consistent and comparable

[52] PacifiCorp Reply Comments, at 37-38.
[53] 2023 IRP, Volume I, at 306.

basis relative to other resources. Natrium certainly has potential due to its unique characteristics as described in PacifiCorp's reply comments.[54] However, the IRP contains no discussion of the potential for significant cost overruns or delayed construction timelines typical to the development and construction of nuclear projects. Natrium was selected as a least-cost, least-risk resource in the Preferred Portfolio based solely on its positive, unique attributes. We recognize the sensitivity of PacifiCorp's costs and performance assumptions for Natrium; however, our process provides protections for highly confidential information that may have allowed parties to perform at least a general cost analysis, and PacifiCorp failed to use it. We find it is impossible to compare Natrium with other resources on a comparable and consistent basis without cost and performance assumptions and a realistic assessment of all the potential attributes of Natrium, both positive and negative.

We also find disparate treatment by PacifiCorp of non-emitting resource technologies relative to CCUS technologies. For example, despite the P20 CCUS variant being the top or near the top-performing variant under five different scenarios,[55] PacifiCorp did not select it as a least-cost, least-risk resource in the Preferred Portfolio. The reasons PacifiCorp argues for rejecting CCUS, e.g., that cost assumptions are not based on bids and commercial operation is unproven, apply with

[54] PacifiCorp Reply Comments, at 36.
[55] *See* DPU Comments, at 24.

equal, if not greater, force to the Natrium and non-emitting resource technologies PacifiCorp includes in the P-MM Preferred Portfolio.

Finally, the use by PacifiCorp of a 10-year life for new natural gas plants was arbitrary and unjustified, and prevented their consistent and comparable treatment relative to other resources. The PSC recognizes risks may exist to natural gas plant lifespans attendant to the OTR and other federal regulations. Such risks are inherent in the planning process and require analysis and articulated reasoning on how best to measure and account for them. In this instance, however, the restriction on useful life is unilateral and arbitrary. Neither the OTR nor any other federal regulation changes the depreciable lives of natural gas plants from 40 to 10 years. Moreover, any Oregon, Washington, and California laws that may impact the lives of new natural gas plants do not apply in Utah. Accordingly, the PSC finds that PacifiCorp did not treat natural gas plant options on a comparable and consistent basis relative to other resources, contrary to Guidelines 4.b., 4.b.iii., and 4.h.

2. Reliability and Granularity Adjustments

Sierra Club requests PacifiCorp clarify its methodology for its reliability adjustments and explain the reason the long-term model produces significant energy shortfalls that must be manually addressed. Sierra Club also requests an opportunity to recommend alternative reliability adjustments, and clarification of the values

PacifiCorp uses in the granularity adjustments.[56] Sierra Club suggests that PacifiCorp base its coal units' granularity adjustments on total fuel costs.[57]

PacifiCorp explains that both reliability and granularity adjustments are specific measures that address specific enhancements and there are no logical alternatives because both procedures are dictated by model math.[58] It further explains that in extreme cases where the adjustments exceed plus or minus $100/kW-year, it limits the adjustment to plus or minus $100/kW-year to prevent the granularity adjustment from overwhelming long-term outcomes based on extreme values driven by conditions that will not be relevant in final reliable portfolios.[59] PacifiCorp comments it makes resource adjustments on the basis of measured deficiencies and by applying calculated resource values to determine the appropriate action to cover deficiencies. It states its approach is specific to stated goals and a direct application of model outcomes to improve results. We find PacifiCorp's explanations to be reasonable and sufficiently responsive to Sierra Club's requests. Therefore, we find that no additional information related to its reliability and granularity adjustments is necessary.

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[56] Sierra Club Comments, at 4.
[57] *Id.*, at 4 and 42.
[58] PacifiCorp Reply Comments, at 19.
[59] *Id.*, at 20.

3. Customer Rate Impact Analysis

In response to OCS's claim that PacifiCorp failed to comply with Guideline 4.g. by not including a customer rate impact analysis, PacifiCorp states that the IRP includes an indicator of customer rate pressure over time among the initial portfolios relative to the P-MM Preferred Portfolio. It explains that Volume II, Appendix J, stochastic simulation results show incremental and cumulative estimated customer rate impacts over the 20-year planning period that apply equitably across all classes of ratepayers.[60] PacifiCorp indicates that while the approach provides a reasonable representation of relative differences in projected total system revenue requirement among portfolios, it is not a prediction of future revenue requirement for ratemaking purposes. PacifiCorp also explains that the IRP is informed by proxy resources where exact costs cannot be known until specific resources are known. We find, based on PacifiCorp's explanation and our review of Volume II, Appendix J, including the figures showing net differences in total system costs, that its analysis meets Guideline 4.g., and no additional analysis is necessary.

4. Miscellaneous Changes to the Presentation of Data

Alternative Portfolio Variants, Cluster Resources, and Scenarios. In response to Sierra Club's request for PacifiCorp to complete model runs of P01-JB3-4 GC, P04-Huntington RET28, and P17-Col3-4 RET25 variants under all of the different pricing

[60] *Id.*, at 22.

scenarios, PacifiCorp responds that because it is constrained from evaluating all studies under all possible conditions, it must prioritize which model variant to analyze. It bases its decisions on the likely investigative value. PacifiCorp states the P01, P04, and P17 results, for example, are so conclusive that further analysis under other, less likely, price scenarios doesn't add likely investigative value. PacifiCorp states that P17, for example, was examined only to determine the cost-effectiveness of an early retirement of both Colstrip units over the optimally selected approach of retiring one unit and continuing the other. PacifiCorp also explains the 2023 IRP evaluates portfolios under five price policy scenarios with attention to investigative value and resource availability. PacifiCorp states it cannot evaluate all studies under all possible conditions and therefore prioritizes cases. At the same time, PacifiCorp asserts, it has been responsive to stakeholder requests, conducting additional studies as time and resources allow.

PacifiCorp explains that the analysis of P18 and P19 likewise was conducted with the understanding that additional resources would likely result in a higher cost PVRR outcome and that the value of the studies was to assess the magnitude of that PVRR impact to determine possible least-regret paths to consider for the Preferred Portfolio. It further explains that the results of the studies supported the selection of the Preferred Portfolio without the additional marginal cluster resources in the East or West.

We find PacifiCorp's explanation that it cannot evaluate all studies under all possible conditions, and therefore prioritizes cases, is reasonable. We also find that PacifiCorp has been responsive to stakeholder requests for alternative and additional model runs, conducting additional studies as time and resources allow, and that running the proposed additional variants would produce more portfolios but would not change the final outcome and, therefore, be of limited value. Based on this, we find it is unnecessary for PacifiCorp to run the requested additional modeling.

Coal fuel costs for JB and pipeline capacity for conversions. We find PacifiCorp's response to the request that it use the base tier pricing from the 2023 JB long-term fuel plan for the JB plant, to be reasonable. PacifiCorp states that the fixed and variable cost structure assumed in the 2023 IRP captures the cost of continuing or ceasing coal-fired operation at JB units 3 and 4. It explains that opportunities to optimize coal supply for particular circumstances are ill-suited for modeling in the IRP and provide limited incremental benefit.

We also find PacifiCorp's response to Sierra Club's request that PacifiCorp provide an assessment of the availability and cost of firm interstate pipeline capacity necessary to supply its planned coal to gas conversions in the 2023 IRP Update, to be reasonable. PacifiCorp explains that due to confidentiality agreements between it and third-party entities, it is unable to disclose any terms on firm interstate pipeline capacity for planned conversions.

Carbon. Sierra Club recommends PacifiCorp increase the medium carbon price assumption to reflect recent federal regulations and incorporate the developments in the 2023 IRP Update. According to PacifiCorp, the request is based on a misunderstanding of the medium CO2 price assumption cost function. It explains that the medium CO2 price assumption is a proxy for future drivers. Its CO2 proxy cost forecast represents an established trend of decarbonization into the future and is based on a survey of (then) currently available forecasts. PacifiCorp explains that it is not the role of the proxy cost to drive decarbonization, rather its role is to represent drivers that can be reasonably forecast. It further explains its forecasting of the decarbonization trend will continue into the future. Regarding the request for elimination of "the medium gas price, zero CO2 price ('MN') price-policy scenario or zero CO2 ('LN') price-policy scenarios generally,"[61] PacifiCorp states this would generally eliminate a source of information from the robustness of portfolios that indicates what may occur if the expected case CO2 proxy forecast is not realized. PacifiCorp asserts that while the medium gas price-policy scenario is the most likely, eliminating it or any alternative, as requested, is unnecessary. We find PacifiCorp's response credible. On this basis, we find that it is unnecessary to run the requested analyses.

[61] *Id.*, at 26.

Collocated Resources. UAE recommends the PSC direct PacifiCorp to make its requested changes to Tables 9.31, 9.32, and 9.33, and Figures 9.60 and 9.62 in future IRP filings. UAE's main concern is that the tables lack detail on whether the generation and storage resources shown are collocated or standalone resources. PacifiCorp responds that collocation information is illustrated in Figure I.1 of the 2023 IRP. It lists the portfolio resources selected by location and year, including solar and wind resources that are collocated with storage. PacifiCorp also refers to the discussion on the expansion of collocation opportunities in section III.A.2 – *Process Improvements,* in the 2023 IRP indicating that collocation options are no longer constrained in the modeling. We find PacifiCorp's explanation is responsive to UAE's requests; therefore, we decline to order the requested changes in future IRP filings.

Surplus Interconnection. Sierra Club requests PacifiCorp allow storage to be paired with not only new renewable resources, but also existing fossil fuel resources. According to Sierra Club, this use of a thermal asset with a storage resource "would increase the flexibility of the asset and provide lower emission reliability services, such as spinning reserve" and likely "reduce operating costs as the storage asset could operate more responsively."[62]

PacifiCorp responds that it has modeled surplus interconnection in the 2023 IRP, where storage resource options were available to be selected with potentially

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[62] Sierra Club Comments, at 55-56.

any technology or combination of technologies, allowing portfolio optimization to recognize the best location, size, and timing for storage concurrently with considerations of existing technology profiles, and also in tandem with thermal retirement options. PacifiCorp adds that storage options that were not part of a cluster study were considered unconstrained by transmission requirements, such that any amount could be placed at any modeled location on the system. It explains that its strategy has exceeded the requests by allowing the model to make the best collocation determinations endogenously and refers Sierra Club to the IRP discussion of expanded collocation opportunities in section III.A.2 - *Process Improvements*. We find PacifiCorp's response to be reasonable and find that PacifiCorp has already modeled the requested interconnection scenario, and no additional modeling is necessary.

C. PROCESS ISSUES

DPU contends the 2023 IRP was filed after the March 31 deadline for the third IRP cycle in a row, and the continual filing delay disadvantages stakeholders as it compresses their opportunity to review and evaluate the IRP. DPU explains it agreed to PacifiCorp's extension request because it was the least objectionable alternative. OCS, UAE, and UCE also contend that PacifiCorp's failure to provide the modeling results to stakeholders before it filed the preliminary IRP prevented them from having any opportunity to review, evaluate, and provide public input, which OCS and UAE claim violates Guideline 3. DPU and OCS note that even the media knew the modeling results before stakeholders who invest significant time and resources into the IRP planning process. UCE agrees that PacifiCorp should provide the modeling results to stakeholders to allow for sufficient review before filing the IRP. WRA also joins DPU, OCS, UAE, and UCE in the overall concern that time constraints impact not only the ability to appropriately review, evaluate, and provide input, but also lessen the accuracy and quality of the IRP. WRA also asserts the current IRP process and timeline do not work and suggests the PSC make a structural change.

PacifiCorp responds the two-month extension to file the 2023 IRP by May 31, 2023 was necessary to allow PacifiCorp to incorporate recent federal and state law changes such as the OTR, the IRA interconnection rules, and other state regulatory requirements. PacifiCorp asserts that while several parties expressed concern over the requested extension, no one recommended the PSC deny it and notes that stakeholders requested PacifiCorp provide a draft IRP in comments related to the 2021 IRP. PacifiCorp further asserts the extended stakeholder engagement process enhanced the accuracy and comprehensiveness of the IRP that led to a significantly improved analysis in the final 2023 IRP. In sum, PacifiCorp notes that the public input process affords many opportunities for comment and quotes the PSC stating, "'[t]he purpose[] of the process is *not* to allow stakeholder[s] an early preview of what

PacifiCorp has [ultimately] elected to do. The purpose is to allow them an opportunity to provide meaningful feedback at each stage of a collaborative process.'"[63]

Our direction on the interpretation of Guideline 3 has been clear. The opportunity for stakeholders to examine and provide information during the IRP development, rather than after the fact, is an important aspect of the process.[64] The IRP is to be developed in consultation with stakeholders who must have ample opportunity for meaningful feedback and information exchange during the development of the plan and at each stage of the process.[65] In this docket, PacifiCorp did not share its modeling results and the Preferred Portfolio, two of the most critical aspects of the IRP, with stakeholders until after it filed its preliminary IRP on April 3, 2023. This is the first time that PacifiCorp has not provided modeling results and Preferred Portfolio selections before making its IRP public. However, this is also the first time that we have added an extended filing period that included the filing of a preliminary IRP and a comment deadline. In light of the uncertainties created by this new procedure, we do not find PacifiCorp violated Guideline 3. Nevertheless, we

[63] PacifiCorp Reply Comments, at 11. In quoting the PSC's order about the purpose of the process, PacifiCorp unfortunately misinterpreted our language and quoted it out of context. The PSC was reacting to PacifiCorp's pattern of untimeliness, of presenting meeting materials at the last minute, and of making key modeling decisions without giving stakeholders time to review and provide meaningful input. A major purpose of the IRP Guidelines is to assure PacifiCorp collaborates and shares information with stakeholders before decisions, in particular crucial ones like the selection of the Preferred Portfolio, are made.
[64] PacifiCorp's 2017 Integrated Resource Plan, Docket No. 17-035-16, Report and Order issued March 2, 2018, at 7-8.
[65] *Id.*, at 7.

remain troubled by the evident lack of collaboration, in particular with respect to key decision points in the IRP planning process. Here, parties did not collaborate on the most consequential aspects of the IRP — modeling results and the Preferred Portfolios - before the preliminary IRP became public. Therefore, in this order we provide notice that in all future IRP dockets, Guideline 3 will apply to preliminary IRP disclosures and filings. As we have said before, PacifiCorp must provide parties ample opportunity to review, analyze, and provide meaningful input at all stages of the IRP process. Moreover, this must be done with adequate time for PacifiCorp to evaluate and, as appropriate, apply that input before filing any IRP, whether preliminary or final.

D. MISCELLANEOUS REQUESTS RELATED TO THE 2025 IRP

Modeling extreme weather events.

The OCS and DPU recommend PacifiCorp include in its modeling the effects of long-lasting extreme weather events. OCS specifically cites the September 2022 heatwave and the February 2021 Texas extreme cold event as examples of the types of weather events that should be modeled in order to identify potential system reliability issues. PacifiCorp responds that it already models several weather scenarios, and will continue to model them in upcoming IRP cycles. It explains that it not only considers climate change within its baseline forecast, but within multiple load forecast scenarios. As an example, PacifiCorp states that the 1-in-20-year extreme weather scenario evaluates peak weather impacts using the most extreme peak observed over the past 20 years. PacifiCorp also states the 20-year normal weather scenario evaluates the weather impacts on load assuming weather is consistent with the average temperatures observed over the prior 20 years.

We find PacifiCorp's modeling of weather scenarios amply addresses OCS's concerns. To the extent other methodologies for modeling extreme weather events arise, we encourage PacifiCorp to study and discuss them with stakeholders during the IRP planning process.

Modeling GET.

OCS asserts the IRP model does not, but should, contain a process to evaluate GET or other advancements to maximize the efficiency of the grid. OCS explains that by avoiding construction of very costly transmission lines or transmission interconnection activities, GET could enable the development of lower cost Preferred Portfolios. Likewise, Interwest recommends that PacifiCorp include GET in future IRPs.

PacifiCorp responds that Chapter 4 and Appendix E of the 2023 IRP review the potential for reconductoring with advanced conductors as well as using other GET. It states it considers and identifies network upgrades using advanced conductors and GET wherever feasible, and this approach provides adequate analysis for the long-term. We find the 2023 IRP sufficiently evaluates GET as evidenced in Chapter 4 and Appendix E. We therefore decline to direct PacifiCorp to perform additional analysis in this area.

Modeling Enhanced Geothermal Systems ("EGS").

UCE recommends PacifiCorp consider evaluating EGS technologies in the 2025 IRP cycle. UCE explains that Utah is home to the Utah Frontier Observatory for Research in Geothermal Energy ("FORGE") project[66] which is sponsored by the Department of Energy for developing, testing, and accelerating breakthroughs in EGS. UCE states that Fervo Energy is developing the 400 MW Cape Station project in Beaver County, Utah that is expected to go online in 2028. UCE concludes that EGS should be added to other emerging technologies like Natrium and non-emitting (hydrogen) resources that PacifiCorp evaluates.[67]

PacifiCorp responds that it studied and updated geothermal technologies as an option in the 2023 IRP, but they were not selected in the Preferred Portfolio. PacifiCorp states it intends to continue to include geothermal options and update its costs and technical assumptions in future IRPs and remains open to considering geothermal competitive bids in its RFP processes.[68] We find, based on PacifiCorp's explanation, that it has considered, and intends to continue to consider, EGS as another emerging technology for evaluation in future IRPs.

[66] UCE Comments, at 7.
[67] *Id.*, at 8.
[68] PacifiCorp Reply Comments, at 31-32.

Federal and state incentives.

Sierra Club recommends PacifiCorp apply tax bonus credits for "energy communities" to all qualifying communities and correct inaccuracies and update its supply side resource workpapers to include the investment tax credits and production tax credits granted under the IRA for storage resources.[69] PacifiCorp responds it will continue to pursue opportunities to share government funding updates with stakeholders.[70] PacifiCorp also states that not all resources planned in the 2023 IRP over the 10-year period qualify for EIR, as Sierra Club appears to imply.

For example, PacifiCorp explains that only company-owned resources would be expected to qualify, and this would exclude non-owned purchase power agreements selected by the RFP process.[71] PacifiCorp reiterates that the long-term IRP is based on proxy resource selection. PacifiCorp asserts that cost-saving opportunities, such as those provided by federal incentives, are addressed during the acquisition process and will manifest through an all-source RFP. PacifiCorp encourages stakeholders to actively monitor PacifiCorp press releases to look for new funding developments.

We find PacifiCorp's response is reasonable. No additional analysis on federal and state funding opportunities is necessary in the IRP. We find that incentive-based

[69] Sierra Club Comments, at 3.
[70] PacifiCorp Reply Comments, at 29.
[71] *Id.*

savings opportunities associated with specific resources are more appropriately considered in the acquisition approval regulatory process.

Participation in Regional Transmission Planning.

Interwest contends that solar-rich regions of PacifiCorp's service territory could provide valued capacity and energy diversity and recommends PacifiCorp include in the next IRP detailed participation updates regarding coordination between NorthernGrid and WestConnect regional planning authorities.[72] Additionally, Interwest suggests the PSC direct PacifiCorp to participate in and report on other transmission planning efforts such as the Western Transmission Expansion Coalition. Interwest further recommends that PacifiCorp include an analysis of potential interconnection points to other utilities.[73]

PacifiCorp responds that participation in regional planning authorities is important and that it is an active member of NorthernGrid and coordinates with WestConnect through NorthernGrid via Interregional Coordination meetings.[74] PacifiCorp points to Volume I, Chapter 3 - Planning Environment, of the 2023 IRP for information on the Western Energy Imbalance Market, Extended Day-Ahead Market, the WRAP, "Markets+" a Southwest Power Pool day-ahead market offering, and other developments to demonstrate it takes an active role in regional planning. It also states

[72] Interwest Comments, at 25.
[73] *Id.*
[74] PacifiCorp Reply Comments, at 43.

that collaborating with other utilities is a common practice in transmission planning, and where feasible, collaborations with other utilities can be used to inform the IRP.[75]

The PSC finds the IRP sufficiently discusses and analyzes PacifiCorp's participation in regional planning and provides adequate information on PacifiCorp's regional market participation and the significant benefits that current energy imbalance market participation brings to customers. The PSC finds it is not necessary to require the requested additional analysis.

Integration costs reporting.

Interwest urges PacifiCorp to study and report in the 2025 IRP the costs of inflexible thermal resources in assigning integration costs.[76] PacifiCorp explains that integration costs represent the incremental cost of holding reserves for additional renewable resources. It states that the number of reserves required is reduced because wind and solar resources are added to a pool of reserve requirements that includes load, wind, solar, and non-dispatchable thermal and hydro resources.[77]

PacifiCorp explains that using a pool of reserves to cover variations reduces the reserve requirement. For example, higher than expected wind output may offset lower than expected solar output, load may drop at the same time as wind output, and both circumstances can result in a reduced need for reserves to be deployed.[78]

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[75] *Id.*
[76] Interwest Comments, at 30.
[77] PacifiCorp Reply Comments, at 44.
[78] *Id.*

PacifiCorp states that as part of the 2025 IRP, it intends to develop updated reserve requirements for load, wind, solar, and non-dispatchable resources, and will present the analysis and results as part of the public input process for stakeholder feedback. PacifiCorp adds that as part of model optimization, PLEXOS ensures these reserve requirements are met by dispatchable resources specific to a given portfolio, where portfolios with more dispatchable resources can fulfill those requirements at lower cost.[79] As a result, integration costs are embedded within the reported cost results. PacifiCorp states that portfolio results do not have a dollar per megawatt-hour integration cost added for wind and solar generation, as these costs are part of the core optimization calculation and in any case differ widely across portfolios and future conditions.

The PSC finds PacifiCorp's explanation that integration costs are embedded within the reported cost results satisfies Interwest's request. Other than PacifiCorp's plan to develop updated reserve requirements and the presentation of its analysis as part of the 2025 IRP public input process, we find that no other analysis at this time is necessary.

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[79] *Id.*, at 44-45.

E. PROPOSED STRUCTURAL CHANGES TO THE IRP PROCESS

We recognize this is the third cycle in a row that PacifiCorp has requested and received additional time to finalize its IRP. WRA provides evidence that since 1992, almost half of the IRPs were filed after significant delay and only three were unequivocally timely filed.[80] In this instance, the 2023 IRP, its Action Plan, and Preferred Portfolios were developed in the context of rapidly changing laws and energy policies. This necessitated an extension of the schedule to provide some opportunity for stakeholders to review the modeling results and the Preferred Portfolios. The two-month extension turned out to be too short. Both DPU and WRA note that non-confidential supporting information was not made available to stakeholders until April 17, 2023, confidential information supporting the filing was made available on May 1, 2023 after the April 30, 2023 comment deadline, and final confidential supporting information was filed on June 16 and June 20, 2023. The last of the finalized information was filed more than 11 weeks after the 2023 IRP original due date.

It is evident once again in this IRP cycle that the current IRP planning process, even with the authorized extensions, does not provide sufficient time 1) for PacifiCorp to develop an effective IRP, and 2) for stakeholders to review, evaluate, and provide

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[80] WRA states, "[o]f the fifteen planning cycles [since] 1992, three were unequivocally timely; one provided a partial filing on the required date but added an addendum three months later; three were late by days rather than months; but six, close to half, were more significantly delayed … rang[ing] from one month to two-and-a-half years with a median delay of five months." WRA Comments, at 6.

meaningful input at all phases of IRP development. Consequently, we direct DPU, and invite OCS and other IRP participants, to file in this docket by May 30, 2024 recommendations concerning changes to the IRP schedule that will better provide PacifiCorp and all IRP participants adequate time to meet the public collaboration and participation objectives of the Guidelines and described in this and prior IRP orders. We will issue an order outlining the next steps in our consideration of changes to the IRP schedule after reviewing parties' recommendations.

F. THE P-MM PREFERRED PORTFOLIO AND THE LEAST-COST, LEAST-RISK RESOURCE

The fundamental objective of the IRP planning process is to arrive at the least-cost, least-risk resources otherwise known as the Preferred Portfolio. As discussed in detail above,[81] the disparate and inconsistent treatment of Natrium, non-emitting resources, new natural gas plants, and CCUS technologies, resulted in a Preferred Portfolio that fails to withstand scrutiny. Most parties recommended we not acknowledge the 2023 IRP, in part, due to the lack of analytical consistency. DPU put it best that "… small assumptions or changes in inputs can have a large impact on the resource mix ten years down the road … ."[82] The impact of consequential decisions like a dramatic change in the cost recovery period for new proxy gas plants is even greater and should not be made arbitrarily and unilaterally. For these reasons, we

[81] *See* Section IV.B.1. of our Order.
[82] DPU Comments, at 29.

find and conclude the portfolio selection process, and the P-MM Preferred Portfolio, lack credibility and do not acknowledge them.

G. THE ACTION PLAN

The 2023 Action Plan identifies specific actions PacifiCorp intends to take over the next two- to four-year period to deliver resources included in the Preferred Portfolio. PacifiCorp requests that we acknowledge and express support for this Action Plan. Utah Admin. Code R746-430-1 defines "Action Plan" and outlines the contents and supporting information and analysis required. It also states: "Nothing in these rules requires any acknowledgment, acceptance[,] or order pertaining to the Action Plan submitted." Despite that provision, for clarity we state explicitly that we decline to acknowledge or approve the Action Plan submitted with the 2023 IRP. We agree with parties who assert the suspension of the 2022 AS RFP must certainly and substantially impact the Action Plan, yet, on this record we have no way to know exactly how or to what precise degree. Additionally, as with the Preferred Portfolio, the unjustified inconsistencies in the modeling of various resource types cast serious doubts as to the trustworthiness of the resulting Action Plan. In particular, we find the decision to model a 10-year technical life for a proxy new natural gas plant impacts near-term decisions that could prevent customers from potentially attaining significant savings starting in the 2028-2030 period.[83] This finding is corroborated by

[83] *See* Figure 9.45, 2023 IRP Volume I, page 306.

DPU, OCS, and several other parties that urge us to refrain from acknowledging the Action Plan.[84]

V. SUMMARY AND CONCLUSIONS

We recognize the substantial body of quality work completed by PacifiCorp in preparing the 2023 IRP. PacifiCorp filed extensive documentation and workpapers with the 2023 IRP. The level of detail is useful, and the information provided is well organized. We encourage PacifiCorp to continue to provide such detailed back-up data and workpapers in future IRPs.

We also appreciate the diligent efforts and thoughtful comments provided by all parties. We recognize the frustration expressed by many participants with the limitations on their opportunities to provide timely feedback at each stage of the planning process.

After fully considering the 2023 IRP and the parties' comments and reply comments, we acknowledge that, with the exceptions noted, PacifiCorp substantially adhered to the Guidelines in developing its 2023 IRP. Nevertheless, the identified exceptions are of such significance they undermine our confidence in the portfolio selection process, the P-MM Preferred Portfolio, and the Action Plan. Accordingly, we do not acknowledge these aspects of the IRP.

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[84] *See e.g.,* Section IV.A. and IV.B.1. of our Order.

VI. ORDER

We direct DPU, and invite OCS and other IRP participants, to file in this docket by **Thursday, May 30, 2024**, recommendations concerning changes to the IRP schedule that will better provide PacifiCorp and all IRP participants adequate time to meet the Guidelines' public collaboration and participation objectives, including those described in this and prior IRP orders.

DATED at Salt Lake City, Utah, April 17, 2024.

/s/ David R. Clark, Commissioner

/s/ John S. Harvey, Ph.D. Commissioner

Attest:

/s/ Gary L. Widerburg
PSC Secretary
DW#333432

Notice of Opportunity for Agency Review or Rehearing

Pursuant to Utah Code Ann. §§ 63G-4-301 and 54-7-15, a party may seek agency review or rehearing of this order by filing a request for review or rehearing with the PSC within 30 days after the issuance of the order. Responses to a request for agency review or rehearing must be filed within 15 days of the filing of the request for review or rehearing. If the PSC fails to grant a request for review or rehearing within 30 days after the filing of a request for review or rehearing, it is deemed denied. Judicial review of the PSC's final agency action may be obtained by filing a Petition for Review with the Utah Supreme Court within 30 days after final agency action. Any Petition for Review must comply with the requirements of Utah Code Ann. §§ 63G-4-401, 63G-4-403, and the Utah Rules of Appellate Procedure.

CERTIFICATE OF SERVICE

I CERTIFY that on April 17, 2024, a true and correct copy of the foregoing was served upon the following as indicated below:

By Email:

Data Request Response Center (datareq@pacificorp.com, utahdockets@pacificorp.com)
PacifiCorp

Jana Saba (jana.saba@pacificorp.com)
Rocky Mountain Power

Stanley Holmes (stholmes3@xmission.com)
David Bennett (davidbennett@mac.com)
Utah Citizens Advocating Renewable Energy

Monica Hilding (mohilding@gmail.com)
Utah Environmental Caucus

Sophie Hayes (sophie.hayes@westernresources.org)
Karl Boothman (karl.boothman@westernresources.org)
Nancy Kelly (nancy.kelly@westernresources.org)
Western Resource Advocates

Sarah Puzzo (spuzzo@utahcleanenergy.org)
Logan Mitchell (logan@utahcleanenergy.org)
Sarah Wright (sarah@utahcleanenergy.org)
Utah Clean Energy

Rose Monahan (rose.monahan@sierraclub.org)
Leah Bahramipour (leah.bahramipour@sierraclub.org)
Sierra Club

Phillip J. Russell (prussell@jdrslaw.com)
James Dodge Russell & Stephens, P.C.
Don Hendrickson (dhendrickson@energystrat.com)
Energy Strategies, LLC
Utah Association of Energy Users

Chris Leger (chris@interwest.org)
Sam Johnston (sam@interwest.org)
Interwest Energy Alliance

Laura Singer (laura.singer@fervoenergy.com)
Fervo Energy Company

Patricia Schmid (pschmid@agutah.gov)
Patrick Grecu (pgrecu@agutah.gov)
Robert Moore (rmoore@agutah.gov)
Utah Assistant Attorneys General

Madison Galt (mgalt@utah.gov)
Division of Public Utilities

Alyson Anderson (akanderson@utah.gov)
Bela Vastag (bvastag@utah.gov)
Alex Ware (aware@utah.gov)
Jacob Zachary (jzachary@utah.gov)
(ocs@utah.gov)
Office of Consumer Services

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Administrative Assistant

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-26-21
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-130:
Idaho PUC on Pac 2023 IRP

Office of the Secretary
Service Date
October 31, 2023

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF PACIFICORP'S APPLICATION FOR ACKNOWLEDGEMENT OF THE 2023 INTEGRATED RESOURCE PLAN	)))))	**CASE NO. PAC-E-23-10** **ORDER NO. 35977**

On March 31, 2023, Rocky Mountain Power, a division of PacifiCorp ("Company"), filed an application ("Application") with the Idaho Public Utilities Commission ("Commission") requesting acknowledgment of the Company's 2023 Integrated Resource Plan ("IRP"). On May 31, 2023, the Company submitted an amended 2023 IRP ("2023 IRP").

The Company represented that it submitted the 2023 IRP filing in compliance with Order No. 22299, Case No. U-1500-165, dated January 1989; whereby the Commission ordered biennial filings of the electric integrated resource plan. The Company stated that its plan was also submitted to the Commission as the Resource Management Report on the Company's resource planning status.

The Company represented that the 2023 IRP contains information outlining how the Company has addressed the Commission's integrated resource planning requirements, and the Company requested that the Commission acknowledge the 2023 IRP in accordance with the Commission's rules, and fully support the 2023 IRP conclusions, including the proposed action plan.

The Company files an IRP on a biennial basis with the state utility commissions of Utah, Oregon, Washington, Wyoming, Idaho, and California. The Company represented that the 2023 IRP fulfills the Company's commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest. 2023 IRP Vol. 1 at 35.

The Company represented that the 2023 IRP was developed through a collaborative public input process with involvement from regulatory staff, advocacy groups, and other interested parties, and that the Company's selection of the 2023 IRP preferred portfolio was supported by comprehensive data analysis and an extensive public-input process, and includes substantial new renewables, facilitated by incremental transmission investments, demand-side management ("DSM") resources, significant storage resources, advanced nuclear, and non-emitting peaking resources. *Id.*

The Company represented that the 2023 IRP preferred portfolio includes new resources from the 2020 All-Source Request for Proposals ("RFP") including 1,792 megawatts ("MW") of wind and 495 MW of solar additions with 200 MW of battery storage capacity. *Id.* The Company stated that these resources will come online in the 2024-to-2025 timeframe, and that the preferred portfolio also includes the acquisition and repowering of Rock River I (50 MW) and Foote Creek II-IV (43 MW) wind projects located in Wyoming. *Id.* The Company also represented that through the end of 2026, the 2021 IRP preferred portfolio includes an additional 745 MW of wind and an additional 600 MW solar co-located with storage, for which the 2022 All-Source RFP is currently soliciting and evaluating resources to fulfill. *Id*.

The Company represented that the 2023 IRP preferred portfolio includes the 500 MW advanced nuclear Natrium demonstration project, anticipated to achieve online status by summer 2030, 1,000 MW of additional advanced nuclear resources through 2033, and 1,240 MW of non-emitting peaking resources through 2037. *Id.* Additionally, the Company stated that over the 20-year planning horizon, the 2023 IRP preferred portfolio includes 9,114 MW of new wind and 7,855 MW of new solar. *Id.*

The Company represented that the preferred portfolio includes the construction of a 416-mile 500-kilovolt ("kV") transmission line known as Gateway South connecting southeastern Wyoming and northern Utah, the 59-mile 230 kV transmission line in eastern Wyoming known as Gateway West Segment D.1, and the 500 kV, 290-mile transmission line across eastern Oregon and southwestern Idaho known as Boardman to Hemingway (B2H). *Id.*

STAFF COMMENTS

Based on Staff's review of the Company's 2023 IRP and Staff's participation in the series of 2023 IRP Stakeholder Meetings, Staff believed that the 2023 IRP addresses the requirements outlined in Commission Order No. 22299. Staff recommended that the Commission acknowledge the 2023 IRP.

However, Staff is concerned that recent change in federal policy exposes the Company's customers to higher costs and risks as the Company accelerates its transition away from dispatchable coal-fired generation toward other dispatchable resources. Staff is also concerned that technological and permitting challenges for implementing the new Natrium Nuclear plants add potential risk and higher cost if these plants are not completed as forecast; and that highly variable natural gas prices relative to more stable priced coal exposes customers to higher energy costs in both the near-term and long-term as the Company relies on more natural gas to maintain dispatchable capacity for its system as it transitions away from coal as part of its coal unit conversions and exits.

Based on its review of the 2023 IRP, Staff recommended that:

1. The Company review its practices for hedging natural gas fuel supply to mitigate fuel-supply risk as it continues to step away from coal and into increased use of natural gas for dispatchable generation;
2. The Company keep the Commission informed with regular updates on the Company's progress toward implementation of the Natrium Nuclear plants;
3. The Company consider strategies to address potential delays in the capacity provided by the B2H transmission line; and
4. The Company begin forecasting the benefits of WRAP when it is projected to become a binding participant in the next IRP.

COMPANY REPLY COMMENTS

The Company noted that its risk management policy, which includes the power and gas limits program, is reviewed/revised at least once per year. The Company also stated that it is open to providing the Commission with updates to the status of the Natrium demonstration project as needed. Additionally, the Company represented that the 2023 IRP process includes ongoing evaluation of the Boardman-to-Hemmingway project, and that the Company remains open to suggestions for future analysis. Finally, the Company explained that it expects that its 2025 IRP will include discussion of the impacts of WRAP compliance and will include appropriate modeling of planning reserve margin and resource requirements.

PUBLIC COMMENTS

The Commission received seventeen (17) public comments, all of which reflect the same basic concern that the Company is not doing enough to commit to reducing greenhouse gas emissions.

COMMISSION FINDINGS AND DECISION

The Company is a public utility as defined in *Idaho Code* §§ 61-119 and -129, and the Commission has jurisdiction over it and the issues in this case under Title 61 of the Idaho Code, including Idaho Code § 61-501. Having reviewed the record, the Commission finds that the Company's 2023 IRP satisfies the requirements in the Commission's prior orders, and the Commission acknowledges the 2023 IRP.

In doing so, the Commission once again reiterates that an IRP is a working document that incorporates many assumptions and projections at a specific point in time. An IRP is a plan, not a blueprint, and by issuing this Order we merely acknowledge the Company's ongoing planning process, not the conclusions or results reached through that process.

The Commission does not approve the 2023 IRP, or any resource acquisitions referenced in it, endorse any particular element in it, opine on the Company's prudence in selecting the 2023 IRP's preferred resource portfolio, nor allow or approve any form of cost recovery. The appropriate place to determine the prudency of the Company's decisions to follow or not follow the 2023 IRP, and the validation of predicted performance under the 2023 IRP, is a general rate case or other proceeding where the issue is noticed.

ORDER

IT IS HEREBY ORDERED that the Company's 2023 IRP is acknowledged.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date upon this Order regarding any matter decided in this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *See Idaho Code* §§ 61-626 and 62-619.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 31st day of October 2023.

ERIC ANDERSON, PRESIDENT

JOHN R. HAMMOND JR., COMMISSIONER

EDWARD LODGE, COMMISSIONER

ATTEST:

Jan Noriyuki
Commission Secretary

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-26-21
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-131:
FERC Western Energy Markets Explainer

Western Energy Markets Explainer

This explainer offers a comprehensive overview of the electricity markets in the Western United States. It covers key features of the markets that enable coordinated and efficient management of the region's electric transmission grid system. This explainer will help you understand how new developments in electricity markets in the West may impact energy costs, system reliability, and the implementation and achievement of state-level energy policies.

This explainer is organized with four major sections:

This explainer offers a summary of publicly available information about Western markets and should not be relied upon as a legal document.

Key Terms

Balancing Authorities oversee electricity transfers and ensure grid stability by maintaining a balance between the production and consumption of electricity. They typically oversee long-term efforts to maintain that key balance on the grid, such as resource planning, as well as short-term balancing by committing electricity supply resources to operate and real-time load-frequency control within a balancing authority area. Certain electric utilities and power marketing administrations (see below) are typical examples of balancing authorities.

A **Balancing Authority Area** is a geographic region that incorporates a collection of generation facilities, transmission lines, and loads (aggregated consumer demand for electricity) where electric metering is performed by a balancing authority. The responsibility of maintaining a balance between the load and resources (supply of electricity) within this area falls under the jurisdiction of the balancing authority. One example of a balancing authority area is a utility service territory.

Congestion occurs when a portion of the transmission grid becomes overloaded with electricity. Congestion can occur when a line or transformer reaches its limit and cannot carry any more electricity. When congestion occurs, the lowest-priced electricity cannot flow freely to a specific area.

Congestion Revenue Rights are financial tools used to manage the cost variability of congestion on the grid based on the electricity pricing approach used, called locational marginal pricing (see below). Such rights are often acquired to hedge against congestion costs in the day-ahead market, but sometimes are purchased as an investment.

A **Day-Ahead Market** is a voluntary financial market where individuals and companies can buy and sell wholesale electric energy at financially binding prices for the next day.

Hedging is the act of engaging in transactions to reduce risk from price volatility (see below) for a company and/or customers. Hedging transactions can help electricity suppliers meet their customers' demands while reducing or eliminating the risk of fluctuating prices.

Locational Marginal Pricing or Prices (LMP) refer, respectively, to the overall pricing scheme or the actual prices paid for wholesale electric energy at a specific location within an electric transmission grid at a specific point in time. LMP data is used to track the prices of electricity in different parts of the grid and to help manage supply and demand for electricity.

Price Volatility describes how quickly or widely prices can change. In the energy industry, price volatility can refer to electricity or natural gas supply prices, relative to consumer demand. Volatility is measured by the day-to-day variation (percentage difference) in the price of the commodity.

A **Power Marketing Administration** is a federal agency within the Department of Energy that markets electric power produced by federal dams and multiple-purpose water projects providing service to customers.

A **Real-Time Energy Market** is a spot market that allows consumers, companies, and energy distribution businesses to buy and sell wholesale electric energy in real-time, usually an hour before delivery. The real-time market balances the differences between day-ahead resource commitments and demand forecasts and the actual real-time demand for and production of electricity.

Resource Adequacy is the ability of an electric transmission grid to meet consumer demand for power. Resource adequacy ensures that there is enough energy generating capacity and reserves to maintain a balanced supply and demand across an electric system.

Wholesale Electric Energy, also referred to as wholesale electricity, is electric energy that is purchased or sold for resale, whereas retail electric energy is electric energy that is purchased by or sold to the ultimate consumer.

California ISO Extended Day-Ahead Market is a voluntary day-ahead electricity market designed to deliver significant reliability, economic, and environmental benefits to balancing areas and utilities throughout the West. The initial structure of EDAM was approved, in most part by the Commission in December 2023.

Introduction

In the U.S., the power grid is a complex network of power plants and transmission lines with extra-high-voltage connections between utilities. This expansive infrastructure allows the movement of electricity from one part of the network to another.[1] Over time, the U.S. power grid has evolved into three large interconnected systems, which are shown in Figure 1:

1. the Eastern Interconnection that operates in states east of the Rocky Mountains
2. the Western Interconnection that covers the Pacific Coast to the Rocky Mountain states
3. the Texas Interconnected System, known as ERCOT

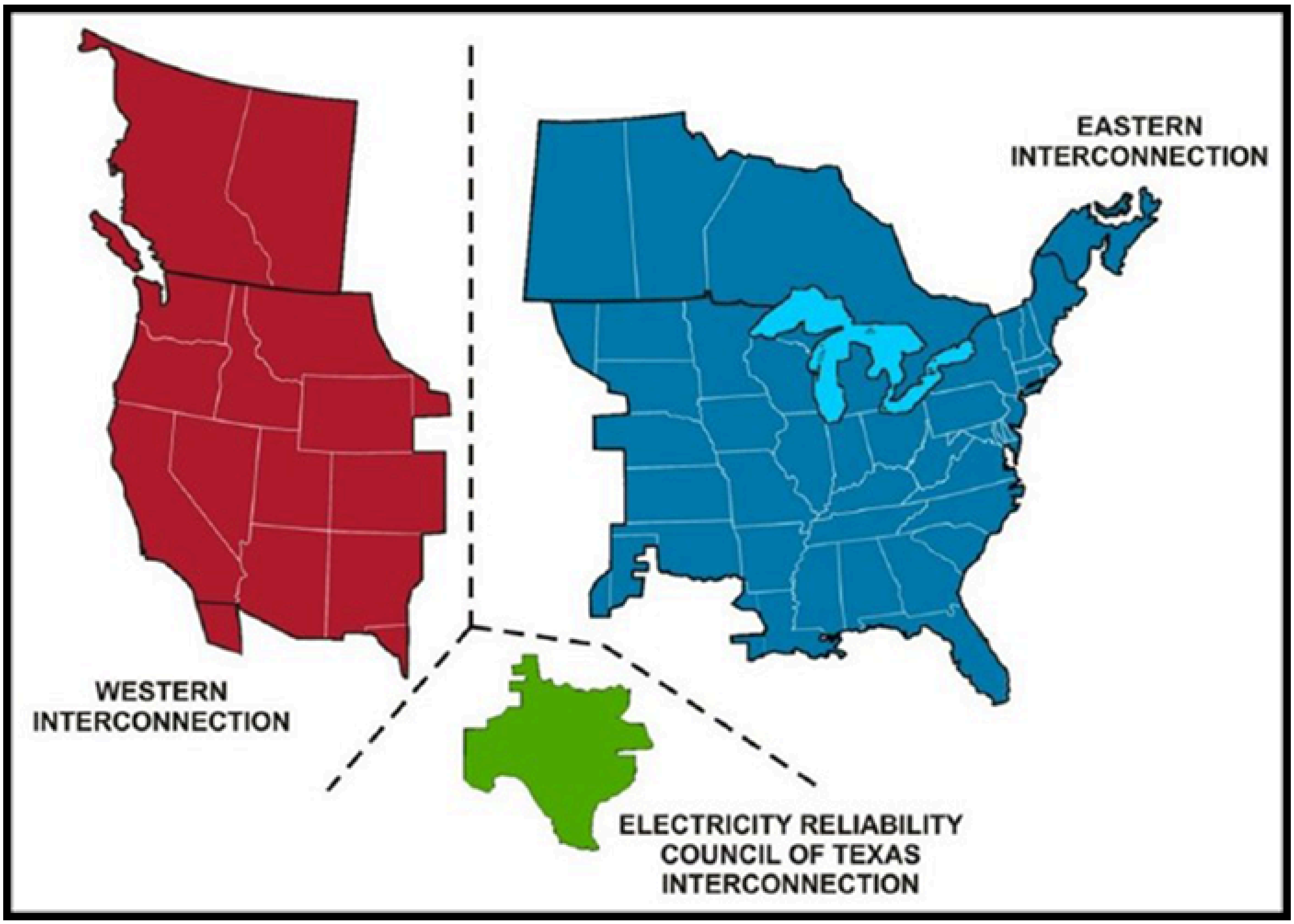


Figure 1. The Three Major Interconnections of the U.S. Electric Power Grid. Source: North American Electric Reliability Corporation.

The electric grid must comply with standards developed by the North American Electric Reliability Corporation (NERC) to ensure reliability of the grid. Because these three systems encompass unique geographic areas, NERC also assigns responsibilities to six regional entities who apply standards and act as compliance authorities. In the Western Interconnection, the Western Electricity Coordinating Council (WECC) is the regional entity, which oversees bulk power system reliability and security in the region. [2]

In the late 1990s, FERC initiated significant reforms in the electricity sector to support competition in the energy marketplace. The milestones included:

- Order No. 888 (1996): established the foundation for organized wholesale markets by promoting independent system operators (ISOs).[3] These entities were designed to foster competition among electricity generators at the wholesale level.
- Order No. 2000 (1999): encouraged utilities to join regional transmission organizations (RTOs). The aim was to enhance the operation of transmission systems and to develop equitable transmission management practices.[4]

Today, RTOs and ISOs play a crucial role in electricity policy. They serve approximately two-thirds of U.S. electricity consumers, managing both power markets and regional transmission systems (Figure 2 shows the boundary areas the RTO and ISO regions).[5]

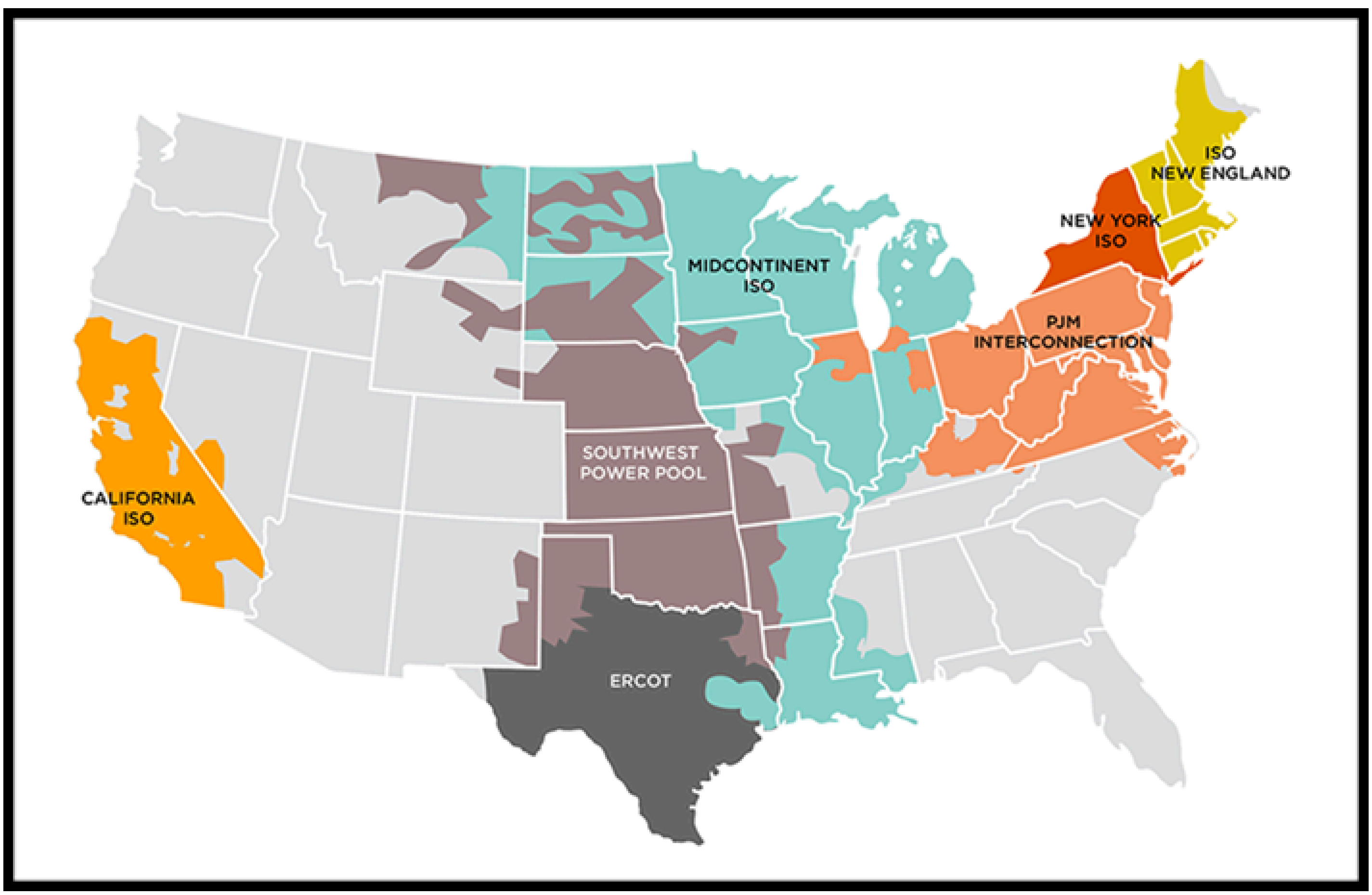


Figure 2. Seven RTO and ISO Regions in the Continental United States.

The West has progressively developed its regional wholesale electricity markets, adopting new systems and improvements step-by-step. Unlike other regions that may implement large-scale changes all at once, the West has chosen to evolve its electricity markets gradually, with each stage of development building upon the last.[6] For example, a single organized market manages energy trades for most of California—the California Independent System Operator (CAISO)—and there are currently no multistate RTOs (although, as seen in Figure 2, CAISO territory includes a small area of Nevada).[7]

The West uses a coordinated system of regional real-time energy supply markets and bilateral trading between a specified buyer and a specified seller of electricity. The Western Area Power Administration and the Bonneville Power Administration, two Western Power Marketing Administrations within the Department of Energy, sell electric power produced by federal dams to utilities (Figure 3 shows the boundary areas of the four Power Marketing Administrations).

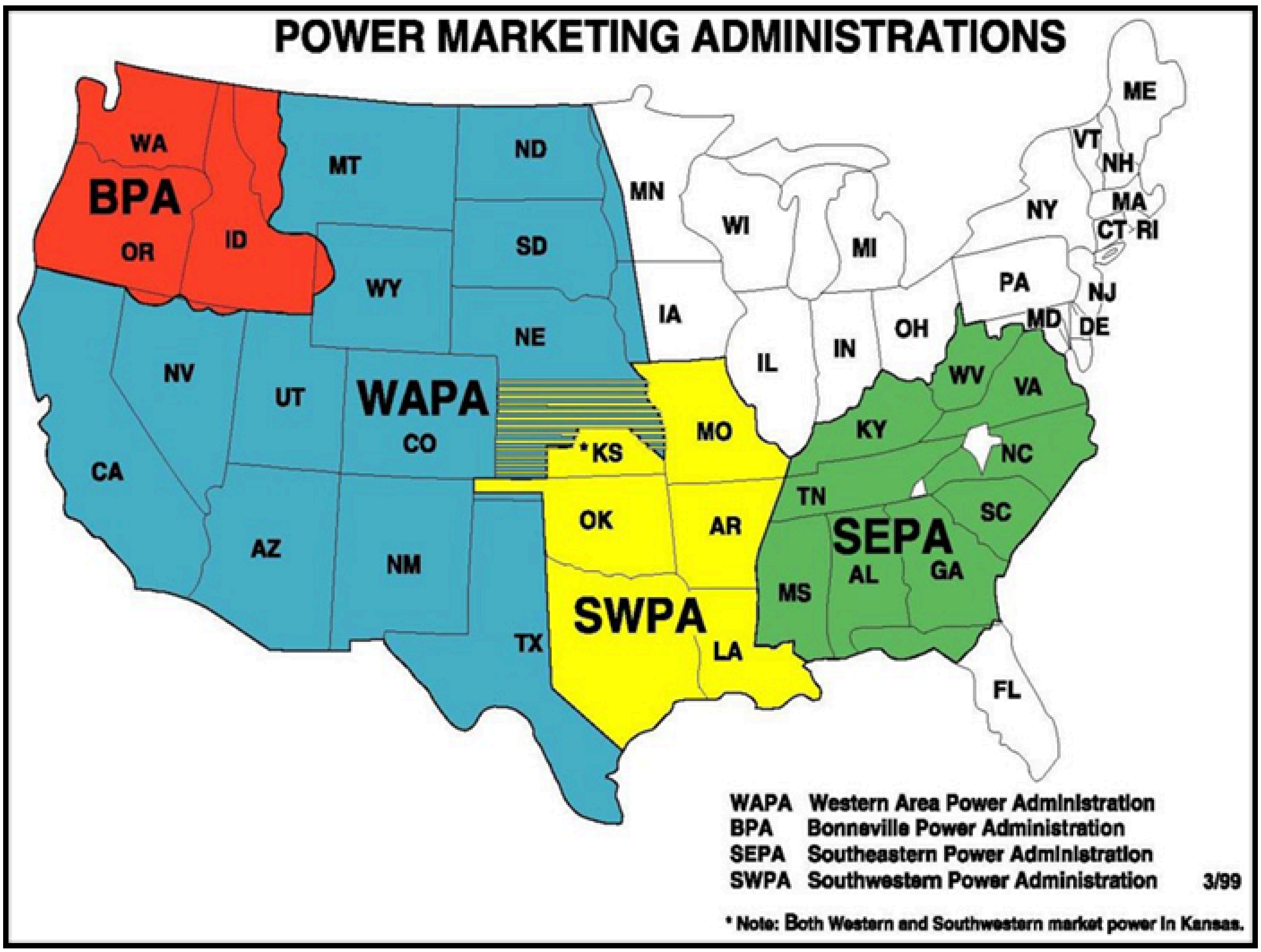


Figure 3. Power Marketing Administrations in the Continental United States. Source: SPP

While CAISO is currently the only ISO in the West, FERC has approved several market initiatives in the last twenty years that have led to a more integrated Western electric system that encompasses several Western states. The rest of this explainer will discuss CAISO as well as other initiatives and entities that contribute to the region's electricity landscape.

Overview of Electricity Markets in the West

California Independent System Operator (CAISO)

Figure 4. California Independent System Operator (CAISO) area.

The California Independent System Operator (CAISO)[8] was founded in 1998 and became a fully functioning ISO in 2008. CAISO manages the flow of electricity across the high-voltage, long-distance power lines serving 80% of California and a part of Nevada (Figure 4 shows the boundary areas of CAISO).[9]

CAISO provides open access to the transmission lines it operates and performs long-term transmission planning. In managing the grid, CAISO centrally dispatches generation and coordinates the movement of wholesale electricity in the area shown. CAISO's wholesale energy markets comprise day-ahead and real-time processes that include energy products, such as real-time energy, day-ahead energy, ancillary services, and congestion revenue rights. The Commission also approved, in most part, CAISO's Extended Day-Ahead Market proposal in December 2023.

Western Energy Imbalance Market (WEIM)

In 2014, CAISO initiated the Western Energy Imbalance Market (WEIM) with the purpose of expanding real-time market access to utilities in the Western Interconnection who are not members of CAISO. Utilities participating in the WEIM include utilities and balancing authorities outside of CAISO's territory. Among other benefits, the WEIM provides its participants with access to least-cost electricity across the region. There are also operational and reliability benefits to the sharing of electricity through WEIM. For example, when one part of the West is experiencing an electric energy shortage while others are not, there can be sales of excess electric energy to the area that needs it.

Concerning day-to-day operations, the WEIM is a real-time energy market that allows participating utilities to balance their supply and demand within 15 minutes or 5 minutes of delivery using the least-cost resources available across a wider footprint, helping to manage system needs. This creates a coordinated system of regional real-time energy supply markets, which, while not a full RTO or ISO, offers a structured approach to energy trading and system balancing in the West.

Since the WEIM began offering real-time market access to utilities outside of CAISO's territory, the WEIM has grown to serve parts of Arizona, California, Idaho, Montana, Nevada, New Mexico, Oregon, Texas, Utah, Washington, and Wyoming, and extends to the border with Canada and Mexico, totaling 22 participating entities representing 79% of the energy load in the WECC.[10] The WEIM's ability to leverage CAISO's market optimization tools to service the needs of the utilities outside its ISO structure have led to reported cost-savings.[11] Presently, the WEIM claims to have delivered more than $5 billion in benefits by connecting a broader area with access to lower-cost electricity.[12]

The WEIM is governed by a five-member body with shared authority from the CAISO Board of Governors on rules specific to participation in the WEIM.[13] As designed by regional stakeholders, the WEIM Governing Body is nominated by a committee of Western stakeholders. The WEIM Governing Body and CAISO Board of Governors frequently hold public sessions that include a toll-free number for members of the public to listen to the meeting. These public sessions include opportunities for public comment following briefings on policy initiatives as well as WEIM benefits and market updates.

Southwest Power Pool (SPP)

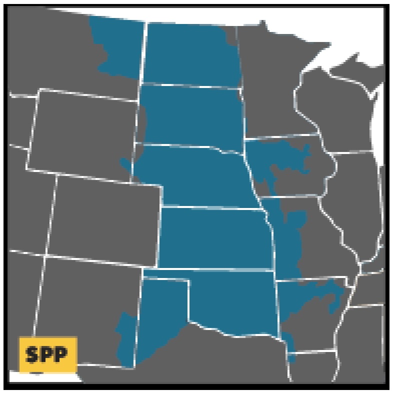


Figure 5. Southwest Power Pool (SPP) area.

The Southwest Power Pool (SPP), an RTO operating primarily in the Midwest, operates energy markets in both the Eastern and Western interconnections. Founded in 1941 as an 11-member power pool that allowed for power sharing among participating utilities, SPP achieved RTO status in 2004. Based in Little Rock, Arkansas, SPP manages transmission in portions of fourteen states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. Its membership comprises investor-owned utilities, municipal systems, generation and transmission cooperatives, state authorities, independent power producers, power marketers, and independent transmission companies.

In 2015, SPP's footprint expanded when the Western Area Power Administration—Upper Great Plains (WAPA-UGP) region, the Basin Electric Power Cooperative, and the Heartlands Consumer Power District—joined the RTO. The expansion nearly doubled SPP's service territory and added more than 5,000 MW of peak demand and over 7,000 MW of generating capacity. WAPA-UGP is the first federal power marketing administration to join an RTO.

In January 2025, FERC also approved, subject to condition, SPP's Markets+ proposal.

Additionally, in March 2025, FERC approved, subject to condition, SPP's RTO West proposal.

Western Energy Imbalance Service (WEIS) Market

In 2020, SPP established the Western Energy Imbalance Service (WEIS) market with the purpose of providing real-time market access to utilities in the Western Interconnection who are not members of the SPP RTO. Like CAISO's WEIM, SPP's WEIS seeks to provide participants with access to least-cost electric energy and to create reliability and operational advantages, such that power from areas with excess electric energy can flow to an area experiencing a shortage (such as during a weather emergency).

WEIS centrally dispatches generation to balance supply and demand in real-time and allows parties to continue to trade wholesale electricity bilaterally. Additionally, the WEIS has a goal of allowing participants to hedge against transmission congestion while coordinating the movement of wholesale electricity. In 2022, according to the WEIS Benefit of Market Report, WEIS claims to have provided $31.7 million in net benefits to its 12 participating Western utilities.[14]

SPP's independent Board of Directors provides ultimate oversight of the WEIS's administration; however, the Western Markets Executive Committee is responsible, through its designated working groups, committees, and task forces, for developing and recommending policies, procedures, and system enhancements related to the administration of the WEIS by SPP under the Western Joint Dispatch Agreement in the Western Interconnection.[15] In coordination with the Western Markets Executive Committee, the Western Markets Working Group provides a public forum for customers to engage in matters of governance and strategy with other stakeholders.[16] In 2024, all Western Markets Executive Committee meetings will be joint with the Western Markets Working Group. Members of the public may register on www.SPP.org for these meetings and attend in-person or by phone.

Western Power Pool (WPP)

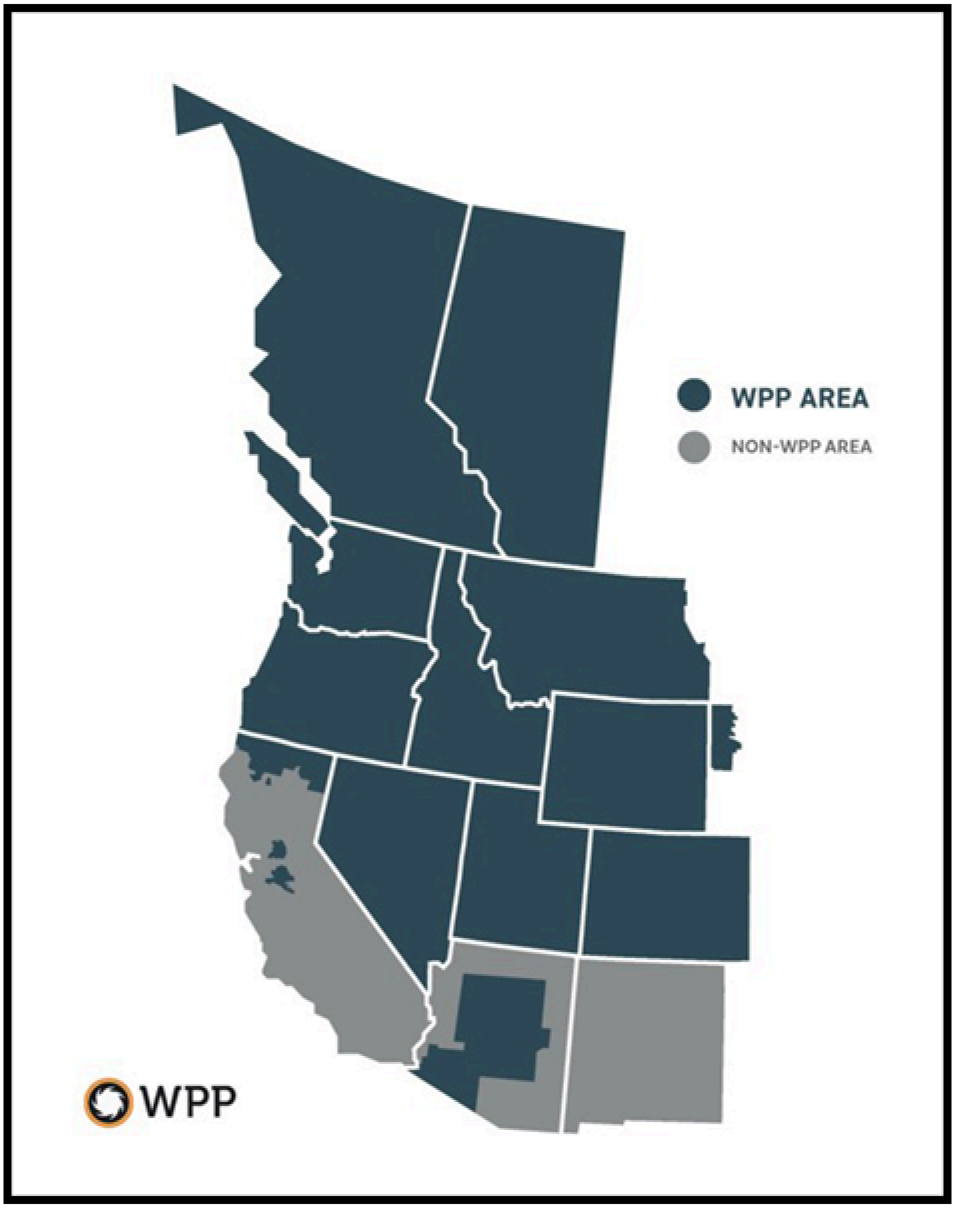


Figure 6. Western Power Pool (WPP) area. Source: WPP

The Western Power Pool (WPP), previously known as the Northwest Power Pool, is a group of utilities and other entities that coordinate and share resources in the Western Interconnection (Figure 6 shows the boundary areas of WPP). The WPP provides services to its members, such as transmission planning and tariff administration.[17] The WPP was formed in 1983 to promote increased efficiency, competition, and coordination in the electric power industry.[18] The WPP is governed by a Board of Directors, a Governing Body, and various committees and working groups that represent the interests of its members and stakeholders. The WPP also collaborates with other regional entities, such as the WECC, SPP, and CAISO, to enhance the reliability and efficiency of the Western Interconnection. While the WPP does not provide transmission service and is not an RTO/ISO, it does provide significant benefits by ensuring reliable energy capacity and reserves across the electric system.

To that end, in August 2022, the WPP filed at FERC the Western Resource Adequacy Program (WRAP) proposal, in Docket No. ER22-2762, which is intended to enhance resource adequacy. Resource adequacy ensures that there is enough energy capacity and reserves to maintain a balanced supply and demand across the electric system.[19] The WRAP was approved by FERC in February 2023 and is expected to launch in mid-2025.[20]

Western Resource Adequacy Program (WRAP)

The WRAP is not an organized market like CAISO's WEIM or SPP's WEIS but is instead a program WPP runs to ensure that the electricity supply in the West can meet the demand and reliability needs of customers. When implemented, the WRAP will have two main components: (1) a forward showing program, where participants demonstrate their ability to meet their peak demand plus a reserve margin for the next year; and (2) an operations program, where participants monitor and report their daily resource availability and demand as well as comply with dispatch instructions from the program operator. SPP acts as the program operator and, as directed by WPP, provides services for the WRAP, such as modeling, analytics, real-time operations, and technical improvement.

The WRAP is designed to be compatible with existing markets and programs in the West, such as the WEIM and the CAISO markets. The WRAP is also open to area participants who want to join the program and benefit from its regional approach. The WRAP seeks to help participants address the challenges of resource adequacy in the West in a manner consistent with state goals, such as increasing demand, retiring coal plants, and integrating variable renewable energy sources.[21]

To Learn More

Additional information on the topics discussed is available on FERC's website, including the FERC rulings cited in this explainer, the 2024 Energy Primer, as well as on the:

- CAISO website
- SPP website
- WPP website

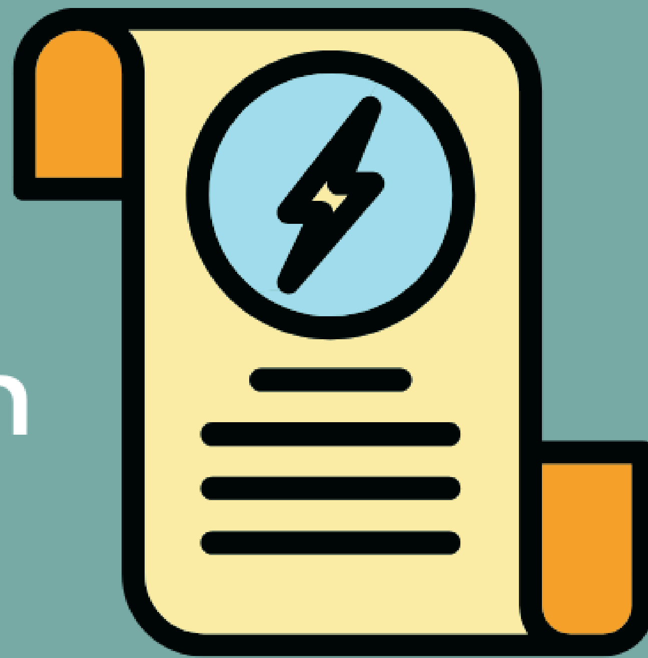
In addition to the existing markets and programs discussed above, the Western area markets may continue to develop and change. To follow FERC matters relevant to the expansion of the Western markets, you may:

- Subscribe to the Office of Public Participation (OPP) newsletter;
- Follow stakeholder processes with the stakeholder centers of CAISO and SPP; and
- eSubscribe to electronically receive information related to a particular FERC docket or set of dockets in which you have an interest.

OPP is dedicated to helping the public understand and participate in FERC proceedings. Members of the public can contact OPP for assistance in navigating FERC proceedings and receiving information on when and how to comment, intervene, or file motions during proceedings.

Please contact OPP by e-mail at OPP@ferc.gov, by phone at (202) 502-6595, or see our website at www.FERC.gov/OPP for additional information and resources.

Western Markets Expansion



CAISO

Order No. 2000

CAISO ISO Open Access Transmission Tariff (OATT)

Western Energy Imbalance Market WEIM (CAISO)

147 FERC ¶ 61,231 (2014)

Docket No. ER14-1386

EIM Section to CAISO OATT

Western Energy Imbalance Service WEIS (SPP)

173 FERC ¶ 61,267 (2020)

Docket Nos. ER21-3/ER21-4

WEIS OATT

Western RA program WRAP (Western Power Pool)

182 FERC ¶ 61,063

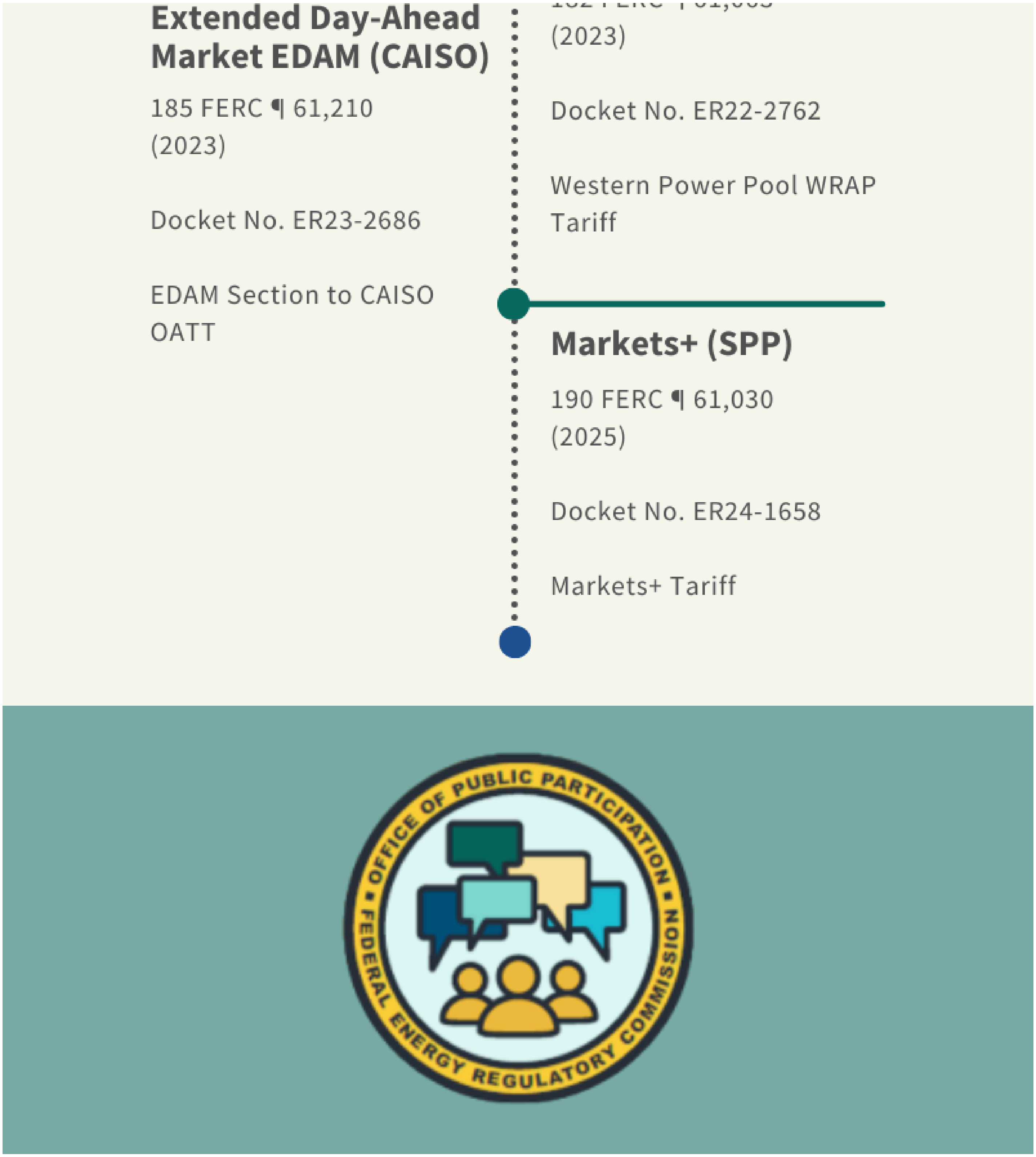


Figure 7. Western Markets Expansion infographic.

[1] Transmission Agency of Northern California. https://www.tanc.us/understanding-transmission/the-western-us-power-system.

[2] Specifically, FERC mandated NERC to oversee the reliability of the bulk power system, which includes parts of Mexico and Canada. For further information, see the Office of Public

Participation's Reliability Primer. https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf.

[3] Electricity Markets Explainer. https://www.ferc.gov/introductory-guide-electricity-markets-regulated-federal-energy-regulatory-commission.

[4] Order 2000 can be viewed at: https://www.ferc.gov/sites/default/files/2020-06/RM99-2-00K_1.pdf.

[5] Electric Power Markets. https://www.ferc.gov/electric-power-markets.

[6] A description of the history and motivating factors for market developments in the West: https://www.rabobank.com/knowledge/d011408934-no-rto-no-problem-rethinking-regulated-markets-in-the-us-electricity-heartland.

[7] In the case of CAISO, the ISO has chosen not to seek RTO status. RTOs are electric power transmission system operators that coordinate, control, and monitor a multistate electric grid. ISOs are like RTOs, which also coordinate, control, and monitor the operation of the electrical power system. However, ISOs cover geographic areas within a state or a smaller region.

[8] Understanding and Participating in CAISO Processes. https://www.ferc.gov/understanding-and-participating-california-iso-caiso-processes.

[9] CAISO. http://www.caiso.com/about/Pages/OurBusiness/Default.aspx.

[10] CAISO. https://www.westerneim.com/Documents/weim-first-quarter-benefits-for-2023-reach-418-million.pdf.

[11] A description of the history and motivating factors for market developments in the West: https://www.rabobank.com/knowledge/d011408934-no-rto-no-problem-rethinking-regulated-markets-in-the-us-electricity-heartland.

[12] WEIM. https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

[13] WEIM. https://www.westerneim.com/Pages/Governance/GoverningBody.aspx.

[14] SPP. https://spp.org/western-services-documents/?id=371676.

[15] SPP. https://spp.org/documents/61046/wmec%20charter%2020221018.pdf.

[16] SPP. https://spp.org/western-services/weis/.

[17] Western Power Pool. https://www.westernpowerpool.org/private-media/documents/WPP_WRAP_Interoperability_with_Markets_June_2023.pdf.

[18] Western Power Pool. https://www.westernpowerpool.org/.

[19] CAISO. https://www.caiso.com/Documents/Resource-Adequacy-Fact-Sheet.pdf.

[20] *Northwest Power Pool*, 182 FERC 61,063 at P 13-14 (2023).

[21] Western Power Pool. https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program.

Quick Links

- Introduction to Western Markets Expansion

Contact Information

Office of Public Participation (OPP)
Telephone: 202-502-6595
Email: OPP@ferc.gov

This page was last updated on April 18, 2025

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-26-21
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-145:
Western Pool Reserve Sharing Program

Northwest Power Pool
Reserve Sharing Program Documentation

NWPP Reserve Sharing Program 1.18.2006
RSG Committee Approved, effective: 10.1.2025

NWPP RSG
POWERED BY WPP

NWPP Reserve Sharing Documentation

TABLE OF CONTENTS

NWPP Reserve Sharing Program

ATTACHMENTS

NWPP Reserve Sharing Program

A. INTRODUCTION AND OVERVIEW

Standards established by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC) require all Balancing Authorities to carry reserve for defined categories of contingencies. As permitted by NERC and WECC standards, Participating Balancing Authorities within the Northwest Power Pool (NWPP) have instituted the NWPP Reserve Sharing Program for Contingency Reserve.

By sharing Contingency Reserve, Participants are entitled to use not only their own "internal" reserve resources, but to call on other Participants for assistance if internal reserve does not fully cover a contingency. Except when communication links are down or the Reserve Sharing Computer System is not functioning, the NWPP Reserve Sharing Program is automated, operating through direct communication of data and Contingency Reserve deployment signals between the Reserve Sharing Computer System and the Participating Balancing Authorities. The WPP Staff is responsible for preparing and submitting required NERC and WECC compliance reports, and responding to compliance audits, on behalf of the NWPP Reserve Sharing Group for BAL-002. Participants are relieved of BAL-002 compliance reporting obligations, and do not report to NERC or WECC on BAL-002 compliance individually.

This document describes how the NWPP Reserve Sharing Program works. It covers:

- key terminology for the NWPP Reserve Sharing Program (Section B),
- an overview of the key elements of the NWPP Reserve Sharing Program (Section C),
- how much Contingency Reserve each participant is required to carry (Attachment A),
- what events allow participants to deploy their own Contingency Reserve, and, if necessary, request assistance reserve, how a participant may request assistance reserve from other participants (Attachment B and Section E),
- participants' obligations to supply assistance reserve (Section F),
- eligibility to participate in reserve sharing and how eligible Balancing Authorities become participants (Section G),
- the roles and responsibilities of participants, the WPP Staff, and others (Section H),
- general data requirements and the functions of the reserve sharing computer system (Section I),
- data requirements related to requests for assistance reserve (Section J),
- how participants settle when assistance reserve is supplied under the NWPP Reserve Sharing Program (Section K and Attachment D),

- tracking and reporting procedures related to the NWPP Reserve Sharing Program (Section L),
- identification of "zones" within the NWPP Reserve Sharing Group for delivering reserve energy, and the sequence in which assistance reserve from adjacent zones is deployed if the assistance reserve inside a given zone is insufficient to meet a contingency (Section M and Attachment C);
- backup procedures participants will use if the communication links that enable automated reserve sharing go down (Section N and Attachment E);
- procedures for addressing issues that affect the NWPP Reserve Sharing Program when the process under the *Agreement Appointing Agent and Establishing Responsibilities Related to Reserve Sharing Group Compliance with BAL-002* is insufficient (Section O);
- an explanation of why the NWPP Reserve Sharing Group does not activate Contingency Reserve during operation of BPA remedial action schemes that are designed to suspend automatic generation control (Attachment M),

This document includes several attachments, some of which have been noted above. The full set of attachments and their titles are as follows:

Attachment A – Calculation of Contingency Reserve Obligations; Requirements Related to WECC Operating Reserve - Supplemental

Attachment B – Qualifying Events

Attachment C – Reserve Sharing Zone and Levels

Attachment D – Process Chart

Attachment E – Backup Procedures for NWPP Reserve Sharing Program

Attachment F – Transmission Mapping and Tag Template Change Process

Attachment G – Backup Process for After-the-Fact Reserve Sharing Tags

Attachment H – Balancing Authority Areas of Participating Balancing Authorities

Attachment I – *Reserved for Future Use*

Attachment J – *Reserved for Future Use*

Attachment K – Typical Planning MSSC in Real Time, Jointly Owned Dynamic Generation Resources, Jointly Owned Static Generation Resources, and Multi Use Transformer(s) Tables

Attachment L – Cut Planes and Cut Plane Monitors Between Reserve Sharing Zones

Attachment M – Overview of BPA Remedial Action Schemes That Suspend Automatic Generation Control and Result in Expected Changes to NWPP Reserve Sharing Group Reporting ACE

Attachment N – Correlation Table of Participants, Reliability Coordinators, and Zones

B. KEY TERMINOLOGY

The terms identified below have the meanings given to them in this document for purposes of the NWPP Reserve Sharing Program. Most terms defined by NERC or the WECC are conformed to the NERC or WECC definitions, but some terms' definitions may not be identical to those established by NERC or the WECC.

ACE: Area Control Error, as defined in the NERC Glossary.

Actual Net Interchange (NI_A): Actual Net Interchange, as defined in the NERC Glossary.

Agency Agreement: The *Agreement Appointing Agent and Establishing Responsibilities Related to Reserve Sharing Group Compliance with BAL-002*, as initially effective on July 1, 2008, together with any subsequent amendments or restatements.

Assistance Reserve: Contingency Reserve of one Participant that is delivered to another Participant in response to a Reserve Sharing Request.

BAL-002: For the RSG, BAL-002 means:

- NERC Reliability Standards BAL-002 and BAL-002-WECC
- And with respect to a Participant, those provisions of the foregoing (or any substantially similar standard) applicable to the Participant by law or regulation.

Balancing Authority (BA): Balancing Authority, as defined in the NERC Glossary.

Balancing Authority Area (BAA): Balancing Authority Area, as defined in the NERC Glossary.

Balancing Authority Area MSSC: A NWPP Reserve Sharing Group Participant Balancing Authority and its Balancing Authority Area's real-time MSSC based on actual configurations and provided to the Reserve Sharing Computer System via ICCP in real time.

Balancing Contingency Event: Balancing Contingency Event, as defined in the NERC Glossary.

<u>Contingency Event Recovery Period</u>: Contingency Event Recovery Period, as defined in the NERC Glossary.

<u>Contingency Reserve</u>: Contingency Reserve, as defined in the NERC Glossary.

<u>Contingency Reserve Available (CRA)</u>: Contingency Reserve committed by a Participating Balancing Authority, which the Participating Balancing Authority reports to the Reserve Sharing Computer Program, that:

- is fully deployable within ten minutes for use as Internal Reserve (except for amounts reported as already deployed for Qualifying Events);
- is fully deployable within ten minutes of an Assistance Reserve Sharing Request for delivery (except for amounts reported as already deployed for Qualifying Events); and
- is sustainable for 60 minutes from the time of a request for Assistance Reserves.

Subject to the foregoing requirements, a Participating Balancing Authority's Contingency Reserve Available:

- will, for monitoring purposes, be deemed to include a Participant's Contingency Reserve reported as available for deployment; and
- may include Contingency Reserve purchased or otherwise transferred to the Participating Balancing Authority. Reporting ACE transferred from one Participant to another Balancing Authority Area would be considered a transfer; and
    - if arranged from another entity from outside of the Participant's zone (as detailed in Attachment C) and deployed for a valid request, details of deployment shall be reported to the WPP Staff.
- may include load committed to be shed for Contingency Reserve if a Participant is in an EEA; and
- must exclude Contingency Reserve the Participating Balancing Authority has sold to any other party.

A Participating Balancing Authority's Contingency Reserve Available plus amounts reported as Used for internal Qualifying Events and the amount deployed in response to a request for Assistance Reserves must be equal to or greater than its Contingency Reserve Obligation.

<u>Contingency Reserve Obligation (CRO)</u>: As specified in Attachment A to this document, Contingency Reserve Obligation is the minimum amount of Contingency Reserve that must be carried by a particular Participant for its Balancing Authority Area(s) or by the NWPP Reserve Sharing Group as a whole (as the context requires) to respond to Qualifying Events. Although the acronym "CRO," as used in this document, may sometimes designate base calculation of a Participating Balancing Authority's Contingency Reserve Obligation (before adjustments described in Attachment A), the written term "Contingency Reserve Obligation" as used in this document refers to the total amount of Contingency Reserve that must be carried for a Participant's Balancing Authority Area(s) (or the NWPP Reserve Sharing Group as a whole), taking into account all applicable adjustments specified in Attachment A.

Firm Demand: Firm Demand, as defined in the NERC Glossary.

Internal Reserve: The Contingency Reserve of a Participating Balancing Authority when deployed to respond to a Qualifying Event on the Participating Balancing Authority's own system (as opposed to Contingency Reserve delivered as Assistance Reserve to another Participating Balancing Authority).

Long-Term Zonal MSSC Limit: An identified normal system MSSC documented in Attachment K.1. by each zone's Participant Balancing Authority/Balancing Authority Areas.

Most Severe Single Contingency (MSSC): The Most Severe Single Contingency, as defined in the NERC Glossary.

NERC Glossary: The NERC Glossary of Terms Used in Reliability Standards.

North American Electric Reliability Corporation (NERC): A self-regulatory nonprofit organization, subject to oversight by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada, whose mission is to ensure the reliability of the bulk power system in North America. NERC develops and enforces reliability standards, assesses reliability annually via 10-year and seasonal forecasts, monitors the bulk power system, and educates, trains, and certifies industry personnel.

Northwest Power Pool (NWPP): The geographic area encompassed by the electric systems of the NWPP Agreement Signatories. There is also a separate corporation named "Northwest Power Pool," which provides staffing and other resources to support implementation of the NWPP Agreement. In general, when this document refers to the Northwest Power Pool or the NWPP, it is referring to the geographic area and the associated electric power systems of the NWPP Agreement Signatories.

NWPP Agreement: A multilateral agreement to promote cooperation among participating organizations to achieve reliable operation, coordinate generation operation and power system planning, and assist in planning of transmission within the NWPP area.

NWPP Agreement Signatory (Signatory): An entity that is a party to the NWPP Agreement.

NWPP Reserve Sharing Group: The group composed of all Participants, collectively.

NWPP Reserve Sharing Group Long-Term MSSC Limit: The identified long-term maximum limit of the NWPP Reserve Sharing Group's MSSC is the largest Long-Term Zonal MSSC Limit as documented in Attachment K.1.

NWPP Reserve Sharing Group Reporting ACE: The algebraic sum of the Reporting ACE of the Participant(s) experiencing the RBCE (or multiple BCEs occurring within 60 seconds) and the Reporting ACE of those Participant(s) delivering Assistance Reserve to the Requesting Participant(s) -see Attachment C "Reserve Sharing Zones and Levels", including any Participant delivering transferred Assistance Reserve.

NWPP Reserve Sharing Program: The procedures, data, computer programs, and related information and requirements described in this document that enable Participants to request and provide Assistance Reserve as needed to respond to Qualifying Events.

Operating Plan: Operating Plan, as defined in the NERC Glossary.

Operating Process: Operating Process, as defined in the NERC Glossary.

Operating Reserve: Operating Reserve, as defined in the NERC Glossary.

Participating Balancing Authority or Participant: An entity that (a) operates one or more Balancing Authority Areas and (b) has become a participant in the NWPP Reserve Sharing Program as described in Section G.1. The terms "Participant" and "Participating Balancing Authority" are used interchangeably in this document. Attachment H contains a list of the Balancing Authority Areas of the current Participating Balancing Authorities.

Qualifying Event: Those events designated in Attachment B of this document as Qualifying Events.

Recovery Reporting ACE Target: The average value of a requesting Participant's Reporting ACE in the 16-second interval immediately prior to the start of the Qualifying Event (or zero, whichever is less) or the average value of a Participant's Reporting ACE that is providing Assistance Reserve in the 16-second interval immediately prior to the request of Assistance Reserves (or zero, whichever is less) based on EMS scan rate data.

Reliability Coordinator (RC): Any one or more organizations performing the NERC-registered function (or its equivalent in Canada) of reliability coordination within the Northwest Power Pool.

Reportable Balancing Contingency Event: Reportable Balancing Contingency Event, as defined in the NERC Glossary.

Reporting ACE: Reporting ACE, as defined in the NERC Glossary.

Reserve Sharing Computer System: The software and hardware used for automated reserve sharing under the NWPP Reserve Sharing Program.

Reserve Sharing Request: A request by Participating Balancing Authority that has satisfied the conditions specified in Section E.2 for delivery of Assistance Reserve.

Reserve Sharing Zone: A designated set of Balancing Authority Area(s) within the Reserve Sharing Group that is separated from other Balancing Authority Area(s) within the Reserve Sharing Group by transmission facilities that have been shown through studies to constrain reserve deliveries, at times, between the designated set and the other Balancing Authority Areas. Attachment C to this document identifies the Reserve Sharing Zones that have been established for the NWPP Reserve Sharing Program, together with the sequence through which Assistance Reserve is deployed for each Reserve Sharing Zone.

RSG Committee: The committee established under the terms of the NWPP Agreement to administer the NWPP Reserve Sharing Program.

Scheduled Net Interchange (NI_S): Scheduled Net Interchange, as defined in the NERC Glossary.

System Operator: System Operator, as defined in the NERC Glossary.

Third-Party Generation: Any generating resource that is within the metered boundaries of the Balancing Authority Area of a Participating Balancing Authority but is neither owned by nor under contract to that Participating Balancing Authority.

WECC Soft Price Cap: The price cap adopted by the Federal Energy Regulatory Commission in *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services*, 93 FERC ¶ 61,121 (2000) and *Western Electric Coordinating Council*, 133 FERC ¶ 61,026 (2010), subject to the guidance provided by the Federal Energy Regulatory Commission in *ConocoPhillips Company, et al*., 175 FERC ¶ 61,226 (2021)

WECC Operating Reserve - Supplemental: WECC Operating Reserve - Supplemental is the portion of Operating Reserve consisting of:

- generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Contingency Event Recovery Period following a contingency event; or
- load fully removable from the system within the Contingency Event Recovery Period following the contingency event;

provided, however, that for purposes of the NWPP Reserve Sharing Program (as required by WECC Standard BAL-002-WECC-3), WECC Operating Reserve - Supplemental must also be:

- capable of fully responding within ten minutes.

Western Electricity Coordinating Council (WECC): A nonprofit corporation with the mission to foster and promote reliability and efficient coordination in the Western Interconnection.

WPP Staff: The employees of the Northwest Power Pool Corporation doing business as the Western Power Pool.

C. OVERVIEW OF KEY RESERVE SHARING PROGRAM ELEMENTS

C.1. How Much Contingency Reserve a Participating Balancing Authority Must Carry (Contingency Reserve Obligation)

The processes for calculating how much Contingency Reserve each Participant must carry for its Balancing Authority Area(s), and the Contingency Reserve Obligation for the NWPP Reserve Sharing Group as a whole, are set forth in Attachment A to this document along with the process chart as reflected in Attachment D.

C.2. When a Participating Balancing Authority May Deploy Contingency Reserve and Request Assistance Reserve (Qualifying Events)

A Participating Balancing Authority must experience a “Qualifying Event” before it is entitled to deploy any portion of its Contingency Reserve Obligation (as Internal Reserve) or request Assistance Reserve. The definition of Qualifying Event is set forth in Attachment B to this document.

C.3. What a Participating Balancing Authority Must Do Before Requesting Assistance Reserve

A Participating Balancing Authority must fully commit an amount of its Balancing Authority Area’s Internal Reserve that equals or exceeds the requesting Participant’s CRO requirement to the NWPP before requesting Assistance Reserve to respond to a Qualifying Event. This requirement is more fully explained in Section E.2 of this document. There are also requirements concerning the timing and duration of Assistance Reserve Sharing Requests, which are set forth in Section E.3.

C.4. Where to Find Additional Information on Participant Eligibility and Obligations

Eligibility

Provisions governing eligibility to participate in the NWPP Reserve Sharing Program are in Section G of this document.

Additional Operating Reserve for R3 and R4 of WECC BAL-002-WECC-3

Section D.4 describes Participating Balancing Authorities' obligations to enable the NWPP Reserve Sharing Group to demonstrate compliance with Sections R3 and R4 of BAL-002-WECC-3.

Data Obligations

Section I contains information on the data requirements for the general operation of the NWPP Reserve Sharing Program, as well the functions of the Reserve Sharing Computer System. Section J describes data requirements for making and responding to Reserve Sharing Requests.

Providing Assistance Reserve

Participants' obligations to provide Assistance Reserve are explained in Section F.

Restoring Contingency Reserve Following Deployment

Section E.6 describes Participants' obligations to restore their Contingency Reserve following deployment (either as Internal Reserve or Assistance Reserve).

D. RESERVE REQUIREMENTS

D.1. How NWPP Reserve Sharing Program Rules Relate to BAL-002

The NWPP Reserve Sharing Program is intended to enable the NWPP Reserve Sharing Group to comply with BAL-002, as well as certain additional rules the NWPP Reserve Sharing Group has elected to adopt for itself.

Participants are required at all times to meet the requirements of BAL-002, as revised, supplemented, or superseded from time to time in accordance with applicable NERC, WECC, or regulatory procedures. BAL-002 constitutes the foundation on which the NWPP Reserve Sharing Group rules are built. Compliance with the NWPP Reserve Sharing Group rules for Contingency Reserve is intended to ensure compliance with the BAL-002, but cannot serve to excuse any compliance failure related to the NERC or WECC standards.

NERC Standard BAL-002-3 requires Balancing Authorities (or reserve sharing groups) to recover, within the Contingency Event Recovery Period, from Reportable Balancing Contingency Events (subject to certain exceptions).

WECC Standard BAL-002-WECC-3 governs Contingency Reserve, but also includes requirements (set forth in Sections R3 and R4 of BAL-002-WECC-3) for additional Operating Reserve that must be carried by Participants engaging in certain types of transactions involving purchases from units supplying Contingency Reserve or sales of Operating Reserve. This document addresses, at Section D.4, requirements for Participating Balancing Authorities to enable the NWPP Reserve Sharing Group to demonstrate compliance with Sections R3 and R4 of BAL-002-WECC-3.

D.2. Contingency Reserve Obligations and Associated Requirements Related to WECC Operating Reserve - Supplemental

Section 1 of Attachment A to this document provides a detailed explanation of how to calculate the Contingency Reserve Obligation for each Participating Balancing Authority. Section 1 also explains the manner in which the Participating Balancing Authorities' Contingency Reserve Obligations are combined to yield an aggregate obligation for the NWPP Reserve Sharing Group. Section 2 of Attachment A specifies what portion of Participating Balancing Authorities' Contingency Reserve Obligations must be carried as permitted sources of WECC Operating Reserve - Supplemental. Every Participating Balancing Authority must include in its operating procedures provisions that require it to:

a. maintain and have available an amount of Contingency Reserve Available that is equal to or greater than its Contingency Reserve Obligation,

b. perform such calculations as may be necessary (including consideration of transmission constraints) to ensure that it can deploy Contingency Reserve reported as available, and

c. deploy its Contingency Reserve Available for Qualifying Events as provided in this document.

Section 3 explains the Participating Balancing Authorities calculation of Contingency Reserve Obligation(s) when communications with the Reserve Sharing Computer System are disrupted.

D.3. Additional Policies Governing Contingency Reserve

a. <u>No Double Counting</u>

As expressed in the policies of the RSG Committee, multiple Participants may not count the same portion of resource capacity (*e.g.,* reserves from jointly owned generation) toward any portion of their Contingency Reserve Obligations, and the NWPP Reserve Sharing Group rules do not permit this.

b. <u>Contingency Reserve Available</u>

All Participants must continuously calculate and update their Contingency Reserve Available. A Participating Balancing Authority's Contingency

Reserve Available plus amounts reported as Used for internal Qualifying Events and the amount deployed in response to a request for Assistance Reserves must be equal to or greater than its Contingency Reserve Obligation.

c. Purchased Power

To provide flexibility in recovering from a Qualifying Event, any Participant may use power purchased from another Participant (or another supplier) to meet its Contingency Reserve Obligation. Any Participant that uses purchased power for recovery must report the source Balancing Authority(s) of the purchased power, the time the power was purchased, the start time and ramp rate for the mutually agreed-upon purchased power (or transaction). The WPP Staff will be responsible for determining whether a Participant providing purchased power fulfilled its obligations to deploy Contingency Reserve to enable the NWPP Reserve Sharing Group to comply with BAL-002. The requesting Participant must also arrange for transmission for delivery of the power. If the Balancing Authority from which the power was purchased is not a Participant in the NWPP Reserve Sharing Program, then any failure of the selling Balancing Authority to deliver the purchased power will be deemed, for purposes of the NWPP Reserve Sharing Program, as a failure to deliver of the Participant relying on the purchased power.

d. Aggregate Contingency Reserve Available

The aggregate Contingency Reserve Available for the NWPP Reserve Sharing Group (together with any Contingency Reserve deployed for Qualifying Events) must at all times equal or exceed both the NWPP Reserve Sharing Group's Most Severe Single Contingency and its combined Contingency Reserve Obligation.

e. RSG Committee Responsibilities; Monitoring and Follow-Up

The RSG Committee is responsible for developing guidelines and arranging for periodic reporting of the Contingency Reserve Obligation of the NWPP Reserve Sharing Group and the Contingency Reserve Available within the NWPP Reserve Sharing Group. WPP Staff monitors Participants' compliance with Contingency Reserve Obligations. The RSG Committee is responsible for addressing problems with deficient or poorly performing Participants, for developing remedies and proposed solutions, and for identifying and implementing any follow-up actions.

f. Determination of NWPP Reserve Sharing Group's Most Severe Single

Contingency

Each Participant is responsible for (i) determining, based on appropriate system modeling and applicable NERC definitions and guidelines, the Most Severe Single Contingency for its Balancing Authority Area(s), (ii) reporting its Most Severe Single Contingency determinations to the WPP Staff and making sure they are correctly reflected in Attachment K, and (iii) notifying WPP Staff whenever previously submitted Most Severe Single Contingency determinations need to be updated. The Most Severe Single Contingency for the NWPP Reserve Sharing Group at any given time is set by whichever of the Participants' Most Severe Single Contingencies is greatest at that time. The RSG Committee will review, at each of its meetings (and in any event no less than once a year), the NWPP Reserve Sharing Group's Operating Processes and its Most Severe Single Contingency to ensure the BAA MSSC's in Attachment K and other applicable tables are up to date and comply with applicable NERC and WECC requirements.

g. Participants' Monitoring of Real-Time Most Severe Single Contingencies

Every Participant is responsible for determining and telemetering to the Reserve Sharing Computer System, as provided in Section I.1.g, its Most Severe Single Contingency (and any adjustments upward or downward) based on real-time operating conditions. When determining Most Severe Single Contingencies in real time, each Participant must take into account its real-time generation output and its real-time generation and transmission outages. Real-time adjustments to a Participant's Most Severe Single Contingency should be captured and updated every data scan cycle.

h. All Participants' Contingency Reserve Available Constitutes NWPP Reserve Sharing Program Contingency Reserve Available

The amount of Contingency Reserve carried by the Participants to meet the requirements of NERC, WECC, and the NWPP Reserve Sharing Program is calculated so as to meet the needs of the NWPP Reserve Sharing Group as a whole and the Contingency Reserve Available reported by each Participant is deemed to be Contingency Reserve Available to the NWPP Reserve Sharing Program. Accordingly, if any Participant activates a portion of its Contingency Reserve to respond to a Qualifying Event, this will constitute activation of a portion of NWPP Reserve Sharing Program Contingency Reserve, including for purposes of calculating whether the Qualifying Event constitutes a Reportable Balancing Contingency Event, even if the activation of Contingency Reserve is not for a Reportable Balancing Contingency Event and even if the affected Participant does not make a Reserve Sharing Request. Any Qualifying Event affecting any Participant constitutes a Qualifying Event for the NWPP Reserve Sharing Group, and therefore, unless at the time of the Qualifying Event the affected Participant is in "non-participating" status, recovery from the Qualifying Event will be determined with respect to the NWPP Reserve Sharing Group as a whole, and not the individual Participant.

i. Participant Obligation to Respond to Reportable Balancing Contingency Events

A Participant that has experienced a Qualifying Event (within its Balancing Authority Area):

- shall recover its ACE within the 15-minute Contingency Event Recovery Period for any loss greater than 50 MW, and
- must, if the Qualifying Event is equal to or greater than the threshold for Reportable Balancing Contingency Events, take all commercially reasonable actions that are necessary, in its good-faith judgment, to enable the NWPP Reserve Sharing Group to recover its Reporting ACE according to the requirements of BAL-002. To fulfill this obligation, the Participant is expected, among other things, to (i) deploy its Contingency Reserve, and (ii) if the Participant meets the conditions specified in Section E.2 and cannot fully recover from the Qualifying Event with reserve capability on its own system (and any purchased reserve rights), make a Reserve Sharing Request.

For Qualifying Events that result from the loss of a jointly owned facility, affected Participants must use the total MW of facility output lost to determine whether the Qualifying Event is equal to or greater than the threshold for Reportable Balancing Contingency Events (rather than whatever portion of the lost output a given Participant may have scheduled or been entitled to).

j. NWPP Reserve Sharing Program Automation and Exceptions.

Every Participant is always in active status with respect to the Reserve Sharing Program. All Participants must continuously and automatically telemeter to the Reserve Sharing Computer System the data specified in Section I.1, (unless unable to do so due to failure of communications capabilities between the Participant and the Reserve Sharing Computer System). Every Participant must also indicate (unless unable to do so) whether its participation is through automatic or manual capabilities. Valid reasons for Participants to indicate manual participation mode include, but are not limited to: failure of inter-control center communications protocol (ICCP) links, suspension of automatic generation control (AGC), and system testing.

D.4. Additional Operating Reserve: Obligations Under R3 and R4 of WECC BAL-002-WECC-3 and Compliance Documentation

a. Participants Must Carry Required Additional Operating Reserve

Each Participating Balancing Authority must carry, in addition to its Contingency Reserve Obligation calculated in accordance with Attachment A, sufficient Operating Reserve to fulfill the requirements of R3 and R4 of BAL-002-WECC-3.

b. Participants Must Maintain and Provide Documentation to Demonstrate Compliance

Each Participating Balancing Authority must maintain appropriate documentation for any periods during which it has implemented

- any Interchange Transactions (as that term is defined by NERC) (i) with counterparties that are not Participants, (ii) for which it was the sink Balancing Authority, and (iii) that were designated as part of the source Balancing Authority's WECC Operating Reserve - Supplemental; or
- any Operating Reserve transactions (x) with counterparties that are not Participants, and (y) for which it was the source Balancing Authority.

The Participating Balancing Authority's documentation must be sufficient to demonstrate that, during all relevant periods, it maintained additional Operating Reserve as required by R3 and R4 of BAL-002-WECC-3.

Each Participating Balancing Authority must, on at least a quarterly basis, submit summaries to the WPP Staff of transactions subject to R3 and R4 of BAL-002-WECC-3, in the form specified by the WPP Staff (in consultation with the Participating Balancing Authorities). Participating Balancing Authorities that prefer to submit this information to the WPP Staff on a more frequent basis (including through the Reserve Sharing Computer System in real-time) may do so in coordination with the WPP Staff.

In addition, all Participating Balancing Authorities must supply copies of supporting documentation to the NWPP Reserve Sharing Group (or the WPP Staff) promptly upon request.

c. <u>Deployment of Additional Operating Reserve Not Restricted to Qualifying Events</u>

Because the additional Operating Reserve necessary to comply with R3 and R4 of BAL-002-WECC-3 is incremental to Participants' Contingency Reserve Obligations, Participants are not limited in their use of this additional Operating Reserve to Qualifying Events. Participants are entitled to deploy this additional Operating Reserve to respond to interruption of Interchange Transactions (as described in BAL-002-WECC-3 R3) or fulfillment of Operating Reserve transactions (as described in BAL-002-WECC-3 R4) even if these do not constitute Qualifying Events.

E. REQUESTING ASSISTANCE RESERVE

E.1. Qualifying Events

The Qualifying Events that permit Participants to deploy Internal Reserve, and, if the conditions specified in Section E.2 are satisfied, request Assistance Reserve, are specified in Attachment B to this document.

E.2. Action Required Before Requesting Assistance Reserve

If a Participant experiences a Qualifying Event (Attachment B parts A, B, or C), the requesting Participant is entitled to request and schedule Assistance Reserve (up to the amount lost minus their Contingency Reserve Obligation to fully recover from the Qualifying Event) through the NWPP Reserve Sharing Program **<u>only</u>** after the requesting Participant has made commitments to use an amount of Internal Reserve that equals or exceeds the requesting Participant's Contingency Reserve Obligation. A Participant experiencing a Qualifying Event from Attachment B part D is entitled to request Assistance Reserve to meet Firm Demand as necessary after committing to use ALL Internal Reserve. At the time of the Participant's request for Assistance Reserve, the fulfillment of the Participant's obligation to fully commit its Contingency Reserve Obligation will be evaluated taking into account any Internal Reserve lost because of the Qualifying Event (such as the loss of a generator on which reserve was being carried, whether due to conditions affecting the generator itself or due to loss of generator interconnection or transmission facilities necessary for delivery of output from the generator). The amount of Contingency Reserve carried by any unit that is lost due to the Qualifying Event will be considered deployed and added to the used Contingency Reserve reported.

If the requesting Participant improperly reflects their UsedCR less than their $TotCRO_{CA}$, the program will reduce the amount of Assistance Reserves provided (not including any rounding that occurs programmatically) by the amount that UsedCR is less than $TotCRO_{CA}$.

a. <u>Response to an Energy Emergency Alert 3</u>

A Participant may utilize Contingency Reserve to respond to an Energy Emergency Alert 3 (EEA 3), as described in Attachment B, Section D.

If time allows, the Participant will notify the Western Power Pool staff on the 24/7 support line 503.673.6744 of the situation, which will enable the staff to provide any clarification that may be needed.

E.3. Timing of Requests for Assistance Reserve

After experiencing a Qualifying Event as described in Attachment B parts A, B, or C and fulfilling the conditions specified in Section E.2, a Participant that requires Assistance Reserve may submit a Reserve Sharing Request, however, must do so within 60 minutes following the start of the Qualifying Event. Reserve Sharing Requests must be made in whole MWs.

Even though an eligible Participant may make a Reserve Sharing Request at any time within 60 minutes following that start of a Qualifying Event, the NWPP Reserve Sharing Group may, with respect to administering the terms of the Agency Agreement, differentiate between Reserve Sharing Requests submitted promptly—that is, within four minutes following the start of the Qualifying Event—and Reserve Sharing Requests that are delayed beyond four minutes. The "four-minute rule" does not affect Participants' obligations to deliver Assistance Reserve to other Participants that have made Reserve Sharing Requests, which, as stated in Section F, applies to all Reserve Sharing Requests made within 60 minutes following the start of the Qualifying Event.

If (a) a Reserve Sharing Request is made more than four minutes following the start of the Qualifying Event, and (b) the NWPP Reserve Sharing Group's Reporting ACE does not recover from the Qualifying Event within the applicable Contingency Event Recovery Period, then for purposes of any potential compliance consequences associated with the Qualifying Event, the matter will be addressed in accordance with Sections 7.2, 7.3, 8, and 9 of the Agency Agreement.

A Participant that has made a Reserve Sharing Request may rely on Assistance Reserve for a maximum period of 60 minutes from the time of the Qualifying Event.

The Qualifying Event outlined in Attachment B part D, allows for a request to be made at any time during the declared EEA 3 instead of immediately upon declaration of the EEA 3. An Assistance Reserve Request made for an EEA 3 allows the Participant to receive Assistance Reserve for up to 60 minutes from the time of the initial request. Subsequent hours of an EEA 3 are not additional Qualifying Events. If a participant is out of a declared EEA 3 for more than one hour before another EEA 3 is declared that next EEA 3 declaration will be considered a new Qualifying Event.

If another Qualifying Event occurs, it is a separate event, and the Participant may make an additional request for Assistance Reserve.

E.4. Performance Metric

Deployment of Contingency Reserve by a Participant requesting Assistance Reserve will be measured through evaluation of the Participant's Pre-Reporting Contingency Event ACE through the following criteria:

- In the first fifteen-minute period after the disturbance occurs, the Participant's Reporting ACE must be above their Recovery Reporting ACE Target for at least one scan; and
- Within nineteen minutes after the disturbance occurs and after the initial Reporting ACE recovery, the Participant's Reporting ACE must stay at or above their Recovery Reporting ACE Target minus 25% of their individual BAA's L_{10} value (as published by NERC) for at least five clock-minute average periods.
- If the request is not made within the required 4-minute period after the start of the Qualifying Event, the entity will be deemed to have not performed to the requirements of the program.

E.5. Accounting for Energy; Transmission for Delivery

Any Participant that requests Assistance Reserve must complete a NWPP RSG Verification Form and must account for scheduled receipt and delivery of Assistance Reserve energy as "Contingency Reserve." Tagging of Energy with respect to deliveries of Assistance Reserve energy is implemented as described in Section K.1.c. of this document.

The delivery of Assistance Reserve is exempt from any costs or charges associated with transmission wheeling or losses. The Reserve Sharing Computer System builds in sufficient transmission capacity for delivering Assistance Reserve (see Section M). There may be incremental transmission usage between some Reserve Sharing Zones, but this usage is effectively limited in real-time up to the current System Operating Limit (SOL) of the transmission facilities making up the cut planes between Reserve Sharing Zones (subject to certain further limitations with respect to particular cut planes as described the *NWPP RSG Cut Planes and Derivation Limits* document). Participants in the NWPP Reserve Sharing Program recognize the regional benefits associated with the NWPP Reserve Sharing Program and have agreed to waive any rights to financial settlement for any transmission needed to deliver Assistance Reserve to other Participants.

E.6. Restoring Reserves

If a Participant uses any portion of its Contingency Reserve Obligation in response to a Qualifying Event (whether use is limited to Internal Reserve or requires additional Assistance Reserve), the Participant should take appropriate action to restore Contingency Reserve Available on its system (to at least the level of its Contingency Reserve Obligation) as promptly as practicable. A Participant may not take longer than 60 minutes (measured from the start of the Qualifying Event) to restore Contingency Reserve Available on its system to at least the level of its

Contingency Reserve Obligation.

F. OBLIGATION TO PROVIDE ASSISTANCE RESERVE

Each Participant is obligated to deliver Assistance Reserve up to the full amount of its Balancing Authority Area's Contingency Reserve Obligation (after deducting for any capacity that has been deployed to respond to any Qualifying Events) in response to any Reserve Sharing Request that has met the requirements in Section E.2 and is made within 60 minutes following the start of the Qualifying Event.

Deployment of Contingency Reserve by a Participant providing Assistance Reserves will be measured through evaluation of the Participant's Reporting ACE through the following criteria:

- In the first ten-minute period after the request for Assistance Reserve, or any increase thereof, is received, the Participant's Reporting ACE must be above their Recovery Reporting ACE Target for at least one scan; and
- Within fifteen minutes of the request for Assistance Reserves and after the initial Reporting ACE recovery, the Participant's Reporting ACE must stay at or above their Recovery Reporting ACE Target minus 25% of their individual BAA's L_{10} value (as published by NERC) for at least five clock-minute average periods.

If a Participant has deployed all or a portion of its Balancing Authority Area's Contingency Reserve Obligation to respond to a Reserve Sharing Request by another Participant and then, while the deployment is still in effect, experiences its own Qualifying Event, the responding Participant may deploy whatever portion of its Contingency Reserve Obligation is required to recover from its own Qualifying Event. If the conditions necessary to receive Assistance Reserve are satisfied, the Participant may also make a Reserve Sharing Request even if one or more other Participants' Reserve Sharing Requests remain in effect. If the NWPP Reserve Sharing Group experiences sequential Qualifying Events that require one or more responding Participants to deploy Assistance Reserve that was being provided to other Participants, the Reserve Sharing Computer System will recalculate the distribution of Assistance Reserve and allocate to remaining Participants any amount necessary to replace the deployed Assistance Reserve.

G. ELIGIBILITY FOR AND PARTICIPATION IN RESERVE SHARING PROGRAM

G.1. Eligibility to Participate in the NWPP Reserve Sharing Program

All Balancing Authorities that operate Balancing Authority Areas located within the Northwest Power Pool and that elect to become NWPP Agreement Signatories must participate in the NWPP Reserve Sharing Program and must become parties to the Agency Agreement.

G.2. Treatment of Third-Party Generation

Each Participating Balancing Authority must, in calculating its Contingency Reserve Obligation, include all generation that is within its metered boundaries and for which the Participating Balancing Authority has an obligation or has agreed to provide Contingency Reserve. The term "Qualifying Event" with respect to a Participating Balancing Authority applies to any generation (including Third-Party Generation) that has been included in that Participating Balancing Authority's calculation of its Contingency Reserve Obligation.

H. ROLES AND RESPONSIBILITIES

H.1. Participant Responsibilities

Participants are responsible for abiding by the NWPP Reserve Sharing Group rules specified in this document, together with any corresponding policies adopted by the RSG Committee. These include requirements to meet Contingency Reserve Obligations, to provide Assistance Reserve when requested by another Participant, and to settle for deliveries of Assistance Reserve energy as provided in Section K.

Participants must also provide and receive data for the NWPP Reserve Sharing Program in accordance with Section I for general operation of the NWPP Reserve Sharing Program and Section J for making and responding to requests for Assistance Reserve.

a. Notifications

Participants must notify the WPP Staff and the NWPP Reserve Sharing Group Committee whenever a substantive change to the Participant's Balancing Authority Area is planned to occur. This would include, at a minimum, a change in Balancing Authority Area footprint or boundary, transfer of load or generation with another Balancing Authority Area, or any change that could have an impact to the deliverability of contingency reserves or the MSSC within the Participant's zone. This notification should occur prior to any changes being made to allow adequate time for appropriate impact studies to be completed and Program Document or computer program modifications, as needed.

The Participating Balancing Authorities are responsible to provide planned system failover notifications that may have an impact to data being telemetered to the Reserve Sharing Computer System to WPP Staff via an email to nwpprsg@westernpowerpool.org.

b. Program Monitoring

In addition, the Participating Balancing Authorities are responsible to monitor the NWPP Reserve Sharing Group "heartbeat" (as explained in Section I.1.n). If any Participating Balancing Authority discovers the NWPP Reserve Sharing Group heartbeat is inactive for a period of 10 minutes they should contact an adjacent Participating Balancing Authority to confirm this is a system-wide problem and not just a problem with their system or communication link. If the problem is believed to be system-wide that Participating Balancing Authority will contact the WPP Staff.

If a Participating Balancing Authority's heartbeat appears to be inactive at the time it needs to make a Reserve Sharing Request, it should initiate the Reserve Sharing Request as described in Attachment E – *Backup Procedures for NWPP Reserve Sharing Program*.

It is all Participating Balancing Authorities' responsibility to inform all other Participating Balancing Authorities and the WPP Staff if they have discovered a problem. In addition, Participating Balancing Authority System Operators and RSG Committee Representatives can e-mail or call with any questions or issues. WPP Staff will respond as soon as possible.

<u>NWPP Reserve Sharing Group Program Support Contact Information</u>:

- For immediate response the on-call support number at 503.673.6744.
- In addition, for non-urgent issues, you may email "nwpprsg@westernpowerpool.org". WPP Staff will respond to after-hours emails the next business day during normal work hours.

H.2. WPP Staff Monitoring and Reporting Responsibilities

The WPP Staff is responsible for monitoring Participants' compliance with Contingency Reserve Obligations. The RSG Committee is responsible for addressing problems related to Participant deficiencies or poor performance, for developing remedies and presenting proposed solutions, and for identifying and implementing any follow-up actions.

The WPP Staff is responsible for receiving NWPP RSG Verification Forms from Participants that have made Reserve Sharing Requests under the NWPP Reserve Sharing Program. The WPP Staff will perform analysis on each Reportable Balancing Contingency Event that the NWPP Reserve Sharing Group experiences with relationship to Participant's adherence to the Program Rules.

Subject to appropriate confidentiality and use restrictions (as determined by the WPP Staff), the WPP Staff may make available, to a Participant hosting implementation of an ACE Diversity Interchange arrangement, data related to the NWPP Reserve Sharing Program for the purpose of enabling the hosting Participant to harmonize the operation of the NWPP Reserve Sharing Program and the implementation of the ACE Diversity Interchange arrangement.

WPP Staff is responsible for monitoring and assisting in the implementation of the NWPP Reserve Sharing Program. While not staffed 24x7, WPP Staff will provide on-call 24x7 support as may be required. Although Participants are responsible for telemetering data to the Reserve Sharing Computer System as described in Sections I.1, and I.2, if WPP Staff notices missing information, WPP Staff will follow up with the affected Participant(s).

WPP Staff can review the status of each of the individual Participating Balancing Authority's data including heartbeats. If a WPP Staff member discovers a Participating Balancing Authority's heartbeat is inactive, he or she will follow up with the affected Participating Balancing Authority and document any findings by e-mail to all Participating Balancing Authorities.

H.3. RSG Committee Reporting Responsibilities

The RSG Committee is responsible for developing guidelines and arranging for periodic reports on the Contingency Reserve Obligation of the NWPP Reserve Sharing Group and Contingency Reserve Available within the NWPP Reserve Sharing Group as a whole.

I. GENERAL DATA REQUIREMENTS

This section describes data responsibilities for Participants in the NWPP Reserve Sharing Program. Although in general all required data are relayed automatically to the Reserve Sharing Computer System, all Participants must also have the capability to enter data manually if communications between Participating Balancing Authorities and the Reserve Sharing Computer System are interrupted.

I.1. Data Telemetered from Participating Balancing Authorities to the Reserve Sharing Computer System

Each Participant must telemeter the following data to the Reserve Sharing Computer System for each of its Balancing Authority Areas within the Northwest Power Pool:

a. the portion of its Contingency Reserve Available that is WECC Operating Reserve - Spinning ($TotCSR_{CA}$) ready for use as Internal Reserve or Assistance Reserve,

b. total Contingency Reserve Available ($TotAvailCR_{CA}$) ready for use as Internal Reserve or Assistance Reserve,

c. its total Balancing Authority Area Load (LOAD), as used to calculate its Contingency Reserve Obligation (CRO_{CA}) in accordance with Attachment A,

d. its total Balancing Authority Area Generation (GEN), as used to calculate its Contingency Reserve Obligation (CRO_{CA}) in accordance with Attachment A,

e. any portion of its reported Contingency Reserve Available already in use ($UsedCR_{CA}$),

f. its Reporting ACE (ACE_{raw}), as calculated according to the NERC glossary of terms,

g. its Most Severe Single Contingency ($MSSC_{CA}$),

h. Scheduled Net Interchange values (NET_SCHED_INT), as used to calculate an equivalent ACE,

i. Actual Net Interchange values (NET_ACTUAL_INT), as used to calculate an equivalent ACE,

j. its Reserve Sharing Request dynamic schedule ($RSReq_{CA}$),

k. request for Reserve Sharing Status Indication ($RSReq\_Confirmd_{CA}$)

    No Request = Status Open

    Assistance Requested = Status Closed,

l. reserve sharing response (RSResp),

m. indication (manually entered) of availability to provide Assistance Reserve (Participating Balancing Authorities not available to provide Assistance Reserve can still receive Assistance Reserve) (BA_Participate)

    Cannot Provide Assistance Reserve = Status Open

    Can Provide Assistance Reserve = Status Closed,

n. status of the communications links that enable it to participate in the NWPP Reserve Sharing Program on an automated basis, also known as its "heartbeat" (signaled by continuing changes to indicator data not to exceed 999,999, which the Reserve Sharing Computer System monitors at 10-second intervals; if there is no change to the data for a period of 60 seconds, the Participating Balancing Authority is presumed to be able to participate in the NWPP Reserve Sharing Program only through manual action; when the indicator data begin to change again, the Participating Balancing Authority is presumed to have regained the ability to participate in the NWPP Reserve Sharing Program through automated action) (BA_heart_beat), and

o. its frequency bias setting. (BA_FBS)

p. its meter error term (BA_Ime)

q. its ATEC term (BA_ATEC)

r. its ADI term if not included in Scheduled Net Interchange or Actual Net Interchange values above (BA_ADI)

I.2. Cut Planes

Explanatory note: As used in this Section I.2, the term "cut plane" is intended generally to describe an imaginary line separating two areas within a transmission system (or two different transmission systems) to enable the evaluation of flow of electrical energy on multiple lines connecting these two areas (or systems). The cut planes referred to below are sets of multiple lines connecting Reserve Sharing Zones.

Participants that are operators of the major transfer facilities must telemeter to the Reserve Sharing Computer System actual flow ($ACTUAL_{PATHnn}$) and transfer limit ($LIMIT_{PATHnn}$) for each direction of flow for the cut planes, as identified in Attachment L, between Reserve Sharing Zones as described in the next Section I.3.e.

The RSG Committee maintains a separate document, *NWPP RSG Cut Planes and Derivation Limits*, that more fully details the major transfer facilities and any associated Participant derivation information, including applicable calculations for which the Participant that monitors that cut plane, address the evaluation of flow of electrical energy on multiple lines.

I.3 Functions of the Reserve Sharing Computer System

Except when communications links or the necessary computer capabilities are down, the Reserve Sharing Computer System performs the tasks listed below. WPP Staff is able to monitor the Reserve Sharing Computer System and receive all Participants' data described in Sections I.1 and I.2. If WPP Staff notices that there is missing information, WPP Staff will consult directly with any Participating Balancing Authorities for which information is missing to make any necessary corrections.

a. Determine the Most Severe Single Contingency for the NWPP as a whole ($MSSC_{NWPP}$).

b. Determine the aggregate Contingency Reserve Obligation for the NWPP as a whole ($TotCRO_{NWPP}$) to ensure that the Contingency Reserve Available within the NWPP Reserve Sharing Group is sufficient to cover the Contingency Reserve Obligation for the NWPP as a whole.

c. Determine the Contingency Reserve Obligation ($TotCRO_{CA}$) for each Participant's Balancing Authority Area(s), calculated in accordance with Attachment A.

d. Compute a pro rata allocation of any applicable adjustments to Contingency Reserve Obligations ($AdjCRO\_MSSC_{CA}$ and $AdjCRO\_ZONE\_MSSC_{CA}$, which together are summed into $AdjCRO_{CA}$) for each Participant's Balancing Authority Area(s) to address shortages with respect to the MSSC for the NWPP Reserve Sharing Group or within a particular Reserve Sharing Zone.

e. In calculating any potential need to carry additional Contingency Reserve within a Reserve Sharing Zone, take into account transfer limits ($LIMIT_{Pathnn}$), actual flows ($ACTUAL_{Pathnn}$), and, where applicable, scheduled flows ($SCHED_{Pathnn}$) on the transmission facilities connecting that Reserve Sharing Zone to its adjacent Reserve Sharing Zone(s). With respect to the facilities linking the Pacific Northwest-Montana Reserve Sharing Zone with the Northern California Reserve Sharing Zone, this also reflects limits on ownership rights.

f. Maintain a pro rata allocation of the Reserve Sharing delivery dynamic schedule based upon each $TotCRO_{CA}$ for each Participant's Balancing Authority Area(s) relative to the $TotCRO_{NWPP}$.

g. Upon receipt of a Reserve Sharing Request dynamic schedule from a Participating Balancing Authority that is requesting Assistance Reserve, validate and activate the pro rata sharing signal to all other Participating Balancing Authorities.

h. Whenever Assistance Reserve is being delivered across facilities connecting two different Reserve Sharing Zones, continue to monitor actual flows ($ACTUAL_{Pathnn}$) in comparison to transfer limits ($LIMIT_{Pathnn}$) between the Reserve Sharing Zones, and, to the extent actual flows fall below transfer limits, allow deliveries to increase if needed to fully respond to the Reserve Sharing Request.

i. Maintain hourly integrated Reserve Sharing Request dynamic schedules from each Participating Balancing Authority.

j. Calculate a NWPP Reserve Sharing Group ACE (TOTACE_POOL) for entire NWPP Reserve Sharing Group.

k. Calculate a NWPP Reserve Sharing Group Reporting ACE for each Requesting Zone and Level 1 (or Level 2 for NCAL) Participants (ZONEACE_XXX – See Attachment C).

Each Participating Balancing Authority should consistently review the Contingency Reserve Obligation (CRO_{CA}) value transmitted to it by the Reserve Sharing Computer System to confirm the accuracy of the calculation and should promptly contact WPP Staff if it suspects there may be an error in the Reserve Sharing Computer System's calculation.

I.4. Data Telemetered from the Reserve Sharing Computer System to Participating Balancing Authorities

The Reserve Sharing Computer System makes available to each Participant the following telemetered data:

a. The Reserve Sharing Computer System's calculation of total Contingency Reserve Obligation ($TotCRO_{CA}$) for the Participant's Balancing Authority Area(s), as described in Attachment A. This includes, as applicable,

- calculation of base Contingency Reserve Obligation based on three percent of load and three percent of generation (CRO_{CA}),

- any adjustment to address shortages with respect to the MSSC for the NWPP Reserve Sharing Group ($AdjCRO\_MSSC_{CA}$),
- any adjustment to address shortages within a particular Reserve Sharing Zone ($AdjCRO\_ZONE\_MSSC_{CA}$), and
- combined adjustments to Contingency Reserve Obligation ($AdjCRO_{CA}$) to address shortages with respect to the MSSC for the NWPP Reserve Sharing Group or within a particular Reserve Sharing Zone.
- total Contingency Reserve Obligation ($TotCRO_{CA}$) as adjusted to address shortages with respect to the MSSC for the NWPP Reserve Sharing Group or within a particular Reserve Sharing Zone.

b. If the total Contingency Reserve Available within the NWPP Reserve Sharing Group ($TotAvailCR_{NWPP}$) is less than to total Contingency Reserve Obligation for the NWPP Reserve Sharing Group ($TotCRO_{NWPP}$), the NWPP Reserve Sharing Computer System calculates and telemeters necessary adjustments to total Contingency Reserve Obligation ($TotCRO_{CA}$) for each Participant's Balancing Authority Area(s) to reflect the shortfall in total Contingency Reserve Available within the NWPP Reserve Sharing Group ($AdjCRO\_SHORT_{CA}$). Each Participant must carry this adjustment amount in addition to its $TotCRO_{CA}$.

c. If a Participant is in the penalty level 4 status, a flag (TBD) will be set by WPP Staff to communicate to the program and to the Participant that they are required to carry additional Contingency Reserves.

d. Reserve Sharing Delivery dynamic schedule (RSDel) for Participating Balancing Authority that is delivering Assistance Reserve:[1]

$RSDel_{CA(Level\ 1)} = RSReq_{CA} * (TotCRO_{CA} / S\ TotCRO_{CA(Level\ 1)})$, limited to the portion of its Contingency Reserve Obligation ($TotCRO_{CA}$), if any, the Participating Balancing Authority is able to deliver at that time (after accounting for any portion of its $TotCRO_{CA}$ previously deployed)

Where,

$RSReq_{CA}$ £ $MW_{LOSS} - TotCRO_{CA}$

- If $S\ RSDel_{CA(Level\ 1)} < RSReq_{CA}$, then

[1] (All "CA" designations in these formulas refer to the particular Participating Balancing Authority to which a given value applies. References to "Levels" are to the Levels related to the Reserve Sharing Zones, as identified in Attachment C.)

$RSReq_{Short} = RSReq_{CA} - S\ RSDel_{CA(Level\ 1)}$

and,

$RSDel_{CA(Level\ 2)} = RSReq_{Short} * (TotCRO_{CA} / S\ TotCRO_{CA(Level\ 2)})$.

- If the amount of Assistance Reserve that can be delivered from the Participating Balancing Authorities at Level 2 is insufficient to meet whatever portion of the Reserve Sharing Request remains after deliveries from Participating Balancing Authorities at Level 1, the process is repeated as described above for Level 3, and, if applicable, Level 4 and Level 5.

- If there are multiple requests for Assistance Reserve, the $RSDel_{CA}$ would be calculated to reflect the sum of all amounts to be delivered as Assistance Reserve to requesting Participants, but the Reserve Sharing Computer System separately tracks the amounts to be delivered to each of the requesting Balancing Authorities (so that payment and return energy obligations can be properly determined).

- Requests for Assistance Reserve are not allowed to exceed the Contingency Reserve Available for the NWPP Reserve Sharing Group as a whole.

- Transmission constraints are included the Reserve Sharing Computer System's calculation of how much Assistance Reserve can be delivered from each Level for each Reserve Sharing Zone, and so do not need to be separately computed and applied.

e. Delivery of Reserve Sharing Confirmation Flag ($RSDel\_Confirmd_{CA}$),

No Request = Status Open

Assistance Requested = Status Closed

f. Reserve Sharing time remaining for the requesting Balancing Authority from the most recent request for Assistance Reserve (TimeLeft)

g. Number of active Reserve Sharing Requests (RSAct)

h. The MSSC for the NWPP Reserve Sharing Group as a whole ($MSSC_{NWPP}$)

i. The Contingency Reserve Obligation for the NWPP Reserve Sharing Group as a whole ($TotCRO_{NWPP}$)

j. The Contingency Reserve Available for the NWPP Reserve Sharing Group as a whole ($TotAvailCR_{NWPP}$)

k. NWPP Reserve Sharing Group Reporting ACE (ACE_{NWPP})

l. Reportable Balancing Contingency Event (RpDist)

Where,

RpDist = the lesser of (a) 0.8 * $MSSC_{NWPP}$ or 500 MW

m. Total number of minutes remaining since the most recent request for the NWPP (RSTimRem)

n. The indication that the Reserve Sharing Computer System and associated communication links are operational is also known as the NWPP Reserve Sharing Group "heartbeat."

o. When activity on the Reserve Sharing Computer System is due to testing rather than power system conditions, this is indicated by a testing flag. WPP Staff will arrange for this flag to be set while testing is underway, which may include helping a Participating Balancing Authority test its system(s). (The NWPP Reserve Sharing Program is fully operational while testing is in progress and Reserve Sharing Requests may be made normally. If there is a Reserve Sharing Request during testing, the test will be terminated.)

p. The Reserve Sharing Computer System's calculation for each Reserve Sharing Zone as reflected in Attachment C,

- The MSSC ($MSSC_{zone}$)
- The total Contingency Reserve within the zone ($TOTCR_{zone}$),
- Calculation of the zonal Contingency Reserve Obligation based on the zonal Participant(s) three percent of load and three percent of generation ($TOTCRO_{zone}$),
- The total Contingency Reserve Available to the zone ($TOTCRA_{zone}$),

q. The Reserve Sharing Computer System's information or calculation for each cut plane between Reserve Sharing Zones as reflected in in Section I.2.

- The actual flow ($ACTUAL_{PATHnn}$) and transfer limit ($LIMIT_{PATHnn}$) for each direction of flow
- The actual room ($ROOM_{PATHnn}$) and reserve ($RESERVE_{PATHnn}$) for each direction of flow

I.5. Informational Data Telemetered from the Reserve Sharing Computer System to the Reliability Coordinators

The Reserve Sharing Computer System telemeters to the Reliability Coordinators the following informational data:

a. The MSSC for the NWPP Reserve Sharing Group as a whole ($MSSC_{NWPP}$),

b. The Reserve Sharing Group Reporting ACE (ACE_{NWPP}),

c. The Contingency Reserve Obligation for the NWPP Reserve Sharing Group as a whole ($TotCRO_{NWPP}$), and

d. The Contingency Reserve Available for the NWPP Reserve Sharing Group as a whole ($TotAvailCR_{NWPP}$).

e. Data for each of the Reserve Sharing Zones as follows:
   - The MSSC for the Reserve Sharing Zone,
   - The Contingency Reserve Obligation for the Reserve Sharing Zone, and
   - The Contingency Reserve Available for the Reserve Sharing Zone.

Attachment N is a correlation table of Participants, Reliability Coordinators, and Reserve Sharing Zones.

J. DATA REQUIREMENTS RELATED TO RESERVE SHARING REQUESTS

The general data requirements for Participants in the NWPP Reserve Sharing Program are described in Section I. The provisions below explain the steps for making and responding to Reserve Sharing Requests.

J.1. Requesting Participant

a. A Participant that has met the conditions to make a Reserve Sharing Request (as described in Section E.2) must calculate the amount of Assistance Reserve for which it is eligible, enter the deficient amount needed into a Reserve Sharing Request dynamic schedule, and send the request, at a zero-ramp span time, to the Reserve Sharing Computer System.

Where,

$RSReq_{CA}$ £ $MW_{LOSS} - TotCRO_{CA}$

RqstRSSI = 1.

At this point in time, the Participant's anticipated CR_{CA} should be zero if their CR_{CA} was equal to $TotCRO_{CA}$. If CR_{CA} was higher than $TotCRO_{CA}$, CR_{CA} should decrease by the amount shown as $UsedCR_{CA}$.

$TotCRO_{CA} - UsedCR_{CA} \leq 0$

c. Requesting Participants are expected to restore the Contingency Reserve Available on their systems, to at least the level of their Contingency Reserve Obligations, as promptly as practicable, but in no event longer than 60 minutes from the start of the Qualifying Event.

d. As a safeguard, the Reserve Sharing Computer System will remove the Reserve Sharing Request dynamic schedule within 65 minutes following the Reserve Sharing Request.

$RSReq_{CA}$ = 0, ten-minute ramp to zero beginning at 55 minutes after the request first started.

RqstRSSI = 0

e. If during the request the Requesting Participant detects a Reserve Sharing Computer System failure, it should assume that the Responding Participants will continue to deliver reserves for the full 65 minutes as called for in J.1.d.

f. If a Participant makes a Reserve Sharing Request for an initial Qualifying Event and, before the end of the 60 minutes during which the Participant is allowed to rely on Assistance Reserve (as provided in Section E.3 of this document), experiences one or more additional Qualifying Events for which it wishes to request Assistance Reserve, the Participant may initiate additional Reserve Sharing Requests by (1) activating the additional Reserve Sharing Request toggle on the Reserve Sharing Computer System (which indicates that the requesting Participant has two or more active Reserve Sharing Requests), then (2) revising the deficient amount needed, as calculated in accordance with Section J.1.a above, to include the additional amount of Assistance Reserve required for the additional Qualifying Event(s). The activation of any additional Reserve Sharing Request will re-set the overall event timer to 65 minutes (the permitted 60-minute reliance period plus an additional five minutes to complete ramping). While the Reserve Sharing Computer System continues to run separate event timers for each Qualifying Event, Participants are able to see only the time remaining for a Participant's last-initiated Reserve Sharing Request, and not for any of its previously initiated Reserve Sharing Requests.

J.2. Responding Participants

a. Responding Participants should initiate a response to a Reserve Sharing Delivery dynamic schedule from the Reserve Sharing Computer System by including $RSDel_{CA}$ in their ACE equation shown below. A security check on the Reserve Sharing Request dynamic schedule includes a crosscheck such that Reserve Sharing Status Indication = 1. The sign of the $RSDel_{CA}$ is negative for Participating Balancing Authorities requesting Assistance Reserve. The sign of the $RSDel_{CA}$ is positive for Participating Balancing Authorities providing Assistance Reserve.

Where,

$ACE_{CA} = (NI_A - NI_S) - 10B\ (F_A - F_S) - I_{ME} + I_{ATEC}$

NI_S = S(adjacent Balancing Authority schedules) + S(dynamic schedules) + $RSDel_{CA}$

Each responding Participant will maintain an internal timer equal to $TotTmRem_{NWPP}$ and continue to count down this timer to zero if the value from the Reserve Sharing Computer System fails to decrement (indicating probable loss of data link). Whenever a responding Participant is operating in an assumed disconnected mode, $RSDel_{CA}$ is internally frozen. When the internal count-down timer reaches zero, the responding Participant should set $RSDel_{CA}$ to zero.

K. SETTLEMENT

A Participant that receives Assistance Reserve energy must compensate all Participants that deliver Assistance Reserve energy financially.

Participants may mutually agree to an alternate procedure, provided the affected Participants can account for the transaction appropriately.

This section explains how the data used for settlement is developed and the process through which Participants complete financial settlement. Attachment D includes a settlement process chart as reference of this process.

K.1. Settlement Data

Each hour, whether or not there has been a Reserve Sharing Request, the Reserve Sharing Computer System will transmit the hour-ending integrated dynamic schedule quantities (MWh) to all Participating Balancing Authorities. These data will be referred to as “Settlement Data” and will include source/sink energy information without consideration of transmission “wheeling” through intervening systems. Settlement Data are rounded and used to develop adjacent Balancing Authority interchange schedules. Settlement Data will be used to construct the official reserve sharing energy matrix (the “Matrix”).

a. <u>Rounding</u>

Settlement Data are rounded to whole integers to accommodate scheduling and accounting systems:

- All Settlement Data quantities less than 1 MWh will be rounded to 0 MWh (e.g., 0.7 yields 0 MWh). This practice will reduce nuisance scheduling of small quantities.

- For quantities equal to or greater than 1 MWh, conventional rounding practices will apply. Fractional quantities less than 0.5 will be rounded down (*e.g.*, 27.2 yields 27 MWh) and fractional quantities of 0.5 or greater will be rounded up (*e.g.*, 27.9 yields 28 MWh). After rounding, Settlement Data are compiled into the matrix.

b. Mapping of Energy Schedules

Energy schedules must be mapped to adjacent Balancing Authorities to allow proper energy accounting consistent with existing reliability standards and regional business practices. The Participants have agreed to a pre-defined set of tag templates to account for the transmission mapping for the deliveries of Assistance Reserve Energy. This mapping includes wheeling parties between nonadjacent Balancing Authorities, and as further explained in Section K.1.c below, serves as the basis to create after-the-fact tags.

c. Automatic Tagging and Tag Templates

The Participants' tag templates reflect the transmission mapping for the delivery of Assistance Reserve energy between Participating Balancing Authorities. The Northwest Power Pool Corporation has a contract with Open Access Technology International, Inc. (OATI) to produce after-the-fact energy schedule tags for all deliveries of Assistance Reserve energy. These tags are provided to the Participants and the WECC Western Interchange Tool (WIT).

The WPP Staff is responsible for assisting with the maintenance of these tag templates used by OATI, and keeping them up-to-date in accordance with requests made by Participating Balancing Authorities. Attachment F describes the NWPP Reserve Sharing Group's procedures for revising the transmission mapping as reflected in the tag templates.

The Participants' tag templates are not publicly available and are only accessible to the RSG Representatives, their designated RSG Alternate Representatives and tagging personnel. The designated representatives may access and download the most current version of *NWPP RSG Tagging Templates.xls* on the Western Power Pool website (www.westernpowerpool.org) in the Reserve Sharing Group's Documents.

K.2. Financial Settlement

The NWPP Reserve Sharing Group utilizes the Intercontinental Exchange (ICE) day-ahead peak and off-peak index prices at the Mid-Columbia (Mid-C) and Palo Verde (PV) trading hubs, for the calculation of the settlement price as noted in subsection (a.) below.

A Participant will be financially reimbursed for providing Assistance Reserve energy.

For purposes of the NWPP Reserve Sharing Program, the "Settlement Price" for peak hours will be the average of the ICE day-ahead peak index prices for the Mid-C and PV trading hubs. The "Settlement Price" for off-peak hours will be the average of the ICE day-ahead off-peak index prices for the Mid-C and PV trading hubs, *provided, however*, that (a) if ICE does not publish a Day-Ahead Price for a relevant operating day or Request Hour, then the Settlement Price shall be the average of the other Day-Head Price for the Request Hour and (b) in no event will the Settlement

Price ($/MWh) be less than zero or greater than the WECC Soft Price Cap in accordance with regulations and orders of the Federal Energy Regulatory Commission (FERC).

<u>Examples of settlement for 10 MWh of dispatched energy</u>:

Example 1:
Index prices: Mid-C $50, PV $75
Calculation: ($50+$75)/2 = $62.50 settlement price x 10MWh = $625

Example 2:
Index prices: Mid-C $50, PV-No Trade.
Calculation: $50+ (excluded) = $50 settlement price x 10MWh = $500

Example 3:
Index prices: Mid-C $-20 (below price cap), PV $5,
Calculation: ($0 + $5)/2 = $2.50 Settlement Price x 10MWh = $25

Example 4:
Index prices: Mid-C $1035 (above WECC Soft Energy Price Cap), PV $750,
Calculation: ($1,000 + $750)/2 = $875*10MWh = $8,750

With respect to FERC-jurisdictional entities, the Settlement Price will be set forth in the Participant's individual tariff on file with and approved by FERC. In the event that the Settlement Price set forth in a. above is amended, such amended Settlement Price will not be effective until all FERC-jurisdictional entities have approved amended tariffs.

During the RSG Committee's third quarter meeting the RSG Committee (or a work group or task force appointed by the RSG Committee) will review the definition of "Settlement Price," to ensure the selected trading hubs and applicable day-ahead peak and off-peak index price continue to represent a fair value of energy within the NWPP Reserve Sharing Group footprint. The RSG Committee may elect to either maintain the current definition of "Settlement Price" or propose a modified definition to be considered for approval at the next meeting of the RSG Committee. The effective date of any modification to the definition of "Settlement Price" will be coordinated to allow Participants with applicable tariffs filed with FERC to make any necessary filings with FERC.

Unless the affected Participants have agreed otherwise, financial settlements will occur under the responding Participant's normal monthly billing cycle.

WPP Staff will be responsible for determining and posting Settlement Prices, calculated as described in subsection (a) above of this Section K.3, in accordance with the following procedures:

a. WPP Staff will use the day-ahead peak and off-peak prices posted by ICE at the end of each trading day to programmatically calculate and post the Settlement Price for all hours of the days for which prices were published (operating days).

b. In the first three (U.S.) business days following the first (U.S.) business day of each month (referred to in these procedures as the "lock down date"), WPP Staff may confer with designated Participants for assistance in validating the applicable prices posted by ICE for the preceding month and the computation of the Settlement Prices as necessary.

c. By the end of the third (U.S.) business day following the lock-down date, WPP Staff will post finalized Settlement Prices for all hours of the preceding month, computed as described in this subsection (e).

d. If, as of the lock-down date, information needed to compute one or more Settlement Prices has not yet been posted by ICE, WPP Staff will compute and post Settlement Prices for those applicable dates and hours within three (U.S.) business days following the date on which the necessary information is first posted by ICE.

e. Settlement Prices that have been posted by WPP Staff in accordance with the procedures set forth above will not be subject to further adjustment, except by agreement of all affected Participants.

L. INTERNAL NWPP RESERVE SHARING GROUP REPORTING

L.1 Obligation to Submit a NWPP RSG Verification Form

A Participant must, within two (U.S.) business days following the triggering event, prepare and submit to the WPP Staff a completed NWPP RSG Verification Form whenever any one of four conditions described below occurs:

a. The Participant makes a Reserve Sharing Request under the NWPP Reserve Sharing Program (including use of backup procedures specified in Section N if the automated process fails).

b. The Participant or the NWPP Reserve Sharing Group has experienced a Qualifying Event that is a Reportable Balancing Contingency Event (equal to or greater than the lesser of (i) 500 MW, or (ii) 80% of the Most Severe Single Contingency) for the NWPP Reserve Sharing Group at the time of the Qualifying Event.

c. The WPP Staff contacts the Participant requesting a NWPP RSG Verification Form because the Participant has ownership or contractual rights in a jointly owned facility and the WPP Staff is following up with the Participant as described in Section L.2.

d. The Participant has experienced a Reliability Coordinator declared Energy Emergency Alert (as described in NERC Standard EOP-011 or successor standard).

NWPP RSG Verification Forms are available on the WPP Website. The Participants will transmit completed forms via e-mail to nwpprsg@westernpowerpool.org. The Western Power Pool Corporation, in its capacity as agent for the NWPP Reserve Sharing Group, may request additional data and information as may be required and is responsible for submitting periodic reports to the WECC and NERC in accordance with their requirements.

L.2 Reporting Balancing Authority Obligation to Notify WPP Staff

A Participant that is the Reporting/Operating Balancing Authority (as specified in Attachment K) for a jointly owned facility must, as soon as feasible, but in any case within two (U.S.) business days following the triggering event, provide written notice to the WPP Staff (which may be by electronic mail) whenever the jointly owned facility for which it is the Reporting/Operating Balancing Authority has experienced a Qualifying Event that is a Reportable Balancing Contingency Event (equal to or greater than the lesser of (a) 500 MW, or (b) 80% of the Most Severe Single Contingency) for the NWPP Reserve Sharing Group at the time of the Qualifying Event.

The WPP Staff will promptly follow up with all other Participants that have ownership or contractual rights in the jointly owned facility to request that those Participants submit completed NWPP RSG Verification Forms.

M. RESERVE SHARING ZONES

The NWPP Reserve Sharing Program takes into account the effect constrained transmission facilities can have on the ability of Participants to deliver Assistance Reserve energy to one another. When a Participating Balancing Authority (or a group of Participating Balancing Authorities) is separated from remaining Participants by constrained transmission facilities, the effect of the constraint is reflected in the establishment of Reserve Sharing Zones. Attachment C to this document identifies the Reserve Sharing Zones for the NWPP Reserve Sharing Program, together with the sequence (levels) through which Assistance Reserve is deployed for each Reserve Sharing Zone.

The Long-Term Zonal MSSC Limits account for limitations, as determined by the Participant Balancing Authority(ies) of each zone as identified in Attachment K.1.

Proposed system changes that will result in an increase to a Long-Term Zonal MSSC as identified in Attachment K, must be approved by the Balancing Authorities of the impacted zone within 120 days of system change being identified.

In addition, any proposed change to the NWPP Reserve Sharing Group Long-Term MSSC Limit as identified in Attachment K, must be approved by the NWPP Reserve Sharing Group Committee.

N. BACKUP PROCEDURES

Reserve Sharing Requests and delivery of Assistance Reserve energy are normally implemented through the Reserve Sharing Computer System. When a Participant cannot access the Reserve Sharing Computer System (or the system is inoperable), the Participant should use the manual backup procedures as reflected in Attachment D's respective process chart and described in Attachment E and to make any Reserve Sharing Requests. In these circumstances, a responding Participant is obligated to provide Assistance Reserve only up to the amount of its available transmission capacity or its Contingency Reserve Obligation, whichever is smaller. The settlement process for delivery of Assistance Reserve energy using the backup procedure is the same as for the automated reserve sharing process, except that requesting and responding Participants must agree (on a case-by-case basis) to any reserve sharing transactions instead of obtaining the information from the Reserve Sharing Computer System. This process must be in accordance with Attachment G for production of after-the-fact tags and in accordance with existing reliability standards and regional business practices.

O. PROCEDURES FOR ADDRESSING ISSUES AFFECTING RESERVE SHARING PROGRAM WHEN AGENCY AGREEMENT PROCESS IS INSUFFICIENT

To facilitate reporting and compliance activities related to NERC or WECC reliability standards that may affect the NWPP Reserve Sharing Program, the Participating Balancing Authorities have entered into the Agency Agreement. All Participating Balancing Authorities, as well as the Northwest Power Pool Corporation, are parties to the Agency Agreement. The Agency Agreement contains provisions that enable Participating Balancing Authorities to call meetings on specified prior notice and make decisions about matters concerning the Agency Agreement or the NWPP Reserve Sharing Program. Any meeting or vote under the Agency Agreement requires at least 10 days' prior notice.

If an urgent matter related to NWPP Reserve Sharing Program arises, and the WPP Staff determines in good faith that either (1) there is insufficient time to address the matter through the procedures in the Agency Agreement or (2) the matter is outside the scope of the Agency Agreement, the WPP Staff will:

- make commercially reasonable efforts to promptly deliver electronic notice of the matter to each designated contact for notice under the Agency Agreement;
- convene a meeting by telephone conference (with the option of in-person attendance at the offices of the Northwest Power Pool Corporation if feasible) of all available Participating Balancing Authorities, giving as much advance notice and facilitating attendance of as many Participating Balancing Authorities as feasible in view of any need for prompt action;

- seek input from the Participating Balancing Authorities as to what action should be taken, and, if appropriate in the judgment of the WPP Staff or requested by any Participating Balancing Authority, take a vote of the Participating Balancing Authorities (on the basis that a vote of not less than two-thirds of the Participating Balancing Authorities present at the time the vote is taken will be necessary to approve an action or decision); and
- make commercially reasonable efforts to take follow-up action consistent with the input received or results of any vote taken in accordance with this Section O.

No vote of the Participating Balancing Authorities conducted in accordance with this Section O may have the effect of (a) amending this NWPP Reserve Sharing Program documentation, (b) amending the Agency Agreement, (c) authorizing settlement of any NERC or WECC compliance-related matter that will or could cause any party to incur violation(s), monetary penalties or other legal liability (unless the party or parties incurring violation(s), monetary penalties or legal liability have given their prior written consent); or (d) restricting the ability of any party to independently exercise whatever legal or procedural rights it may have to challenge action taken by or petition an Enforcement Authority (as that term is defined in the Agency Agreement) in connection with any NERC or WECC compliance-related matter.

P. PENALTIES FOR NON-PERFORMANCE (Effective July 1, 2024)

P.1 Grading

Events will be assessed shortly after they occur to provide feedback to the involved BAAs. Official grading for events will occur once that entity reaches the evaluation threshold. An entity may fail per the defined performance metrics and receive a score greater than 0%.

The evaluation threshold is any calendar quarter that the BAA participated in ten or more events. If an entity participates in fewer than ten events in any calendar quarter, that quarter will be considered a null quarter, and the events roll over to the next calendar quarter. Once ten events are accumulated, those events and any others during that quarter, will be evaluated and scored.

Each Assistance Reserve request and response will be evaluated and scored as follows:

For a Participant requesting Assistance Reserve:

- 50% for initial ACE Recovery in the first fifteen-minute period after the disturbance, plus
- 10% for each clock-minute average period sustained above Recovery Reporting ACE Target minus 25% of their individual BAA’s L10 value (as published by NERC) in the first nineteen clock-minutes after the disturbance with a maximum of 50% for five or more sustained clock-minutes.
- With a total maximum score of 100%

If the request is not made within the required 4-minute period after the start of the Qualifying Event, the score will then be reduced by 10% for each minute (or portion thereof) beyond the 4-minute period the request is delayed. The minimum score a BAA may have is 0%.

For a Participant providing Assistance Reserve:

- 50% for initial ACE recovery in the first ten-minute period after the request for Assistance Reserve, plus
- 10% for each clock-minute average period sustained above Recovery Reporting ACE Target minus 25% of the individual BAA's L_{10} value (as published by NERC) in the first fifteen clock-minutes after the request for Assistance Reserve with a maximum of 50% for five or more sustained clock-minutes.
- With a total maximum score of 100%

All events for the quarter will be individually scored and averaged together and rounded to the nearest 0.1%, to provide a total score for the quarter. If a BAA receives a score of less than 95%, they will be determined to have failed the quarter. These scores will be reported to the RSG Committee at each meeting. If the BAA does not have any events for a quarter, that quarter will be considered a null quarter and not count as a "Pass" or a "Fail".

P.2 Edge Case Events Review and Final Determination

All RSG events will be reviewed by WPP Staff. Events that are found to have characteristics making them more difficult to respond to (ex. requests where the value is changing during the analysis period or coming in and out) will be flagged for further review. Any of these events where it is later determined that there is no impact to any member's quarterly grade (Pass/Fail) will be removed from the overall calculation. Any events with an impact will be brought to the Reserve Sharing Group Committee for final determination.

If a BAA believes that an event should be removed from consideration, they may present their case to the RSG Committee during a committee meeting. The committee will then make a determination and the quarterly score will be recalculated as necessary.

P.3 Penalties

Penalties will be assessed based on how many quarters a BAA has failed. All BAA's begin at Level 0 and increase one level from their current level with a failed quarter (ex. Q1). Penalties will be analyzed in the following quarter (ex. Q2) and any level changes implemented at 0600 pacific prevailing time the first NERC scheduling day of the quarter after that (ex. Q3). For example: Q1 will be analyzed in Q2 and any level changes implemented in Q3. Decreasing levels and null quarters are addressed in section P.4.

The penalty levels are:

Level 1:

- An official letter to the Participant RSG Representative(s) notifying them of the failed quarter
- The Participant RSG Representative(s) will present a Corrective Action Plan with milestones and completion dates to the RSG Committee
- The Participant RSG Representative(s) will designate a Company Executive to be notified if Level 2 is reached

Level 2:

- An official letter to the designated Company Executive notifying them of the failed quarter
- The Participant RSG Representative(s) will present a Corrective Action Plan with milestones and completion dates to the RSG Committee

Level 3:

- An official letter to the designated Company Executive notifying them of the failure and that their BAA will be required to carry additional Contingency Reserves with an additional failed quarter
- The Participant RSG Representative(s) will present a Corrective Action Plan with milestones and completion dates to the RSG Committee

Level 4:

- An official letter to the designated Company Executive notifying them of the failure and that their BAA is now required to carry additional Contingency Reserves
- The BAA will be required to carry additional reserves and be limited on the events that qualify for requesting Assistance Reserves the for one Quarter.
    - The BAA will be obligated to carry the lesser of their MSSC or 150% of their regularly calculated CRO
    - The BAA will be allowed to call on Assistance Reserve only if they experience a loss greater than their increased obligation
    - During this quarter, the BAA must still respond to requests for Assistance Reserves
    - The BAA must update their EMS or other impacted IT/OT applications to reflect these changes
    - Meet all financial obligations associated with RSG membership

- The Participant RSG Representative(s) will present a Corrective Action Plan with milestones and completion dates to the RSG Committee
- While in this level, an additional failed quarter will result in that BAA(s) triggering a vote to be removed from NWPP Reserve Sharing Group by the membership.

Level 0:

- An official letter to the Participant RSG Representative(s) notifying them of the return to Level 0 Operations
- Normal Operations – no restrictions

P.4 Reset

Each quarter a BAA passes will reduce the penalty level under which they are operating. A "null quarter" will keep the BAA at the level they were at for the previous quarter unless the BAA was at Level 4 in which case the BAA would go to Level 3 until they have passed two consecutive quarters excluding null quarters.

ATTACHMENTS

Attachment A

Calculation of Contingency Reserve Obligations; Requirements Related to WECC Operating Reserve - Supplemental

1. Calculation of Participating Balancing Authority Contingency Reserve Obligation

The NWPP Reserve Sharing Group has determined that the Contingency Reserve Obligation for each Participant's Balancing Authority Area(s), as well as the Contingency Reserve Obligation for the NWPP Reserve Sharing Group as a whole, will be calculated as set forth below. The measure of the Contingency Reserve Obligation for each Participant's Balancing Authority Area(s), as well as the Contingency Reserve Obligation for the NWPP Reserve Sharing Group as a whole, will be based on real-time measurements of load and generation, which, for compliance purposes, will be used to calculate integrated hourly averages. These integrated hourly averages will be compared to hourly averages of Contingency Reserve Available (also based on real-time measurements) to determine whether the NWPP Reserve Sharing Group's Contingency Reserve Available was sufficient to meet the requirements of BAL-002. The amount of Contingency Reserve Available within the NWPP Reserve Sharing Group for each clock hour must be equal to or greater than the NWPP Reserve Sharing Group's Contingency Reserve Obligation during that same clock hour.

As described in detail in Section 1 of this Attachment A and reflected in Attachment D's process chart for Calculation of CRO, the Reserve Sharing Computer System uses a four-step process to determine the Contingency Reserve Obligation a Participating Balancing Authority is required to meet for its Balancing Authority Area(s) under normal circumstances, using real-time measurements as described above. The Reserve Sharing Computer System completes the calculations necessary for this process (with updated real-time measurements) every data scan cycle (that is, no less frequently than every six seconds).

These calculation processes can be summarized as follows:

First, the Reserve Sharing Computer System calculates three percent of load plus three percent of generation. Next, the Reserve Sharing Computer System sums of all Participants' Contingency Reserve calculations to see whether this calculated sum is at least equal to the Most Severe Single Contingency for the NWPP Reserve Sharing Group. If it is not, the Reserve Sharing Computer System allocates, on a pro rata basis, the additional amount of Contingency Reserve necessary to cover the NWPP Reserve Sharing Group's Most Severe Single Contingency and determines the Contingency Reserve Obligation for each Participant's Balancing Authority Area(s) as adjusted for the NWPP Reserve Sharing Group's Most Severe Single Contingency.

The third step calculates the amount of any additional Contingency Reserve that may be needed in a Reserve Sharing Zone to cover the Most Severe Single Contingency within that Reserve

Sharing Zone and determines each the Total Contingency Reserve Obligation for each Participant's Balancing Authority Area(s), reflecting both applicable adjustments for the NWPP Reserve Sharing Group's Most Severe Single Contingency and any adjustments necessary to address the Most Severe Single Contingency within a Reserve Sharing Zone.

The fourth step checks to make sure the aggregate amount of Contingency Reserve Available within the NWPP Reserve Sharing Group is at least equal to Contingency Reserve Obligation of the NWPP Reserve Sharing Group according to the requirements of BAL-002 (both the WECC and the NERC versions). If it is not, the Reserve Sharing Computer System allocates, on a pro rata basis, the additional amount of Contingency Reserve necessary to fully comply with the Contingency Reserve requirements of BAL-002. Each Participating Balancing Authority must add this adjustment amount to its total Contingency Reserve Obligations and stand ready to deploy this adjusted Contingency Reserve Obligation (excluding amounts already deployed to respond to Qualifying Events) at all times for use as Internal Reserve and Assistance Reserve.

Section 4 of this Attachment sets out the process a Participating Balancing Authority should follow to determine its Contingency Reserve Obligation(s) when communication links between the Participating Balancing Authority and the Reserve Sharing Computer System are down, or when the Reserve Sharing Computer System is unavailable.

Set forth below are explanations and formulas for each step in the process to determine the total amount of Contingency Reserve a Participating Balancing Authority is required to carry.[2] For any Participant that has more than one Balancing Authority Area within the Northwest Power Pool, the calculations below are done separately for each of its Balancing Authority Areas.

a. <u>Step One – Calculation of Participating Balancing Authority Base Contingency Reserve Obligation</u>:

   The base Contingency Reserve Obligation for each Participant's Balancing Authority Area(s), or "CRO_{CA}" (before the adjustments described in the remainder of Section 1 of this Attachment A), is the sum of (i) three percent of the Load (as defined below) for the Participant's Balancing Authority Area(s), plus (ii) three percent of the Generation (as defined below) for the Participant's Balancing Authority Area(s).

   $\mathbf{CRO}_{CA}$ = (0.03 × Generation) + (0.03 × Load),

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[2] For consistency with formulas used in the Reserve Sharing Computer System, individual Participating Balancing Authority obligations are designated by the subscript "$_{CA}$." This is because the formulas in the Reserve Sharing Computer System were established when the function roughly corresponding to a Balancing Authority was referred to as a control area.

Where,

- **CRO_{CA}** = base Contingency Reserve Obligation
- **Generation** = BAA Net Generation - Designated Dynamically Scheduled Exports + Designated Dynamically Scheduled Imports [*see* Note 1]
- **Load** = BAA Net Generation - Actual Net Interchange [*see* Notes 2 and 3]
- **BAA Net Generation** = the sum of Net Generation for all generating units (whether measured by individual units or at the plant level or both) inside the Balancing Authority Area
- **Net Generation** (whether for an individual generating unit or a generating plant) = the greater of (a) the gross metered generation minus station service load, or (b) zero
- **Actual Net Interchange (NI_A)** has the meaning given to this term in the NERC Glossary
- **Scheduled Net Interchange (NI_S)** has the meaning given to this term in the NERC Glossary
- **Designated Dynamically Scheduled Exports =** all Dynamically Scheduled exports for which the sink (receiving) Balancing Authority has agreed to carry Contingency Reserve, as reflected in the Balancing Authority Area's Scheduled Net Interchange value [*see* Note 4]
- **Designated Dynamically Scheduled Imports** for which the sink (receiving) Balancing Authority has agreed to carry Contingency Reserve, as reflected in the Balancing Authority Area's Scheduled Net Interchange value [*see* Note 4]
- **Dynamically Scheduled** corresponds to the term "Dynamic Schedule," as defined in the NERC Glossary

<u>Note 1</u>: All generation within the Balancing Authority Area's or the NWPP Reserve Sharing Group's metered boundaries should be included in this calculation, with the only exception being generation expressly permitted to be excluded by the terms of BAL-002-WECC-3 (or comparable standards in jurisdictions outside the United States). Generation within a Balancing Authority Area by Pseudo-Tie (as defined in the NERC Glossary) is considered within the metered boundaries of the Balancing Authority Area into which it is Pseudo-Tied and is included in its generation calculation.

Note 2: Generation within a Balancing Authority Area by Pseudo-Tie is reflected in Actual Net Interchange in the ACE equation.

Note 3: Load within a Balancing Authority Area by Pseudo-Tie is reflected in Actual Net Interchange in the ACE equation. Load within a Balancing Authority Area by Pseudo-Tie is considered within the metered boundaries of the Balancing Authority Area into which it is Pseudo-Tied and is included in its load calculation by virtue of its inclusion in the Actual Net Interchange equation.

Note 4: This term captures net generation responsibility transferred, reflecting that Dynamically Scheduled generation exports can be subtracted from the exporting Balancing Authority's generation obligation (except when the source Balancing Authority and sink Balancing Authority have agreed otherwise), and Dynamically Scheduled generation imports should be added to the importing Balancing Authority's generation obligation (except when the source Balancing Authority and sink Balancing Authority have agreed otherwise).

b. Step Two – Check for Deficiency Related to Most Severe Single Contingency for the NWPP:

Once the Participating Balancing Authorities' base Contingency Reserve Obligations have been calculated, the second step in the process is to check for any potential deficiency, should the Most Severe Single Contingency for the NWPP exceed the sum of the Participating Balancing Authorities' Contingency Reserve Obligations as calculated in step one.

The NWPP's Most Severe Single Contingency is compared to the sum of all Participating Balancing Authorities' base Contingency Reserve Obligations. If the Most Severe Single Contingency is greater, the difference between these two figures (the "shortfall") is allocated among the Participating Balancing Authorities in proportion to their relative shares of the NWPP Reserve Sharing Group's base Contingency Reserve Obligation, as calculated in step one. This results in an upward adjustment to the base Contingency Reserve Obligation for each Participant's Balancing Authority Area(s).

The formulas for this step are as follows:

If $S\ CRO_{CA} < MSSC_{NWPP}$, then

$$CRO\_SHORT_{NWPP} = MSSC_{NWPP} - S\ CRO_{CA}$$

and

$AdjCRO\_MSSC_{CA} = CRO\_SHORT_{NWPP} * CRO_{CA} / S\ CRO_{CA}$

Where,

$S\ CRO_{CA}$ = sum of all Participating Balancing Authorities' base Contingency Reserve Obligations, as calculated through step one;

$MSSC_{NWPP}$ = the Most Severe Single Contingency for the NWPP Reserve Sharing Group, determined in accordance with the Typical Planning MSSC in real time table set forth in Attachment K;

CRO_SHORT_{NWPP} = the amount by which the Most Severe Single Contingency for the NWPP exceeds the sum of the Participating Balancing Authorities' base Contingency Reserve Obligations;

CRO_{CA} = the Participating Balancing Authority's base Contingency Reserve Obligation as calculated in step one;

$AdjCRO\_MSSC_{CA}$ = the adjustment to the Participating Balancing Authority's base Contingency Reserve Obligation to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group.

$MSSC_{NWPP}$ is revised whenever the output of the generator (or loading of the transmission line) that sets the $MSSC_{NWPP}$ increases or decreases by one MW or more.

c. <u>Step Three – Check for Deficiency Related to Most Severe Single Contingency for a Reserve Sharing Zone and Sum of Adjustments</u>:

The third step in the process is to check for any potential deficiency within a Reserve Sharing Zone if the Zone's Most Severe Single Contingency exceeds the sum of (i) the Contingency Reserve Obligation for the Zone's Participating Balancing Authorities and (ii) the amount of Contingency Reserve that can be imported from adjacent Reserve Sharing Zones. This Zone adjustment is then summed with the adjustment from step two and added to the Participant's base Contingency Reserve Obligation to give Total Contingency Reserve Obligation.

The Reserve Sharing Computer System continuously monitors transfer limits ($LIMIT_{Pathnn}$), actual flows ($ACTUAL_{Pathnn}$), and, where applicable, scheduled flows ($SCHED_{Pathnn}$) on transmission facilities connecting Reserve Sharing Zones.

If, after accounting for Contingency Reserve Obligation that can be delivered from adjacent Reserve Sharing Zones, the combined Contingency Reserve Obligations within the Zone is less than the Zone's Most Severe Single Contingency, this shortfall is allocated among the Zone's Participating Balancing Authorities in proportion to their relative shares of the aggregate Contingency Reserve Obligations (as calculated through steps one and two) for the Reserve Sharing Zone.

The formulas for adjusting Contingency Reserve Obligations, if necessary, for the Most Severe Single Contingency for a Reserve Sharing Zone are as follows:

If $S\,(CRO_{CA} + AdjCRO\_MSSC_{CA}) + ASDEL_{ZONE} < MSSC_{ZONE}$, then

$CRO\_SHORT_{ZONE} = MSSC_{ZONE} - (S\,(CRO_{CA} + AdjCRO\_MSSC_{CA}) + ASDEL_{ZONE})$

and

$AdjCRO\_ZONE\_MSSC_{CA} = CRO\_SHORT_{ZONE} * (CRO_{CA} + AdjCRO\_MSSC_{CA}) / S\,(CRO_{CA} + AdjCRO\_MSSC_{CA})$

and

$AdjCRO_{CA} = AdjCRO\_MSSC_{CA} + AdjCRO\_ZONE\_MSSC_{CA}$

and

$TotCRO_{CA} = CRO_{CA} + AdjCRO_{CA}$

Where,

$S\,CRO\_MSSC_{CA}$ = the sum of Contingency Reserve Obligations for all Participating Balancing Authorities in the Reserve Sharing Zone (as calculated through steps one and two);

CRO_MSSC_{CA} = the Contingency Reserve Obligation for a Participating Balancing Authority in the Reserve Sharing Zone, as adjusted to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group;

$ASDEL_{ZONE}$ = the amount of Assistance Reserve that can be delivered to the Reserve Sharing Zone from adjacent Reserve Sharing Zones, after accounting for relevant transfer limits, actual flows, and if applicable, scheduled flows on transmission facilities connecting Reserve Sharing Zones;

$MSSC_{ZONE}$ = the Most Severe Single Contingency for the Reserve Sharing Zone;

CRO_SHORT_{ZONE} = the amount by which the Most Severe Single Contingency for the Reserve Sharing Zone exceeds the sum of (i) the aggregate Contingency Reserve Available of the Participating Balancing Authorities in the Reserve Sharing Zone (S CRO_MSSC_{ZONE}), plus (ii) amount of Assistance Reserve that can be delivered to the Reserve Sharing Zone from adjacent Reserve Sharing Zones ($ASDEL_{Lim}$);

CRO_{CA} = the Participating Balancing Authority's Contingency Reserve Obligation;

$AdjCRO\_ZONE\_MSSC_{CA}$ = the additional amount of Contingency Reserve a Participating Balancing Authority needs to carry to reflect the Most Severe Single Contingency for the Reserve Sharing Zone;

$AdjCRO\_MSSC_{CA}$ = the adjustment to the Participating Balancing Authority's base Contingency Reserve Obligation to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group;

$AdjCRO_{CA}$ = the total adjustment amounts to be added to a Participant's base Contingency Reserve Obligation to reflect any applicable adjustments for the NWPP Reserve Sharing Group's Most Severe Single Contingency and the Most Severe Single Contingency for a Reserve Sharing Zone; and

$TotCRO_{CA}$ = the Participating Balancing Authority's Contingency Reserve Obligation as adjusted to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group and for its Reserve Sharing Zone.

$MSSC_{ZONE}$ is revised whenever the output of the generator (or loading of the transmission line) that sets the $MSSC_{ZONE}$ increases or decreases by one MW or more.

d. Step Four – Calculation of Aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group and Check for NWPP Reserve Sharing Group Shortfall:

The fourth step in the process calculates the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group and makes sure the total Contingency Reserve Available within the NWPP Reserve Sharing Group is at least equal to the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group.

The aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group is calculated by summing the total Contingency Reserve Obligations (as calculated in steps one through three) for all Participants' Balancing Authority Areas.

The formula for this step is as follows:

$TotCRO_{NWPP} = S\ TotCRO_{CA}$

Where,

$TotCRO_{NWPP}$ = the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group; and

$S\ TotCRO_{CA}$ = the sum of the total Contingency Reserve Obligations of all Participating Balancing Authorities, as adjusted to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group and for applicable Reserve Sharing Zones.

If the Contingency Reserve Available within the NWPP Reserve Sharing Group is less than the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group, the difference between these two figures (the "shortfall") is allocated among the Participating Balancing Authorities in proportion to their relative shares of the NWPP Reserve Sharing Group's Contingency Reserve Obligation (without factoring in adjustments for shortfalls within a Reserve

Sharing Zone). This results in an upward adjustment to the Contingency Reserve Obligation for each Participant's Balancing Authority Area(s).

The formulas for this final check are as follows:

If $TotAvailCR_{NWPP} < TotCRO_{NWPP}$, then

$TotCRO\_SHORT_{NWPP} = TotCRO_{NWPP} - TotAvailCR_{NWPP}$

and

$AdjCRO\_SHORT_{CA} = (TotCRO\_SHORT_{NWPP} * (CRO_{CA} + AdjCRO\_MSSC_{CA}) / S (CRO_{CA} + AdjCRO\_MSSC_{CA}))$

Where,

$TotCRO_{NWPP}$ = the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group;

$TotAvailCR_{NWPP}$ = the total amount of Contingency Reserve Available in the NWPP Reserve Sharing Group;

$TotCRO\_SHORT_{NWPP}$ = the amount by which the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group exceeds the total Contingency Reserve Available;

CRO_{CA} = the Participating Balancing Authority's base Contingency Reserve Obligation as calculated in steps one;

$AdjCRO\_SHORT_{CA}$ = the adjustment to the Participating Balancing Authority's Contingency Reserve Obligation to reflect the shortfall in total Contingency Reserve Available; and

$AdjCRO\_MSSC_{CA}$ = the adjustment to the Participating Balancing Authority's base Contingency Reserve Obligation to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group.

Each Participant must add the adjustment amount ($AdjCRO\_SHORT_{CA}$) to the total Contingency Reserve Obligation for its Balancing Authority Area(s) as calculated in step three ($TotCRO_{CA}$) and stand ready to deploy the combined amount of Contingency Reserve Available (excluding amounts already deployed to respond to a Qualifying Event) at all times for use as Internal Reserve and Assistance Reserve.

The NWPP Reserve Sharing Group will experience a shortfall only if one or more Participants have not fully met their Contingency Reserve Obligations.

2. Permitted Amounts and Types of WECC Operating Reserve - Supplemental

A Participating Balancing Authority's Contingency Reserve Obligation(s) may be met with WECC Operating Reserve - Supplemental, provided that any WECC Operating Reserve - Supplemental applied to a Participating Balancing Authority's Contingency Reserve Obligation can be made fully effective within 10 minutes.

<u>Permitted Sources of WECC Operating Reserve - Supplemental</u>

A Participating Balancing Authority is permitted to use WECC Operating Reserve - Supplemental to meet a portion of its Contingency Reserve Obligation(s) calculated in accordance with Section 1 of this Attachment A, the following may be used as sources of WECC Operating Reserve - Supplemental:

1. WECC Operating Reserve - Spinning,

2. WECC Operating Reserve - Supplemental,

3. Interchange Transactions designated by the Source Balancing Authority as WECC Operating Reserve - Supplemental,

4. Reserve held by other entities by agreement that is deliverable on Firm Transmission Service,

5. A resource, other than generation or load, that can provide energy or reduce energy consumption,

6. Load, including demand response resources, demand-side management resources, direct control load management, interruptible load or interruptible demand, or any other load made available for curtailment by the Participating Balancing Authority or the NWPP Reserve Sharing Group via contract or agreement, and

7. All other load, not identified in the foregoing items, once a Reliability Coordinator for the Northwest Power Pool has declared an energy emergency alert signifying that interruption of Firm Demand is imminent or in progress.

3. Participating Balancing Authority Calculation of Contingency Reserve Obligation(s) When Communications with Reserve Sharing Computer System Are Disrupted

During periods when communication links between a Participating Balancing Authority and the Reserve Sharing Computer System are down, or when the Reserve Sharing Computer System is unavailable, responsibility for calculating Contingency Reserve Obligations shifts to the Participating Balancing Authority. Any Participating Balancing Authority that is unable to access the Reserve Sharing Computer System's calculation of its Contingency Reserve Obligations should use good-faith estimates of the inputs needed to determine its Contingency Reserve Obligation, based on the last available input data known to be valid, and apply as many of the steps described in Section 1 of this Attachment A as it can, consistent with good utility practice. The Participating Balancing Authority should continue this process, adjusting as appropriate for relevant changes to system conditions, until availability of and communications with the Reserve Sharing Computer System are restored.

Attachment B

Qualifying Events

A "Qualifying Event" is any single event described in subsections (A), (B), (C), or (D) below, or any series of such otherwise single events, with each separated from the next by one minute or less. Any capitalized term used below that is not defined within this document has the meaning given to it in the NERC Glossary. This Attachment B may be modified from time to time by action of the RSG Committee.

(A) Sudden Loss of Generation

a. due to
   i. unit tripping (*see note 1 below), or*
   ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or
   iii. sudden unplanned outage of transmission Facility;

b. and, that causes an unexpected change to the responsible entity's ACE (*see note 2 below*)

(B) Sudden Loss of an Import

a. due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection. (*See note 3 below*).

(C) Sudden Restoration of Demand

a. that was used as a resource that causes an unexpected change to the responsible entity's ACE

(D) Energy Emergency Alert

a. where a Participating Balancing Authority's inability to meet Firm Demand such that the Participating Balancing Authority has requested its Reliability Coordinator to declare, and the Reliability Coordinator has declared an Energy Emergency Alert 3 (as described in NERC Standard EOP-011 or a successor standard) the Participant:
   i. May utilize its CRO to serve Firm Demand while the Participant is in an EEA 3;

ii. Must keep the RSG Computer System current with any portion of its Contingency Reserve Available already in use ($UsedCR_{CA}$);

iii. Should reach out to neighboring BA's to verify no energy is available;

iv. Should reach out to cut-plane monitors for limit verification of any cut-planes with constraints impacting the BA's ability to receive Assistance Reserves;

v. May request Assistance Reserve through the NWPP Reserve Sharing Program for up to 60 minutes to prevent shedding Firm Demand, not to restore their Contingency Reserves.

1. Once the timeframe above has been depleted, then the Participant may continue to utilize its CRO to server Firm Demand. The Participant may need to shed Firm Demand to maintain Reporting ACE until the Participant is no longer in an EEA 3.

<u>Note 1</u>:

For purposes of this Attachment B, the term "unit tripping" means:

(1) the automatic operation of a device or capability designed to protect a power-producing resource from damage, or

(2) the unexpected failure of a power-producing resource to maintain, increase, or remain available due to equipment failure, or

(3) the unexpected failure of a power-producing resource to start (a) due to equipment failure, and (b) not associated with the failure to procure fuel,

which, in all cases, results in loss of MW output serving (or needed to serve) one or more Participants' Demand obligations.

<u>Note 2:</u>

The events described in Note 1 are Qualifying Events even when they do not result in an immediate change to the responsible entity's ACE.

<u>Note 3</u>:

Given typical operating practices followed in the Western Interconnection, the loss of an import would generally be expected to result in a corresponding adjustment to generation.

Attachment C

Reserve Sharing Zones and Assistance Reserve Responder Levels

Each Reserve Sharing Zone, as identified in the table below, has one or more Balancing Authority Participants.

Zones	Balancing Authority Participants
Alberta (AB)	AESO
Arizona -Nevada (AZNV)	AZPS, BNBA, DEAA, GRID, SRP, TEPC, WALC & NEVP
British Columbia (BC)	BCHA
Eastern Colorado (ECO)	PSCO
Mountain West (MTWEST)	IPCO & PACE
Northern California (NCAL)	BANC & TID
Pacific Northwest – Montana (PNWMT)	AVA, AVRN, BPA, CHPD, DOPD, GCPD, GRID, GWA, NWMT, PACW, PGE, PSEI, SCL, TPWR, & WAUW
Southern California (SCAL)	IID
Texas – New Mexico (TXNM)	EPE & PNM
Western Colorado (WCO)	WACM

Assistance Reserve Responder Levels

Each Reserve Sharing Zone has multiple levels for providing Assistance Reserve. Level 1 is the list of initial providers. If there is insufficient Assistance Reserve at Level 1 or there are transmission constraints between Reserve Sharing Zones, additional zones will be included by moving out one level at a time until there is sufficient Assistance Reserve or all Participating Balancing Authorities are included.

		Responding Zone									
		AB	AZNV	BC	ECO	MTWEST	NCAL	PNWMT	SCAL	TXNM	WCO
Requesting Zone	AB	-	4	1	6	3	3	2	5	5	5
	AZNV	5	1	4	3	2	4	3	1	1	2
	BC	1	3	-	5	2	2	1	4	4	4
	ECO	6	2	5	-	3	5	4	3	3	1
	MTWEST	3	2	2	4	1	2	1	3	3	3
	NCAL	4	4	3	6	2	1	2	5	5	5
	PNWMT	3	3	2	5	2	2	1	4	4	4
	SCAL	5	1	4	3	2	4	3	-	1	2
	TXNM	5	1	4	3	2	4	3	1	1	2
	WCO	6	2	5	1	3	5	4	3	3	-

Alberta Zone (AB)

Level 1: BC
Level 2: BC + PNWMT
Level 3: BC + PNWMT + MTWEST + NCAL
Level 4: BC + PNWMT + MTWEST + NCAL + AZNV
Level 5: BC + PNWMT + MTWEST + NCAL + AZNV+ SCAL + TXNM + WCO
Level 6: BC + PNWMT + MTWEST + NCAL + AZNV+ SCAL + TXNM + WCO + ECO

Arizona Nevada Zone (AZNV)

Level 1: AZNV + SCAL + TXNM
Level 2: AZNV + SCAL + TXNM + MTWEST + WCO
Level 3: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT
Level 4: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT + BC + NCAL
Level 5: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT + BC + NCAL + AB

British Columbia Zone (BC)

Level 1: AB + PNWMT
Level 2: AB + PNWMT + MTWEST + NCAL
Level 3: AB + PNWMT + MTWEST + NCAL + AZNV

Level 4: AB + PNWMT + MTWEST + NCAL + AZNV + SCAL + TXNM + WCO
Level 5: AB + PNWMT + MTWEST + NCAL + AZNV + SCAL + TXNM + WCO + ECO

Eastern Colorado Zone (ECO)
Level 1: WCO
Level 2: WCO + AZNV
Level 3: WCO + AZNV + MTWEST + SCAL + TXNM
Level 4: WCO + AZNV + MTWEST + SCAL + TXNM + PNWMT
Level 5: WCO + AZNV + MTWEST + SCAL + TXNM + PNWMT + BC
Level 6: WCO + AZNV + MTWEST + SCAL + TXNM + PNWMT + BC + AB

Mountain West Zone (MTWEST)
Level 1: MTWEST + PNWMT
Level 2: MTWEST + PNWMT + AZNV + BC + NCAL
Level 3: MTWEST + PNWMT + AZNV + BC + NCAL + AB + SCAL + TXNM + WCO
Level 4: MTWEST + PNWMT + AZNV + BC + NCAL + AB + SCAL + TXNM + WCO + ECO

Northern California Zone (NCAL)

Level 1: NCAL
Level 2: NCAL + MTWEST + PNWMT
Level 3: NCAL + MTWEST + PNWMT + BC
Level 4: NCAL + MTWEST + PNWMT + BC + AB + AZNV
Level 5: NCAL + MTWEST + PNWMT + BC + AB + AZNV + SCAL + TXNM + WCO
Level 6: NCAL + MTWEST + PNWMT + BC + AB + AZNV + SCAL + TXNM + WCO + ECO

Pacific Northwest-Montana Zone (PNWMT)

Level 1: PNWMT
Level 2: PNWMT + BC + MTWEST+ NCAL
Level 3: PNWMT + BC + MTWEST+ NCAL + AB + AZNV
Level 4: PNWMT + BC + MTWEST+ NCAL + AB + AZNV + SCAL + TXNM + WCO
Level 5: PNWMT + BC + MTWEST+ NCAL + AB + AZNV + SCAL + TXNM + WCO + ECO

Southern California Zone (SAL)

Level 1: AZNV + TXNM
Level 2: AZNV + TXNM+ MTWEST + WCO
Level 3: AZNV + TXNM+ MTWEST + WCO + ECO + PNWMT
Level 4: AZNV + TXNM+ MTWEST + WCO + ECO + PNWMT + BC + NCAL
Level 5: AZNV + TXNM+ MTWEST + WCO + ECO + PNWMT + BC + NCAL + AB

Texas New Mexico Zone (TXNM)

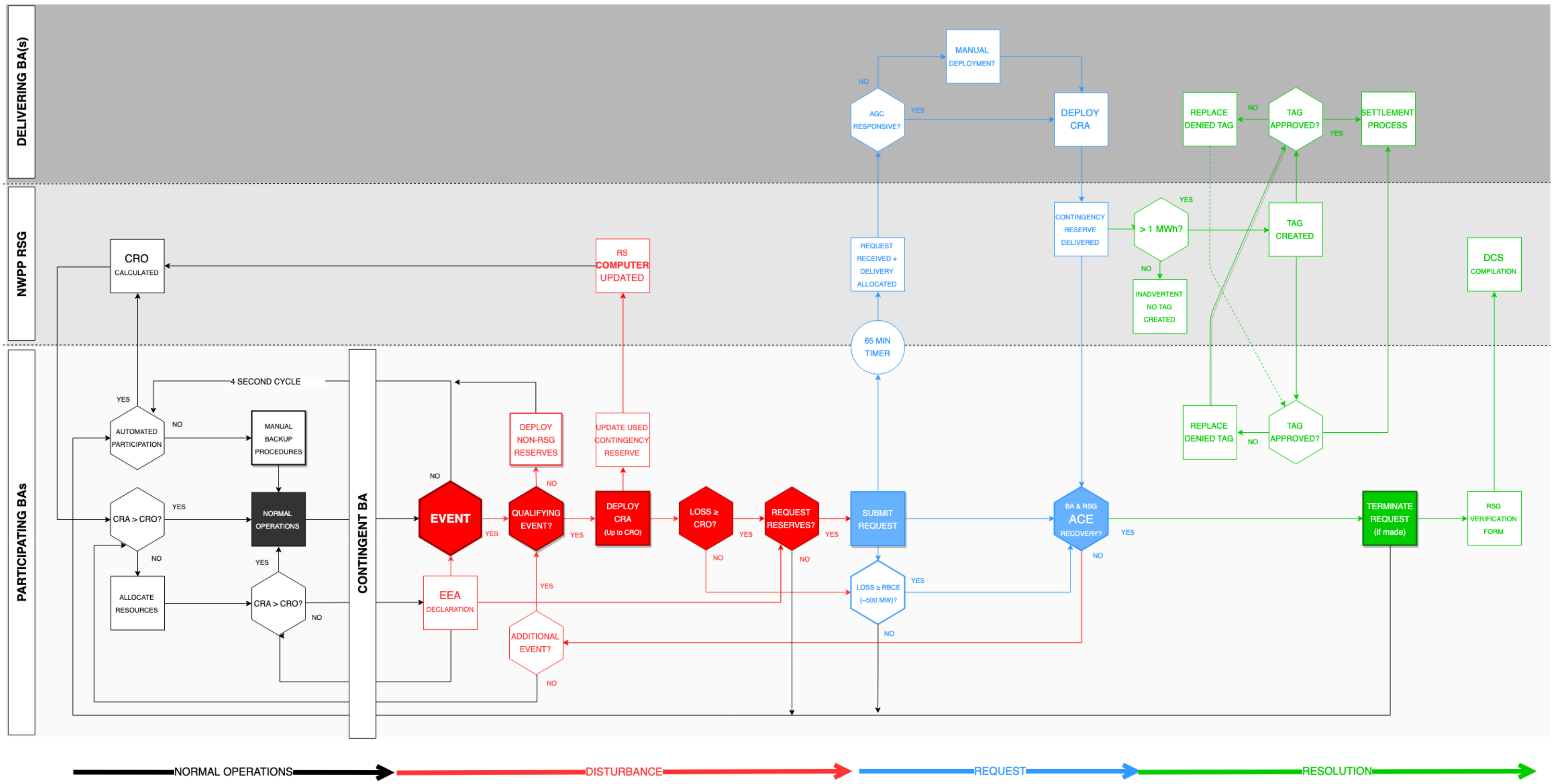
Level 1: AZNV + SCAL + TXNM
Level 2: AZNV + SCAL + TXNM + MTWEST + WCO
Level 3: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT
Level 4: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT + BC + NCAL
Level 5: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT + BC + NCAL + AB

<u>Western Colorado Zone (WCO)</u>

Level 1: ECO
Level 2: ECO + AZNV
Level 3: ECO + AZNV + MTWEST + SCAL + TXNM
Level 4: ECO + AZNV + MTWEST + SCAL + TXNM + PNWMT
Level 5: ECO + AZNV + MTWEST + SCAL + TXNM + PNWMT + BC + NCAL
Level 6: ECO + AZNV + MTWEST + SCAL + TXNM + PNWMT + BC + NCAL + AB

Attachment D

NWPP Process Charts



CONTINGENCY RESERVE OBLIGATION (CRO)

- Zonal MSSC
- 3% GENERATION + 3% LOAD

QUALIFYING EVENTS

- Sudden Loss of Generation
- Sudden Loss of an Import
- Sudden Restoration of a Demand
- Energy Emergency Alert

Four Minute Requirement

- 4 min allows adequate response time for ACE
- < 4 mins - RSG responsible
- > 4 mins - BA responsible if compliance failure occurs

RESERVE REQUESTS

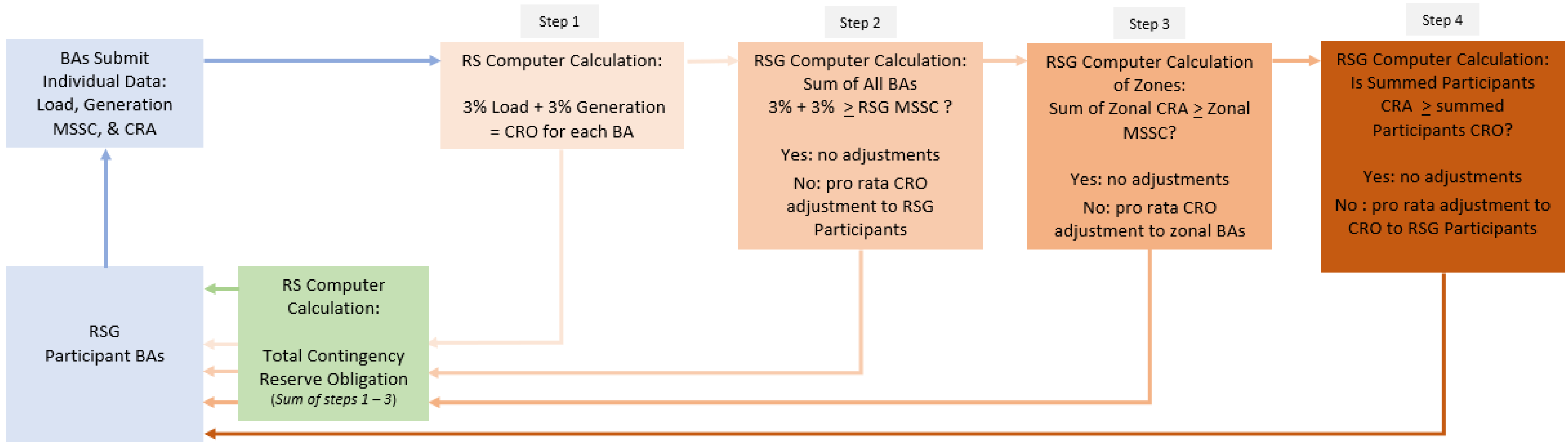
- Request is optional
- **RBCE = Reportable Balancing Contingency Event**

SETTLEMENT

- Powerdex Mid-Columbia Hourly Index

Northwest Power Pool
RESERVE SHARING PROGRAM
PROCESS CHART v19

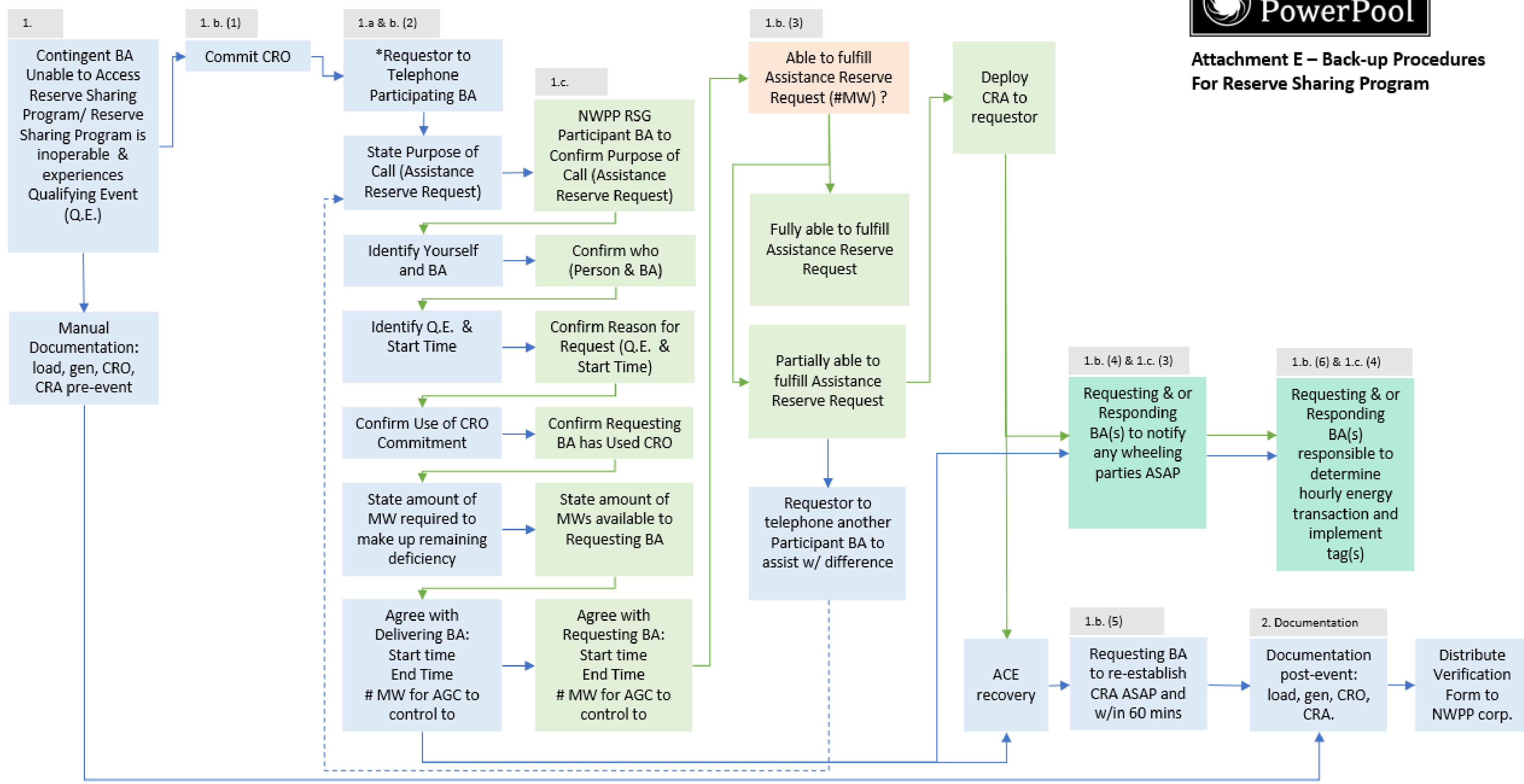
Attachment A – Calculation of CRO



ICCP outputs for each step:
Step 1: BA-CRO
Step 2: BA-ADJ_MSSC_POOL
Step 3: BA-ADJ_MSSC_ZONE
Step 4: BA-ADJCRO_POOL

Total Contingency Reserve Obligation ICCP output: BA-TOTCRO

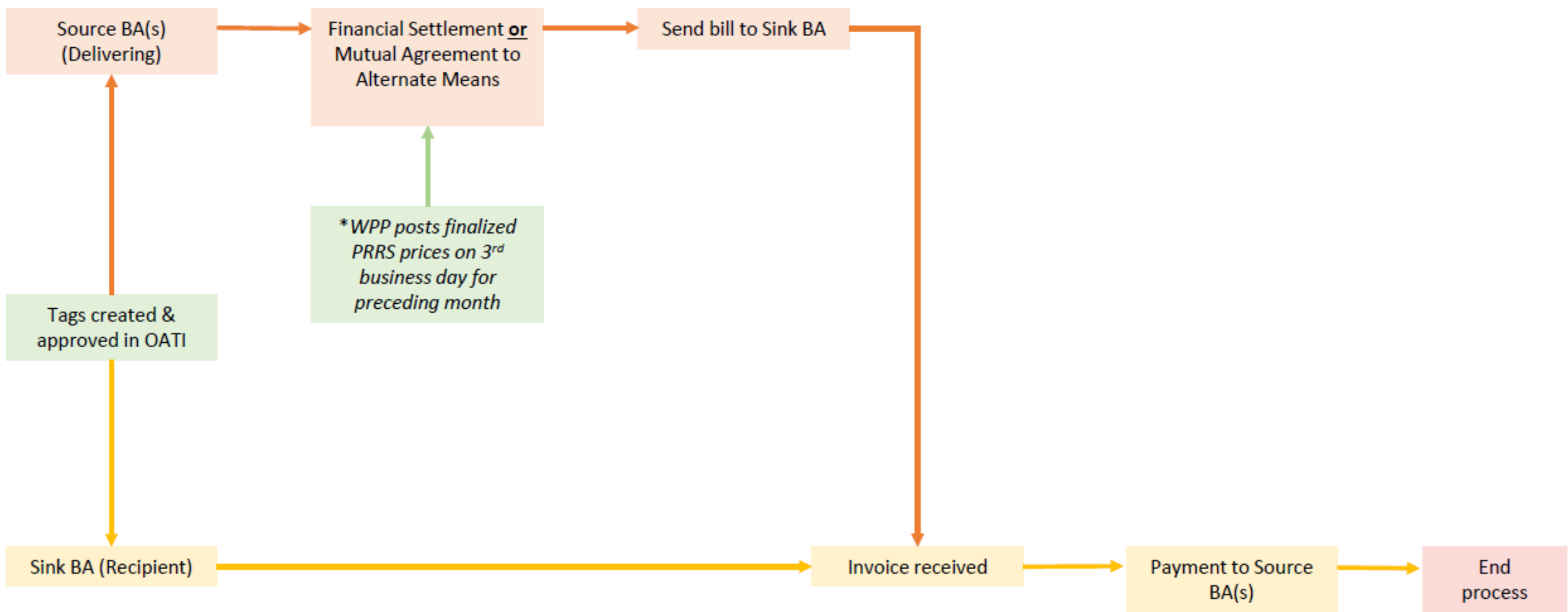
Attachment E – Back-up Procedures For Reserve Sharing Program



* To minimize potential transmission problems call adjacent BA first. If adjacent BA is unable to fulfill Assistance Reserve Request, contingent BA should move and call next adjacent BA. The process would be the same if the adjacent BA is able to partially fill request or unable to fill request.

NORTHWEST PowerPool

Section K – Settlement Process



Attachment E

BACKUP PROCEDURES FOR RESERVE SHARING PROGRAM

1. Participant Cannot Access Reserve Sharing Computer System or Reserve Sharing Computer System Is Inoperable

Reserve Sharing Requests and delivery of Assistance Reserve are normally implemented through the Reserve Sharing Computer System. When the Reserve Sharing Computer System is inoperable or inaccessible, a Participant that needs to make a Reserve Sharing Request should contact other Participants by telephone to request Assistance Reserve. Attachment D reflects the respective process described in this attachment. The provisions below (Sections 1.a, 1.b, and 1.c) will apply for the manual backup procedure. The settlement process for delivery of Assistance Reserve using the backup procedure is the same as for the automated reserve sharing process, except that requesting and responding Participants must agree (on a case-by-case basis) to any reserve sharing transactions instead of obtaining the information from the Reserve Sharing Computer System. This process must be in accordance with Attachment G for production of after-the-fact tags and in accordance with existing reliability standards and regional business practices.

a. Transmission Limitations; Adjacent Utilities

To minimize potential transmission problems, whenever possible a Participant that needs to request Assistance Reserve by telephone should contact an adjacent Participant first.

b. Backup Reserve Sharing Procedure – Telephone Requests

Because NERC BAL-002-3 requires recovery of Reporting ACE within 15 minutes, the number of telephoned assistance requests that a Participant's dispatcher can make is limited. To enhance Participants' ability to meet this standard, Participants may use the following procedure (and Participants may use any economic arrangements under existing contracts by mutual agreement at any point in the following sequence):

(1) As provided in Section E.2, a Participant must commit its Internal Reserve up to the full amount of its Contingency Reserve Obligation before requesting Assistance Reserve.

(2) If a Participant that has deployed its Contingency Reserve Obligation and needs additional capacity to meet the 15-minute criterion, that Participant may call another Participant for assistance. The responding Participant will make available its unused Contingency Reserve Available up to its Contingency Reserve Obligation.

The caller must:

(a) state that the purpose of the call is to make a Reserve Sharing Request,

(b) identify who is making the request,

(c) identify the Qualifying Event it has experienced and the start time of the event,

(d) confirm that it committed to use Contingency Reserve up to the full amount of its Contingency Reserve Obligation to respond to the event,

(e) state the amount of Assistance Reserve that is required to make up the remaining deficiency, and

(f) agree with the responding Participant on the amount, start-time, and end-time of the Contingency Reserve delivery to be entered into the AGC controller total. The end-time may be shortened thereafter, if the requesting Participant determines that it does not need Assistance Reserve through the original end-time.

(3) If the Assistance Reserve made available and delivered from the responding Participant is insufficient to cover the Qualifying Event, the requesting Participant will cover the remaining deficit by requesting Assistance Reserve from another Participant.

(4) As soon as possible, the requesting Participant must notify any intermediate wheeling Balancing Authority(s) of the scheduled delivery of Assistance Reserve and its duration. Each Participating Balancing Authority that is needed for intermediate wheeling will make transmission capacity available up to its maximum operating limit by any means necessary including the curtailment of interruptible schedules.

(5) The Participant requesting assistance must re-establish its Contingency Reserve Available that is ready for deployment (to at least the level of its Contingency Reserve Obligation) as soon as possible by adding generation, adjusting interchange schedules, or dropping load. As provided in Section F.3, a Participant that requests Assistance Reserve must relinquish the Assistance Reserve within 60 minutes following the start of the Qualifying Event.

(6) Any Participant that requests Assistance Reserve must contact the party within its organization that is responsible for energy scheduling and notify that party of the actions taken to request Assistance Reserve. The party responsible for scheduling must then contact its counterpart from the responding Participant to determine an agreed-upon hourly energy transaction and to agree on transaction wheeling amounts in accordance with the paths identified in the Participants pre-defined tag templates.

c. Backup Reserve Sharing Procedure – Telephone Responses

The following responses may be appropriate for a Participant that receives a Reserve Sharing Request by telephone:

(1) If a Participant that has deployed its Contingency Reserve needs additional capacity to meet the 15-minute criterion, that Participant may call another Participant for assistance.

The responding Participant will make available its unused Contingency Reserve up to its Contingency Reserve Obligation.

(2) The Participant that is being asked to provide Assistance Reserve may make the following responses:

(a) confirm that the purpose of the call is to make a Reserve Sharing Request,

(b) confirm who is making the request,

(c) confirm the reason for the request (*e.g.*, identify the Qualifying Event and the start time of the event),

(d) confirm that the requesting Participant has committed to use Contingency Reserve Available up to the full amount of its Contingency Reserve Obligation to respond to the event,

(e) state the amount of Assistance Reserve available to the requesting Participant,

(f) agree with the requesting Participant on the amount, start-time, and end-time of the Assistance Reserve to be entered into the AGC controller total.

(3) As soon as possible, the responding Participant should notify any intermediate wheeling Balancing Authority(s) of the scheduled delivery of Assistance Reserve energy and its duration. Each Participating Balancing Authority that is needed for intermediate wheeling will make transmission capacity available up to its maximum operating limit by any means necessary including the curtailment of interruptible schedules.

(4) Any Participant that provides Assistance Reserve must contact the party within its organization that is responsible for energy scheduling and notify that party of the actions taken to provide Assistance Reserve. The party responsible for scheduling must then contact its counterpart from the requesting Participant to determine an agreed-upon hourly energy transaction.

2. Documentation

Any Participant that requests Assistance Reserve using the backup procedures in this Attachment E must document its load, generation, Contingency Reserve Obligation, and Contingency Reserve Available immediately before the Qualifying Event. It must document the amount of its capacity lost or other characteristics of the Qualifying Event, the amount and components of Contingency Reserve deployed, and the amount of Assistance Reserve requested and received. The requesting Participant must also comply with Attachment G, Backup Process for After-the Fact Reserve Sharing Tags.

NWPP RSG Verification Forms are available on the WPP Website. The requesting Participant must send this documentation to all responding Participants, and to the WPP Staff, on the next working day.

Attachment F

TRANSMISSION MAPPING AND TAG TEMPLATE CHANGE PROCESS

A. Process for Changing Tagging Templates Delivery Paths Between NWPP Reserve Sharing Participants

1. Any Participant that wishes to request a change to the transmission mapping set forth in Participants' pre-defined tag templates must first obtain the agreement of all other Participants that would be affected by the requested change.
2. All affected Participants must be given adequate time to make any software changes to downstream or legacy scheduling systems.
3. Participant(s) requesting the change must complete any necessary registrations (or updates to registrations) related to the NAESB Electric Industry Registry (EIR) and Western Interchange Tool (WIT) Registry, or any successor industry registration systems.
4. Participants must submit requests for changes to the tag templates to the WPP Staff.
5. OATI will coordinate testing of the new or revised tag templates and confirm that the templates will pass WIT Registry validations.
6. WPP Staff and the affected Participants will coordinate with OATI to determine an implementation date and time for the new templates.
7. WPP Staff will advise all Participants of the implementation date for the revised templates.
8. OATI will make appropriate tag template changes effective as of the implementation date and time.

B. Process for Changing Tag Templates with No Change to Delivery Paths

(No Impact to Other Balancing Authorities)

1. The Participant with changes will notify the WPP Staff and provide WPP Staff with required changes to its tag templates.
2. The Participant with changes will complete any necessary EIR and WIT registrations or updates.
3. WPP Staff will communicate the requested changes to OATI.
4. OATI will coordinate testing of new or revised tag templates and confirm that the templates will pass WIT validations.

5. WPP Staff and the requesting Participant will determine an implementation date and time for the new tag templates.
6. OATI will make appropriate tag template changes effective as of the implementation date and time.
7. OATI will provide the WPP with the most current workbook of NWPP tag templates.

C. Process for Adding a New Participant to NWPP Reserve Sharing Program

1. WPP Staff will provide a newly admitted Participant(s) with the tag templates for further development to reflect the inclusion of the new Participant(s). If a new Reserve Sharing Zone is required, Attachment C will be revised to reflect the addition of a new Reserve Sharing Zone.
2. The New Participant(s) will provide WPP Staff with a workbook containing only their newly developed tag matrix (to and from each Participant BA) of completed tag templates.
3. WPP Staff will assist with distribution of these new tag templates to all Participants for review as required.
4. Participant(s) must review the new templates and implement any necessary changes to their own accounting and billing systems.
5. WPP Staff will communicate approved new tag templates to OATI.
6. OATI will coordinate testing of the new tag templates and confirm that the templates will pass WIT validations.
7. WPP Staff and all Participants will determine an implementation date and time for the new templates.
8. WPP Staff will advise all Participants of the implementation date and time for the new templates.
9. OATI will make the new tag templates effective as of the implementation date and time.

Attachment G

Backup Process for After-The-Fact Reserve Sharing Tags

A. Failure of Participant Internal Program or Reserve Sharing Computer System

If a Participant that has requested Assistance Reserve (or is providing Assistance Reserve) experiences a failure of any internal program related to reserve sharing, or if a Reserve Sharing Request is made or in effect during a time when the Reserve Sharing Computer System is not functioning, then the Participants receiving and providing Assistance Reserve energy will be responsible for all necessary after-the-fact tagging.

B. Failure of Automated After-the-Fact Tagging Process

If the automated tag creation process fails,

1. WPP Staff will
   a. contact OATI and coordinate the next possible time OATI can rerun automated tag creation for the event;
   b. make reasonable efforts (and request that OATI make reasonable efforts) to give Participants at least 24 hours' advance notice before the reissuing of the tags, and if this is not possible, attempt to give notice as far in advance as feasible; and
   c. notify Participants by e-mail distribution of the re-issuance of the tags.
2. If the affected Participants anticipate that the automated tag creation process will not be able to reissue the tags before the after-the-fact tagging deadline, the sink Participant will coordinate with the source Participants to facilitate the sink Participant's efforts to manually issue after-the-fact tags according to the most recent reserve sharing tag templates.
3. Participants shall contact WPP Staff to resolve failure of the automated tag creation process during normal business hours.

C. Replacing Denied Reserve Sharing Tags

1. If one Participant denies an after-the-fact the tag (properly or not), the denying Participant will coordinate with all other Participants to facilitate the denying Participant's efforts to manually reissue the after-the-fact tag(s).

a. If the problem with the original tag was due to an error in the tag template, the denying Participant will immediately notify all other Participants listed in the template of the necessary correction.

b. Participants needing to correct a tag template will follow the appropriate procedures specified in Attachment F to make changes to the tag template.

2. If more than one Participant denies a tag, the sink Participant will coordinate with all other affected Participants to facilitate the sink Participant's efforts to manually reissue the after-the-fact tag.

c. If the problem with the original tag was due to an error in the tag template, the denying Participants will immediately notify all other Participants listed in the template of the necessary correction.

d. Participants needing to correct a tag template will follow the appropriate procedures specified in Attachment F to make changes to the tag template.

Attachment H

Balancing Authority Areas of the Participating Balancing Authorities

Alberta Electric System Operator (AESO)

Arizona Public Service Company (AZPS)

Arlington Valley, LLC (DEAA)

Avangrid Renewables, LLC (AVRN)

Avista Corporation (AVA)

Balancing Authority of Northern California (BANC)

British Columbia Hydro and Power Authority (BCHA)

Bonneville Power Administration (BPAT)

Chelan County Public Utility District (CHPD)

Douglas County Public Utility District (DOPD)

El Paso Electric Company (EPE)

First LightEnergy, LLC (BNBA)

Grant County Public Utility District (GCPD)

Gridforce Energy Management, LLC (GRID)

Idaho Power Company (IPCO)

Imperial Irrigation District (IID)

BHEM Power Watch, LLC (GWA)

Nevada Power (NEVP)

NorthWestern (NWMT)

PacifiCorp East (PACE)

PacifiCorp West (PACW)

Portland General Electric (PGE)

Public Service Company of Colorado (PSCo)

Public Service Company of New Mexico (PNM)

Puget Sound Energy (PSE)

Salt River Project Agriculture Improvement and Power District (SRP)

Seattle City Light (SCL)

Tacoma Power (TPWR)

Tucson Electric Power Company (TEPC)

Turlock Irrigation District (TID)

Western Area Power Administration – Desert Southwest Region (WALC)

Western Area Power Administration – Rocky Mountain Region (WACM)

Western Area Power Administration Upper Great Plains West (WAUW)

Attachment I

Reserved for Future Use

Attachment J

Reserved for Future Use

Attachment K

NWPP Reserve Sharing Group
MSSC and Long-Term Zonal MSSC Limit, Jointly Owned Dynamic Generation Resources, Jointly Owned Static Generation Resources, and Multi Use Transformer(s) Tables

1. Balancing Authority Area MSSC, NWPP Reserve Sharing Group Long-Term Zonal MSSC Limit, and NWPP Reserve Sharing Group Long-Term MSSC Limit.

The Participant Balancing Authorities have documented their BAA MSSCs in the table below which are used to derive the Long-Term Zonal MSSC Limit and the NWPP Reserve Sharing Group Long Term MSSC limit under normal system conditions.

Zone	Resource(s)	Reporting/ Operating BAA	Maximum Allowable Zonal MSSC MW	BAA System Normal MSSC MW	Plant Capability	Modeled Outage
Alberta	Genesse #3	AESO	466	466	1286	Loss of generation
Arizona - Nevada	Arlington Generation	AZPS	1122	565	600	Loss of transmission Line
	Arlington Valley	DEAA		580	600	Loss of transmission Line
	BrightNight PV Solar Project	BNBA		300	300	Loss of tie line
	Harquahala – Hassayampa Tie Line	SRP		975	1068	Loss of Transmission Line
	Gila River Blocks 2 &/ 3	TEPC		605	1100	Loss of generation
	Southpoint Energy Center	WALC		250	520	Loss of generation
	Silverhawk	NEVP		620	1055	Loss of transmission Line
British Columbia	Revelstoke – 3 Units	BCHA	1505	1505	2505	Revelstoke 500 kV main bus, three units (5MB2)
Eastern Colorado	Rush Creek Gen Tie	PSCO	1600	1600	1600	RAS Action
Southern California	El Centro Unit 3 / 230kV S-Line	IID	270	117/270	134	Loss of generation or line if scheduled greater than unit
Mountain West	Langley Gulch	IPC	1500	329	329	Unit trip of Langley Gulch – various issues
	Jim Bridger – 2 Units on RAS	PACE		1212	2120	RAS Action
Northern California	Consumnes	BANC	306	306	612	1X1 Generator outage, Gen Tie to plant
	Walnut Energy Center	TID		129	258	Loss of generation
Pacific Northwest - Montana	Noxon Plant RAS Trip	AVA	1500	540	550	Nox 239 East bus with RAS armed

	Schoolhouse	AVRN		598	598	Loss of John Day 239/500 kV transformer
	Columbia Generation Stn	BPAT		1180	1180	Loss of generation
	Rocky Reach – River Crossing 7-8-9	CHPD		410	1272	River crossing 7-8-9
	Wells	DOPD		168	840	Loss of generator step-up transformer (T1-T5) at Wells
	Wanapum – 4 Units	GCPD		440	1000	Trip of Wanapum Powerhouse #1 line or #2 line
	Centralia #2	GRID		710	710	Loss of generation
	BHE Power Watch	GWA		189	189	Loss of Hay Lakke-Rim Rock East & West 230 kV Generation Tie Line
	Clearwater	NWMT		750	1490	Loss of generation or generator lead line
	Chehalis	PACW		540	540	Loss of Napavine-Chehalis 500 kV line
	Carty	PGE		490	490	Loss of generation or generator lead line
	Penstemon Solar, Wild Horse Wind, Vantage Wind	PSE		382	382	230 kV Wind Ridge – Wanapum line
	Boundary Unit #55 or #56	SCL		234	1106	Loss of generation
	Mossyrock	TPWR		203	378	Generator – Transmission outage
	Fort Peck	WAUW		44	90	Loss of generation
Texas – New Mexico	Newman 5 in 2x1 configuration	EPE	900	228	268	Loss of generation
	Afton	PNM		235	235	Loss of generation
Western Colorado	Laramie River Station #2 or #3	WACM	570	570	570	Loss of generation

NWPP RSG Long-Term MSSC Limit	**Eastern Colorado Zone**		**1600**			

2. Jointly Owned Dynamic Generation Resources

This table below is a listing of jointly owned dynamic generation that could be considered a BCE under certain outage configurations.

Resource(s)	Reporting/ Operating BA	MSSC MW	Plant Capability	Balancing Authorities Participating in Jointly Owned Dynamic Generation	Capacity in MW as applicable
Four Corners 4	APS	770	1540	AZPS 70%	*
Four Corners 5		770		PNM 13%	*
				SRP 10%	*
				TEPC 7%	*
Pale Verde 1	APS	969	2907	APS	*
Pale Verde 2		969		EPE	*
Pale Verde 3		969		PNM	*
				SRP	*
Rock Island	CHPD	216	606	AVA 10%	*
				CHPD 50%	*
				PSE 40%	*
Rocky Reach – River Crossing 7-8-9	CHPD	410	1272	AVA 10%	*
				CHPD 44.46%	*
				DOPD 5.54%	*
				PSE 40%	*
Wells	DOPD	168	840	AVA	*
				CHPD	*
				DOPD	*
				PSE	`*

Resource(s)	Reporting/ Operating BA	MSSC MW	Plant Capability	Balancing Authorities Participating in Jointly Owned Dynamic Generation	Capacity in MW as applicable
Priest Rapids – 4 Units	GCPD	365	930	AVA	*
				GCPD	*
				PACW	*
				PGE	*
				PSE	*
				SCL	*
				TPWR	*
Wanapum - 4 units	GCPD	440	1000	AVA	*
				NWMT	*
				PACW	*
				PGE	*
				PSE	*
Colstrip 3 & 4	NWMT	740	1480	AVA	222
				NWMT	444
				PACW	148
				PGE	296
				PSE	370
					1480
Luna	PNM	570	570	PNM 66.33%	380
				TEPC 33.33 %	190
					570
Hermiston / Perennial	PACW	474	474	GRID	237
					237
					474

Resource(s)	Reporting/ Operating BA	MSSC MW	Plant Capability	Balancing Authorities Participating in Jointly Owned Dynamic Generation	Capacity in MW as applicable
Jim Bridger – RAS 2 Unit + Remote Wind	PACE	1212	2120	IPC	707
				PACE	1413
					2120
Gila River - *Blocks 1 & 4	SRP	550	2200	SRP 100%	1100
Gila River - *Blocks 2 & 3	TEPC	585		SRP 100%	1100
					2200
TEP and SRP have their own share based on blocks.					
**Under normal conditions this is not a JOU however SRP may report entire 2200MW based on N-4 conditions.*					
Springerville 1 & 2	**TEPC	450		TEP	*
Springerville 3	*PNM	458		PNM	*
				SRP	*
**PNM does not own the generation, but PNM ACE is affected by the loss of generation and must request MW during disturbances to recover.*					
***Under normal conditions this is not a JOU however TEP may report the entire amount based on potential N-4 conditions*					
Springerville 4	SRP	410		SRP	*

3. Jointly Owned Static Generation Resources

This table is a listing of jointly owned static generation that could be considered a BCE under certain outage configurations.

Resource(s)	Reporting/ Operating BA	MSSC MW	Plant Capability	Balancing Authorities Participating in Jointly Owned Dynamic Generation	Capacity in MW as applicable
Valmy	NEVP	268	395	IPC	134
				NEVP	261
					395

4. Multi Use Transformer(s)

This is a listing of transformers that are jointly utilized that could be a BCE under studied outage configurations.

Transformer(s)	Operating BA	Facility Rating	BA(s) with associated transformers	Generators	Generating Capacity in MW
John Day	BPA	1300 MVA	AVRN	Klondike I, II, III A, III GE, III Siemens, Starpoint, Hay Canyon, Golden Hills	809
			PGE	Biglow 1, Biglow 2, Biglow 3	450
					1259
Slatt	BPA	1300 MVA	AVRN	Montague Wind, Montague Solar	363
			BPA	Shepherds North (North Hurlburt)	265
			BPA	Shepherds South (South Hurlburt)	290
			BPA	Horseshoe Bend (Shepherds Central)	290
					1208
Rock Creek	BPA	1300 MVA	AVRN	Juniper Canyon, Lund Hil	299
			BPA	Windy Flats/Dooley	262
			BPA	White Creek Wind	205
			BPA	Harvest Wind	99
			PAC	Goodnoe Hills	150
					1015

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Attachment L

Cut Planes and Cut Plane Monitors Between Reserve Sharing Zones

The following is a listing of the NWPP Reserve Sharing Group Participants that are monitors of the major transfer facilities and cut planes between Reserve Sharing Zones:

1) The Alberta Electric System Operator Balancing Authority (AESO) monitors the cut plane connecting the Alberta Reserve Sharing Zone with the British Columbia Reserve Sharing Zone,

2) The Bonneville Power Administration (BPA) Balancing Authority monitors the cut plane connecting the Pacific Northwest-Montana Reserve Sharing Zone with the British Columbia Reserve Sharing Zone,

3) The Idaho Power (IPC) Balancing Authority monitors the cut plane connecting the Mountain West Reserve Sharing Zone with the Pacific Northwest-Montana Reserve Sharing Zone,

4) The Balancing Authority of Northern California Balancing Authority (BANC) monitors the cut plane connecting the Pacific Northwest-Montana Reserve Sharing Zone with the Northern California Reserve Sharing Zone,

5) The PacifiCorp (PAC) Balancing Authority monitors the cut plane connecting the Mountain West Reserve Sharing Zone with the Arizona Nevada Reserve Sharing Zone,

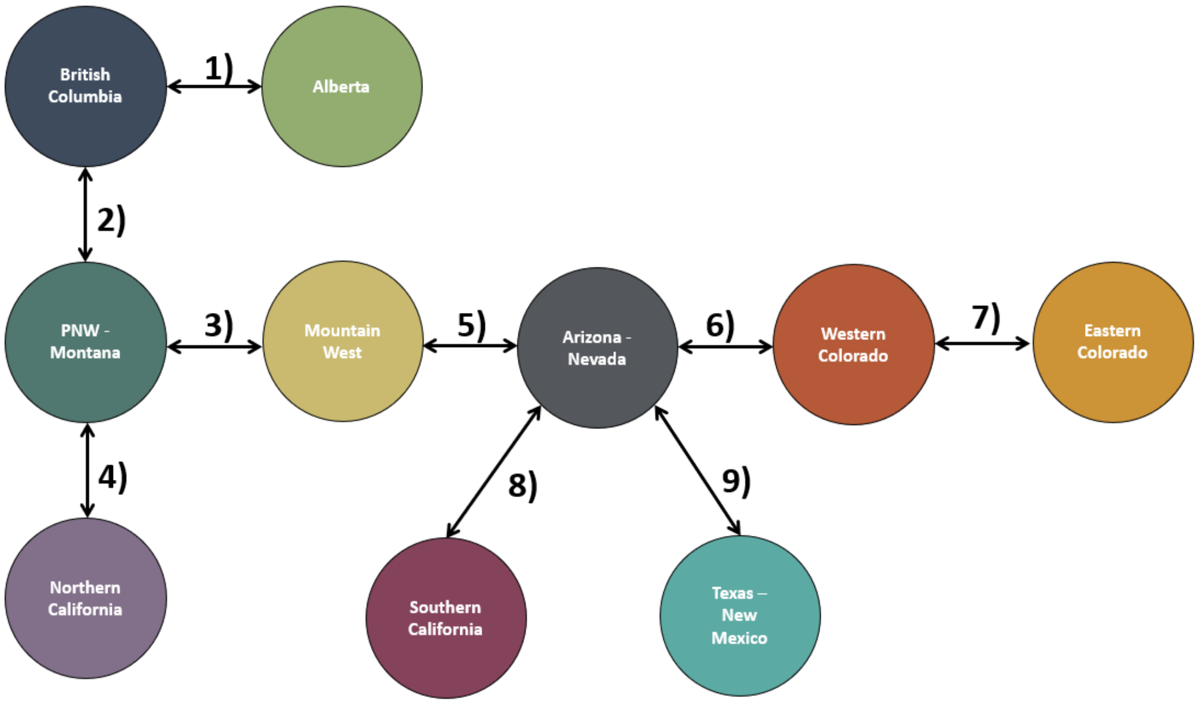
6) The Western Area Power Administration’s Rocky Mountain Region (WACM) and Lower Colorado (WALC) Balancing Authorities monitor the cut plane connecting the Arizona Nevada Reserve Sharing Zone with the Western Colorado Reserve Sharing Zone,

7) The Western Area Power Administration’s Rocky Mountain Region (WACM) Balancing Authority monitors the cut plane connecting the Western Colorado Reserve Sharing zone with the Eastern Colorado Reserve Sharing Zone,

8) The Imperial Irrigation District (IID) Balancing Authority monitors the cut plane connecting the Southern California Reserve Sharing zone with the Arizona Nevada Reserve Sharing Zone, and

9) The El Paso Electric Company (EPE) Balancing Authority monitors cut plane connecting the Arizona Nevada Reserve Sharing zone with the Texas New Mexico Reserve Sharing Zone.

See supporting picture of cut planes as identified above and represented between each of the zones:



Attachment M

Overview of BPA Remedial Action Schemes That Suspend Automatic Generation Control and Result in Expected Changes to NWPP Reserve Sharing Group Reporting ACE

Background:

This attachment (1) describes the operation and purposes of BPA Remedial Action Schemes (as defined in the NERC Glossary; also known as RAS) that are designed to drop generation and intentionally suspend Automatic Generation Control (AGC) actions to achieve the required flow mitigation effects of the RAS for transmission line outages that have large impacts to the integrity of the Western Interconnection, (2) explains why efforts by a Participating Balancing Authority or by the NWPP Reserve Sharing Group to immediately recover NWPP Reserve Sharing Group Reporting ACE following operation of this category of RAS would undermine the designed reliability benefits of the RAS, and (3) explains that the change in NWPP Reserve Sharing Group Reporting ACE that results from the planned, intentional generation dropping of these RAS is not unexpected and therefore does not meet the definition of a Balancing Contingency Event.

RAS Description:

For certain types of potential exceedances of System Operating Limits and Interconnection Reliability Operating Limits (SOL/IROL), BPA has designed RAS to intentionally drop generation and suspend related AGC actions. This category of RAS is intended to mitigate flow and stability impacts associated with various contingency events on transmission facilities. These transmission facilities are designed to operate at maximum transfer levels that rely on protection provided by the associated RAS. For example, RAS for the California-Oregon Intertie system (COI) and Pacific Direct Current Intertie system (PDCI) are in this category. There are other transmission facilities in the Northwest that also rely on this category of RAS to maximize transfer capability. Additional remedial actions for this category of RAS may include other actions such as fast switching of reactive devices and insertion of dynamic braking resistors.

This category of RAS intentionally suspends AGC within the BPA Balancing Authority and any other host Balancing Authorities of the associated generating units to avoid counteracting the intended flow mitigation benefit of the RAS. Even with AGC suspended, active governors of synchronized generators are expected to respond to the changed load-resource balance and resulting frequency drop. The Bulk Electric System within the Western Interconnection, including the affected areas, are expected to perform according to the BAL-003 requirements and immediately provide primary frequency control through governor action to arrest the frequency decline and stabilize the system.

Overall system recovery continues as the affected systems adjust transfers and generation or deploy contingency reserves, and the affected systems rebalance for the new level of transfers associated with the SOL/IROL. Each affected Balancing Authority restores its AGC once transfers are adjusted. Generation then ramps up (receiving areas with imports curtailed) or down (sending areas with exports curtailed) to the new required levels, which enables each affected Balancing Authority to recover its Reporting ACE.

The Significance of BPA RAS in Relation to Reporting ACE:

Because certain planned generation dropping through RAS action is intended to protect affected transmission facilities within the NWPP from overloads, instability, or cascading outages, any action by Participants in the NWPP Reserve Sharing Group to immediately recover Reporting ACE following these specific RAS events may adversely affect reliability of the Bulk Electric System. Changes to the NWPP Reserve Sharing Group's Reporting ACE due to RAS actions are expected and, as such, are not Balancing Contingency Events. Generation is dispatched appropriately to accommodate the post-RAS system configuration, which may take more than 15 minutes.

BPA is responsible for notifying the WPP Staff whenever an event involving operation of this category of RAS has occurred, and therefore 15-minute recovery of NWPP Reserve Sharing Group Reporting ACE is not expected for that event.

Attachment N

Correlation Table of Participants, Reliability Coordinators, and Reserve Sharing Zones

Participant	Reliability Coordinator	Zone	Transfer Date
AESO	AESO	AB	N/A
AZPS	RC West	AZNV	11/1/2019
DEAA	SPP	AZNV	12/1/2019
AVA	RC West	PNWMT	11/1/2019
AVRN	RC West	PNWMT	11/1/2019
BANC	RC West	NCAL	7/1/2019
BCHA	BCHydro RC	BC	9/2/2019
BNBA	SPP	AZNV	7/1/2025
BPAT	RC West	PNWMT	11/1/2019
CHPD	RC West	PNWMT	11/1/2019
DOPD	RC West	PNWMT	11/1/2019
EPE	SPP	TXNM	12/13/2019
GCPD	RC West	PNWMT	11/1/2019
GRID (North)	SPP	PNWMT	12/3/2019
GRID (South)	SPP	AZNV	12/1/2019
GWA	RC West	PNWMT	11/1/20219
IID	RC West	SCAL	7/1/2019
IPC	RC West	ID	11/1/2019
NVE	RC West	HD	11/1/2019
NWMT	RC West	PNWMT	11/1/2019
PACE	RC West	PNWMT	11/1/2019

PACW	RC West	PNWMT	11/1/2019
PGE	RC West	PNWMT	11/1/2019
PSCO	SPP	ECO	12/3/2019
PNM	RC West	TXNM	11/1/2019
PSEI	RC West	PNWMT	11/1/2019
SRP	RC West	AZNV	11/1/2019
SCL	RC West	PNWMT	11/1/2019
TEP	SPP	AZNV	12/1/2019
TID	RC West	NCAL	7/1/2019
TPWR	RC West	PNWMT	11/1/2019
WACM	SPP	WCO	12/3/2019
WALC	SPP	AZNV	12/1/2019
WAUW	SPP	PNWMT	12/3/2019

DOCUMENTATION HISTORY

Updates:	Date:
NWPP Reserve Sharing Program	1-18-2006
Accommodation for new Balancing Authorities: SMUD & TID	6-07-2007
Combining of SPP and PACE zones into SPP-PACE zone	3-31-2008
Update of section D.3 for jointly owned generation	5-18-2008
Accommodation for new Balancing Authorities: GWA	10-13-2008
Updated terminology and addition of Attachments F, G, and H.	1-30-2009
Update of Attachment D to reflect tag template updates	3-31-2009
Update for requirement omission from 10-13-2008 version to 01-30-2009 version	3-31-2009
Clarity to sections I.5.l and H.2	4-8-2009
Update for computer failure, continuance to deliver reserve for full 60 minutes	4-8-2009
Clarification to Attachment B – Covered contingencies	5-12-2009
Update to Attachment B – Loss of wind generation due to temperature	7-1-2009
Grammar revision to definition of “Reportable Disturbance”	7-30-2009
Accommodation of information for the ACE Diversity Interchange (ADI) program	10-15-2009
Update of Attachment D – transmission mapping between NWMT and PGE	11-1-2009
Clarifying revisions and reorganization throughout; addition of language to Attachment B specifying Operating Committee authority to designate additional “Qualifying Events”; addition of Attachment K	10-18-2010
British Columbia Hydro and Power Authority NERC Registry acronym change from BCTC to BCHA	12-1-2010
Addition of definition of “RSG Committee”; replacement of most references to Operating Committee and all references to NWPP Reserve Sharing Subcommittee with references to RSG Committee; Updates of Attachment K	4-6-2011
Revision to Attachment B – addition of energy emergency as a Qualifying Event	10-5-2011
Update to section K.3. Financial Settlement with Powerdex Mid-Columbia Hourly	1-1-2012
Update to definition of Single Contingency, Section J.1.f with additional request language, and Section K.3. Financial Settlement clarification	6-7-2012
Revisions to Section 1.a of Attachment A to incorporate new requirements for photovoltaic and other types of generation; threshold in second bullet of	

definition of "Reportable Disturbance" lowered from 190 MW to 170 MW and updates to Attachment K Tables 1 and 3 — 1-10-2013

Clarifying updates throughout document including the addition of Section D.3.f, revisions to Sections E.2, E.4, F and updates to Attachments B, C, F and K — 4-4-2013

Update to Attachment B and removal of (e) Unexpected loss of Contingency Reserve with new language to section (c) — 6-6-2013

Updates to Attachments D, H, and K for incorporation of the NaturEner Wind Watch BA, WWA into program documentation — 10-30-2013

Updates to Attachments D, H, and K for incorporation of the Constellation Energy Control and Dispatch BA, WWA into program documentation along with other clarifying updates throughout the document — 11-25-2013

Updates to Attachments C, D, H, and K to reflect Nevada Power Company (NEVP), as operator of the consolidated Balancing Authority Area encompassing the Balancing Authority Areas previously operated separately by Sierra Pacific Power Company (SPPC) and Nevada Power Company (NEVP) — 1-9-2014

Revisions throughout document to reflect implementation of WECC Standard BAL-002-WECC-2, to incorporate terms governing Loss of a Unit-Contingent Purchase, and to reflect the name change of the organization formerly known as Constellation Energy Control and Dispatch (CSTO) to Gridforce Energy Management, LLC (GRID) — 8-15-2014 – Effective 10-1-2014

Revisions to incorporate language concerning RSG compliance with R3 and R4 of WECC BAL-002-WECC-2 — 8-22-2014 – Effective 10-1-2014

Clarifying revisions to the description of Contingency Reserve Obligation calculation in Attachment A, with conforming changes in body of document and other minor clean-up items — 1-8-2015

Clarifying revisions to timing of requests for assistance reserve in section E.3; changes to section I.2, Major Transmission Facility Information; Attachment A, revisions regarding Balancing Authority Calculation of Contingency Reserve Obligation When Communications with Reserve Sharing Computer System Are Disrupted; and a new Attachment L, Transmission Facilities Making up Cut Planes Between Reserve Sharing Zones — 4-2-2015

Clarifying revisions to section K.3.e to address how and when the NWPP Staff will complete and post calculations of applicable settlement prices — 4-17-2015 – Effective 5-1-2015

Revisions to "Introduction and Overview" section to clarify that NWPP Staff are responsible for compliance reporting, not individual Participants; revisions to Section D.4.b to require at least quarterly reporting of data for R.3. and R.4 of WECC Standard BAL-002-WECC-2	10-8-2015
Addition and incorporation of the defined term "Contingency Reserve Available" and editorial cleanup revisions	4-1-2016
Clarifications related to NWPP Reserve Sharing Program participation status, determining real-time Most Severe Single Contingency, and reflection of NWPP Reserve Sharing Program requirements in Participant operating procedures	10-13-2016
Removal of language in Attachment B Qualifying Events, (d) Declaration of Energy Emergency Alert 2 or 3	05-12-2017
Effective May 12, 2017 - Participation in WECC Field Test Waiving Enforcement of BAL-002-WECC-2a, Requirement R2	05-12-2017
Revisions to harmonize definitions and other relevant provisions to NERC Standard BAL-002-2(i) and the NERC Glossary; miscellaneous cleanup and clarifying revisions	10-25-2017
Newly added definition for Operating Plan, clarifying changes to MSSC definition, and conforming changes sections D. 3., E.4. and L.	11-30-2017
Clarifying changes to term Reserve Sharing Zone, addition of terms: System Operator, BAA Net Generation, Net Generation, Actual Net Interchange, Scheduled Net Interchange; clarifying changes to Sections D.3.j, revisions to Section I.1,, addition of Section I.5.d., clarifying changes to Attachment A of BAA Net Generation, Net Generation, Actual Net Interchange, Scheduled Net Interchange; revisions to Attachments D, H, and K to reflect addition of Avangrid Renewables as a new Participant. Changes to update the WECC and NERC BAL-002 standards to conform through the entire document.	5-10-2018
Clarifying changes to section D.3.k. to clarify NWPP RSG procedures related to Energy Emergency Alerts. In addition, clarifying language was added to Section L. regarding Obligation to submit a NWPP RSG Verification Form and new Section L.2. added regarding Reporting Balancing Obligation to Notify NWPP Staff.	11-8-2018

New term added for NWPP Reserve Sharing Group Reporting ACE. In addition, new Attachment M – *Overview of BPA Remedial Action Schemes That Suspend Automatic Generation Control and Result in Expected Changes to NWPP Reserve Sharing Group Reporting ACE* and Attachment N -

Correlation Table of Participants, Reliability Coordinators and Zones. Clarifying changes to section I.5. regarding data telemetered from Reserve Sharing Program to the Reliability Coordinator with the addition of the NWPP RSG Reporting ACE and new Section I.6. – Management of Data Related to Reserve Sharing Zones. 2-14-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 2-14-2019

Clarifying notes to Attachment B - Qualifying Events with new *note 2* and formatting (similar to NERC Definition for Balancing Contingency Event). Additional housekeeping items to clarify front page with BAL-002-WECC-2a, Section H.3. with updated contact information, corrected bulleting in Attachment A, and updated Attachment L with appropriate AESO Cut Plane facilities. 5-16-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 5-16-2019

Clarification to WECC Waiver regarding BAL-002-WECC-2a R2. Balancing Contingent Event term added and conforming changes throughout document for a Reportable Balancing Contingent Event. Reporting ACE clarification to Section I.1.f. and J.2.a. Language added to section L.1 to address RSG reporting of EEAs. Clarification of zones to response levels to Attachment C, including new tables for zones and associated BAs along with responding levels. In addition, the removal of Attachment D with new reference to NWPP RSG Tag Templates and conforming changes. Housekeeping changes to conform document with Attachment N. 7-1-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 7-1-2019

Updates to address the addition of new BA Participants, WACM and PSCO for live operation 9-3-2019. Conforming changes throughout document (Section I.2., I.4.d., Attachment C, Attachment H, Attachment K, Attachment L, and Attachment N). 7-1-2019 – effective 9-3-2019

Revisions to Attachment M by removing "Reportable" from references to Balancing Contingency Event. 8-8-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 8-8-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 11-7-2019

Clarifications made to section E.3. Timing of Requests for Assistance Reserve. Additions to section H.3. with respect providing ICCP failover notifications to NWPP staff. Revisions to section I.5. regarding Data Telemetered to the RCs and elimination of section I.6 as it is all covered in the revised section I.5. Revisions to section K. Settlement with the elimination of Energy In-Kind settlement and conforming changes. 11-7-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 2-6-2020

Housekeeping update to WECC Waiver extension to BAL-002-WECC-2a R2 on front page. 4-6-2020

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Housekeeping update to font formatting and indexing. Addition of Process Diagrams as Attachment D (General Process Diagram, Settlement Process, Calculation of CRO, and Back-up Procedures). Consistent naming of generator contingencies in Attachment K. 5-7-2020

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Revised Section B. term for *Participating Balancing Authority or Participant*. Revisions to Section C.3. to address Balancing Authority versus Balancing Authority Area and program functionality. Revisions to Section F. to further clarify program functionality for commitment of Contingency Reserve Obligation when requesting Assistance Reserve, including conforming changes to Section I.4.d. and elimination of Section 2. *Discretion of Participating BA to Carry More Contingency Reserve Than Required by Calculation of Minimum Contingency Reserve Obligation; Obligation to Make All Reported Contingency Reserve Available*. Section I.1. revision and addition of new data from Participant BAs to program (BA_FBS, BA_Ime, BA_ATEC, and BA_ADI). Updates to section L. as related to Internal RSG Reporting. Revisions to Attachment A, Section 1. to address program update to MSSC Deadbands. Attachment K MSSC Updates to PGE MSSC. 11-5-2020

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Housekeeping update to font formatting and indexing. Revisions to Section B. Terminology's *BAL-002* term. Revisions to Sections E.2. regarding actions required to respond to an EEA. Revisions to Section

E.3. regarding length of time for accessing Contingency Reserve to respond to EEAs. Conforming changes to address Section B. *Contingency Reserve Available* term relating to EEA. Last, updates to Section I.1. h. & i. to reflect correct use of NI_A and NI_S. 2-4-2021

Updated language to Section H.2. to for NWPP Staff to perform analysis on each Reportable Balancing Contingency Event that the NWPP RSG experiences. 3-30-2021

Updated cover page to reflect WECC-0115 BAL-002-WECC-2a, Requirement R2, Compliance Waiver Extension 4-6-2021

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Revisions to section D.2. to address appropriate reference to Attachment A and its sections. Revisions to Attachment A. 1 to remove the 1.5 shortfall multiplier to address the current functionality of computer program. 5-6-2021

RSGC approved updates (Feb. 4, 2021) to conform documentation with new Standard BAL-002-WECC-3, effective June 28, 2021 6-28-2021

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 8-5-2021

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Clarifying changes to Contingency Reserve Available (CRA) term, clarifying changes to NWPP Reserve Sharing Group Reporting ACE term, clarifying changes to Section D.3.i - ACE recovery period and size, clarifying changes to Section I.3.j. & k to address calculation of Reporting ACE, addition to Section F. regarding metrics for Deployment of Contingency Reserve, clarifying changes to Section H. regarding Participant responsibilities related BA footprint changes to MSSC (Unit configuration, RAS, etc.), and update to Section K.2.c. regarding annual review period. 11-5-2021

Updates to Section H. to address clarifications to Roles and Responsibilities of the Participant, NWPP Staff with on-call support 24x7, and RSG Committee. 1-12-2022

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Addition of new to Sections I.4. p. and I.4.q. as approved in 2018.11.09. 2-3-2022

Updated Attachment K Tables with new Table 4 to address AVRN's new Gold Hills Wind Project connected to BPA transformer. 3-11-2022

Housekeeping from NWPP to WPP (*NWPP doing business as WPP*), including associated email addresses. Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 5-5-2022

Updated Attachment K Tables with PAC transfer of Jim Bridger from PACW to PACE BAA, updating new MSSCs for both, effective July 6, 2022 6-29-2022

More conforming updates to address NWPP to WPP. New Section E.3. and conforming changes to address performance metric for deployment of Contingency Reserve. Updates to Section K.2. Financial Settlement from use of Powerdex to the Intercontinental Exchange (ICE) in October 2022 (Mid-Columbia and Palo Verde). Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 8-4-2022

Section B. Clarifying updates CRA Definition and conforming updates to Section D.3.b., Section E.2. and Section J.1. Section B. new term: 'Recovery Reporting ACE Target'. Performance Metric updates to Section E.4 and F. Clarifying updates to section K.2.Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 11-3-2022

Attachment K Tables updated with GCPD MSSC to Tables 1 - Priest Rapids and Table 3 - Wanapum. 12-21-2022

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Attachment K Table 1 with GCPD MSSC and clarifying change to term 'Recovery Reporting ACE Target' 2-2-2023

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Attachment K Table 1 Colstrip Capacity Numbers, Table 2 Valmy Shares, and Table 3 AESO Plant Capability, 5-4-2023

Updated NaturEner Attachment H with NaturEner Balancing Authority Name change to BHEM Power Watch, LLC and BHEM Wind Watch, LLC 5-5-2023

Updated Qualifying Events from all EEAs to EEA3 only – Deleted previous section D.3.k (Script for talking to RC to prevent unnecessary EEAs). Clarifications to Sections E.2

., E.3. Attachment B. 6-8-2023

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 8-3-2023

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Attachment K Table 1 for PACE and GCPD along with Table 3 for PACE. 11-2-2023

Updates to conform documentation with zonal transition from Idaho and High Desert Zones to Mountain West and Arizona Nevada Zone to Section I.2., Attachments C, K, L & N. 1-24-2024

Clarifying language added to Section F, newly added Section P – Penalties for Non-Performance (Effective July 1, 2024), and conforming changes to Section I.4.c. In addition, reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Attachment K Table 1 Rocky Reach-River Crossing 7-8-9 Participants. 2-8-2024

Conforming changes with the addition of the new Balancing Authority Participants (AZPS, DEAA, EPE, IID, HGMA, PNM, SRP, TEPC, WALC) effective May 1, 2024 to Attachment C, Attachment H, Attachment K, Attachment L updates and conforming changes to Section I.2., and Attachment N. In addition, consistency with use of term 'RSG Committee', removal of standards documentation to Attachment I NERC BAL-002 and Attachment J BAL-002-WECC. 3-20-2024

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Attachment K Table 1 for BANC and TEPC 5-17-2024

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 8-8-2024

Updates to Section P for a review process to allow for partial credit, to provide clarity that an entity may still receive credit for the "clock-minute averages" independently of meeting the Recovery Reporting ACE Target criteria. In addition, reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 11-7-2024

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Program Documentation with new terms: Balancing Authority Area MSSC, Long-Term Zonal MSSC Limit, and NWPP Reserve Sharing Group Long-Term MSSC Limit. Conforming changes to Section M to address MSSC limits, and conforming changes to Attachment K Table 1 with Maximum Allowable Zonal MSSC and NWPP RSG Long-Term MSSC Limit. 2-6-2025

Review and update to Attachment K, 1. column header from BAA MSSC MW to BAA System Normal MSSD MW. 2-12-2025

Conforming changes with the consolidation of HGMA BA into SRP BA, effective June 1, 2025, the addition of the new First LightEnergy, LLC BA (BNBA), effective July 1, 2024 to Attachment C, Attachment H, Attachment K, Attachment N. 7-1-2025

Updates to Attachment K, 1. BAA MSSC for NEVP and 2., adding back Jim Bridger for PACE and IPC. 9-23-2025

Conforming changes with the consolidation of BHE Montana's WWA BA into the GWA BA, effective October 1, 2025. 10-1-2025

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-26-21
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-146:
Western Frequency Response Sharing Group

WESTERN FREQUENCY RESPONSE SHARING GROUP

NEWS | EVENTS | DOCUMENTS

WFRSG WORKGROUPS > WFRSGC

As permitted by the NERC Standard, BAL-003-2, many Balancing Authorities within the Northwest Power Pool Area have instituted the Western Frequency Response Sharing Group (WFRSG). By collectively participating in the WFRSG, participants are entitled to calculate their annual Frequency Response Measure (FRM) in aggregate to achieve an FRM that is equal to or more negative than its' (the WFRSG) FRO to assure sufficient Frequency Response is provided to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation.

MORE INFO

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DOCUMENTS | VIEW ALL

WFRSG - WFRSGC

WFRSG Agenda and Meeting Materials

WFRSG Agenda and Meeting Materials

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WFRSG - WFRSGC

2024 Q3 Updates - FRS Form 1 and FRS Form 2

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WFRSG - WFRSGC

2024 Q2 Updates - FRS Form 1 and FRS Form 2

LOCKED

MANAGER

ChaRee DiFabio
RSGC & WFRSG Manager
WPP | 503-445-1079
charee.difabio@westernpo...

WFRSG PARTICIPANTS

aeso ALBERTA ELECTRIC SYSTEM OPERATOR

AVANGRID

AVISTA

BANC

BHE MONTANA A BERKSHIRE HATHAWAY ENERGY COMPANY

Black Hills Energy

Bonneville POWER ADMINISTRATION

P.U.D. CHELAN COUNTY

DOUGLAS COUNTY P.U.D.

Grant PUD

GRIDFORCE

IDAHO POWER An IDACORP Company

NorthWestern Energy Delivering a Bright Future

NVEnergy A MIDAMERICAN ENERGY HOLDINGS COMPANY

PACIFICORP A MIDAMERICAN ENERGY HOLDINGS COMPANY

PGE

Xcel Energy

PSE PUGET SOUND ENERGY

SRP

Seattle City Light

SPP Southwest Power Pool

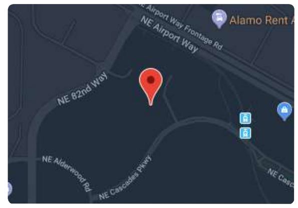
TACOMA POWER TACOMA PUBLIC UTILITIES

TID WATER & POWER Serving Central California since 1887

Western Area Power Administration

WPP HEADQUARTERS

7525 NE Ambassador Place, Suite M
Portland, Oregon, 97220
(503) 445-1074



PROGRAMS

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ABOUT

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CONTACT

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-26-21
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-147:
WRAP Tariff

WESTERN RESOURCE ADEQUACY PROGRAM

TARIFF

OF

NORTHWEST POWER POOL

D/B/A

WESTERN POWER POOL

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PART I GENERAL PROVISIONS

1. Definitions

Unless the context otherwise specifies or requires, capitalized terms used in this Tariff shall have the respective meanings assigned herein for all purposes of this Tariff (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Parts, Sections, Schedules, or Attachments, are to Parts, Sections, Schedules, or Attachments of this Tariff.

Applicable Price Index: A published index of wholesale electric prices, or Locational Marginal Prices duly calculated and posted by a FERC-regulated market operator, in either case as designated under Part III of this Tariff for use in connection with an identified Subregion.

Administration Charge or WRAP Administration Charge: The charge established under Schedule 1 of this Tariff for recovery of the costs of the WRAP.

Advance Assessment: Analyses and calculations of Participant load, resource, and other information performed in advance of each Binding Season as set forth in Part II of this Tariff.

Aggregate Capacity Deficiency: As to a Binding Season, the sum of the maximum Monthly Deficiencies of all Participants that submitted FS Submittals for such Binding Season, as determined following completion of the Cure Period for such Binding Season.

Available Transfer Capability ("ATC"): Transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains demand and resource balance within a Balancing Authority Area, and supports interconnection frequency in real time.

Balancing Authority Area: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

Base Charge: A component of the WRAP Administration Charge as established under Schedule 1 of this Tariff.

Base Costs: Base Costs shall have the meaning provided in Schedule 1 of this Tariff.

Base Services Cost Centers: The cost centers comprising the Base Charge as defined in Schedule 1 of this Tariff.

Base Services Percentage: Base Services Percentage shall have the meaning provided in Schedule 1 of this Tariff.

Binding Season: The Summer Season or the Winter Season.

Board of Directors or Board: The Board of Directors of the Northwest Power Pool d/b/a Western Power Pool.

Business Day: Any Day that is a Monday through Friday, excluding any holiday established by United States federal authorities.

Business Practice Manuals: The manuals compiling further details, guidance, and information that are appropriate or beneficial to the implementation of the rules, requirements, and procedures established by this Tariff. Business Practice Manuals do not include such internal rules or procedures as the Western Power Pool may adopt for its operation and administration, including but not limited to any corporate by-laws of the Western Power Pool, or for any services or functions provided by the Western Power Pool other than those established by this Tariff.

CAISO: The California Independent System Operator Corporation, a California nonprofit public benefit corporation.

Capacity Benefit Margin: An amount of transmission transfer capability permitted under open access transmission rules to be reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

Capacity Critical Hours ("CCH"): Those hours during which the net regional capacity need for the WRAP Region is expected to be above the 95th percentile, based on historical and synthesized data for the WRAP Region's gross load, variable energy resource performance, and interchange.

Capacity Deficiency: A shortfall in a Participant's Portfolio QCC relative to that Participant's FS Capacity Requirement, as further defined in Part II of this Tariff.

Cash Working Capital Fund: Cash Working Capital Fund shall have the meaning provided in Schedule 1 of this Tariff.

Cash Working Capital Support Charge: A charge assessed to Participants under Schedule 1 of this Tariff to fund the Cash Working Capital Fund.

Cash Working Capital Support Charge Rate: Cash Working Capital Support Charge Rate shall have the meaning provided in Schedule 1 of this Tariff.

Central Hub: A designated point or named group of points on the transmission system within a Subregion identified by the Program Administrator that permits energy deliveries from multiple points within such Subregion.

Cost of New Entry ("CONE"): The estimated cost of new entry of a new peaking natural gas-fired generation facility, as determined under, and used in, Part II of this Tariff.

CONE Factor: A factor employed in the calculation of Deficiency Charges under Part II of this Tariff, to reflect whether, and the extent to which, the WRAP Region as a whole is expected to have a capacity deficiency during the period for which the Deficiency Charge is being calculated or a factor employed when a Participant has had repeated deficiencies in sequential years.

Committee of State Representatives ("COSR"): Committee of State Representatives, as established in Part I of this Tariff.

Contingency Reserve: As more fully described in the NERC WECC reliability standards, a quantity of reserves, consisting of generation, load, interchange, or other resources, that are deployable within ten minutes, equal to the greater of (i) the MW quantity of the loss of the most severe contingency and (ii) the megawatt quantity equal to the sum of 3% of hourly integrated load plus 3% of hourly integrated generation.

Critical Mass: *The threshold level of participation in a Subregion, as established in the Business Practice Manuals, below which each Participant of such Subregion may elect to participate as a Non-Binding Participant.*

Cumulative Delivery Failure Period: Any period of five consecutive years, ending with and including the most recent Energy Delivery Failure as of the time of determination of a possible Delivery Failure Charge.

Day: A calendar day.

Day-Ahead Price: A price for wholesale electric transactions designated as a day-ahead price in an Applicable Price Index.

Default Allocation Assessment: A charge assessed on non-defaulting Participants to recover the costs associated with a default by a Participant, as set forth in Part I of this Tariff.

Deficiency Charge: A charge assessed for a Capacity Deficiency or Transmission Deficiency, as set forth in Part II of this Tariff.

Delivery Failure Charge: A charge assessed for a Participant's failure to deliver a required Energy Deployment, as set forth in Part III of this Tariff.

Delivery Failure Charge Rate: A rate employed in the determination of a Delivery Failure Charge as more fully set forth in Part III of this Tariff.

Delivery Failure Factor: A factor used in the determination of a Delivery Failure Charge to recognize the relative severity or impact of an Energy Delivery Failure, as set forth in Part III of this Tariff.

Demand Response: A quantifiable load reduction or otherwise controllable load for which a Participant has two mutually-exclusive options to use to affect its FS Capacity Requirements in a FS for a Binding Season: (1) leave the effects of historically deployed demand response as part of its load provided for the Advance Assessment; or (2) utilize as a Demand Response Capacity Resource.

Demand Response Capacity Resource: A Qualifying Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements established under Part II of this Tariff utilized to meet a Participant's FS Capacity Requirement.

Demonstrated FS Transmission: A Participant's demonstration in its Forward Showing Submittal that it has secured firm transmission service rights of the type and quantity sufficient to provide reasonable assurance, as of the time of the Forward Showing Submittal, of delivery of capacity from the Qualifying Resources and the resources associated with the power purchase agreements in the Participant's Portfolio QCC.

Discounted Deficiency Change: *A reduced Deficiency Charge during the Transition Period that enables a deficient Participant that demonstrates commercially reasonable efforts but is unable to cure deficiencies to access Operations Program capacity.*

Dual Benefit Cost Centers: Dual Benefit Cost Centers shall have the meaning provided in Schedule 1 of this Tariff.

Effective Load Carrying Capability ("ELCC"): A methodology employed to determine the Qualified Capacity Contribution of certain types of Qualifying Resources, as more fully set forth in Part II of this Tariff.

Energy Declined Settlement Price: A pricing component used as part of the calculation of settlements for Holdback Requirements and Energy Deployments under Part III of this Tariff.

Energy Delivery Failure: A failure by a Participant to provide an Energy Deployment assigned to such Participant under Part III of this Tariff.

Energy Deployment: A delivery of energy that a Participant is required to provide during an Operating Day, as set forth in Part III of this Tariff.

Energy Storage Resource: A resource, not including a Storage Hydro Qualifying Resource, designed to capture energy produced at one time for use at a later time.

Excused Transition Deficit: A Participant's inability during the Transition Period to demonstrate full satisfaction of the Participant's FS Capacity Requirement, which, under certain conditions and limitations prescribed by Part II of this Tariff, permits *the Participant to pay a Discounted* Deficiency Charge.

Federal Power Marketing Administration: A United States federal agency that operates electric systems and sells the output of federally owned and operated hydroelectric dams located in the United States.

FERC: The Federal Energy Regulatory Commission.

Forced Outage Factor: The factor resulting from dividing the number of hours a generating unit or set of generating units is not synchronized to the grid system, not in reserve shutdown state and considered to be out of service for unplanned outages—or a startup failure, by the number of total hours in the period multiplied by 100% or a Program Administrator calculated equivalent forced outage factor that reflects the likelihood and extent to which a resource will be unavailable from time to time due to factors outside management control.

Forward Showing Program: The program and requirements as set forth in Part II of this Tariff.

Forward Showing Submittal ("FS Submittal"): The submissions a Participant is required to submit in advance of each Binding Season to demonstrate its satisfaction of the FS Capacity Requirement and FS Transmission Requirement, as set forth in Part II of this Tariff.

Forward Showing Year: A period consisting of a Summer Season and the immediately succeeding Winter Season.

FS Capacity Requirement: The minimum quantity of capacity a Participant is required to demonstrate for a Binding Season, as set forth in Part II of this Tariff.

FS Deadline: The deadline for Participants' submissions of their FS Submittals for a Binding Season, as established under Part II of this Tariff.

FS Planning Reserve Margin ("FSPRM"): An increment of resource adequacy supply needed to meet conditions of high demand in excess of the applicable peak load forecast and other conditions such as higher resource outages, or lower availability of resources, expressed as a percentage of the applicable peak load forecast, as determined in accordance with Part II of this Tariff.

FS Transmission Requirement: The minimum quantity of transmission service rights a Participant is required to demonstrate for a Binding Season, as set forth in Part II of this Tariff.

High-Priced Day: The most recent day in the CAISO in which prices in the day-ahead market were at least $200/MWh.

Holdback Capacity: Capacity that is voluntarily supplied or is the result of a positive Sharing Calculation result that is bindingly committed to the WRAP after it is claimed by one or more Participants with a negative Sharing Calculation result.

Holdback Requirement: A MW quantity, as determined on a Preschedule Day, that a Participant is required to be capable of converting into an Energy Deployment on a given hour of the succeeding Operating Day, as more fully set forth in Part III of this Tariff.

ICE Index: A wholesale electric price index prepared and published by the Intercontinental Exchange.

Incremental Cash Working Capital Support Charge: Incremental Cash Working Capital Support Charge shall have the meaning provided in Schedule 1 of this Tariff.

Independent Evaluator: An independent entity engaged to provide an independent assessment of the performance of the WRAP and any potential beneficial design modifications, as set forth in Part I of this Tariff.

Installed Capacity: Nameplate capacity adjusted for conditions at the site of installation.

International Power Marketing Entity: An entity that (i) owns, controls, purchases and/or sells resource adequacy supply and is responsible under the WRAP program for meeting LRE obligations associated with one or more loads physically located outside the United States.

Legacy Agreement: A power supply agreement entered into prior to October 1, 2021.

Load Charge: A component of the WRAP Administration Charge as established under Schedule 1 of this Tariff.

Load Charge Rate: Load Charge Rate shall have the meaning provided in Schedule 1 of this Tariff.

Load Services Costs: Load Services Costs shall have the meaning provided in Schedule 1 of this Tariff.

Load Services Cost Centers: Load Services Cost Centers shall have the meaning provided in Schedule 1 of this Tariff.

Load Services Percentage: Load Services Percentage shall have the meaning provided in Schedule 1 of this Tariff.

Load Responsible Entity ("LRE"): An LRE is an entity that (i) owns, controls, purchases and/or sells resource adequacy supply, or is a Federal Power Marketing Administration or an International Power Marketing Entity, and (ii) has full authority and capability, either through statute, rule, contract, or otherwise, to:

(a) submit capacity and system load data to the WRAP Program Operator at all hours;

(b) submit Interchange Schedules within the WRAP Region that are prepared in accordance with all NERC and WECC requirements, including providing E-Tags for all applicable energy delivery transactions pursuant to WECC practices and as required by the rules of the WRAP Operations Program;

(c) procure and reserve transmission service rights in support of the requirements of the WRAP Forward Showing Program and Operations Program; and

(d) track and bilaterally settle holdback and delivery transactions.

Subject to the above-mentioned criteria, an LRE may be a load serving entity, may act as an agent of a load serving entity or multiple load serving entities, or may otherwise be responsible for meeting LRE obligations under the WRAP.

Locational Marginal Price: The cost of delivering an additional unit of energy to a given node, as calculated under a FERC-regulated wholesale electric tariff.

Loss of Load Expectation ("LOLE"): An expression of the frequency with which a single event of failure, due to resource inadequacy, to serve firm load would be expected (based on accepted reliability planning analysis methods) to result from a given FS Planning Reserve Margin.

Make Whole Adjustment: A component used as part of the calculation of settlements for Holdback Requirements and Energy Deployments under Part III of this Tariff.

Maximum Base Charge: The maximum amount prescribed in Schedule 1 of the Tariff that the Base Charge cannot exceed.

Maximum Load Charge Rate: The maximum rate prescribed in Schedule 1 of the Tariff that the Load Charge Rate cannot exceed.

Median Monthly P50 Peak Loads: Median Monthly P50 Peak Loads has the meaning prescribed by Schedule 1 of this Tariff.

Month: A calendar month.

Monthly Capacity Deficiency: A Participant's Capacity Deficiency for a given Month.

Monthly Deficiency: An identification under Part II of this Tariff whether, and the extent to which, a Participant's need for capacity or transmission for a given Month is greater than the capacity or transmission, respectively, the Participant can demonstrate for such Month.

Monthly FS Capacity Requirement: FS Capacity Requirement determined as to a Month.

Monthly FSPRM: The FS Planning Reserve Margin applicable to a given Month of a given Binding Season, as determined in accordance with Part II of this Tariff.

Monthly Transmission Deficiency: A Participant's Transmission Deficiency for a given Month.

Monthly Transmission Demonstrated: A Participant's Demonstrated FS Transmission for a given Month.

Monthly Transmission Exceptions: Exceptions from the FS Transmission Requirement approved under Part II of this Tariff for a Participant for a given Month.

Multi-Day-Ahead Assessment: A period of days preceding each Operating Day, and ending on the Preschedule Day, during which Sharing Calculations are successively performed based in each case on Operating Day conditions expected at the time of calculation.

North American Electric Reliability Corporation ("NERC"): A not-for-profit international regulatory authority that serves as the designated electric reliability organization for the continental United States, Canada, and a portion of Mexico.

Net Contract QCC: The QCC, which may be a positive or negative value, calculated, in sum and on net, for a Participant's power purchase agreements and power sale agreements, in accordance with Part II of this Tariff.

Non-Binding Season: As to a Participant, *any* Binding Season during which the *provisions of Section 15A.1* of this Tariff *apply*.

Non-Binding Participant: For any Binding Season, a Participant that has made an election by which such Binding Season is a Non-Binding Season for that Participant.

Open Access Transmission Tariff: A governing document on file with FERC establishing the rates, terms, and conditions of open access transmission service, or equivalent tariff of a transmission service provider that is not required to file its transmission service tariff with FERC.

Operating Day: A current Day of actual electric service from resources to load, for which Sharing Events are determined and Energy Deployments may be required, as set forth in Part III of this Tariff.

Operations Program: The program and requirements set forth in Part III of this Tariff.

P50 Peak Load Forecast: A peak load forecast prepared on a basis, such that the actual peak load is statistically expected to be as likely to be above the forecast as it is to be below the forecast.

Participant: A Load Responsible Entity that is a signatory to the WRAPA.

Portfolio QCC: As to a Participant, the sum of the Resource QCC provided by all of a Participant's Qualifying Resources plus the Net Contract QCC of such Participant, as adjusted to reflect RA Transfers as described in Section 16.2 7 and Planned Outages as described in Section 16.2.8.

Preschedule Day: The applicable scheduling Day for a given Operating Day as defined in scheduling calendar established by WECC.

Program Administrator: The Western Power Pool, in its role as the entity responsible for administering the WRAP.

Program Operator: A third party that has contracted with the Program Administrator to provide technical, analytical, and implementation support to the Program Administrator for the WRAP.

Program Review Committee ("PRC"): The stakeholder sector committee as established in Section 4.2 of this Tariff.

Pure Capacity: A MW quantity of capacity without any assigned forced outage rate employed in ELCC determinations under Part II of this Tariff.

Qualifying Capacity Contribution ("QCC"): The MW quantity of capacity provided by a resource, contract, or portfolio which qualifies to help satisfy a Participant's FS Capacity Requirement, as determined in accordance with Part II of this Tariff.

Qualifying Resource: A generation or load resource that meets the qualification and accreditation requirements established by and under Part II of this Tariff.

Real-Time Price: A price for wholesale electric transactions designated as a real-time price in an Applicable Price Index.

Resource Adequacy Participant Committee ("RAPC"): The committee comprised of representatives from each Participant as established in Part I of this Tariff.

Resource QCC: The QCC provided by a Qualifying Resource, as determined in accordance with Part II of this Tariff.

Run-of-River Qualifying Resource ("ROR"): A hydro-electric power project that does not have the capability to store a sufficient volume of water to support continuous generation at the project's stated maximum capacity for a period of one hour. Resource does not meet the definition of a Storage Hydro Qualifying Resource.

Safety Margin: An additional factor allocated among Participants with positive sharing calculations when warranted by certain conditions as prescribed by Part III of this Tariff.

Senior Official Attestation: A signed statement of a senior official of a Participant attesting that it has reviewed such Participant's information submission required under this Tariff, that the statements therein are true, correct and complete to the best of such official's knowledge and belief following due inquiry appropriate to the reliability and resource adequacy matters addressed therein, and containing such further statements as required by this Tariff or the applicable Business Practice Manual for the information submission at issue.

Sharing Calculation: A calculation used in the Operations Program under Part III of this Tariff to identify any hour in which any Participant is forecast to have a capacity deficit.

Sharing Event: An hour or hours of an Operating Day for which one or more Participants has a negative Sharing Calculation result, as determined in accordance with Part III of this Tariff.

Storage Hydro Qualifying Resource: A hydro-electric power project with an impoundment or reservoir located immediately upstream of the powerhouse intake structures that can store a sufficient volume of water to support continuous generation at the project's stated maximum capacity for a period of one hour or longer.

Subregion: An area definition approved by the Board of Directors and identified in the Business Practice Manuals, that is wholly contained within the WRAP Region, which is separated from one or more other Subregions by transmission constraints on capacity imports or on capacity exports that result, or are expected to result, in differing FSPRM determinations for that Subregion relative to such other Subregion.

Summer Season: A period of time that commences on June 1 of a Year and terminates on September 15 of the same Year.

System Sale: A bilateral agreement that conveys generating capacity from a group of generating resources from one party to another.

Transition Period: The Binding Seasons within the time period from June 1, 2025, through March 15, *2029*, plus the time period required to implement the requirements and procedures of Part II of this Tariff applicable to such Binding Seasons.

Transmission Deficiency: A shortfall in a Participant's demonstration of secured transmission service rights, after accounting for any approved transmission exceptions, relative to that Participant's FS Transmission Requirement, as further defined in Part II of this Tariff.

Unforced Capacity: The percentage of Installed Capacity available after a unit's forced outage rate is taken into account.

Variable Energy Resource ("VER"): An electric generation resource powered by a renewable energy source that cannot be stored by the facility owner or operator and that has variability that is beyond the control of the facility owner or operator, including but not limited to a solar or wind resource.

VER Zone: A geographic area delineated in accordance with Section 16.2.5.2 of this Tariff for a given type of VER, where each VER of that type located in such area is anticipated to be comparably affected by meteorological or other expected conditions in such area to a degree that warrants distinct calculation of ELCC allocations for such VERs of that type in such area.

Voluntary Holdback: Capacity that is offered to the Operations Program by a Participant with excess supply that is not obligated to the WRAP through a positive Sharing Calculation result, some or all of which can used as part of the offering Participant's Holdback Requirement. For a Participant in a Subregion without a Central Hub, Voluntary Holdback for an hour must additionally include a total quantity for all identified points from Section 19.4 at which it can deliver that is no less than the amount of the Voluntary Holdback capacity for such hour.

Western Electricity Coordinating Council ("WECC"): A non-profit corporation that has been approved by FERC as the regional entity for the western interconnection and that also has NERC delegated authority to create, monitor, and enforce reliability standards.

Western Resource Adequacy Program Agreement ("WRAPA"): The participation agreement for the Western Resource Adequacy Program, as set forth as Attachment A to this Tariff, or as set forth for an individual Participant in a non-conforming version of such participation agreement accepted by FERC.

Western Resource Adequacy Program ("WRAP"): The Western Resource Adequacy Program, as established under this Tariff.

Western Power Pool ("WPP"): Northwest Power Pool, d/b/a Western Power Pool, which serves as Program Administrator for the WRAP under this Tariff and holds exclusive rights under section 205 of the Federal Power Act to file amendments to this Tariff.

Winter Season: A period of time that commences on November 1 of a Year and terminates on March 15 of the immediately following Year.

WRAP Cost Assignment Matrix: The matrix set forth in Schedule 1 of this Tariff to identify which WRAP costs are assessed to the Base Charge and the Load Charge components of the WRAP Administration Charge.

WRAP Region: The area comprising, collectively, (i) the duly recognized and established load service areas of all loads in the United States that all Participants are responsible for serving, (ii) the duly recognized and established load service areas of all loads in the United States that all load serving entities, on whose behalf a Participant acts in accordance with this Tariff, are responsible for serving, and (iii) the applicable location(s) on the United States side of the United States international border that form the basis for an International Power Marketing Entity's participation under the WRAP, in all cases excluding, for any Binding Season, any loads permitted by this Tariff to be excluded from Participants' Forward Showing Submittal for such Binding Season.

Year: A calendar year.

2. Role of Western Power Pool

2.1 WPP, acting under the direction of its Board of Directors, shall administer the WRAP as Program Administrator. Except as specified in Section 3 of this Tariff, WPP, as authorized by its Board of Directors, shall have the sole authority to submit to FERC amendments to the rates, terms, and conditions set forth in this Tariff under section 205 of the Federal Power Act, 16 U.S.C. § 824d. Nothing contained herein shall be construed as affecting in any way the right of any Participant or any other entity to apply to FERC for amendments to the rates, terms, and conditions contained herein under section 206 of the Federal Power Act, 16 U.S.C. § 824e, or any other applicable provision of that Act.

2.1.1 WPP president and staff shall support the Board of Directors in overseeing all aspects of the WRAP, including oversight and management of the Program Operator(s) in accordance with any Program Operator agreement(s) entered into by WPP under Section 2.2 of this Tariff.

2.1.2 WPP and its staff shall provide all legal, regulatory, and accounting support for the WRAP, including support for making filings with FERC as authorized by the Board of Directors.

2.1.3 WPP staff shall provide all logistical support necessary to facilitate implementation of the WRAP and specifically all logistical needs of the Board of Directors and reasonable logistical assistance to facilitate meetings and activities of the RAPC, PRC, and all subordinate organizational groups.

2.2 As Program Administrator, WPP shall undertake all actions as necessary to implement and administer the WRAP, including but not limited to engaging one or more Program Operator(s) to perform technical operations of the WRAP including both the Forward Showing Program and Operations Program. Except as otherwise provided herein, WPP may contract for certain activities required by this Tariff to be provided by one or more Program Operator(s) subject to oversight by the Board of Directors, provided, however, that the Program Operator shall operate solely as a contractor under the oversight of WPP, and WPP shall remain the sole point of compliance with this Tariff. WPP shall have the sole authority to enter into contracts for such engagements and is responsible for providing support and compensation for such Program Operator(s) pursuant to any contract(s).

2.2.1 WPP will contract with Program Operator(s) to assist WPP with providing reasonable technical support and expertise to all WRAP organizational groups as governed by the Program Operator's contract with WPP.

3. Role of the Board of Directors and Limitations on Board Authority

3.1 Authority: Ultimate authority over all aspects of the WRAP as established under this Tariff shall be vested in the independent Board of Directors. Each member of the Board of Directors shall at all times exhibit financial independence from all Participants and classes of Participants, as further provided in the WPP Bylaws and policies. As set forth in Section 2.1 of this Tariff, the Board of Directors shall have the exclusive authority to approve and direct WPP to file amendments to this Tariff with FERC under section 205 of the Federal Power Act, 16 U.S.C. § 824d, subject to the limitations and prohibitions imposed under Section 3.4 of this Tariff. The Board of Directors shall also have the exclusive authority to approve the Business Practice Manuals and any amendments to the Business Practice Manuals, subject to the terms, conditions, and limitations imposed under this Tariff.

3.2 The Board of Directors generally shall meet in open session for all matters related to the WRAP; however, the Board of Directors may meet in closed session as the chair deems necessary to safeguard the confidentiality of sensitive information, including but not limited to discussing matters related to personnel, litigation, or proprietary, confidential, or security sensitive information. The Board of Directors shall not take action on any proposed amendment to this Tariff or the Business Practice Manuals in closed session. During open session, the chair of the Board of Directors will reasonably accommodate stakeholder requests to address the Board within the discretion of the chair.

3.3 The Board of Directors shall only consider amendments to this Tariff or the Business Practice Manuals after such amendments are first acted upon by the RAPC, subject to the following additional conditions:

3.3.1 In the event that the RAPC has voted to reject or has not voted to support a proposed amendment to this Tariff or the Business Practice Manuals, any stakeholder may appeal such decision to the Board of Directors, and the Board of Directors shall consider the appeal.

3.3.2 In the event that the RAPC has voted to reject or has not voted to support a proposed amendment to this Tariff or the Business Practice Manuals and a stakeholder has not appealed such decision, the Board of Directors may, on its own motion or motion of any member of the Board of Directors, consider the proposed amendment.

3.3.3 In the event that the COSR as a body opposes or appeals a RAPC decision to the Board of Directors regarding an amendment to this Tariff or the Business Practice Manuals, the process set forth in Section 4.3.3 of this Tariff shall apply prior to the Board of Directors' consideration of the RAPC decision.

3.3.4 In the event that the Board of Directors wishes to initiate an amendment to this Tariff or the Business Practice Manuals that has not undergone PRC and RAPC review, the Board of Directors shall first submit such proposed amendment to the PRC for review under the processes set forth in Sections 4.1 and 4.2 of this Tariff.

3.3.5 Expedited Review Process: In the event that the RAPC determines that an expedited review process is necessitated by an exigent circumstance as set forth in Section 4.1.3.1.1 of this Tariff, the Board of Directors shall review the RAPC's recommended Tariff or Business Practice Manual amendment expeditiously and invite comment from the PRC, COSR, and stakeholders concurrently with its consideration of the RAPC proposal.

3.4 WPP is specifically prohibited from amending this Tariff to:

3.4.1 Alter, usurp, control, or otherwise materially modify the Participants' existing functional control and responsibility over their generation and transmission assets, including but not limited to planning and operation of such assets, Open Access Transmission Tariff administration, interfering with Balancing Authority duties and responsibilities, or imposing a must-offer requirement on any specific generation resources.

3.4.2 Administer Open Access Transmission Tariff service, engage in Balancing Authority operations, impose transmission planning requirements, or assume any transmission planning responsibilities with regard to any of the Participant's transmission assets.

3.4.3 Form any type of organized market, including but not limited to a capacity market, a regional transmission organization, a real-time market, or any other type of FERC-approved regional construct, unless such action is also approved by the RAPC under its voting procedures set forth in Section 4.1.6 of this Tariff.

3.4.4 Impose any requirements on Participants beyond the assessment of financial charges as specified in this Tariff or suspension or termination of participation for failure to meet any WRAP requirements.

3.4.5 Amend in any way this Section 3 of this Tariff without the approval of the RAPC under its voting procedures set forth in Section 4.1.6 of this Tariff.

3.4.6 Amend the RAPC voting thresholds set forth in Section 4.1.6 of this Tariff.

3.5 Subject to the limitations and prohibitions imposed under Section 3.4 of this Tariff, if the Board of Directors votes to file at FERC to expand the WRAP to include market optimization or transmission planning services, WPP will initiate a formal process with COSR and other stakeholders to conduct a full review of governance structures and procedures, including the role of states. If COSR does not support any revised governance structure that emerges from such WPP review process, the WPP will file, along with any WPP governance proposal to FERC, an alternative governance structure on behalf of the COSR so long as such COSR alternative governance structure is supported by 75% of the COSR.

4. Organizational Groups for the WRAP

4.1 Resource Adequacy Participants Committee

4.1.1 Authority and Purpose: The RAPC shall be the highest level of authority for representation by Participants in the WRAP governance structure and shall represent the interests of Participants directly to the Board of Directors.

4.1.2 Composition: The RAPC shall be composed of one representative from each Participant. Such representative shall be a senior management official with binding decision-making authority on behalf of the Participant, or a designated representative of a Participant's senior management official. A designated representative shall be required to have binding decision-making authority on behalf of the Participant and shall have all voting rights delegated from the senior management official. Participant shall appoint a designated representative no less than one Business Day in advance of a meeting for that designated representative to be eligible to vote during the meeting.

4.1.3 Functions: The RAPC:

4.1.3.1 Shall consider and recommend that the Board of Directors approve or reject all proposed amendments to this Tariff or Business Practice Manuals prior to the Board of Directors considering such amendments, including any amendments reviewed and referred by the PRC.

4.1.3.1.1 Exigent Circumstances: When the RAPC determines that an amendment to the Tariff or the Business Practice Manuals requires expedited Board of Directors review due to exigent circumstances, it may propose such amendment directly to the Board of Directors without awaiting review by other committees and stakeholders. Exigent circumstances include: (i) a FERC-mandated amendment to this Tariff or the Business Practice Manuals; (ii) an amendment to this Tariff or the Business Practice Manuals to address an immediate reliability impact; or (iii) an amendment to this Tariff or the Business Practice Manuals that the RAPC has determined has significant impacts to utility service.

4.1.3.2 Shall consider and vote to recommend that the Board of Directors approve or reject any proposed amendments to this Tariff or the Business Practice Manuals.

4.1.3.3 May provide input to the Board of Directors on any proposed WPP rules that apply both to the WRAP and other WPP services.

4.1.3.4 May evaluate and provide input to the Board of Directors on the WRAP administration budget and budget allocation to Participants, including amendments to the WRAP Administration Charge as calculated in accordance with Schedule 1 of this Tariff.

4.1.3.5 Shall form and organize all of the organizational groups under its responsibilities.

4.1.3.6 May take other actions reasonably related to its role as the senior-level Participant advisory committee to the Board of Directors regarding WRAP matters.

4.1.4 Leadership: The RAPC shall select from among its members a chair and vice chair.

4.1.5 Meetings:

4.1.5.1 Meetings of the RAPC will generally be open to all stakeholders. WPP shall provide advanced written notice of the date, time, place, and purpose of each RAPC meeting. All RAPC decisional items shall be placed on the open meeting agenda and allotted adequate time for public comment and deliberation.

4.1.5.1.1 The RAPC may meet in closed session as the RAPC chair deems necessary; provided, however, that the RAPC shall allow the designated COSR support staff member as specified in Section 4.3 of this Tariff to attend any closed meeting. The RAPC shall not take action on any proposed amendment to this Tariff or the Business Practice Manuals in closed session.

4.1.5.2 The quorum for a meeting of the RAPC or any organizational group organized under it shall be one-half of the representatives thereof, but not less than three representatives, provided that a lesser number may serve as a quorum for the sole purpose of voting to adjourn the meeting to a later time.

4.1.6 Voting:

4.1.6.1 Each RAPC representative shall have one vote.

4.1.6.2 Voting in the RAPC shall utilize a “House and Senate” model.

4.1.6.2.1 Each Participant’s “House” vote shall represent the proportion of the Participant’s Median Monthly P50 Peak Load, as described in Section 2 of Schedule 1 of this Tariff, compared to the sum of all Participants’ Median Monthly P50 Peak Loads. A Participant may choose to divide its

House vote but is responsible for announcing such at the time of voting.

4.1.6.2.2 Each Participant shall receive a single, non-weighted "Senate" vote.

4.1.6.2.3 For an action to be approved by the RAPC, it must pass both "House" and "Senate" votes as follows. For purposes of voting, the percentages identified below specify the percentage threshold of the entire RAPC (whether in attendance or not) that is needed for passage of an action.

4.1.6.2.3.1 Actions to amend any of the limitations on Board authority set forth in Section 3.4 of this Tariff require an 80% affirmative approval by both the House and the Senate vote tallies to be approved.

4.1.6.2.3.2 Actions brought before the RAPC that have been approved by the PRC require a 67% affirmative approval by both the House and Senate vote tallies to be approved.

4.1.6.2.3.3 All other actions not specified in this Section 4.1.6.2.3 require a 75% affirmative approval by both the House and Senate vote tallies to be approved.

4.1.6.2.4 If at any time a single Participant's P50 load for voting purposes would result in that Participant possessing a veto over any votes taken under Section 4.1.5.2.3, such Participant's House vote shall be capped at 1% below the amount that would convey such a veto, such that no single Participant will possess a veto over any action taken under Section 4.1.6.2.3.

4.2 Program Review Committee

4.2.1 Authority and Purpose: The PRC is a sector-representative group comprised in accordance with Section 4.2.2 of this Tariff. The PRC is responsible for receiving, considering, and proposing amendments to this Tariff and the Business Practice Manuals. The PRC shall serve as a clearinghouse of all recommended amendments to this Tariff or the Business Practice Manuals, except for those designated by the RAPC as involving an exigent circumstance under Section 4.1.3.1.1 of this Tariff, amendments to Schedule 1 of this Tariff and cost allocation for the WRAP, and amendments to the WRAPA set forth as Attachment A of this Tariff. The PRC shall serve in an advisory capacity to the RAPC and, when applicable, the Board of Directors.

4.2.1.1 The PRC shall present all proposals received to the RAPC, along with the PRC's recommendation and summaries of all comments and feedback received.

4.2.1.2 The PRC's decisions are advisory-only and are not binding on the RAPC, the Board of Directors, or WPP.

4.2.2 Composition: The PRC shall be composed of up to twenty representatives from the following ten sectors: four representatives of RAPC Participant investor-owned utilities; four representatives of RAPC Participant publicly-owned (consumer or municipal) utilities; two representatives of RAPC Participant retail competition load serving entities; two representatives from RAPC Participant Federal Power Marketing Administrations; two representatives of independent power producers; two representatives of public interest organizations; one representative of retail consumer advocacy groups; one representative of industrial customer advocacy groups; one representative of load serving entities with loads in the WRAP that are represented by other LREs and are not otherwise eligible for any other sector; a representative from the COSR. Expectations for sectors to consider regional, operational, geographic, demographic, and other forms of diversity in selecting their sector representatives are set forth in more detail in the PRC charter, which shall be posted and maintained on the WRAP website or other appropriate public location.

4.2.3 The PRC shall establish a process and criteria for receiving and reviewing proposed amendments to this Tariff and the Business Practice Manuals. Such review will include procedures for stakeholder comment.

4.2.4 Meetings: The PRC shall meet primarily in open session; provided that the PRC may schedule closed meetings if it determines that doing so would be beneficial to safeguard the confidentiality of sensitive information. The PRC shall not take action on any proposed amendment to this Tariff or the Business Practice Manuals in closed session.

4.2.5 Voting: The PRC shall endeavor to operate by consensus. When voting is necessary, voting shall consist of one sector one vote, with an affirmative vote of six sectors (as specified in Section 4.2.2 of this Tariff) constituting approval of an action before the PRC.

4.2.5.1 For sectors with four seats, three sector representatives must agree with the action for the sector to be considered an affirmative vote for the action.

4.2.5.2 For sectors with two seats, both sector representatives must agree with the action for the sector to be considered an affirmative vote for the action.

4.2.6 Participants and other entities shall participate in no more than one PRC sector. If a Participant or other entity is eligible to participate in more than one sector, such Participant or other entity shall declare in which sector it will participate.

4.3 Committee of State Representatives

4.3.1. Composition: The COSR is a committee composed of one representative from each state or provincial jurisdiction (either public utility commission or state/provincial energy office) that regulates at least one Participant.

4.3.2 Leadership: The COSR shall determine its leadership, including a chair and vice chair. The chair or vice chair will be requested to attend all open sessions of the RAPC to provide input and advice.

4.3.2.1 The COSR shall designate a COSR support staff member to attend and audit closed meetings of the RAPC under a non-disclosure agreement.

4.3.3 Authority:

4.3.3.1 If the COSR determines that a proposal approved by the RAPC is substantially different from the proposal submitted to the RAPC by the PRC, the COSR may engage in additional public review and comment before the RAPC decision is presented to the Board of Directors; provided that this additional public review and comment does not unreasonably delay presentation to the Board of Directors.

4.3.3.2 If the COSR as a body opposes or appeals a RAPC decision to the Board of Directors, the Board of Directors will not consider the RAPC's decision until the RAPC engages with the COSR to discuss, in at least two public discussions, to attempt to reach a mutually agreeable solution.

4.3.3.2.1 If the appeal relates to an amendment that the RAPC designated as involving an exigent circumstance under Section 4.1.3.1.1 of this Tariff, COSR can require no more than one public discussion, provided that such additional discussion does not unreasonably hinder the timeline for Board of Directors consideration of the proposed amendment.

4.3.4 Voting, Meetings, and Quorum: The COSR may develop its own rules governing voting, meetings, and quorum for action. COSR shall be responsible for its own costs.

5. Independent Evaluator

5.1 WPP shall engage an Independent Evaluator to provide an independent assessment of the performance of the WRAP and any potential beneficial design modifications. The Independent Evaluator shall report directly to the Board of Directors.

5.2 The Independent Evaluator shall conduct an annual review of the WRAP, including but not limited to analyzing prior year program performance, accounting and settlement, and program design.

5.3 The Independent Evaluator shall prepare an annual report of its findings, and any recommended modifications to WRAP design, and present its findings to the WRAP committees and the Board of Directors, subject to any necessary confidentiality considerations. Any data included in the Independent Evaluator's report shall be reported on an aggregated basis as applicable to preserve confidentiality. The Independent Evaluator's annual reports shall be available to the public, except to the extent they contain information designated as confidential under this Tariff, or information designated as confidential by the Independent Evaluator.

5.4 The Independent Evaluator shall not:

5.4.1 Evaluate individual Participants.

5.4.2 Possess any decision-making authority regarding the WRAP or design modifications.

5.4.3 Evaluate WPP's day-to-day operations of the WRAP (except as part of review of prior year program performance).

6. WPP Invoicing and Settlement

6.1 WPP shall be responsible for issuing invoices to, and collecting from, Participants all charges under Schedule 1 of this Tariff for recovery of all WPP costs associated with administering the WRAP.

6.2 WPP shall be responsible for invoicing, collecting, and (as applicable) distributing revenues from Deficiency Charges under Part II of this Tariff and Delivery Failure Charges under Part III of this Tariff.

6.3 Participants are not required to provide credit assurances to WPP to cover charges under Schedule 1 of this Tariff, Deficiency Charges under Part II of this Tariff, or Delivery Failure Charge under Part III of this Tariff.

6.4 Participants shall make full payment of all invoices rendered by WPP for which payment is required to WPP within thirty calendar days following the receipt of the WPP invoice, notwithstanding any disputed amount, but any such payment shall not be deemed a waiver of any right with respect to such dispute. Any Participant that fails to make full and timely payment to WPP of amounts owed upon expiration of the cure period specified in Section 6.4.1 of this Tariff will be in default.

6.4.1 If a Participant fails to make timely payment as required by Section 6.4, WPP shall so notify such Participant. The notified Participant may remedy such asserted breach by paying all amounts due, along with interest on such amounts calculated in accordance with the methodology specified for interest on refunds in FERC's regulations at 18 C.F.R. § 35.19a(a)(2)(iii); provided, however, that any such payment may be subject to a reservation of rights, if any, to refer such matter to dispute resolution procedures under Section 9 of this Tariff. If the Participant has not remedied such asserted breach by 5:00 p.m. Pacific Prevailing Time on the second Business Day following WPP's issuance of a written notice of breach, then the Participant shall be in default.

6.4.2 In the event of a Participant's default under Section 6.4.1 of this Tariff, WPP in its discretion may pursue collection through such actions, legal or otherwise, as it reasonably deems appropriate, including but not limited to the prosecution of legal actions and assertion of claims in the state and federal courts as well as under the United States Bankruptcy Code. After deducting any costs associated with pursuing such claims, any amounts recovered by WPP with respect to defaults for which there was a Default Allocation Assessment shall be distributed to the Participants who have paid their Default Allocation Assessment in proportion to the Default Allocation Assessment paid by each Participant, as calculated pursuant to Section 6.4.3 of this Tariff. In addition to any amounts in default, the defaulting Participant shall be liable to WPP for all reasonable costs incurred in enforcing the defaulting Participant's obligations.

6.4.3 In the event of a Participant's default with respect to an invoice issued by WPP for charges under Schedule 1 of this Tariff, in order to ensure that WPP remains revenue neutral, the Board of Directors may assess against, and collect from, the Participants not in default a Default Allocation Assessment to recover the costs associated with the default. Such assessment shall in no way relieve the defaulting Participant of its obligations.

6.4.3.1 The Default Allocation Assessment shall be equal to:

(20% × (1/N) + (80% × (Participant Median Monthly P50 Peak Load / Sum Participants Median Monthly P50 Peak Load)

where:

N = the total number of Participants, calculated as of the date WPP declares a Participant in default.

Participant Median Monthly P50 Peak Load = for each Participant included in factor "N" above, the Participant's Median Monthly P50 Peak Load as determined in Section 2 of Schedule 1 of this Tariff, recalculated on the day the WPP declares a Participant in default.

All Participants Median Monthly P50 Peak Load = the sum of the Participant Median Monthly P50 Peak Load values for all Participants included in factor "N" above.

7. Credit Requirements and Settlement for Holdback and Delivered Energy

7.1 Credit and Settlement for Holdback and Delivered Energy: Settlement of holdback and delivered energy shall be completed bilaterally between Participants, subject to the following:

7.1.1 Neither WPP nor the Program Operator(s) shall take title to energy or be party to any settlement of holdback or delivered energy.

7.1.2 Participants shall establish credit with each other through one of the following mechanisms. Neither WPP nor the Program Operator(s) shall be involved in the calculation of credit or credit limits.

7.1.2.1 Establish credit directly with each Participant: Participants may establish credit directly with other Participants from whom they may receive delivered energy.

7.1.2.1.1 Such credit should be established in advance of the applicable season.

7.1.2.1.2 The amount of such credit and any credit limit shall be at the discretion of each Participant.

7.1.2.2 WPP shall conduct a competitive solicitation process to identify a third-party service provider to serve as central credit organization and clearing house for credit and settlement. Once such central credit organization is selected, Participants that have not already directly established credit with all other Participants under Section 7.2.2.1 of this Tariff shall establish credit with the central credit organization.

7.1.2.2.1 WPP will provide the central credit organization any Operations Program related information necessary for them to perform their obligations as set forth in the agreement between WPP and the central credit organization.

7.1.2.2.2 All costs associated with the central credit organization service shall be borne by Participants as established in the agreement between WPP and the central credit organization and either billed directly on a transactional basis or else recovered under Schedule 1 of this Tariff.

7.1.2.3 The obligation to arrange sufficient credit shall at all times be on the deficient Participant (i.e., a Participant with a negative sharing calculation in the Operations Program). If a deficient Participant has not made good faith and commercially reasonable efforts to obtain sufficient credit with a delivering Participant, such delivering Participant shall so notify WPP and shall be excused from any obligation to deliver to such deficient Participant. Nothing in this Section 7 requires a Participant to violate its written risk or credit policy.

7.2 All settlement pricing calculated under this Tariff shall be final and no adjustments to settlement prices shall be allowed after the later of: (1) ninety Days after such settlement prices are posted by WPP; or (2) the final outcome of any dispute resolution process that is initiated by a Participant to dispute a settlement price pursuant to the Dispute Resolution Procedures set forth in Section 9 of this Tariff.

7.2.1 A Participant may invoke the Dispute Resolution Procedures set forth in Section 9 of this Tariff to address calculation errors in any settlement price, but may not invoke the Dispute Resolution Procedures to dispute data sources or to request the use of alternative data sources.

8. Force Majeure, Limitation of Liability, and Indemnification

8.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, pandemic, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation, or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither WPP nor the Participant will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff. Notwithstanding the foregoing, the physical inability to perform because of an event of Force Majeure shall not relieve the party of any financial obligations incurred under this Tariff or as a result of the Force Majeure event, unless, and to the extent, such financial obligation is waived or excused under provisions of Part II or Part III of this Tariff expressly providing for such waiver or excuse.

8.2 Limitation of Liability:

8.2.1 Neither WPP nor the Program Operator shall be liable, whether based on contract, indemnification, warranty, tort, strict liability or otherwise, to any Participant, other entity owning a Qualifying Resource, third party, or other person for any damages whatsoever, including, without limitation, direct, incidental, consequential, punitive, special, exemplary, or indirect damages arising or resulting from any act or omission in any way associated with service provided under this Tariff or any agreement hereunder, including, but not limited to, any act or omission that results in an interruption, deficiency or imperfection of service, except to the extent that the damages are direct damages that arise or result from the gross negligence or intentional misconduct of WPP or Program Operator, in which case WPP shall only be liable for direct damages.

8.2.2 Neither WPP nor the Program Operator shall be liable for damages arising out of services provided under this Tariff or any agreement entered into hereunder, including, but not limited to, any act or omission that results in an interruption, deficiency, or imperfection of service, occurring as a result of conditions or circumstances beyond the control of WPP, or resulting from electric system design common to the domestic electric utility industry or electric system operation practices or conditions common to the domestic electric utility industry.

8.2.3 To the extent that a Participant or other person has a claim against WPP, the amount of any judgment or arbitration award on such claim entered in favor of such entity shall be limited to the value of WPP's assets. No party may seek to enforce any claims under this Tariff or any Agreements entered into hereunder against the directors, managers, members, shareholders, officers, employees, or agents of WPP, or against the Program Operator, who shall have no personal liability for obligations of WPP by reason of their status as directors, managers, members, shareholders, officers, employees, or agents of WPP or by virtue of their status as Program Operator.

8.2.4 To the extent that WPP is required to pay any money damages or compensation or pay amounts due to its indemnification of any other party as it relates to any services provided, acts, or omissions under this Tariff or any agreement entered into hereunder, WPP shall be allowed to recover any such amounts under Schedule 1 of this Tariff as part of the WRAP Administration Charge. Notwithstanding the foregoing, WPP shall be prohibited from recovering under this Tariff any costs associated with any damages, compensation, or indemnification costs that arise: (i) with regard to any acts or omissions that occur outside of this Tariff and any agreements entered into hereunder, or (ii) if a court of competent jurisdiction determines that the damages are direct damages that arise or result from the gross negligence or intentional misconduct of WPP or the Program Operator.

8.2.5 A Participant's liability to another Participant under this Tariff for failure to comply with obligations under this Tariff shall be limited to any charges or payments calculated pursuant to this Tariff; provided, however, that nothing in this Section 8.2.5 shall limit or is intended to foreclose any Participant's liability that may arise under any bilateral agreements between Participants.

8.3 Indemnification: The Participants shall at all times indemnify, defend, and save WPP (and any of its Program Operator(s), agents, consultants, directors, officers, or employees) harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties arising out of or resulting from the performance of activities under this Tariff by WPP, any Program Operator(s), or agents, consultants, directors, officers, or employees of WPP, except in cases of gross negligence or intentional wrongdoing by WPP or the Program Operator. WPP shall credit any proceeds from insurance or otherwise recovered from third parties to Participants who have paid to indemnify WPP under this Section 8.3.

8.4 Actions upon Unavailability of Program Operator(s): In the event that the Program Operator(s) become(s) unwilling, unable, or otherwise unavailable to perform contractual duties necessary for WPP to discharge its obligations under this Tariff and WPP’s agreement(s) with the Program Operator(s), WPP shall engage with Participants as soon as practicable to determine what actions to take, including but not limited to filing with FERC a request to waive one or more provisions of this Tariff up to and including immediate suspension of all rights and obligations under this Tariff until a replacement Program Operator(s) can assume all relevant Program Operator functions.

9. Dispute Resolution Procedures

9.1 Internal Dispute Resolution Procedures: Subject to the limitations set forth in Section 7.2.1 of this Tariff, any dispute between a Participant and WPP under the Tariff (excluding amendments to the Tariff or to any agreement entered into under the Tariff, which shall be presented directly to the FERC for resolution) shall be referred to a designated senior representative of WPP and a senior representative of the Participant for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty days (or such other period as the parties may agree upon) by mutual agreement, such dispute shall then be referred to the chief executive officer or comparable executive of each party for resolution. In the event that the executives are unable to resolve the dispute within thirty days (or such other period as the parties may agree upon), such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

9.2 External Arbitration Procedures: Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the parties to the dispute. If the parties fail to agree upon a single arbitrator within ten days of the referral of the dispute to arbitration, each party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable FERC regulations.

9.3 Arbitration Decisions: Unless otherwise agreed by the parties, the arbitrator(s) shall render a decision within ninety days of appointment and shall notify the parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and/or any agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the FERC if it affects jurisdictional rates, terms and conditions of service or facilities.

9.4 Costs: Each party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (i) the cost of the arbitrator chosen by the party to sit on the three-member panel and one half of the cost of the third arbitrator chosen; or (ii) one half the cost of the single arbitrator jointly chosen by the Parties.

9.5 Rights Under the Federal Power Act: Nothing in this section shall restrict the rights of any person to file a complaint with the FERC under relevant provisions of the Federal Power Act or of WPP to file amendments to this Tariff under the relevant provisions of the Federal Power Act.

10. Treatment of Confidential and Commercially Sensitive Information of Participants

10.1 Terms: For purposes of this Section 10 only, the term "WPP" shall also include, as applicable, any directors, officers, employees, agents, or consultants of WPP, the Independent Evaluator established under Section 5 of this Tariff, and any central credit organization established under Section 7 of this Tariff. WPP shall be bound by the rights, obligations, and conditions set forth in this Section 10. For purposes of this Section 10, the term "Disclosing Entity" shall include any Participant that discloses information to WPP that the Disclosing Entity deems and identifies as confidential or commercially sensitive. WPP's collection and handling of non-Participant data shall be governed by separate non-disclosure agreements with such non-Participants.

10.2 Treatment of Confidential or Commercially Sensitive Information: WPP shall identify in the Business Practice Manuals categories of Participant-specific data and information received from Participants that shall be treated as confidential or commercially-sensitive, which WPP shall not disclose publicly or to any other Participant or other entity except as provided for in this Section 10. In addition, WPP shall maintain the confidentiality of all of the documents, data, and information provided to it by any Participant that such disclosing Participant deems and specifically identifies as confidential or commercially sensitive. Notwithstanding the foregoing, WPP need not keep confidential: (i) information that is publicly available or otherwise in the public domain; or (ii) information that is required to be disclosed under this Tariff or any applicable legal or regulatory requirement (subject to the procedures set forth in Section 10.4 of this Tariff).

10.2.1 WPP staff may develop and release publicly composite or aggregated data based upon Participant confidential or commercially sensitive information, provided that such composite or aggregated data cannot be used to identify or attribute a disclosing Participant's confidential or commercially sensitive data. Such release of composite or aggregated data shall be governed by the following process.

10.2.1.1 Prior to the initial release of such composite or aggregated data, WPP staff shall present the form and format of such data to each Participant whose confidential information or data will be used to create the composite or aggregated data. If any such Participant objects to the form and format as revealing or allowing for attribution of confidential or commercially sensitive Participant-specific data, WPP staff shall determine whether to modify the form and format or to retain the proposed form and format for release. If WPP staff elects to retain the proposed form and format, the Participant shall have the right to appeal to the RAPC and WPP staff shall be prohibited from releasing the composite or aggregated data in the proposed form and format until the Participant's appeal rights as specified in this Section 10.2.1

are exhausted.

10.2.1.2 If a Participant appeals a WPP staff decision regarding the form and format of composite or aggregated data to the RAPC, the RAPC shall consider whether the form and format reveals or allows for attribution of confidential or commercially sensitive Participant-specific data. If the RAPC determines that the proposed form and format is sufficient to protect against the release of confidential or commercially sensitive Participant-specific data, WPP staff is authorized to release the composite or aggregated data in the proposed form and format unless the Participant timely appeals the RAPC decision to the Board of Directors.

10.2.1.3 If a Participant appeals a RAPC decision regarding the form and format of composite or aggregated data to the Board of Directors, the Board of Directors shall consider whether the form and format is sufficient to protect against the release or attribution of confidential or commercially sensitive Participant-specific data. If the Board of Directors determines that the proposed form and format is sufficient to protect against the release of confidential or commercially sensitive Participant-specific data, WPP staff is authorized to release the composite or aggregated data in the proposed form and format.

10.2.1.4 Once a proposed form and format of composite or aggregated data is approved by the WPP staff and is not appealed or appeals are unsuccessful, such form and format may be used for all future disclosures of composite or aggregate information and no Participant may dispute such release. If WPP staff proposes to alter the form and format, including but not limited to changing the granularity of data, WPP staff shall be required to follow the process set forth in this Section 10.2.1 and Participants shall have the right to appeal such changes in form and format as set forth herein. Notwithstanding the foregoing, if the composition of Participants in the WRAP changes in such a way that the form and format of composite or aggregated data is no longer sufficient to protect against disclosure or attribution of confidential or commercially sensitive Participant-specific data, an aggrieved Participant shall have a one-time right to raise the issue promptly with WPP Staff for presentation to and review by the Board of Directors, and the Board of Directors in its sole discretion shall decide whether the change in composition results in the form and format of the composite or aggregated data becoming insufficient to protect against the release or attribution of confidential or commercially sensitive Participant-specific data; provided, however, that if an aggrieved Participant does not raise its concerns with the Board of Directors promptly following the change in composition, such Participant shall have waived its right to contest the release of such composite or aggregated data.

10.2.2 Notwithstanding anything to the contrary in this Section 10.2, if the RAPC unanimously votes to disclose publicly any particular category of Participant-specific data, such data shall no longer be deemed confidential regardless of any such designation by a disclosing Participant, and this election shall be binding on any current and future Participants until such time as the RAPC votes unanimously to prohibit public release of such category of data. A list of the categories of Participant-specific data that the RAPC unanimously votes to make public shall be included in the Business Practice Manuals.

10.3 Access to Confidential or Commercially Sensitive Information: Except as otherwise provided in Section 10.2 of this Tariff, no Participant, entity owning a Qualifying Resource, or any third party shall have the right hereunder to receive from WPP or to otherwise obtain access to any documents, data or other information that has been identified as or deemed to be confidential or commercially sensitive under Section 10.2 of this Tariff by a disclosing Participant. The provisions of this Section 10.3 do not apply to WPP (including any Independent Evaluator, member of the Board of Directors, or any WPP officer, employee, agent, or consultant that requires access to confidential or commercially sensitive information); provided that access to Participant-specific confidential or commercially sensitive information shall be solely for the purpose of performing the duties or functions under this Tariff or otherwise advising or assisting WPP. WPP shall develop internal policies and controls governing the handling and protection of confidential or commercially sensitive Participant-specific data by members of the Board of Directors, officers, employees, agents, consultants, or any Independent Evaluator.

10.4 Exceptions: Notwithstanding anything in this Section 10 to the contrary:

10.4.1 If WPP is required by applicable laws or regulations, or in the course of administrative or judicial proceedings, to disclose information that is otherwise required to be maintained in confidence pursuant to this Section 10, WPP may disclose such information; provided, however, that as soon as practicable after WPP learns of the disclosure requirement and prior to making such disclosure, WPP shall notify any affected disclosing Participant of the requirement and the terms thereof. Any such disclosing Participant may, at its sole discretion and own cost, direct any challenge to or defense against the disclosure requirement and WPP shall cooperate with such disclosing Participant to take all reasonable available steps to oppose or otherwise minimize the disclosure of the information permitted by applicable legal and regulatory requirements. WPP shall further cooperate with such disclosing Participant to the extent reasonably practicable to obtain proprietary or confidential treatment of confidential or commercially sensitive information by the person to whom such information is disclosed prior to any such compelled disclosure.

10.4.2 WPP may disclose confidential or commercially sensitive information, without notice to any affected disclosing Participant(s), in the event that FERC, during the course of an investigation or otherwise, requests information that is confidential or commercially sensitive. In providing the information to FERC, WPP shall take action, consistent with 18 C.F.R. §§ 1b.20 and/or 388.112, to request that the information be treated by FERC as confidential and non-public and, if appropriate, as Critical Energy Infrastructure Information and that the information be withheld from public disclosure. WPP shall provide the requested information to FERC within the time provided for in the request for information. WPP shall notify any affected disclosing Participant(s) within a reasonable time after WPP is notified by FERC that a request for disclosure of, or decision to disclose, the confidential or commercially sensitive information has been received, at which time WPP and any affected disclosing Participant may respond before such information would be made public.

10.5 Notwithstanding any efforts undertaken pursuant to Section 10.4 to prevent or limit the release of a Participant's confidential or commercially sensitive information, in the event that FERC or a court of competent jurisdiction orders or otherwise permits the public release of a Participant's confidential or commercially sensitive information, the affected Participant shall have a one-time right to elect to terminate its participation in the WRAP under the expedited termination provisions set out in Section 11.2 of the WRAPA.

10.6 WPP shall handle any information identified or deemed to be Controlled Unclassified Information/Critical Energy Infrastructure Information in accordance with FERC's regulations set forth at 18 C.F.R. § 388.113 and any applicable FERC policies or other regulations, including but not limited to restricting access to such information on a password-protected portion of WPP's website or similar precautions.

10.7 Nothing in this Section 10 is intended to limit a Participant's ability to disclose or release publicly its own confidential or commercially sensitive information or data, or to limit a Participant's ability to authorize WPP's disclosure of such material to a specified recipient.

11. Timing

11.1 In the event that any deadline specified in this Tariff shall fall on a day that is not a Business Day, the deadline shall be extended to the next Business Day.

12. Application and Registration

12.1 Any entity wishing to participate in the WRAP must submit an application and registration in accordance with the Business Practices Manuals and must execute the WRAPA as set forth in Attachment A of this Tariff, or a non-conforming version of such participation agreement that is approved by FERC for an individual Participant. Such application and registration must be submitted in accordance with the timelines set forth in the Business Practices Manuals in advance of the next Binding Season.

12.2 Each Participant must register all of its resources and loads, regardless of whether such resources will be used to satisfy the WRAP requirements and regardless of whether certain loads will be subject to the requirements of the WRAP. Participants may modify their registration of resources and loads in accordance with the timing procedures set forth in the Business Practices Manuals.

12.3 In the event that more than one Participant attempts to register the same resource or load, the following procedure will be used to assign the resource or load to a Participant:

12.3.1 If a Participant attempts to register a load or resource that has already been registered by a different Participant, the resource or load will remain registered by the original Participant registering the resource or load until such time as both Participants mutually inform WPP that a change to the registration is required.

12.3.2 If two or more Participants attempt to register the same resource or load during the same registration window, WPP shall request that the Participants determine among themselves the appropriate registration of the resource or load before that resource or load is included in the WRAP.

PART II FORWARD SHOWING PROGRAM

13. Overview

13.1 In the Forward Showing Program, as set forth in this Part II of the Tariff, and as further detailed in the Business Practice Manuals, each Participant shall, in advance of each Binding Season, show as to such Binding Season: (i) the total capacity, referred to and defined herein as the FS Capacity Requirement, required by the provisions of this Tariff for such Binding Season for reliable service to the loads for which such Participant is responsible; (ii) the demonstration of capacity, referred to and defined herein as the Qualifying Capacity Contribution, or QCC, provided by the Qualifying Resources the Participant provides or procures to meet its FS Capacity Requirement; and (iii) at least the minimum level of firm transmission service, referred to and defined herein as the FS Transmission Requirement, needed for reliable delivery of the QCC of the Participant's Qualifying Resources from such resources to the loads for which the Participant is responsible.

13.2 As also set forth in this Part II of the Tariff, and as further detailed in the Business Practice Manuals: (i) WPP shall, in advance of each Binding Season, review the Forward Showing Submittals of each Participant for such Binding Season; (ii) WPP shall identify to the Participant any deficiencies in the Participant's Portfolio QCC (whether as to contracts or directly owned or controlled resources) relative to the FS Capacity Requirement, and any deficiencies in the identified firm transmission service relative to the FS Transmission Requirement, within sixty days of the Forward Showing Submittal deadline; (iii) the Participant shall have an opportunity to cure such deficiencies, within sixty days of notification of deficiency; and (iv) if the Participant fails to cure all such deficiencies on or before the deadlines prescribed herein, the Participant shall be assessed a Forward Showing Deficiency Charge.

14. Forward Showing Program Process and Timeline

14.1 The Forward Showing Program has two Binding Seasons, defined as the Summer Season and the Winter Season. The Summer Season is the period beginning on June 1 of each Year and ending on September 15 of that same Year. The Winter Season is the period beginning on November 1 of each Year and ending on March 15 of the succeeding Year. This Tariff does not establish resource or showing obligations outside the periods defined by the Summer Season and Winter Season.

14.2 Each Participant shall submit its Forward Showing Submittals for each Month of each Binding Season, with all required supporting materials and information as detailed in the Business Practice Manuals, on or before the FS Deadline for the Binding Season. The FS Deadline for each Binding Season shall be seven months before the start of such Binding Season.

14.2.1 Forward Showing Submittal:

14.2.1.1 Absent the exception in Section 14.2.1.2, each Participant shall submit a separate Forward Showing Submittal for loads for which it is responsible if transmission constraints between areas where its loads are located, including, without limitation, when Participant is responsible for loads in more than one Subregion, prevent application, in the manner more fully described in the Business Practice Manuals, of Resource QCC or Net Contract QCC from one load area to the FS Capacity Requirement of another load area.

14.2.1.2 Notwithstanding Section 14.2.1.1, a Participant responsible for loads in two Subregions may submit for a given Month a single Forward Showing Submittal for such loads, and may employ for determination of its FS Capacity Requirement for such Month the lower of the two FSPRM values determined for the Subregions where its loads are located, if the Participant demonstrates in such Forward Showing Submittal, in accordance with the procedures and requirements set forth in the Business Practice Manuals, transmission service rights of the type required by the FS Transmission Requirement, in a quantity, in addition to that required by the FS Transmission Requirement, equal to the difference in the two FSPRM values multiplied by the Participant's P50 Peak Load Forecast for such Month, with a point of delivery in the Subregion with the higher FSPRM value and the point of receipt in the Subregion with the lower FSPRM value. Each such showing shall identify the MW quantity, Month of service, point of receipt, and point of delivery of such transmission service rights, and such other information as specified in the Business Practice Manuals, and shall verify that the offered rights are NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service.

14.2.2 Each Participant's Forward Showing Submittal shall include a Senior Official Attestation.

14.3 The FSPRM values used in the Forward Showing Submittals for a Binding Season shall be those values approved by the Board of Directors as the culmination of an Advance Assessment process. No later than twelve months before the FS Deadline for each Binding Season, WPP will determine and post the recommended FSPRM for each Subregion for each Month of such Binding Season. Participants shall provide their load, resource and other information reasonably required to perform the analyses and calculations required for the Advance Assessment, in accordance with the Advance Assessment information submission details and schedule specified in the Business Practice Manuals. No later than nine months before the FS Deadline for such Binding Season, the Board of Directors shall take its final action regarding approval of the FSPRM values for each Month of such Binding Season.

14.3.1 In connection with an Advance Assessment process, or otherwise in connection with consideration of a change to the Business Practice Manuals, the Board of Directors may determine that designation of Subregions would encourage the relief, in whole or part, of transmission constraints on the transfer of capacity within the WRAP Region (whether through development or commitment of transmission, of Qualifying Resources, or by other means) to the benefit of the WRAP Region and the advancement of the objectives of the WRAP. Each such Subregion shall be identified in the Business Practice Manuals.

14.3.2 Any Participant may choose to offer in the Advance Assessment process transmission service rights owned or controlled by such Participant for firm delivery of capacity from one Subregion to another Subregion, for use by other Participants under the terms of Part III of this Tariff during any or all identified Months of the applicable Binding Season. Each such offer shall identify the MW quantity, Month of service, point of receipt, and point of delivery of such transmission service rights, and such other information as specified in the Business Practice Manuals, and shall verify that the offered rights are NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service. No Participant is obligated to offer any such transmission service rights in the Advance Assessment process, but any offer so made and not withdrawn before the deadline during the Advance Assessment process specified in the Business Practice Manuals shall be considered a binding offer of the identified transmission service rights which may not be withdrawn before the end of the last Day of the Month for which such transmission service is offered. WPP shall take account of such offered transmission service rights, along with other transmission deliverability reasonably anticipated to be available for use by Participants for WRAP purposes during the applicable Binding Season in its determination of the recommended FSPRM values for each Month of the applicable Binding Season for the WRAP Region and for each affected Subregion.

14.4 No later than sixty Days after the FS Deadline for a Binding Season, WPP will (i) provide the values of the Participant's FS Capacity Requirement and FS Transmission Requirement for each Month of the Binding Season; (ii) affirm that the Portfolio QCC of such Participant for each Month of the Binding Season equals or exceeds the FS Capacity Requirement of such Month for such Participant or notify such Participants of any deficiencies in the Forward Showing Submittal that result in a failure to demonstrate satisfaction of the FS Capacity Requirement; and (iii) affirm that the Demonstrated FS Transmission plus approved Monthly Transmission Exceptions of such Participant for each Month of the Binding Season equals or exceeds the FS Transmission Requirement of such Month for such Participant or notify such Participants of any deficiencies in the Forward Showing Submittal that result in a failure to demonstrate satisfaction of the FS Transmission Requirement.

14.5 Within 120 Days after the FS Deadline, the Participant shall (i) submit revisions to its Forward Showing Submittal, including, without limitation, additions or revisions to the Participant's Resource QCC, Net Contract QCC, or Demonstrated FS Transmission; (ii) in order to fully cure all identified deficiencies and demonstrate that such Participant's Portfolio QCC for each Month of the Binding Season equals or exceeds its FS Capacity Requirement; and (iii) fully provide Demonstrated FS Transmission for each Month of the Binding Season that equals or exceeds its FS Transmission Requirement for the same Month of the Binding Season where WPP identified deficiencies.

14.5.1 Any Participant that fails to cure identified deficiencies in its Forward Showing Submittal within the period prescribed above shall be assessed a Deficiency Charge.

15. Transition Period

15.1 Except as specified in Section 15.1.1, the Binding Season beginning November 1, 2027, will be the first Binding Season for which all Participants will assume the obligations of demonstrating capacity and making surplus capacity available to other Participants and will receive the benefits of reliance upon other Participants' surplus capacity. Any Binding Season during the Transition Period occurring before November 1, 2027, shall be a Non-Binding Season, as specified in Section 15A of this Tariff.

15.1.1 No later than January 15, 2026, a Participant may elect the Binding Season beginning June 1, 2027, as the first Binding Season for which it will assume the obligations of demonstrating capacity and making surplus capacity available to other Participants and will receive the benefits of reliance upon other Participants' surplus capacity by providing written notice of its election.

15.2 Within two years prior to the start of the first Binding Season of the WRAP, a Participant who has elected to participate in the first Binding Season may request a vote of all Participants who have elected to participate in the first Binding Season to delay implementation of the first Binding Season for up to two Seasons. Delayed implementation of the first Binding Season shall be approved if 75% of the Participants who elected to participate in the first Binding Season vote in favor of such delay, with approval requiring a vote of 75% of both the House and Senate vote tallies (as described in Sections 4.1.6.2.1 and 4.1.6.2.2 of this Tariff) of all Participants who elected to participate in the first Binding Season.

15.2.1 The deferral vote may only occur for the first Binding Season of the WRAP. If the Participants who elected to participate in the first Binding Season of the WRAP vote to delay implementation of the first Binding Season, all compliance charges for the Forward Showing Program and Operations Program are automatically deferred; except that the Participants may vote to delay implementation only of the Operations Program portion of the first Binding Season and retain the binding Forward Showing Program portion of the first Binding Season.

15A. Non-Binding Seasons

15A.1 A Participant will participate as a Non-Binding Participant for certain Binding Seasons in the Transition Period, as detailed in Section 15.1 of this Tariff, and when Critical Mass is not achieved for a given Binding Season, as detailed in Section 15A.2 of this Tariff. As to a Non-Binding Season, the Participant:

15A.1.1 Shall not be subject to Deficiency Charges, Transmission Deficiency Charges, Holdback Requirements, Energy Deployment obligations, or Delivery Failure Charges;

15A.1.2 Shall submit Forward Showing Submittals but shall not be required to cure deficiencies;

15A.1.3 Shall not have a mandatory Holdback Requirement as a result of the Sharing Calculation;

15A.1.4 May only receive Holdback Capacity offered voluntarily by other Participants in accordance with Part III of this Tariff; and

15A.1.5 Shall have all rights and be subject to all obligations under Part I of this Tariff and the Participant's WRAPA, including, without limitation, voting rights, committee participation, and the obligation to pay the WRAP Administration Charge.

15A.2 Once WPP has given notice to Participants that their Subregion does not have Critical Mass for a given Binding Season, each such Participant will have 30 days to provide notice to WPP if it intends to participate as a Non-Binding Participant for that Binding Season. Such notice and election will be given similarly for each season without Critical Mass participation.

16. Components of the Forward Showing

16.1 FS Capacity Requirement. The FS Capacity Requirement shall be determined for each Participant on a monthly basis by applying the applicable Monthly FSPRM for a Month to such Participant's peak load forecast for that Month. The Participant's peak load forecast for a given Month of a Binding Season will be the P50 Peak Load Forecast for the Binding Season multiplied by a shaping factor based on the historical relationship, for such Participant, of the seasonal peak for the Winter Season or Summer Season, as applicable, and the monthly peaks for the Months in such season, as more fully described in the Business Practice Manuals.

16.1.1 P50 Peak Load Forecast. The P50 Peak Load Forecast is a peak load forecast prepared on a basis, such that the actual peak load is statistically expected to be as likely to be above the forecast as it is to be below the forecast. The Business Practice Manuals shall specify an approved load forecasting methodology for use by all Participants for their WRAP-required load forecasts which shall include (i) a base monthly peak derived from a recent historical period that recognizes additions and removals of load during the historical period, (ii) adjustments for known additions and removals of load during the forecast window; and (iii) a specified load growth factor.

16.1.2 FS Planning Reserve Margin

16.1.2.1 The FSPRM is an increment of resource adequacy supply needed to meet conditions of high demand in excess of the applicable peak load forecast and other conditions such as higher resource outages, expressed as a percentage of the applicable peak load forecast. The FSPRM shall be determined based on probabilistic analysis, taking account of uncertainties in generation and load, as the margin above peak load that provides an expectation of no more than a single event-day of loss of load in ten years (sometimes referred to herein as the "1-in-10 LOLE") for each Binding Season. The FSPRM shall be determined in a manner that accounts for the governing principles of QCC value determinations set forth in Section 16.2.5 of this Tariff and shall employ the applicable peak load for the applicable Binding Season and Months. Additional details, assumptions, methodologies, and procedures for determination of the FSPRM shall be as set forth in the Business Practice Manuals.

16.1.2.2 WPP shall calculate in the Advance Assessment process the recommended Monthly FSPRM for each Month of each Binding Season, for approval by the Board of Directors as set forth in this Part II.

16.1.2.3 The FSPRM shall employ (i) a simulated resource stack using capacity accreditation principles consistent with those used for WRAP QCC determinations; (ii) an adjustment in the total WRAP-required QCC value as needed to meet a 1-in-10 LOLE for each Binding Season, and (iii) while maintaining the 1-in-10 LOLE for each Binding Season in (ii), include a monthly reduction of capacity to ensure that each Month has at least 0.01 annual LOLE. The FSPRM for a Month shall be the simulated QCC as adjusted to meet the 1-in-10 LOLE for each Binding Season minus the P50 Peak Load Forecast for the Month, divided by the P50 Peak Load Forecast for the Month.

16.1.2.4 The FSPRM shall include an approximation of Contingency Reserves as set forth in the Business Practice Manuals.

16.1.3 Contingency Reserves Adjustment. A Participant's FS Capacity Requirement will be adjusted as set forth in the Business Practice Manuals to account for changes in Contingency Reserve requirements resulting from energy contract purchases and contract sales.

16.1.4 A Participant responsible for loads located in a Subregion for which an FSPRM value has been determined that is higher than the FSPRM value determined for a different Subregion may, in lieu of demonstrating a MW increment of Portfolio QCC otherwise required to satisfy such Participant's FS Capacity Requirement for a given Month, demonstrate in its Forward Showing Submittal, in accordance with the procedures and requirements set forth in the Business Practice Manuals, transmission service rights of the type required by the FS Transmission Requirement, in a quantity, in addition to that required by the FS Transmission Requirement, that is no greater than the difference in the two FSPRM values multiplied by the Participant's P50 Peak Load Forecast, with the point of delivery in the Subregion with the higher FSPRM value and the point of receipt in the Subregion with the lower FSPRM value. The MW quantity of the additional transmission so demonstrated shall reduce for such Month, by the same MW quantity, the Portfolio QCC the Participant would otherwise be required to demonstrate to satisfy its FS Capacity Requirement for such Month. Each such demonstration shall identify the MW quantity, Month of service, point of receipt, and point of delivery of such transmission service rights, and such other information as specified in the Business Practice Manuals, and shall verify that the offered rights are NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service.

16.2 Qualified Capacity Contribution

16.2.1 For each Participant and each Binding Season, the Forward Showing shall show and support the Portfolio QCC, which shall be the sum of the QCC of the Participant's Qualifying Resources ("Resource QCC"), the QCC of its contracted capacity ("Net Contract QCC"), and any transfers of capacity already accredited by another Participant ("Total RA Transfer," which could be positive or negative). The Portfolio QCC effective for a Binding Season shall be the value determined by WPP.

16.2.2 A resource will not be assigned a Resource QCC or counted toward Portfolio QCC unless it is a Qualifying Resource. Qualifying Resources are those that, before they are included in a Forward Showing Submittal, are first registered with WPP. A Participant seeking registration of a resource must submit a request for registration providing the resource information described in the Business Practice Manuals.

16.2.3 The minimum resource size for registration of a resource is 1 MW, provided, however, that Participants with responsibility for individual resources of less than 1 MW may aggregate them to meet the 1 MW minimum requirement, under the conditions and limitations specified in the Business Practice Manuals.

16.2.4 A Participant may include in its Forward Showing Submittal a request for an exception from its FS Capacity Requirement for an insufficiency of its Portfolio QCC solely due to (i) a catastrophic failure of one or more Qualifying Resources due to an event of Force Majeure as defined by Section 8.1 of this Tariff that (ii) the Participant is unable to replace on commercially reasonable terms prior to the FS Deadline as a result of the timing and magnitude of such catastrophic failure and its consequences. As more fully set forth in the Business Practice Manuals, such exception request shall be supported by a Senior Official Attestation. The exception request must include complete information on the nature, causes and consequences of the catastrophic failure, and must describe the Participant's specific, concrete efforts prior to the FS Deadline to secure replacement Qualifying Resources for the applicable Binding Season. WPP will consider the exception criteria established by this section, the information provided in the exception request, the completeness of the exception request, and other relevant data and information, in determining whether to grant or deny an FS Capacity Requirement exception request. WPP shall provide such determination no later than sixty days after submission of such Participant's FS Submittal containing such FS Capacity Requirement exception request. A Participant granted an exception hereunder must complete a monthly exception check report demonstrating that either the circumstances necessitating the exception have not changed; or that Qualifying Resources have become available, and the Participant has acquired them and no longer requires the exception. Failure to timely submit a required monthly report will result in assessment of a Deficiency Charge, unless the deficiency is cured within seven days of notice of non-compliance. A Participant denied an exception request hereunder may appeal such denial to the Board of Directors in accordance with the procedures and deadlines set forth in the Business Practice Manuals. In such event, the requested exception shall be denied or permitted as, when and to the extent permitted by the Board, in accordance with the procedures and timing set forth in the Business Practice Manuals. WPP shall give notice of any exception granted hereunder in the time and manner provided by the Business Practice Manuals.

16.2.5 QCC: WPP shall determine QCC values for the resource types specified below in accordance with the governing principles specified below for each resource type, and consistent with further details specified for each resource type in the Business Practice Manuals.

16.2.5.1 For resources that use conventional thermal fuels, including but not limited to, coal, natural gas, nuclear, and biofuel, WPP will determine QCC based on an Unforced Capacity methodology that employs resource-specific capability testing and capability requirements to determine an Installed Capacity value, and a forced outage calculation methodology based on historical performance during Capacity Critical Hours over a specified multi-year period (excluding outages properly reported as "outside management control"), or based on class-average forced outage data, as specified in the Business Practice Manuals, if there is insufficient data on historical performance.

16.2.5.2 For resources that are Variable Energy Resources, including, but not limited to, wind and solar resources, WPP will determine QCC based on an ELCC methodology, that accounts for synergistic portfolio effects within and among VER types at different resource penetration levels that influence the extent to which the WRAP Region can rely on those VER categories to meet overall capacity needs.

16.2.5.2.1 For such purpose, a separate ELCC value will be calculated in the aggregate for all VER resources of a given type in an identified VER Zone, to be delineated in the Business Practice Manuals based on factors such as geography, performance, meteorological considerations, and penetration.

16.2.5.2.2 As more fully described in the Business Practice Manuals, the zonal aggregate VER-resource-type value will be calculated by (i) conducting a benchmark LOLE study that includes all resource types except the VER resource type being studied, employing a model and assumptions consistent with those used to calculate FSPRM, and adding, or subtracting, the same MW quantity of Pure Capacity to every hour of the applicable Binding Season until, respectively, an initial LOLE value above 0.1 day per Binding Season becomes 0.1 day per Binding Season, or an initial LOLE value below 0.1 day per Binding Season becomes 0.1 day per Binding Season; (ii) conducting an LOLE study that includes all resource types including the VER resource type being studied, employing a model and assumptions consistent with those used to calculate FSPRM, and adding, or subtracting, the same MW quantity of Pure Capacity to every hour of the applicable Binding Season until, respectively, an initial LOLE value above 0.1 day per Binding Season becomes 0.1 day per Binding Season, or an initial LOLE value below 0.1 day per Binding Season becomes 0.1 day per Binding Season; and (iii) subtracting the Pure Capacity value determined under subpart (ii) from the Pure Capacity value determined under subpart (i) (for which calculation a Pure Capacity value subtracted from each hour in either subpart (i) or subpart (ii) will be assigned a negative value; (iv) repeating steps (i) through (iii) for each Binding Season of the study period employing historical, or as necessary, synthesized, data; and (v) basing the aggregate value of the studied VER resource type for the studied VER Zone on the results of the calculation in step (iii) for the Binding Seasons studied, which may include differential weighting of the Binding Seasons studied as appropriate to improve the quality and predictive capacity of the final result.

16.2.5.2.3 The aggregate capacity calculated for each VER resource type in each VER Zone will then be allocated to VERs of that type in that VER Zone based on each such resource's average historical performance if at least three years of historical performance or three years of synthesized forecast data during the WRAP Region's CCH is available at the time of such allocation. If three years historical performance or synthesized forecast data is not then available, the average ELCC from the VER Zone will be assigned.

16.2.5.3 For resources that are Energy Storage Resources, WPP will determine QCC based on an ELCC methodology comparable to that used for VERs. The ELCC methodology will model Energy Storage Resources at the level of their usable capacity that can be sustained for a minimum duration of four hours. An Energy Storage Resource need not have a nameplate rating that assumes a minimum of four hours in order to receive a QCC determination, but the QCC in that case will be scaled to reflect the capability that can be sustained for four hours, as more fully described in the Business Practice Manuals.

16.2.5.4 A Participant's Demand Response used as a Demand Response Capacity Resource must be controllable and dispatchable by the Participant or by the host utility, and must have met certain testing requirements consistent with Business Practice Manuals. WPP will determine Demand Response Load Modifier QCC by multiplying the load reduction in MWs by the number of hours the resource can demonstrate load reduction capability (for a period of up to five continuous hours) divided by five. The effects of Demand Response used as a Demand Response Capacity Resource must not be included in load provided for a Participant's Advance Assessment.

16.2.5.5 For Storage Hydro Qualifying Resources, the Participant will calculate a QCC based on a methodology detailed in the Business Practice Manuals that: (i) considers each resource's actual generation output, residual generating capability, water in storage, reservoir levels, and flow or project constraints over the previous ten-year historical period; (ii) determines the project's QCC by assessing the historical generation during CCHs on any given day and ability to increase generation during CCHs on the same day, subject to useable water in storage, inflows/outflows, and expected project operating parameters/constraints and limitations; (iii) incorporates forced outage rates; and (iv) determines QCC as average contribution to the CCH for each Winter Season and Summer Season over the previous ten years. If ten years of historical data is not available for the Storage Hydro Qualifying Resource, the Participant may alternatively employ data on the same metrics from a demonstrably comparable facility or apply another method that provides reasonable confidence in the reliability of the predicted values, as more fully set forth in the Business Practice Manuals. The Participant's QCC calculation shall be subject to review and validation by WPP. In connection with such review, the Participant shall provide WPP with the following information necessary to calculate a QCC for Storage Hydro Qualifying Resources: (i.a) historical reservoir elevation levels; (ii.a) historical plant generation; (iii.a) elevation versus capacity curves; (iv.a) any minimum or maximum reservoir level constraints; (v.a) forced outage rates; (vi.a) volume of water versus reservoir elevation storage tables; and (vii.a) turbine discharge versus generation efficiency curve.

16.2.5.6 For Run of River Qualifying Resources, WPP will determine QCC based on the monthly average performance of such resource during Capacity Critical Hours, as further specified in the Business Practice Manuals

16.2.5.7 For resources that (i) are not within the meaning of any of Sections 16.2.5.1 through 16.2.5.5, and that (ii) either (a) are not dispatchable; or (b) require the purchaser of energy from the resource to take energy as available from such resource, including but not limited to a qualifying facility as defined under the Public Utility Regulatory Policies Act of 1978, WPP will determine QCC based on the monthly average performance of such resource during Capacity Critical Hours, as further specified in the Business Practice Manuals.

16.2.6 Net Contract QCC: WPP shall determine Net Contract QCC for the agreement types specified below in accordance with the governing principles specified below for each agreement type, and consistent with further details specified for each agreement type in the Business Practice Manuals. Net Contract QCC may be either positive or negative, to take account of, for example, a Participant's agreements for the sale of capacity to any other party.

16.2.6.1 Absent one of the exceptions described and limited below, capacity supply agreements qualifying for a Net Contract QCC in the WRAP must be resource specific, and therefore must include, among other requirements, an identified source, an assurance that the capacity is not used for another entity's resource adequacy requirements, an assurance that the seller will not fail to deliver in order to meet other supply obligations, and affirmation of NERC Priority 6 or 7 firm point-to-point transmission service rights or network integration transmission service rights from the identified resource to the point of delivery/load. The specific resources identified in a capacity supply agreement qualifying for Net Contract QCC shall meet the same Resource QCC accreditation requirements for the given resource type, as specified in Section 16.2.5.

16.2.6.2 A system sales contract can qualify for a Net Contract QCC value, provided that if the seller is not a Participant, the system capacity that is the subject of the agreement must be deemed surplus to the seller's estimated needs, there must be an assurance that the seller will not fail to deliver in order to meet other commercial obligations, and there must be NERC Priority

6 or 7 firm point-to-point transmission service rights or network integration transmission service rights from the identified resource to the point of delivery/load. Surplus status may be demonstrated by a Senior Official Attestation with pertinent supporting details for such surplus status, including written assent of the non-Participant Seller, secured by the purchasing Participant. Such attestation is not required if the seller is a Participant, because the information needed to verify surplus status is already available.

16.2.6.3 A supply agreement entered into prior to October 1, 2021 (“Legacy Agreement”) can qualify for a Net Contract QCC value; provided that where a legacy agreement does not identify the source, it must be possible for WPP to presume a source or sources for the contract, including with the written assent of the supplier under such Legacy Agreement, conveyed in the form and manner set forth in the Business Practice Manuals. A Legacy Agreement for which such resource determination cannot be reasonably made will not be counted as adding to the Portfolio QCC.

16.2.7 Total RA Transfer: A Participant may agree with another Participant on a transfer of a portion of its Portfolio QCC to meet the other’s FS Capacity Requirement (“RA Transfer”), provided that the details and duration of such transfer are reported to WPP for validation in accordance with procedures and information requirements specified in the Business Practice Manuals. Where such transfers have been duly reported and validated, an RA Transfer will be added to the purchasing Participant’s Portfolio QCC and subtracted from the selling Participant’s Portfolio QCC.

16.2.8 Planned Outages: Participants shall include in their Forward Showing Submittal for a Binding Season information on all Qualifying Resources that are currently out of service with a scheduled return date that falls during the Binding Season or after the Binding Season. Capacity associated with such resources must be deducted from Participants’ Portfolio QCC as specified in the Business Practice Manuals to ensure no credit is granted for such resources during the planned outage. The aggregate of any additional outages that are planned to occur during the Binding Season but have not yet begun at the time of submission must be within the Participant’s remaining surplus (or replaced with other supply). Participants may provide information on all Qualifying Resources that are planned to be out of service but if such data cannot be supplied with reasonable specificity, a Participant may provide a Senior Official Attestation at the time of the submission of its FS Submittal that it expects the sum of planned outages to be equal to or less than the surplus stated in its FS Submittal throughout the Binding Season.

16.2.8.1 If a Qualifying Resource is planned to return to service within the first five days of a Binding Season, WPP may approve a qualified acceptance of the FS Submittal, provided the deficiency is less than 500 MW.

16.2.8.2 A planned outage shall not justify a waiver of or exception to a Participant's holdback or energy delivery obligations under Part III of this Tariff. Participants will be expected to procure the necessary capacity or energy to meet the Operations Program requirements, regardless of planned outage schedules or FS Submittal acceptance.

16.3 FS Transmission Requirement

16.3.1 As part of its Forward Showing Submittal for a Binding Season, each Participant must demonstrate, as specified in the Business Practice Manuals, that it has secured firm transmission service rights, including under supply arrangements with a third party that holds or has committed transmission service rights, sufficient to deliver a MW quantity equal to at least 75% of the MW quantity of its FS Capacity Requirement. To the extent a Participant holds transmission service rights with a point of receipt at a Qualifying Resource, or in connection with an RA Transfer to such Participant, any such rights from such point in a MW quantity, respectively, in excess of the QCC of such Qualifying Resource, or in excess of the value of such RA Transfer, shall not contribute toward satisfaction of such Participant's FS Transmission Requirement. The FS Transmission Requirement must be met with NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service or network integration transmission service, from such Participant's Qualifying Resource(s) or from the delivery points for the resources identified for its Net Contract QCC or for its RA Transfer to such Participant's load. Notwithstanding the foregoing, authorized use of Capacity Benefit Margin will satisfy the FS Transmission Requirement. Demonstration of the FS Transmission Requirement shall not, in and of itself, relieve any Participant of responsibility for a Delivery Failure Charge as determined under Section 20.7 if such Participant's failure to obtain or maintain firm transmission service of the type and quantity expected by the Operations Program, as described in Section 20.6 of this Tariff, caused or contributed to an Energy Delivery Failure.

16.3.2 A Participant may include in its Forward Showing Submittal a request for an exception from a limited part of its FS Transmission Requirement, provided the exception request meets the terms, conditions, and limitations of one or more of the following four exception categories below. As more fully set forth in the Business Practice Manuals, such exceptions may be subject to overall WRAP limits, and shall be supported by a Senior Official Attestation. WPP will consider the exception category terms, conditions and limitations set forth below, and may consider the completeness of the exception request, information from transmission service providers, OASIS data, and data readily available to WPP from other reliable and validated sources concerning the duration, timing, firmness and quantity of available transmission service or equivalent options (including transmission construction), in determining whether to grant or deny a transmission exception request. WPP shall provide such determination no later than sixty days after submission of such Participant's FS Submittal containing such transmission exception request. A Participant denied an exception request hereunder may appeal such denial to the Board of Directors in accordance with the procedures and deadlines set forth in the Business Practice Manuals. In such event, the requested exception shall be denied or permitted as, when and to the extent permitted by the Board, in accordance with the procedures and timing set forth in the Business Practice Manuals. WPP shall give notice of any exception granted hereunder in the time and manner provided by the Business Practice Manuals. A Participant granted a transmission exception under either Section 16.3.2.1 or Section 16.3.2.2 must complete a monthly transmission exception check report demonstrating that either (i) the circumstances necessitating the exception have not changed; (ii) transmission has become available and the Participant has acquired it; or (iii) the Participant has acquired a different resource, and associated transmission service rights, and no longer requires the exception. Failure to timely submit a required monthly report will result in assessment of a Deficiency Charge, unless the deficiency is cured within seven days of notice of non-compliance.

16.3.2.1 Enduring Constraints. Participant is unable to demonstrate sufficient NERC Priority 6 or NERC Priority 7 firm point-to-point or network integration transmission service rights on any single segment of a source to sink path for a Qualifying Resource; and Participant demonstrates that no ATC for such transmission service rights is available (either from the transmission service provider or through a secondary market) at the FS Deadline on the applicable segment for the Month(s) needed (for a duration of one year or less) at the applicable Open Access Transmission Tariff rate or less; and Participant submits a Senior Official Attestation that Participant has taken commercially reasonable efforts to procure firm transmission service rights, and that Participant has posted Firm Transmission Requirements on a relevant bulletin board prior to the FS Deadline. In the event such transmission service rights are only available for a duration of more than one year (whether from the transmission service provider or through a secondary market) at the FS Deadline on the applicable segment for the Month(s) needed at the applicable Open Access Transmission Tariff rate or less, a Participant is not required to obtain such service in order to qualify for the Enduring Constraints exception hereunder. Notwithstanding the foregoing, if such Participant declines to obtain such available service and is granted the exception hereunder, such Participant shall not qualify for an exception hereunder for the same path (or across the same constraint) for the same season of the subsequent year if the Participant again declines to obtain such transmission service rights that are available for a duration of more than one year. In addition to the foregoing, Participant must further demonstrate that there was remaining available transmission transfer capability (i.e., non-firm ATC after the fact) for all CCHs in the same season of the most recent year for which CCHs have been calculated; or, if the path was constrained in at least one CCH of the CCHs in the same season of the most recent year for which CCHs have been calculated, Participant in that case must demonstrate either that it is constructing or contracting for a new local resource for at least the amount of the exception requested, or that it is pursuing long-term firm transmission service rights by entering the long-term queue and taking all appropriate steps to obtain at least the amount of the exception requested.

16.3.2.2 Future Firm ATC Expected. Participant demonstrates that ATC for NERC Priority 6 or NERC Priority 7 firm point-to-point or network integration transmission service rights is not posted or available prior to the FS Deadline (for a duration of one year or less) at the applicable Open Access Transmission Tariff rate or less, and that the transmission service provider has, after the FS Deadline, released additional ATC for such transmission service rights in every one of the CCHs of the most recent year for which CCHs have been calculated on the applicable path. In the event ATC for such transmission service rights is only posted or available prior to the FS Deadline for a duration of more than one year (whether from the transmission service provider or through a secondary market) on the applicable segment for the Month(s) needed at the applicable Open Access Transmission Tariff rate or less, a Participant is not required to obtain such service in order to qualify for the Future Firm ATC Expected exception hereunder. Notwithstanding the foregoing, if such Participant declines to obtain such available service and is granted the exception hereunder, such Participant shall not qualify for an exception hereunder for the same path (or across the same constraint) for the same season of the subsequent year if the Participant again declines to obtain such transmission service rights that are available for a duration of more than one year. The Participant must also demonstrate that the exception request meets volume and duration limitations specified in the Business Practice Manuals.

16.3.2.3 Transmission Outages and Derates. Participant demonstrates that an applicable segment of its existing transmission service rights from its source to sink path for its Qualifying Resource is expected to be derated or out-of-service and the ATC for NERC Priority 6 or NERC Priority 7 firm point-to-point or network integration transmission service rights is not otherwise available, and that the exception request meets volume and duration limitations specified in the Business Practice Manuals.

16.3.2.4 Counterflow of a Qualifying Resource. Participant demonstrates that either: (i) Participant's use of firm transmission service in connection with the delivery of capacity from Participant's Qualifying Resource (or from the resource associated with its Net Contract QCC) to Participant's load (or other qualifying delivery point permitted by the WRAP) or (ii) a second Participant's use of firm transmission service in connection with the delivery of capacity from the second Participant's Qualifying Resource (or from the resource associated with its Net Contract QCC) to the second Participant's load (or other qualifying delivery point permitted by the WRAP) provides a direct and proportional counterflow transmission that supports the first Participant's delivery of capacity from the first Participant's Qualifying Resource (or from the resource associated with its Net Contract QCC) to the first Participant's load (or other qualifying delivery point permitted by the WRAP) Qualifying Resource to their load. If the exception is requested under subpart (ii) of this subsection, the Participant requesting the exception shall include a written acknowledgement from the second Participant that it is aware of such exception request.

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16.3.3 To the extent a Participant does not demonstrate satisfaction of its FS Transmission Requirement by the FS Deadline, the Participant may correct any such deficiency on or before the end of the cure period prescribed by Section 14.5 of this Tariff to avoid a Deficiency Charge.

16.3.4. Any deficiency of transmission service rights ultimately determined by WPP will be treated, for purposes of Deficiency Charge determinations, as in conjunction with, and not additive to, any deficiencies of QCC determined pursuant to Section 16.2.

17. Forward Showing Deficiency Charge

17.1 If a Participant fails during the cure period to demonstrate that it has resolved any identified deficiencies in either or both of its FS Capacity Requirement and its FS Transmission Requirement, the Participant will be assessed a Deficiency Charge for each Month for which a deficiency is identified in accordance with this section. In such case, the deficiency for which the Participant will be assessed a Deficiency Charge will be calculated in accordance with the following:

Participant's Monthly Capacity Deficiency = Maximum of (Monthly FS Capacity Requirement – Monthly Portfolio QCC, 0)

Participant's Monthly Transmission Deficiency (MW) = Maximum of ((75% × Monthly FS Capacity Requirement) – (Monthly Transmission Demonstrated + Approved Monthly Transmission Exemptions), 0)

Where Monthly Transmission Demonstrated is the amount of transmission service rights submitted by a Participant per the requirements in Section 16.3 and validated by WPP for each month.

Monthly Deficiency (MW) = Maximum of (Monthly Capacity Deficiency, Monthly Transmission Deficiency)

17.2 A Participant's Deficiency Charges shall be calculated as set forth in this Section 17.2, subject to the Transition Period rules in Section 17.3, and shall take account of multiple Monthly Deficiencies within a Forward Showing for a single Binding Season, multiple Deficiencies across a Forward Showing Year, consisting of a Summer Season and the immediately succeeding Winter Season, and any Monthly Deficiencies in a previous Forward Showing Year, in accordance with the following:

17.2.1 The Monthly Deficiency with the highest MW value in a Forward Showing for a Summer Season shall be assessed a Deficiency Charge equal to:

Max Summer Deficiency (MW) × Annual CONE ($/kW-year) × 1000 × Summer Season Annual CONE Factor

17.2.2 Any other Monthly Deficiency in the Participant's Forward Showing for the same Summer Season shall be assessed a Deficiency Charge equal to:

Additional Summer Deficiency (MW) × (Annual CONE ($/kW-year)/12) × 1000 × 200%

17.2.3 Any Monthly Deficiency in the Forward Showing for the immediately succeeding Winter Season with a higher MW value than the highest MW value of the Monthly Deficiency in the Summer Season shall be assessed a Deficiency Charge on the incremental MW value above the Summer Season equal to:

Maximum of (Max Winter Deficiency – Max Summer Deficiency, 0) (MW) × Annual CONE ($/kW-year) × 1000 × Winter Season Annual CONE Factor

and in such case where there is a Monthly Deficiency in the Winter Season with a higher MW value than the highest MW value of any Monthly Deficiency in the Summer Season, the Monthly Deficiency with the highest MW value in the Summer Season shall be assessed an additional Deficiency Charge calculated in accordance with Section 17.2.2.

17.2.4 Any other Monthly Deficiency in the Participant's Forward Showing Submittal for the same Winter Season shall be assessed a Deficiency Charge equal to:

Additional Winter Capacity Deficiency × (Annual CONE/12) × 1000 × 200%

17.2.5 For purposes of the above, CONE is the estimated cost of new entry of a new peaking natural gas-fired generation facility. The CONE estimate shall be based on publicly available information relevant to the estimated annual capital and fixed operating costs of a hypothetical natural gas-fired peaking facility. The CONE estimate shall not consider the anticipated net revenue from the sale of capacity, energy, or ancillary services from the hypothetical facility, nor shall it consider variable operating costs necessary for generating energy.

17.2.6 WPP shall review the CONE estimate annually for a possible update. Any proposed changes in the CONE estimate shall be subject to review through the stakeholder process for program rule changes.

17.2.7 The Summer Season Annual CONE Factor shall vary based on the ratio ("Summer % Deficit") of the Aggregate Capacity Deficiency for the WRAP as a whole for that Summer Season, divided by the P50 Peak Load Forecast for the Summer Season, as follows:

If the Summer % Deficit is less than or equal to 1%, the Summer Season Annual CONE Factor = 125%

If the Summer % Deficit is greater than 1% but less than or equal to 2%, the Summer Season Annual CONE Factor = 150%

If the Summer % Deficit is greater than 2% but less than or equal to 3%, the Summer Season Annual CONE Factor = 175%

If the Summer % Deficit is greater than 3%, the Summer Season Annual CONE Factor = 200%

17.2.8 The Winter Season Annual CONE Factor shall vary based on the ratio ("Winter % Deficit") of the Aggregate Capacity Deficiency for the WRAP as a whole for that Winter Season, divided by the P50 Peak Load Forecast for the Winter Season, as follows:

If the Winter % Deficit is less than or equal to 1%, the Winter Season Annual CONE Factor = 125%

If the Winter % Deficit is greater than 1% but less than or equal to 2%, the Winter Season Annual CONE Factor = 150%

If the Winter % Deficit is greater than 2% but less than or equal to 3%, the Winter Season Annual CONE Factor = 175%

If the Winter % Deficit is greater than 3%, the Winter Season Annual CONE Factor = 200%

17.2.9 Notwithstanding Sections 17.2.7 and 17.2.8, if a *Participant incurred any FS Deficiency Charges* in a Forward Showing Year *after the Transition Period*, then for the immediately following Forward Showing Year, both the Summer Season Annual CONE Factor and the Winter Season Annual CONE Factor shall be 200% *for such Participant*.

17.2.10. Subject to the Transition Period rules in Section *15A.1*, revenues from the payment of Deficiency Charges as to a Binding Season shall be allocated among those Participants with no Deficiency Charges for that Binding Season, pro rata based on each Participant's share of all such Participants' Median Monthly P50 Peak Loads for such Binding Season.

17.3 During the Transition Period, Deficiency Charges otherwise calculated under Section 17.2 shall be reduced as, when, and to the extent, and subject to the conditions, provided in Section 17.3.2; and revenue allocations otherwise calculated under Section 17.2 shall be adjusted as, when, and to the extent, and subject to the conditions, provided in Section 17.3.4.

17.3.1. During the Transition Period, a Participant with a Monthly Capacity Deficiency can pay a *Discounted* Deficiency Charge for so much of such Monthly Capacity Deficiency as was due to an Excused Transition Deficit. To obtain an Excused Transition Deficit for a Binding Season, the Participant must provide a Senior Official Attestation attesting that the Participant *or a relevant third party servicing load for which the Participant is the LRE* has made commercially reasonable efforts to secure Qualifying Resources in the quantity needed to satisfy the Participant's FS Capacity Requirement for the Binding Season, but is unable to obtain Qualifying Resources in the quantity required for the Binding Season because the supply of such resources on a timely basis and on commercially reasonable terms is at that time inadequate. *If the attestation relates to a third-party servicing load for which the Participant is the LRE, the Senior Official Attestation may be signed by a Senior Official of the third party load service provider, as further detailed in the Business Practices.* Excused Transition Deficits are not resource specific, relate to a MW quantity of the Participant's FS Capacity Requirement, and are limited for each Participant as to a Binding Season during the Transition Period to a maximum permissible MW quantity equal to a percentage value times the FSPRM applicable to such Participant for all Forward Showing Submittals submitted by such Participant for such Binding Season. For purposes of such calculation, the percentage value is*: 200*% for each of the *2027* Summer Season and *2027-2028* Winter Season*; and 100*% for each of the *2028* Summer Season and *2028-2029* Winter Season.

17.3.2 A Participant will pay a *Discounted* Deficiency Charge as to the portion of its Monthly Capacity Deficiency for which it obtained an Excused Transition Deficit. The *FS* Deficiency Charge otherwise applicable to such Participant under Section 17.2 shall be reduced by a percentage value equal to 75% for each of the *2027* Summer Season and *2027-2028* Winter Season*; and* 50% for each of the *2028* Summer Season and *2028-2029* Winter Season. The Participant will be assessed a*n FS* Deficiency Charge calculated under Section 17.2, without reduction or adjustment, for any of its Monthly Capacity Deficiency that is in excess of the amount of such deficiency for which it obtained an Excused Transition Deficit.

17.3.3 Whether or not a Participant obtains an Excused Transition Deficit as to a Binding Season, the Participant may reduce a Monthly Capacity Deficiency otherwise calculated under Section 17.1 for a Binding Season during the Transition Period to the extent such deficiency is due to the Participant's inability to obtain assent from the supplier under a Legacy Agreement to the accreditation required for such Legacy Agreement under Part II of this Tariff and the Business Practice Manuals. To obtain such relief, the Participant must provide a Senior Official Attestation attesting that the Participant made commercially reasonable efforts to execute the required accreditation form with the supplier under the Legacy Agreement, but the supplier was unable or unwilling to counter sign the accreditation form. The reduction in Monthly Capacity Deficiency permitted by this Section 17.3.3 as to any Participant for all Forward Showing Submittals submitted by such Participant for any Binding Season during the Transition Period shall not exceed a MW quantity equal to 25% times the FSPRM applicable for such Participant for such Binding Season. To the extent a Participant reduces a Monthly Capacity Deficiency under this subsection, the percentage of the Participant's FSPRM corresponding to the reduction hereunder shall reduce the maximum permissible percentage of FSPRM reduction allowed under Section 17.3.1 for Excused Transition Deficits for the same Binding Season.

17.3.4 A Participant that, as a result of application of this Section 17.3, pays no Deficiency Charge as to a Binding Season, shall not be deemed a "Participant[ ] with no Deficiency Charges" for purposes of Section 17.2.10, and shall not receive an allocation of revenues from the payment of Deficiency Charges as to such Binding Season.

PART III OPERATIONS PROGRAM

18. Operations Program Overview

18.1 The Operations Program facilitates access to collective capacity made available through regional load and resource diversity of all Participants under the terms of this Part III.

18.2 The Operations Program evaluates forecasted system conditions across the seven-day period ("Multi-Day-Ahead Assessment") preceding the Operating Day, commencing at the outset of the assessment period with an initial Sharing Calculation and initial identification of potential Sharing Events for the Operating Day. The assessment is refined as forecasted conditions for the Operating Day are revised and established on the Preschedule Day, a Holdback Requirement for any Sharing Events is then identified. To the extent a Sharing Event continues to be identified for the Operating Day, Holdback Requirements shall be converted into Energy Deployments on the Operating Day.

18.3 The Operations Program prescribes pricing designed to incent Participants to resolve any forecast Operating Day deficiencies before the Operating Day, including through transactions outside the Operations Program, and to fully compensate Participants that provide support through the Operations Program to Participants with Operating Day deficiencies.

19. Operations Program Timeline and Supporting Information

19.1 The Operations Program includes a Multi-Day Ahead Assessment that looks ahead at the next seven Operating Days by performing an indicative Sharing Calculation from Participant forecast data for each future Operating Day up until the Preschedule Day. The Sharing Calculation for the Preschedule Day is not indicative but is binding, subject to Sections 20.2.4 and 20.3. Participants shall provide WPP with forecasts for the next seven Operating Days of expected (i) load, (ii) output of VERs, (iii) output of RORs, (iv) Contingency Reserves, and (v) forced outages, including outages on transmission facilities the Participant utilized to meet its Forward Showing Capacity Requirement, as further described in the Business Practice Manuals. WPP shall utilize the forecast data obtained in the Multi-Day-Ahead Assessment to calculate or revise the indicative Sharing Calculations for each day thereafter, up until the Preschedule Day, and will use such forecast data to revise the indicative Sharing Calculation hourly during the Operating Day. Such forecast data will also be used to calculate the binding Sharing Calculation for the Preschedule Day.

19.2 The Operations Program, during any Binding Season, shall rely on and employ (among other data) the following information from the Forward Showings for such Binding Season: (i) the P50 Peak Load Forecast for each Participant; (ii) the Monthly FSPRMs for each Participant during such Binding Season; (iii) expected performance by Qualifying Resource type and any RA Transfers; (iv) expected forced outage rates by resource type; (v) expected Contingency Reserves; and (vi) firm transmission service rights made available for purposes of regional diversity sharing under the WRAP, permitted under Part II of this Tariff, which shall be assumed to be available for all hours of each Month for which such firm transmission service rights were made available.

19.3 To facilitate WPP's conduct of the Multi-Day-Ahead Assessment, each Participant shall provide the Program Operator information relevant to the Participant's expected demand and supply conditions on each Operating Day, of the type, in the manner, and with the frequency, specified in the Business Practice Manuals.

19.4 Each Participant in any Subregion identified in the Business Practice Manuals as not containing a central transmission hub permitting energy deliveries to that hub from any point within such Subregion, shall, in addition to providing the information required by Section 19.3, identify, on or before the deadline during the Preschedule Day specified in the Business Practice Manuals, for each Hour of the Operating Day each point to which it can deliver energy, each point at which it can take receipt of energy, the quantity it can deliver or receive at each such point, and a numeric factor intended to prioritize use of transmission made available by Participants with positive Sharing Calculations and needed by Participants with negative Sharing Calculations for each such hour. A Participant with a positive Sharing Calculation for an hour must provide a total quantity for all identified points at which it can deliver that is no less than the amount of its positive Sharing Calculation for such hour (adjusted as necessary for any RA Transfer in accordance with Section 20.1.2). A Participant with a negative Sharing Calculation for an hour must provide a total quantity for all identified points at which it can take receipt that is no less than the amount of its negative Sharing Calculation for such hour (adjusted as necessary for any RA Transfer in accordance with Section 20.1.2). Participants shall provide this same information for each Operating Day on an expected or preliminary basis on each day of the Multi-Day-Ahead Assessment following, and based on, the expected Holdback Requirement estimates provided on each such day for the Operating Day.

19.5 Any Participant with excess supply that is not obligated to the WRAP through a positive Sharing Calculation result may, at its sole election, offer such supply to the WRAP as Voluntary Holdback. If the offering Participant has a positive Sharing Calculation result, the offered capacity shall be in addition to that Sharing Calculation result; if the offering Participant has a negative Sharing Calculation result, the offered capacity will only be included in the allocation of Holdback Requirement so long as the offering Participant did not confirm a need for Holdback Capacity for such hour. Such offers must be submitted within the time window identified in the Business Practice Manuals, must include the information identified in Sections 19.3 and 19.4, as applicable, and must conform to the format and content identified in the Business Practice Manuals. An offer of Voluntary Holdback may become part of the Participant's Holdback Requirement when it is included in the allocation on the Preschedule Day prescribed by Section 20.2.

20. Components of the Operations Program

20.1 Sharing Calculation

20.1.1 WPP shall implement, as more fully described in the Business Practice Manuals, with respect to each Forward Showing Submittal accepted by WPP for a Participant under Part II of this Tariff, or with respect to each Subregion in which the Participant is responsible for load regardless of whether the Participant submitted a single Forward Showing Submittal encompassing its loads in both Subregions, the following Sharing Calculation to identify any hour in which any Participant is forecast to have a capacity deficit (known as a "Sharing Event"). This calculation takes into account changes in a Participant's resource availability, resource performance, forecast load, and Contingency Reserve relative to the Forward Showing, plus an Uncertainty Factor. The Sharing Calculation is equal to:

[(**P50) * (1 + FSPRM) + Contingency Reserve Adjustment] – [Load Forecast – Demand Response Capacity Resources + Contingency Reserve Obligation + Uncertainty Factor] + [ΔForced Outages + ΔRoR Performance + ΔVER Performance]**

Where:

P50 refers to the Participant's Monthly P50 Peak Load for that Binding Season's Month;

FSPRM, as described in Section 16.1.2, is an increment of resource adequacy supply needed to meet conditions of high demand in excess of the applicable peak load forecast and other conditions such as higher resource outages and is expressed as a percentage of the applicable Participant P50 Peak Load Forecast for that Binding Season's month;

Contingency Reserve Adjustment accounts for changes in Contingency Reserve expectations (relative to the 6% Contingency Reserve assumed in the FSPRM) resulting from energy contract purchases and contract sales as set forth in the Business Practice Manuals;

Load Forecast refers to the forecast of expected load for the subject hour for the loads for which the Participant is the Load Responsible Entity and that have not been excluded from WRAP participation;

Demand Response Capacity Resource as described in Section 16.2.5.4.

Contingency Reserve Obligation refers to the amount of Contingency Reserve the Participant is carrying during the operating hour equal to (i) 3% of Load Forecast for which the Participant is the WRAP LRE and maintains its Contingency Reserve, (ii) plus 3% of WRAP load for which the Participant is not the LRE but has assumed the Contingency Reserve through a contractual arrangement, (iii) plus 3% of generation used to meet any load for which the Participant is the LRE and maintains the Contingency Reserve, (iv) plus 3% of generation utilized to meet WRAP Load for which the Participant is not the LRE but has assumed the Contingency Reserve through a contractual arrangement;

Uncertainty Factor refers to a factor determined by WPP, as more fully set forth in the Business Practice Manuals, to account for the potential variance between forecasts of load, solar resources, wind resources, and run-of-river resources, and the Operating Day conditions of such load and resources;

$\boldsymbol{\Delta\ Forced\ Outages}$ refers, for the subject hour, to the sum of:

(i) any change in forced outages of any of the thermal resources included in the Participant's Portfolio QCC, relative to the forced outages assumed in the Forward Showing Submittal by application of the Forced Outage Factor; plus

(ii) any change in forced outages of any of the Storage Hydro Qualifying Resources relative to the forced outages assumed in the calculation of the Participant's Resource QCC as more fully described in the Business Practice Manuals; plus

(iii) any reduction in output capability of any of the Energy Storage Resources due to equipment failure or protection

  a. In the first four (4) hours the Forced Outages MWs that can be claimed are equal to [(charge MW x duration)/4]

  b. For all hours beyond four (4) hours, the Forced Outages MW amount that can be claimed for an Energy Storage Resource shall not be greater than the monthly QCC; plus

(iv) any impacts of transmission conditions on previously acquired firm transmission service rights that result in capacity reductions up to the level of the Resource QCC of the associated Qualifying Resource;

$\boldsymbol{\Delta RoR\ Performance}$ refers to any change, for the subject hour, in expected performance of any of the run-of-river resources in the Participant's Portfolio QCC relative to the QCC of those Qualifying Resources; and

$\boldsymbol{\Delta VER\ Performance}$ refers to any change, for the subject hour, in expected performance of the VER Resources in the Participant's Portfolio QCC relative to the QCC of those Qualifying Resources;

20.1.2 In addition to the foregoing, the Sharing Calculation for a Participant that is a purchaser of an RA Transfer shall be performed in two passes, with and without such purchase. If the result of assuming in the first pass that the Participant had not purchased the RA Transfer is that the Participant has a negative Sharing Calculation, then the Participant that sold the RA Transfer must agree, for the time period addressed by the Sharing Calculation, to an energy delivery to the Participant that purchased the RA Transfer, in an amount equal to the lesser of: (i) the MW quantity needed to result in a net zero Sharing Calculation for the Participant that purchased the RA Transfer; and (ii) the MW amount of the RA Transfer. If the result of recognizing the Participant's purchase of the RA Transfer in the second pass is that the Participant has a positive Sharing Calculation, then the Participant that sold the RA Transfer must assume a share of the purchasing Participant's resulting obligation to the Operations Program in an amount equal to the MW quantity of the RA Transfer, minus the MW quantity of the delivery made by the seller of the RA Transfer to the purchaser of the RA Transfer as a result of the first pass.

20.1.3 The Sharing Calculation of any Participant that was found to have a Monthly Capacity Deficiency under Sections 16.1 and 16.2, for which such Participant paid a Deficiency Charge, including any Deficiency Charge reduced by application of Section 17.3 during the Transition Period, shall be reduced by the MW quantity of such Monthly Deficiency.

20.2 Holdback Requirement

To the extent that: (i) WPP's application of the Sharing Calculation identifies on the Preschedule Day a Sharing Event for any hour(s) of the Operating Day; and (ii) the Participant(s) found to be deficient for such hour(s) by the Sharing Calculation confirms to WPP on the Preschedule Day, in accordance with notification and confirmation procedures set forth in the Business Practice Manuals, such Participant's need for capacity for such hour(s), then WPP shall determine the Participants having a Holdback Requirement for such hour(s) and the quantity of the Holdback Requirement for each such Participant in accordance with this Section 20.2. The Operations Program will prioritize offers of Voluntary Holdback in the allocation and assignment of Holdback Requirements. Holdback Requirements shall be expressed as whole MWs for each hour for which they are estimated or established and shall not be specific to any Qualifying Resource.

20.2.1 Subregion with Central Hub

For any hour, as to any Subregion identified in the Business Practice Manuals as containing a central transmission hub permitting energy deliveries to that hub from any point within such Subregion ("Central Hub"), the aggregate of the holdback needed to meet the requirements of all Participants with negative Sharing calculation results that have confirmed their need for holdback will be allocated and assigned first among offers of Voluntary Holdback, and second, to the extent such needs remain unmet, among Participants with positive Sharing Calculation results.

20.2.1.1 Allocation of Voluntary Holdback: Voluntary Holdback will be allocated in one of three alternative ways, based on comparing the aggregate confirmed need for holdback among Participants with negative Sharing Calculation results against the aggregate of all offers for Voluntary Holdback.

20.2.1.1.1 If the total MW quantity of all Voluntary Holdback offered is equal to the total MW quantity of all deficient Participants' confirmed requests for holdback, then each Participant that offered Voluntary Holdback is assigned its offered Voluntary Holdback as its Holdback Requirement.

20.2.1.1.2 If the total MW quantity of all Voluntary Holdback offered is more than the total MW quantity of all deficient Participants' confirmed requests for holdback, then each Participant that offered Voluntary Holdback is assigned as its Holdback Requirement a percentage of the total confirmed need for holdback based on the ratio of the Participant's MWs of offered Voluntary Holdback to the sum of all Participants' MWs of offered Voluntary Holdback.

20.2.1.1.3 If the total MW quantity of all Voluntary Holdback offered is less than the total MW quantity of all deficient Participants' confirmed requests for holdback, then each Participant's Holdback Requirement is determined as set forth in section 20.2.1.2.

20.2.1.2 Allocation of Remaining Holdback Requirement: Sharing Calculation Results

If the total MW quantity of all Voluntary Holdback offered is less than the total MW quantity of all deficient Participants' confirmed requests for holdback, then the maximum Voluntary Holdback offered is used as the first term in the Holdback Requirement. The remaining term of the Holdback Requirement is met by application of the Sharing Calculation, and the results of the two terms are summed for each Participant. The remaining need for holdback that is not met by Voluntary Holdback is allocated among all Participants with positive Sharing Calculation results pro rata based on the ratio for each Participant of the Participant's positive Sharing Calculation result to the sum of the positive Sharing Calculation results. The sum of these two values for each applicable Participant is the Holdback Requirement for that Participant.

20.2.2 Subregion without Central Hub

For any hour, any Subregion not containing a Central Hub, the Program Operator shall conduct an optimization-based allocation to pair surplus and deficient Participants. The allocation methodology will utilize the points at which surplus Participants can deliver their Holdback Requirement, the points at which deficient Participants can take receipt of their allocation of the total Holdback Capacity, and the transfer capability that exists to the points at which surplus Participants can deliver and the points at which deficient Participants can take receipt.

The optimization will generally attempt to prioritize (i) Voluntary Holdback; (ii) Holdback Capacity matched pursuant to the information provided per Section 19.4 on a nearest neighbor and cluster basis, allocated pro rata among Participants within such cluster; (iii) Holdback Capacity matched pursuant to the information provided and allocated among Participants within the same Subregion to the extent not matched and allocated under category (ii); and finally (iv) Holdback Capacity from Participants in another Subregion, paired with any transmission service per Section 14.3.2.

20.2.3 Absent a Holdback Requirement Transfer as described below, a Participant's Holdback Requirement for any hour of an Operating Day shall not exceed the level first set by WPP on the Preschedule Day for that Participant for that hour.

20.2.4 Any Participant may agree with any other Participant for the first Participant to transfer to the second Participant some or all of the Holdback Requirement established for the first Participant for any hour on any Operating Day. Any such Holdback Requirement Transfer shall be a bilateral arrangement settled outside the Operations Program, provided, however, that both Participants must timely notify WPP, by the time and in the manner described in the Business Practice Manuals, of such Holdback Requirement Transfer. Any necessary transmission arrangements and any transaction settlements shall be the sole responsibility of the Participants that are the parties to such bilateral arrangement.

20.2.4.1 No Holdback Requirement transfer for any hour shall be permitted if notice of such bilateral transaction is not fully reported to WPP, in the form required by the Business Practice Manuals, by 120 minutes before the start of such hour.

20.3 Release of Surplus Capacity

20.3.1 As detailed in the Business Practice Manuals, WPP will review the indicative Sharing Calculation results from the Multi-Day Ahead Assessment and to the extent the WPP determines any indicative Sharing Calculations can be reduced, it may release all or a portion of Participants' future Holdback Requirements. WPP may permit a release of future Holdback Requirements to the extent WPP has not applied a Safety Margin for such hour and (i) WPP's continued Sharing Calculations determine that no Participant has a negative indicative Sharing Calculation result for such hour; and (ii) WPP determines there is a low probability of a Sharing Event for the hour; or (iii) WPP grants a Participant's request for extenuating circumstances of all or any portion of that Participant's future Holdback Requirement for the hour.

20.3.2 Upon release of all or any portion of a future Holdback Requirement, the quantity of future Holdback Requirement so released shall no longer be subject to an Energy Deployment requirement under the Operations Program for the subject hour.

20.4 Energy Deployment

20.4.1 Participants shall provide energy during an hour, in support of any Participants with a negative Sharing Calculation result and a confirmed need for energy under the Operations Program for such hour, in accordance with WPP's calculation of the Energy Deployment for such hour. The total Energy Deployment required of all Participants that are subject to Energy Deployment shall equal the sum, in MWh for that hour, of the energy confirmed as being needed in that hour by Participants in such Subregion with negative Sharing Calculation results in such hour, to the extent that can be supported by the Program. The Energy Deployment assigned to each Participant shall not exceed that Participant's Holdback Requirement calculated on the Preschedule Day, adjusted for any applicable transfer of Holdback Requirement as allocated and assigned for the Preschedule Day, and, as further adjusted to reflect the election, made after the Preschedule Day, of any Participant with a negative Sharing Calculation result on the Preschedule Day to decline all or any part of the Holdback Capacity to which it would have been entitled based on the Holdback Requirements determined on the Preschedule Day.

20.4.1.1 In Subregions with a Central Hub, Energy Deployments required hereunder shall be delivered to the Central Hub in such Subregion, or to an alternate delivery point mutually agreed by the parties to a specific Energy Deployment, provided both parties to the transaction report such alternative delivery arrangements to WPP in the form and manner described in the Business Practice Manuals.

20.4.1.2 In Subregions without a Central Hub, Energy Deployments required hereunder shall be delivered to the receipt point and delivery point as indicated by the optimization allocation, or to an alternate delivery point mutually agreed by the parties to a specific Energy Deployment, provided both parties to the transaction report such alternative delivery arrangements to WPP in the form and manner described in the Business Practice Manuals.

20.4.2 The Energy Deployment a Participant may receive for any hour shall be no greater than the negative Sharing Calculation result calculated for such Participant for such hour. Such Participant shall confirm, by no later than 85 minutes before the start of such hour, the quantity of Energy Deployment for which it requires delivery for such hour, through the procedures outlined in the Business Practice Manuals. Any Participant that does not confirm required Energy Deployment deliveries for such hour by such deadline will be deemed to waive all deliveries of Energy Deployment under the Operations Program for such hour.

20.4.3 The Energy Deployment a Participant can be required to supply for an hour shall not exceed the final Holdback Requirement calculated for such Participant on Preschedule Day, including any duly reported exchange of Holdback Requirement, as of 85 minutes before the start of such hour.

20.4.4 WPP shall advise each Participant with a required Energy Deployment for an hour of the required MWh quantity and delivery point of such Energy Deployment by no later than 80 minutes before the start of such hour.

20.5 Safety Margin

20.5.1 WPP may establish on the Preschedule Day a Safety Margin for the WRAP Region or any identified Subregion thereof for any hour of an Operating Day when warranted by such circumstances as potential large resource trips, heavy transmission outage conditions, significant environmental conditions, or other similar regional or subregional conditions, as more fully set forth in the Business Practice Manuals.

20.5.2 Any Safety Margin so determined for an hour shall be allocated pro rata among Participants with a positive Sharing Calculation result, based on their relative shares of the sum of all positive Sharing Calculation results for such hour, provided, however, that the Safety Margin allocated to a Participant may not result in a Holdback Requirement for such Participant greater than such Participant’s Sharing Calculation result. A Participant allocated holdback for a Safety Margin hereunder does not receive compensation under this Tariff for such allocation of holdback.

20.5.3 WPP shall notify all Participants of application of a Safety Margin for any hour, including in such notice the total timeframe, the MW amount, and the rationale for such Safety Margin.

20.6 Operations Program Transmission Service Requirements

Participant shall have in place, prior to the Operating Day, transmission service satisfying NERC Priority 6 or 7 for each hour of such Operating Day for which a Sharing Event has been established, in a quantity sufficient for deliveries from the Qualifying Resources relied upon in such Participant's Forward Showing Submittal to demonstrate satisfaction of such Participant's FS Capacity Requirement (or from replacement Qualifying Resources) to serve such Participant's loads during such hours. In the event a Participant has an Energy Delivery Failure, the review associated with the possible assessment of a Delivery Failure Charge on such Participant shall, as further described in the Business Practice Manuals, include whether a failure to secure sufficient NERC Priority 6 or Priority 7 firm transmission service rights caused or contributed to such Energy Delivery Failure. For such purpose, the Participant will have been expected to have complied with the transmission service requirement stated in this subsection.

20.7 Failure to Deliver Energy Deployments

20.7.1 A Participant assigned a required Energy Deployment pursuant to Section 20.4.4 of this Tariff for any hour that fails to deliver the specified energy during such hour, and that does not obtain a waiver of its Energy Deployment obligation, shall be assessed a Delivery Failure Charge.

20.7.2 A Participant shall be deemed to have an Energy Delivery Failure if Participant fails to deliver the Energy Deployment quantity established under Section 20.4.1, absent grant of a waiver pursuant to Section 20.7.3 of this Tariff.

20.7.3 A Participant anticipating an Energy Delivery Failure should provide WPP notice of such expected Energy Delivery Failure as soon as practicable after becoming aware of the anticipated failure. Whether anticipated or not, a Participant may request a waiver of an Energy Deployment obligation after an Energy Delivery Failure has occurred. The WPP shall review all such waiver requests and shall determine whether the Participant's justification for the Energy Delivery Failure is valid and warrants waiver of its Energy Deployment obligation. The WPP also shall consider whether the Participant knew in advance, or reasonably should have known in advance, of an Energy Delivery Failure, and what efforts the Participant took to notify the WPP in advance of such Energy Delivery Failure. The procedures for addressing such waiver requests, including a non-exclusive list of valid justifications for an Energy Delivery Failure shall be set forth in the Business Practice Manuals. A Participant denied a waiver request hereunder may appeal such denial to the Board of Directors in accordance with the procedures and deadlines set forth in the Business Practice Manuals. In such event, the requested waiver shall be denied or permitted as, when and to the extent permitted by the Board, in accordance with the procedures and timing set forth in the Business Practice Manuals. WPP shall report on the disposition of each waiver request received.

20.7.4 The Delivery Failure Charge for each hour shall be the Charge Rate applicable for such hour times the MWhs of energy that were required to be, but were not, delivered pursuant to an Energy Deployment during such hour. The Charge Rate shall be the higher of the Day-Ahead price or Real-Time price provided by the Day-Ahead Applicable Price Index and Real-Time Applicable Price Index as specified in the Business Practice Manuals for the Subregion applicable to the location of the delivering entity, applicable to the day and hour of the energy delivery, respectively, for the hour, times a Delivery Failure Factor, as follows:

20.7.4.1 If the deficit is fully covered by other Participants through the Operations Program, in each instance of failure, the Delivery Failure Factor shall be five for the first non-waived Energy Delivery Failure in a Cumulative Delivery Failure Period; ten for the second non-waived Energy Delivery Failure in a Cumulative Delivery Failure Period; and twenty for the third and subsequent non-waived Energy Delivery Failures in a Cumulative Delivery Failure Period. For purposes of applying the Delivery Failure Factors under this Section 20.7.4 or the review referenced in Section 20.7.5, multiple Energy Delivery Failures occurring in one day shall be treated as a single instance of failure.

20.7.4.2 If the deficit is not fully covered by other Participants through the Operations Program, the Delivery Failure Factor is twenty-five for the first non-waived Energy Delivery Failure in a Cumulative Delivery Failure Period; and fifty for the second and subsequent non-waived Energy Delivery Failures (regardless of whether the prior instance(s) of delivery failure were fully covered by other Participants) in a Cumulative Delivery Failure Period.

20.7.4.3 Revenues from Delivery Failure Charges assessed in cases where the deficit was fully satisfied by other Participants will be used to reduce WPP costs that are recovered under Schedule 1, WRAP Administration Charge. Revenues from Delivery Failure Charges assessed in cases where the deficit was not fully met by other Participants will be collected by the WPP and provided to the Participant that had an unserved deficit.

20.7.4.4 Notwithstanding anything to the contrary in this Section 20.7.4, the Delivery Failure Charges assessed on a Participant, regardless of application of the Delivery Failure Factor, shall not exceed, over the course of a Summer Season and the immediately succeeding Winter Season, the dollar amount that, as more fully detailed in the Business Practice Manuals, would have been assessed cumulatively under Section 17 as Deficiency Charges if the Participant had one or more Forward Showing Capacity Deficiencies over the course of such Summer Season and Winter Season in the same MW amounts as the highest MW amount of Delivery Failure experienced by such Participant in each Month of such Summer Season and Winter Season. The maximum dollar amount described herein shall be calculated on an ongoing basis during such Summer Season and Winter Season, and increased or reduced accordingly, without awaiting the end of the combined period of such Summer Season and Winter Season.

20.7.5 In addition to assessment of the Delivery Failure Charge, a third or subsequent instance of non-waived delivery failure, when all such delivery failures are fully covered by other Participants, or a second or subsequent instance of non-waived delivery failure when such instance is not fully covered by other Participants, will subject the Participant to review for expulsion from the WRAP.

20.8 Voluntary Response to Increased Deficiencies Identified After Preschedule Day

20.8.1 A Participant that identifies an unmet need for energy for any hour of an Operating Day that is outside of assistance provided or to be provided by Holdback Requirements or Energy Deployments established hereunder may, in accordance with procedures specified in the Business Practice Manuals, notify WPP of the need for such assistance. WPP will establish a portal or other procedure, as specified in the Business Practice Manuals, to facilitate provision of assistance, on a voluntary, bilateral basis, by other Participants to the Participant that identified the unmet need. Compensation, terms, and conditions of any resulting bilateral transactions will be determined by the affected parties outside of this Tariff. While Participant response to any such notification is voluntary, Participants are encouraged to provide assistance to other Participants in the circumstances described in this subsection, in consideration of the mutual support each Participant has agreed to provide to each other Participant by its agreement to participate in the WRAP, including this Operations Program.

21. Operations Program Settlements

21.1 Nature of Operation Program Settlements

21.1.1 Operations Program settlements are bilateral transactions; they are not purchases from or sales to a central market.

21.1.2 Operations Program transactions use existing transaction systems and processes.

21.1.3 The WPP will calculate and post settlement quantities and prices based on the Energy Deployment and Holdback Requirement, in accordance with procedures specified in the Business Practice Manuals for provision of transaction information by and among Participants and WPP, but WPP has no role in the transaction itself. WPP is not a settlement entity.

21.1.4 Settlement Prices calculated under Section 21.2 shall recognize pricing differences among Subregions. Where the seller and buyer are located in the same Subregion, the Applicable Price Index shall be the price index specified for that Subregion in the Business Practice Manuals. Where the seller and buyer are located in different Subregions, the following components of the settlement price calculation in Section 21.2 will be calculated using the Applicable Price Index for the Subregion that provides the higher index price: (i) Possible Block Sale Revenue; (ii) Total Settlement Price; (iii) Energy Declined Settlement Price; and (iv) Realtime Value of Unheld Energy. If a third participant is involved by providing transmission service rights between Subregions, the Participant that provided holdback or Energy Deployment shall receive the settlement price of the Subregion from which the holdback or Energy Deployment was sourced, and the Participant that provided Subregion to Subregion transmission service rights pursuant to Section 19.4 shall receive the difference between each Subregion's Total Settlement Price, or zero, whichever is greater.

21.2 Settlement Price Calculation. Settlement prices shall be calculated in accordance with the following, as more fully set forth in the Business Practice Manuals.

21.2.1 A Participant assigned a Holdback Requirement on a Preschedule Day for any hour of an Operating Day shall be paid the Holdback Settlement Price times the MW quantity of the Holdback Requirement. A Participant that provides energy to another Participant pursuant to an Energy Deployment shall be paid the Energy Declined Settlement Price, defined in Section 21.2.4, times the MWhs of energy provided to such other Participant, and its total payments shall be reduced by the Energy Declined Settlement Price times the MWhs of energy that would have been provided under a Holdback Requirement but were declined by the other Participant. A Participant assigned a Holdback Requirement also shall be paid, when applicable, a Make Whole Adjustment, as provided below in Section 21.2.5.

21.2.2 A Participant that had a negative Sharing Calculation result for any hour of an Operating Day, which was incorporated in the calculation of Holdback Requirements of any Participants for such hour, determined as of the Preschedule Day, shall pay the Holdback Settlement Price times the MW quantity of such negative Sharing Calculation result. In addition, any Participant that had a negative Sharing Calculation result that was incorporated in the calculation of a Holdback Requirement shall contribute to the payment of the Make Whole Adjustment based on its negative Sharing Calculation. A Participant that declines energy that would have been provided under a Holdback Requirement shall be credited the Energy Declined Settlement Price times the MWhs of energy declined by such Participant.

21.2.3 The Holdback Settlement Price shall equal the Total Settlement Price minus the Energy Declined Settlement Price.

21.2.4 The Energy Declined Settlement Price shall equal the Applicable Real-Time Index Price for the hour.

21.2.5 The Make Whole Adjustment is applied in the event that the settlement revenue and the estimated value of the non-dispatched energy is less than the estimated revenues the selling entity would have received had such entity not been subject to a Holdback Requirement and had sold a day-ahead block of energy with a MW value equal to the maximum amount of Holdback Requirement for the hours in the block. The Make Whole Adjustment has a minimum value of zero and is determined as follows:

Make Whole Adjustment (when applicable) =
Maximum of (Possible Block Sale Revenue
– Final Settlement Revenue
– Realtime Value of Declined Energy
– Realtime Value of Unheld Energy, 0)

Where:

Realtime Value of Declined Energy = Energy Declined × Energy Declined Settlement price

provided that Declined Energy is only applicable to those hours where there was a positive Holdback Requirement.

Realtime Value of Unheld Energy = (Maximum Holdback MW in Block – Holdback MW Requested) × Applicable Index Price

21.2.6 The Total Settlement Price used in the above calculations shall be determined in accordance with the following formula:

Total Settlement Price = Maximum of (Minimum of (Hourly Shaping Factor × Day Ahead Applicable Index Price × 110%, 2000 $/MWh), 0)

where:

Hourly Shaping Factor is based on the most recent High-Priced Day for the relevant season, defined as a day in which at least one hour has a system marginal energy cost ("SMEC") greater than $200/MWh, and shall be calculated as follows:

1 + {[CAISO Hourly Day Ahead SMEC - CAISO Average Day Ahead SMEC (on- or off-peak hours)] / [CAISO Average Day Ahead SMEC (on- or off-peak hours)]}

Day-Ahead Applicable Index Price is the day-ahead heavy load/light load ICE Index price that is specified in the Business Practice Manuals for the Subregion applicable to the location of the delivering entity, applicable to the day and hour of the energy delivery. If transmission via Section 14.3.2 was used to facilitate holdback, the Applicable Index Price shall be the higher of the two subregional day-ahead index prices for that portion of the holdback.

Real-Time Applicable Index Price is the real-time index price that is specified in the Business Practice Manuals for the Subregion applicable to the location of the delivering entity, applicable to the day and hour of the energy delivery.

SCHEDULE 1

WESTERN RESOURCE ADEQUACY PROGRAM ADMINISTATIVE COST RECOVERY CHARGE

The Western Power Pool's Costs of administering and operating the Western Resource Adequacy Program including, without limitation, all costs incurred or obligated by WPP as Program Administrator, all costs paid or payable by WPP to the Program Operator or other service providers, all costs of the Board of Directors in directing, supervising, or overseeing the WRAP, and the costs of maintaining a reasonable reserve as provided in Section 1 of this Schedule 1, shall be recovered from Participants pursuant to the charges set forth in this Schedule 1.

Section 1. WRAP Costs

1. As used herein, Costs shall mean WPP's costs, expenses, disbursements and other amounts incurred (whether paid or accrued) or obligated of administering and operating the WRAP as described above, including, without limitation, operating expenses, general and administrative expenses, costs of outside services, taxes, fees, capital costs, depreciation expense, interest expense, working capital expense, any costs of funds or other financing costs, and the costs of a reasonable reserve as provided herein.
2. The Costs included in a WRAP Administration Charge assessed for a Month shall be the Costs determined as being incurred for that Month, including, without limitation, for each Month, one-twelfth of any annual charge(s).

3. The Costs included in the WRAP Administration Charge for a reasonable reserve shall be those designed to establish over the first twelve months that this WRAP Administration charge is in effect an amount equal to 6% of the expected Costs, exclusive of such reserve, for one year; and to maintain such reserve thereafter at an amount equal to 6% of the expected Costs, exclusive of such reserve for the then-current year. WPP shall record on its income statement deferred regulatory expense, and WPP's balance sheet will reflect as a cumulative deferred regulatory liability, revenues collected under this Schedule 1 that are in excess of the Costs exclusive of such reserve and taking account of and including any accrued tax expense effects of this regulatory liability. The deferred regulatory liability will be reduced when after-tax WPP revenues collected under this Schedule 1 during any Month are less than the Costs exclusive of such reserve. Within thirty days after the end of each Year, to the extent WPP determines that the deferred regulatory liability exceeds 6% of WPP's revenues that were collected under this Schedule 1 during such Year, such excess amounts in the deferred regulatory liability shall be refunded evenly over the applicable billing determinant volumes in the remainder of the subsequent Year through credits to charges to then-current customers under this Schedule 1.

Section 2. WRAP Administration Charge

Each Participant shall be assessed each Month a WRAP Administration Charge equal to the sum of the Base Charge and the Load Charge,

where:

The Base Charge for each Participant equals the Base Costs divided by the number of Participants being assessed the Base Charge for the Month for which the WRAP Administration Charge is being calculated;

The Load Charge for each Participant equals the Load Charge Rate of the Load Services Costs divided by the sum of the Median Monthly P50 Peak Loads of the Participants being assessed the Load Charge for the Month for which the WRAP Administration Charge is being calculated, times that Participant's Median Monthly P50 Peak Load;

And where:

Base Costs means the Costs for the Month of the Base Services Cost Centers shown in the WRAP Cost Assignment Matrix, plus the Base Services Percentage times the Costs for that Month of the Dual Benefit Cost Centers shown below in Section 4: WRAP Cost Assignment Matrix;

Load Services Costs means the Costs for the Month of the Load Services Cost Centers shown in the WRAP Cost Assignment Matrix, plus the Load Services Percentage times the Costs for that Month of the Dual Benefit Cost Centers shown in the WRAP Cost Assignment Matrix; and

Median Monthly P50 Peak Loads means, for each Participant, the median of the Monthly P50 Peak Loads used in the FS Capacity Requirement of such Participant for two Binding Seasons corresponding to the two FS Submittal most recently validated by WPP.

If before or during a Binding Season, a Participant has need to update their Monthly P50 Peak Load for allowable reasons, those updated Monthly P50 Peak Loads will be replaced and the Median Monthly P50 Peak Load value recalculated upon validation of the change in participating load.

A Participant joining the Program will supply data such that WPP can validate Monthly P50 Peak Loads for the first two Binding Seasons for which the Participant will submit an FS Submittal for use in calculating Load Services Costs until these FS Submittals are submitted and reviewed in the normal timeframe.

Section 3. Maximum Charge Rates

3.1 Notwithstanding anything to the contrary in this Schedule 1, the sum of the Base Charges for all Months in a Year shall not exceed the Annual Maximum Base Charge of $59,000/Year, and the sum of the Load Charge Rates for all Months in a Year shall not exceed the Annual Maximum Load Charge Rate of $199/MW. WPP shall, to the extent reasonably practicable, provide two-months' notice prior to WPP's filing at FERC of an application to change the Maximum Base Charge or the Maximum Load Charge Rate, provided that nothing herein shall limit the Board of Director's authority and discretion to seek at FERC a change in the maximum rates in the time and manner the Board determines in the best interests of the Western Resource Adequacy Program. For purposes of clarity, these specified maximum rates on the Base Charge and the Load Charge do not limit the level of the Cash Working Capital Support Charge established under Section 5 of this Schedule 1, nor do they limit the amount of the default Allocation assessment provided under Part I of this Tariff.

3.2 To facilitate Participant planning, the WPP shall prepare, and provide to the RAPC, good faith, non-binding estimates of: (i) reasonably anticipated WRAP budgets for three Years beyond the most recently approved WRAP budget, including sensitivity analyses for reasonably identified major contingencies; (ii) reasonably anticipated numbers of Participants and MWs of Winter and Summer P50 Loads for each such Year; and (iii) reasonably anticipated highest monthly Base Charges and Load Charge Rates for each such Year. All assumptions and estimates in such forecasts and analyses shall be in WPP's sole discretion, which may be informed by RAPC discussion of such topics.

Section 4. WRAP Cost Assignment Matrix

	BASE COSTS	**LOAD COSTS**	**DUAL BENEFIT**
PROGRAM ADMINISTRATION (NON-PARTICIPANT)		100%	
PROGRAM ADMINISTRATION (PARTICIPANT ENGAGEMENT, RAPC FACILITATION)	100%		
WRAP PORTION OF WPP BOD COSTS			50%/50%
PROGRAM OPERATIONS STAFFING AND OVERHEAD		100%	
PROGRAM OPERATIONS TECHNOLOGY		100%	

LEGAL SERVICES	100%
INDEPENDENT EVALUATOR	100%

Section 5. Cash Working Capital Support Charge

5.1 In addition to the WRAP Administration Charge, each Participant shall be assessed a Cash Working Capital Support Charge, to support WPP's maintenance of sufficient funds on hand to make payments required for the operation and administration of the WRAP on a timely basis. Cash Working Capital Support Charges shall be designed to maintain a Cash Working Capital Fund that, at its maximum level over a twelve-month cycle, equals approximately nine-twelfths of the expected annual payment due from the WPP to the Program Operator for its Program Operator services.

5.2 A Participant shall pay a Cash Working Capital Support Charge no later than thirty days after that Participant executes a WRAPA. The Cash Working Capital Support Charge due following WRAPA execution equals the Cash Working Capital Support Charge Rate, calculated as the Cash Working Capital Fund at its required maximum twelve-month cycle level divided by the sum of the Median Monthly P50 Peak Loads of all Participants, times that Participant's Median Monthly P50 Peak Load.

5.3 To the extent the Cash Working Capital Fund is adequately funded at the time a new Participant executes a WRAPA, the revenue from such Participant's payment of the Cash Working Capital Support Charge shall be distributed to all Participants that previously have paid a Cash Working Capital Support Charge, pro rata based on the Median Monthly P50 Peak Loads of all Participants that have previously paid such charge.

5.4 To the extent, and at such time, WPP determines that an incremental addition to the Cash Working Capital Fund is needed due to such causes as, for example, an expected increase in the annual payment to the Program Operator, each Participant shall be assessed an Incremental Cash Working Capital Support Charge equal to the desired incremental addition, divided by the sum of the Median Monthly P50

Peak Loads of all Participants being assessed the Incremental Cash Working Capital Support Charge for the Month for which the Incremental Cash Working Capital Support Charge is being calculated, times that Participant's Median Monthly P50 Peak Load.

ATTACHMENT A

Western Resource Adequacy Program Agreement

This Western Resource Adequacy Program Agreement ("Agreement") dated as of _______________ ("Effective Date") is entered into by and between Western Power Pool Corporation ("WPP") and ______________________ ("Participant"). WPP and Participant are each sometimes referred to in the Agreement as a "Party" and collectively as the "Parties."

In consideration of the mutual promises contained herein, and other good and valuable consideration, the receipt of which is hereby acknowledged, the Parties agree as follows:

1. The Parties agree that this agreement shall be governed by the rates, terms, and conditions of the Western Resource Adequacy Program Tariff ("Tariff") and all such rates, terms, and conditions contained therein are expressly incorporated by reference herein. All capitalized terms that are not otherwise defined herein shall have the meanings ascribed by the Tariff.

2. Participant wishes to participate in the Western Resource Adequacy Program ("WRAP") administered by WPP under the Tariff.

3. Participant certifies that it satisfies all of the following qualifications:

   3.1 Participant is a Load Responsible Entity as that term is defined in the Tariff.

   3.2 Participant commits to complying with all applicable terms and conditions of WRAP participation as set forth in the Tariff and Business Practice Manuals adopted thereunder, including all Forward Showing Program and Operations Program requirements.

4. Participant will register all resources and supply contracts and shall disclose any other obligations associated with those resources and supply contracts.

5. Participant represents and warrants that it is authorized by all relevant laws and regulations governing its business to enter into this Agreement and assume all rights and obligations thereunder.

6. It is understood that, in accordance with the Tariff, WPP, as authorized by its independent Board of Directors, may amend the terms and conditions of this Agreement or the Tariff by notifying the Participant in writing and making the appropriate filing with FERC, subject to any limitations on WPP's authority to amend the Tariff as set forth therein.

7. Participant agrees to pay its share of all costs associated with the WRAP, as calculated pursuant to Schedule 1 of the Tariff. The manner and timing of such payment shall be as specified in Schedule 1 of the Tariff.

8. WPP agrees to provide all services as set forth in the Tariff.

9. Term and termination. This Agreement shall commence upon the Effective Date and shall continue in effect until terminated either by WPP by vote of its Board of Directors or by Participant's withdrawal as set forth herein. WPP and Participant agree that participation in the WRAP is voluntary, subject to the terms and conditions of this Agreement and the Tariff. The date upon which a Participant's withdrawal is effective and its participation in the program terminates is referred to as the "Withdrawal Date."

9.1 Normal Withdrawal: In general, Participant may withdraw from this Agreement by providing written notice to WPP no less than twenty-four months prior to commencement of the next binding Forward Showing Program period. Once notice has been properly given, Participant remains in a "Withdrawal Period" until the Withdrawal Date.

9.1.1 During Participant's Withdrawal Period, Participant remains subject to all requirements and obligations imposed by the Tariff and this Agreement, including but not limited to all obligations imposed in the Forward Showing Program and Operations Program and obligation to pay Participant's share of all costs associated with the WRAP.

9.1.2 All financial obligations incurred prior to and during the Withdrawal Period are preserved until satisfied.

9.1.3 During the Withdrawal Period, Participant is not eligible to vote on any actions affecting the WRAP that extend beyond the Withdrawal Period.

9.2 Expedited Withdrawal: Participant may withdraw from this agreement with less than the required twenty-four month notice as set forth below. Participant shall negotiate with WPP regarding the timing of the Expedited Withdrawal.

9.2.1 Extenuating Circumstances: The following such events and circumstances shall constitute "extenuating circumstances" justifying a withdrawal on less than twenty-four months. Participant invoking an extenuating circumstance shall negotiate with WPP regarding potential ways to minimize the impact of the expedited withdrawal on all other Participants and WPP. Such extenuating circumstances and any mitigation plan to minimize the impact of the expedited withdrawal must be reviewed and approved by the Board of Directors prior to termination of Participant's WRAP obligations. Regardless of the extenuating circumstance, all financial obligations incurred prior to the Withdrawal Date remain in effect until satisfied.

9.2.1.1 A governmental authority takes an action that substantially impairs Participant's ability to continue to participate in the WRAP to the same extent as previously; provided, however, that Participant shall be obligated to negotiate with WPP regarding potential ways to address the impact of the regulatory action without requiring a full withdrawal of Participant from the WRAP if possible.

9.2.1.2 Continued participation in the WRAP conflicts with applicable governing statutes or other applicable legal authorities or orders.

9.2.1.3 Participant voted against a RAPC determination and disagreed with a Board of Directors decision to release composite or aggregated data under Section 10.2.1 of the Tariff, provided that such right to expedited withdrawal is exercised promptly after the first time that the Board of Directors determines that the form and format of composite or aggregated data sufficiently protects against the release of confidential or commercially sensitive Participant data. Failure to exercise this right promptly upon the first occurrence of the Board of Directors voting on a specific form and format of composite or aggregated data shall constitute a waiver of the right to expedited withdrawal for any future disclosures of composite or aggregated data in the same or substantially similar form and format.

9.2.1.4 FERC or a court of competent jurisdiction requires the public disclosure of a Participant's confidential or commercially sensitive information, as further described in Section 10.5 of the Tariff; provided however that such right to expedited withdrawal shall be exercised promptly upon the exhaustion of all legal or administrative remedies aimed at preventing the release.

9.2.2 Exit Fee: If the impact of Participant's withdrawal on WRAP operations can calculated with a high degree of confidence and mitigated by the payment of an "exit fee" to be calculated by WPP, an expedited withdrawal will be permitted. Such exit fee shall include (but not be limited to): (i) any unpaid WRAP fees or charges; (ii) Participant's share of all WRAP administrative costs incurred up to the next Forward Showing Program period; (iii) any costs, expenses, or liabilities incurred by WPP and/or the Program Operator directly resulting from Participant's withdrawal; and (iv) any costs necessary to hold other participants harmless from the voluntary expedited withdrawal. The exit fee may be waived to the extent that it would violate any federal, state, or local statute, regulation, or ordnance or exceed the statutory authority of a federal agency. The exit fee shall be paid in full prior to the Withdrawal Date.

9.2.3 Amendments to Section 3.4 of the Tariff: In the event that amendments to Section 3.4 of the Tariff are approved by the RAPC and Board of Directors, a Participant that voted against such a change may withdraw with less than the required twenty-four month notice, provided that the Participant satisfy all obligations in the Forward Showing Program and Operations Program and satisfy all other financial obligations incurred prior to the date that the amendments to Section 3.4 of the Tariff are made effective by FERC.

9.2.4 Expulsion: The Board of Directors, in its sole discretion, may terminate Participant's participation in the WRAP and may terminate this Agreement with Participant for cause, including but not limited to material violation of any WPP rules or governing documents or nonpayment of obligations. Prior to exercising such right to terminate, the Board of Directors shall provide notice to Participant of the reasons for such contemplated termination and a reasonable opportunity to cure any deficiencies. Such Board of Directors termination shall be after an affirmative vote consistent with the Board of Directors standard voting procedures. Such termination shall not relieve the Participant of any financial obligations incurred prior to the termination date, and WPP may take all legal actions available to recover any financial obligations from Participant.

10. No Waiver of Non-FERC-Jurisdictional Status. If Participant is not subject to the jurisdiction of FERC as a public utility under the Federal Power Act, Participant shall not be required to take any action or participate in any filing or appeal that would confer FERC jurisdiction over Participant that does not otherwise exist. Participant acknowledges that FERC has jurisdiction over the WRAP, including Participant's activities in the WRAP.

[SIGNATURE BLOCKS]

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-148:
WRAP Notice

WESTERN RESOURCE ADEQUACY PROGRAM

WPP Notice to WRAP Resource Adequacy Participants Committee

Oct. 31, 2025, 9:42 a.m. by Rebecca Sexton | Last modified Oct. 31, 2025, 12:54 p.m.

On Friday, October 31, WPP Chief Strategy Officer Rebecca Sexton sent this notice to members of the WRAP Resource Adequacy Participants Committee, regarding participants committed to WRAP binding operations in Winter 2027/2028:

Today is the deadline set in the tariff for Western Resource Adequacy Program (WRAP) participants to notify us if they plan to exit the program before binding operations start in Winter 2027/2028.

As of the deadline there are 16 current participants that will remain in the program for binding operations, including five in addition to the 11 who sent a commitment letter last month, and we expect more companies to join in the future. The committed participants bring significant load (over 58,000 MW in peak load) and resources and a large, diverse geographic footprint, making WRAP one of the largest RA programs in the country and giving us critical mass for a binding program. The group includes members committed to or leaning toward both EDAM and Markets+, as well as some who have not indicated they will join a day-ahead market. The committed participants are:

- Arizona Public Service Company
- Avista Corp
- Bonneville Power Administration
- PUD No. 1 of Chelan County
- Clatskanie People's Utility District
- Constellation
- PUD #2 of Grant County
- Idaho Power
- NorthWestern Energy
- Powerex Corp.
- Puget Sound Energy
- Salt River Project Agricultural Improvement and Power District
- Seattle City Light
- Tacoma Power
- The Energy Authority, Inc.
- Tucson Electric Power

The following companies provided formal notice of intent to exit:

- Calpine Energy Solutions
- Eugene Water & Electric Board
- NV Energy
- PacifiCorp
- Portland General Electric Company
- Public Service Company of New Mexico

To all participants, thank you for your efforts in the last six years to build WRAP into a program that can help the region tackle the significant challenge of resource adequacy.

To our exiting participants, over the next two years, we encourage you to stay engaged in committees, task forces, and the stakeholder process to continue to evolve and improve WRAP and potentially resolve the concerns that prevented you from committing to binding operations at this time. As we have communicated previously, should your concerns be resolved, you have the option to rejoin the program and can commit to the Winter 2027/2028 season as late as September 15, 2026.

We have received a lot of positive outreach and support as we neared this deadline, and I will share just one example - part of a note we received from Lauren Tenney Denison, Director of Market Policy & Grid Strategy for Public Power Council. She wrote, "You have designed a remarkable program, from the ground up. WRAP has forever changed the way the West approaches markets and regional programs. There is a large and diverse footprint of entities committed to the binding season. That is a lot to be excited about."

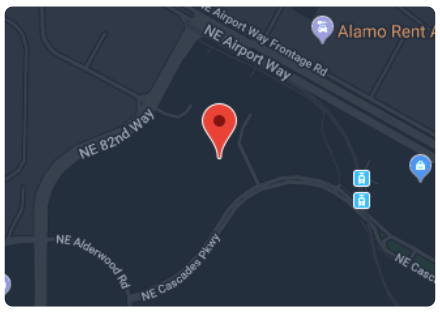
I wanted you all to see this too because the congratulations for designing this program are for all of us and because there is a lot of progress to be excited about.

We look forward to continuing to work collaboratively to support reliability and resource adequacy across the West.

Rebecca Sexton
Chief Strategy Officer
WPP | 253-279-3002
rebecca.sexton@westernpo...

WPP HEADQUARTERS

7525 NE Ambassador Place, Suite M
Portland, Oregon, 97220
(503) 445-1074



PROGRAMS

NEWS

EVENTS

DOCUMENTS

ABOUT

SIGN IN

CONTACT

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

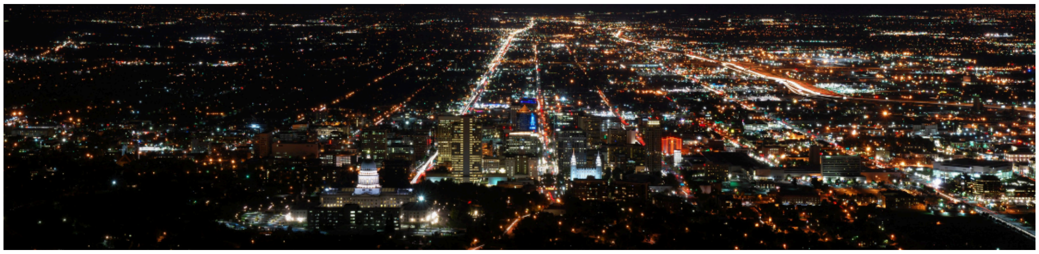
Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-26-21
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-149:
About WECC webpage

LOGIN



About WECC

The Western Electricity Coordinating Council (WECC) is a non-profit corporation that exists to ensure a reliable Bulk Electric System in the geographic area known as the Western Interconnection. WECC has been approved by the Federal Energy Regulatory Commission (FERC) as the Regional Entity for the Western Interconnection. The North American Electric Reliability Corporation (NERC) delegated some of its authority to create, monitor, and enforce reliability standards to WECC through a Delegation Agreement.

WECC promotes bulk power system reliability and security in the Western Interconnection. WECC is the Regional Entity responsible for compliance monitoring and enforcement and oversees reliability planning and assessments. In addition, WECC provides an environment for the development of Reliability Standards and the coordination of the operating and planning activities of its members as set forth in the WECC Bylaws.

There are six Regional Entities given authority by NERC and FERC. Of those six entities, WECC oversees the largest and most geographically diverse region, known as the Western Interconnection. WECC's footprint extends from Canada to Mexico and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between.

Membership in WECC is open to all entities that meet the qualifications in the WECC Bylaws. WECC strives for transparency and open participation in all of its meetings and processes.

2024 State of the Interconnection Report

Our History

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-26-21
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
PacifiCorp, and Xcel Energy	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-150:
NERC Rules of Procedure

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Rules of Procedure

Effective: November 28, 2023

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SECTION 100 — APPLICABILITY OF RULES OF PROCEDURE

NERC and NERC Members shall comply with these Rules of Procedure. Each Regional Entity shall comply with these Rules of Procedure as applicable to functions delegated to the Regional Entity by NERC or as required by an Applicable Governmental Authority or as otherwise provided.

Each Bulk Power System owner, operator, and user shall comply with all Rules of Procedure of NERC that are made applicable to such entities by approval pursuant to applicable legislation or regulation, or pursuant to agreement.

Any entity that is unable to comply or that is not in compliance with a NERC Rule of Procedure shall immediately notify NERC in writing, stating the Rule of Procedure of concern and the reason for not being able to comply with the Rule of Procedure.

NERC shall evaluate each case and inform the entity of the results of the evaluation. If NERC determines that a Rule of Procedure has been violated, or cannot practically be complied with, NERC shall notify the Applicable Governmental Authorities and take such other actions as NERC deems appropriate to address the situation.

NERC shall comply with each approved Reliability Standard that identifies NERC or the Electric Reliability Organization as a responsible entity. Regional Entities shall comply with each approved Reliability Standard that identifies Regional Entities as responsible entities. A violation by NERC or a Regional Entity of such a Reliability Standard shall constitute a violation of these Rules of Procedure.

SECTION 200 — DEFINITIONS OF TERMS

Definitions of terms used in the NERC Rules of Procedure are set forth in **Appendix 2**, *Definitions Used in the Rules of Procedure*.

SECTION 300 — RELIABILITY STANDARDS DEVELOPMENT

301. General

NERC shall develop and maintain Reliability Standards that apply to Bulk Power System owners, operators, and users and that enable NERC and Regional Entities to measure the reliability performance of Bulk Power System owners, operators, and users; and to hold them accountable for Reliable Operation of the Bulk Power Systems. The Reliability Standards shall be technically excellent, timely, just, reasonable, not unduly discriminatory or preferential, in the public interest, and consistent with other applicable standards of governmental authorities.

302. Essential Attributes for Technically Excellent Reliability Standards

1. **Applicability** — Each Reliability Standard shall clearly identify the functional classes of entities responsible for complying with the Reliability Standard, with any specific additions or exceptions noted.[1] Each Reliability Standard shall also identify the geographic applicability of the Reliability Standard, such as the entire North American Bulk Power System, an Interconnection, or within a Region. A Reliability Standard may also identify any limitations on the applicability of the Reliability Standard based on electric Facility characteristics.

2. **Reliability Objectives** — Each Reliability Standard shall have a clear statement of purpose that shall describe how the Reliability Standard contributes to the reliability of the Bulk Power System. The following general objectives for the Bulk Power System provide a foundation for determining the specific objective(s) of each Reliability Standard:

   2.1 **Reliability Planning and Operating Performance** — Bulk Power Systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.

   2.2 **Frequency and Voltage Performance** — The frequency and voltage of Bulk Power Systems shall be controlled within defined limits through the balancing of Real and Reactive Power supply and demand.

   2.3 **Reliability Information** — Information necessary for the planning and operation of reliable Bulk Power Systems shall be made available to those entities responsible for planning and operating Bulk Power Systems.

   2.4 **Emergency Preparation** — Plans for emergency operation and system restoration of Bulk Power Systems shall be developed, coordinated, maintained, and implemented.

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[1] When a Reliability Standard identifies a class of entities to which it applies, that class must be defined in the Glossary of Terms Used in NERC Reliability Standards.

2.5 **Communications and Control** — Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of Bulk Power Systems.

2.6 **Personnel** — Personnel responsible for planning and operating Bulk Power Systems shall be trained and qualified, and shall have the responsibility and authority to implement actions.

2.7 **Wide-Area View** — The reliability of the Bulk Power Systems shall be assessed, monitored, and maintained on a Wide-Area basis.

2.8 **Security** — Bulk Power Systems shall be protected from malicious physical or cyber attacks.

3. **Performance Requirement or Outcome** — Each Reliability Standard shall state one or more performance Requirements, which if achieved by the applicable entities, will provide for a reliable Bulk Power System, consistent with good utility practices and the public interest. Each Requirement is not a "lowest common denominator" compromise, but instead achieves an objective that is the best approach for Bulk Power System reliability, taking account of the costs and benefits of implementing the proposal.

4. **Measurability** — Each performance Requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that Requirement. Each performance Requirement shall have one or more associated measures used to objectively evaluate compliance with the Requirement. If performance can be practically measured quantitatively, metrics shall be provided to determine satisfactory performance.

5. **Technical Basis in Engineering and Operations** — Each Reliability Standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field.

6. **Completeness** — Reliability Standards shall be complete and self-contained. The Reliability Standards shall not depend on external information to determine the required level of performance.

7. **Consequences for Noncompliance** — In combination with guidelines for Penalties and sanctions, as well as other ERO and Regional Entity compliance documents, the consequences of violating a Reliability Standard are clearly presented to the entities responsible for complying with the Reliability Standards.

8. **Clear Language** — Each Reliability Standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practices, are able to arrive at a consistent interpretation of the required performance.

9. **Practicality** — Each Reliability Standard shall establish Requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.

10. **Consistent Terminology** — To the extent possible, Reliability Standards shall use a set of standard terms and definitions that are approved through the NERC Reliability Standards development process.

303. Relationship between Reliability Standards and Competition

To ensure Reliability Standards are developed with due consideration of impacts on competition, to ensure Reliability Standards are not unduly discriminatory or preferential, and recognizing that reliability is an essential requirement of a robust North American economy, each Reliability Standard shall meet all of these market-related objectives:

1. **Competition** — A Reliability Standard shall not give any market participant an unfair competitive advantage.

2. **Market Structures** — A Reliability Standard shall neither mandate nor prohibit any specific market structure.

3. **Market Solutions** — A Reliability Standard shall not preclude market solutions to achieving compliance with that Reliability Standard.

4. **Commercially Sensitive Information** — A Reliability Standard shall not require the public disclosure of commercially sensitive information or other Confidential Information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with Reliability Standards.

5. **Adequacy** — NERC shall not set Reliability Standards defining an adequate amount of, or requiring expansion of, Bulk Power System resources or delivery capability.

304. Essential Principles for the Development of Reliability Standards

NERC shall develop Reliability Standards in accordance with the NERC *Standard Processes Manual*, which is incorporated into these Rules of Procedure as **Appendix 3A**. Appeals in connection with the development of a Reliability Standard shall also be conducted in accordance with the NERC *Standard Processes Manual*. Any amendments or revisions to the NERC *Standard Processes Manual* shall be consistent with the following essential principles:

1. **Openness** — Participation shall be open to all Persons and who are directly and materially affected by the reliability of the North American Bulk Power System. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in NERC or any other organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

2. **Transparency** — The process shall be transparent to the public.

3. **Consensus-building** —The process shall build and document consensus for each Reliability Standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.

4. **Fair Balance of Interests** — The process shall fairly balance interests of all stakeholders and shall not be dominated by any two Segments as defined in **Appendix 3D**, *Development of the Registered Ballot Body*, of these Rules of Procedure, and no single Segment, individual or organization shall be able to defeat a matter.

5. **Due Process** — Development of Reliability Standards shall provide reasonable notice and opportunity for any Person with a direct and material interest to express views on a proposed Reliability Standard and the basis for those views, and to have that position considered in the development of the Reliability Standards.

6. **Timeliness** — Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the Bulk Power System.

305. Registered Ballot Body

NERC Reliability Standards shall be approved by a Registered Ballot Body prior to submittal to the Board and then to Applicable Governmental Authorities for their approval, where authorized by applicable legislation or agreement. This Section 305 sets forth the rules pertaining to the composition of, and eligibility to participate in, the Registered Ballot Body.

1. **Eligibility to Vote on Reliability Standards** — Any person or entity may join the Registered Ballot Body to vote on Reliability Standards, whether or not such person or entity is a Member of NERC.

2. **Inclusive Participation** — The Segment qualification guidelines are inclusive; i.e., any entity with a legitimate interest in the reliability of the Bulk Power System that can meet any one of the eligibility criteria for a Segment is entitled to belong to and vote in each Segment for which it qualifies, subject to limitations defined in Sections 305.3 and 305.5.

3. **General Criteria for Registered Ballot Body Membership** — The general criteria for membership in the Segments are:

   3.1 **Multiple Segments** — A corporation or other organization with integrated operations or with affiliates that qualifies to belong to more than one Segment (e.g., Transmission Owners and Load-Serving Entities) may join once in each Segment for which it qualifies, provided that each Segment constitutes a separate membership and the organization is represented in each Segment by a different representative. Affiliated entities are collectively limited to one membership in each Segment for which they are qualified.

3.2 **Withdrawing from a Segment or Changing Segments** — After its initial registration in a Segment, each registered participant may elect to withdraw from a Segment at any time or apply to change Segments as described in the *Development of the Registered Ballot Body* in **Appendix 3D**. In the event a change in corporate or organizational structure results in merged or affiliated entities having more than one membership in a particular Segment, the merged or affiliated entities shall withdraw the additional memberships before joining any new ballot pools or voting on any standards action as part of an existing ballot pool.

3.3 **Review of Segment Criteria** — The Board shall review the qualification guidelines and rules for joining Segments periodically to ensure that the process continues to be fair, open, balanced, and inclusive. Public input will be solicited in the review of these guidelines.

4. **Proxies for Voting on Reliability Standards** — Any registered participant may designate an agent or proxy to vote on its behalf. There are no limits on how many proxies an agent may hold. However, for the proxy to be valid, NERC must have in its possession written documentation signed by the representative of the registered participant that the voting right by proxy has been transferred from the registered participant to the agent.

5. **Segments** — The specific criteria for membership in each Registered Ballot Body Segment are defined in the *Development of the Registered Ballot Body* in **Appendix 3D.**

6. **Review of Segment Entries** — NERC shall review all applications for joining the Registered Ballot Body, and shall make a determination of whether the applicant's self-selection of a Segment satisfies at least one of the guidelines to belong to that Segment. The entity shall then become eligible to participate as a voting member of that Segment. The Standards Committee shall resolve disputes regarding eligibility for membership in a Segment, with the applicant having the right of appeal to the Board.

306. Standards Committee

The Standards Committee shall provide oversight of the Reliability Standards development process to ensure stakeholder interests are fairly represented. The Standards Committee shall not under any circumstance change the substance of a draft or approved Reliability Standard.

1. **Membership** — The Standards Committee is a representative committee comprising representatives of two members of each of the Segments in the

Registered Ballot Body and two officers elected to represent the interests of the industry as a whole.

2. **Elections** — Standards Committee members are elected for staggered (one per Segment per year) two-year terms by the respective Segments in accordance with the *Procedure for the Election of Members of the NERC Standards Committee*, which is incorporated into these Rules of Procedure as **Appendix 3B**. Segments may use their own election procedure if such a procedure is ratified by two-thirds of the members of a Segment and approved by the Board.

3. **Canadian Representation**

   The Standards Committee will include Canadian representation as provided in **Appendix 3B**, *Procedure for the Election of Members of the NERC Standards Committee*.

4. **Open Meetings** — All meetings of the Standards Committee shall be open and publicly noticed on the NERC website.

307. Standards Process Management

NERC standards staff shall be responsible for ensuring that the development and revision of Reliability Standards are in accordance with the NERC *Standard Processes Manual* and shall work to achieve the highest degree of integrity and consistency of quality and completeness of the Reliability Standards. NERC staff shall coordinate with any Regional Entities that develop Regional Reliability Standards to ensure those Regional Reliability Standards are effectively integrated with the NERC Reliability Standards.

308. Steps in the Development of Reliability Standards

1. **Procedure** — NERC shall develop Reliability Standards through the process set forth in the NERC *Standard Processes Manual* (**Appendix 3A**). The NERC *Standard Processes Manual* includes provisions for developing Reliability Standards that can be completed using expedited processes, including a process to develop Reliability Standards to address national security situations that involve confidential issues.

2. **Board Adoption** — Reliability Standards or revisions to Reliability Standards approved by the ballot pool in accordance with the NERC *Standard Processes Manual* shall be submitted for adoption by the Board. No Reliability Standard or revision to a Reliability Standard shall be effective unless adopted by the Board.

3. **Governmental Approval** — After Board adoption, a Reliability Standard or revision to a Reliability Standard shall be submitted to all Applicable Governmental Authorities in accordance with Section 309. No Reliability Standard or revision to a Reliability Standard shall be effective within a geographic area over which an Applicable Governmental Authority has jurisdiction unless it is approved by such Applicable Governmental Authority or

is otherwise made effective pursuant to the laws applicable to such Applicable Governmental Authority.

309. Filing of Reliability Standards for Approval by Applicable Governmental Authorities

1. **Filing of Reliability Standards for Approval** — Where authorized by applicable legislation or agreement, NERC shall file with the Applicable Governmental Authorities each Reliability Standard, modification to a Reliability Standard, or withdrawal of a Reliability Standard that is adopted by the Board. Each filing shall be in the format required by the Applicable Governmental Authority and shall include: a concise statement of the basis and purpose of the Reliability Standard; the text of the Reliability Standard; the implementation plan for the Reliability Standard; a demonstration that the Reliability Standard meets the essential attributes of Reliability Standards as stated in Section 302; the drafting team roster; the ballot pool and final ballot results; and a discussion of public comments received during the development of the Reliability Standard and the consideration of those comments.

2. **Remanded Reliability Standards and Directives to Develop New or Modified Reliability Standards** — If an Applicable Governmental Authority remands a Reliability Standard to NERC, NERC shall within five (5) business days notify all other Applicable Governmental Authorities. Reliability Standards that are directed by an Applicable Governmental Authority shall be developed using the NERC *Standard Processes Manual*. The waiver provisions of the NERC *Standard Processes Manual* may be applied if necessary to meet a timetable for action required by the Applicable Governmental Authority, respecting to the extent possible the provisions in the *NERC Standard Processes Manual* for reasonable notice and opportunity for public comment, due process, openness, and a balance of interest in developing Reliability Standards. If the Board of Trustees determines that the standards process did not result in a Reliability Standard that adequately addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply.

3. **Directives to Develop Reliability Standards under Extraordinary Circumstances** — An Applicable Governmental Authority may, on its own initiative, determine that extraordinary circumstances exist requiring expedited development of a Reliability Standard. In such a case, the Applicable Governmental Authority may direct the development of a Reliability Standard within a certain deadline. NERC staff shall prepare the Standards Authorization Request. The proposed Reliability Standard will then proceed through the Reliability Standards development process, using the waiver provisions of the NERC *Standard Processes Manual* as necessary to meet the specified deadline. The timeline will be developed to respect, to the extent possible, the provisions in the Reliability Standards development process for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests

in developing Reliability Standards. If the Board of Trustees determines that the standards process did not result in a Reliability Standard that adequately addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply, with appropriate modification of the timeline.

310. Annual Reliability Standards Development Plan

NERC shall develop and provide an annual Reliability Standards Development Plan for development of Reliability Standards to the Applicable Governmental Authorities. NERC shall consider the comments and priorities of the Applicable Governmental Authorities in developing and updating the annual Reliability Standards Development Plan. Each annual Reliability Standards Development Plan shall include a progress report comparing results achieved to the prior year's Reliability Standards Development Plan.

311. Regional Entity Standards Development Procedures

1. **NERC Approval of Regional Entity Reliability Standards Development Procedure** — To enable a Regional Entity to develop Regional Reliability Standards that are to be recognized and made part of NERC Reliability Standards, a Regional Entity may request NERC to approve a Regional Reliability Standards development procedure.

2. **Public Notice and Comment on Regional Reliability Standards Development Procedure** — Upon receipt of such a request, NERC shall publicly notice and request comment on the proposed Regional Reliability Standards development procedure, allowing a minimum of 45 days for comment. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to withdraw the request, revise the Regional Reliability Standards development procedure and request another posting for comment, or submit the Regional Reliability Standards development procedure, along with its consideration of any objections received, for approval by NERC.

3. **Evaluation of Regional Reliability Standards Development Procedure** — NERC shall evaluate whether a Regional Reliability Standards development procedure meets the criteria listed below and shall consider stakeholder comments, any unresolved stakeholder objections, and the consideration of comments provided by the Regional Entity, in making that determination. If NERC determines the Regional Reliability Standards development procedure meets these requirements, the Regional Reliability Standards development procedure shall be submitted to the Board for approval. The Board shall consider the recommended action, stakeholder comments, any unresolved stakeholder comments, and the Regional Entity consideration of comments in determining whether to approve the Regional Reliability Standards development procedure.

   3.1 **Evaluation Criteria** — The Regional Reliability Standards development procedure shall be:

3.1.1 **Open** — The Regional Reliability Standards development procedure shall provide that any person or entity who is directly and materially affected by the reliability of the Bulk Power Systems within the Regional Entity shall be able to participate in the development and approval of Reliability Standards. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in the Regional Entity, a Regional Entity or any organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

3.1.2 **Inclusive** — The Regional Reliability Standards development procedure shall provide that any Person with a direct and material interest has a right to participate by expressing an opinion and its basis, having that position considered, and appealing through an established appeals process if adversely affected.

3.1.3 **Balanced —** The Regional Reliability Standards development procedure shall have a balance of interests and shall not permit any two interest categories to dominate a matter or any single interest category to defeat a matter.

3.1.4 **Due Process** — The Regional Reliability Standards development procedure shall provide for reasonable notice and opportunity for public comment. At a minimum, the Regional Reliability Standards development procedure shall include public notice of the intent to develop a Regional Reliability Standard, a public comment period on the proposed Regional Reliability Standard, due consideration of those public comments, and a ballot of interested stakeholders.

3.1.5 **Transparent** — All actions material to the development of Regional Reliability Standards shall be transparent. All Regional Reliability Standards development meetings shall be open and publicly noticed on the Regional Entity's website.

3.1.6 **Accreditation of Regional Standards Development Procedure** — A Regional Entity's Regional Reliability Standards development procedure that is accredited by the American National Standards Institute shall be deemed to meet the criteria listed in this Section 311.3.1, although such accreditation is not a prerequisite for approval by NERC.

3.1.7 **Use of NERC Procedure** — A Regional Entity may adopt the NERC *Standard Processes Manual* as the Regional Reliability Standards development procedure, in which case the Regional

Entity's Regional Reliability Standards development procedure shall be deemed to meet the criteria listed in this Section 311.3.1.

4. **Revisions of Regional Reliability Standards Development Procedures** — Any revision to a Regional Reliability Standards development procedure shall be subject to the same approval requirements set forth in Sections 311.1 through 311.3.

5. **Duration of Regional Reliability Standards Development Procedures** — The Regional Reliability Standards development procedure shall remain in effect until such time as it is replaced with a new version approved by NERC or it is withdrawn by the Regional Entity. The Regional Entity may, at its discretion, withdraw its Regional Reliability Standards development procedure at any time.

312. Regional Reliability Standards

1. **Basis for Regional Reliability Standards** — Regional Entities may propose Regional Reliability Standards that set more stringent reliability requirements than the NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard. Such Regional Reliability Standards shall in all cases be submitted to NERC for adoption and, if adopted, made part of the NERC Reliability Standards and shall be enforceable in accordance with the delegation agreement between NERC and the Regional Entity or other instrument granting authority over enforcement to the Regional Entity. No entities other than NERC and the Regional Entity shall be permitted to develop Regional Reliability Standards that are enforceable under statutory authority delegated to NERC and the Regional Entity.

2. **Regional Reliability Standards That are Directed by a NERC Reliability Standard** — Although it is the intent of NERC to promote uniform Reliability Standards across North America, in some cases it may not be feasible to achieve a reliability objective with a Reliability Standard that is uniformly applicable across North America. In such cases, NERC may direct Regional Entities to develop Regional Reliability Standards necessary to implement a NERC Reliability Standard. Such Regional Reliability Standards that are developed pursuant to a direction by NERC shall be made part of the NERC Reliability Standards.

3. **Procedure for Developing an Interconnection-wide Regional Standard** — A Regional Entity organized on an Interconnection-wide basis may propose a Regional Reliability Standard for approval as a NERC Reliability Standard to be made mandatory for all applicable Bulk Power System owners, operators, and users within that Interconnection.

   3.1 **Presumption of Validity** — An Interconnection-wide Regional Reliability Standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities, shall be adopted as a NERC Reliability Standard. NERC shall rebuttably presume that a Regional Reliability Standard developed, in accordance with a Regional Reliability Standards development process approved by NERC, by a Regional Entity organized on an Interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities.

3.2 **Notice and Comment Procedure for Interconnection-wide Regional Reliability Standard** — NERC shall publicly notice and request comment on the proposed Interconnection-wide Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to comment on or withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for approval by NERC.

3.3 **Adoption of Interconnection-wide Regional Reliability Standard by NERC** — NERC shall evaluate and recommend whether a proposed Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections that could serve as a basis for rebutting the presumption of validity of the Regional Reliability Standard. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning the proposed Regional Reliability Standard, shall have the option of presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, NERC's recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

3.4 **Applicable Governmental Authority Approval** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

3.5 **Enforcement of Interconnection-wide Regional Reliability Standard** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or is otherwise made effective within Canada as mandatory within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

4. **Procedure for Developing Non-Interconnection-Wide Regional Reliability Standards** — Regional Entities that are not organized on an Interconnection-wide basis may propose Regional Reliability Standards to apply within their respective Regions. Such Regional Reliability Standards may be developed through the NERC Reliability Standards development procedure, or alternatively, through a Regional Reliability Standards development procedure that has been approved by NERC.

4.1 **No Presumption of Validity** — Regional Reliability Standards that are not proposed to be applied on an Interconnection-wide basis are not presumed to be valid but may be demonstrated by the proponent to be valid.

4.2 **Notice and Comment Procedure for Non-Interconnection-wide Regional Reliability Standards** — NERC shall publicly notice and request comment on the proposed Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to comment on or resolve any objections identified in the comments and may choose to withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for adoption by NERC.

4.3 **NERC Adoption of Non-Interconnection-wide Regional Reliability Standards** — NERC shall evaluate and recommend whether a proposed non-Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning proposed Regional Reliability Standard, shall have the option of presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, the recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

4.4 **Applicable Governmental Authority Approval** — A non-Interconnection-wide Regional Reliability Standard that has been adopted by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

4.5 **Enforcement of Non-Interconnection-wide Regional Reliability Standards** — A non-Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or is otherwise made effective within Canada as mandatory within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

5. **Appeals** — A Regional Entity shall have the right to appeal NERC's decision not to adopt a proposed Regional Reliability Standard or Variance to the Commission or other Applicable Governmental Authority.

313. Other Regional Criteria, Guides, Procedures, Agreements, Etc.

1. **Regional Criteria** — Regional Entities may develop Regional Criteria that are necessary to implement, to augment, or to comply with NERC Reliability Standards, but which are not Reliability Standards. Regional Criteria may also address issues not within the scope of Reliability Standards, such as resource adequacy. Regional Criteria may include specific acceptable operating or planning parameters, guides, agreements, protocols or other documents used to enhance the reliability of the Bulk Power System in the Region. These documents typically provide benefits by promoting more consistent implementation of the NERC Reliability Standards within the Region. These documents are not NERC Reliability Standards, Regional Reliability Standards, or regional Variances, and therefore are not enforceable under authority delegated by NERC pursuant to delegation agreements and do not require NERC approval.

2. **Catalog of Regional Criteria** — Each Regional Entity that has Regional Criteria shall maintain a publicly-available, current catalog of its Regional Criteria. Regional Entities shall provide any Regional Criteria to NERC upon written request.

314. Conflicts with Statutes, Regulations, and Orders

Notice of Potential Conflict — If a Bulk Power System owner, operator, or user determines that a NERC or Regional Reliability Standard may conflict with a function, rule, order, tariff, rate schedule, legislative requirement or agreement that has been accepted, approved, or ordered by a governmental authority affecting that entity, the entity shall expeditiously notify the governmental authority, NERC, and the relevant Regional Entity of the conflict.

1. **Determination of Conflict —** NERC, upon request of the governmental authority, may advise the governmental authority regarding the conflict and

propose a resolution of the conflict, including revision of the Reliability Standard if appropriate.

2. **Regulatory Precedence** — Unless otherwise ordered by a governmental authority, the affected Bulk Power System owner, operator, or user shall continue to follow the function, rule, order, tariff, rate schedule, legislative requirement, or agreement accepted, approved, or ordered by the governmental authority until the governmental authority finds that a conflict exists and orders a remedy and such remedy is affected.

315. Revisions to NERC Standard Processes Manual

Any person or entity may submit a written request to modify NERC *Standard Processes Manual*. Consideration of the request and development of the revision shall follow the process defined in the NERC *Standard Processes Manual*. Upon approval by the Board, the revision shall be submitted to the Applicable Governmental Authorities for approval. Changes shall become effective only upon approval by the Applicable Governmental Authorities or on a date designated by the Applicable Governmental Authorities or as otherwise applicable in a particular jurisdiction.

316. Reserved

317. Periodic Review of Reliability Standards

NERC shall complete a periodic review of each NERC Reliability Standard in accordance with the NERC *Standard Processes Manual*. As a result of this review, the NERC Reliability Standard shall be reaffirmed, revised, or withdrawn. If the review indicates a need to revise or withdraw the Reliability Standard, a request for revision or withdrawal shall be prepared, submitted and addressed in accordance with the NERC *Standard Processes Manual*.

318. Coordination with the North American Energy Standards Board

NERC shall maintain a close working relationship with the North American Energy Standards Board and ISO/RTO Council to ensure effective coordination of wholesale electric business practice standards and market protocols with the NERC Reliability Standards.

319. Archived Standards Information

NERC shall maintain a historical record of Reliability Standards information that is no longer maintained on-line. For example, Reliability Standards that have been retired may be removed from the on-line system. Archived information shall be retained indefinitely as practical, but in no case less than six years or one complete Reliability Standards review cycle from the date on which the Reliability Standard was no longer in effect. Archived records of Reliability Standards information shall be available electronically within 30 days following the receipt by NERC staff of a written request.

320. Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels

1. **Development of Violation Risk Factors and Violation Severity Levels** — NERC shall follow the process for developing Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) as set forth in the Standard Processes Manual, Appendix 3A to these Rules of Procedure.

2. **Remands of Directed Revision of VRFs and VSLs by Applicable Governmental Authorities** — If an Applicable Governmental Authority remands or directs a revision to a Board-approved VRF or VSL assignment, the NERC director of standards, after consulting with the standard drafting team, Standards Committee, and the NERC director of compliance operations, will recommend to the Board one of the following actions: (1) filing a request for clarification; (2) filing for rehearing or for review of the Applicable Governmental Authority decision; or (3) approval of the directed revisions to the VRF or VSL. If and to the extent time is available prior to the deadline for the Board's decision, an opportunity for interested parties to comment on the action taken will be provided.

3. **Alternative Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels** — In the event the Reliability Standards development process fails to produce Violation Risk Factors or Violation Severity Levels for a particular Reliability Standard in a timely manner, the Board of Trustees may approve Violation Risk Factors or Violation Severity Levels for that Reliability Standard after notice and opportunity for comment. In approving VRFs and VSLs, the Board shall consider the inputs of the Member Representatives Committee, affected stakeholders and NERC staff.

321. Special Rule to Address Certain Regulatory and Board of Trustees Directives

In circumstances where this Rule 321 applies, the Board of Trustees shall have the authority to take one or more of the actions set out below. The Board of Trustees shall have the authority to choose which one or more of the actions are appropriate to the circumstances and need not take these actions in sequential steps; provided that the Board of Trustees shall, to the extent feasible and consistent with its obligations and established deadlines, choose actions that seek to maximize stakeholder participation.

1. The Standards Committee shall have the responsibility to ensure that standards drafting teams address specific matters that are identified in directives issued by Applicable Governmental Authorities or by the NERC Board of Trustees pursuant to its authority in Section 322. If the Board of Trustees is presented with a proposed Reliability Standard that fails to adequately address such directives, the Board of Trustees has the authority to remand, with instructions (including establishing a timetable for action), the proposed Reliability Standard to the Standards Committee.

2. Upon a written finding by the Board of Trustees that a ballot pool has failed to approve a proposed Reliability Standard that contains a provision to adequately address a specific matter identified in a directive issued by an Applicable Governmental Authority or by the NERC Board of Trustees pursuant to its

authority in Section 322, the Board of Trustees has the authority to remand the proposed Reliability Standard to the Standards Committee, with instructions to (i) convene a public technical conference to discuss the issues surrounding the regulatory or Board directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified; (ii) working with NERC staff, prepare a memorandum discussing the issues, an analysis of the alternatives considered and other appropriate matters; (iii) use the input from the technical conference to revise the proposed Reliability Standard, as appropriate; and (iv) re-ballot the proposed Reliability Standard one additional time, with such adjustments in the schedule as are necessary to meet the deadline contained in paragraph 2.1 of this Rule.

2.1 Such a re-ballot shall be completed within forty-five (45) days of the remand. The Standards Committee memorandum shall be included in the materials made available to the ballot pool in connection with the re-ballot.

2.2 In any such re-ballot, negative votes without comments related to the proposal shall be counted for purposes of establishing a quorum, but only affirmative votes and negative votes with comments related to the proposal shall be counted for purposes of determining the number of votes cast and whether the proposed Reliability Standard has been approved.

3. If the re-balloted proposed Reliability Standard achieves at least an affirmative two-thirds majority vote of the weighted Segment votes cast, with a quorum established, then the proposed Reliability Standard shall be deemed approved by the ballot pool and shall be considered by the Board of Trustees for approval.

4. If the re-balloted proposed Reliability Standard fails to achieve at least an affirmative two-thirds majority vote of the weighted Segment votes cast, but does achieve at least a sixty percent affirmative majority of the weighted Segment votes cast, with a quorum established, then the Board of Trustees has the authority to consider the proposed Reliability Standard for approval under the following procedures:

4.1 The Board of Trustees shall issue notice of its intent to consider the proposed Reliability Standard and shall solicit written public comment particularly focused on the technical aspects of the provisions of the proposed Reliability Standard that address the specific matter identified in the regulatory or Board directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified.

4.2 The Board of Trustees may, in its discretion, convene a public technical conference to receive additional input on the matter.

4.3 After considering the developmental record, the comments received during balloting and the additional input received under paragraphs 4.1 and 4.2 of this Rule, the Board of Trustees has authority to act on the proposed Reliability Standard.

4.3.1 If the Board of Trustees finds that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to approve the proposed Reliability Standard and direct that it be filed with Applicable Governmental Authorities with a request that it be made effective. In addition, the Board of Trustees may direct further revisions in accordance with Rule 322.

4.3.2 If the Board of Trustees is unable to find that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to take one of the following actions:

4.3.2.1 For a regulatory directive, the Board of Trustees may treat the proposed Reliability Standard as a draft Reliability Standard and direct that the draft Reliability Standard and complete developmental record, including the additional input received under paragraphs 4.1 and 4.2 of this Rule, be filed with the Applicable Governmental Authorities as a compliance filing in response to the order giving rise to the regulatory directive, along with a recommendation that the Reliability Standard not be made effective and an explanation of the basis for the recommendation.

4.3.2.2 For a Board directive, the Board of Trustees may remand the proposed Reliability Standard and direct further work under this Section.

5. Upon a written finding by the Board of Trustees that standard drafting team has failed to develop, or a ballot pool has failed to approve, a proposed Reliability Standard that contains a provision to adequately address a specific matter identified in a directive issued by an Applicable Governmental Authority or the Board of Trustees, the Board of Trustees has the authority to direct the Standards Committee (with the assistance of stakeholders and NERC staff) to prepare a draft Reliability Standard that addresses the regulatory or Board directive, taking account of the entire developmental record pertaining to the matter. If the Standards Committee fails to prepare such draft Reliability Standard, the Board of

Trustees may direct NERC management to prepare such draft Reliability Standard.

5.1 The Board of Trustees may, in its discretion, convene a public technical conference to receive input on the matter. The draft Reliability Standard shall be posted for a 45-day public comment period.

5.2 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees finds that the draft Reliability Standard, with such modifications as the Board of Trustees determines are appropriate in light of the comments received, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to approve the draft Reliability Standard and direct that the proposed Reliability Standard be filed with Applicable Governmental Authorities with a request that the proposed Reliability Standard be made effective. In addition, the Board of Trustees may direct further work in accordance with Rule 322.

5.3 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees is unable to find that the draft Reliability Standard, even with modifications, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to take one of the following actions:

5.3.1 For a regulatory directive, the Board of Trustees may direct that the draft Reliability Standard and complete developmental record be filed as a compliance filing in response to the regulatory directive with the Applicable Governmental Authority issuing the regulatory directive, with a recommendation that the draft Reliability Standard not be made effective.

5.3.2 For a Board directive, the Board of Trustees may remand the proposed Reliability Standard and direct further work under this Section.

5.4 The filing of the Reliability Standard under either paragraph 5.2 or paragraph 5.3 of this Rule shall include an explanation of the basis for the decision by the Board of Trustees.

6. NERC shall on or before March 31st of each year file a report with Applicable Governmental Authorities on the status and timetable for addressing each outstanding directive to address a specific matter received from an Applicable Governmental Authority.

322. Special Authority to Address Reliability Matters Necessary to Maintain the Reliability of the Bulk Power System

To meet NERC's statutory responsibility under Section 215 of the Federal Power Act to develop Reliability Standards that provide for an adequate level of reliability for the Bulk Power System, the Board of Trustees shall have the authority to direct the development of a new or revised Reliability Standard. The Board of Trustees will only exercise this authority in extraordinary circumstances, where the Board determines a directive is essential to provide for an adequate level of reliability for the Bulk Power System consistent with Section 215 of the Federal Power Act. This authority shall be in addition to the Board of Trustees' other authorities regarding Reliability Standards as provided in these Rules of Procedure and the Bylaws. In issuing such directives, the following process shall be used:

1. The Board of Trustees shall provide public notice of its intent to direct the development of a new or revised Reliability Standard to address a matter it has deemed essential to provide for an adequate level of reliability for the Bulk Power System. This notice shall take the form of a written document that includes, at a minimum, the following:

   1.1 the proposed date for issuing the proposed directive, which shall be no earlier than 60 days from the date of the notice, and the period for public comment, which shall be no less than 45 days;

   1.2 a description of the proposed directive, including any deadlines for standards development;

   1.3 the reliability basis for the proposed directive;

   1.4 the reasons why the Board has preliminarily determined that extraordinary circumstances exist, and that the proposed directive is essential to assure the reliable operation of the Bulk Power System;

   1.5 identification of any past, current, or planned stakeholder-initiated standards development projects to address the reliability matter addressed by the proposed directive; and

   1.6 An explanation of why the Board has preliminarily determined that the reliability matter cannot be addressed adequately or in a timely manner through stakeholder-initiated projects or a project initiated by NERC Staff.

2. NERC shall publicly post the notice and set a public comment period for the time described in the notice.

3. The Board of Trustees may direct the development of a new or revised Reliability Standard, as originally proposed or with modifications, if it determines that such action is just, reasonable, not unduly discriminatory, and in the public interest. This action shall take the take the form of a written determination containing, at a minimum, the following:

   1.1 the effective date of the directive;

   1.2 a description of the directive, including any deadlines for standards development;

   1.3 the reliability basis for the directive;

   1.4 the reasons why the Board has determined that extraordinary circumstances exist, and that the directive is essential to assure the reliable operation of the Bulk Power System;

   1.5 identification of any past, current, or planned stakeholder-initiated standards development projects to address the reliability matter addressed by the proposed directive;

   1.6 An explanation of why the Board has determined that the reliability matter cannot be addressed adequately or in a timely manner through stakeholder-initiated projects or a project initiated by NERC Staff; and

   1.7 a description of how the Board of Trustees considered any advice provided by the Member Representatives Committee, or any comments provided by the public, NERC standing committees, Applicable Governmental Authorities or other regulatory authorities, the Regional Entities, or NERC management.

4. Any person or entity with directly and materially affected interests in the subject of a Board of Trustees directive, including any nonprofit association representing members with such interests, may request the Board of Trustees reconsider or clarify its determination. Such request shall be submitted in writing within 30 calendar days of the issuance of the determination and contain, at a minimum, a description of the matter for which the entity is seeking reconsideration or clarification, the reasons therefor, and the interests that would be affected if the requested reconsideration or clarification is not granted. If the Board of Trustees does not act on the request within 30 days, it may be deemed denied. Unless

otherwise directed by the Board of Trustees, no deadline for action shall be stayed pending the disposition of any request for reconsideration or clarification.

5. NERC shall publicly post all Board of Trustees directives and any supporting documentation. This information shall become part of the record of development for the resulting Reliability Standard.

6. Where the Board of Trustees has determined to direct the development of a new or revised Reliability Standard, NERC Staff shall prepare a Standards Authorization Request for submission to the Standards Committee.

7. Reliability Standards that are directed by the Board of Trustees shall be developed using the NERC Standard Processes Manual. The waiver provisions of the NERC *Standard Processes Manual* may be applied if necessary to meet a timetable for action required by the Board of Trustees, respecting to the extent possible the provisions in the *NERC Standard Processes Manual* for reasonable notice and opportunity for public comment, due process, openness, and a balance of interest in developing Reliability Standards. If the Board of Trustees determines that the process did not result in a Reliability Standard that addresses a specific matter that is identified in its directive, then the Board of Trustees may, in its discretion, apply Rule 321 of these Rules of Procedure.

SECTION 400 — COMPLIANCE MONITORING AND ENFORCEMENT

401. Scope of the Compliance Monitoring and Enforcement Program

1. **Components of the Compliance Monitoring and Enforcement Program** — NERC shall develop and implement a Compliance Monitoring and Enforcement Program (CMEP) to promote the reliability of the Bulk Power System by enforcing compliance with approved Reliability Standards in those regions of North America in which NERC and/or a Regional Entity (pursuant to a delegation agreement with NERC or other legal instrument approved by an Applicable Governmental Authority) has been given enforcement authority.

2. **Who Must Comply** — Where required by applicable legislation, regulation, rule or agreement, all Bulk Power System owners, operators, and users are required to comply with all approved Reliability Standards at all times. Regional Reliability Standards and Variances approved by NERC and the Applicable Governmental Authority shall be considered Reliability Standards and shall apply to all Bulk Power System owners, operators, or users responsible for meeting those Reliability Standards within the Regional Entity boundaries, whether or not the Bulk Power System owner, operator, or user is a member of the Regional Entity.

3. **Data Access** — All Bulk Power System owners, operators, and users shall provide to NERC or the Compliance Enforcement Authority (CEA) such Documents, data, and information as is necessary to monitor and enforce compliance with the Reliability Standards. NERC and the CEA will define the data retention and reporting requirements.

4. **Role of Regional Entities in the Compliance Monitoring and Enforcement Program** — Each Regional Entity that has been delegated authority through a delegation agreement or other legal instrument approved by the Applicable Governmental Authority shall, in accordance with the terms of the approved delegation agreement, administer the CMEP provided in these Rules of Procedure.

5. **Program Continuity** — NERC will ensure continuity of compliance monitoring and enforcement within the geographic boundaries of a Regional Entity if NERC does not have a delegation agreement with a Regional Entity, the Regional Entity or NERC terminates the delegation agreement, or the Regional Entity does not administer the CMEP in accordance with the delegation agreement or other applicable requirements.

   5.1 In the circumstances outlined above, the following will apply:

      1. This monitoring and enforcement can be coordinated with staff from another approved Regional Entity.

2. If an existing delegation agreement with a Regional Entity is terminating, the Regional Entity shall promptly provide to NERC all relevant information regarding Registered Entities in the geographic footprint or for which the Regional Entity has CMEP responsibilities under coordinated oversight of Registered Entities, as specified in a termination agreement.

3. NERC will levy and collect all Penalties directly and will utilize any Penalty monies consistent with Section 1107 of the Rules of Procedure.

5.2 Should a Regional Entity seek to withdraw from its delegation agreement, NERC will seek agreement from another Regional Entity to amend its delegation agreement with NERC to extend that Regional Entity's boundaries for compliance monitoring and enforcement. In the event no Regional Entity is willing to accept this responsibility, NERC will administer the CMEP within the geographical boundaries of the Regional Entity seeking to withdraw from the delegation agreement, in accordance with Section 401.5.1.

6. **Risk Elements** — NERC, with input from the Regional Entities, stakeholders, and regulators, shall at least annually identify ERO and Regional Entity-specific risk elements, together with related Reliability Standards and Requirements are to be considered to prioritize CMEP activities. NERC coordinates with the Regional Entities to identify the risk elements using data including, but not limited to: compliance findings; event analysis experience; data analysis; and the expert judgment of NERC and Regional Entity staff, committees, and subcommittees. Compliance is required, and NERC and the Regional Entities have authority to monitor compliance, with all applicable Reliability Standards whether or not they are identified as areas of focus to be considered for compliance oversight in the annual ERO CMEP Implementation Plan or are included in a Regional Entity's oversight plan for the Registered Entity.

7. **Penalties, Sanctions, and Remedial Action Directives** — NERC and Regional Entities will apply Penalties, sanctions, and Remedial Action Directives that bear a reasonable relation to the seriousness of a violation and take into consideration timely remedial efforts as defined in the NERC *Sanction Guidelines*, which are incorporated into these rules as **Appendix 4B**.

8. **Multiple Enforcement Actions** – A Registered Entity shall not be subject to an enforcement action by NERC and a Regional Entity, or by more than one Regional Entity (unless the Registered Entity is registered in more than one Region in which the violation occurred), for the same violation.

9. **Records** — NERC and Regional Entities shall coordinate to maintain a record of each compliance submission, including potential noncompliance with approved

Reliability Standards; associated Penalties, sanctions, Remedial Action Directives, and settlements; and the status of Mitigating Activities.

10. **Confidential Information** — The types of CMEP information that will be considered confidential and will not (subject to statutory and regulatory requirements) be disclosed in any public information reported by NERC are identified in Section 1500.

    The disclosure by the CEA or NERC of any CMEP Confidential Information shall follow Section 1500.

11. **Public Posting** — When the affected Bulk Power System owner, operator, or user either agrees with the resolution of a potential noncompliance with a Reliability Standard(s) or a report of a Compliance Audit or Compliance Investigation, or enters into a settlement agreement concerning a potential noncompliance or Alleged Violation(s), or the time for submitting an appeal is passed, or all appeals processes are complete, NERC shall, subject to the requirements, rules, and regulations of the Applicable Governmental Authority and the confidentiality requirements of these Rules of Procedure, publicly post information on each such noncompliance, Penalty or sanction, settlement agreement, and final Compliance Audit or Compliance Investigation, on its website. As required by an Applicable Governmental Authority, NERC will also post information concerning noncompliance disposed of as Compliance Exceptions, subject to Section 1500 of these Rules of Procedure.

    11.1 Each Bulk Power System owner, operator, or user may provide NERC with a statement to accompany the publicly posted information. The statement must be on company letterhead and include a signature, as well as the name and title of the person submitting the information.

    11.2 Subject to the disclosure requirements of the Applicable Governmental Authority and redaction of Critical Energy Infrastructure Information, Critical Electric Infrastructure Information, or other Confidential Information, for each resolved noncompliance submitted to the Applicable Governmental Authority, the public posting shall include: a) the name of any relevant entity, b) the nature, time period, and circumstances of the noncompliance, c) any Mitigation Plan or other Mitigating Activities to be implemented by the Registered Entity, and d) sufficient facts to assist owners, operators and users of the Bulk Power System to evaluate whether they have engaged in or are engaging in similar activities.

12. **Review of Noncompliance** — NERC staff shall periodically review and analyze reports of noncompliance to identify trends and other pertinent reliability issues.

402. NERC Oversight of the Compliance Monitoring and Enforcement Program

1. **Oversight** — NERC shall oversee each Regional Entity that has been delegated authority. The objective of this oversight is to ensure that the Regional Entity

carries out its obligations under the CMEP in accordance with these Rules of Procedure and the terms of the delegation agreement, and to ensure consistency and fairness of the Regional Entity's execution of the CMEP. Oversight by NERC shall be accomplished through an annual Compliance Monitoring and Enforcement Program review, program audits, regular evaluations of Regional Entity Compliance Monitoring and Enforcement Program performance metrics, risk-based monitoring activities, and performance reports. Through this oversight, NERC evaluates the Regional Entity's effectiveness and implementation of the CMEP using, among other things, the criteria developed by the NERC Compliance and Certification Committee.

1.1 **Annual ERO CMEP Implementation Plan** — NERC and the Regional Entities will maintain and update an ERO CMEP Implementation Plan. The ERO CMEP Implementation Plan reflects ERO and Regional Entity-specific risk elements that CEAs should prioritize for oversight of Registered Entities.

1.2 **Regional Entity Compliance Monitoring and Enforcement Program Evaluation** — NERC shall annually evaluate the goals, tools, and procedures of each Regional Entity Compliance Monitoring and Enforcement Program to determine the effectiveness of each Regional Entity Compliance Monitoring and Enforcement Program, using criteria developed by the NERC Compliance and Certification Committee.

1.3 **Regional Entity Compliance Monitoring and Enforcement Program Audit** — At least once every five years, NERC shall conduct an audit to evaluate how each Regional Entity implements the CMEP. The audit shall be based on these Rules of Procedure, including Appendix 4C, the delegation agreements, directives in effect pursuant to the delegation agreements, the approved annual ERO CMEP Implementation Plan, required CMEP attributes, and NERC CMEP guidance and procedures. The audit shall be provided to the Applicable Governmental Authorities to demonstrate the effectiveness of each Regional Entity. In addition, audits of Cross-Border Regional Entities shall cover applicable requirements imposed on the Regional Entity by statute, regulation, or order of, or agreement with, provincial governmental and/or regulatory authorities for which NERC has auditing responsibilities over the Regional Entity's compliance with such requirements within Canada or Mexico. Participation of a representative of an Applicable Governmental Authority shall be subject to the limitations of sections 4.1.4 and 8.0 of Appendix 4C of these Rules of Procedure regarding disclosures of non-public compliance information related to other jurisdictions. NERC shall maintain an audit procedure containing the requirements, steps, and timelines to conduct an audit of each Regional Entity.

1.3.1. NERC shall establish a program to audit bulk power system owners, operators, and users operating within a regional entity to verify the findings of previous compliance audits conducted by the regional entity to evaluate how well the regional entity compliance enforcement program is meeting its delegated authority and responsibility.

1.4 Applicable Governmental Authorities will be allowed to participate as an observer in any audit conducted by NERC of a Regional Entity's implementation of the CMEP.

2. **Consistency in Regional Implementation of the Compliance Monitoring and Enforcement Program** — To provide for consistency and fairness of the processes used for Regional Entity findings of compliance and noncompliance and the application of Penalties and sanctions for all Bulk Power System owners, operators, and users required to comply with approved Reliability Standards, NERC shall maintain a single CMEP, which is incorporated into these Rules of Procedure as **Appendix 4C**. Any differences in CMEP methods, including determination of noncompliance and Penalty assessment, shall be justified on a case-by-case basis and fully documented in each Regional Entity delegation agreement.

2.1 NERC shall periodically conduct Regional Entity CMEP manager meetings. These meetings shall identify and resolve CMEP differences into a set of best practices over time.

3. **Information Collection and Reporting** — NERC and the Regional Entities shall implement data management procedures that address data reporting requirements, data integrity, data retention, data security, and data confidentiality.

4. **Noncompliance Disclosure** — NERC shall follow the process in **Appendix 4C**.

5. **Authority to Determine Noncompliance, Levy Penalties and Sanctions, and Issue Remedial Action Directives** — The CEA shall have the authority and responsibility to make initial determinations of compliance or noncompliance, and where authorized by the Applicable Governmental Authorities or where otherwise authorized, to determine Penalties and sanctions for noncompliance with a Reliability Standard, and issue Remedial Action Directives. Remedial Action Directives may be issued by a CEA that is aware of a Bulk Power System owner, operator, or user that is, or is about to engage in an act or practice that would result, in noncompliance with a Reliability Standard, where such Remedial Action Directive is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat. If, after receiving such a Remedial Action Directive, the Bulk Power System owner, operator, or user does not take appropriate action to avert noncompliance with a Reliability Standard, NERC may petition the Applicable Governmental Authority to issue a compliance order.

6. **Due Process** — NERC shall establish and maintain a fair, independent, and nondiscriminatory appeals process. The appeals process is set forth in Sections

408-410. The process shall allow Bulk Power System owners, operators, and users to appeal the Regional Entity's findings of noncompliance and to appeal Penalties, sanctions, and Remedial Action Directives that are levied by the Regional Entity. Appeals beyond the NERC process will be heard by the Applicable Governmental Authority.

7. **Conflict Disclosure** — NERC shall disclose to the Applicable Governmental Authority any potential conflicts between a market rule and the enforcement of a Reliability Standard.

8. **Confidentiality** — To maintain the integrity of the CMEP, NERC and Regional Entities, Compliance Audit team members, and committee members shall maintain the confidentiality of information obtained and shared during CMEP activities.

   8.1 NERC and the Regional Entity shall have in place appropriate codes of conduct and confidentiality agreements for all participants in CMEP activities.

   8.2 A participant's failure to follow the code of conduct or Confidential Information provisions of these Rules of Procedure may result in that person and any member organization with which the person is associated losing access to Confidential Information on a temporary or permanent basis and being subject to appropriate action by the Regional Entity or NERC, including prohibiting participation in future CMEP activities. Nothing in Section 1500 precludes an entity whose information was improperly disclosed from seeking a remedy in an appropriate court.

9. **Auditor Training** — NERC shall develop and provide training in auditing skills to participants in NERC and Regional Entity Compliance Audits. Training for NERC and Regional Entity personnel and others who serve as Compliance Audit team leaders shall be more comprehensive than training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

403. Required Attributes of Regional Entity Implementation of the Compliance Monitoring and Enforcement Program

Each Regional Entity shall (i) conform to and comply with the CMEP, **Appendix 4C** to these Rules of Procedure, except to the extent of any deviations that are stated in the Regional Entity's delegation agreement, and (ii) meet all of the attributes set forth in this Section 403.

Program Structure

1. **Independence** — Each Regional Entity's governance of its CMEP activities shall exhibit independence, meaning the Regional Entity shall be organized so that its CMEP activities are carried out separately from other activities of the Regional

Entity. The CMEP activities shall not be unduly influenced by the Bulk Power System owners, operators, and users being monitored. Regional Entities must include rules providing that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

2. **Exercising Authority** — Each Regional Entity shall exercise the responsibility and authority in carrying out the delegated functions of the CMEP in accordance with delegation agreements and **Appendix 4C**.

3. **Delegation of Authority** — To maintain independence, fairness, and consistency in the CMEP, a Regional Entity shall not sub-delegate its CMEP duties to entities or persons other than the Regional Entity Staff, unless (i) required by statute or regulation in the applicable jurisdiction, or (ii) by agreement with express approval of NERC and of FERC or other Applicable Governmental Authority, to another Regional Entity.

4. **Hearings of Contested Findings or Sanctions —** Unless the Regional Entity has elected to participate in the Consolidated Hearing Process, the Regional Entity board or compliance panel reporting directly to the Regional Entity board will designate a Hearing Body (with appropriate recusal procedures) that will be vested with the authority for conducting all compliance hearings, pursuant to the hearing process selected under Section 403.15, in which any Bulk Power System owner, operator, or user provided a Notice of Alleged Violation may present facts and other information to contest a Notice of Alleged Violation or any proposed Penalty, sanction, any Remedial Action Directive, or any Mitigation Plan component. Compliance hearings shall be conducted in accordance with the Hearing Procedures set forth in Attachment 2 to **Appendix 4C**. If a stakeholder body serves as the Hearing Body, no two industry sectors may control any decision and no single sector may veto any matter related to compliance after recusals.

Program Resources

5. **Regional Entity Staff** — Each Regional Entity shall have sufficient resources to meet delegated compliance monitoring and enforcement responsibilities, including the necessary professional staff to manage and implement the CMEP.

6. **Regional Entity Staff Independence** — The Regional Entity Staff, collectively, shall be capable and required to: a) make all determinations of compliance and noncompliance; b) determine Penalties, sanctions, and Remedial Action Directives; and c) review and accept Mitigation Plans and other Mitigating Activities.

   6.1 Regional Entity Staff shall not have a conflict of interest, real or perceived, in the outcome of compliance monitoring and enforcement processes, reports, or sanctions. The Regional Entity shall have in effect a conflict of interest policy.

6.2 Regional Entity Staff shall have the authority and responsibility to carry out compliance monitoring and enforcement processes, make determinations of compliance or noncompliance, and levy Penalties and sanctions without interference or undue influence from Regional Entity members and their representative or other industry entities.

6.3 Regional Entity Staff may call upon independent technical subject matter experts who have no conflict of interest in the outcome of the compliance monitoring and enforcement process to provide technical advice or recommendations in the determination of compliance or noncompliance.

6.4 Regional Entity Staff shall abide by the confidentiality requirements contained in Section 1500 and **Appendix 4C** of these Rules of Procedure and the delegation agreement

6.5 Contracting with independent consultants or others working for the Regional Entity shall be permitted provided the individual has not received compensation from a Bulk Power System owner, operator, or user being monitored for a period of at least the preceding six months and owns no financial interest in any Bulk Power System owner, operator, or user being monitored for compliance to the Reliability Standard, regardless of where the Bulk Power System owner, operator, or user operates. Any such individuals shall be considered as augmenting Regional Entity Staff under these Rules of Procedure.

7. **Use of Industry Subject Matter Experts and Regional Entity Members** — Industry experts and Regional Entity members may be called upon to provide their technical expertise in CMEP activities.

7.1 The Regional Entity shall have procedures defining the allowable involvement of industry subject matter experts and Regional Entity members. The procedures shall address applicable antitrust laws and conflicts of interest.

7.2 Industry subject matter experts and Regional Entity members shall have no conflict of interest or financial interests in the outcome of their activities.

7.3 Regional Entity members and industry subject matter experts, as part of teams or Regional Entity committees, may provide input to the Regional Entity so long as the authority and responsibility for (i) evaluating and determining compliance or noncompliance and (ii) levying Penalties, sanctions, or Remedial Action Directives shall not be delegated to any person or entity other than Regional Entity staff. Industry subject matter experts, Regional Entity members, or Regional Entity committees shall not make determinations of noncompliance or levy Penalties, sanctions, or Remedial Action Directives. Any committee involved shall be organized so that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

7.4 Industry subject matter experts and Regional Entity members shall sign a confidentiality agreement appropriate for the activity being performed.

7.5 All industry subject matter experts and Regional Entity members participating in Compliance Audits and Compliance Investigations shall successfully complete auditor training provided by NERC or the Regional Entity prior to performing these activities

Program Design

8. **Antitrust Provisions** — Each Regional Entity's CMEP activities shall be structured and administered to abide by United States antitrust law and Canadian competition law.

9. **Information Submittal** — All Bulk Power System owners, operators, and users responsible for complying with Reliability Standards within the Regional Entity shall submit timely and accurate Documents, data, and information when requested by the Regional Entity or NERC. Where appropriate, Submitting Entities should comply with the requirements of Section 1500 in submitting such Documents, data, and information. NERC and the Regional Entities shall preserve any mark of confidentiality on information submitted pursuant to Section 1502.1.

9.1 Each Regional Entity has the authority to collect the necessary Documents, data, and information to determine compliance and shall develop processes for gathering Documents, data, and information from the Bulk Power System owners, operators, and users the Regional Entity monitors.

9.2 The Regional Entity or NERC has the authority to request information from Bulk Power System owners, operators, and users pursuant to Section 401.3 or this Section 403.9 without invoking a specific compliance monitoring and enforcement process in **Appendix 4C**, for purposes of determining whether to pursue one such process in a particular case and/or validating in the enforcement phase of a matter the conclusions reached through the compliance monitoring and enforcement process(es).

9.3 When required or requested, the Regional Entities shall report information to NERC promptly and in accordance with **Appendix 4C** and other NERC procedures.

9.4 Regional Entities shall notify NERC of noncompliance with Reliability Standards by Registered Entities over which the Regional Entity has compliance monitoring and enforcement authority, in accordance with **Appendix 4C**.

9.5 As requested by the CEA, a Bulk Power System owner, operator, or user found in noncompliance with a Reliability Standard shall submit a Mitigation Plan or conduct Mitigating Activities in accordance with **Appendix 4C**. The Regional Entity Staff shall review and accept the Mitigation Plan in accordance with **Appendix 4C**.

9.6 An officer of a Bulk Power System owner, operator, or user shall certify as accurate all Self-Reports to the Regional Entity, including Documents, data, and information provided with the Self-Report.

9.7 Regional Entities shall develop and implement procedures to verify the compliance information submitted by Bulk Power System owners, operators, and users.

10. **Compliance Monitoring of Bulk Power System Owners, Operators, and Users** — Each Regional Entity will maintain and implement a program for risk-based compliance monitoring, to include Compliance Audits of Bulk Power System owners, operators, and users responsible for complying with Reliability Standards, in accordance with **Appendix 4C**.

10.1 For an entity registered as a Balancing Authority, Reliability Coordinator, or Transmission Operator, the Compliance Audit will be performed at least once every three years.

11. **Confidentiality of Compliance Monitoring and Enforcement Processes** — All compliance monitoring and enforcement processes, and Documents, data, and information obtained from such processes, are to be non-public and treated in accordance with Section 1500 and **Appendix 4C** of these Rules of Procedure, unless NERC, the Regional Entity, or FERC or another Applicable Governmental Authority with jurisdiction determines a need to conduct a Compliance Monitoring and Enforcement Program process on a public basis. Advance authorization from the Applicable Governmental Authority is required to make public any compliance monitoring and enforcement process or any information relating to a compliance monitoring and enforcement process, or to permit interventions when determining whether to impose a Penalty. This prohibition on making public any compliance monitoring and enforcement process does not prohibit NERC or a Regional Entity from publicly disclosing (i) the initiation of or results from an analysis of a significant system event under Section 807 or of off-normal events or system performance under Section 808, or (ii) information of general applicability and usefulness to owners, operators, and users of the Bulk Power System concerning reliability and compliance matters, so long as such disclosures are in accordance with Section 1500 and Appendix 4C of these Rules of Procedure.

12. **Critical Energy Infrastructure Information and Critical Electric Infrastructure Information** — Information that would jeopardize Bulk Power System reliability, including information relating to a Cyber Security Incident will

be identified and protected from public disclosure as Confidential Information. In accordance with Section 1500, information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information or Critical Electric Infrastructure Information shall be redacted according to NERC procedures and shall not be released publicly.

13. **Penalties, Sanctions, and Remedial Action Directives** — Each Regional Entity will apply all Penalties, sanctions, and Remedial Action Directives in accordance with the approved *Sanction Guidelines*, **Appendix 4B** to these Rules of Procedure. Any changes to the *Sanction Guidelines* to be used by any Regional Entity must be approved by NERC and submitted to the Applicable Governmental Authority for approval. All Confirmed Violations, Penalties, and sanctions, including Confirmed Violations, Penalties, and sanctions specified in a Regional Entity Hearing Body decision, will be provided to NERC for review and filing with Applicable Governmental Authorities as a Notice of Penalty, in accordance with **Appendix 4C**.

14. **Hearing Process** — Each Regional Entity shall adopt either the Regional Entity Hearing Process (Section 403.15A) or the Consolidated Hearing Process (403.15B) and conduct all hearings pursuant to the selected process. In either case, the selected hearing process shall be a fair, independent, and nondiscriminatory process for hearing contested violations and any Penalties or sanctions levied, in conformance with Attachment 2 to **Appendix 4C** to these Rules of Procedure and any deviations therefrom that are set forth in the Regional Entity's delegation agreement. The hearing process shall allow Bulk Power System owners, operators, and users to contest findings of compliance violations, any Penalties and sanctions that are proposed to be levied, proposed Remedial Action Directives, and components of proposed Mitigation Plans. The hearing process shall (i) include provisions for recusal of any members of the Hearing Body with a potential conflict of interest, real or perceived, from all compliance matters considered by the Hearing Body for which the potential conflict of interest exists and (ii) provide that no two industry sectors may control any decision and no single sector may veto any matter brought before the Hearing Body after recusals.

    A Regional Entity may modify its selection of hearing process by giving notice to NERC six (6) months prior to such modification becoming effective. Hearings will be conducted pursuant to the process in effect at the Regional Entity at the time of the submission of the hearing request by the registered entity.

    Each Regional Entity will notify NERC of all hearings and NERC may observe any of the proceedings. Each Regional Entity will notify NERC of the outcome of all hearings.

    If a Bulk Power System owner, operator, or user or a Regional Entity has completed the Regional Entity Hearing Process or the Consolidated Hearing Process and desires to appeal the outcome of the hearing, the Bulk Power System owner, operator, or user or the Regional Entity shall appeal to NERC in accordance with Section 409 of these Rules of Procedure, except that a determination of violation or Penalty that has been directly adjudicated by an Applicable Governmental Authority shall be appealed with that Applicable Governmental Authority.

14A. **Regional Entity Hearing Process** — The Regional Entity Hearing Process shall be conducted before a Hearing Body composed of the Regional Entity board or a balanced committee established by and reporting to the Regional Entity board as the final adjudicator at the Regional Entity level, provided, that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions.

14B. **Consolidated Hearing Process** — The Consolidated Hearing Process shall be conducted before a Hearing Body composed of five members, unless a smaller number is necessary, as discussed below. The Hearing Body will issue a final decision, provided that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions. Up to two members will be appointed by the Regional Entity from which the case originates. If stakeholder members are appointed, the stakeholders shall not represent the same industry sector. Should a Regional Entity choose to appoint one or no representative, then the NERC Board of Trustees Compliance Committee ("Compliance Committee") will select additional representatives to fill those vacancies. The Compliance Committee will appoint the NERC representatives to the Hearing Body, chosen among NERC trustees not serving on the Compliance Committee at the time of the request for hearing. The Regional Entity and NERC members appointed to the Hearing Body will appoint an additional member to the Hearing Body, chosen among NERC trustees not serving on the Compliance Committee at the time of the request for hearing or from the Regional Entity from which the case originates. If the Hearing Body does not select a NERC trustee or a regional representative, the Hearing Body will appoint an additional member in accordance with the criteria specified in Appendix 4C, Attachment 2, Section 1.4.3(a). In the event a Regional Entity chooses not to appoint representatives to the Hearing Body and there are not five NERC trustees available to participate on the Hearing Body, as determined by the Compliance Committee, the Hearing Body may be composed of three members (three NERC trustees not serving on the Compliance Committee). The Hearing Body will appoint a Hearing Officer to preside over the hearing.

404. NERC Monitoring of Compliance for Bulk Power System Owners, Operators, or Users

1. **NERC Obligations** —NERC will directly monitor Bulk Power System owners, operators, and users for compliance with Reliability Standards in any geographic area for which there is not a delegation agreement in effect with a Regional Entity, in accordance with **Appendix 4C**. In such cases, NERC will serve as the CEA described in **Appendix 4C**. Compliance matters contested by Bulk Power

System owners, operators, and users in such an event will be heard by the NERC Compliance and Certification Committee.

2. **Appeals Process** — Any Bulk Power System owner, operator or user found by NERC to be in noncompliance with a Reliability Standard may appeal the findings of noncompliance with Reliability Standards and any sanctions or Remedial Action Directives that are issued by, or Mitigation Plan components imposed by, NERC, pursuant to the processes described in Sections 408 through 410.

405. Monitoring NERC's Compliance with the Rules of Procedure

The Compliance and Certification Committee shall monitor NERC's compliance with its Rules of Procedure for the Reliability Standards Development, Compliance Monitoring and Enforcement, and Organization Registration and Certification Programs in accordance with this section and Section 506. The Compliance and Certification Committee's monitoring shall not be used to circumvent the appeals processes established for those programs. The Compliance and Certification Committee shall use independent expert monitors with no conflict of interest, real or perceived. Compliance and Certification Committee findings shall be addressed with the NERC Board of Trustees and other appropriate Board committees.

406. Independent Audits of the Compliance Monitoring and Enforcement Program

NERC shall provide for an independent audit of the Compliance Monitoring and Enforcement Program at least once every three years, or more frequently as determined by the NERC Board of Trustees in coordination with the Compliance and Certification Committee. The audit shall be conducted by independent expert auditors as selected by the NERC Board of Trustees. The independent audit shall meet the following minimum requirements and any other requirements established by the NERC Board of Trustees.

1. **Effectiveness** — The audit shall evaluate the success and effectiveness of the Compliance Monitoring and Enforcement Program in achieving its mission.

2. **Relationship** — The audit shall evaluate the relationship between NERC and the Regional Entities in implementing the Compliance Monitoring and Enforcement Program and the effectiveness of the program in ensuring reliability.

3. **Final Report Posting** — The final report shall be posted by NERC for public viewing in accordance with Appendix 4C.

4. **Response to Recommendations** — If the audit report includes recommendations to improve the Compliance Monitoring and Enforcement Program, the administrators of the Compliance Monitoring and Enforcement Program shall provide a written response and plan to the NERC Board of Trustees within 30 days of the release of the final audit report to the NERC Board of Trustees or other appropriate Board committee. NERC will post the written response and plan for public viewing when authorized by the NERC Board of Trustees or other

appropriate Board committee. NERC will post the written response and plan for public viewing.

407. Penalties, Sanctions, and Remedial Action Directives

1. **NERC Review of Regional Entity Penalties and Sanctions —** NERC shall review all Penalties, sanctions, and Remedial Action Directives imposed by each Regional Entity for violations of Reliability Standards, including Penalties, sanctions, and Remedial Action Directives that are specified by a Hearing Body final decision issued pursuant to Attachment 2 to **Appendix 4C**, to determine if the Regional Entity's determination: a) is supported by a sufficient record compiled by the Regional Entity; b) is consistent with the *Sanction Guidelines* incorporated into these Rules of Procedure as **Appendix 4B** and with other directives, guidance, and directions issued by NERC pursuant to the delegation agreement; and c) is consistent with Penalties, sanctions, and Remedial Action Directives imposed by the Regional Entity and by other Regional Entities for violations involving the same or similar facts and circumstances.

2. **Developing Penalties and Sanctions** — The Regional Entity Staff shall use the *Sanction Guidelines*, which are incorporated into these Rules of Procedure as **Appendix 4B**, to develop an appropriate Penalty, sanction, or Remedial Action Directive for a violation, and shall notify NERC of the Penalty, sanction, or Remedial Action Directive.

3. **Effective Date of Penalty** — Where authorized by applicable legislation or agreement, no Penalty imposed for a violation of a Reliability Standard shall take effect until the thirty-first day after NERC files, with the Applicable Governmental Authority, a Notice of Penalty and the record of the proceedings in which the violation and Penalty were determined, or such other date as ordered by the Applicable Governmental Authority.

408. Review of NERC Decisions

1. **Scope of Review** — A Registered Entity wishing to challenge a finding of noncompliance and the imposition of a Penalty for a compliance measure directly administered by NERC, or a Regional Entity wishing to challenge a Regional Entity audit finding, may do so by filing a notice of the challenge with NERC's Director of Enforcement no later than 30 days after issuance of the notice of finding of violation or audit finding. Appeals by Registered Entities or Regional Entities of decisions of Hearing Bodies shall be pursuant to Section 409.

2. **Contents of Notice** — The notice of challenge shall include the full text of the decision that is being challenged, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief.

3. **Response by NERC Compliance Monitoring and Enforcement Program —** Within 30 days after receiving a copy of the notice of challenge, the NERC

Director of Enforcement may file with the Hearing Panel a response to the issues raised in the notice, with a copy to the Regional Entity.

4. **Hearing by Compliance and Certification Committee** — For matters subject to its review, the Compliance and Certification Committee shall provide representatives of the Regional Entity or Registered Entity and the NERC Compliance Monitoring and Enforcement Program an opportunity to be heard and shall decide the matter based upon the filings and presentations made, with a written explanation of its decision.

5. **Appeal** — The Regional Entity or Registered Entity may appeal the decision of the Compliance and Certification Committee by filing a notice of appeal with NERC's Director of Enforcement no later than 21 days after issuance of the written decision by the Compliance and Certification Committee. The notice of appeal shall include the full text of the written decision of the Compliance and Certification Committee that is being appealed, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief. No factual material shall be presented in the appeal that was not presented to the Compliance and Certification Committee.

6. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 21 days after receiving a copy of the notice of appeal, NERC may file its response to the issues raised in the notice of appeal, with a copy to the entity filing the notice.

7. **Reply** — The entity filing the appeal may file a reply within 7 days.

8. **Decision** — The Board of Trustees Compliance Committee shall decide the appeal, in writing, based upon the notice of appeal, the record, the response, and any reply. At its discretion, the Board of Trustees Compliance Committee may invite representatives of the Regional Entity or Registered Entity and the NERC Compliance Monitoring and Enforcement Program to appear before the Board of Trustees Compliance Committee. Decisions of the Board of Trustees Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

9. **Impartiality** — No member of the Compliance and Certification Committee or the Board of Trustees Compliance Committee having an actual or perceived conflict of interest in the matter may participate in any aspect of the challenge or appeal except as a party or witness.

10. **Expenses** — Each party in the challenge and appeals processes shall pay its own expenses for each step in the process.

11. **Non-Public Proceedings —** All challenges and appeals shall be closed to the public to protect Confidential Information.

409. Appeals from Final Decisions of Hearing Bodies

1. **Time for Appeal** — A Regional Entity acting as the CEA, or an owner, operator, or user of the Bulk Power System, shall be entitled to appeal from a final decision of a Hearing Body concerning an Alleged Violation of a Reliability Standard, a proposed Penalty or sanction for violation of a Reliability Standard, a proposed Mitigation Plan, or a proposed Remedial Action Directive, by filing a notice of appeal with NERC's Director of Enforcement, with copies to the Clerk, the Regional Entity, and any other Participants in the Hearing Body proceeding, no later than 21 days after issuance of the final decision of the Hearing Body. The Board of Trustees Compliance Committee shall render its decision within 180 days following the receipt by NERC's Director of Enforcement of the notice of appeal. The Board of Trustees Compliance Committee may extend this deadline for good cause and shall provide written notice of any extension to all Participants.

2. **Contents** — The notice of appeal shall include the full text of the final decision of the Hearing Body that is being appealed, a concise statement of the error or errors contained in the final decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief. No factual material shall be presented in the appeal that was not first presented during the proceeding before the Hearing Body.

3. **Response to Notice of Appeal** — Within 21 days after the date the notice of appeal is filed, the Clerk shall file the entire record of the Hearing Body proceeding with NERC's Director of Enforcement, with a copy to all Participants. Within 35 days after the date of the notice of appeal, all Participants in the proceeding before the Hearing Body, other than the Participant filing the notice of appeal, shall file their responses to the issues raised in the notice of appeal.

4. **Reply** — The party filing the appeal may file a reply to the responses within 7 days.

5. **Decision** — The Board of Trustees Compliance Committee shall decide the appeal, in writing, based upon the notice of appeal, the record of the proceeding before the Hearing Body, the responses, and any reply filed with NERC. The Board of Trustees Compliance Committee shall review the appealed issue(s) under a *de novo* standard. At its discretion, the Board of Trustees Compliance Committee may invite representatives of the entity making the appeal and the other Participants in the proceeding before the Hearing Body to appear before the Board of Trustees Compliance Committee. Decisions of the Board of Trustees Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

6. **Expenses** — Each party in the appeals process shall pay its own expenses for each step in the process.

7. **Non-Public Proceedings** — All appeals shall be closed to the public to protect Confidential Information.

8. **Appeal of Hearing Body Decisions Granting or Denying Motions to Intervene** — This section is not applicable to an appeal of a decision of a Hearing Body granting or denying a motion to intervene in the Hearing Body proceeding. Appeals of decisions of Hearing Bodies granting or denying motions to intervene in Hearing Body proceedings shall be processed and decided pursuant to Section 414.

410. Hold Harmless

A condition of invoking the challenge or appeals processes under Section 408 or 409 is that the entity requesting the challenge or appeal agrees that neither NERC (defined to include its Members, Board of Trustees, committees, subcommittees, staff and industry subject matter experts), any person assisting in the challenge or appeals processes, nor any company employing a person assisting in the challenge or appeals processes, shall be liable, and they shall be held harmless against the consequences of: a) any action or inaction; b) any agreement reached in resolution of the dispute; or c) any failure to reach agreement as a result of the challenge or appeals proceeding. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

411. Requests for Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards

A Registered Entity that is subject to an Applicable Requirement of a NERC Critical Infrastructure Protection Standard for which Technical Feasibility Exceptions are permitted, may request a Technical Feasibility Exception to the Requirement. The request will be reviewed, approved or disapproved, and if approved, implemented, in accordance with the NERC *Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standards*, Appendix 4D to these Rules of Procedure.

412. Certification of Questions from Hearing Bodies for Decision by the NERC Board of Trustees Compliance Committee

1. A Hearing Body that is conducting a hearing concerning a disputed compliance matter pursuant to Attachment 2, Hearing Procedures, of Appendix 4C, may certify to the Board of Trustees Compliance Committee, for decision, a significant question of law, policy, or procedure, the resolution of which may be determinative of the issues in the hearing in whole or in part, and as to which there are other extraordinary circumstances that make prompt consideration of the question by the Board of Trustees Compliance Committee appropriate, in accordance with Section 1.5.12 of the Hearing Procedures. All questions certified by a Hearing Body to the Board of Trustees Compliance Committee shall be considered and disposed of by the Board of Trustees Compliance Committee.

2. The Board of Trustees Compliance Committee may accept or reject a certification of a question for decision. If the Board of Trustees Compliance Committee rejects the certified question, it shall issue a written statement that the certification is rejected.

3. If the Board of Trustees Compliance Committee accepts the certification of a question for decision, it shall establish a schedule by which the Participants in the hearing before the Hearing Body may file memoranda and reply memoranda stating their positions as to how the question certified for decision should be decided by the Board of Trustees Compliance Committee. The Board of Trustees Compliance Committee may also request, or provide an opportunity for, the NERC Compliance department, the NERC Enforcement department, and/or the NERC general counsel to file memoranda stating their positions as to how the question certified for decision should be decided. After receiving such memoranda and reply memoranda are filed in accordance with the schedule, the Board of Trustees Compliance Committee shall issue a written decision on the certified question.

4. Upon receiving the Board of Trustees Compliance Committee's written decision on the certified question, the Hearing Body shall proceed to complete the hearing in accordance with the Board of Trustees Compliance Committee's decision.

5. The Board of Trustees Compliance Committee's decision, if any, on the certified question shall only be applicable to the hearing from which the question was certified and to the Participants in that hearing.

413. Review and Processing of Hearing Body Final Decisions that Are Not Appealed

NERC shall review and process all final decisions of Hearing Bodies issued pursuant to Attachment 2 to Appendix 4C concerning an Alleged Violation, proposed Penalty or sanction, or proposed Mitigation Plan that are not appealed pursuant to Section 409, as though the determination had been made by the Regional Entity. NERC shall review and process such final decisions, and may require that they be modified by the Regional Entity, in accordance with, as applicable to the particular decision, Sections 5.8, 5.9, and 6.5 of Appendix 4C.

414. Appeals of Decisions of Hearing Bodies Granting or Denying Motions to Intervene in Hearing Body Proceedings

1. **Time to Appeal** — An entity may appeal a decision of a Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** denying the entity's motion to intervene in a Hearing Body proceeding, and the Regional Entity Staff or any other Participant in the Hearing Body proceeding may appeal a decision of the Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** granting or denying a motion to intervene in the Hearing Body proceeding, in either case by filing a notice of appeal with the NERC Director of Enforcement, with copies to the Clerk of the Hearing Body, the Hearing Body, the Hearing Officer, the Regional Entity Staff, and all other Participants in the Hearing Body proceeding,

no later than seven (7) days following the date of the Hearing Body decision granting or denying the motion to intervene.

2. **Contents of Notice of Appeal** — The notice of appeal shall set forth information and argument to demonstrate that the decision of the Hearing Body granting or denying the motion to intervene was erroneous under the grounds for intervention specified in Section 1.4.4 of Attachment 2 of **Appendix 4C** and that the entity requesting intervention should be granted or denied intervention, as applicable. Facts alleged in, and any offers of proof made in, the notice of appeal shall be supported by affidavit or verification. The notice of appeal shall include a copy of the original motion to intervene and a copy of the decision of the Hearing Body granting or denying the motion to intervene.

3. **Responses to Notice of Appeal** — Within ten (10) days following the date the notice of appeal is filed, the Clerk shall transmit to the NERC Director of Enforcement copies of all pleadings filed in the Hearing Body proceeding on the motion to intervene. Within fourteen (14) days following the date the notice of appeal is filed, the Hearing Body, the Regional Entity Staff, and any other Participants in the Hearing Body proceeding, may each file a response to the notice of appeal with the NERC Director of Enforcement. Within seven (7) days following the last day for filing responses, the entity filing the notice of appeal, and any Participant in the Hearing Body proceeding that supports the appeal, may file replies to the responses with the NERC Director of Enforcement.

4. **Disposition of Appeal** — The appeal shall be considered and decided by the Board of Trustees Compliance Committee. The NERC Director of Enforcement shall provide copies of the notice of appeal and any responses and replies to the Board of Trustees Compliance Committee. The Board of Trustees Compliance Committee shall issue a written decision on the appeal; provided, that if the Board of Trustees Compliance Committee does not issue a written decision on the appeal within forty-five (45) days following the date of filing the notice of appeal, the appeal shall be deemed denied and the decision of the Hearing Body granting or denying the motion to intervene shall stand. The NERC Director of Enforcement shall transmit copies of the Board of Trustees Compliance Committee's decision, or shall provide notice that the forty-five (45) day period has expired with no decision by the Board of Trustees Compliance Committee, to the Clerk, the Hearing Body, the entity filing the notice of appeal, the Regional Entity Staff, and any other Participants in the Hearing Body proceeding that filed responses to the notice of appeal or replies to responses.

5. **Appeal of Board of Trustees Compliance Committee Decision to FERC or Other Applicable Governmental Authority** — Any entity aggrieved by the decision of the Board of Trustees Compliance Committee on an appeal of a Hearing Body decision granting or denying a motion to intervene in a Hearing Body proceeding (including a denial of such appeal by the expiration of the forty-five (45) day period as provided in Section 414.4) may appeal or petition for review of the decision of the Board of Trustees Compliance Committee to FERC

or to another Applicable Governmental Authority having jurisdiction over the matter, in accordance with the authorities, rules, and procedures of FERC or such other Applicable Governmental Authority. Any such appeal or petition for review shall be filed within the time period, if any, and in the form and manner, specified by the applicable statutes, rules, or regulations governing proceedings before FERC or the other Applicable Governmental Authority.

SECTION 500 — ORGANIZATION REGISTRATION AND CERTIFICATION

501. Scope of the Organization Registration and Organization Certification Programs

The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the FERC approved Reliability Standards. Organizations that are registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and for complying with all applicable Reliability Standards. Registered Entities are not and do not become Members of NERC or a Regional Entity, by virtue of being listed on the NCR. Membership in NERC is governed by Article II of NERC's Bylaws; membership in a Regional Entity or regional reliability organization is governed by that entity's bylaws or rules.

The purpose of the Organization Certification Program is to ensure that the new entity (i.e., applicant to be an RC, BA, or TOP that is not already performing the function for which it is applying to be certified as) has the tools, processes, training, and procedures to demonstrate their ability to meet the Requirements/sub-Requirements of all of the Reliability Standards applicable to the function(s) for which it is applying thereby demonstrating the ability to become certified and then operational.

Organization Registration and Organization Certification may be delegated to Regional Entities in accordance with the procedures in this Section 500; the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into these Rules of Procedure as **Appendix 5A**; and, approved Regional Entity delegation agreements or other applicable agreements.

1. **NERC Compliance Registry** — NERC shall establish and maintain the NCR of the Bulk Power System owners, operators, and users that are subject to approved Reliability Standards.

1.1 (a) The NCR shall set forth the identity and functions performed for each organization responsible for meeting Requirements/sub-Requirements of the Reliability Standards. Bulk Power System owners, operators, and users (i) shall provide to NERC and the applicable Regional Entity information necessary to complete the Registration, and (ii) shall provide NERC and the applicable Regional Entity with timely updates to information concerning the Registered Entity's ownership, operations, contact information, and other information that may affect the Registered Entity's Registration status or other information recorded in the Compliance Registry.

(b) Entities may address registration obligations for applicable function types using a Joint Registration Organization (JRO), in lieu of each of the JRO's parties'entities being registered individually for one or more functions. Refer to Section 507.

(c) Entities may each register using a Coordinated Functional Registration

(CFR) for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function pursuant to a written agreement for the division of compliance responsibility. Refer to Section 508.

1.2 In the development of the NCR, NERC and the Regional Entities shall determine which organizations should be placed on the NCR based on the criteria provided in the NERC *Statement of Compliance Registry Criteria* which is incorporated into these Rules of Procedure as **Appendix 5B**.

1.3 NERC and the Regional Entities shall use the following rules for establishing and maintaining the NCR based on the Registration criteria as set forth in **Appendix 5B** *Statement of Compliance Registry Criteria*:

1.3.1 NERC shall notify each organization that it is on the NCR. The Registered Entity is responsible for compliance with all the Reliability Standards applicable to the functions for which it is registered from the time it receives the Registration notification from NERC.

1.3.2 Any organization receiving such a notice may challenge its placement on the NCR according to the process in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section V.

1.3.3 The Compliance Committee of the Board of Trustees shall promptly issue a written decision on the challenge, including the reasons for the decision.

1.3.4 The decision of the Compliance Committee of the Board of Trustees shall be final unless, within 21 days of the date of the Compliance Committee of the Board of Trustees decision, the organization appeals the decision to the Applicable Governmental Authority.

1.3.5 Each Registered Entity identified on the NCR shall notify its corresponding Regional Entity(s) of any corrections, revisions, deletions, changes in ownership, corporate structure, or similar matters that affect the Registered Entity's responsibilities with respect to the Reliability Standards. Failure to notify will not relieve the Registered Entity from any responsibility to comply with the Reliability Standards or shield it from any Penalties or sanctions associated with failing to comply with the Reliability Standards applicable to its associated Registration.

1.4 For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and required by the Reliability

Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall:

1.4.1 Ensure that all areas are under the oversight of one and only one Reliability Coordinator.

1.4.2 Ensure that all Balancing Authorities and Transmission Operator entities[2] are under the responsibility of one and only one Reliability Coordinator.

1.4.3 Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator.

1.4.4 Ensure that all Loads and generators are under the responsibility and control of one and only one Balancing Authority.

1.5 NERC shall maintain the NCR of organizations responsible for meeting the Requirements/sub-Requirements of the Reliability Standards currently in effect on its website and shall update the NCR monthly.

1.6 With respect to: (i) entities to be registered for the first time; (ii) currently-registered entities or (iii) previously-registered entities, for which registration status changes are sought, including availability and composition of a sub-set list of applicable Reliability Standards (which specifies the Reliability Standards and may specify Requirements/sub-Requirements), the registration process steps in Section III of **Appendix 5A** apply.

1.7 NERC shall establish a NERC-led, centralized review panel, comprised of a NERC lead with Regional Entity participants, in accordance with **Appendix 5A**, *Organization Registration and Organization Certification Manual*, Section III.D and **Appendix 5B**, *Statement of Compliance Registry Criteria*.

2. **Entity Certification** — NERC shall provide for Certification of all entities with primary reliability responsibilities requiring Certification. The NERC programs shall:

[2] Some organizations perform the listed functions (e.g., Balancing Authority, Transmission Operator) over areas that transcend the Footprints of more than one Reliability Coordinator. Such organizations will have multiple Registrations, with each such Registration corresponding to that portion of the organization's overall area that is within the Footprint of a particular Reliability Coordinator.

2.1 Evaluate the entity's tools, personnel, facilities, and processes used to perform the duties and tasks identified in and required by the Reliability Standards. The entities currently requiring Certification include Reliability Coordinators, Transmission Operators, and Balancing Authorities.

2.2 Certify each applicant's ability to perform the function for a specified Area.[3]

2.3 Maintain process documentation.

2.4 Maintain records of currently certified entities.

2.5 Issue a Certification document to the applicant that successfully demonstrates its competency to perform the evaluated functions.

3. **Delegation and Oversight**

3.1 NERC may delegate responsibilities for Organization Registration and Organization Certification to Regional Entities in accordance with requirements established by NERC. Delegation will be via the delegation agreement between NERC and the Regional Entity or other applicable agreement. The Regional Entity shall administer Organization Registration and Organization Certification Programs in accordance with such delegations to meet NERC's programs goals and requirements subject to NERC oversight.

3.2 NERC shall develop and maintain a plan to ensure the continuity of Organization Registration and Organization Certification within the geographic or electrical boundaries of a Regional Entity in the event that no entity is functioning as a Regional Entity for that Region, or the Regional Entity withdraws as a Regional Entity, or does not operate its Organization Registration and Organization Certification Programs in accordance with delegation agreements.

3.3 NERC shall develop and maintain a program to monitor and oversee the NERC Organization Registration and Organization Certification Programs activities that are delegated to each Regional Entity through a delegation agreement or other applicable agreement.

3.3.1 This program shall monitor whether the Regional Entity carries out those delegated activities in accordance with NERC requirements,

[3] When the term "Area" is used and capitalized it is being used in the certification context, and is inclusive of terms currently defined in NERC Glossary of Terms and Appendix 2 of the ROP, specifically, "Balancing Authority Area," "Reliability Coordinator Area," or "Transmission Operator Area."

and whether there is consistency, fairness of administration, and comparability.

3.3.2 Monitoring and oversight shall be accomplished through direct participation in the Organization Registration and Organization Certification Programs with periodic reviews of documents and records of both programs.

502. Organization Registration and Organization Certification Program Requirements

1. NERC shall maintain the Organization Registration and Organization Certification Programs.

1.1 The roles and authority of Regional Entities in the programs are delegated from NERC pursuant to the Rules of Procedure through regional delegation agreements or other applicable agreements.

1.2 Processes for the programs shall be administered by NERC and the Regional Entities. Materials that each Regional Entity uses are subject to review and approval by NERC.

1.3 The appeals process for the Organization Registration and Organization Certification Programs are identified in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Sections VI and VII, respectively.

1.4 The Certification Team membership is identified in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section IV.

2. To ensure consistency and fairness of the Organization Registration and Organization Certification Programs, NERC shall develop procedures to be used by all Regional Entities and NERC in accordance with the following criteria:

2.1 NERC and the Regional Entities shall have data management processes and procedures that provide for confidentiality, integrity, and retention of data and information collected.

2.2 Documentation used to substantiate the conclusions of the Regional Entity/ NERC related to Registration and/or Certification must be retained by the Regional Entity for (6) six years, unless a different retention period is otherwise identified, for the purposes of future audits of these programs.

2.3 To maintain the integrity of the NERC Organization Registration and Organization Certification Programs, NERC, Regional Entities, Certification Team members, program audit team members (Section 506), and committee members shall maintain the confidentiality of information provided by an applicant or entities.

2.2.1 NERC and the Regional Entities shall have appropriate codes of conduct and confidentiality agreements for staff, Certification Team, Certification related committees, and Certification program audit team members.

2.2.2 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall maintain the confidentiality of any Registration or Certification-related discussions or documents designated as confidential (see Section 1500 for types of Confidential Information).

2.2.3 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall treat as confidential the individual comments expressed during evaluations, program audits and report-drafting sessions.

2.2.4 Copies of notes, draft reports, and other interim documents developed or used during an entity Certification evaluation or program audit shall be destroyed after the public posting of a final, uncontested report.

2.2.5 Information deemed by an applicant, entity, a Regional Entity, or NERC as confidential, including Critical Energy Infrastructure Information, shall not be released publicly or distributed outside of a committee or team.

2.2.6 In the event that an individual violates any of the confidentiality rules set forth above, that individual and any member organization with which the individual is associated will be subject to immediate dismissal from the audit team and may be prohibited from future participation in Compliance Monitoring and Enforcement Program activities by the Regional Entity or NERC.

2.2.7 NERC shall develop and provide training in auditing skills to all individuals prior to their participation in Certification evaluations. Training for Certification Team leaders shall be more comprehensive than the training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

2.4 An applicant that is determined to be competent to perform a function after completing all Certification requirements shall be deemed certified by NERC to perform that function for which it has demonstrated full competency.

2.4.1 All NERC certified entities shall be included on the NCR.

503. Regional Entity Implementation of Organization Registration and Organization Certification Program Requirements

1. **Delegation** — Recognizing the Regional Entity's knowledge of and experience with its members, NERC may delegate responsibility for Organization Registration and Organization Certification to the Regional Entity through a delegation agreement.

2. **Registration** — The following Organization Registration activities shall be managed by the Regional Entity per the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into the Rules of Procedure as Appendix 5A *Organization Registration and Organization Certification Manual*:

   2.1 Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4).

3. **Certification —** The following Organization Certification activities shall be managed by the Regional Entity in accordance with an approved delegation agreement or another applicable agreement:

   3.1 An entity seeking Certification to perform one of the functions requiring Certification shall contact the Regional Entity for the Region(s) in which it plans to operate to apply for Certification.

   3.2 An entity seeking Certification and other affected entities shall provide all information and data requested by NERC or the Regional Entity to conduct the Certification process.

   3.3 Regional Entities shall notify NERC of all Certification applicants.

   3.4 NERC and/or the Regional Entity shall evaluate the competency of entities requiring Certification to meet the NERC Certification requirements.

   3.5 NERC or the Regional Entity shall establish Certification procedures to include evaluation processes, schedules and deadlines, expectations of the applicants and all entities participating in the evaluation and Certification processes, and requirements for Certification Team members.

      3.5.1 The NERC / Regional Entity Certification procedures will include provisions for on-site visits to the applicant's facilities to review the data collected through questionnaires, interviewing the operations and management personnel, inspecting the facilities and equipment (including requesting a demonstration of all tools identified in the Certification process), reviewing all necessary documents and data (including all agreements, processes, and procedures identified in the Certification process), reviewing

Certification documents and projected system operator work schedules, and reviewing any additional documentation needed to support the completed questionnaire or inquiries arising during the site visit.

3.5.2 The NERC/ Regional Entity Certification procedures will provide for preparation of a written report by the Certification Team, detailing any deficiencies that must be resolved prior to granting Certification, along with any other recommendations for consideration by the applicant, the Regional Entity, or NERC.

504. Appeals

1. NERC shall maintain an appeals process to resolve any disputes related to Registration or Certification activities per the *Organization Registration and Organization Certification Manual,* which is incorporated in these Rules of Procedure as Appendix 5A.

2. The Regional Entity Certification appeals process shall culminate with the Regional Entity board or a committee established by and reporting to the Regional Entity board as the final adjudicator, provided that where applicable, Canadian provincial governmental authorities may act as the final adjudicator in their jurisdictions. NERC shall be notified of all appeals and may observe any proceedings **(Appendix 5A** *Organization Registration and Organization Certification Manual*).

505. Program Maintenance

NERC shall maintain its program materials, including such manuals or other documents as it deems necessary, of the governing policies and procedures of the Organization Registration and Organization Certification Programs.

506. Independent Audit of NERC Organization Registration and Organization Certification Program

1. NERC, through the Compliance and Certification Committee, shall provide for an independent audit of its Organization Registration and Organization Certification Programs at least once every three years, or more frequently, as determined by the Board. The audit shall be conducted by independent expert auditors as selected by the Board.

2. The audit shall evaluate the success, effectiveness and consistency of the NERC Organization Registration and Organization Certification Programs.

3. The final report shall be provided to the NERC Board of Trustees or its appropriate committees, and posted for public viewing. Confidential Information shall be handled in accordance with the NERC Rules of Procedure Section 1500, *Confidential Information*.

4. If the audit report includes recommendations to improve the program, the administrators of the program shall provide a written response to the Board within 30 days of the final report, detailing the disposition of each and every recommendation, including an explanation of the reasons for rejecting a recommendation and an implementation plan for the recommendations accepted.

507. Provisions Relating to Joint Registration Organizations (JRO)

1. In addition to registering as the entity responsible for all function type(s) that it performs itself, an entity may execute an agreement to register as a Lead Entity of a JRO on behalf of one or more parties to the agreement for one or more function type(s) for which such parties would otherwise be required to register. The Lead Entity thereby, accept on behalf of such parties all compliance responsibility for the function types(s) covered by the JRO registration, including all reporting requirements. The Lead Entity of a JRO must execute a written agreement with the parties on whose behalf it registers that: (1) governs the relationship between the parties; (2) addresses the function type(s) described within Appendix 5B for which the Lead Entity is registering for and taking responsibility, and which would otherwise be the responsibility of one or more of the other parties to the JRO; (3) identifies which entity is the Lead Entity and a point of contact within the Lead Entity; and (4) identifies a point of contact for each of the parties to the JRO.

2. For every JRO, the written agreement must be submitted to the appropriate Regional Entity for its retention. Neither NERC nor the Regional Entity shall be parties to any such agreement. Neither NERC nor the Regional Entity shall have responsibility for reviewing or approving any such agreement, other than to verify that the agreement addresses the function type(s) consistent with the Lead Entity's Registration.

3. The JRO Registration data must include all Registration and Certification information as needed by the Regional Entity to complete the Registration process and to perform assessments of compliance. All Compliance Monitoring and Enforcement related communications shall be directed to the primary compliance contact identified for the Lead Entity of the JRO.[4]

4. The Regional Entity shall notify NERC when it registers a Lead Entity of a JRO. The notification will identify the point of contact and the function type(s) for which the Lead Entity of the JRO is registered on behalf of the JRO parties and a point of contact for each of the JRO parties.

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[4] The primary compliance contact for the Lead Entity of a JRO can be the same person who serves as the point of contact for the Lead Entity of the JRO. However, it is not required that the same person serve as both the primary compliance contact and the point of contact.

5. For purposes of Compliance Audits, the Regional Entity shall keep a list of all JROs, the Lead Entities, the JRO parties,es and the function type(s) for which the Lead Entity of the JRO has registered for each partythat. It is the responsibility of the Lead Entity of the JRO to provide the Regional Entity with this information as well as the applicable JRO agreement(s).

6. The Regional Entity can request clarification of any list submitted to it that identifies the parties to the JRO and can request such additional information as the Regional Entity deems appropriate.

7. The Regional Entity's acceptance of a Lead Entity's registration as part of a JRO shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded that the registration of the Lead Entity of the JRO meets the Registration requirements of Section 501(1.4).

8. NERC shall maintain, and post on its website, a listing of all JROs, Lead Entities, JRO parties, and the function type(s) for which the Lead Entity of the JRO has registered for each party.

9. The Lead Entity of the JRO shall inform the Regional Entity of any changes to an existing JRO. The Regional Entity shall promptly notify NERC of each such revision.

10. Nothing in Section 507 shall preclude any party to a JRO from registering on its own behalf and undertaking full compliance responsibility for the function type(s) for which the Lead Entity of the JRO has registered. Such registration shall include submission of data or information that includes any documentation that the agreement supporting the JRO has been terminated as to the registering party. In addition to any notification requirements contained within the written agreement, a JRO party, that registers as responsible for any function type(s) for which the Lead Entity of a JRO was previously responsible shall inform the Lead Entity of the JRO and/or other parties once its Registration has been accepted by the Regional Entity.

508. Provisions Relating to Coordinated Functional Registration (CFR) Entities

1. In addition to registering as an entity responsible for all functions that it performs itself, multiple entities using a CFR must register for the function associated with the CFR. The CFR submission to the Regional Entity must include a written agreement that: (1) governs itself; (2) specifies the entities' respective compliance responsibilities; (3) identifies which entity is the Lead Entity, a point of contact within the Lead Entity, and a point of contact for each of the parties to the CFR The Lead Entity identified for each CFR is responsible for providing the written agreement between the parties, including submitting updates for currently active CFRs to the Regional Entity related to the CFR Registration; and (4) lists one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function type.

2. Neither NERC nor the Regional Entity shall be parties to any such agreement. Neither NERC nor the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the function type for which the parties are registered and the responsibility(ies) which are addressed through the CFR.

3. The CFR Registration data must include all Registration and Certification information and data, as needed by the Regional Entity to complete the Registration process and to perform assessments of compliance, as it relates to the CFR. All Compliance Monitoring and Enforcement related communications shall be directed to the primary compliance contact(s) identified for each of the CFR parties.

4. Each party to a CFR shall have compliance responsibility for those Reliability Standards and/or Requirements/sub-Requirements for which it has registered pursuant to the CFR.

5. The Regional Entity shall notify NERC of each CFR that the Regional Entity accepts, and the notification shall include identification of the Lead Entity of a CFR, the function type that the CFR addresses, a point of contact for each of the CFR parties, and any updates to currently active CFRs.

6. For purposes of Compliance Audits, the Regional Entity shall keep a list of all CFRs, the Lead Entities, the CFR parties, the function type that the CFR addresses, and the responsibilities assigned to each of the CFR parties.

7. The Regional Entity can request clarification of any list submitted to it that identifies the parties to the CFR and can request such additional information as the Regional Entity deems appropriate.

8. The Regional Entity's acceptance of a Lead Entity's registration as part of a CFR shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded that the registration of the CFR meets the Registration requirements of Section 501(1.4).

9. NERC shall maintain, and post on its website, a listing of all CFRs, the Lead Entity of CFRs, CFR parties, the function type that the CFR addresses, and the responsibilities assigned to each of the CFR parties. The posting shall clearly list all the Reliability Standards or Requirements/sub-Requirements thereof for which each entity of the CFR is responsible for under the CFR.

10. Any noncompliance shall be investigated in accordance with the NERC Rules of Procedure Section 400, *Compliance Enforcement*.

11. Nothing in Section 508 shall preclude a party to a CFR from registering on its own behalf and undertaking full compliance responsibility including reporting Requirements for the Reliability Standards to which a CFR is applicable. Such

registration shall include submission of data or information that includes any documentation that the agreement supporting the CFR has been terminated or revised as to the Reliability Standards for which the registering party is now taking compliance responsibility. In addition to any notification requirements contained within the written agreement, an entity registered in a CFR that registers as responsible for any Reliability Standard or Requirement/sub-Requirement of a Reliability Standard shall inform the Lead Entity of the CFR and/or other parties once its Registration has been accepted by the Regional Entity.

509. Exceptions to the Definition of the Bulk Electric System

An Element is considered to be (or not be) part of the Bulk Electric System by applying the BES Definition to the Element (including the inclusions and exclusions set forth therein). Appendix 5C sets forth the procedures by which (i) an entity may request a determination that an Element that falls within the definition of the Bulk Electric System should be exempted from being considered a part of the Bulk Electric System, or (ii) an entity may request that an Element that falls outside of the definition of the Bulk Electric System should be considered part of the Bulk Electric System.

SECTION 600 — PERSONNEL CERTIFICATION AND CREDENTIAL MAINTENANCE PROGRAM

601. Scope of Personnel Certification and Credential Maintenance Program

Maintaining the reliability of the Bulk Power System through implementation of the Reliability Standards requires skilled, and qualified personnel, including system operators. NERC shall develop a Personnel Certification and Credential Maintenance Program to:

1. provide the mechanism to determine system operators' essential knowledge relating to NERC Reliability Standards as well as principles of Bulk Power System operations;

2. administer a system operator Certification exam;

3. award the system operator Certification Credential to individuals who pass the exam; and,

4. prescribe requirements for System Operators to maintain their Certification Credential.

The NERC Personnel Certification and Credential Maintenance Program shall be international in scope consistent with the ERO's international regulatory responsibility for the reliability of the Bulk Power System in North America.

NERC Reliability Standards define which system operators require certification pursuant to the NERC Personnel Certification Program.

The NERC Personnel Certification Governance Committee (PCGC) is the governing body that both establishes the policies, sets fees, and monitors the performance of the Personnel Certification and Credential Maintenance Program for system operators.

602. Structure of ERO Personnel Certification and Credential Maintenance Program

1. PCGC shall develop a system operator program manual, approved by the NERC Board of Directors, which outlines the following:

   1.1 requirements for administering the system operator examinations;

   1.2 requirements for exam eligibility;

   1.3 requirements for awarding the Certification Credential;

   1.4 requirements for Certification Credential maintenance;

      1.4.1 NERC requires a system operator to earn CE Hours in NERC-Approved Learning Activities within the three-year period preceding the expiration date of his/her certificate as determined by the PCGC and posted in the NERC System Operator Program Manual.

1.4.2 NERC requires a system operator to request a renewal and submit the appropriate fee for Certification renewal evaluation.

1.5 dispute resolution procedures; and

1.6 disciplinary action guidelines.

2. PCGC shall develop a Credential Maintenance Program and maintain an accompanying manual, which outlines the following:

   2.1 requirements for approving contining education Providers and Learning Activities;

   2.2 requirements for auditing continuing education Providers and Learning Activities;

   2.3 multi-layer review process for disputed application reviews, interpretations of guideline and standards, probation or suspension of NERC-approved Provider status, and credential maintenance disputes; and,

   2.4 requirements on fees for continuing education Providers and Learning Activities.

603. Examination and Maintenance of NERC System Operator Certification Credentials

1. System operators seeking to obtain a Credential must pass an examination to earn the Credential.

2. A certificate will be issued to successful candidates which is valid for three years.

3. A system operator must earn Continuing Education Hours (CE Hours) in NERC-Approved Learning Activities within the three-year period preceding the expiration date of his/her certificate as determined by the PCGC and posted in the NERC System Operator Program Manual. A system operator must request a renewal and submit the appropriate fee for Certification renewal evaluation.

4. The Credential of a certified system operator who does not accumulate the required number and balance of CE Hours within the three-year period will be Suspended. A system operator with a Suspended certificate cannot perform any task that requires an operator to be NERC-certified. The system operator with a Suspended Credential will have up to twelve months to acquire the necessary CE Hours.

   4.1 During the time of suspension, the original anniversary date will be maintained. Therefore, should the system operator accumulate the required number of CE Hours within the twelve month suspension period, he/she will be issued a certificate that will be valid for three years from the previous expiration date.

4.2 At the end of the twelve-month suspension period, if the system operator has not accumulated the required number of CE Hours, the Credential will be Revoked and all CE Hours earned will be forfeited. After a Credential is Revoked, the system operator will be required to pass an examination to become certified.

5. Hardship: Due to unforeseen events and extenuating circumstances, a certified system operator may be unable to accumulate the necessary CE Hours in the time frame required by the Personnel Certification Program to maintain the Credential. In such an event, the individual must submit a written request containing a thorough explanation of the circumstances and supporting information to the NERC Personnel Certification Manager. The PCGC retains the right to invoke this hardship clause as it deems appropriate to address such events or circumstances.

604. Dispute Resolution Process

1. Any dispute arising under the NERC agreement establishing the *NERC Personnel Certification Program* or from the establishment of any NERC rules, policies, or procedures dealing with any segment of the Certification process shall be subject to the NERC System Operator Certification Dispute Resolution Process. The Dispute Resolution Process is for the use of persons who hold an operator Certification or persons wishing to be certified to dispute the validity of the examination, the content of the test, the content outlines, or the Registration process.

2. Dispute Resolution Process consists of three steps.

2.1. Notify NERC Personnel Certification Program Staff: This first step can usually resolve the issues without further actions. It is expected that most disputes will be resolved at this step. If the issue(s) is not resolved to the satisfaction of the parties involved in the first step, the issue can be brought to the PCGC Dispute Resolution Task Force.

2.2. PCGC Dispute Resolution Task Force: If the NERC staff did not resolve the issue(s) to the satisfaction of the parties involved, a written request must be submitted to the chairman of the PCGC through NERC staff explaining the issue(s) and requesting further action. Upon receipt of the letter, the PCGC chairman will present the request to the PCGC Dispute Resolution Task Force for action. This task force consists of three current members of the PCGC. The PCGC Dispute Resolution Task Force will investigate and consider the issue(s) presented and make a decision. This decision will then be communicated to the submitting party, the PCGC chairman, and the NERC staff within 45 calendar days of receipt of the request.

3. Personnel Certification Governance Committee: If the PCGC Dispute Resolution Task Force's decision did not resolve the issue(s) to the satisfaction of the parties involved, the final step in the process is for the issue(s) to be brought before the PCGC. Within 45 days of the date of the Task Force's decision, the disputing party shall submit a written request to the PCGC chairman through NERC staff requesting that the issue(s) be brought before the PCGC for resolution. The chairman shall see that the necessary documents and related data are provided to the PCGC members as soon as practicable. The PCGC will then meet or conference to discuss the issue(s) and make their decision within 60 calendar days of the chairman's receipt of the request. The decision will be provided to the person bringing the issue(s) and the NERC staff. The PCGC is the governing body of the Certification program and its decision is final.

4. Dispute Resolution Process Expenses: All individual expenses associated with the Dispute Resolution Process, including salaries, meetings, or consultant fees, shall be the responsibility of the individual parties incurring the expense.

5. Decision Process: Robert's Rules of Order shall be used as a standard of conduct for the Dispute Resolution Process. A majority vote of the members present will decide all issues. The vote will be taken in a closed session. No member of the PCGC may participate in the Dispute Resolution Process, other than as a party or witness, if he or she has an interest in the particular matter.

   5.1 A stipulation of invoking the Dispute Resolution Process is that the entity invoking the Dispute Resolution Process agrees that neither NERC (its members, Board of Trustees, committees, subcommittees, and staff), any person assisting in the Dispute Resolution Process, nor any company employing a person assisting in the Dispute Resolution Process, shall be liable, and they shall be held harmless against the consequences of or any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the Dispute Resolution Process. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

605. Disciplinary Action

1. Disciplinary action may be necessary to protect the integrity of the system operator Credential. The PCGC may initiate disciplinary action should an individual act in a manner that is inconsistent with expectations, including but not limited to:

   1.1. Willful, gross, and/or repeated violation of the NERC Reliability Standards as determined by a NERC investigation.

1.2. Willful, gross, and/or repeated negligence in performing the duties of a certified system operator as determined by a NERC investigation.

1.3. Intentional misrepresentation of information provided on a NERC application for a system operator Certification exam or to maintain a system operator Credential using CE Hours.

1.4. Intentional misrepresentation of identification in the exam process, including a person identifying himself or herself as another person to obtain Certification for the other person.

1.5. Any form of cheating during a Certification exam, including, but not limited to, bringing unauthorized reference material in the form of notes, crib sheets, or other methods of cheating into the testing center.

1.6. A certified system operator's admission to or conviction of any felony or misdemeanor directly related to his/her duties as a system operator.

2. Hearing Process: Upon report to NERC of a candidate's or certified system operator's alleged misconduct, the NERC PCGC Credential Review Task Force will convene for the determination of facts. An individual, government agency, or other investigating authority can file a report. Unless the Task Force initially determines that the report of alleged misconduct is without merit, the candidate or certified system operator will be given the right to notice of the allegation. A hearing will be held and the charged candidate or certified system operator will be given an opportunity to be heard and present further relevant information. The Task Force may seek out information from other involved parties. The hearing will not be open to the public, but it will be open to the charged candidate or certified system operator and his or her representative. The Task Force will deliberate in a closed session, but the Task Force cannot receive any evidence during the closed session that was not developed during the course of the hearing.

3. Task Force's decision: The Task Force's decision will be unanimous and will be in writing with inclusion of the facts and reasons for the decision. The Task Force's written decision will be delivered to the PCGC and by certified post to the charged candidate or certified system operator. In the event that the Task Force is unable to reach a unanimous decision, the matter shall be brought to the full committee for a decision.

3.1. No Action: Allegation of misconduct was determined to be unsubstantiated or inconsequential to the Credential.

3.2. Probation: A letter will be sent from NERC to the offender specifying:

3.2.1. The length of time of the probationary period (to be determined by the PCGC).

3.2.2. Credential will remain valid during the probationary period.

3.2.3. The probationary period does not affect the expiration date of the current certificate.

3.2.4. During the probationary period, a subsequent offense of misconduct, as determined through the same process as described above, may be cause for more serious consequences.

3.3. Revoke for Cause: A letter will be sent from NERC to the offender specifying:

3.3.1. The length of time of the probationary period (to be determined by the PCGC).

3.3.2. Credential is no longer valid.

3.3.3. Successfully passing an exam will be required to become recertified.

3.3.4. An exam will not be authorized until the revocation period expires

3.4. Termination of Credential: A letter will be sent from NERC to the offender specifying permanent removal of Credential.

4. Credential Review Task Force: The Credential Review Task Force shall be comprised of three active members of the PCGC assigned by the Chairman of the PCGC on an ad hoc basis. No one on the Credential Review Task Force may have an interest in the particular matter. The Task Force will meet in a venue determined by the Task Force chairman.

5. Appeal Process: The decision of the Task Force may be appealed using the NERC System Operator Certification Dispute Resolution Process.

606. Candidate Testing

1. The PCGC shall develop exams to evaluate individual competence in a manner that is objective, and fair to all candidates, and to determine essential knowledge relating to NERC Reliability Standards as well as principles of the Bulk Power System operations.

2. The PCGC shall oversee exam administration as follows:

1.1 Adopt and implement a formal policy of periodic review of exams to assess ongoing relevance to knowledge and skill needed in the discipline; and

1.2 Conduct ongoing studies to substantiate the reliability and validity of exams.

3. The PCGC shall develop and utilize policies and procedures to ensure the integrity and security of exams and the transparency of test administration consistent with the following:

   1.1 The PCGC shall establish pass/fail levels that protect the public with a method that is based on competence and generally accepted standards in the psychometric community as being fair and reasonable;

   1.2 The PCGC shall conduct ongoing studies to substantiate the reliability and validity of the exams;

   1.3 The PCGC shall dictate how long examination records are kept in their original format; and

   1.4 The PCGC shall demonstrate that different revisions of the exams assess equivalent content.

607. Public Information About the Personnel Certification Program

The PCGC shall maintain and publish the following:

1. a summary of the information, knowledge, or functions covered by each examination administered pursuant to the Personnel Certification Program; and

2. an annual summary of Certification activities for the Personnel Certification Program, including, the number of examinations delivered, the number of applicants who passed, the number of applicants who failed, and the number of applicants certified.

608. Responsibilities to Applicants for Certification or Re-Certification

The PCGC shall adhere to the following with respect to personnel applicants:

1. comply with all requirements of applicable federal and state/provincial laws with respect to all Certification and re-Certification activities, and shall require compliance of all contractors and/or providers of services;

2. make available to all applicants copies of formalized procedures for application for, and attainment of, personnel Certification and re-Certification and shall uniformly follow and enforce such procedures for all applicants;

3. implement a formal policy for the periodic review of eligibility criteria and application procedures for fairness;

4. provide competently proctored examination sites; and

5. uniformly provide applicants with examination results and give content summary after the examination.

609. Responsibilities to Employers of Certified Personnel

The PCGC shall adhere to the following with respect to certified personnel:

1. demonstrate that the exams adequately measure essential knowledge relating to NERC Reliability Standards as well as principles of Bulk Power System operations;

2. award Certification and re-Certification only after the skill and knowledge of the individual have been evaluated and determined to be acceptable;

3. maintain, in an electronic format, a current list of those personnel certified in the programs and have policies and procedures that delineate what information about a Certification Credential holder may be made public and under what circumstances; and

4. develop formal policies and procedures for discipline of a Certification Credential holder, including the revocation of the certificate, for conduct deemed harmful to the public or inappropriate to the discipline (e.g., incompetence, unethical behavior, physical or mental impairment affecting performance). These procedures shall incorporate due process.

610. [PLACEHOLDER]

SECTION 700 — RELIABILITY READINESS EVALUATION AND IMPROVEMENT AND FORMATION OF SECTOR FORUMS

701. Confidentiality Requirements for Readiness Evaluations and Evaluation Team Members

1. All information made available or created during the course of any reliability readiness evaluation including, but not limited to, data, Documents, observations and notes, shall be maintained as confidential by all evaluation team members, in accordance with the requirements of Section 1500.

2. Evaluation team members are obligated to destroy all confidential evaluation notes following the posting of the final report of the reliability readiness evaluation.

3. NERC will retain reliability readiness evaluation-related documentation, notes, and materials for a period of time as defined by NERC.

4. These confidentiality requirements shall survive the termination of the NERC Reliability Readiness Evaluation and Improvement Program.

702. Formation of Sector Forum

1. NERC will form a sector forum at the request of any five members of NERC that share a common interest in the safety and reliability of the Bulk Power System. The members of sector forum may invite such others of the members of NERC to join the sector forum as the sector forum deems appropriate.

2. The request to form a sector forum must include a proposed charter for the sector forum. The Board must approve the charter.

3. NERC will provide notification of the formation of a sector forum to its membership roster. Notices and agendas of meetings shall be posted on NERC's website.

4. A sector forum may make recommendations to any of the NERC committees and may submit a Standards Authorization Request to the NERC *Reliability Standards Development Procedure*.

SECTION 800 — RELIABILITY ASSESSMENT AND PERFORMANCE ANALYSIS

801. Objectives of the Reliability Assessment and Performance Analysis Program

The objectives of the NERC Reliability Assessment and Performance Analysis Program are to: (1) conduct, and report the results of, an independent assessment of the overall reliability and adequacy of the interconnected North American Bulk Power Systems, both as existing and as planned; (2) analyze off-normal events on the Bulk Power System; (3) identify the root causes of events that may be precursors of potentially more serious events; (4) assess past reliability performance for lessons learned; (5) disseminate findings and lessons learned to the electric industry to improve reliability performance; and (6) develop reliability performance benchmarks. The final reliability assessment reports shall be approved by the Board for publication to the electric industry and the general public.

802. Scope of the Reliability Assessment Program

1. The scope of the Reliability Assessment Program shall include:

    1.1 Review, assess, and report on the overall electric generation and transmission reliability (adequacy and operating reliability) of the interconnected Bulk Power Systems, both existing and as planned.

    1.2 Assess and report on the key issues, risks, and uncertainties that affect or have the potential to affect the reliability of existing and future electric supply and transmission.

    1.3 Review, analyze, and report on Regional Entity self-assessments of electric supply and bulk power transmission reliability, including reliability issues of specific regional concern.

    1.4 Identify, analyze, and project trends in electric customer demand, supply, and transmission and their impacts on Bulk Power System reliability.

    1.5 Investigate, assess, and report on the potential impacts of new and evolving electricity market practices, new or proposed regulatory procedures, and new or proposed legislation (e.g. environmental requirements) on the adequacy and operating reliability of the Bulk Power Systems.

2. The Reliability Assessment Program shall be performed in a manner consistent with the Reliability Standards of NERC including but not limited to those that specify reliability assessment Requirements.

803. Reliability Assessment Reports

The number and type of periodic assessments that are to be conducted shall be at the discretion of NERC. The results of the reliability assessments shall be documented in three reports: the long-term and the annual seasonal (summer) and the annual seasonal (winter) assessment reports. NERC shall also conduct special reliability assessments from time to time as circumstances warrant. The reliability assessment reports shall be reviewed and approved for publication by the Board. The three regular reports are described below.

1. **Long-Term Reliability Assessment Report** — The annual long-term report shall cover a ten-year planning horizon. The planning horizon of the long-term reliability assessment report shall be subject to change at the discretion of NERC. Detailed generation and transmission adequacy assessments shall be conducted for the first five years of the review period. For the second five years of the review period, the assessment shall focus on the identification, analysis, and projection of trends in peak demand, electric supply, and transmission adequacy, as well as other industry trends and developments that may impact future electric system reliability. Reliability issues of concern and their potential impacts shall be presented along with any mitigation plans or alternatives. The long-term reliability assessment reports will generally be published in the fall (September) of each year. NERC will also publish electricity supply and demand data associated with the long-term reliability assessment report.

2. **Summer Assessment Report** — The annual summer seasonal assessment report typically shall cover the four-month (June–September) summer period. It shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected summer peak demands. It shall also identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may include possible mitigation alternatives. The report will generally be published in mid-May for the upcoming summer period.

3. **Winter Assessment Report** — The annual winter seasonal assessment report shall cover the three-month (December–February) winter period. The report shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected winter peak demands. Similar to the summer assessment, the winter assessment shall identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may also include possible mitigation alternatives. The winter assessment report will generally be published in mid-November for the upcoming winter period.

4. **Special Reliability Assessment Reports** — In addition to the long-term and seasonal reliability assessment reports, NERC shall also conduct special reliability assessments on a regional, interregional, and Interconnection basis as conditions warrant, or as requested by the Board or governmental authorities. The teams of reliability and technical experts also may initiate special assessments of key

reliability issues and their impacts on the reliability of a regions, subregions, or Interconnection (or a portion thereof). Such special reliability assessments may include, among other things, operational reliability assessments, evaluations of emergency response preparedness, adequacy of fuel supply, hydro conditions, reliability impacts of new or proposed environmental rules and regulations, and reliability impacts of new or proposed legislation that affects or has the potential to affect the reliability of the interconnected Bulk Power Systems in North America.

804. Reliability Assessment Data and Information Requirements

To carry out the reviews and assessments of the overall reliability of the interconnected Bulk Power Systems, the Regional Entities and other entities shall provide sufficient data and other information requested by NERC in support of the annual long-term and seasonal assessments and any special reliability assessments.

Some of the data provided for these reviews and assessment may be considered confidential from a competitive marketing perspective, a Critical Energy Infrastructure Information perspective, or for other purposes. Such data shall be treated in accordance with the provisions of Section 1500 – Confidential Information.

While the major sources of data and information for this program are the Regional Entities, a team of reliability and technical experts is responsible for developing and formulating its own independent conclusions about the near-term and long-term reliability of the Bulk Power Systems.

In connection with the reliability assessment reports, requests shall be submitted to each of the Regional Entities for required reliability assessment data and other information, and for each Regional Entity's self-assessment report. The timing of the requests will be governed by the schedule for the preparation of the assessment reports.

The Regional Entity self-assessments are to be conducted in compliance with NERC Reliability Standards and the respective regional planning criteria. The team(s) of reliability and technical experts shall also conduct interviews with the Regional Entities as needed. The summary of the Regional Entity self-assessments that are to be included in the assessment reports shall follow the general outline identified in NERC's request. This outline may change from time to time as key reliability issues change.

In general, the Regional Entity reliability self-assessments shall address, among other areas, the following topics: demand and Net Energy for Load; assessment of projected resource adequacy; any transmission constraints that may impact bulk transmission adequacy and plans to alleviate those constraints; any unusual operating conditions that could impact reliability for the assessment period; fuel supply adequacy; the deliverability of generation (both internal and external) to Load; and any other reliability issues in the Region and their potential impacts on the reliability of the Bulk Power Systems.

805. Reliability Assessment Process

Based on their expertise, the review of the collected data, the review of the Regional Entity self-assessment reports, and interviews with the Regional Entities, as appropriate, the teams of reliability and technical experts shall perform an independent review and assessment of the generation and transmission adequacy of each Region's existing and planned Bulk Power System. The results of the review teams shall form the basis of NERC's long-term and seasonal reliability assessment reports. The review and assessment process is briefly summarized below.

1. **Resource Adequacy Assessment** — The teams shall evaluate the regional demand and resource capacity data for completeness in the context of the overall resource capacity needs of the Region. The team shall independently evaluate the ability of the Regional Entity members to serve their obligations given the demand growth projections, the amount of existing and planned capacity, including committed and uncommitted capacity, contracted capacity, or capacity outside of the Region. If the Region relies on capacity from outside of the Region to meet its resource objectives, the ability to deliver that capacity shall be factored into the assessment. The demand and resource capacity information shall be compared to the resource adequacy requirements of the Regional Entity for the year(s) or season(s) being assessed. The assessment shall determine if the resource information submitted represents a reasonable and attainable plan for the Regional Entity and its members. For cases of inadequate capacity or reserve margin, the Regional Entity will be requested to analyze and explain any resource capacity inadequacies and its plans to mitigate the reliability impact of the potential inadequacies. The analysis may be expanded to include surrounding areas. If the expanded analysis indicates further inadequacies, then an interregional problem may exist and will be explored with the applicable Regions. The results of these analyses shall be described in the assessment report.

2. **Transmission Adequacy and Operating Reliability Assessment** — The teams shall evaluate transmission system information that relates to the adequacy and operating reliability of the regional transmission system. That information shall include: regional planning study reports, interregional planning study reports, and/or regional operational study reports. If additional information is required, another data request shall be sent to the Regional Entity. The assessment shall provide a judgment on the ability of the regional transmission system to operate reliably under the expected range of operating conditions over the assessment period as required by NERC Reliability Standards. If sub-areas of the regional system are especially critical to the Reliable Operation of the regional bulk transmission system, these Facilities or sub-areas shall be reviewed and addressed in the assessment. Any areas of concern related to the adequacy or operating reliability of the system shall be identified and reported in the assessment.

3. **Seasonal Operating Reliability Assessment** — The team(s) shall evaluate the overall operating reliability of the regional bulk transmission systems. In areas with potential resource adequacy or system operating reliability problems,

operational readiness of the affected Regional Entities for the upcoming season shall be reviewed and analyzed. The assessment may consider unusual but possible operating scenarios and how the system is expected to perform. Operating reliability shall take into account a wide range of activities, all of which should reinforce the Regional Entity's ability to deal with the situations that might occur during the upcoming season. Typical activities in the assessment may include: facility modifications and additions, new or modified operating procedures, emergency procedures enhancement, and planning and operating studies. The teams shall report the overall seasonal operating reliability of the regional transmission systems in the annual summer and winter assessment reports.

4. **Reporting of Reliability Assessment Results** — The teams of reliability and technical experts shall provide an independent assessment of the reliability of the Regional Entities and the North American interconnected Bulk Power System for the period of the assessment. While the Regional Entities are relied upon to provide the information to perform such assessments, the review team is not required to accept the conclusions provided by the Regional Entities. Instead, the review team is expected, based on their expertise, to reach their own independent conclusions about the status of the adequacy of the generation and bulk power transmission systems of North America.

The review team also shall strive to achieve consensus in their assessments. The assessments that are made are based on the best information available at the time. However, since judgment is applied to this information, legitimate differences of opinion can develop. Despite these differences, the review team shall work to achieve consensus on their findings.

In addition to providing long-term and seasonal assessments in connection with the Reliability Assessment Program, the review team of experts shall also be responsible for recommending new and revised Reliability Standards related to the reliability assessments and the reliability of the Bulk Power Systems. These proposals for new or revised Reliability Standards shall be entered into NERC's Reliability Standards development process.

Upon completion of the assessment, the team shall share the results with the Regional Entities. The Regional Entities shall be given the opportunity to review and comment on the conclusions in the assessment and to provide additional information as appropriate. The reliability assessments and their conclusions are the responsibility of NERC's technical review team and NERC.

The preparation and approval of NERC's reliability assessment reports shall follow a prescribed schedule including review, comment, and possible approval by appropriate NERC committees. The long-term and seasonal (summer and winter) reliability assessment reports shall be further reviewed for approval by the Board for publication to the electric industry.

806. Scope of the Reliability Performance and Analysis Program

The components of the program will include analysis of large-scale outages, disturbances, and near misses to determine root causes and lessons learned; identification and continuous monitoring of performance indices to detect emerging trends and signs of a decline in reliability performance; and communications of performance results, trends, recommendations, and initiatives to those responsible to take actions; followed with confirmation of actions to correct any deficiencies identified. Within NERC, the reliability performance program will provide performance results to the Reliability Standards Development and Compliance Monitoring and Enforcement Programs to make the necessary adjustments to preserve reliability based on a risk-based approach.

807. Analysis of Major Events

Responding to major events affecting the Bulk Power System such as significant losses of Load or generation, significant Bulk Power System disturbances, or other emergencies on the Bulk Power System, can be divided into four phases: situational assessment and communications; situation tracking and communications; data collection, investigation, analysis, and reporting; and follow-up on recommendations.

1. NERC's role following a major event is to provide leadership, coordination, technical expertise, and assistance to the industry in responding to the major event. Working closely with the Regional Entities and Reliability Coordinators, and other appropriate Registered Entities, NERC will coordinate and facilitate efforts among industry participants, and with state, federal, and provincial governments in the United States and Canada to support the industry's response.

2. When responding to any major event where physical or cyber security is suspected as a cause or contributing factor to the major event, NERC will immediately notify appropriate government agencies and coordinate its activities with them.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator of the Bulk Power System shall also provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entity as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

4. During the conduct of NERC analyses, assistance may be needed from government agencies. This assistance could include: authority to require data reporting from affected or involved parties; communications with other agencies of government; investigations related to possible criminal or terrorist involvement in the major event; resources for initial data gathering immediately after the major

event; authority to call meetings of affected or involved parties; and technical and analytical resources for studies.

5. NERC shall work with all other participants to establish a clear delineation of roles, responsibilities, and coordination requirements among industry and government for the investigation and reporting of findings, conclusions, and recommendations related to major events with the objective of avoiding, to the extent possible, multiple investigations of the same major event. If the major event is confined to a single Regional Entity, NERC representatives will participate as members of the Regional Entity analysis team. NERC will establish, maintain, and revise from time to time as appropriate based on experience, a manual setting forth procedures and protocols for communications and sharing and exchange of information between and among NERC, the affected Regional Entity or Entities, and relevant governmental authorities, industry organizations and Bulk Power System user, owners, and operators concerning the investigation and analysis of major events.

6. NERC and applicable entity(s) will apply, as appropriate to the circumstances of the major event, the NERC *Blackout and Disturbance Response Procedures*, which are incorporated into these Rules of Procedure as **Appendix 8**. These procedures provide a framework to guide NERC's response to major events that may have multiregional, national, or international implications. Experienced industry leadership shall be applied to tailor the response to the specific circumstances of the major event. In accordance with those procedures, the NERC president will determine whether the major event warrants analysis at the NERC level. A Regional Entity may request that NERC elevate any analysis of a major event to the NERC level.

7. NERC will screen and analyze the findings and recommendations from the analysis, and those with generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

808. Analysis of Off-Normal Occurrences, Bulk Power System Performance, and Bulk Power System Vulnerabilities

1. NERC and Regional Entities will analyze Bulk Power System and equipment performance occurrences that do not rise to the level of a major event, as described in Section 807. NERC and Regional Entities will also analyze potential vulnerabilities in the Bulk Power System that they discover or that are brought to their attention by other sources including government agencies. The purpose of these analyses is to identify the root causes of occurrences or conditions that may be precursors of major events or other potentially more serious occurrences, or that have the potential to cause major events or other more serious occurrences, to assess past reliability performance for lessons learned, and to develop reliability performance benchmarks and trends.

2. NERC and Regional Entities will screen and analyze off-normal occurrences, Bulk Power System performance, and potential Bulk Power System vulnerabilities for significance, and information from those indicated as having generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator, of the Bulk Power System shall provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entities as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

809. Reliability Benchmarking

NERC shall identify and track key reliability indicators as a means of benchmarking reliability performance and measuring reliability improvements. This program will include assessing available metrics, developing guidelines for acceptable metrics, maintaining a performance metrics "dashboard" on the NERC website, and developing appropriate reliability performance benchmarks.

810. Information Exchange and Issuance of NERC Advisories, Recommendations and Essential Actions

1. Members of NERC and Bulk Power System owners, operators, and users shall provide NERC with detailed and timely operating experience information and data.

2. In the normal course of operations, NERC disseminates the results of its events analysis findings, lessons learned and other analysis and information gathering to the industry. These findings, lessons learned and other information will be used to guide the Reliability Assessment Program.

3. When NERC determines it is necessary to place the industry or segments of the industry on formal notice of its findings, analyses, and recommendations, NERC will provide such notification in the form of specific operations or equipment Advisories, Recommendations or Essential Actions:

    3.1 Level 1 (Advisories) – purely informational, intended to advise certain segments of the owners, operators and users of the Bulk Power System of findings and lessons learned;

    3.2 Level 2 (Recommendations) – specific actions that NERC is recommending be considered on a particular topic by certain segments of owners, operators, and users of the Bulk Power System according to each entity's facts and circumstances;

3.3 Level 3 (Essential Actions) – specific actions that NERC has determined are essential for certain segments of owners, operators, or users of the Bulk Power System to take to ensure the reliability of the Bulk Power System. Such Essential Actions require NERC Board approval before issuance.

4. The Bulk Power System owners, operators, and users to which Level 2 (Recommendations) and Level 3 (Essential Actions) notifications apply are to evaluate and take appropriate action on such issuances by NERC. Such Bulk Power System owners, operators, and users shall also provide reports of actions taken and timely updates on progress towards resolving the issues raised in the Recommendations and Essential Actions in accordance with the reporting date(s) specified by NERC.

5. NERC will advise the Commission and other Applicable Governmental Authorities of its intent to issue all Level 1 (Advisories), Level 2 (Recommendations), and Level 3 (Essential Actions) at least five (5) business days prior to issuance, unless extraordinary circumstances exist that warrant issuance less than five (5) business days after such advice. NERC will file a report with the Commission and other Applicable Governmental Authorities no later than thirty (30) days following the date by which NERC has requested the Bulk Power System owners, operators, and users to which a Level 2 (Recommendation) or Level 3 (Essential Action) issuance applies to provide reports of actions taken in response to the notification. NERC's report to the Commission and other Applicable Governmental Authorities will describe the actions taken by the relevant owners, operators, and users of the Bulk Power System and the success of such actions taken in correcting any vulnerability or deficiency that was the subject of the notification, with appropriate protection for Confidential Information or Critical Energy Infrastructure Information.

811. Equipment Performance Data

Through its Generating Availability Data System (GADS), NERC shall collect operating information about the performance of electric generating equipment; provide assistance to those researching information on power plant outages stored in its database; and support equipment reliability as well as availability analyses and other decision-making processes developed by GADS subscribers. GADS data is also used in conducting assessments of generation resource adequacy.

SECTION 900 — TRAINING AND EDUCATION

901. Scope of the Training and Education Program

Assuring the Reliable Operation of the North American Bulk Power System requires informed knowledgeable and skilled personnel. NERC shall oversee the coordination and delivery of learning materials, resources, and activities to allow for training and education of:

1. ERO Enterprise staff supporting statutory and delegation-related activities; and

2. Bulk Power System industry participants consistent with ERO functional program requirements.

902. [PLACEHOLDER]

SECTION 1000 — SITUATION AWARENESS AND INFRASTRUCTURE SECURITY

1001. Situation Awareness

NERC shall through the use of Reliability Coordinators and available tools, monitor present conditions on the Bulk Power System and provide leadership coordination, technical expertise, and assistance to the industry in responding to events as necessary. To accomplish these goals, NERC will:

1. Maintain real-time situation awareness of conditions on the Bulk Power System;

2. Notify the industry of significant Bulk Power System events that have occurred in one area, and which have the potential to impact reliability in other areas;

3. Maintain and strengthen high-level communication, coordination, and cooperation with governments and government agencies regarding real-time conditions; and

4. Enable the Reliable Operation of interconnected Bulk Power Systems by facilitating information exchange and coordination among reliability service organizations.

1002. Reliability Support Services

NERC may assist in the development of tools and other support services for the benefit of Reliability Coordinators and other system operators to enhance reliability, operations and planning. NERC will work with the industry to identify new tools, collaboratively develop requirements, support development, provide an incubation period, and at the end of that period, transition the tool or service to another group or owner for long term operation of the tool or provision of the service. To accomplish this goal, NERC will:

1. Collaborate with industry to determine the necessity of new tools or services to enhance reliability;

2. For those tools that the collaborative process determines should proceed to a development phase, provide a start-up mechanism and development system;

3. Implement the tool either on its own or through an appropriate group or organization; and

4. Where NERC conducts the implementation phase of a new tool or service, develop a transition plan to turn maintenance and provision of the tool or service over to an organization identified in the development stage.

In addition to tools developed as a result of a collaborative process with industry, NERC may develop reliability tools on its own, but will consult with industry concerning the need for the tool prior to proceeding to development.

Tools and services being maintained by NERC as of January 1, 2012, will be reviewed and, as warranted, transitioned to an appropriate industry group or organization. NERC will develop and maintain a strategic reliability tools plan that will list the tools and services being maintained by NERC, and, where applicable, the plans for transition to an appropriate industry group or organization.

1003. Infrastructure Security Program

NERC shall participate in and, where appropriate, coordinate electric industry activities to promote Critical Infrastructure protection of the Bulk Power System in North America. NERC shall, where appropriate, take a leadership role in Critical Infrastructure protection of the electricity sector to help reduce vulnerability and improve mitigation and protection of the electricity sector's Critical Infrastructure. To accomplish these goals, NERC shall perform the following functions.

1. Electricity Information Sharing and Analysis Center (E-ISAC)

    1.1 NERC shall operate the E-ISAC on behalf of the electricity sector. In 1998, the U.S. Secretary of Energy asked NERC to serve as the information sharing and analysis center for the electricity sector, in implementation of Presidential Decision Directive 63, as part of a public/private partnership to deal with matters related to infrastructure security.

    1.2 The E-ISAC gathers and analyzes security information, coordinates incident management, and communicates mitigation strategies with stakeholders within the electricity sector, across interdependent sectors, and with government partners. The E-ISAC, in collaboration with the United States Department of Energy (DOE) and the Electricity Subsector Coordinating Council (ESCC), serves as the primary security communications channel for the electricity sector and enhances the sector's ability to prepare for and respond to cyber and physical threats, vulnerabilities, and incidents.

    1.3 NERC shall improve the capability of the E-ISAC to fulfill its mission.

    1.4 NERC shall work closely with governmental agencies, including, among others, DOE, the United States Department of Homeland Security, Natural Resources Canada, and Public Safety Canada.

    1.5 NERC shall strengthen and expand these functions and working relationships with the electricity sector, other Critical Infrastructure industries, governments, and government agencies throughout North America to ensure the protection of the infrastructure of the Bulk Power System.

    1.6 NERC shall coordinate with the ESCC and the Government Coordinating Council.

1.7 NERC shall coordinate with other Critical Infrastructure sectors through active participation with the other Sector Coordinating Councils, other ISACs, and the National Infrastructure Advisory Council.

1.8 NERC shall encourage and participate in coordinated Critical Infrastructure protection exercises, including interdependencies with other Critical Infrastructure sectors.

1.9 As part of the E-ISAC's efforts to fulfill its mission, it may issue, as circumstances warrant, written communications, referred to as All Points Bulletins (APBs), to disseminate critical security information rapidly to electricity sector asset owners and operators as security threats and attacks develop, and critical, time-sensitive security information becomes available. The E-ISAC shall share all APBs with Federal Energy Regulatory Commission staff no later than at the time of issuance.

2. Security Planning

2.1 NERC shall take a risk management approach to Critical Infrastructure protection, considering probability and severity, through identification, protection, detection, response, and recovery functions.

2.2 NERC shall consider security along-side considerations of reliability and resiliency of the Bulk Power System.

2.3 NERC shall keep abreast of the changing threat environment through collaboration with appropriate government agencies.

2.4 NERC shall develop criteria to identify critical physical and cyber assets, assess security threats, identify risk assessment methods, and assess effectiveness of physical and cyber protection measures.

2.5 NERC shall support implementation of the Critical Infrastructure Protection Standards through education and outreach.

2.6 NERC shall review and improve existing security guidelines, develop new security guidelines to meet the needs of the electricity sector, and consider whether any guidelines should be developed into Reliability Standards.

2.7 NERC shall conduct education and outreach initiatives to increase awareness of security matters and respond to the security needs of the electricity sector.

2.8 NERC shall strengthen relationships with federal, state, and provincial government agencies on Critical Infrastructure protection matters.

2.9 NERC shall maintain and endeavor to improve mechanisms for the sharing of sensitive or classified information with federal, state, and provincial government agencies on Critical Infrastructure protection matters.

2.10 NERC shall improve methods to assess the impact of a possible physical attack on the Bulk Power System and means to deter, mitigate, and respond following an attack.

SECTION 1100 — ANNUAL NERC BUSINESS PLANS AND BUDGETS

1101. Scope of Business Plans and Budgets

The Board shall determine the content of the budgets to be submitted to the Applicable Governmental Authorities with consultation from the members of the Member Representatives Committee, Regional Entities, and others in accordance with the Bylaws. The Board shall identify any activities outside the scope of NERC's statutory reliability functions, if any, and the appropriate funding mechanisms for those activities.

1102. NERC Funding and Cost Allocation

1. In order that NERC's costs shall be fairly allocated among Interconnections and among Regional Entities, the NERC funding mechanism for all statutory functions shall be based on Net Energy for Load (NEL).

2. NERC's costs shall be allocated so that all Load (or, in the case of costs for an Interconnection or Regional Entity, all Load within that Interconnection or Regional Entity) bears an equitable share of such costs based on NEL.

3. Costs shall be equitably allocated between countries or Regional Entities thereof for which NERC has been designated or recognized as the Electric Reliability Organization.

4. Costs incurred to accomplish the statutory functions for one Interconnection, Regional Entity, or group of entities will be directly assigned to that Interconnection, Regional Entity, or group of entities provided that such costs are allocated equitably to end-users based on Net Energy for Load.

1103. NERC Budget Development

1. The NERC annual budget process shall be scheduled and conducted for each calendar year so as to allow a sufficient amount of time for NERC to receive Member inputs, develop the budget, and receive Board and, where authorized by applicable legislation or agreement, Applicable Governmental Authority approval of the NERC budget for the following fiscal year, including timely submission of the proposed budget to FERC for approval in accordance with FERC regulations.

2. The NERC budget submittal to Applicable Governmental Authorities shall include provisions for all ERO functions, all Regional Entity delegated functions as specified in delegation agreements and reasonable reserves and contingencies.

3. The NERC annual budget submittal to Applicable Governmental Authorities shall include description and explanation of NERC's proposed ERO program activities for the year; budget component justification based on statutory or other authorities; explanation of how each budgeted activity lends itself to the accomplishment of the statutory or other authorities; sufficiency of resources provided for in the budget to carry out the ERO program responsibilities;

explanation of the calculations and budget estimates; identification and explanation of changes in budget components from the previous year's budget; information on staffing and organization charts; and such other information as is required by FERC and other Applicable Governmental Authorities having authority to approve the proposed budget.

4. NERC shall develop, in consultation with the Regional Entities, a reasonable and consistent system of accounts, to allow a meaningful comparison of actual results at the NERC and Regional Entity level by the Applicable Governmental Authorities.

1104. Submittal of Regional Entity Budgets to NERC

1. Each Regional Entity shall submit its proposed annual budget for carrying out its delegated authority functions as well as all other activities and funding to NERC in accordance with a schedule developed by NERC and the Regional Entities, which shall provide for the Regional Entity to submit its final budget that has been approved by its board of directors or other governing body no later than July 1 of the prior year, in order to provide sufficient time for NERC's review and comment on the proposed budget and approval of the Regional Entity budget by the NERC Board of Trustees in time for the NERC and Regional Entity budgets to be submitted to FERC and other Applicable Governmental Authorities for approval in accordance with their regulations. The Regional Entity's budget shall include supporting materials in accordance with the budget and reporting format developed by NERC and the Regional Entities, including the Regional Entity's complete business plan and organization chart, explaining the proposed collection of all dues, fees, and charges and the proposed expenditure of funds collected in sufficient detail to justify the requested funding collection and budget expenditures.

2. NERC shall review and approve each Regional Entity's budget for meeting the requirements of its delegated authority. Concurrent with approving the NERC budget, NERC shall review and approve, or reject, each Regional Entity budget for filing.

3. NERC shall also have the right to review from time to time, in reasonable intervals but no less frequently than every three years, the financial books and records of each Regional Entity having delegated authority in order to ensure that the documentation fairly represents in all material aspects appropriate funding of delegated functions.

1105. Submittal of NERC and Regional Entity Budgets to Governmental Authorities for Approval

1. NERC shall file for approval by the Applicable Governmental Authorities at least 130 days in advance of the start of each fiscal year. The filing shall include: (1) the complete NERC and Regional Entity budgets including the business plans and organizational charts approved by the Board, (2) NERC's annual funding

requirement (including Regional Entity costs for delegated functions), and (3) the mechanism for assessing charges to recover that annual funding requirement, together with supporting materials in sufficient detail to support the requested funding requirement.

2. NERC shall seek approval from each Applicable Governmental Authority requiring such approval for the funding requirements necessary to perform ERO activities within their jurisdictions.

1106. NERC and Regional Entity Billing and Collections

1. NERC shall request the Regional Entities to identify all Load-Serving Entities[5] within each Regional Entity and the NEL assigned to each Load-Serving Entity, and the Regional Entities shall supply the requested information. The assignment of a funding requirement to an entity shall not be the basis for determining that the entity must be registered in the Compliance Registry.

2. NERC shall accumulate the NEL by Load-Serving Entities for each Applicable Governmental Authority and submit the proportional share of NERC funding requirements to each Applicable Governmental Authority for approval together with supporting materials in sufficient detail to support the requested funding requirement.

3. NEL reported by Balancing Authorities within a Region shall be used to rationalize and validate amounts allocated for collection through Regional Entity processes.

4. The billing and collection processes shall provide:

   4.1 A clear validation of billing and application of payments.

   4.2 A minimum of data requests to those being billed.

   4.3 Adequate controls to ensure integrity in the billing determinants including identification of entities responsible for funding NERC's activities.

   4.4 Consistent billing and collection terms.

5. NERC will bill and collect all budget requirements approved by Applicable Governmental Authorities (including the funds required to support those functions assigned to the Regional Entities through the delegation agreements) directly from the Load-Serving Entities or their designees or as directed by particular Applicable Governmental Authorities, except where the Regional Entity is required to collect the budget requirements for NERC, in which case the Regional

[5] A Regional Entity may allocate funding obligations using an alternative method approved by NERC and by FERC and other Applicable Governmental Authorities, as provided for in the regional delegation agreement.

Entity will collect directly from the Load-Serving Entities or as otherwise provided by agreement and submit funds to NERC. Alternatively, a load-serving entity may pay its allocated ERO costs through a Regional Entity managed collection mechanism.

6. NERC shall set a minimum threshold limit on the billing of small LSEs to minimize the administrative burden of collection.

7. NERC shall pursue any non-payments and shall request assistance from Applicable Governmental Authorities as necessary to secure collection.

8. In the case where a Regional Entity performs the collection for ERO, the Regional Entity will not be responsible for non-payment in the event that a user, owner or operator of the Bulk Power System does not pay its share of dues, fees and charges in a timely manner, provided that such a Regional Entity shall use reasonably diligent efforts to collect dues, fees, and other charges from all entities obligated to pay them. However, any revenues not paid shall be recovered from others within the same Region to avoid cross-subsidization between Regions.

9. Both NERC and the Regional Entities also may bill members or others for functions and services not within statutory requirements or otherwise authorized by the Applicable Governmental Authorities. Costs and revenues associated with these functions and services shall be separately identified and not commingled with billings associated with the funding of NERC or of the Regional Entities for delegated activities.

1107. Penalty Applications

1. Where NERC or a Regional Entity initiates a compliance monitoring and enforcement process that leads to imposition of a Penalty, the entity that initiated the process shall receive any Penalty monies imposed and collected as a result of that process, unless a different disposition of the Penalty monies is provided for in the delegation agreement, or in a contract or a disposition of the violation that is approved by NERC and FERC.

2. All funds from financial Penalties assessed in the United States received by the entity initiating the compliance monitoring and enforcement process shall be applied as a general offset to the entity's budget requirements for the subsequent fiscal year, if received by July 1, or for the second subsequent fiscal year, if received on or after July 1. Funds from financial Penalties shall not be directly applied to any program maintained by the entity conducting the compliance monitoring and enforcement process. Funds from financial Penalties assessed against a Canadian entity shall be applied as specified by legislation or agreement.

3. In the event that a compliance monitoring and enforcement process is conducted jointly by NERC and a Regional Entity, the Regional Entity shall receive the Penalty monies and offset the Regional Entity's budget requirements for the subsequent fiscal year.

4. Exceptions or alternatives to the foregoing provisions will be allowed if approved by NERC and by FERC or any other Applicable Governmental Authority.

1108. Special Assessments

On a demonstration of unforeseen and extraordinary circumstances requiring additional funds prior to the next funding cycle, NERC shall file with the Applicable Governmental Authorities, where authorized by applicable legislation or agreement, for authorization for an amended or supplemental budget for NERC or a Regional Entity and, if necessary under the amended or supplemental budget, to collect a special or additional assessment for statutory functions of NERC or the Regional Entity. Such filing shall include supporting materials to justify the requested funding, including any departure from the approved funding formula or method.

SECTION 1200 — REGIONAL DELEGATION AGREEMENTS

1201. Pro Forma Regional Delegation Agreement

NERC shall develop and maintain a pro forma Regional Entity delegation agreement, which shall serve as the basis for negotiation of consistent agreements for the delegation of ERO functions to Regional Entities.

1202. Regional Entity Essential Requirements

NERC shall establish the essential requirements for an entity to become qualified and maintain good standing as a Regional Entity.

1203. Negotiation of Regional Delegation Agreements

NERC shall, for all areas of North America that have provided NERC with the appropriate authority, negotiate regional delegation agreements for the purpose of ensuring all areas of the North American Bulk Power Systems are within a Regional Entity Region. In the event NERC is unable to reach agreement with Regional Entities for all areas, NERC shall provide alternative means and resources for implementing NERC functions within those areas. No delegation agreement shall take effect until it has been approved by the Applicable Governmental Authority.

1204. Conformance to Rules and Terms of Regional Delegation Agreements

NERC and each Regional Entity shall comply with all applicable ERO Rules of Procedure and the obligations stated in the regional delegation agreement.

1205. Sub-delegation

The Regional Entity shall not sub-delegate any responsibilities and authorities delegated to it by its regional delegation agreement with NERC except with the approval of NERC and FERC and other Applicable Governmental Authorities. Responsibilities and authorities may only be sub-delegated to another Regional Entity. Regional Entities may share resources with one another so long as such arrangements do not result in cross-subsidization or in any sub-delegation of authorities.

1206. Nonconformance to Rules or Terms of Regional Delegation Agreement

If a Regional Entity is unable to comply or is not in compliance with an ERO Rule of Procedure or the terms of the regional delegation agreement, the Regional Entity shall immediately notify NERC in writing, describing the area of nonconformance and the reason for not being able to conform to the Rule of Procedure. NERC shall evaluate each case and inform the affected Regional Entity of the results of the evaluation. If NERC determines that a Rule of Procedure or term of the regional delegation agreement has been violated by a Regional Entity or cannot practically be implemented by a Regional Entity, NERC shall notify the Applicable Governmental Authorities and take any actions necessary to address the situation.

1207. Regional Entity Audits

Approximately every five years and more frequently if necessary for cause, NERC shall audit each Regional Entity to verify that the Regional Entity continues to comply with NERC Rules of Procedure and the obligations of NERC delegation agreement. Audits of Regional Entities shall be conducted, to the extent practical, based on professional auditing standards recognized in the U.S., including Generally Accepted Auditing Standards, Generally Accepted Government Auditing Standards, and standards sanctioned by the Institute of Internal Auditors, and if applicable to the coverage of the audit, may be based on Canadian or other international standards. The audits required by this Section 1207 shall not duplicate the audits of Regional Entity Compliance Monitoring and Enforcement Programs provided for in **Appendix 4A**, Audit of Regional Compliance Programs, to these Rules of Procedure.

1208. Process for Considering Registered Entity Requests to Transfer to Another Regional Entity

1. A Registered Entity that is registered in the Region of one Regional Entity and believes its registration should be transferred to a different Regional Entity may submit a written request to both Regional Entities requesting that they process the proposed transfer in accordance with this section. The Registered Entity's written request shall set forth the reasons the Registered Entity believes justify the proposed transfer and shall describe any impacts of the proposed transfer on other Bulk Power System owners, operators, and users.

2. After receiving the Registered Entity's written request, the two Regional Entities shall consult with each other as to whether they agree or disagree that the requested transfer is appropriate. The Regional Entities may also consult with affected Reliability Coordinators, Balancing Authorities and Transmission Operators as appropriate. Each Regional Entity shall post the request on its website for public comment period of 21 days. In evaluating the proposed transfer, the Regional Entities shall consider the location of the Registered Entity's Bulk Power System facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators; and users, the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments to other Load-Serving Entities of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity would be transitioned from the current Regional Entity to the transferee Regional Entity; along with any other reasons for the proposed transfer stated by the Registered Entity and any other reasons either Regional Entity considers relevant. The Regional Entities may request that the Registered Entity provide additional data and information concerning the proposed transfer for the Regional Entities' use in their evaluation. The Registered Entity's current Regional Entity shall notify the Registered Entity

in writing as to whether (i) the two Regional Entities agree that the requested transfer is appropriate, (ii) the two Regional Entities agree that the requested transfer is not appropriate and should not be processed further, or (iii) the two Regional Entities disagree as to whether the proposed transfer is appropriate.

3. If the two Regional Entities agree that the requested transfer is appropriate, they shall submit a joint written request to NERC requesting that the proposed transfer be approved and that the delegation agreement between NERC and each of the Regional Entities be amended accordingly. The Regional Entities' joint written submission to NERC shall describe the reasons for the proposed transfer; the location of the Registered Entity's Bulk Power System Facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators, and users; the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity will be transitioned from the current Regional Entity to the transferee Regional Entity. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

4. If the two Regional Entities do not agree with each other that the proposed transfer is appropriate, the Regional Entity supporting the proposed transfer shall, if requested by the Registered Entity, submit a written request to NERC to approve the transfer and the related delegation agreement amendments. The Regional Entity's written request shall include the information specified in Section 1208.3. The Regional Entity that does not believe the proposed transfer is appropriate will be allowed to submit a written statement to NERC explaining why the Regional Entity believes the transfer is not appropriate and should not be approved. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

5. Prior to action by the NERC Board of Trustees on a proposed transfer of registration under Section 1208.3 or 1208.4, NERC shall post information concerning the proposed transfer, including the submissions from the Regional Entities, on its website for at least twenty-one (21) days for the purpose of receiving public comment.

6. If the NERC Board of Trustees disapproves a proposed transfer presented to it pursuant to either Section 1208.3 or 1208.4, the Regional Entity or Regional Entities that believe the transfer is appropriate may, if requested to do so by the Registered Entity, file a petition with FERC pursuant to 18 C.F.R. section 39.8(f) and (g) requesting that FERC order amendments to the delegation agreements of the two Regional Entities to effectuate the proposed transfer.

7. No transfer of a Registered Entity from one Regional Entity to another Regional Entity shall be effective (i) unless approved by FERC, and (ii) any earlier than the first day of January of the second calendar year following approval by FERC, unless an earlier effective date is agreed to by both Regional Entities and NERC and approved by FERC.

SECTION 1300 — COMMITTEES

1301. Establishing Standing Committees

The Board may from time to time create standing committees. In doing so, the Board shall approve the charter of each committee and assign specific authority to each committee necessary to conduct business within that charter. Each standing committee shall work within its Board-approved charter and shall be accountable to the Board for performance of its Board-assigned responsibilities. A NERC standing committee may not delegate its assigned work to a member forum, but, in its deliberations, may request the opinions of and consider the recommendations of a member forum.

1302. Committee Membership

Each committee shall have a defined membership composition that is explained in its charter. Committee membership may be unique to each committee, and can provide for balanced decision-making by providing for representatives from each Sector or, where Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area, by bringing together a wide diversity of opinions from industry experts with outstanding technical knowledge and experience in a particular subject area. Committee membership shall also provide the opportunity for an equitable number of members from the United States and Canada, based approximately on proportionate Net Energy for Load. All committees and other subgroups (except for those organized on other than a Sector basis because Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area) must ensure that no two stakeholder Sectors are able to control the vote on any matter, and no single Sector is able to defeat a matter. With regard to committees and subgroups pertaining to development of, interpretation of, or compliance with Reliability Standards, NERC shall provide a reasonable opportunity for membership from Sectors desiring to participate. Committees and subgroups organized on other than a Sector basis shall be reported to the NERC Board and the Member Representatives Committee, along with the reasons for constituting the committee or subgroup in the manner chosen. In such cases and subject to reasonable restrictions necessary to accomplish the mission of such committee or subgroup, NERC shall provide a reasonable opportunity for additional participation, as members or official observers, for Sectors not represented on the committee or subgroup.

1303. Procedures for Appointing Committee Members

Committee members shall be nominated and selected in a manner that is open, inclusive, and fair. Unless otherwise stated in these Rules of Procedure or approved by the Board, all committee member appointments shall be approved by the board, and committee officers shall be appointed by the Chairman of the Board.

1304. Procedures for Conduct of Committee Business

1. Notice to the public of the dates, places, and times of meetings of all committees, and all nonconfidential material provided to committee members, shall be posted on NERC's website at approximately the same time that notice is given to

committee members. Meetings of all standing committees shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided that the meeting may be held in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance enforcement matters, litigation, or commercially sensitive or Critical Energy Infrastructure Information of any entity.

2. NERC shall maintain a set of procedures, approved by the Board, to guide the conduct of business by standing committees.

1305. Committee Subgroups

Standing committees may appoint subgroups using the same principles as in Section 1302.

SECTION 1400 — AMENDMENTS TO THE NERC RULES OF PROCEDURE

1401. Proposals for Amendment or Repeal of Rules of Procedure

In accordance with the Bylaws of NERC, requests to amend or repeal the Rules of Procedure may be submitted by (1) any fifty Members of NERC, which number shall include Members from at least three membership Sectors, (2) the Member Representatives Committee, (3) a committee of NERC to whose function and purpose the Rule of Procedure pertains, or (4) an officer of NERC.

1402. Approval of Amendment or Repeal of Rules of Procedure

Amendment to or repeal of Rules of Procedure shall be approved by the Board after public notice and opportunity for comment in accordance with the Bylaws of NERC. In approving changes to the Rules of Procedure, the Board shall consider the inputs of the Member Representatives Committee, other ERO committees affected by the particular changes to the Rules of Procedure, and other stakeholders as appropriate. After Board approval, the amendment or repeal shall be submitted to the Applicable Governmental Authorities for approval, where authorized by legislation or agreement. No amendment to or repeal of the Rules of Procedure shall be effective until it has been approved by the Applicable Governmental Authorities.

SECTION 1500 — CONFIDENTIAL INFORMATION

1501. Definitions

1. **Confidential Information** means (i) Confidential Business and Market Information; (ii) Critical Electric Infrastructure Information; (iii) Critical Energy Infrastructure Information; (iv) personnel information that identifies or could be used to identify a specific individual, or reveals personnel, financial, medical, or other personal information; (v) work papers, including any records produced for or created in the course of an evaluation or audit; (vi) investigative files, including any records produced for or created in the course of an investigation; or (vii) Cyber Security Incident Information; provided, that public information developed or acquired by an entity shall be excluded from this definition.

2. **Confidential Business and Market Information** means any information that pertains to the interests of any entity, that was developed or acquired by that entity, and that is proprietary or competitively sensitive.

3. **Critical Electric Infrastructure** means a system or asset of the bulk power system, whether physical or virtual, the incapacity or destruction of which would negatively affect national security, economic security, public health or safety, or any combination of such matters.

4. **Critical Electric Infrastructure Information** means information related to proposed or existing Critical Electric Infrastructure. Such term includes information that qualifies as Critical Energy Infrastructure Information as defined herein.

5. **Critical Energy Infrastructure Information** means specific engineering, vulnerability, or detailed design information about proposed or existing Critical Infrastructure that (i) relates details about the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on Critical Infrastructure; and (iii) does not simply give the location of the Critical Infrastructure.

6. **Critical Infrastructure** means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.

7. **Cyber Security Incident Information** means any information related to, describing, or which could be used to plan or cause a Cyber Security Incident.

1502. Protection of Confidential Information

1. **Identification of Confidential Information** — An owner, operator, or user of the Bulk Power System and any other party (the "Submitting Entity") shall mark as confidential any information that it submits to NERC or a Regional Entity (the

"Receiving Entity") that it reasonably believes contains Confidential Information as defined by these Rules of Procedure, indicating the category or categories defined in Section 1501 in which the information falls, and by adding any labels required by rules or regulations of an Applicable Governmental Authority. If the information is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the Submitting Entity shall so indicate and provide supporting references and details.

2. **Confidentiality** — Except as provided herein, a Receiving Entity shall keep in confidence and not copy, disclose, or distribute any Confidential Information or any part thereof without the permission of the Submitting Entity, except as otherwise legally required.

3. **Information no longer Confidential –** If a Submitting Entity concludes that information for which it had sought confidential treatment no longer qualifies for that treatment, the Submitting Entity shall promptly so notify NERC or the relevant Regional Entity.

1503. Requests for Information

1. **Limitation** — A Receiving Entity shall make information available only to one with a demonstrated need for access to the information from the Receiving Entity. Commission regulations regarding access to Critical Electric Infrastructure Information or Critical Energy Infrastructure Information will also apply as appropriate when the Commission is the Submitting Entity.

2. **Form of Request** — A person with such a need may request access to information by using the following procedure:

   2.1 The request must be in writing and clearly marked "Request for Information."

   2.2 The request must identify the individual or entity that will use the information, explain the requester's need for access to the information, explain how the requester will use the information in furtherance of that need, and state whether the information is publicly available or available from another source or through another means. If the requester seeks access to information that is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the requester shall describe how it qualifies to receive such information.

   2.3 The request must stipulate that, if the requester does not seek public disclosure, the requester will maintain as confidential any information received for which a Submitting Party has made a claim of confidentiality in accordance with NERC's rules. As a condition to gaining access to such information, a requester shall execute a non-disclosure agreement provided by NERC.

3. **Notice and Opportunity for Comment** — Prior to any decision to disclose information marked as confidential, the Receiving Entity shall provide written notice to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed. Failure to provide such comments or otherwise respond is not deemed waiver of the claim of confidentiality.

4. **Determination by ERO or Regional Entity** — Based on the information provided by the requester under Rule 1503.2, any comments provided by the Submitting Entity, and any other relevant available information, the chief executive officer or his or her designee of the Receiving Entity shall determine whether to disclose such information.

5. **Appeal** — A person whose request for information is denied in whole or part may appeal that determination to the President of NERC (or the President's designee) within 30 days of the determination. Appeals filed pursuant to this Section must be in writing, addressed to the President of NERC (or the President's designee), and clearly marked "Appeal of Information Request Denial."

   NERC will provide written notice of such appeal to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed; provided that any such comments must be received within 30 days of the notice and any failure to provide such comments or otherwise respond is not deemed a waiver of the claim of confidentiality.

   The President of NERC (or the President's designee) will make a determination with respect to any appeal within 30 days. In unusual circumstances, this time limit may be extended by the President of NERC (or the President's designee), who will send written notice to the requester setting forth the reasons for the extension and the date on which a determination on the appeal is expected.

6. **Disclosure of Information** — In the event the Receiving Entity, after following the procedures herein, determines to disclose information designated as Confidential Information, it shall provide the Submitting Entity no fewer than 21 days' written notice prior to releasing the Confidential Information in order to enable such Submitting Entity to (a) seek an appropriate protective order or other remedy, (b) consult with the Receiving Entity with respect to taking steps to resist or narrow the scope of such request or legal process, or (c) waive compliance, in whole or in part, with the terms of this Section. Should a Receiving Entity be required to disclose Confidential Information, or should the Submitting Entity waive objection to disclosure, the Receiving Entity shall furnish only that portion

of the Confidential Information which the Receiving Entity's counsel advises is legally required.

7. **Posting of Determinations on Requests for Disclosure of Confidential Information** — Upon making its determination on a request for disclosure of Confidential Information, NERC or the Regional Entity, as applicable, shall (i) notify the requester that the request for disclosure is granted or denied, (ii) publicly post any determination to deny the request to disclose Confidential Information, including in such posting an explanation of the reasons for the denial (but without in such explanation disclosing the Confidential Information), and (iii) publicly post any determination that information claimed by the Submitting Entity to be Confidential Information is not Confidential Information (but without in such posting disclosing any information that has been determined to be Confidential Information).

1504. Employees, Contractors and Agents

A Receiving Entity shall ensure that its officers, trustees, directors, employees, subcontractors and subcontractors' employees, and agents to whom Confidential Information is exposed are under obligations of confidentiality that are at least as restrictive as those contained herein.

1505. Provision of Information to FERC and Other Governmental Authorities

1. **Request** — A request from FERC for reliability information with respect to owners, operators, and users of the Bulk Power System within the United States is authorized by Section 215 of the Federal Power Act. Other Applicable Governmental Authorities may have similar authorizing legislation that grants a right of access to such information. Unless otherwise directed by FERC or its staff or the other Applicable Governmental Authority requesting the information, upon receiving such a request, a Receiving Entity shall provide contemporaneous notice to the applicable Submitting Entity. In its response to such a request, a Receiving Entity shall preserve any mark of confidentiality and shall notify FERC or other Applicable Governmental Authorities that the Submitting Entity has marked the information as confidential.

2. **Continued Confidentiality** — Each Receiving Entity shall continue to treat as confidential all Confidential Information that it has submitted to NERC or to FERC or another Applicable Governmental Authority, until such time as FERC or the other Applicable Governmental Authority authorizes disclosure of such information.

1506. Permitted Disclosures

1. **Resolved Noncompliance** — Nothing in this Section 1500 shall prohibit the disclosure of a noncompliance at the point when the matter is filed with an Applicable Governmental Authority, a Registered Entity admits to the violation, or the Registered Entity and the CEA resolve the noncompliance in accordance with Appendix 4C.

2. **Information Exchange** — NERC and the Regional Entities are authorized to exchange Confidential Information to perform their respective statutory and delegated functions, including, but not limited to, evaluations, Compliance Audits, and Compliance Investigations in furtherance of the Compliance Monitoring and Enforcement Program, on condition they continue to maintain the confidentiality of such information consistent with the delegation agreement.

1507. Remedies for Improper Disclosure

Any person engaged in NERC or Regional Entity activity under Section 215 of the Federal Power Act or the equivalent laws of other Applicable Governmental Authorities who improperly discloses Confidential Information may lose access to Confidential Information on a temporary or permanent basis and may be subject to adverse personnel action, including suspension or termination. Nothing in Section 1500 precludes an entity whose information was improperly disclosed from seeking a remedy in an appropriate court.

SECTION 1600 — REQUESTS FOR DATA OR INFORMATION

1601. Scope of a NERC or Regional Entity Request for Data or Information

Within the United States, NERC and Regional Entities may request data or information that is necessary to meet their obligations under Section 215 of the Federal Power Act, as authorized by Section 39.2(d) of the Commission's regulations, 18 C.F.R. § 39.2(d). In other jurisdictions NERC and Regional Entities may request comparable data or information, using such authority as may exist pursuant to these Rules of Procedure and as may be granted by Applicable Governmental Authorities in those other jurisdictions. The provisions of Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information; the Requirements in the Reliability Standards govern. The provisions of Section 1600 shall also not apply to data or information requested in connection with a compliance or enforcement action under Section 215 of the Federal Power Act, Section 400 of these Rules of Procedure, or any procedures adopted pursuant to those authorities, in which case the Rules of Procedure applicable to the production of data or information for compliance and enforcement actions shall apply.

1602. Procedure for Authorizing a NERC Request for Data or Information

1. NERC shall provide a proposed request for data or information or a proposed modification to a previously-authorized request, including the information specified in Section 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability at least twenty-one (21) days prior to initially posting the request or modification for public comment. Submission of the proposed request or modification to the Office of Electric Reliability is for the information of the Commission. NERC is not required to receive any approval from the Commission prior to posting the proposed request or modification for public comment in accordance with Section 1602.2 or issuing the request or modification to Reporting Entities following approval by the Board of Trustees.

2. NERC shall post a proposed request for data or information or a proposed modification to a previously authorized request for data or information for a forty-five (45) day public comment period.

    2.1. A proposed request for data or information shall contain, at a minimum, the following information: (i) a description of the data or information to be requested, how the data or information will be used, and how the availability of the data or information is necessary for NERC to meet its obligations under applicable laws and agreements; (ii) a description of how the data or information will be collected and validated; (iii) a description of the entities (by functional class and jurisdiction) that will be required to provide the data or information ("Reporting Entities"); (iv) the schedule or due date for the data or information; (v) a description of any restrictions on disseminating the data or information (e.g., "Confidential Information," "Critical Energy Infrastructure Information," "aggregating" or "identity masking"); and (vi) an estimate of the relative burden imposed on the Reporting Entities to accommodate the data or information request.

2.2. A proposed modification to a previously authorized request for data or information shall explain (i) the nature of the modifications; (ii) an estimate of the burden imposed on the Reporting Entities to accommodate the modified data or information request, and (iii) any other items from Section 1602.2.1 that require updating as a result of the modifications.

3. After the close of the comment period, NERC shall make such revisions to the proposed request for data or information as are appropriate in light of the comments. NERC shall submit the proposed request for data or information, as revised, along with the comments received, NERC's evaluation of the comments and recommendations, to the Board of Trustees.

4. In acting on the proposed request for data or information, the Board of Trustees may authorize NERC to issue it, modify it, or remand it for further consideration.

5. NERC may make minor changes to an authorized request for data or information without Board approval. However, if a Reporting Entity objects to NERC in writing to such changes within 21 days of issuance of the modified request, such changes shall require Board approval before they are implemented.

6. Authorization of a request for data or information shall be final unless, within thirty (30) days of the decision by the Board of Trustees, an affected party appeals the authorization under this Section 1600 to the Applicable Governmental Authority.

1603. Owners, Operators, and Users to Comply

Owners, operators, and users of the Bulk Power System registered on the NERC Compliance Registry shall comply with authorized requests for data and information. In the event a Reporting Entity within the United States fails to comply with an authorized request for data or information under Section 1600, NERC may request the Commission to exercise its enforcement authority to require the Reporting Entity to comply with the request for data or information and for other appropriate enforcement action by the Commission. NERC will make any request for the Commission to enforce a request for data or information through a non-public submission to the Commission's enforcement staff.

1604. Requests by Regional Entity for Data or Information

1. A Regional Entity may request that NERC seek authorization for a request for data or information to be applicable within the Region of the Regional Entity, either as a freestanding request or as part of a proposed NERC request for data or information. Any such request must be consistent with this Section 1600.

2. A Regional Entity may also develop its own procedures for requesting data or information, but any such procedures must include at least the same procedural

elements as are included in this Section 1600. Any such Regional Entity procedures or changes to such procedures shall be submitted to NERC for approval. Upon approving such procedures or changes thereto, NERC shall file the proposed procedures or proposed changes for approval by the Commission and any other Applicable Governmental Authorities applicable to the Regional Entity. The Regional Entity procedures or changes to such procedures shall not be effective in a jurisdiction until approved by, and in accordance with any revisions directed by, the Commission or other Applicable Governmental Authority.

1605. Confidentiality

If the approved data or information request includes a statement under Section 1602.1.1(v) that the requested data or information will be held confidential or treated as Critical Energy Infrastructure Information, then the applicable provisions of Section 1500 will apply without further action by a Submitting Entity. A Submitting Entity may designate any other data or information as Confidential Information pursuant to the provisions of Section 1500, and NERC or the Regional Entity shall treat that data or information in accordance with Section 1500. NERC or a Regional Entity may utilize additional protective procedures for handling particular requests for data or information as may be necessary under the circumstances.

1606. Expedited Procedures for Requesting Time-Sensitive Data or Information

1. In the event NERC or a Regional Entity must obtain data or information by a date or within a time period that does not permit adherence to the time periods specified in Section 1602, the procedures specified in Section 1606 may be used to obtain the data or information. Without limiting the circumstances in which the procedures in Section 1606 may be used, such circumstances include situations in which it is necessary to obtain the data or information (in order to evaluate a threat to the reliability or security of the Bulk Power System, or to comply with a directive in an order issued by the Commission or by another Applicable Governmental Authority) within a shorter time period than possible under Section 1602. The procedures specified in Section 1606 may only be used if authorized by the NERC Board of Trustees prior to activation of such procedures.

2. Prior to posting a proposed request for data or information, or a modification to a previously-authorized request, for public comment under Section 1606, NERC shall provide the proposed request or modification, including the information specified in paragraph 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability. The submission to the Commission's Office of Electric Reliability shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information. The submission shall be made to the Commission's Office of Electric Reliability as far in advance, up to twenty-one (21) days, of the posting of the proposed request or modification for public comments as is reasonably possible under the circumstances, but in no event less than two (2) days in advance of the public posting of the proposed request or modification.

3. NERC shall post the proposed request for data or information or proposed modification to a previously-authorized request for data or information for a public comment period that is reasonable in duration given the circumstances, but in no event shorter than five (5) days. The proposed request for data or information or proposed modification to a previously-authorized request for data or information shall include the information specified in Section 1602.2.1 or 1602.2.2, as applicable, and shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information.

4. The provisions of Sections 1602.3, 1602.4, 1602.5 and 1602.6 shall be applicable to a request for data or information or modification to a previously-authorized request for data or information developed and issued pursuant to Section 1606, except that (a) if NERC makes minor changes to an authorized request for data or information without Board approval, such changes shall require Board approval if a Reporting Entity objects to NERC in writing to such changes within five (5) days of issuance of the modified request; and (b) authorization of the request for data or information shall be final unless an affected party appeals the authorization of the request by the Board of Trustees to the Applicable Governmental Authority within five (5) days following the decision of the Board of Trustees authorizing the request, which decision shall be promptly posted on NERC’s website.

SECTION 1700 — CHALLENGES TO DETERMINATIONS

1701. Scope of Authority

Section 1702 sets forth the procedures to be followed for Registered Entities to challenge determinations made by Planning Coordinators under Reliability Standard PRC-023. Section 1703 sets forth the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

1702. Challenges to Determinations by Planning Coordinators Under Reliability Standard PRC-023

1. This Section 1702 establishes the procedures to be followed when a Registered Entity wishes to challenge a determination by a Planning Coordinator of the sub-200 kV circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers (defined as "Registered Entities" for purposes of this Section 1702) must comply with the requirements of Reliability Standard PRC-023.

2. Planning Coordinator Procedures

   2.1 Each Planning Coordinator shall establish a procedure for a Registered Entity to submit a written request for an explanation of a determination made by the Planning Coordinator under PRC-023.

   2.2 A Registered Entity shall follow the procedure established by the Planning Coordinator for submitting the request for explanation and must submit any such request within 60 days of receiving the determination under PRC-023 from the Planning Coordinator.

   2.3 Within 30 days of receiving a written request from a Registered Entity, the Planning Coordinator shall provide the Registered Entity with a written explanation of the basis for its determination under PRC-023, unless the Planning Coordinator provided a written explanation of the basis for its determination when it initially informed the Registered Entity of its determination.

3. A Registered Entity may challenge the determination of the Planning Coordinator by filing with the appropriate Regional Entity, with a copy to the Planning Coordinator, within 60 days of receiving the written explanation from the Planning Coordinator. The challenge shall include the following: (a) an explanation of the technical reasons for its disagreement with the Planning Coordinator's determination, along with any supporting documentation, and (b) a copy of the Planning Coordinator's written explanation. Within 30 days of receipt of a challenge, the Planning Coordinator may file a response to the Regional Entity, with a copy to the Registered Entity.

4. The filing of a challenge in good faith shall toll the time period for compliance with PRC-023 with respect to the subject facility until such time as the challenge is withdrawn, settled or resolved.

5. The Regional Entity shall issue its written decision setting forth the basis of its determination within 90 days after it receives the challenge and send copies of the decision to the Registered Entity and the Planning Coordinator. The Regional Entity may convene a meeting of the involved entities and may request additional information. The Regional Entity shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

6. A Planning Coordinator or Registered Entity affected by the decision of the Regional Entity may, within 30 days of the decision, file an appeal with NERC, with copies to the Regional Entity and the Planning Coordinator or Registered Entity. The appeal shall state the basis of the objection to the decision of the Regional Entity and shall include the Regional Entity decision, the written explanation of the Planning Coordinator's determination under PRC-023, and the documents and reasoning filed by the Registered Entity with the Regional Entity in support of its objection. The Regional Entity, Planning Coordinator or Registered Entity may file a response to the appeal within 30 days of the appeal.

7. The Board of Trustees shall appoint a panel to decide appeals from Regional Entity decisions under Section 1702.5. The panel, which may contain alternates, shall consist of at least three appointees, one of whom must be a member of the NERC staff, who are knowledgeable about PRC-023 and transmission planning and do not have a direct financial or business interest in the outcome of the appeal. The panel shall decide the appeal within 90 days of receiving the appeal from the decision of the Regional Entity and shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

8. The Planning Coordinator or Registered Entity affected by the decision of the panel may request that the Board of Trustees review the decision by filing its request for review and a statement of reasons with NERC's Chief Reliability Officer within 30 days of the panel decision. The Board of Trustees may, in its discretion, decline to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. Within 90 days of the request for review under this Section 1702.8, the Board of Trustees may either (a) issue a decision on the merits, which shall be the final NERC decision, or (b) issue a notice declining to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. If no written decision or notice declining review is issued within 90 calendar days, the appeal shall be deemed to have been denied by the Board of Trustees and this will have the same effect as a notice declining review.

9. The Registered Entity or Planning Coordinator may appeal the final NERC decision to the Applicable Governmental Authority within 30 days of receipt of

the Board of Trustees' final decision or notice declining review, or expiration of the 90-day review period without any action by NERC.

10. The Planning Coordinator and Registered Entity are encouraged, but not required, to meet to resolve any dispute, including use of mutually agreed to alternative dispute resolution procedures, at any time during the course of the matter. In the event resolution occurs after the filing of a challenge, the Registered Entity and Planning Coordinator shall jointly provide to the applicable Regional Entity a written acknowledgement of withdrawal of the challenge or appeal, including a statement that all outstanding issues have been resolved.

1703. Challenges to NERC Determinations of BES Exception Requests Under Section 509

1. This Section 1703 establishes the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

2. A Submitting Entity (or Owner if different) aggrieved by the decision of NERC to approve or disapprove an Exception Request or to terminate an Exception with respect to any Element may, within 30 days following the date of the decision, file a written challenge to the decision with the NERC director of compliance operations, with copies to the Regional Entity and the Submitting Entity or Owner if different. The challenge shall state the basis of the objection to the decision of NERC. The Regional Entity, and the Submitting Entity or Owner if different, may file a response to the challenge within 30 days following the date the challenge is filed with NERC.

3. The challenge shall be decided by the Board of Trustees Compliance Committee. Within 90 days of the date of submission of the challenge, the Board of Trustees Compliance Committee shall issue its decision on the challenge. The decision of the Board of Trustees Compliance Committee shall be the final NERC decision; provided, that the Board of Trustees Compliance Committee may extend the deadline date for its decision to a date more than 90 days following submission of the challenge, by issuing a notice to the Submitting Entity, the Owner (if different) and the Regional Entity stating the revised deadline date and the reason for the extension.

4. The Submitting Entity, or Owner if different, may appeal the final NERC decision to, or seek review of the final NERC decision by, the Applicable Governmental Authority(ies), in accordance with the legal authority and rules and procedures of the Applicable Governmental Authority(ies). Any such appeal shall be filed within thirty (30) days following the date of the decision of the Board of Trustees Compliance Committee, or within such other time period as is provided for in the legal authority, rules or procedures of the Applicable Governmental Authority.