Resource Adequacy Program – Conceptual Design

JULY 2020

Northwest Power Pool

NORTHWEST PowerPool

Table of Contents

1. Background

This Conceptual Design document describes the work done and progress accomplished by the Steering Committee[1] during this phase of the Resource Adequacy Program Development Project (RAPDP) and the activities anticipated for future stages of the project. The proposed design elements are preliminary and subject to change as the detailed design is considered in Phase 2B and feedback is received from internal stakeholders, the Stakeholder Advisory Committee (SAC),[2] and other stakeholders in the region.

Work completed in Phase 2A includes:

- Successful collaboration between 18 funding entities to stand up a project organization and committee structure, schedule and scope of the resource adequacy (RA) program, and other management needs;
- Documentation of a conceptual design for the RA program, focused on generation of regional metrics, forward showing obligations, and program requirements;
- Creation of an excel spreadsheet workbook that provided insight into how certain elements common to RA programs across the country could impact a region-specific program[3]; and
- Exploration of legal and regulatory issues related to governance and organizational structure of a future RA program.

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[1] The Steering Committee for Phase 2A consisted of representatives from entities who funded Phase 2A.

[2] The Stakeholder Advisory Committee includes approximately 25 members, with individuals expected to represent perspectives and serve as liaisons within their industry sector. Sector representation includes state representatives (Commissions or State Energy Office), public power stakeholder groups, environmental community stakeholders, independent power producers, large consumers, ratepayer advocacy groups, and natural gas utilities. The Stakeholder Advisory Committee provides input to the Steering Committee as the Steering Committee develops RA Program concepts. The Steering Committee will take written comments from the Stakeholder Advisory Committee on the proposed conceptual design and will consider this feedback as program design moves forward in the detailed design phase.

[3] The Excel workbook was developed by E3 in collaboration with the Steering Committee. A description of E3's work and the major findings, as well as a representative forward showing workbook, are provided in a separate public document.

This document provides additional detail on the project team's approach to this effort, these accomplishments, and next steps identified for Phase 2B: Detailed Design.

1.1. Project Management Phases

The RAPDP has been divided into management phases (Figure 1), as follows:

Figure 1. Phase implementation for RAPDP.

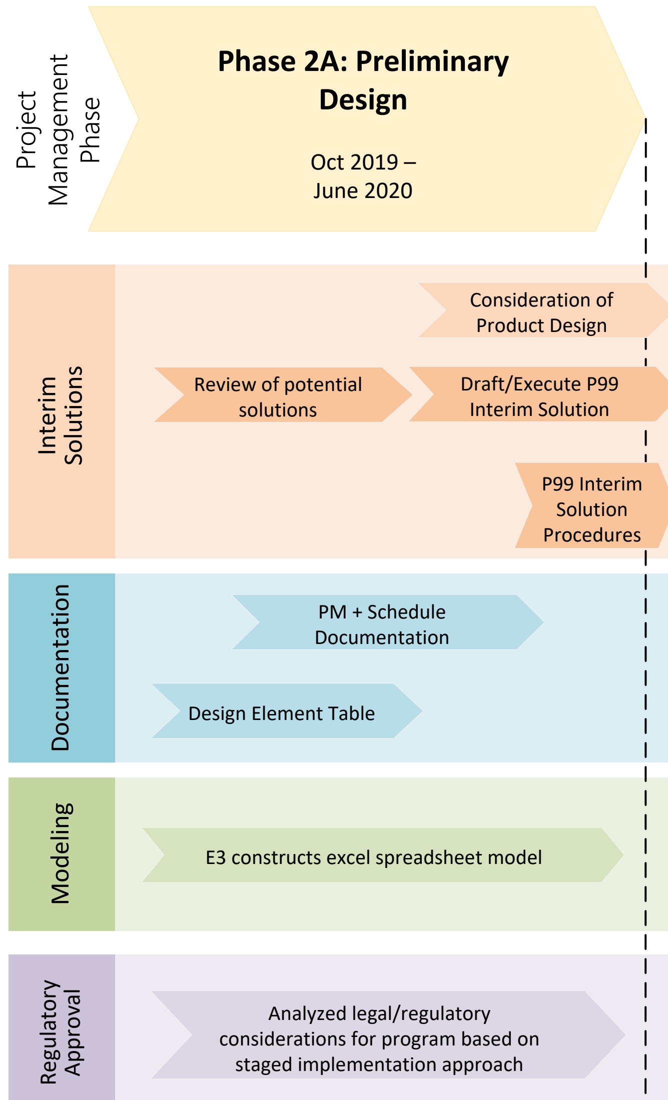
Phase 1: Information Gathering – This phase consisted of gathering information on existing regional studies of RA, reviewing current RA practices among Western utilities, surveying and summarizing best RA practices, evaluating the impacts of constraints on fuel supply and transmission deliverability, and communicating these results and findings by publishing a report titled *Exploring a Resource Adequacy Program for the Pacific Northwest, October 2019.*

Phase 2A: Preliminary Design – This phase consisted of developing a conceptual design for the RA program, including a proposal for the organizational structure and governance, the high-level technical design elements, a forward showing workbook tool, management plan, and planning level cost estimates.

Phase 2B: Detailed Design – This phase provides details on the program design including rules, regulations, and governance and a detailed design of modeling tools necessary for program implementation. A Program Developer will be hired to assist in detailed program design, end-state modeling design, cost estimation, and regulatory and stakeholder communications.

Phase 3: Implementation – Implementation of the RA program will be performed by a Program Administrator, which will lead the development of modeling tools, procedures, and processes, and seek regulatory approvals as determined necessary. The program will be implemented in stages, as described in 1.2.2 Staged Functionality.

1.1.1. Phase 2A: Preliminary Design Process



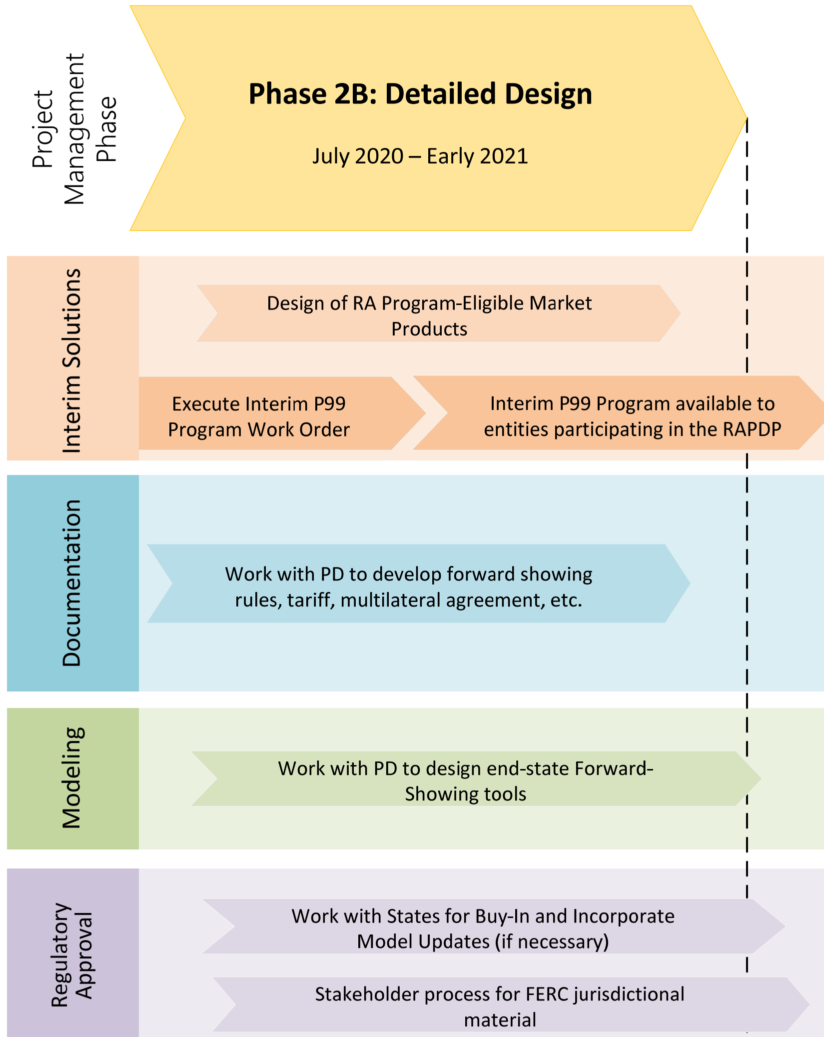
This section summarizes the work completed as part of Phase 2A: Preliminary Design. As part of this phase, the RAPDP Steering Committee has held multiple work sessions, developed a proposed conceptual design, considered and evaluated how certain elements common to RA programs across the country could impact a region-specific program, evaluated regulatory pathways, stood up a Stakeholder Advisory Committee, and conducted several public meetings.

In Phase 2A: Preliminary Design, the Steering Committee evaluated design elements identified at the conclusion of Phase 1; a list of 21 elements of an RA program were identified in the earlier phase through research into RA programs in the United States and other countries. Early in Phase 2A: Preliminary Design, the Steering Committee evaluated existing documentation (tariffs, rules, procedures) for both the Southwest Power Pool (SPP) and California Public Utility Commission and California ISO (CAISO), and summarized how the entities approach each of the 21 elements. Where necessary, examples were sought from other RA programs in North America for comparison.

In late 2019, the Steering Committee discussed each of these elements in detail, determining what approaches were appropriate for and applicable to the NWPP region. Through these discussions, the Steering Committee recorded details for each of the design elements. Steering Committee representatives took that draft back to their entities for further discussion, questions, and refinement in February 2020. In addition, the Steering Committee shared key preliminary program design elements and considerations underway with the Stakeholder Advisory Committee as well as the public.

Throughout the next 3 months, the Steering Committee refined, clarified, and worked to memorialize the design elements as questions were brought forward from participating entities and stakeholders.

1.1.2. Phase 2B: Detailed Design



Looking forward, Phase 2B (which began in July 2020) will focus on adding detail and specificity to the conceptual design developed and proposed in Phase 2A. Also, in this phase, the Steering Committee anticipates additional stakeholder engagement, further consideration of organizational and governance needs and constraints, and design of a forward showing model for development in Phase 3 (Implementation Phase).

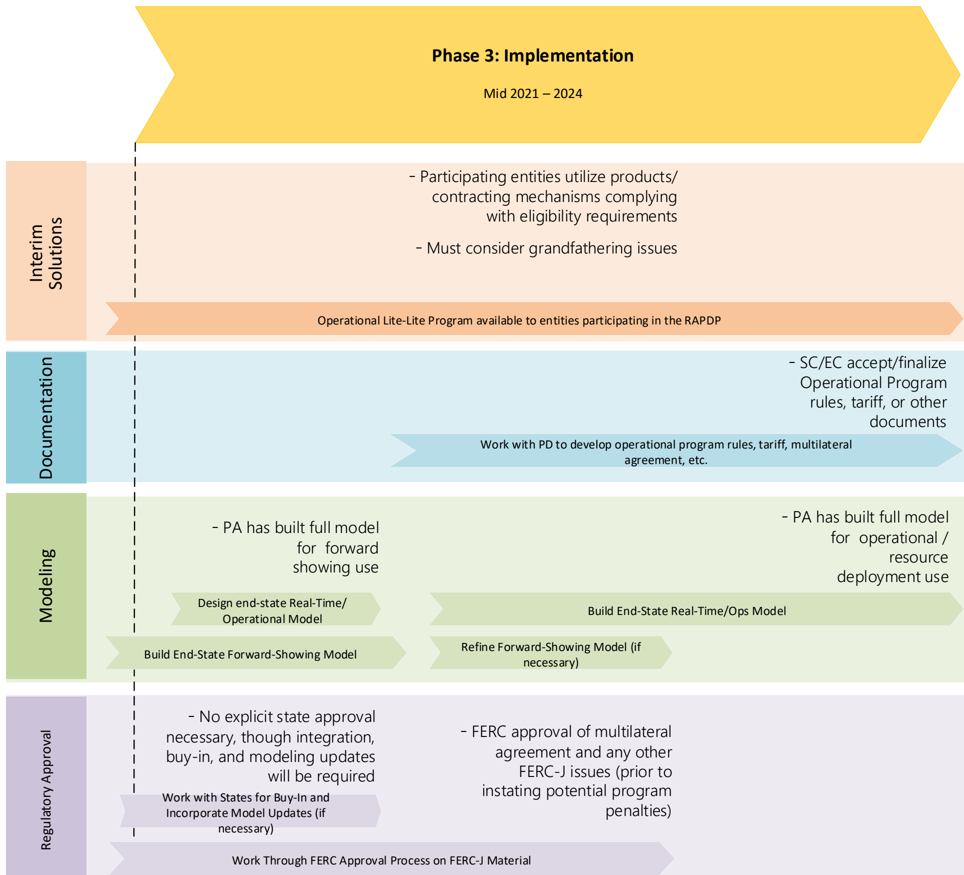
As part of this phase, the Steering Committee expects to hire a Program Developer with experience working in other RA programs and experience in modeling/monitoring RA programs in both the forward showing and operational periods. The Program Developer will work with the Steering Committee and the NWPP to complete the detailed program design; develop cost estimates for the final design and implementation phase; conduct stakeholder communications and develop an outreach strategy; develop a regulatory strategy and engage with regulatory and governmental affairs; and assist the Steering Committee and Project Management Organization[4] with program administration and governance. The role of the Program Developer will be augmented by hiring an independent advisor to the Executive Committee and NWPP President.

[4] The Project Management Organization is a subset of the Steering Committee focused on managing the overall program scope, schedule, and budget consistent with Steering Committee direction.

Phase 2B: Detailed Design is expected to begin July 2020 and run through early 2021.

1.1.3. Phase 3: Implementation

Phase 3 is the implementation and building of the RA Program. In this phase, the Program Administrator will be hired, and will be performing the bulk of the implementation and management work, including building business processes and management systems. This phase will also include filings with FERC, or any other regulatory agencies identified.



Phase 3: Implementation is expected to begin mid 2021 and run through 2024.

1.2. Staged Functionality

The Steering Committee has recommended implementing functionality of an RA program in a staged approach (Figure 2), providing benefits of an organized program to the region as soon as they can be made available. The full program will be implemented in three stages (Stages 1, 2, and 3).

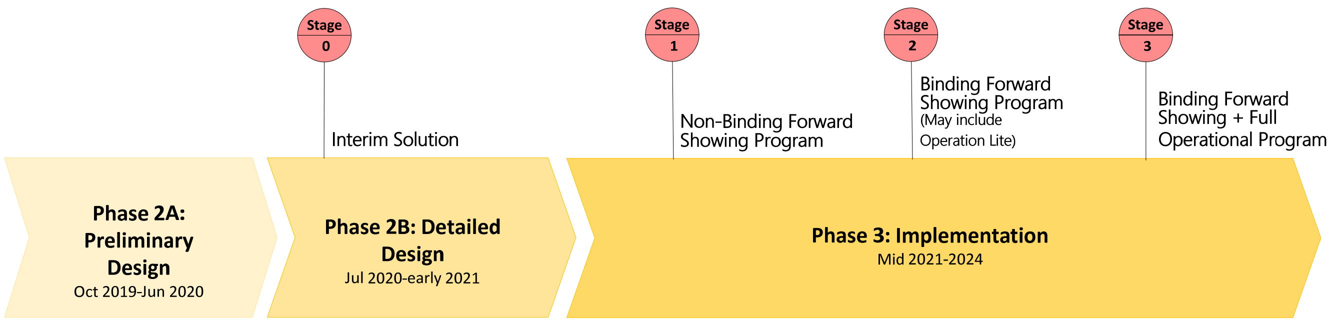


Figure 2. Staging RA program functionality.

Prior to implementation of the staged final program design, an interim solution (Stage 0), which will allow program participants to voluntarily assist other program participants facing potential RA shortfalls, is being explored, for implementation as early as the summer of 2020.

Stage 1: Entities will participate in a non-binding version of a "forward showing" program[5]. The Program Administrator will inform participants of their respective RA requirements[6], participating entities will submit information to the Program Administrator on the established timelines and the Program Administrator will certify whether they have met obligations. Entities not meeting their obligations will not incur penalties[7] during Stage 1; other than lack of penalties, the program would operate as designed in full (e.g., with complete models, forward showing timelines and procedures, data sharing, etc.). This stage is anticipated to last two seasons (summer and winter).

Stage 2: The forward showing program would be fully implemented with the introduction of compliance penalties. Introduction of penalties for jurisdictional and non-jurisdictional entities may have additional legal implication, including FERC- jurisdictional implications – see 2 Forward Showing Program Conceptual Design for additional details on the conceptual design.

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[5] More information on forward showing programs can be found in 2 Forward Showing Program Conceptual Design.

[6] More information on RA requirements programs can be found in 2.1 Showing and Compliance Timing and 2.2 Regional Metrics.

[7] More information on penalties can be found in 2.4 Penalty for Non-Compliance.

Stage 3: A full operational program[8] will be added, enabling participating entities to access pooled regional resources in a structured program. However, note that given that the metrics utilized for the forward showing program will anticipate access to pooled capacity, the viability of prior stages may require some operational period components. This need will be further considered in Phase 2B; current thinking is that access to the pooled resources may be necessary in a less formal mechanism prior to Stage 3.

1.3. Capacity RA Program

After careful consideration, the Resource Adequacy Program Development Project (RAPDP) Steering Committee elected to pursue a capacity RA program as the best way to address the region's reliability concerns in a timely and efficient manner, recognizing that our unique challenge would be made much more complex by attempting to pursue an energy RA program.

Once the capacity RA program is implemented, the Steering Committee will explore other solutions that could build upon this program, such as an energy or flexibility RA program. The Steering Committee recognizes that capacity and energy issues are interrelated, especially in the NWPP hydro dominated footprint, and the Steering Committee is doing its best to consider both what is feasible to implement and what is currently most needed for reliability.

1.4. RA Program Goals & Objectives

At the beginning of the RAPDP conceptual design effort, entities in the NWPP signed onto a project charter (October 2019), agreeing to fund Phase 2A: Preliminary Design. This charter established goals and objectives for the project and the future RA program. Our goals aimed to identify what a future RA program must do to be successful; our objectives identified key considerations to be accounted for in our program design and implementation.

[8] More information on forward showing programs can be found in 3 Operational Program Conceptual Design.

1.4.1. Goals

The RAPDP, as agreed to in its Charter, will build a regional RA program supporting the following overall goals:

Reliability: Ensure the footprint has enough resources installed and committed to reliably serve demand, including during stressed grid and market conditions, with a high degree of confidence.

Improve Effectiveness and Efficiency: Enable member entities to take advantage of the benefits associated with diversity in demand and supply across the footprint and better utilization of transmission infrastructure, in an equitable way, using a robust and dependable analytical approach.

Improved Visibility and Coordination: Through a centralized RA program, establish full visibility for the members and Program Administrator into the combined capabilities and requirements of the footprint. This will enable member entities and their stakeholders to make fully informed RA planning and procurement decisions, using collaboratively established common best practice approaches, so that RA needs are met in the most reliable, efficient, and economical way.

Fair and Unbiased: The RA program will develop rules, procedures and business practices that are fair and unbiased to all members with respect to member type and size, resource make-up, and capacity surplus or deficit.

1.4.2. Objectives

The RA program will also support the following objectives:

1. Ensure that Balancing Authorities and load serving entities (LSEs) can continue to operate safely, efficiently, and reliably.
2. Ensure that the recommended RA program and its components deliver investment savings through diversity benefits.
3. Ensure the RA program respects local autonomy over investment decisions and operations and continues to respect the rights and characteristics of individual utilities, transmission service providers, Balancing Authorities and other entities through program design.

4. Make recommendations that are acceptable within the current and evolving regulations and requirements of each applicable federal, state, and local jurisdiction.
5. Ensure that the participation, evaluation, and qualification of resources is technology neutral.
6. Ensure that all products and services transacted to meet the requirements of the RA program are well defined, voluntarily transacted through existing competitive market frameworks, and accurately tracked.
7. Ensure that the proposed RA program can be extended to other regions in the West.
8. Ensure that entities that voluntarily choose to participate in the RA program equitably pay and receive benefits for services provided by the program.
9. Ensure the RA program provides efficient long-term investment signals as well as a process for exit and entry of resources.

2. Forward Showing Program Conceptual Design

The forward showing program establishes regional metrics and requires that entities prove they meet the regional metrics months in advance of a season. Table 1 provides a high-level overview of the forward showing time horizon.

Table 1. Snapshot of conceptual design, additional detail on the program is found below.

NWPP RA Program Snapshot	
Market Structure	Bi-lateral; entities will continue to be responsible for determining what resources and products to procure and from where.
Participation	Voluntary to join; joining commits participants to meeting established requirements or incurring penalties (i.e., not “voluntary” to comply once committed) and to an operational program where they are obligated to deliver diversity benefit when called upon. Process will be established to join or leave the program.
Point of Compliance	For further discussion with stakeholders in Phase 2B: Detailed Design. Currently considering obligations at the LSE level.

NWPP RA Program Snapshot	
Administration	Program Administrator will likely have to be a FERC jurisdictional entity to the extent that it administers program elements that are subject to FERC jurisdictions, which means it will also have to meet federal "public utility" standards for neutrality. Phase 2B will also consider multiple layers of program administration that may not require FERC jurisdiction.
Compliance Period(s)	Two binding seasons: Summer and Winter. Fall and Spring seasons would be advisory (no penalties for non-compliance, but metrics would be provided).
Forward Showing Period	Forward showing will occur 7 months in advance of binding seasons, with a 2-month cure period.
Planning Reserve Margin	Seasonal Planning Reserve Margins will be determined for summer and winter periods and expressed as a percentage of the 1-in-2-year seasonal peak load forecast.
Resource Capacity Accreditation	Resource Capacity Accreditation will be based on methodologies appropriate to resource type, including: *Variable Energy Resources:* ELCC analysis *Run of River Hydro:* historical data and ELCC analysis *Storage Hydro:* Common hydro model that considers appropriate set of water conditions allowing Program Administrator to verify data. Phase 2A included development of a conceptual storage hydro capacity methodology, which will be further considered as part of Phase 2B: Detailed Design. *Thermal:* UCAP method *Other resource capacity crediting (e.g., demand-side resource, pump storage, behind-the-meter solar):* for further development in Phase 2B: Detailed Design.
Penalty for Non-Compliance	Deficiency payment based on CONE for a new peaking gas plant (e.g., SPP's CONE calculation). Further discussions on deficiency payments are anticipated in Phase 2B.

Note: CONE: cost of new entry; ELCC: effective load carrying capacity; FERC: Federal Energy Regulatory Commission; LSE: load serving entity; PRM: planning reserve margin; SPP: Southwest Power Pool; UCAP: Unforced Capacity.

2.1. Showing and Compliance Timing

A seven-month time horizon meets the reliability needs of the program due to availability requirements in the near-term operating window.

There will be two binding forward showing seasons: Winter and Summer; metrics for each season will be determined annually by the Program Administrator. Seven months in advance of the two binding seasons, compliance showings will be required. The Program Administrator will provide advisory metrics for Fall and Spring seasons; there will be no compliance showing for those seasons, and thus no penalties for non-compliance with the advised metrics. See Table 2 and Figure 3.

Table 2. Proposed compliance seasons.

Season	Binding/Advisory	Duration	Compliance Showing Date	Cure Period
Winter	Binding	November – March	March 31	April 1 – May 31)
Summer	Binding	June – September	October 31 (of prior year)	November 1 – December 31 (of prior year)
Spring	Advisory	April – May	N/A	N/A
Fall	Advisory	October	N/A	N/A

Members will provide information for the duration of the forward showing period with a specified granularity, in addition to contracts for resources energy services and transmission capacity that will then be aggregated to meet the seasonal requirements.

Once program participation is known, the Program Administrator will be able to determine an *advisory* out-year and *binding* one-year regional and individual RA requirement.

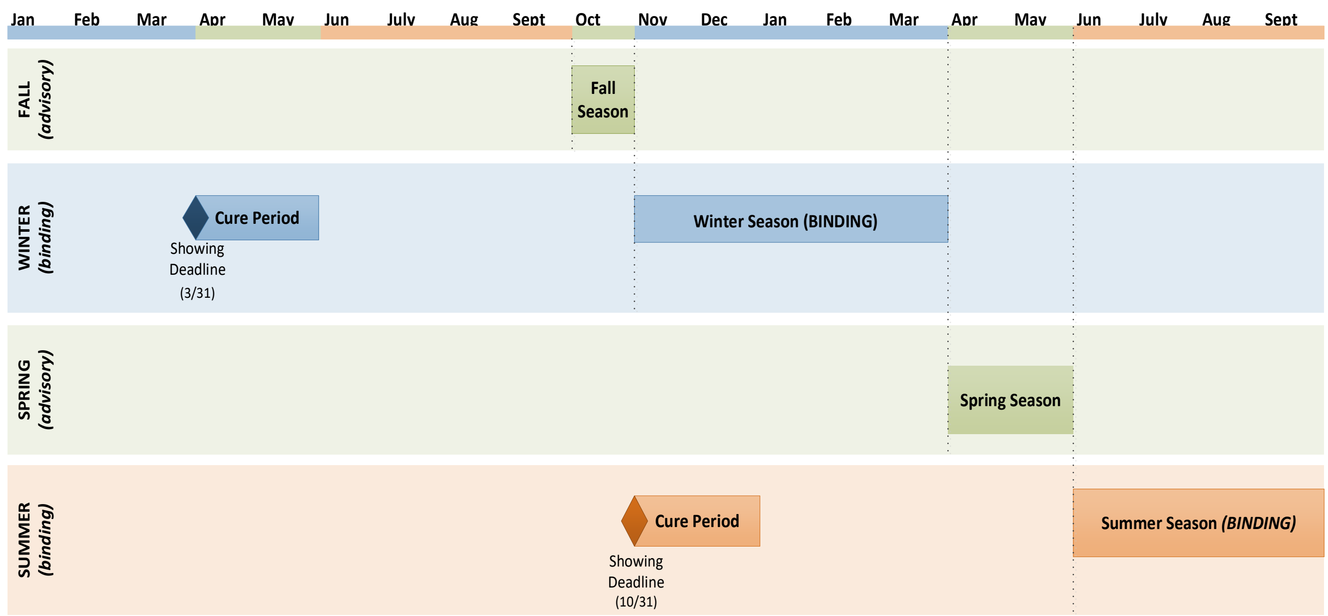

Figure 3. Proposed schedule and time periods for forward showing program.

As part of Phase 2B: Detailed Design, the Steering Committee and Program Developer will consider (among other topics):

- When the showing requirements are published by the Program Administrator for the region and program participants;
- If showing requirements can be shaped throughout the season (pending outcomes from modeling work in Phase 2B);
- Determination of critical hours and seasonal period definitions to ensure the fairness, reliability and benefits of the program;
- When, relative to these compliance showing timelines, entities would be able to join or leave the program.

2.2. Regional Metrics

2.2.1. Regional Adequacy Objective

The regional adequacy objective ensures total available capacity over a specific period will be available to sufficiently serve demand.

The RA program will be designed to achieve a target loss of load expectation (LOLE) on a forward basis. LOLE analysis is performed to determine the amount of capacity that needs to be available to meet desired reliability targets at any time during the day, over a ten-year period.

The Steering Committee recommends an LOLE objective of 1 day in 10 years where capacity is expected to be insufficient to meet load plus contingency reserves. Seasonal LOLE objectives will be determined for summer and winter periods.

The probabilistic analysis to measure where the region stands for meeting its LOLE adequacy objective is the same analysis that will determine the planning reserve margin (PRM) and capacity contribution of resources and will be performed by the Program Administrator prior to determining the regional and individual requirements on a seasonal basis.

2.2.2. Planning Reserve Margin

The Planning Reserve Margin (PRM) is a percentage of dependable capacity needed above the 1-in-2 peak load forecast to meet unforeseen increases in demand and other unexpected conditions.

For an RA program, a PRM is a key component in determining the necessary amount of "perfect capacity", expressed in MWs, needed to meet the agreed upon adequacy objective for each applicable season. For the purposes of this program, perfect capacity is defined as a resource with 100% availability at all times. Using the perfect capacity approach, the Program Administrator will identify the total MW capacity required to meet the 1 in 10 LOLE adequacy objective for the NWPP's footprint if all generators were 100% available; this will serve as the "load" side of the RA evaluation. Using this convention ensures that the PRM is driven by load and is independent of the types of resources in the footprint and their characteristics.

The PRM is the output of a probabilistic analysis. This same type of analysis is used to assess capacity contribution and the ability to meet the adequacy objective. It includes contingency reserves but regulating reserves and other Balancing Authority Area-specific reserves will not be included in the PRM calculation. In Phase 2B, the Program Developer and participants will further clarify the necessary requirements for contingency reserves, regulating reserves, load following requirements and variable energy resources (VERs) uncertainty, etc.).

Seasonal PRMs will be determined for summer and winter periods and expressed as a percentage of the 1-in-2 seasonal peak of the aggregated load across the footprint of participants. The PRM will be calculated for the entire region and each responsible entity

(Balancing Authority or LSE) is required to "show" sufficient available capacity, to meet its own P50 load forecast plus the PRM target.

As part of Phase 2B: Detailed Design, the Program Developer and Steering Committee will consider (among other topics):

- Evaluating the import and export capability from various footprints (regional, Western Electricity Coordinating Council, California ISO, etc.) during constrained periods, and
- The frequency for updating the overall PRM.

2.2.3. Load Forecasting for Forward Showing

In order to set regional metrics appropriately, the Program Administrator will model either the coincident or non-coincident peak demand for the region (to be further considered in Phase 2B: Detailed Design).

Participating entities (Balancing Authorities or LSEs) will provide the Program Administrator historical load data (currently suggested as 5-years of hourly data, adjusted for curtailed loads, demand response, and known incremental energy efficiency measures not already captured). Participating entities will also provide relevant forward-looking data and forecasts, supported by evidence, to help inform the Program Administrator's load forecasting. Load forecasts provided by participating entities to the Program Administrator should tie to public documents/processes that are consistent across all member entities. There will be an established process for participating entities to resolve disputes/discrepancies with the Program Administrator's load forecast.

RA requirements for each participating entity (Balancing Authority or LSE) will be based on the entity's applicable peak load forecast. To derive a participating entity's RA requirements for the season, their applicable peak load forecast will be multiplied by (100% + the PRM for the season). In Phase 2B, participants will work with the Program Developer to consider whether to use entities' own load forecasting or an independent load forecast (in collaboration with participating entities) to establish these peak load numbers.

The following areas will be considered for development as part of Phase 2B: Detailed Design:

- The aforementioned dispute resolution process;
- Policies and procedures for the submission of all relevant data;

- Whether to proceed with a coincident or non-coincident peak (discussion to be informed by Program Developer recommendations).
- Consideration of what data, information, or submittals would be made available to the public.

2.2.4. Regional Import and Export Assumptions

In setting regional metrics, it will be important to understand how much of the capacity residing within the footprint will be available to serve load within the footprint under stressed grid conditions (capacity critical hours). In the next few years of program development and implementation, existing bi-lateral contracts may be grandfathered, and participating entities may need to change their market activities to accommodate showing standards. When initial models are run to set regional metrics, the Program Administrator may need to make assumptions regarding the magnitude of imports and exports in order to appropriately set planning reserve metrics to ensure reliability.

These assumptions and a common method for treating imports and exports in the load and resource calculations will be carefully considered as part of the scope of Phase 2B: Detailed Design, understanding their potential implications not only on regional metrics but also potentially on qualifying capacity contributions for individual resources types (e.g., imports or exports could influence the duration or timing of capacity critical hours, impacting the appropriate calculation of capacity contribution of various resource types).

2.3. Resource Eligibility and Qualification

Resource eligibility will require a registration and certification process for all resources; in other RA programs, eligibility and qualification often include operational and/or capacity tests. The Steering Committee recommends that historical performance would meet the operational test requirements for existing resources.

The proposed minimum resource size for recognition by the RA program is 1 MW. Resources within the same system could be aggregated to meet this requirement, however the definition of a system and the process/ability to aggregate will be considered during Phase2B: Detailed Program Design.

2.3.1. Import Capacity

Import capacity contribution (either from within or from outside the regional RA footprint) will be calculated as specified by program rules for each type of resource (Table 3). The amount of the import transaction within the regional RA footprint will be reflected as an RA capacity resource for the buyer and an RA capacity obligation for the seller, so long as the following requirements are met:

- Demonstrated ownership or contractual rights
- Firm, conditional firm, or secondary network transmission from the resource to the load[9]; and
- Identified source (unit, plant, or system specified).

Developing mechanisms to support the commercial procurement of qualifying RA resources will require significant effort involving many stakeholders in the region. Accordingly, priority will be placed on finalizing the contractual requirements and qualifying resource characteristics in the final design effort to allow time to develop the supporting commercial procurement structures, processes, and contract language.

2.3.2. Export Capacity

Firm capacity exports outside the footprint must be declared and included as a capacity obligation. Non-firm capacity exports will not be deducted (from forward showing capacity contribution) but must be curtailable in the operational timeframe.

2.3.3. Capacity Contribution of Resources

Capacity contributions will be determined for all resources contributing to an entity's forward showing (Table 3). The capacity contribution of a resource will represent the number of MWs of perfect capacity available by the resource. The capacity contribution calculations will be updated by the Program Administrator on an annual basis using the analytical tools/modeling for the forward showing program in a manner consistent with the determination of the LOLE

[9] In Phase 2B: Detailed Design the Program Developer and Steering Committee will consider whether member entities can provide an attestation in lieu of firm, conditional firm, or secondary network transmission at the compliance showing deadline. Firm, conditional firm, or secondary network transmission would be required before the end of the cure period.

and PRM. The methodology for assessing resources should accurately reflect a resource type's capacity contribution during critical hours.

Most RA programs use an Installed Capacity (ICAP) or unforced capacity (UCAP) methodology to value a thermal resource's capacity contribution. ICAP methodology is generally a temperature-adjusted test against the nameplate capacity of a resource. UCAP methodology adjusts a resource's ICAP value to account for outages. Variable generation capacity contributions (wind, solar, run of river hydro) are typically calculated using an effective load carrying capacity (ELCC) analysis. The ELCC approaches uses advanced tools and modeling to predict the effective capacity contribution of resources to meet the reliability needs of the system.

Planned outages are not included in UCAP calculations; planned outages are considered during the forward showing period (i.e., units on planned outages are not included as capacity in the applicable period). This means planned outages will need to be planned in advance of the showing deadline (Table 2).

Capacity contributions of resources within a given system may not be fully separable. In some cases, the capacity provided by two resources considered together may be higher or lower than the sum of the capacity provided by each of the resources individually. This could be due to resource complementarity (resulting in higher capacity contributions – e.g., VERs and batteries) or resource similarities (resulting in lower capacity contributions, similar to declining marginal value – e.g., market saturation of solar). This requires the program to adopt policies and methodologies to determine how these interactions should impact individual resource capacity contributions. The Program Developer will consider this further in Phase 2B: Detailed Design with input from stakeholders and the Steering Committee.

A dispute/exception mechanism is particularly important for large forced outages in 3-year historical data and/or where capital improvements have been made that reduce forced outage rates. The dispute exception mechanism will be considered as part of Phase 2B: Detailed Design.

In addition, the hours of capacity that a resource can provide should be considered in the capacity contribution determination, such as how many hours of output capability are required from a facility (e.g., run-of-river, batteries, etc.). This metric will be informed by the assessment of duration of historical peaks and further developed as part of Phase 2B: Detailed Design.

Finally, because of the prevalence of storage hydro resources in the NWPP region, special consideration needs to be given to the RA capacity contribution of storage hydro resources. As the hydro fleets in other RTO/ISO regions with RA programs are generally run-of-the-river, the methods by which hydro capacity is treated in those regions could not be applied to the more complex nature of storage hydro. As such it was identified by the Steering Committee that a methodology for capacity contribution treatment of storage hydro needed to be developed for the NWPP program.

Table 3. Resources and proposed qualification approaches.

Resource	Qualifying Capacity Contribution Methodology	Notes
Thermal resources	UCAP approach for all hours, using three years of historical data[10] for each season.	Entities must use industry best practices regarding fuel supply standards. PA may apply capacity de-rates or require additional actions to qualify (e.g., firm transport) as appropriate for known significant fuel supply events effecting an upcoming RA period.
VERs	Capacity based on ELCC analysis of historical data (Steering Committee proposes minimum of three years historical data, as available); ELCC will be evaluated by season and by zone.	Zones will be climate/fuel supply-based (vs. transmission-based); definition of these zones in Phase 2B: Detailed Design will include a stakeholder feedback process. New resources or resources with less than three years of data will use the class-average of that resource type.
Run-of-River Hydro[11]	Capacity based on ELCC analysis of historical data (Steering Committee proposes minimum of three years historical data, as available); ELCC will be evaluated by season and by zone.	Run of river is less than one hour of storage, not in coordination with another project. Zones will be climate/fuel supply-based (vs. transmission-based); definition of these zones in Phase 2B: Detailed Design will include a stakeholder feedback process.
Storage Hydro:	Steering Committee proposes a new time-period approach to estimating capacity contribution in a manner that objectively reflects various operational restrictions and targets of hydro resources, and the associated considerations that go into the dispatch decision-making processes.	The NWPP footprint is unique due to the abundance of hydro generation, no other RA program has employed an approach to qualifying capacity that would be appropriate for our footprint. Common hydro model that allows Program Administrator to verify and includes a range of hydrological conditions. Assesses generation output during capacity critical hours, as well as ICAP and usable energy in storage, to determine how much capacity should be expected to be available during capacity critical hours in the future. The storage hydro capacity contribution evaluation will use the same capacity critical hours identified in calculations of regional adequacy metrics (PRM, LOLE, load forecasting, etc.).
Geothermal **Nuclear** **Rooftop solar** **Demand response** **Other**	To be discussed as part of Phase 2B: Detailed Design.	Other resources can and should participate in the RA program. The Program Administrator will be responsible for determining the capacity contributions as new resources are added. These resources will be considered for additional design detail during Phase 2B: Detailed Design. While not comprehensive, the following notes were made about other resource types: Demand response: certified for controllability (should be available for consecutive hours during peak periods – to be addressed further pending modeling effort). Pump storage may require case-by-case analysis. Battery storage will require a certification for availability and related analysis.

Notes- ELCC: effective load carrying capacity; ICAP: installed capacity; LOLE: loss of load expectation; PA: Program Administrator; PRM: planning reserve margin; SC: Steering Committee; UCAP: Unforced Capacity.

[10] GADS or similar with a validation process – accommodating Canadian/Federal entities not using GADS

[11] Methodology is based on data that reflects the actual operation of the facilities during past capacity critical hours and reflects the complexities that went into the operation of the resources during those periods

2.3.4. Planned Outages

Planned outages can be identified at any time before a showing period and will be factored into a unit's capacity contribution for the relevant obligation period. For planned outages that are scheduled after a showing:

- Entities with surplus: net of the outage there is no action required;
- Entities with deficit net of planned outage: a substitution is required unless exemption is granted by the Program Administrator (further details on exemption granting process will be developed, as well as consequences for failure to meet substitution requirements).

Detailed process and substitution rules will be established to ensure loopholes are not created in the RA program as part of Phase 2B: Detailed Design.

2.3.5. Forced Outages

Forced outages are covered by UCAP in 2.3.3 Capacity Contribution of Resources, except for VERs which are covered by ELCC.

2.3.6. De-listing

The program proposes two types of resource de-listing. *Voluntary* de-listing may occur prior to a showing period when a member may delist a resource by excluding it from their RA resource portfolio. *Involuntary* de-listing results from a de-certification process for non-performance. The processes for determining and enforcing de-listing will be developed as part of Phase 2B: Detailed Design.

2.4. Penalty for Non-Compliance

Further discussions on deficiency payments are anticipated in Phase 2B. At this stage, the RAPDP proposes that if an entity fails to meet showing obligations after the cure period, the program will assess a cost of new entry (CONE) penalty against the non-compliant entity. The CONE is based on publicly available information (i.e., information provided by the Energy Information Administration) relevant to the estimated annual capital and fixed operating costs of a hypothetical natural gas-fired peaking facility. The CONE value does not consider the anticipated net revenue from the sale of capacity, energy, or ancillary services.

As an example, the CONE value derived by SPP is 85.61 $/kw-yr. Our program's CONE value will be derived by the Program Administrator and reviewed annually; any changes would be managed by the Program Administrator.

In Phase 2B: Detailed Design, the Program Developer and Steering Committee will consider procedures for levying penalties for non-compliance against participating entities and how the proceeds from such penalties would be used or redistributed. The intent is that the CONE penalty is high enough that it is not expected that entities would fail to meet identified standards with any regularity.

PROPOSED CALCULATION FOR DEFICIENCY CAPACITY AND PENALTY

$$\textbf{Entity's Deficiency Capacity} = \textbf{Resource Adequacy Requirement} - \textbf{Firm Capacity Showings}$$

$$\textbf{Entity's Deficiency Payment} = \textbf{deficiency in capacity (MW)} \times \textbf{CONE} \times \textbf{CONE factor}$$

Where CONE Factor:

- ***125% @ Region has PRM plus 8 percent or more***
- ***150% @ Region has PRM plus 3 percent, but less than 8%***
- ***200% @ Region has PRM less than 3%***

2.5. Transmission and Deliverability

As part of Phase 2B: Detailed Design, the Program Developer will work with the NWPP Transmission Planning Committee (NWPP TPC) and/or NorthernGrid Regional Transmission Organization (NGRPO) to further consider transmission and deliverability concerns related to the forward showing. The Steering Committee will consider in Phase 2B: Detailed Design of a zonal approach to evaluate the proposed RA measurement adequacy.

In a zonal approach, load zones would be identified at the end terminus of major transmission constraints, considering interties and the critical flowgates within, and ties to, participating entities' footprint. For example, loads located south of the South of Allston flowgate could be a load zone; Bonneville Power Administration, PGE and PAC have loads in that zone.

The Program Developer will work with NWPP TPC/NGRPO in coordination with member entities to identify the potential need for local RA within load zones as a result of transmission congestion. If a local zone can't access capacity from program participants because of transmission congestion, then the responsible entities within that zone may need to procure an additional amount of capacity for the forward showing period to maintain system reliability. In Phase 2B the Program Developer will also work with member entities to if there are must-run resources needed to maintain reliability throughout the region to provide voltage support, inertia, frequency response, etc. and assign them to load zones if a zonal model is determined appropriate.

3. Operational Program Conceptual Design

This section outlines key operational program design concepts discussed by the Steering Committee in Phase 2A: Preliminary Design; further exploration will be required during the Phase 2B: Detailed Design with the support of a Program Developer.

The operational RA program is expected to coordinate with on-going regional wholesale power initiatives and other current market requirements such as the Energy Imbalance Market (EIM). The NWPP region does not currently operate within an organized day-ahead market, which presents a unique situation, as this RA program would be stand-alone, likely necessitating coordination with the

ahead market and/or real time markets (e.g., EIM). In other RA programs (integrated with markets), must-offer requirements obligate resources providing RA to offer that capacity into the market. Absent an organized day-ahead or common real time market, the NWPP region will need to identify alternative means accessing pooled regional RA resources in the operational time horizon in order to 'unlock the diversity benefit.' As regional alternatives and market designs mature, the Steering Committee will evaluate the preferred operational implementation in the next phases of the program's development.

3.1. Resource Terminology

When discussing the operational program, it is important to delineate resources to clarify how they would be viewed under a future RA Program. In the forward showing time horizon, participating entities would be responsible for showing capacity to meet regional RA metrics. The resources used to meet these forward showing requirements in the planning time horizon are referred to as "pooled capacity." The operational program will need to enable participating entities to share and compensate each other for access to these pooled resources in the operational time horizon in order to realize the diversity benefit associated with participation in a regional RA program. For this reason, the operational program will make rules related to how and when entities could sell this pooled capacity if it is not needed to ensure regional reliability during the operational time horizon in a binding season.

Capacity possessed by an entity *beyond* the amount required to meet regional metrics in the forward showing time horizon would be "surplus capacity." The operational time horizon of the RA program does not obligate an entity's surplus capacity – capacity beyond that which is required to meet the forward showing can be sold or used by that entity in whatever means they choose.

3.2. Accessing Pooled Capacity

Entities may access the RA Program's pooled capacity only under a defined set of circumstances (a "systems-triggering event"), generally when load, unplanned outages, variable resource deviations or a combination thereof, exceeds an entity's required planning metrics. This should be distinguished from the "Qualifying Event" defined under the NWPP Reserve Sharing Program or with the "Frequency Response Reserves" Program under NWPP. Further discussion is warranted with Program Developer in defining the circumstances that triggers a "systems-triggering event".

PROPOSED TRIGGERING EVENT CONDITIONS FOR ACCESSING POOLED CAPACITY

$$\textit{Load} + \textit{Contingency Reserves} > \textit{Forecasted P50 peak load} + \textit{PRM} - \textit{forced outages} - VER_{underperformance} + VER_{overperformance}$$

3.3. Deploying Pooled Capacity

When the Program Administrator identifies a system-triggering event, the Program Administrator will need to

1. Quantify the required pooled capacity deployment need,
2. Allocate shares of the identified need to participating entities not needing their full pooled capacity to meet their own projected load,
3. Inform participants of a "hold" on their share of the needed pooled capacity, and
4. Coordinate deployment of participating entities' pooled resources, if necessary.

On most days, when an entity's pooled capacity is not required for other purposes, participating entities could sell their portion of the pooled capacity resources (e.g., into the day-ahead market – timelines and processes to be determined).

Processes, allocation methodologies, deliverability test, financial settlement and many other details of this process will be considered in upcoming design phases with assistance from the Program Developer and/or Program Administrator.

3.3.1. Deployed Settlements

The deployment settlement process will be developed as part of Phase 2B: Detailed Design.

3.3.2. Deployment of Resource Compliance

The compliance process for deployment of resources will be developed as part of Phase 2B: Detailed Design.

3.3.3. Planned and Forced Outages After the Showing Period

The process for voluntary de-listing after a showing period for both forced outages and planned outages will be developed as part of Phase 2B: Detailed Design.

3.4. Operating Timeframe

The operational program design would be relevant during the binding summer and winter compliance showing periods. Further technical discussions with the Steering Committee and the Program Developer will determine the day-ahead and real time planning requirements and outline the role of the Program Administrator in this time horizon. Within the day-ahead and real time windows, member entities also participate in various existing wholesale bilateral and organized markets. In Phase 2B, the Steering Committee and Program Developer will further consider how the operational program design will integrate with these markets.

3.5. Load Forecasting

The Program Administrator will ensure that deployment of pooled capacity is validated with actual operational conditions, including expected temperatures, actual loads from prior day, forced outages, transmission outages and variable resource expected performance. Additional details of the process and timeframe for determining a day-ahead load forecast to the Program Administrator will be defined during Phase 2B: Detailed Design.

3.6. Transmission and Deliverability

As part of Phase 2B: Detailed Design, the Program Developer will work with the Steering Committee to determine the need for a network transmission model to implement the operational program; the approach is expected to have sufficient granularity to ensure deliverability of energy to reliably serve load.

3.6.1. Local RA Considerations

During Phase 2B: Detailed Design, and after a local zonal study is conducted, the Program Developer may consider whether further action is necessary to maintain reliability in designated local zones.

In the final RA Program, the Program Administrator will be evaluating transmission deliverability in areas with known constraints. If needed, the Program Administrator may recommend additional capacity requirements or other measure required for reliability purposes in specific areas.

4. Legal and Regulatory Considerations

4.1. Stage 1: Non-Binding Forward Showing Program

The first stage of the RA program implementation would consist of a non-binding "forward showing" program where participants would be informed through the Program Administrator of their respective RA requirements without any penalties. The non-binding, informational character of this initial phase is likely not FERC jurisdictional. None of the functional elements that trigger FERC jurisdiction are present in this stage.

4.1.1. Structure

The Steering Committee recommends that this stage of the RA program be established through a multi-lateral agreement which defines the terms and conditions for Stage 1 functions. The agreement would set forth the scope of the informational forward showing function, provide for data sharing, and would define the role of Program Administrator, among other items. The agreement would need to be written for Stage 1 but with Stages 2-3 in mind; the agreement would need to provide for the ability to amend the agreement or to supersede the agreement for the terms and conditions of Stages 2-3 when those were ready for implementation. The agreement should also provide for an efficient transition if not all Stage 1 participants choose to move to Stages 2-3.

4.1.2. Program Administrator and Governance

For this initial stage, the Program Administrator role would be to act as a data administrator, to perform the calculation of RA requirements, and to provide for each entity's obligation on an informational basis. As such, there is no immediate need to ensure FERC "public utility" requirements are met, including independence of the Program Administrator. Similarly, this approach does not require an immediate need to ensure FERC independence of governing board.

4.2. Stages 2-3: Binding Program Implementations

In Stage 2, the forward showing program would be fully implemented with the introduction of binding requirements and consequences for non-compliance. The third stage would add an operational program, enabling participating entities to access pooled regional resources. Stages 2-3 are assumed to have functions that will be FERC jurisdictional.

4.2.1. Structure

These stages can be achieved through revising or superseding the Stage 1 agreement. The revised agreement for these stages would set forth the functions included for each stage and the agreement would be filed with FERC. If required, parties to the revised agreement would also file amendments and additions to their FERC tariffs (i.e., open access transmissions tariffs) or follow the applicable process established for revising each non-jurisdictional transmission provider's tariff, necessary for enabling and conforming changes in support of the program. Entities may choose to use methods other than their open access transmission tariff to implement the program. The revised agreement would have specific clarifications and conditions to ensure that parties to the agreement that are not FERC jurisdictional remain non-jurisdictional. The agreement with the Program Administrator may also need to be filed with FERC (assuming it was a separate agreement).

4.2.2. Program Administrator and Governance

For Stages 2 and 3, the Program Administrator should meet FERCs “public utility” and independence requirements. This could mean that these stages are performed by an entity that: (1) becomes a FERC “public utility”; or (2) is already qualified as a FERC “public utility”. The RA program’s governing board should meet FERC’s independence requirement; a committee of members with an advisory role and additional committees for other stakeholder sectors (e.g., states, LSEs, etc.) will also be considered.

5. Glossary

Adequacy Metric	A means of measuring RA. Currently, metrics used by utilities and load serving entities (LSEs) vary substantially across the country.
Adequacy Objective	Expected value over a specific period at which available capacity is insufficient to serve demand.
Balancing Authority	Entities responsible for the operation of the electric system. A Balancing Authority ensures, in real time, that power system demand and supply are finely balanced. This balance is needed to maintain the safe and reliable operation of the power system. If demand and supply fall out of balance, local or even wide-area blackouts can result.
Balancing Authority Area (BAA)	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.
Binding Seasons	The time periods in which capacity resources hold a commitment to a buyer to deliver its capacity commitment.
California Independent System Operator (CAISO)	The CAISO is a non-profit Independent System Operator serving California. It oversees the operation of the majority of California's bulk electric power system, transmission lines, and electricity market generated and transmitted by its member utilities.
Capacity	The ability to supply electric energy or reduce electric energy consumption as measured in MW.
Capacity Contribution	The quantity of capacity expressed in MWs that generating asset can reliably sell to a buyer within the RA program. The calculation of that asset's capacity contribution is determined based on asset-type (UCAP, ELCC, hydro methodology).

Coincident Peak	The collective Northwest Power Pool's (NWPP) projected P50 system-wide peak demand across a planning year.
Compliance Showing	The time period between the procurement of capacity and the commencement of the forward showing period.
Contingency Reserve (CR)	Reserve generating capacity (or rights to interrupt delivery of generation) necessary to allow an electric system to recover from disturbances such as generation failures and to provide for load following and frequency regulation.
Continuous Peak Demand	Peak demand period that can last several days (or even weeks) during cold or hot weather events.
Cost of New Entry (CONE)	The estimated annualized cost of a new plant. CONE is calculated as the total annual net revenue (net of variable operating costs) that an economically efficient new generation resource would need to earn in a wholesale market to recover its capital investment and fixed costs, given reasonable expectations about future cost recovery over its economic life.
Critical Peak Demand Hours	Hours of highest demand on summer and winter peak demand days.
Communications and Stakeholder Engagement Team (CSET)	The CSET is responsible for coordinating external communication and stakeholder engagement related to the RA program and internally communicating and coordinating with the Steering Committee.
Cure Period	The time between the procurement of capacity and the commencement of the commitment period, where a buyer and supplier can adjust the procured capacity volume
Day-ahead Sharing Requirement	Entities who are forecast to be *surplus,* set aside a portion of their Planning Reserve Margin (PRM) requirement to potentially be called on in real-time, as required. An entity's Day-ahead Sharing

	Requirement is based on its forecasted surplus planning reserves, weighted against system-wide available planning reserves. The Day-ahead Sharing Requirement will be held aside into real-time (e.g., T-60), where it will either be called upon, or released
De-listing	Removing assets from a participant's forward showing portfolio
Load Forecast	Load forecasting includes both demand forecasting and energy forecasting. It involves the accurate prediction of both the magnitudes and geographical locations over the different periods of the planning period. The basic quantity of interest is typically the hourly total system (or zonal) load. However, load forecast is also concerned with the prediction of hourly, daily, weekly and monthly values of load and of the peak load.
Design Element – Forward Showing Work Group (DEFS)	The DEFS guided the Steering Committee through an evaluation of design elements identified. DEFS expanded their membership and worked to add detail and explanation to the design elements and transitioning it into the Conceptual Design.
Executive Advisory Committee (EAC)	The EAC acts individually and collectively to communicate program progress to the Executive Committee and aids the PMO and CSET in identifying and executing communication strategies.
Effective Load Carrying Capacity (ELCC)	Effective Load Carrying Capability (ELCC) is a percentage that expresses how well a resource is able to meet reliability conditions. It can be calculated as the amount of incremental load a resource can dependably and reliably serve or the amount of reliable capacity that can be avoided by the resource, while considering the probabilistic nature of system reliability needs and resource performance.
Federal Energy Regulatory Commission (FERC)	FERC is the federal agency that regulates the transmission and wholesale sale of electricity and natural gas in interstate commerce and regulates the transportation of oil by pipeline in interstate commerce.

Forced Outages	Unplanned outages experienced in the operational period (after the forward showing period).
Forward Showing Program	The program establishes regional metrics and requires that entities prove they meet the regional metrics months in advance of a season.
Forward Showing Period	This period is the timeframe around the forward showing deadline and the cure period
Forward Showing Seasons	The time between the procurement of capacity and the commencement of the commitment period.
Import Capacity	Capacity from a generating asset outside the NWPP footprint.
Import Transaction	The purchase of capacity from a generating asset outside the NWPP footprint. The asset's capacity contribution must be taken into consideration, along with transmission constraints.
Installed Capacity (ICAP)	A MW value based on the net dependable capability of a unit within the capacity interconnection right limits of the bus to which it is connected. Seasonal net dependable accounts for the impact of ambient weather conditions (Summer) on unit performance.
Independent Power Producer (IPP)	An entity, which is not a public utility, which owns generating resources for sale to utilities or end users.
Load Serving Entity (LSE)	Entities that secure energy and transmission service to serve the electrical demand and energy requirements of its end-use customers.
Loss of Load Expectation (LOLE)	Units of days/yr. – average number of days per year with loss of load (at least once during the day) due to system load exceeding available generating capacity.

Modeling Work Group (MWG)	A work group established by the Steering Committee in Phase 2A to establish a simplified mock-up of the program, providing a framework for understanding how program mechanics might work and enabling the Steering Committee to identify key design and methodology issues for further consideration in Phase 2BThe MWG also developed conceptual design criteria for the end-state RA program forward showing model.
Non-Coincident Peak	A market participant's individual project P50 peak demand.
Operational Program	Describes how capacity is shared, generally on a day-ahead basis, from participant with deficits to participants with surplus. This component will operate during the two binding seasons (Winter and Summer). The program allows participating entities to access pooled regional resources.
Operational Period	Period where entities deploy resources claimed in the forward showing period to meet capacity needs.
P50	An entity's peak load anticipated to occur one out of every two years or with 50% probability.
Peak Demand	The maximum amount of power used at a specific point in time, such as in the evening during very cold or very hot weather after people have arrived home and are using multiple power-consuming devices.
Peak Hourly Demand	Average peak demand over an hour.
Perfect Capacity	A resource with 100% availability at all times.
Planned Outages	Voluntary outages of resources included in RA portfolio.
Planning Reserve Margin (PRM)	Measured as a percentage above system peak load to ensure that there are adequate resources to meet forecasted load.

Project Management Organization (PMO)	The role of the PMO is to manage overall program scope, schedule, and budget of the project. It manages external support, reports regularly on project progress to the Steering Committee, provides support to the Executive Committee and EAC to ensure effective communications, and provides direction to Working Groups.
Program Administrator	The entity that operates and enforces the RA program.
Program Developer	The entity that assists the NWPP with the detailed design details in order to ensure compliance with regulatory requirements.
Reliability Standard	A line that separates adequacy from inadequacy for whatever reliability metric is being used. There is no single industry standard for RA; and utilities, state agencies, and regional transmission operators use a variety of different approaches to establish RA standards. Many standards are tied to the notion of avoiding loss of load more frequently than "one day in ten years."
Time Period	These range from month-ahead to four-years ahead in North American RA programs, though one-year ahead is a typical timeframe.
RAPDP	Resource Adequacy Program Development Project.
Reserves (Planning vs. Operating):	Within the electricity sector, the topic of "reserves" comes up in two contexts: planning and operations. "Planning reserves" refer to capacity resources procured by a utility, typically on a yearly or seasonal time scale, to ensure that enough resources will be available during the most constrained periods on the grid. In contrast, "operating reserves" typically refer to the various ancillary services that system operators hold in day-to-day operations.
Resource Adequacy (RA)	Electric power systems must continuously balance instantaneous supply and demand. However, neither supply nor demand are perfectly predictable. Thermal electric generators are sometimes unavailable due to either planned or forced outages. The outputs of

some renewable generators are subject to large variation due to the availability of sunlight or wind. Loads vary for reasons ranging from weather to behavioral factors. RA refers to having enough resources – generation, efficiency measures and demand-side resources – to serve loads across a wide range of conditions with a sufficient degree of reliability. The North America Electric Reliability Corporation (NERC) defines it as "the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.[12] In order to ensure supply always matches demand, electric system operators and planners rely on reserves. There are two principal types of reserves, shorter-term operating reserves and long-term planning reserves.

Resource Eligibility	Asset-specific details required to qualify an asset for the RA program.
Southwest Power Pool (SPP)	SPP is a regional transmission organization, that manages the electric grid and wholesale power market for the central United States. The SPP is nonprofit corporation mandated by FERC to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale electricity prices.
Thermal Resources	These are electricity producing power plants that rely on converting heat energy to electric power. In most cases the turbine is steam driven. Water is heated, turns into steam and spins a steam turbine which drives an electrical generator. The fuel for the heat is typically oil, natural gas or wood.
Unforced Capacity (UCAP)	Represents the percentage of ICAP available after a unit's forced outage rate is taken into account.

[12] 2018 Long-Term Reliability Assessment, North American Electric Reliability Corporation, December 2018, p. 5. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

Variable Energy Resources (VERs)

VERs are energy sources that are non-dispatchable due to their fluctuating nature, like wind power and solar power, as opposed to a controllable energy source such as hydropower, natural gas, coal, biomass, or geothermal power.