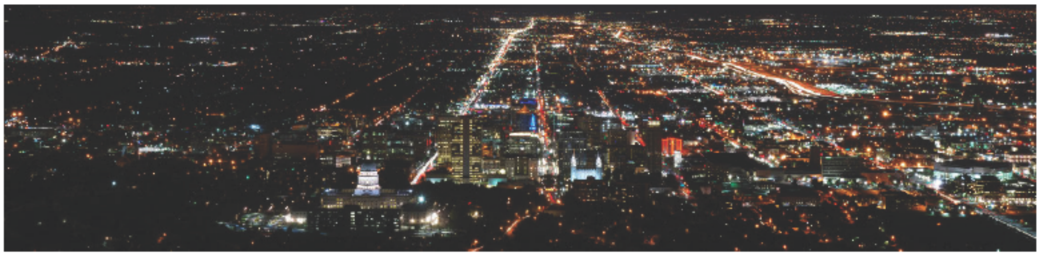
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC)	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-81:
"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

Calendar Contacts

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Exhibit 1-82:
NERC Rules of Procedure

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.

[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

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[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.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-83:
WECC Contingency Reserve Whitepaper

WECC-0142 BAL-002-WECC-3

Contingency Reserve

Request to Retire

WECC-0142 Drafting Team

01/21/2025

Executive Summary

This document supports and requests full retirement of WECC Regional Reliability Standard (RRS) BAL-002-WECC-3, Contingency Reserve.

In FERC Order No. 672, when considering approval of RRSs, FERC agreed to accept two kinds of regional differences: (1) a regional difference that is more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; and (2) an RRS that is necessitated by a physical difference in the Bulk-Power System.[1]

Order 672 also provides authority to retire an RRS.

Since the start of BAL-002-WECC-3 and its predecessors (2007), the original standard and each subsequent iteration have continued as more stringent than the continent-wide equivalent, NERC BAL-002-X, Disturbance Control Standard. Among other things, WECC's BAL-002-WECC has always required most WECC entities to hold more reserves than the continent-wide equivalent. Specifically, BAL-002-WECC-3, Requirement R1.1.1 requires the applicable entity to hold the greater of, either the amount of Contingency Reserve equal to the loss of the most severe single contingency or the amount of Contingency Reserve equal to the sum of 3% of hourly integrated load and 3% of hourly integrated generation.

Though Requirement R1.1.1 was approved in BAL-002-WECC-1, that approval was predicated on distributing burden and the availability of deliverability.[2] There has never been a technical study proving that holding reserves more than required under NERC BAL-002-X enhances the reliability of the Western Interconnection.

By contrast, as variable generation is added to the Interconnection, there is increasing evidence that holding excess reserves may be inhibiting reliability across the interconnection. FERC's recent Order 901 echoes these concerns, addressing operational and performance concerns for variable resources.

Restated, within the Western Interconnection, applicable entities are holding more reserves than the rest of the continent, even though there is no technical basis for doing so. In FERC Order 693, in which NERC BAL-002-1 was first approved, at P341, FERC states:

> 341. We believe a continent-wide contingency reserves policy would assure [sic] that there are adequate magnitude and frequency responsive contingency reserves in each Balancing

[1] Order No. 672 at P 331. See also FERC Order 740, P 4 and P 23. https://www.nerc.com/pa/Stand/Resources/Documents/FERC'S_Criteria_for_Approving_Reliability_Standards_from_Order_672.pdf

[2] FERC Order 740, Remand.

> Authority. This will improve performance so that no Balancing Authority will be doing *less than its fair share*." (Emphasis added.)

By extension, retiring BAL-002-WECC-3 in favor of NERC BAL-002-3, ensures that no Balancing Authority will be doing **more** than its fair share.

Further, requiring Balancing Authorities to hold that excess may be inhibiting the integration and use of variable generation. As a result, BAL-002-WECC-3 creates a mandated scenario in which reserves are used inefficiently and withheld from the marketplace.

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Introduction

Per the Standard Authorization Request (SAR) for WECC-0142,[3] this document explores the full retirement of WECC RRS BAL-002-WECC-3, Contingency Reserve.

The following will show that, if the standard is retired, reliability will continue to be maintained through NERC BAL-002-3, and may be enhanced as resources being held for contingency reserves may be used more efficiently to support variable generation.

By retiring BAL-002-WECC-3 in favor of NERC BAL-002-3:

- Dispatchable resources can be used to support variable generation, addressing issues raised by FERC in Order 901.
- A more efficient use of resources should negate any current negative impacts on the market, thereby enhancing vital public interests.

As the Procedural History and Development History sections note, BAL-002-WECC-3 is an evolution of pre-standards originating in the 1990s. Never during the estimated 30 years of its existence has there been a technical justification for the values and procedures required in the standard. Rather, the stated values and procedures are the result of generalized negotiations taking place between the parties. Because these values and procedures are negotiated, the content of BAL-002-WECC-3 is the lowest common denominator and does not meet the requirements of FERC Order 672.[4]

Because BAL-002-WECC-2a, Contingency Reserve, Request to Retire Requirement R2 provided the technical support for retiring Requirement R2, arguments in that filing are not revisited here.[5]

[3] See WECC-0142 BAL-002-WECC-3, Contingency Reserve, Request to Retire, home page, at the SAR accordion.
[4] FERC Order 672, P329 and P330.
[5] Approved by the NERC Board of Trustees on August 15, 2019, filed with FERC on September 9, 2019.

Standard of Review

While the Commission may approve an RRS that is more stringent than a parallel continent-wide standard, the Commission may also retire such a standard.[6]

> "While a Regional Entity may propose regional Reliability Standards that address specific, unique regional conditions and circumstances, *such regional Reliability Standards can be retired if those justifications are no longer relevant.* Accordingly, the Commission may approve retirement of a more stringent regional requirement "if the Regional Entity demonstrates that the continent-wide Reliability Standard is sufficient to ensure the reliability of that region."[7] (Emphasis added.)

In doing so, the Commission must give due weight to the technical expertise of a Regional Entity, like WECC, that is organized on an interconnection-wide basis with respect to the regional differences applicable to the Western Interconnection.

The technical qualifications of the subject matter experts compiling this paper are provided with this filing, as presented and approved by the WECC Standards Committee (WSC).

[6] The Commission approves regional differences proposed by Regional Entities, such as Regional Reliability Standards and Variances, if the regional difference is just, reasonable, not unduly discriminatory or preferential, and in the public interest. 16 U.S.C. § 824o(d)(2) and 18 C.F.R. § 39.5(a). (See also) Additionally, Commission Order No. 672 requires further criteria for regional differences. A regional difference from a continent-wide Reliability Standard must either be:
(1) more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; or is,
(2) necessitated by a physical difference in the Bulk-Power System.

[7] Version One Regional Reliability Standard for Resource and Demand Balancing,
Order No. 740, 75 FR 65964 (Oct. 27, 2010), 133 FERC ¶ 61,063, P 30 (2010). See also: FERC, 18 CFR Part 40, Docket No. RM19-20-000, WECC Regional Reliability Standard BAL-002-WECC-3 (Contingency Reserve), p.5

Procedural History

In 1996, the Western Systems Coordinating Council (WSCC)[8] adopted the WSCC Reliability Criteria, Minimum Operating Reliability Criteria (MORC). The MORC prescribed levels of reserves that became BAL-002-WECC-3, effective 2021.

In 1999, the MORC became the WECC Reliability Management System (RMS), a contract-based system of accountability that pre-dated mandatory standards.

As the industry approached the onset of mandatory standards (2007) and memorialization of legacy operating practices, the content of the RMS was adapted and approved as BAL-STD-002-0, Operating Reserves (2007). That standard was an attempt to translate the substantive content of the RMS into the sought-after NERC/FERC format of today's reliability standards. The *content* was accepted "as is" with its origins in the 1996 MORC; albeit, the early standard was remanded for remediation, largely on *format* and structural grounds.

In 2013, FERC accepted remediations to BAL-002-WECC-2.

In 2017, an interpretation was added (BAL-002-WECC-2a) and later incorporated into BAL-002-WECC-3, in which Requirement R2 was approved for retirement, with an effective date of August 15, 2019.

In 2025, the Western Interconnection still adheres to similar levels of reserves as it did in 1996. This means that, for over 28 years, the Western Interconnection has held more reserves than the rest of the continent (NERC BAL-002-3) even though there has never been technical justification to do so.

[8] The Western Systems Coordinating Council (WSCC) was formed in 1967 by 40 power systems to coordinate the planning and operations of the electric system in western North America. The WSCC's goal was to provide reliable power to the public.

Development History (Before 1996 to 2024)

Before 1996, members of the WSCC voluntarily operated the Western Interconnection according to the MORC.[9] Although the MORC contained provisions for generation control, generation performance, and Contingency Reserve, the MORC provided no technical support for the reserve thresholds and characteristics it set.[10] Rather, the operating thresholds were established by negotiation—not technical analysis. If this approach were adopted today, FERC would likely deny approval of the standard as contrary to FERC Order 672, P329.[11]

In July and August of 1996, the Western Interconnection experienced two widespread outages resulting from improper vegetation management. The resulting outage reports[12] [13] made several recommendations that would later be adopted in the 1999 WECC RMS.[14] [15] The WECC Operating Committee's recommendation produced portions of the RMS that later evolved into WECC Standard BAL-STD-002-0, Operating Reserves and, ultimately, BAL-002-WECC-3. Like the other initial

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[9] MORC, Maintenance Coordination: 1. Sharing information. The security and reliability of the interconnected power system depends upon periodic inspection and adequate maintenance of generators, transmission lines and associated equipment, control equipment, communication equipment, relaying equipment, and other system facilities. Entities and coordinated groups of entities must establish procedures and responsibility for disseminating information on scheduled outages and for coordinating scheduled outages of major facilities which affect the security and reliability of the interconnected power system.

[10] Minimum Operating Reliability Criterion, Section 1, Generation Control and Performance

[11] FERC Order 672. P329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice—the so-called "lowest common denominator"—if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

[12] The outage reports are available upon request. Western Systems Coordinating Council (WSCC) Disturbance Report for the Power System Outage that Occurred on the Western Interconnection August 10, 1996, as approved by the WSCC Operations Committee on October 18, 1996

[13] "f. The WSCC Operations Committee shall assess whether the levels and allocation of operating reserves contributed to the severity of this disturbance and implement corrective measures as appropriate." Western System Coordinating Council Disturbance Report, For the Power System Outages that Occurred on the Western Interconnection on 2 JUL 1996. Approved by the WSCC Operations Committee on September 19, 1996. RMS Outage Report, page 14.

[14] The RMS was approved 1 SEP 1999. WECC Comment Report – WECC Tier 1- RMS Standard – (BAL-STD-002-0) Question 4, Attachment 2, page 9.

[15] "The majority of these standards were specifically developed to address and mitigate main causes of the two major system outages that occurred in the Western Interconnection in July and August of 1996." Agenda Item 3, Board of Trustees Meeting, March 12, 2007, page 4

standards, the language of the original standard was a translation of the language contained in the RMS.[16]

In March 1997, noting that federal remedial legislation could take years to enact, the WSCC trustees created the WSCC RMS Policy Group[17] establishing a contract-based operational system known as the RMS.[18] [19] In establishing the RMS, the WSCC RMS Policy Group reviewed all NERC and WECC reliability criteria, identified specific criteria deemed critical for reliability management, then moved those criteria into the RMS through a three-phase implementation plan.[20]

On April 14, 1999, FERC asserted jurisdiction over the RMS.

Between September 1998 and February 2000 (phase two of the three-phase RMS implementation), the WSCC turned the content of the RMS into the first mandatory reliability standards (aka Version Zero, 2007). BAL-SDT-002-0, Contingency Reserve was part of that translation.

On December 22, 2006, WECC submitted a request to NERC to approve, and send to FERC for approval, eight proposed RRSs. WECC referred to the eight proposed standards as its Tier One

[16] WECC states that the proposed regional Reliability Standards, which are exact translations of existing regional criteria, either address matters not addressed in the Commission-approved ERO Reliability Standards or contain more stringent requirements than the ERO standards. (FERC accepted Tier One standards evolving from the RMS. AKA: Tier One Order.) FERC, 119 FERC ¶ 61,260 United States of America, Federal Energy Regulatory Commission, Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications (Issued June 8, 2007), page 19.

[17] Following the enactment of EPAct 2005 and the establishment of mandatory Reliability Standards applicable to all owners, operators, and users of the BPS, WECC sought to translate certain of its existing practices under its RMS reliability criteria into regional Reliability Standards to supplement the continent-wide Reliability Standards the Commission approved in Order No. 693. To that end, WECC established a task force to identify criteria in the RMS that should be binding on all BPS users, owners, and operators in the Western Interconnection, not just the Transmission Operators subject to the RMS. The task force chose eight of the identified criteria, which had the highest priority and could be implemented in the near term for translation into regional Reliability Standards. United States of America Before the Federal Energy Regulatory Commission, North American Electric Reliability Corporation (NERC), Docket No. RM16-10-000, Supplemental Information for Petition of the NERC and WECC for Approval of retirement of Regional Reliability Standard TOP-007-WECC-1a, page 5.

[18] Hearing

[19] Electric Reliability Corporation, Helping Owners, Operators, and Users of the Bulk Power System Assure Reliability and Security for More Than 50 Years, By David Nevius, Senior Vice President 1979–2012, Page 40-41.

[20] Hearing

standards originating from the RMS because the proposed standards were translations of standards that were already mandatory within the Western Interconnection as part of the RMS.[21]

Those eight standards—that included Tier One WECC-BAL-STD-002-0 (Operating Reserves)—were near-exact translations of existing WECC criteria that FERC earlier accepted as part of the WECC RMS program.[22] Because the content was a near-exact translation, the format did not match that required by NERC/FERC. This would later lead to a remand of BAL-002-WECC-1 to ensure conformity.

On January 9, 2007, NERC provided WECC with a report of its preliminary findings about the request from December 22, 2006, and provided WECC with a list of required remediations.[23] The request largely addressed styles, formats, and corrections to compliance sections. The NERC Board of Trustees approved the Tier One request subject to remediation and sent the eight proposed standards to FERC with a request for approval.

In June 2007, FERC approved WECC's submittal of eight reliability-crucial Tier One standards, thereby transitioning from the RMS system to that of FERC-approved NERC Reliability Standards.[24] Although earlier versions lacked technical support, FERC agreed with

> "WECC, WIRAB [Western Interconnection Regional Advisory Board] and NERC that approval of [WECC's early BAL] under section 215 would enhance reliability in the Western Interconnection **by making WECC's current practices binding** on all relevant entities in the region and **by strengthening WECC's compliance and enforcement authority.**"[25]

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[21] North American Electric Reliability Corporation, Docket No. RR07-___-000, III. BACKGROUND ON THE DEVELOPMENT OF THE WECC REGIONAL RELIABILITY STANDARDS, Debra A. Palmer of Schiff/Hardin (1666 K STREET N.W., SUITE 300, WASHINGTON, DC 20006) on March 26, 2007.

[22] Loc. Cit. IV. Overview of the Proposed WECC Regional Reliability Standards, page 6.

[23] NERC DECISION APPROVING, WITH CONDITIONS, RELIABILITY STANDARDS PROPOSED BY WESTERN ELECTRICITY COORDINATING COUNCIL, page 2. (Approved by Board of Trustees March 12, 2007)

[24] FERC Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications, Docket No. RR07-11-000, (Issued June 8, 2007)

[25] Tier One Order, p. 43. See also, "The proposed regional Reliability Standards would make eight of those RMS criteria binding on the applicable subset of users, owners and operators of the Bulk-Power System in the United States portion of the Western Interconnection, as identified in each proposed standard. The regional Reliability Standards would supplement rather than replace the Commission-approved Reliability Standards developed by the ERO that will take effect in June 2007. Tier One, p. 10.

Structural Overview of BAL-002-WECC-3

Purpose

The Purpose of currently effective RRS BAL-002-WECC-3—Contingency Reserve is to provide an RRS specifying "the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions."[26]

The NERC Glossary defines Contingency Reserve as:

"The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert level and is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan."

Applicability

BAL-002-WECC-3 applies to Balancing Authorities (BA), unless the BA is a member of a Reserve Sharing Group (RSG), in which case the RSG becomes the applicable entity.

Requirements

The standard consists of four requirements.

Requirement R1

- Provides that each BA and RSG must maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserves, and that the Contingency Reserve must consist of any combination of a list of specified reserve types.

Requirement R2

- Reserved. Retired, subject to cyclical field tests.

[26] BAL-002-WECC-3, Contingency Reserve, Purpose.

Requirement R3

- Each Sink BA and RSG must maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Requirement R4

- Each Source BA and RSG must maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve amounts identified in Requirement R1, equal to the amount and type of Operating Reserves for any Operating Reserve transactions for which it is the Source BA or RSG.

Reliability will be Maintained

Upon retirement of BAL-002-WECC-3, reliability will be maintained by NERC BAL-002-3, Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event, reinforced by the enhanced availability of resources currently unavailable under BAL-002-WECC-3.

Replacing BAL-002-WECC-3 with NERC BAL-002-3 Mitigates Reliability Gaps associated with Variable Generation

As highlighted by FERC in its Order 901, with the growing amount of variable generation replacing more responsive and dispatchable resources, the industry faces the dilemma of how to support these new resources.[27] Unlike traditional resources, much of the new variable generation cannot be quickly dispatched, thus creating a gap in reliability. FERC acknowledged that gap, noting that neither business as usual nor existing reliability standards will remedy this concern. Finally, FERC also recognizes the value that steps taken must apply on a continent-wide basis.[28]

Replacing BAL-002-WECC-3 with the continent-wide NERC BAL-002-3 takes immediate steps towards meeting FERC's concerns.

In Order 901, FERC states:

> "[W]e continue to find that as the resource mix trends towards higher penetrations of IBRs, the need to reliably integrate these resources into the Bulk-Power System is expected to grow, and that the currently effective Reliability Standards do not adequately address IBR reliability risks. *The continuing risks that the increasing penetration of IBRs pose to the reliable operation of the Bulk-Power System underscore the need for mandatory Reliability Standards to address these issues on a nationwide basis.*" (Emphasis added.) Order 901, P24.

When BAL-002-WECC-3 is retired and replaced with NERC BAL-002-3, the amount and type of reserves required to be held back within the Western Interconnection will decrease. That frees those resources to be plied against load. Within the Western Interconnection, a vast majority of these sequestered resources are immediately dispatchable (such as hydro), thus serving as the perfect resource to match the less predictable response of variable generation.

[27] FERC Order 901, P11-15, 185 FERC ¶ 61,042, United States of America, Federal Energy Regulatory Commission (FERC), 18 CFR Part 40, Docket No. RM22-12-000; Reliability Standards to Address Inverter-Based Resources, October 19, 2023. Hereafter: Order 901

[28] Order 901, P24.

By making these dispatchable resources more operationally available, the secondary benefits may be to bolster the supply of generation to the market. This potential secondary benefit directly addresses vital public interests.[29]

Dispatchable Resources Contribute Significantly to Essential Reliability Services (ERS) [30]

ERSs consist of frequency control, ramping capability, and voltage control.

Frequency control is necessary because the electric grid is designed to operate at a frequency of 60 hertz (Hz). Deviations from 60 Hz can have destructive effects on generators, motors, and equipment of all sizes and types. It is critical to maintain and restore frequency after a disturbance such as the loss of generation. This requires an instantaneous (inertial) response from some resources and a fast response from other resources to slow the rate of fall during the arresting period, a fast increase in power output during the rebound period to stabilize the frequency, and a more prolonged contribution of additional power to compensate for lost resources and bring system frequency back to the normal level. Two NERC Reliability Standards address this:

- BAL-002-3 Disturbance Control Standard—Contingency Reserve from a Balancing Contingency Event
- BAL-003-2 Frequency Response and Frequency Bias Setting

Adequate ramping capability (the ability to match load and generation at all times) is necessary to maintain system frequency. Changes to the generation mix or the system operator's ability to adjust resource output can impact the ability of the operator to keep the system in balance. NERC Reliability Standard BAL-001-2 (Real Power Balancing Control Performance) addresses this issue.

Voltage must be controlled to protect system reliability and move power where it is needed in both normal operations and following a disturbance. Voltage issues tend to be local in nature, such as in sub-areas of the transmission and distribution systems. Reactive power is needed to keep electricity flowing and maintain necessary voltage levels. Several NERC Reliability Standards address voltage control.

Restated, replacing BAL-002-WECC-3 with NERC BAL-002-3 frees dispatchable resources to address FERC-identified reliability gaps created by variable generation, and may bolster vital public interests.

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[29] "335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social, and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard. " (Emphasis added.) Order 693, P35.

[30] "Essential Reliability Services (ERS) are the elemental 'reliability building blocks' from resources (generation and demand) necessary to maintain Bulk Power System (BPS) reliability." NERC ERS Task Force – Scope – 2014.

Because adequate levels of reserves are established in NERC BAL-002-3, and supported by BAL-003-2, BAL-002-WECC-3, Requirements R1 through R4 are not needed.

Replacing BAL-002-WECC-3 With NERC BAL-002-3 Provides Sufficient Reserves at a Continent-Wide Level

In the earliest stages of the Western Interconnection's strides to establish adequate Contingency Reserves, the applicable entity's reserves were established by BAL-STD-002-0, Operating Reserves, at 5% of hydro generation and 7% thermal generation (50% spinning and 50% non-spinning).[31] These thresholds were not technically supported; they were the result of contractual negotiations. Today, such a standard would likely not be approved by FERC as violative of the principles established in FERC Order 672. (See foot note 2.)

As BAL-STD-0-2 was replaced with later iterations of that standard, the result was today's BAL-002-WECC-3, in which the Responsible Entity's reserves are set at:

R1.1.1 "The greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;[32] (or)
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation."

Bullet one of BAL-002-WECC-3 describes the Most Severe Single Contingency, or MSSC.

The MSSC ensures that all entities can recover Area Control Error (ACE) within 15 minutes. The MSSC serves as the upper Contingency Reserve threshold for all interconnections, except the Western Interconnection. Within the Western Interconnection, the levels of reserve set by BAL-002-WECC-3 can exceed that of the rest of the continent that is protected by FERC-approved BAL-002-3. As a result, the Western Interconnection carries an excess of reserve that exacerbates concerns raised by FERC in Order 901 wherein FERC addresses the need for continent-wide standards to backstop the operational performance of variable generation. Comparing NERC BAL-002-3 with BAL-002-WECC-3 illustrates this outcome.

NERC BAL-002-3 states that the BA and the RSG are not subject to compliance with BAL-002-3, R1 for multiple events that exceed the MSSC. NERC BAL-002-3 requires the applicable entity to deploy Contingency Reserve *up to its MSSC*; however, it does not require Contingency Reserve deployment *beyond MSSC.*

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[31] See Attachment - Transition from 5-7 to 3-3, as described in 2005 by Merrill Schultz; see also Attachment - History of WECC Reserve 5-7 Spin Merrill Schultz, March 3, 2005; see also BAL-STD-002-0, Operating Reserves.
[32] Also known as the Most Severe Single Contingency (MSSC).

By contrast, BAL-002-WECC-3 requires the applicable entity to maintain a level of Contingency Reserves *exceeding that required under NERC BAL-002-3*, as approved by FERC. Specifically, BAL-002-WECC-3, Requirement R1 requires the applicable entity to carry reserves that equal or exceed the entity's MSSC—beyond that required by BAL-002-3 that adequately serves the balance of the continent. Among other things, this means these valuable dispatchable resources in excess of the MSSC cannot be used to meet FERC's goal of backstopping variable resources as identified in FERC Order 901.

While the application of BAL-002-3 could free resources to enhance reliability, the application of BAL-002-WECC-3 can inhibit reliability when resources are withheld that could otherwise serve load and backstop variable resources.

For example:

Using historical data from January 2020 - May 2024, comparison of the hourly Contingency Reserve Requirement (calculated using 3% generation and 3% load) to the Most Severe Single Contingency (MSSC), the results identified there was more than 5,000 MW of capacity available during the summertime peak hours and between 2,000-2,500 MW during the remaining hours of the year. See figure below.

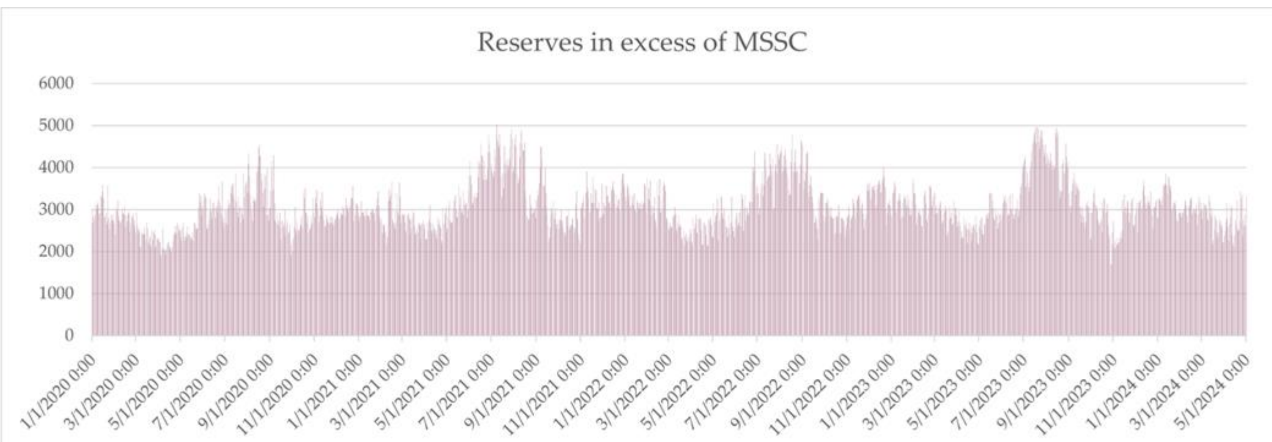


Figure 1: Reserves in excess of MSSC

The Shortened Execution Time of BAL-002-WECC-3 Inhibits Reliability Due to Market Rules in the Western Interconnection

BAL-002-WECC-3, Requirements R3 and R4 require the applicable entity to restore Contingency Reserve within 60 minutes of the initiating event. By contrast, BAL-002-3 requires the applicable entity to achieve the same task in 105 minutes. As a result, BAL-002-WECC-3 requires the performance of the same task 45 minutes earlier than its continent-wide counterpart. This shortened period inhibits reliability in that it forces the applicable entities into transactions agreed upon during an arbitrarily shortened time window. Like BAL-002-3, Requirement R1., there is no technical support suggesting that rushing this transaction enhances reliability—yet it remains in force 28 years after its inception, still lacking any technical support.

Further, the restoration of reserves in a 60-minute timeframe is restrictive on the entity's ability to secure additional resources within the established business practices in the region. The NERC Standard of up to 105 minutes (90 minutes after the 15 minutes Contingency Recovery Period) after the event has less commercial impact and is acceptable from both a commercial standpoint as well as an operational standpoint.

The WECC requirement of 60 minutes from start of a DCS event restricts the deficient entity from rescheduling resources to replace those that were lost during the event. Western market practices require schedules to be submitted and approved well in advance to ensure reliability, and once the schedule windows close, it is difficult to make last-minute changes. Before markets, when transactions were bilateral, a recovery of generation resources was more flexible, and could be more quickly executed.

The NERC BAL-002-3 Contingency Reserve Restoration Period of up to 105 minutes allows applicable entities to use normal market scheduling practices to replace lost generation. FERC's approval of NERC BAL-002-3 shows its belief that the NERC standard of 105 minutes (90 plus 15) is adequate and does not degrade reliability.

In attempting to meet the 60-minute restoration requirement, the applicable entity has two options.

First, the BA must carry significantly more Contingency Reserve than is required to maintain an adequate level of reliability, or second, be prepared to enter an Energy Emergency Alert 3 which allows the BA to deploy Contingency Reserves to serve load. By definition, entering into an Energy Emergency Alert is an indication of reduced reliability. Given normal scheduling practices, a 90-minute restoration time allows a Responsible Entity to restore Contingency Reserve using normal established market scheduling practices.

In addition, many entities own BES equipment in more than one interconnection. Having a single standard enhances these entities' ability to stay in compliance with the standard using consistent business practices across the interconnections.

Reserve Thresholds do Not Reflect Resource Mix

Due to the changing resource mix and the proliferation of renewable generation, battery storage, and retirements of conventional synchronous generation, resource adequacy has become a serious concern. The BAL-002-WECC standard unnecessarily ties up significant generation which is dispatchable, frequency responsive and fast ramping. Generation that could be used to meet ramps, follow variable resources, or simply meet expected loads, is committed to contingency reserve capacity that is not available to serve load. For example, Western Power Pool's Northwest Power Pool Reserve Sharing Group Northwest-Montana zone typically has a 1,200 MW MSSC, yet routinely has over 3,000 MW of reserves being held under the 3/3 requirement. That available capacity, usually in excess 1,800 MW, could be used to meet other reliability related services obligations. The existing 3/3 contingency reserve requirement results in the construction of at least 1800 MW of excess generation in the Northwest-Montana zone. The ability to use this generation capacity exceeding the MSSC will also allow entities to efficiently operate their facilities. Idled excess capacity will be reduced and productive generation increased.

Under NERC standard NERC BAL-002-3, the Eastern, Texas and Quebec Interconnections operate without the additional reserve requirement (3% load and 3% generation), and they are allowed to restore their reserves within 90 minutes. The changing market structure in the Western Interconnection has made it difficult to fully restore the required reserves within 60 minutes due to market scheduling timelines. This can lead to implementation of emergency procedures, typically Energy Emergency Alert 3 conditions, due to an energy shortfall precipitated by the 60-minute recovery period. When the Western markets were mostly bilateral, the 60-minute recovery was consistent with energy scheduling protocols. Market integration has altered energy scheduling protocols making it very difficult to modify schedules within 60 minutes of a generation contingency. For these reasons BAL-002-WECC-3 has become obsolete, while not enhancing reliability.

Reserves are unused or unloaded generation that are in a state of readiness in case there is sudden loss of loaded generation. When reserves are held above the MSSC, as they are in the Western Interconnection, excess capacity must be built that has no other reliability benefit. Every energy customer in the West absorbs this excess cost. Retirement of BAL-002-WECC-3 reallocates these excess resources to the benefit of the interconnection in the form of dispatchable, responsive, and available resources to reliably integrate future variable resources, such as wind, solar, and other renewable resources.

Vital Public Interests will be Enhanced[33] [34]

Market Timing Issues

The emergence of organized markets in WECC, since the inception of BAL-002-WECC-1 has brought a new dynamic in the timing and means by which the reserves are procured. The number of participants in the California ISO Energy Imbalance Market (AKA: Western Energy Imbalance Market, or WEIM)

[33] "Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social, and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard." FERC Order No. 672 at P 335.

[34] "The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently." FERC Order No. 672 at P 328.

has grown significantly in the past several years. CAISO EIM market rules require a participating BA to balance its resources and loads 75 minutes before the next operating hour (T-75). Failure to do this can result in financial penalties to the participating BA. This rule has had the effect of discouraging any bilateral energy trading after T-75 and does not align well with a 60-minute reserve recovery time limit. No bilateral trading for replacement energy reserve is possible for the next operational hour because participating WEIM BAs cannot participate in trades within T-75.

This leaves the contingent BA in a resource short position when the 60-minute contingency restoration time expires. At this point, the contingent BA must activate emergency operating procedures up to asking the Reliability Coordinator to declare an EEA3, including load shedding to balance the contingent BA. By extending the contingency restoration time to 105 minutes (15-minute recovery plus 90-minute restoration), the contingent BA has at least 30 minutes to arrange replacement energy in a bilateral manner from other BAs or schedule their own resource in the WEIM. The additional contingency reserve recovery time allows the contingent BA to make orderly and planned adjustments and continue to serve firm load without the implementation of emergency operating procedures, up to and including shedding firm load.

FERC and the industry have determined that 90 minutes from the end of the recovery period (up to 15 minutes) is sufficient to maintain an adequate level of reliability. The shorter restoration period in the WECC creates artificial reliability issues as the applicable entity tries to rebalance supply and demand in an arbitrarily shorter period than that required in the NERC BAL-002-3.

To give a clear understanding of the impact of either option, the following example is provided.

Assume the NWPP RSG's MSSC is approximately 1,200 MW. Under BAL-002-WECC-3, the NWPP RSG would normally carry approximately 2,200-4,000 MW of Contingency Reserves depending on the time of year. Assuming the MSSC occurs, the NWPP RSG would activate 1,200 MW of its reserves and restore the ACE to the pre-event level. Members now have approximately 60 minutes to restore 1,200 MW of reserves while still carrying more than 1,000–2,800 MW, which is greater than the MSSC, assuming it was not reduced with the loss of the 1,180 MW event. See figure below.

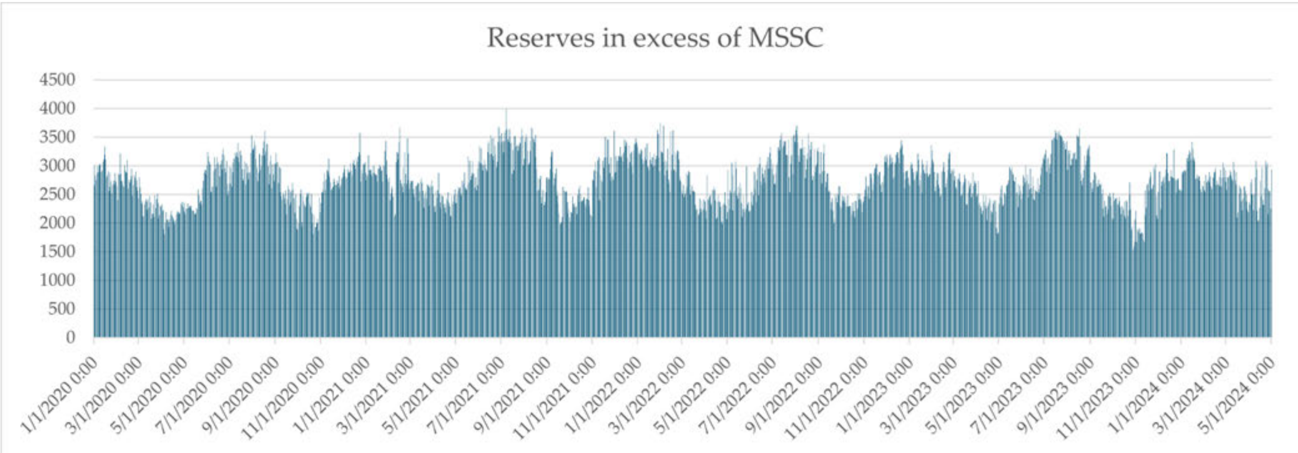


Figure 2: Reserves in excess of MSSC; January 1, 2020, through May 1, 2024

As discussed earlier, due to market rules related to the WEIM in which most entities are taking part, new resources cannot be added to an entity's reserves for the next hour (minimum time to add a resource under the WEIM (75 minutes), or other emerging markets. If a resource is not already in the WEIM, it cannot count toward the reserves needed. So, an entity must have already been carrying reserves greater than required under the WECC standard, or it must reduce load to balance its resources and loads including reserves. (It can be argued that by reducing loads, you are putting the interconnection at greater risk because you have removed one available resource, the load, from being an option for the next event.) To avoid the declaration of an EEA, the NWPP would need to carry an additional 1,000 MW above the required reserves or declare an EEA any time the reserves need to be restored within 60 minutes of the event.

When entities withhold extra reserves to avoid the EEA, this paradigm keeps 2,500 to 4,000 MW from serving load due to the WECC current standard, which has no technical merit, as compared to the NERC Standard. These additional resources could be used to help integrate more inverter-based resources and serve loads more efficiently if it were available for load service.

Entering an Energy Emergency Alert indicates reduced reliability. Given normal scheduling practices, which require bilateral schedules to be completed and approved 75 minutes before the hour, a 60-minute restoration time does not allow adequate time for a Responsible Entity to restore Contingency Reserve in less than 60 minutes from the initiating event, potentially resulting in an Energy Emergency Alert situation.

Capacity Could be Better Used than Simply Holding Reserve

FERC and the industry have determined that the amount of Contingency Reserve needed to maintain an adequate level of reliability is the amount of Contingency Reserve needed to replace the MSSC resource. Holding Contingency Reserve more than MSSC precludes using operating reserve for other purposes, particularly load and resource balancing in real-time. As the grid transitions from conventional synchronous generation to more variable renewable resources, increasing capacity will be needed to manage the variability and faster ramping requirement of these resources. Allocating reserves in excess of that needed to maintain an adequate level of reliability, or MSSC, ultimately detracts from reliability.

Conclusion

Retirement of BAL-002-WECC-3 Contingency Reserve would reduce required reserves in WECC without diminishing the ability to meet the deployment requirement. Freeing up reserves from the Contingency Reserve requirement would increase the resources available to manage variable resources and accommodate increased renewable resource integration.

The existing BAL-002-WECC-3 Contingency Reserve sets a BA's or RSG's Contingency Reserve requirement to the greater of the MSSC or 3% of the applicable entity's generation and 3% of its load. This 3/3 requirement exceeds MSSC for most responsible entities.

By contrast, NERC Standard BAL-002-3 Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event, Requirement R1.3.2 states that the BA/RSG is not subject to compliance with Requirement R1 for multiple events that exceed the MSSC. NERC BAL-002-3 requires the applicable entity to deploy Contingency Reserve up to the MSSC but does not require Contingency Reserve deployment beyond the MSSC.

In BAL-002-3, FERC and the industry have determined that the amount of Contingency Reserve needed to maintain an adequate level of reliability is the amount of Contingency Reserve needed to replace the MSSC resource.

Holding Contingency Reserve more than MSSC precludes using operating reserve for other purposes, particularly load and resource balancing in real time. As the grid transitions from conventional synchronous generation to more variable renewable resources, increasing capacity will be needed to manage the variability and faster ramping requirement of these resources. Allocating reserve in excess of that needed to maintain an adequate level of reliability, or MSSC, ultimately detracts from reliability.

BAL-002-WECC-3 requires an applicable entity to restore Contingency Reserve within 60 minutes of the initiating event (as opposed to up to 105 minutes in BAL-002-3), or 45 minutes sooner than required by BAL-002-3. With respect to impacts to the time to restore Contingency Reserve, FERC and the industry have determined that 90 minutes from the end of the recovery period (up to 15 minutes) is sufficient to maintain an adequate level of reliability. By contrast, the 60-minute requirement within BAL-002-WECC-3 creates potential reliability issues as an applicable entity tries to rebalance in an arbitrarily shorter period than that required in the NERC BAL-002-3. In attempting to meet the 60-minute restoration requirement, an applicable entity has two options. First, the BA must carry significantly more Contingency Reserve than is required to maintain an adequate level of reliability, or second, be prepared to enter an Energy Emergency Alert 3 and deploy Contingency Reserve to serve load. Given normal scheduling practices, a 90-minute restoration time allows an applicable entity to restore Contingency Reserve without employing emergency procedures.

Retirement of BAL-002-WECC-3 will enhance the reliable operation of the Western Interconnection by allowing resources that are presently used for overprotecting above the MSSC to be available to meet the immediate balancing needs of the Interconnection. This will free those resources to be used as needed in a rapidly changing system to maintain overall reliability.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-84:
WECC Risk Factor Criteria

WECC Risk Factor Criteria for Inherent Risk Assessment Effective March 22, 2021				
	Criteria for Assessment			
Risk Factor	**N/A**	**Low Risk**	**Medium Risk**	**High Risk**
CIP - Impact Rating Criteria	Entity has no BES Cyber Systems (BCS)	Entity has one or more low impact BCS(s)	Entity has one or more medium impact BCS(s)	Entity has one or more high impact BCS(s)
ICCP Connectivity	Entity has no BES Cyber Systems (BCS)	Entity has low impact BCS(s) without ICCP connections or external routable connectivity	Entity has low impact BCS(s) with at least one ICCP connection - or - Entity has low impact BCS(s) with external routable connectivity (LERC) - or - Entity has medium impact BCSs	Entity has medium impact BCS(s) with at least one ICCP connection - or - Entity has high impact BCS(s)
Load	Entity does not have any system load	Entity's system load is less than 300 MW	Entity's system load is between 300 - 2,000 MW	Entity's system load is greater than 2,000 MW
Transmission Portfolio	Entity does not own, operate, coordinate, plan, design, or monitor the status of transmission facilities	Entity has transmission facilities less than 200kV	Entity has transmission facilities between 200 - 300 kV - or - Entity has over 1,000 miles of transmission lines 100 kV or greater	Entity has transmission facilities greater than 300 kV - or - Entity has over 4,000 miles of transmission lines 200 kV or greater
Critical Transmission	Entity does not own, operate, coordinate, plan, design, or monitor the status of transmission facilities	Entity's system is not critical to adjacent entities as it is not being used as a flow through system for power flow	Entity's system is critical to adjacent entities as it is being used as a flow through system for power flow	Entity's system includes elements (owned or operated) of an IROL / Flowgate / Major Transmission Path (WECC) / Generic Transmission Limit (Texas RE) / Cranking Path
Voltage Control	Entity does not own or operate any voltage control equipment	----------	Entity owns and/or operates reactive resources to provide voltage control	Entity owns and/or operates reactive resources other than generators to provide voltage control
Largest Generator Facility	Entity does not own any generation facilities	Entity's largest single generation facility is less than 500 MVA	Entity's largest single generation facility is between 500 - 1,000 MVA	Entity's largest single generation facility is greater than 1,000 MVA

Total Generation Capacity	Entity does not own or operate any generation facilities	Entity's total generation nameplate capacity is less than 1,000 MVA	Entity's total generation nameplate capacity is between 1,000 - 5,000 MVA	Entity's total generation nameplate capacity is greater than 5,000 MVA
Variable Generation	Entity does not meet any of the identified criteria	Less than 10% of the entity's BA Area total generation nameplate MVA is comprised of non-dispatchable generation	10% - 25% of the entity's BA Area total generation nameplate MVA is comprised of non-dispatchable generation	Over 25% of the entity's BA Area total generation nameplate MVA is comprised of non-dispatchable generation
Balancing Authority (BA) Coordination	Entity does not meet any of the identified criteria	Entity's BA Area has less than 5,000 MW of generation capacity	Entity's BA Area has between 5,000 - 10,000 MW of generation capacity	Entity's BA Area has greater than 10,000 MW of generation capacity - or - Entity's BA Area has greater than 5,000 MW of generation capacity and its Generation to Peak Load ratio is more than 1.2
Planned Facilities	Entity does not meet any of the identified criteria	Entity is planning on or currently building transmission facilities less than 200 kV in the next three years - or - Entity is planning on or currently building generation facilities that are less than 500 MVA in the next three years	Entity is planning on or currently building transmission facilities between 200 - 300 kV in the next three years - or - Entity is planning on or currently building generation facilities that are between 500 and 1,000 MVA in the next three years	Entity is planning on or currently building transmission facilities greater than 300 kV in the next three years - or - Entity is planning on or currently building generation facilities greater than 1,000 MVA in the next three years
RAS/SPS	Entity does not own, operate, coordinate, plan, design, or monitor the status of a RAS/SPS	----------	Entity owns or designed a RAS/SPS that is not needed to meet TPL requirements - or - Entity owns or operates equipment that is part of a RAS/SPS that is not needed to meet TPL requirements	Entity owns or designed a RAS/SPS that is needed to meet TPL requirements - or - Entity owns or operates equipment that is part of a RAS/SPS that is needed to meet TPL requirements

Workforce Capability	Entity does not meet any of the identified criteria	Less than 25% of the entity's System Operators have less than 5 years of System Operator experience	Between 25 - 50% of the entity's System Operators have less than 5 years of System Operator experience	Greater than 50% of the entity's System Operators have less than 5 years of System Operator experience
System Restoration	Entity has no responsibilities during system restoration	Entity has regional or company system restoration responsibilities limited to load restoration	Entity has Blackstart Resource(s) - or - Entity provides switching or other logistics based on the direction from a different entity responsible for the restoration plan	Entity is an RC - or - Entity is responsible for independent actions coordinated with an RC
UFLS Equipment	Entity does not own or operate UFLS equipment	Entity is responsible for 0% up to 0.3% of the entire regionally identified UFLS program	Entity is responsible for 0.3% to 1.3% of the entire regionally identified UFLS program	Entity is responsible for more than 1.3% of the entire regionally identified UFLS program
UFLS Development and Coordination	Entity is not responsible for developing or coordinating a UFLS program	Entity is responsible for developing and/or coordinating a UFLS program for less than 500 MW of load	Entity is responsible for developing and/or coordinating a UFLS program for 500 MW to 900 MW of load	Entity is responsible for developing and/or coordinating a UFLS program for 900 MW of load
UVLS	Entity does not have any UVLS responsibilities	The Registered Entity owns or operates UVLS that is less than 10% of its peak load	The Registered Entity owns or operates UVLS that is greater than or equal to 10%, but less than 25%, of its peak load	The Registered Entity owns or operates UVLS that is greater than or equal to 25% of its peak load

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-85:
WECC 2024 Western Assessment of Resource Adequacy Appendix

WECC

Western Assessment of Resource Adequacy Appendix

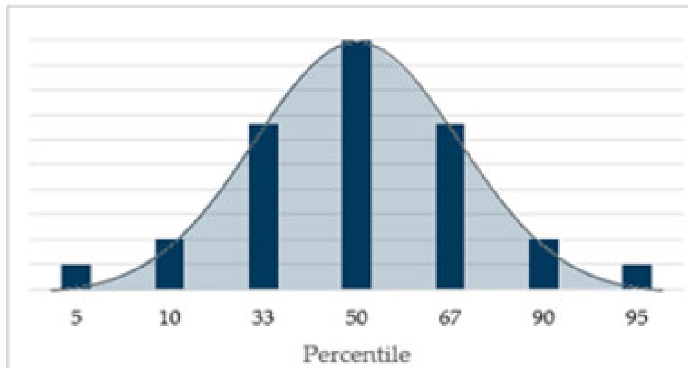
January 24, 2025

Table of Contents

Appendix A: Modeling Methodology

To determine the demand at risk hours (DARH) in the Western Assessment of Resource Adequacy (Western Assessment), WECC uses the Multiple Area Variable Resource Integration Convolution model (MAVRIC). MAVRIC is WECC's internally developed modeling tool that performs energy-based probabilistic assessments by applying the convolution method. In addition to applying the convolution method, a subset of assumptions within the model are also derived via a Monte-Carlo Markov-Chain method (see Appendix B). For a primer on Monte Carlo simulations and convolution methods, please see NERC's Probabilistic Adequacy and Measures Report.

MAVRIC examines the probability that demand and resource availability will intersect at expected energy values given their probability distribution curves. Figure 1 is an example of a probability curve. The curve shows the probability of potential outcomes based on an expected value. For example, if an expected value falls at the 50th percentile, this value has a 1-in-2 chance of occurring. MAVRIC evaluates the probability curves of demand and resource availability together (Figure 2). The overlapping area of the demand and resource availability curves represent the potential for unserved load, or DARHs. The more the two curves overlap, the greater the potential for demand at risk. The goal is to keep the two curves far enough apart that overlap is kept below a certain threshold. For the Western Assessment, WECC has set this threshold to the one-day-in-ten-year (ODITY) level, meaning 99.98% of the demand for each hour is covered by available resources. Put another way, the area of overlap for the availability and demand curves is equal to no more than 0.02% for any given hour.



Probability	Percentile	Likelihood of Occurrence
1-in-20	5th	5%
1-in-10	10th	10%
1-in-3	33rd	33%
1-in-2	50th	50% (expected)
1-in-3	67th	33%
1-in-10	90th	10%
1-in-20	95th	5%

Figure 1: A conceptual normal probability curve with percentiles and likelihood of occurrence

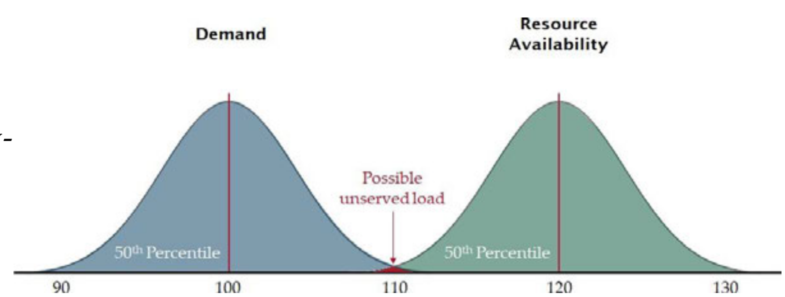


Figure 2: Evaluation of the supply side and demand probability curves for overlap which represents demand at risk

The potential for DARHs can increase or decrease when the demand or availability curves shift, expand, or contract. A shift in the position of a demand curve closer to the availability curve happens when demand uniformly increases without a corresponding increase in resource availability. When rare events occur more frequently, the demand probability curve changes shape and expands. When one or both curves change shape in this way, the overlap can increase, making it more likely that demand will exceed resource availability, as shown in Figure 3. For example, heat waves like those that occurred in the West in 2020 and 2021 were once rare events. The August 2020 Heat Wave was a 1-in-30 event. But, when evaluated considering climate change, it becomes a 1-in-20 event, widening the demand curve.

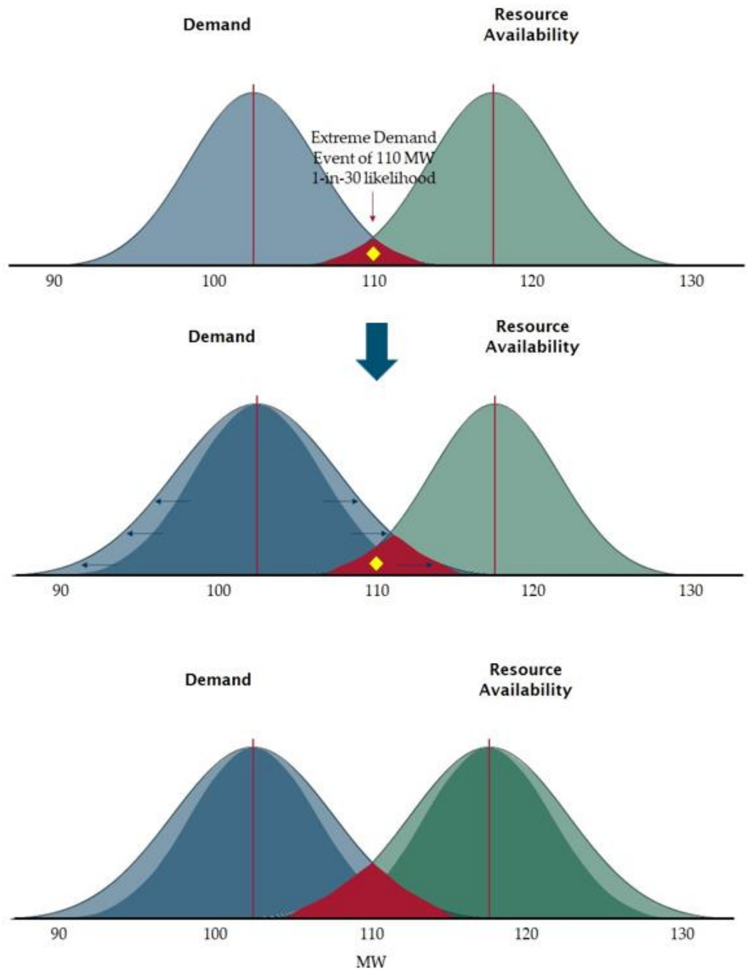


Figure 3: Demand and resource availability curves with increasing overlap due to increased frequency of extreme weather events

As additional variable energy resources (VER) are added to a portfolio, the resource availability curve expands like the demand curve expands when extreme events become more frequent. The variability in output of wind, solar, and hydro resources widens the potential range of expected values. Conversely, a decrease in unplanned outage frequency, or mean time to return from outages, would move the tails of the resource availability curve away from the demand curve. If resource availability decreases, the resource availability curve will shift closer to the demand curve, increasing overlap.

Calculating the Planning Reserve Margin

Assessing DARHs allows for the creation of planning reserve margins (PRM). Figure 4 shows a system with a 1-in-2 chance that demand is 100 MW and resource availability is 120 MW. A 20-MW—or 20%—PRM is needed to maintain 99.98% resource adequacy. This is based on the shapes of the demand and resource availability curves. If the availability curve shifts to the left, and only 115 MW of resources are available, the reserve margin has decreased to 15 MW. This amount of reserve margin will no longer maintain the ODITY threshold. Figure 5 shows the increased DARHs if the PRM does not increase to accommodate the change in distribution shape. To accommodate the change in distribution shape and maintain 99.98% resource adequacy, the PRM must increase. If the PRM is increased to 22 MW, the system returns to being 99.98% resource adequate, maintaining the ODITY threshold (Figure 6). Actual distributions for each subregion are in Appendix D.

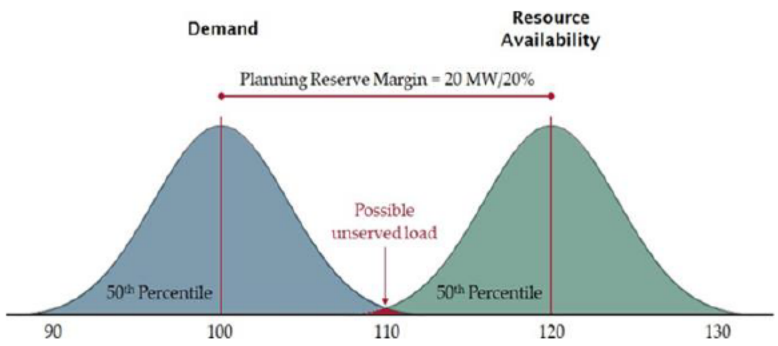


Figure 4: Conceptual system with 99.98% resource adequacy at a PRM of 20 MW

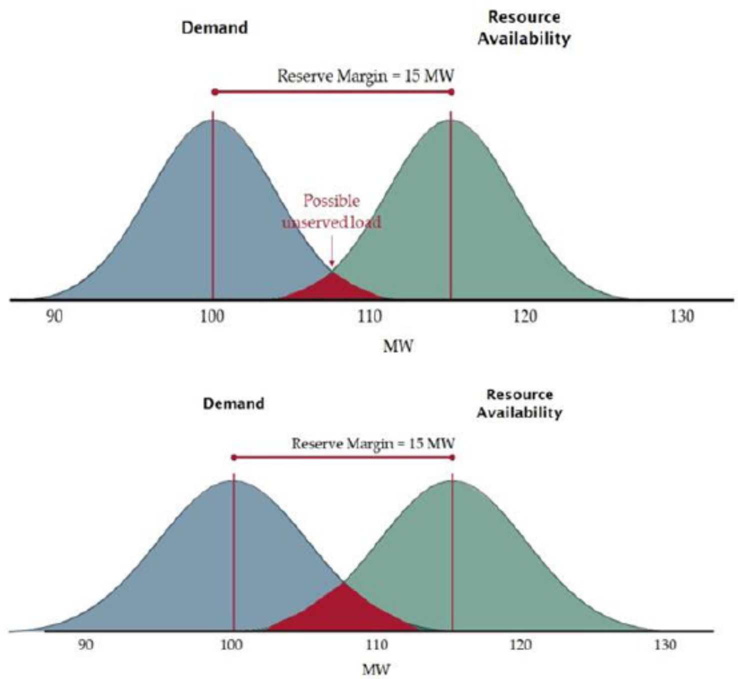


Figure 5: Demonstrates the increased demand at risk if the distributions expand or shift

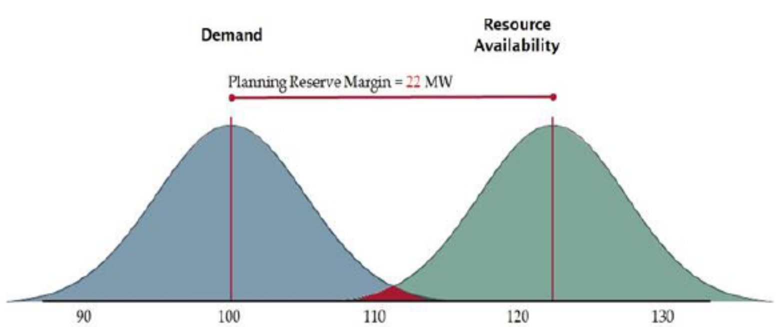


Figure 6: Shows the increased PRM required to maintain 99.98% resource adequacy with the wider distributions

Appendix B: MAVRIC Inputs, Assumptions, & Processes

The Western Interconnection has many transmission connections between demand and supply points, with energy transfers playing a significant role in reliable operations. On top of this, the Western Interconnection is geographically large and contains both winter-peaking and summer-peaking areas. To add to the complexity, there is a large amount of hydro capacity that experiences seasonal variability, and rapid adoption of solar and wind resources, which can vary hourly in output. WECC developed MAVRIC to handle these intricacies. MAVRIC can study all hours of the year, it can factor in dynamic imports from neighboring areas, and account for varying generation patterns dependent on geographical location and resource type. MAVRIC calculates resource adequacy through loss-of-load probabilities (LOLP). It calculates LOLPs on each of the stand-alone Balancing Authorities (BA) without transfers, then balances the system cohesively with transfers to a probabilistic LOLP (see Appendix A). This section will discuss the inputs, assumptions, and processes within MAVRIC required to perform this LOLP calculation. Figure 7 provides an overview of the MAVRIC process.

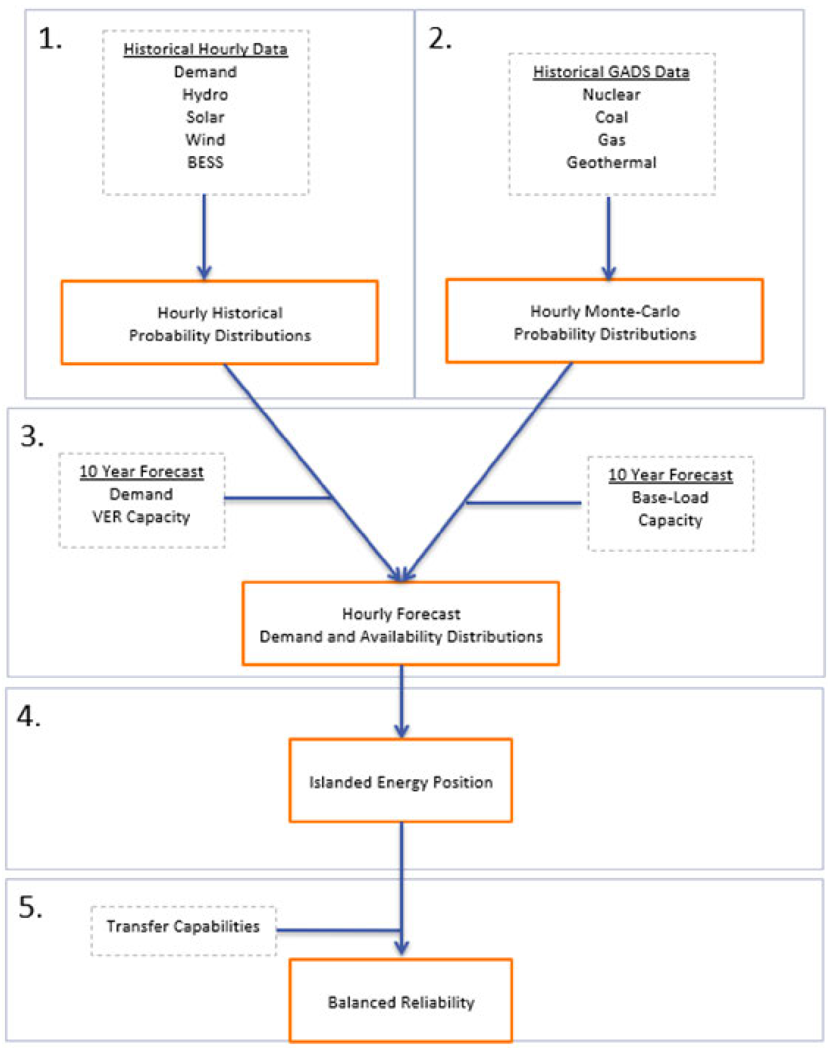


Figure 7: MAVRIC inputs and processes

In step one of Figure 7, hourly historical data for demand and energy output from hydro, solar, wind, and battery energy storage system (BESS) resources are collected in WECC's annual Loads and Resources (L&R) Data Request. To develop hourly probability distributions for demand, hourly demand from previous years must be aligned. The first Sundays of each historical year are aligned so that weekends and weekdays are consistent. Each hour is then compared against a rolling seven-week average for the same hour of the same weekday. This establishes the difference between the historical hour and the average. MAVRIC uses each of these percentages to calculate a percentile probability for a given hour based on the variability of three weeks before and three weeks after the given hour for each historical year. The output of this step is a series of hourly percentile profiles with different probabilities of occurring. Figure 8 represents a demand probability distribution for a single hour. The peak is the expected deterministic forecast and is set at 100%. The profiles to the right of the peak are greater than 100% and those to the left are lower than 100%.

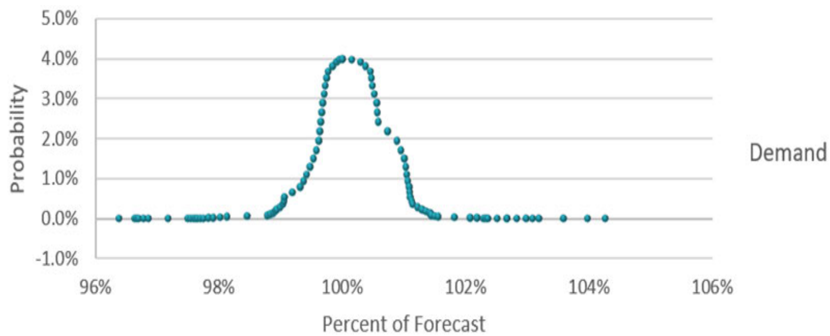


Figure 8: Example of a single hour's demand profile

The availability probability distributions for the VERs, which includes hydro, wind, and solar resources, is derived in a similar manner to that of the demand calculations but with two notable differences. The primary difference is the period used in calculating the VER availability distributions. For VERs, the day of the week does not influence variability, as weather is always variable. Therefore, the need to use data from the same day of the week is not necessary. This allows the VER distributions to be condensed to a rolling seven-day window using the same hour for each of the seven days. The second difference is that the historical generation data is compared against the nameplate capacity to determine the historical capacity factor for that hour, which is then used in the percentile probability calculation. Using nameplate in the denominator allows for the incorporation of unit outages due to non-fuel-related issues. The output of this process is a series of hourly percentile profiles with different probabilities of occurring. A random hour profile for each of the VER types is shown in Figure 9. Wind and hydro run-of-river units are positively skewed, whereas solar and hydro storage units are negatively skewed, meaning their distributions "lean" to the left and right, respectively. The highest point of the distribution indicates the most frequently anticipated capacity factor from the resource for a given hour. For instance, the hour represented in Figure 9 for wind tends to perform at the lower end of the capacity factor spectrum, whereas solar frequently performs at capacity factors above 90%. Hybrid resources such as solar with BESS or wind with BESS, are treated as VERs. MAVRIC does not account for the BESS properties of these resources.

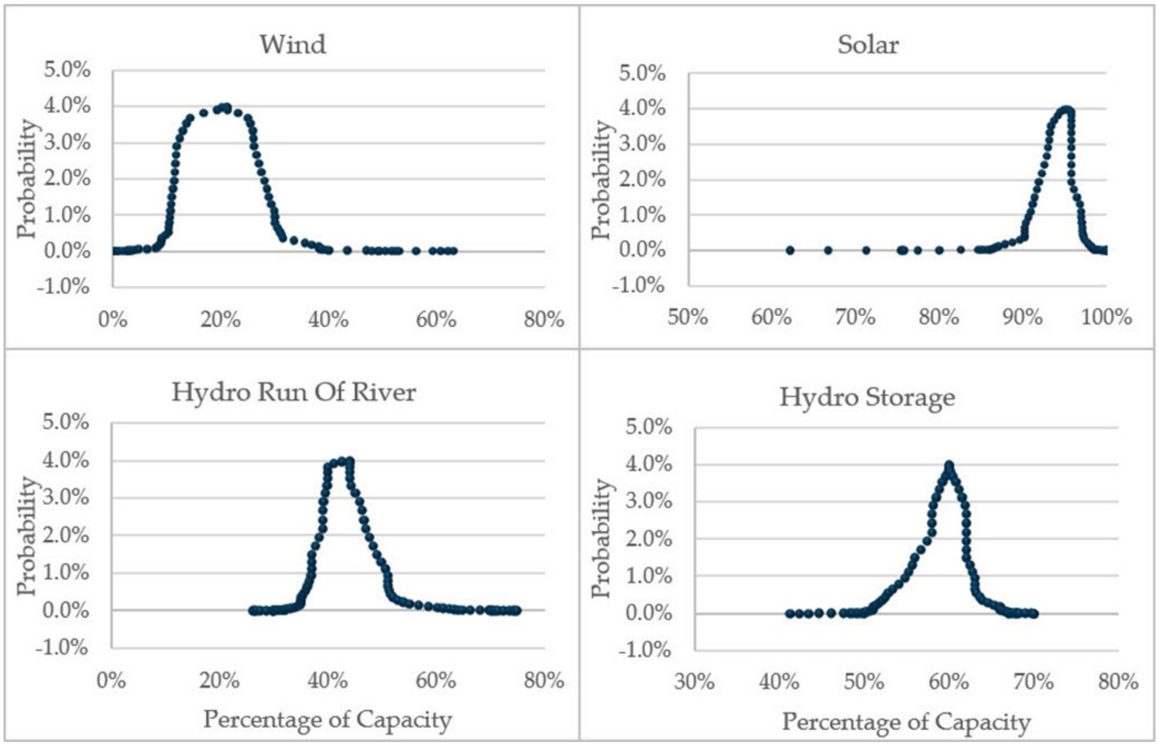


Figure 9: Examples of hourly profiles for each of the VER resource types

Hydro facilities with storage capability are highly correlated with demand. The ability to store the fuel leads to different operating characteristics between weekdays and weekends. Therefore, the availability distributions for hydro facilities with storage are calculated in the same manner as the demand distribution.

For the purposes of baseload resources, MAVRIC uses a Monte-Carlo Markov-Chain method (Step 2 in Figure 7). The distributions of nuclear, coal-fired, gas-fired, biofuel and geothermal resources, are determined by using the historical rate of unexpected failure and the time to return to service from NERC's Generation Availability Data System (GADS). The annual frequency of unexpected outages and recovery time from these outages is used to calculate the availability probability distributions for baseload resources. Based on this data, a random value is calculated for the first hour of the year for each of the units within a BA. If that random value falls below the frequency calculation to be available, the model will force the unit offline. Conversely, if the random value does not fall below the availability frequency calculation, the unit is deemed as available. Available resources are capable for their maximum winter or summer capacity rating, depending on the season. Once the status of each resource is determined, the next hour is then processed. If the resource was determined unavailable in the previous hour, the model will keep the resource unavailable until the average duration of the historical unplanned outages is reached. If the unit was determined as available the previous hour, the random variable for the next hour is checked against the forced outage frequency calculation and the process repeats. Through this random sampling method, MAVRIC performs 1,000 iterations for each resource for each hour. After 1,000 iterations, the data points of availability for each hour are used to generate availability probability distributions. Figure 10 demonstrates a baseload availability distribution. It is consistent with the VER distributions, in that a series of expected values for capacity factors are produced for each hour. BESS resources are treated in the same manner as baseload generators. Their full capacity is available to be discharged when the resource is not in outage. MAVRIC does not account for the charging behavior of batteries.

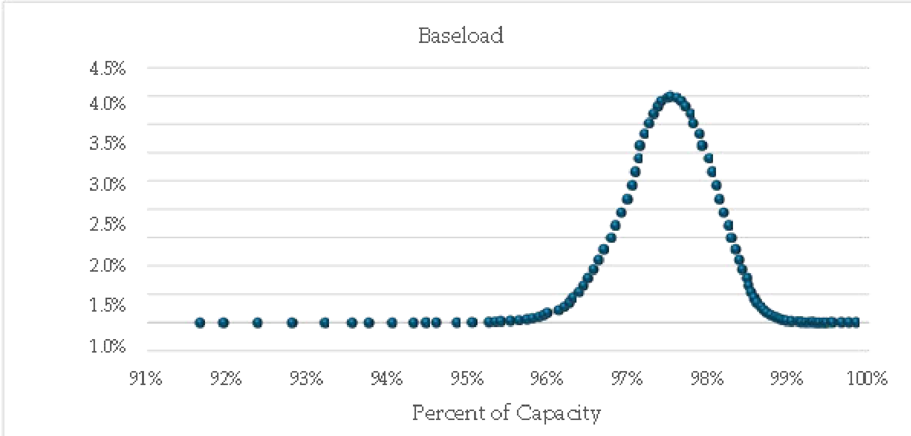


Figure 10: Example hourly probability distribution for thermal resources

In Step 3 of Figure 7, MAVRIC combines the 10-year demand forecast and resource availability to represent the hourly forecast demand and availability distributions. The 50th percentile of the demand distributions is set equal to 100% (as displayed in Figure 8), with the low and high side variability represented by the percentiles to the left and right, respectively. The hourly demand forecast in megawatts is multiplied by each of the percentiles of the probability distribution, creating a distribution of hourly megawatt forecasts. For availability, each of the probability distributions represent capacity factors. Therefore, by taking an expected capacity of each of the different types of resources and multiplying it by each of the hourly profiles, a distribution of hourly megawatt forecasts is derived.

Step 4 represents the comparison of the hourly demand distributions with the hourly availability distributions. For each hour, the distributions are compared to one another to determine the amount of overlap in the upper tail of the demand distribution with the lower tail of the availability distribution. The amount of overlap represents the LOLP. If the probability for a given hour is greater than a selected threshold (such as the ODITY threshold discussed in Appendix A), then that hour is a DARH.

If DARHs are identified in in Step 4, MAVRIC analyzes potential transfers to mitigate them. This is Step 5 in Figure 7. MAVRIC undergoes a step-by-step balancing logic in which excess energy, which is energy above an area's PRM, can be used to satisfy another area's resource adequacy shortfall. This depends on neighboring areas having excess energy and available transfer capability to allow the excess energy to flow. MAVRIC only allows for first and second order transfers to occur. Transfer capabilities are a deterministic input into MAVRIC, and they vary based on the direction of flow (see Appendix C). MAVRIC considers first-order transfers (external assistance from an immediate neighbor) and second-order transfers (external assistance from a neighboring entity's immediate neighbors). After balancing all areas in the system for a given hour, MAVRIC then moves to the next hour and balances the system as needed. The result is an analysis of the Western Interconnection that reflects the ability of all defined areas or subregions to maintain a PRM equal to, or less than, the ODITY threshold.

Appendix C: MAVRIC Topology

Transfer capabilities are a deterministic input into MAVRIC, and they vary based on the direction of flow and season. MAVRIC topology uses a zonal approach, considering the transfer capability between regions but not accounting for nodal congestion. The transfer capabilities within MAVRIC are provided by BAs and Transmission Operators (TO) and resemble expectations during system peaking conditions. The transmission topology in MAVRIC is shown in Figures 11 and 12 for the summer and winter seasons, respectively.

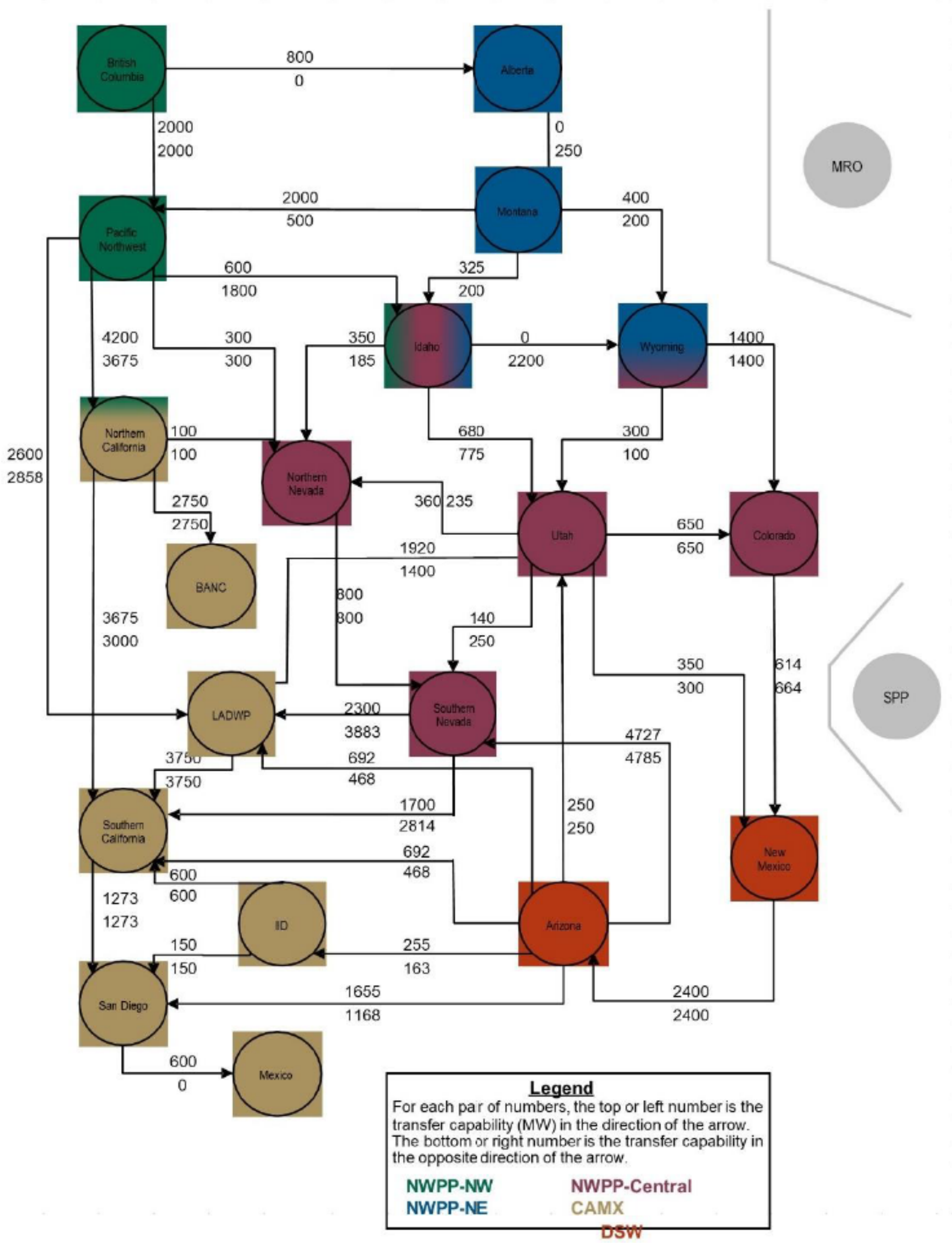


Figure 11: Summer topology in MAVRIC

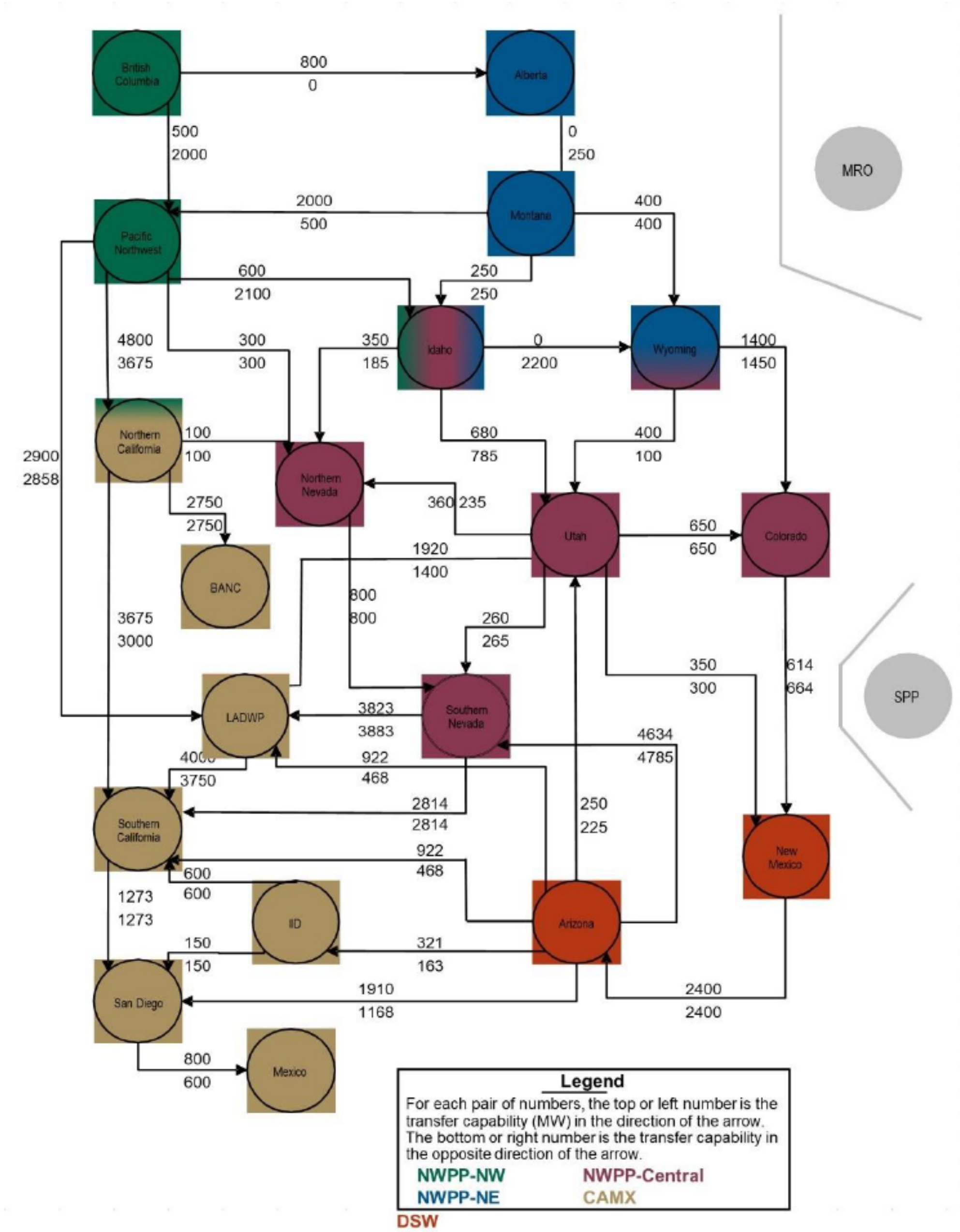


Figure 12: Winter topology in MAVRIC

Appendix D: Regional Portfolios, Variability, & Volatility

Figures 13 through 17 show each subregion's resource portfolio on a capacity basis, demand and supply probability distributions, and demand and supply volatility curves in the 2028 assessment year. The 2028 assessment year was selected for this section to balance current data trends and resource plans without extending so far into the future that the data becomes mostly speculative. As discussed in Appendix A, many factors influence the shape of the demand and availability curves. Increasing the frequency of extreme weather events in a subregion will result in the demand curve developing a positive skew. General forecast growth moves the center of the demand curve closer to the availability curve. Conversely, adding VERs to a subregion's portfolio will widen the availability curve, but also move the center of the availability curve away from the demand curve due to the increase in capacity. Adding thermal and BESS resources will shift the center of the availability curve away from the demand curve. A decrease in forced outage rate will tighten the availability curve. Volatility represents the percent deviation from the 50/50 case that the demand has in the 95th percentile and the availability has in the 5th percentile. Put another way, volatility shows the potential down-side availability risk and high-side demand risk. Availability volatility correlates with a portfolio's share and type of VERs, the capacity factor distributions of those VERs, and forced outage rates. Volatility of demand will be greater in subregions prone to extreme or prolonged weather events. The overlap of the availability and demand distributions represents DARHs. This appendix adds to the insights provided in the subregional documentation for the DARHs calculated in the Scenario Analysis portion of the Western Assessment. The charts below do not account for transfers that may mitigate DARHs.

California & Mexico (CAMX)

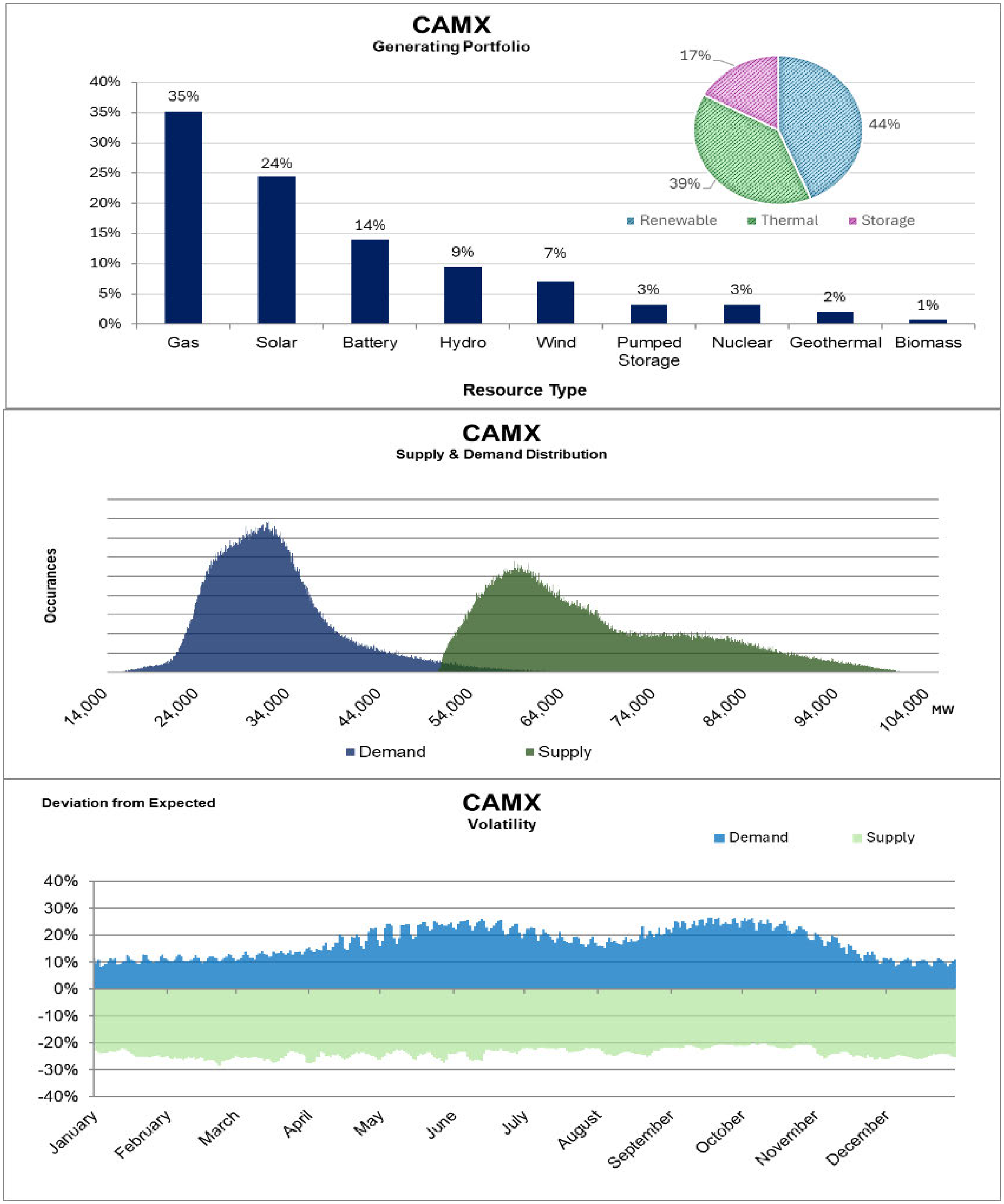


Figure 13: CAMX resource portfolio and variability

For 2028, CAMX shows little overlap of the demand and supply distributions. This indicates that CAMX should be able to meet demand under all but the most extreme circumstances coupled with resource underperformance. In 2028, the CAMX portfolio is forecast to be 39% thermal resources, 17% BESS resources, and the remainder attributed to VERs. A large share of thermal and BESS resources helps maintain certainty in resource output while minimizing volatility on the supply side. CAMX has significant solar contribution in its portfolio, which typically presents at higher capacity factors than other VERs when available. CAMX shows less supply-side volatility than other subregions and a long tail at the high end of its supply curve due to the high percentage of thermal, BESS, and solar contributions. CAMX is a summer-peaking subregion and has experienced prolonged heat wave events over the past four years. Two of these events resulted in new hourly peak loads for the Western Interconnection. This amplifies the positive skew of the demand curve as well as the demand volatility in the early summer through early fall months.

Desert Southwest (DSW)

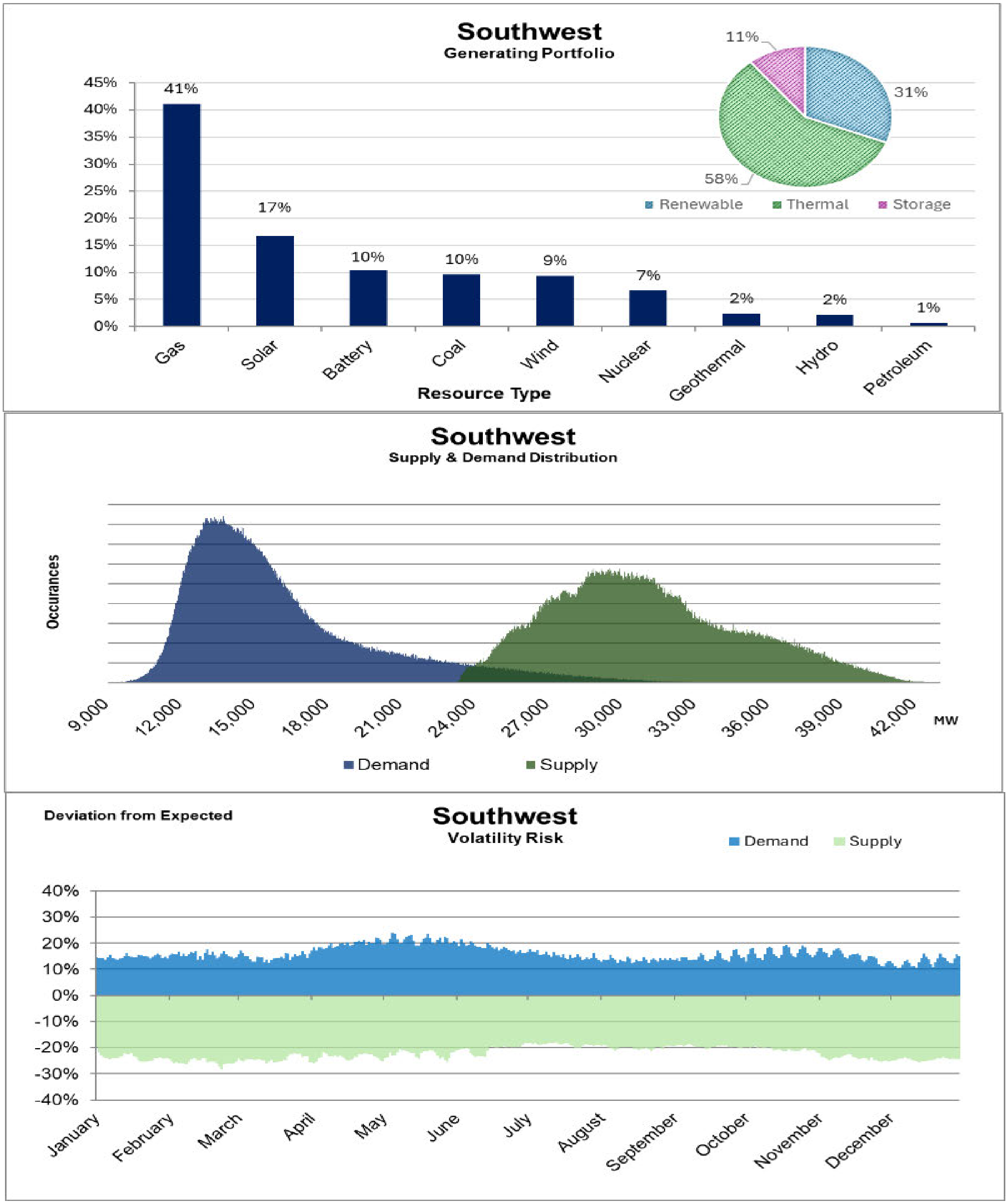


Figure 14: DSW resource portfolio and variability

In 2028, thermal resources are anticipated to comprise 58% of generating capability in the DSW, followed by VERs at 31%, and the remaining being supplied by BESS resources. The DSW is forecast to have the highest share of thermal sites of all subregions, with 41% of its portfolio being natural gas. The DSW is a summer-peaking subregion and has experienced prolonged heat wave events over the past four years. Natural gas resources can be derated in high temperatures which can lower expected contribution during heat wave events. Despite this, the large share of thermal and BESS resources gives the DSW lower volatility on the supply side than other subregions. The DSW also has a large share of solar resources, which are projected to make up 17% of its portfolio. Solar tends to generate at the high end of the capacity factor distribution when available, resulting in less supply side volatility than other VERs. Recent extreme weather events have resulted in the positive skew of the demand distribution and high volatility of demand in the early summer through early fall months.

Northwest-Central (NW-Central)

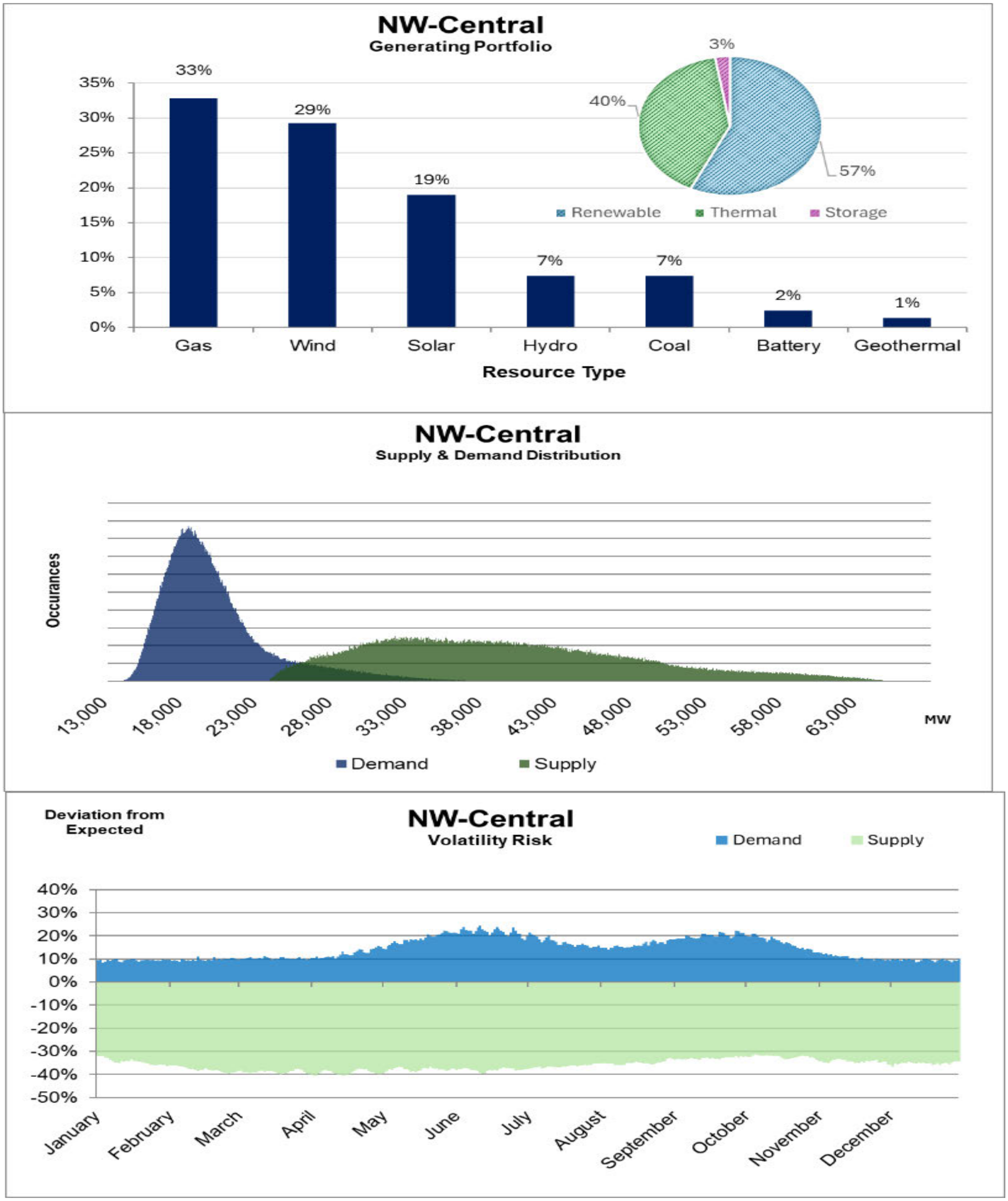


Figure 15: NW-Central resource portfolio and variability

The NW-Central portfolio is forecast to be 29% wind resources in 2028, with solar resources making up just under 20%. The substantial share of wind in this subregion's portfolio results in a wide availability curve due to its high uncertainty in output. The significant wind resources in this subregion also result in supply side volatility that is higher than the other subregions. The spring and winter months carry the greatest supply-side volatility. The large solar contribution results in the extended tail of the availability distribution due to solar resources typically generating at higher capacity factors. The NW-Central subregion is summer peaking and displays the greatest potential for demand volatility in the early summer through early fall months.

Northwest-Northeast (NW-NE)

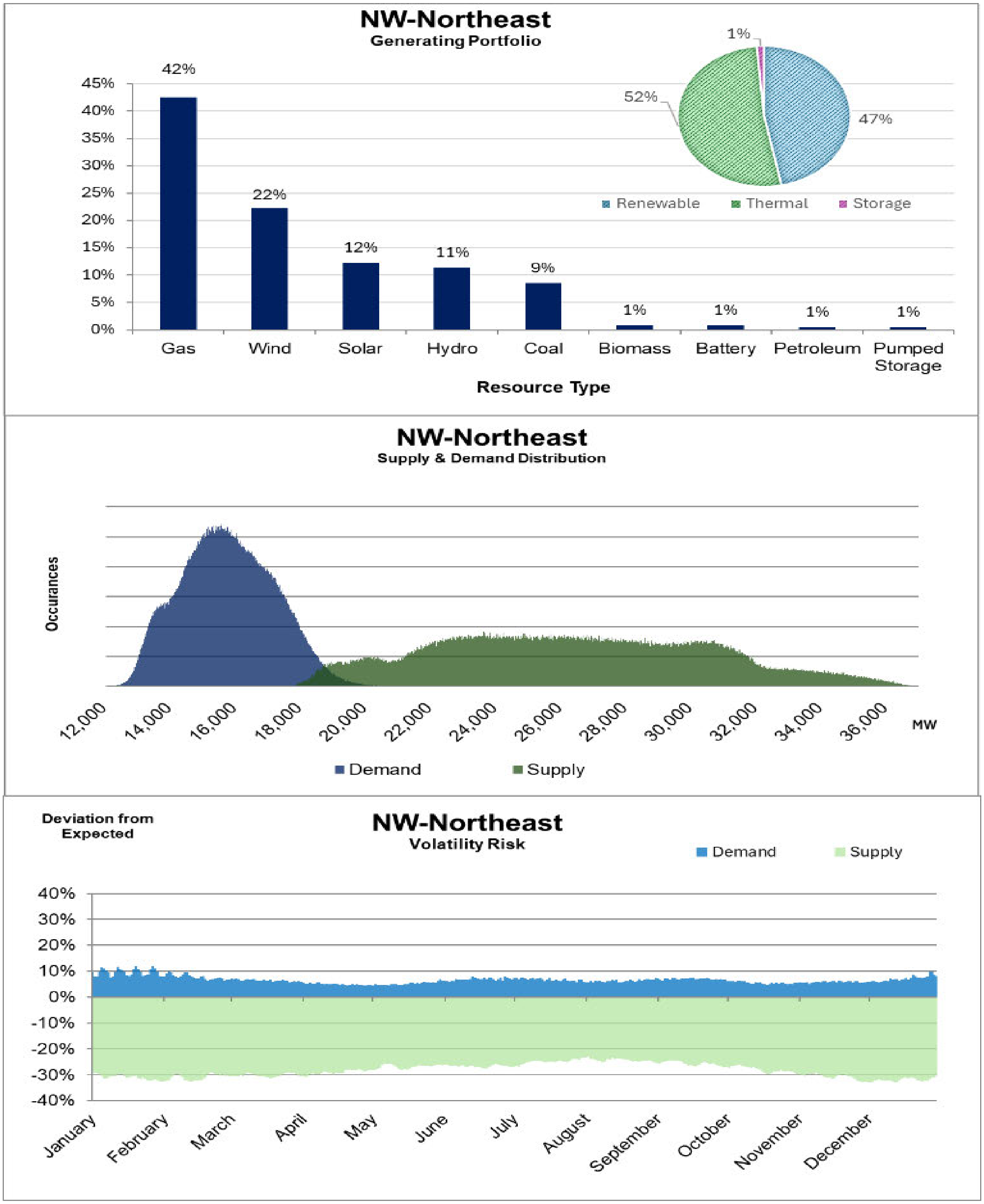


Figure 16: NW-Northeast resource portfolio and variability

The NW-NE is anticipated to have a substantial share of wind that will make up approximately 22% of its generating portfolio in 2028. This results in a wide availability curve due to the high variability of wind resource output. However, the NW-NE also is expected to have a large natural gas contribution, making up 42% of its generating portfolio. The significant share of natural gas in this subregion's portfolio helps shift the NW-NE availability curve away from the demand curve and reduces supply-side volatility in comparison to other regions in the Northwest. The NW-NE can be summer peaking or winter peaking, and generally does not experience extreme heat events to the same degree as the DSW or CAMX subregions. Demand-side volatility is greatest in the winter due to winter storm risk. The NW-NE displays the least demand-side volatility of all the subregions.

Northwest-Northwest (NW-NW)

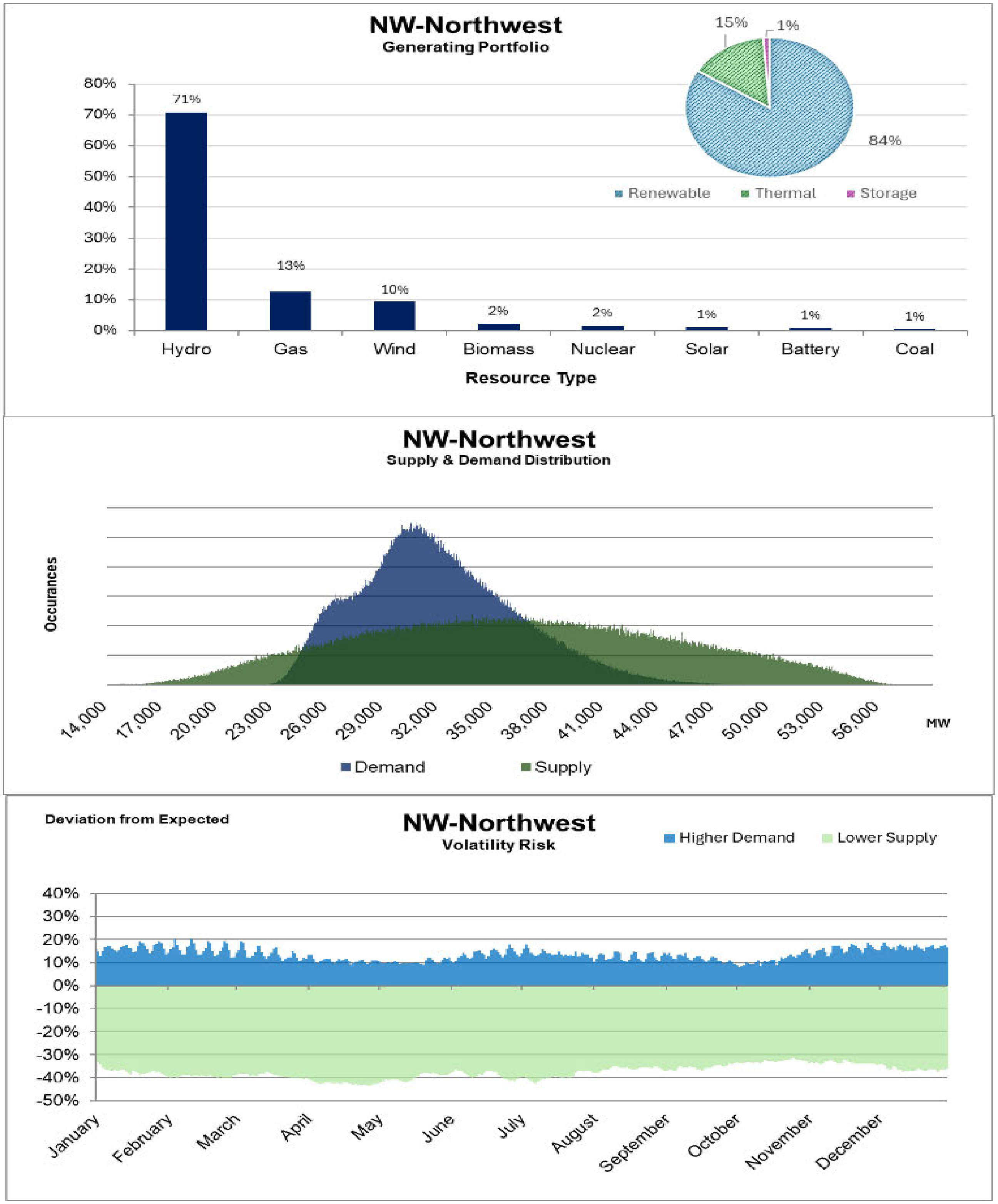


Figure 17: NW-Northwest resource portfolio and variability

The NW-NW portfolio is unique, with over 70% of its generating portfolio projected to be hydro resources in 2028, and over 84% of its portfolio being made up of VERs. The large share of hydro resources gives this subregion an extremely wide availability curve due to historic variability in output. In addition, 10% of the NW-NW generating portfolio is projected to be wind, which further widens the availability distribution. In 2028, the NW-NW subregion shows the greatest overlap of the demand and supply curves, indicating that the potential demand at risk is highest for this subregion. The NW-NW is a winter-peaking subregion, and correspondingly shows increased demand volatility during the winter months due to potential winter storms and cold weather events.

Appendix E: Demand Forecasts

The demand forecasts for each subregion are derived from WECC's Annual L&R Data Request. In this data request, each BA in the Western Interconnection provides demand forecasts, which are combined into subregions. The methodology and sources of demand for each BA's forecasts differ; however, frequently cited load types and factors that BAs account for are:

- Behind-the-meter solar adoption
- Calendar-driven events (i.e., holidays)
- Data centers
- Employment rates
- Historic peak demand
- Income of population
- Increasing efficiency of appliances
- Irrigation
- Local, state, and federal incentives and policies
- Population
- Residential building electrification
- Residential, commercial, and industrial electric sales
- Transportation electrification
- Weather and climate trends

Figures 18 and 19 show the annual and peak hour demand forecasts by subregion for this year's Western Assessment and the 2023 Western Assessment. All subregions are projected to experience growth in total annual demand and peak demand from 2025 through 2034. All times shown in Apprendix E are Pacific Prevailing Time.

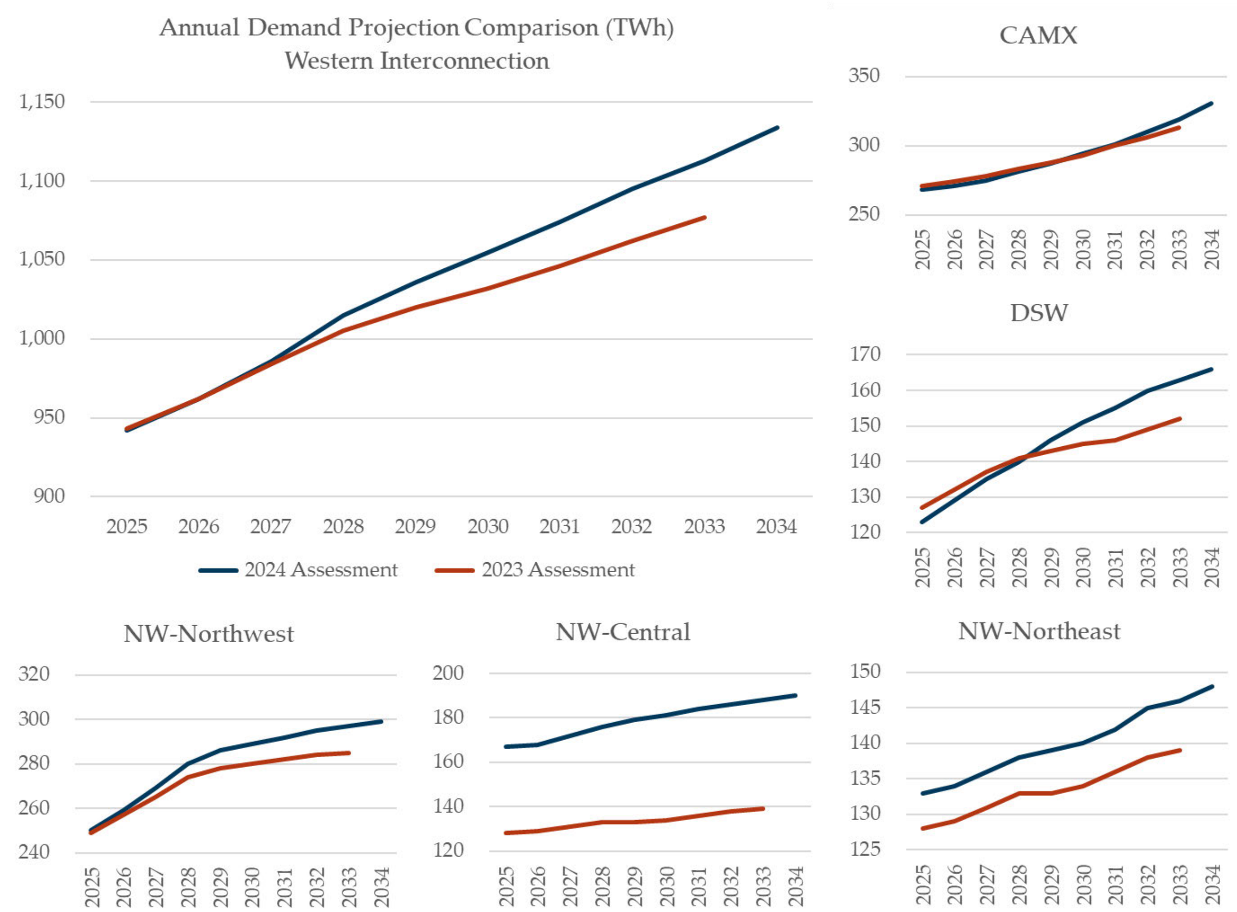


Figure 18: Annual demand forecasts in TWh for the Western Interconnection.

As denoted in the Load Growth section of the Western Assessment, the Western Interconnection is anticipated to grow in annual demand by 20.4% from 942 TWh to 1,134 TWh over the next decade. The greatest rate of growth is seen in the DSW subregion, which forecasts growth from 123 TWh in 2025 to 166 TWh in 2034, an increase of 35%. The majority of this growth has been cited as large industrial and commercial load additions such as data centers. The second-greatest forecast growth is seen in CAMX, which is projected to increase from 268 TWh of annual demand to 331 TWh of annual demand by 2034, a 23.5% increase. This is driven by transportation and building electrification. The NW-NW subregion is forecast to have an annual demand growth rate of 19.6%, increasing from 250 TWh in 2025 to 299 TWh in 2034. This demand is primarily expected to be added in the Pacific Northwest, and is largely correlated with data center additions. Electrification of transportation, buildings, and emerging industries such as hydrogen production account for demand growth in the Canadian portion of the NW-NW subregion. The NW-Central subregion shows annual demand growth of 13.8% from 167 TWh in 2025 to 190 TWh in 2034. Demand growth in this region is driven by data center additions and building and transportation electrification. The subregion showing the lowest growth rate over the next decade is the NW-NE, going from 133 TWh in 2025 to 148 TWh in 2034, an increase of 11.3%. Demand growth in this region is attributed to industrial sources such as gas and oil processing and pulp and paper mill operations, as well as incoming data centers.

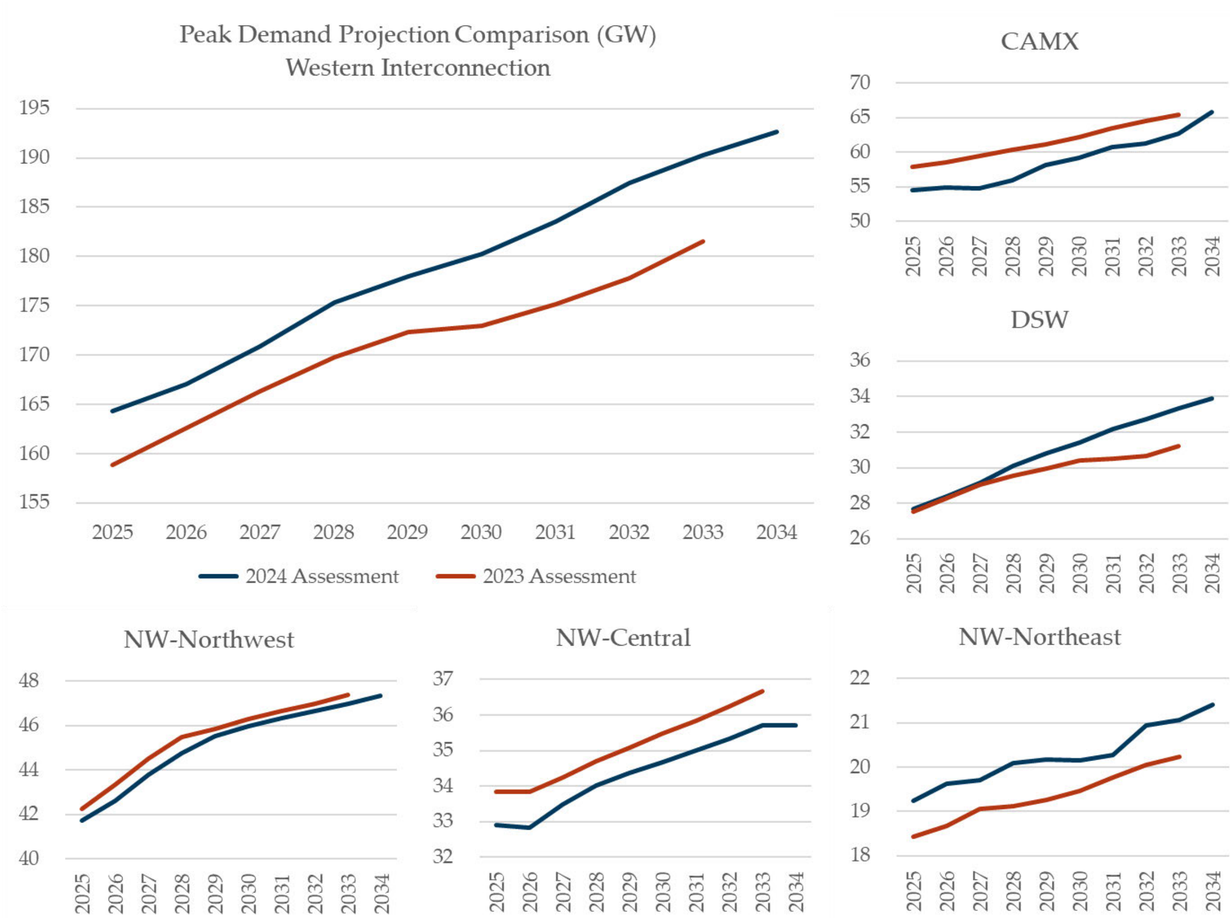


Figure 19: Peak hour demand forecasts in GW for the Western Interconnection.

Peak demand trends closely mimic those observed for annual demand. The DSW subregion leads peak demand growth with an increase of 22.5% over the next 10 years, from 28 GW to 34 GW. CAMX is projecting a peak demand increase of 20.7%, from 55 GW in 2025 to 66 GW in 2034. Both the DSW and CAMX subregions are summer peaking and show peak hours at the same time, hour ending 17:00. However, the month of peak occurrence is different between the two. The DSW peak hour is projected to occur in the mid to late July timeframe, whereas CAMX's peak hour is projected to occur in August or early September. The NW-NW peak hour projection in 2025 is 42 GW and is forecast to increase to 47 GW by 2034, a 13.5% increase. The NW-NW differs from the DSW and CAMX as it is a winter-peaking subregion, with the peak hour projected to occur at hour ending 9:00 in January. The NW-NE shows the second-lowest increase in peak demand growth at 11.3%, forecasting 19 GW as the peak in 2025 and 21 GW in 2034. The NW-NE subregion is dual peaking, meaning a peak hour may occur in either the summer or winter. Summer peak hours are projected to occur in July at hour ending 15:00 or 16:00, and winter peak hours are anticipated to occur in January at hour ending 9:00. The NW-Central shows the smallest percentage increase in peak demand growth, 8.5%, with a projection of 33 GW in 2025 and 36 GW in 2034. This subregion is summer peaking, and is forecast to have peak demand hours in July at hour ending 17:00. From a Western Interconnection perspective, the peak demand is anticipated to grow by 17.2% over the next decade, from 164 GW to 193 GW. The coincident forecast peak for the interconnection is anticipated to occur in August at hour ending 17:00.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-86:
WECC Reliability Assessment Webpage

LOGIN

WECC

Reliability Assessments

WECC's work identifies potential reliability risks to the Bulk Power System stemming from changes in loads and resources over the next 10 years. Through initiatives like the Western Assessment of Resource Adequacy, WECC provides analysis and information on resource adequacy to stakeholders and decision makers. WECC's work supports resource adequacy work at an ERO level by providing information on the West to assessments such as NERC's Long-Term Reliability Assessment (LTRA), Summer Assessment, Winter Assessment, and Probabilistic Assessment.

Request Outreach Event

Western Assessment

Western Assessment Comment Form

Resources

NERC Assessments

WECC Studies

Archive

Reliability Assessments

- Interregional Transfer Capability Study

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-87:
TransAlta Form EIA-860

2024 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

Utility ID	Utility Name	Plant Code	Plant Name	State	County	Generator ID	Technology	Prime Mover	Unit Code	Ownership	Duct Burners	Can Bypass Heat Recovery Steam Generator?
19099	TransAlta Centralia Gen LLC	3845	Transalta Centralia Generation	WA	Lewis	2	Conventional Steam Coal	ST		S	X	X

RTO/ISO LMP Node Designation	RTO/ISO Location Designation for Reporting Wholesale Sales Data to FERC	Nameplate Capacity (MW)	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Minimum Load (MW)	Uprate or Derate Completed During Year	Month Uprate or Derate Completed	Year Uprate or Derate Completed	Status	Synchronized to Transmission Grid	Operating Month
		729.9	0.940	670.0	670.0	250.0	N			OP	X	7

Operating Year	Planned Retirement Month	Planned Retirement Year	Associated with Combined Heat and Power System	Sector Name	Sector	Topping or Bottoming	Energy Source 1	Energy Source 2	Energy Source 3	Energy Source 4	Energy Source 5	Energy Source 6
1973	12	2025	N	IPP Non-CHP	2	X	SUB					

Startup Source 1	Startup Source 2	Startup Source 3	Startup Source 4	Solid Fuel Gasification System?	Carbon Capture Technology?	Turbines or Hydrokinetic Buoys	Time from Cold Shutdown to Full Load	Fluidized Bed Technology?	Pulverized Coal Technology?	Stoker Technology?	Other Combustion Technology?	Subcritical Technology?
DFO				N	N		OVER		Y			Y

Supercritical Technology?	Ultrasupercritical Technology?	Planned Net Summer Capacity Uprate (MW)	Planned Net Winter Capacity Uprate (MW)	Planned Uprate Month	Planned Uprate Year	Planned Net Summer Capacity Derate (MW)	Planned Net Winter Capacity Derate (MW)	Planned Derate Month	Planned Derate Year	Planned New Prime Mover	Planned Energy Source 1	Planned New Nameplate Capacity (MW)

Planned Repower Month	Planned Repower Year	Other Planned Modifications?	Other Modifications Month	Other Modifications Year	Multiple Fuels?	Cofire Fuels?	Switch Between Oil and Natural Gas?
					N	N	N

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, “Public Interest Organizations” or “PIOs”)

Exhibit 1-88:
Wash. Commerce Util. Res. Planning Report (Compiled 2022 & 2024)

Washington State Electric Utility Resource Planning

Washington State Department of Commerce

2022 Report

ENERGY

v3.4

April 2024

Report to the Legislature

Director Mike Fong

Acknowledgments

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For people with disabilities, this report is available on request in other formats. To submit a request, please call 711.

Table of Contents

Executive summary

Chapter 19.280 RCW requires electric utilities develop resource plans to assess their specific future load and resource requirements. The Department of Commerce is tasked with collecting and analyzing the utility resource plans and creating a summary report for the Legislature.[1]

The 2022 Utility Resource Plan Report summarizes the findings of Washington state load and resource information for a 10-year planning cycle – with most utilities using 2021 as the base year.[2] Key findings of the 2022 Utility Resource Plan report are:

- Utilities plan to reduce their use of coal-fired electricity generation serving Washington retail customers and net use of short-term contracts in the forecast periods, and to increase their use of natural gas-fired generation, wind power, other renewables, and Bonneville Power Administration resources. Hydropower will remain the dominant source of electric for Washington utilities over the 10-year forecast period.

- There was no significant variation in the electricity needed to serve the state from 2008 through 2022. Statewide aggregate load growth forecasts by utilities for the next five and 10 years has trended down with each successive Commerce Utility Resource Plan report.

- The statewide aggregate load growth in electricity demand for 2026 and 2031 is expected to be moderate, and most of this growth will be offset through energy conservation programs operated by utilities. With the majority of load growth met by energy conservation programs, new renewable resources primarily serve to replace retiring coal-fired generation and thermal natural gas generation. However, several utilities (Chelan, Douglas and Grant PUDs) are forecasting high load growth rates over the next 10 years due to growth in data centers, computing demand, and cryptocurrency mining.

Most utilities plan to meet load requirements in the lowest-cost, least-risk way by renewing Bonneville Power Administration contracts (for slice or block products or shifting to a load following product), maximizing energy conservation measures, and implementing new demand response measures. While several consumer-owned utilities plan to remove natural gas from their resource portfolios in their five-year forecast, all the investor-owned utilities plan to maintain relatively steady amounts of natural gas in their resource portfolio.

Regional resource planning studies have found the Northwest has adequate resources to meet current demand for electricity and does not face significant risk of outages in the short term, but there needs to be a concerted effort to bolster the electric grid to serve the dual objectives of reducing fossil-fired generation and increasing electric loads for transportation, buildings, and industry.

The Clean Energy Transformation Act (CETA), Washington's 100% clean electricity law, includes requirements for utilities to establish specific standards for resource adequacy and incorporate those standards into their planning and compliance. As utilities reduce reliance on coal-fired and gas-fired power plants and add variable renewable energy such as wind and solar, new approaches and resources will be required to maintain resource

[1] Section 19.280.060, Department's duties—Report to the legislature. (2022, June 29). Retrieved from Revised Code of Washington: https://app.leg.wa.gov/RCW/default.aspx?cite=19.280.060. This report was completed prior to the close of the 2024 legislative session. Any amendments to this statute will be taken into consideration in future reports.
[2] Completed reporting of utility plans under Washington's 100% clean electricity law (RCW 19.405) and proposed legislation to amend this report led Commerce to delay the release of the 2022 report.

adequacy to ensure reliable service to customers. It is equally important to incorporate risks associated with fossil generating resources, including fuel supply risk and weather-driven forced outage risks.

While resource adequacy is an obligation of each electric utility serving end use customers in the state, it also is a shared responsibility of the overall electric power system and the entities that operate, plan, regulate, design, and fund the generation, transmission, and delivery of that system.

At the state level, Commerce and the Utilities and Transportation Commission hold an annual resource adequacy meeting in accordance with RCW 19.280.065.[3] A summary of that meeting is available on Commerce's Resource Adequacy webpage.

Legislative mandate

This report is required biennially per RCW 19.280.060, which states:

> The department shall review the plans of consumer-owned utilities and investor-owned utilities, and data available from other state, regional, and national sources, and prepare an electronic report to the legislature aggregating the data and assessing the overall adequacy of Washington's electricity supply. The report shall include a statewide summary of utility load forecasts, load/resource balance, and utility plans for the development of thermal generation, renewable resources, conservation and efficiency resources, and an examination of assessment methods used by utilities to address overgeneration events. The commission shall provide the department with data summarizing the plans of investor-owned utilities for use in the department's statewide summary. The department shall submit any reports it receives of existing and potential combined heat and power facilities as reported by utilities to the Washington State University extension energy program for analysis. The department may submit its report within the biennial report required under RCW 43.21F.045.

[3] Section 19.280.065, Department and commission meeting—Summary to the governor and legislature. (2022, June 29). Retrieved from Revised Code of Washington: https://app.leg.wa.gov/RCW/default.aspx?cite=19.280.065

Introduction

Background

Washington consumers and businesses depend on electricity service from more than 60 electric utilities operating in this state. These utilities vary greatly in size, geographic scope, history and governance, but each is responsible for ensuring an adequate supply of an essential resource.

Washington law requires each utility plan for the future by examining the projected amounts of electricity that will be required by customers in the coming decade and identifying the power resources that will be used to meet those demands.[4] Each utility must prepare a report every two years and submit it to Commerce. Commerce reviews the utility reports and submits a summary to the Legislature. This is the eighth report since the Legislature enacted the resource planning law in 2006.

Depending on their size and power sources, utilities submit either a resource plan (RP) or an integrated resource plan (IRP). The RP is a short-form report of load[5] and resources and may be submitted only if the utility has fewer than 25,000 customers and is a full requirements customer"[6] of Bonneville Power Administration. The IRP is a more detailed plan and must incorporate a number of specific requirements identified in statute.

Purpose

Utilities develop resource plans to assess their future load and resource situations. This report aggregates the individual reports to provide an assessment at the statewide level of whether utilities are planning for adequate supplies, and what resources are expected to meet any growth in electric power demand.

This report summarizes the electricity loads and resources reported by Washington utilities in their 2022 reports to Commerce. It compares them to estimated summaries of previous years. Resources proposed to meet load are categorized by generating fuel type and source type (such as contract or market). An imbalance of loads and resources may indicate either a resource surplus or deficit.

The information collected for this report is limited to the identification of loads and resources and their associated aggregate quantities. It does not attempt to evaluate specific goals or outcomes for resource acquisition strategies used by utilities.

This report provides information on utilities' energy efficiency and renewable energy resources. It does not analyze issues related to the energy efficiency and renewable energy requirement of, or compliance with, the Energy Independence Act (Chapter 19.285 RCW) or the Clean Energy Transformation Act (Chapter 19.405 RCW).

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[4] Chapter 19.280, Electric Utility Resource Plans. (2022, June 29). Retrieved from Revised Code of Washington: https://app.leg.wa.gov/RCW/default.aspx?cite=19.280

[5] As used in the statute and this report, "load" means the amount of electric energy demanded by a utility's customers during a defined period.

[6] "Full requirements customer" as defined in Section 19.280.020(7) means an electric utility that relies on the Bonneville Power Administration for all power needed to supply its total load requirement other than that served by nondispatchable generating resources totaling no more than six megawatts or renewable resources.

Utility reporting

The utility resource planning statutes (Chapter 19.280 RCW) require that each utility prepare a resource plan (RP) and submit it to Commerce by Sept. 1 of each even-numbered year. Commerce received reports from 63 utilities. The individual reports are presented in Appendix A.

Electric utilities in Washington vary significantly in size and the scope of operations. This is reflected in the way utilities approach resource planning and forecasting. Larger utilities typically use multiple sources of electricity supply to meet their customers' requirements and engage in sophisticated assessments of risks and benefits in evaluating alternative sources of new energy. Many smaller utilities rely on the Bonneville Power Administration, which undertakes the complex planning and forecasting exercise that leads to a resource plan.

The resource planning statute reflects this difference in approaches. It requires that larger utilities prepare and submit IRPs, which are the product of a thorough assessment of future needs and alternatives for meeting those needs through both demand-side and supply-side resources. Smaller utilities are allowed to prepare and submit a simplified assessment of loads and resources.

Interpretation of base year, five-year and 10-year data

The resource plan summary submitted to Commerce includes load and resource information for three points in a 10-year planning cycle. These points are the base year, five-year and 10-year plans. In 2022, most utilities used 2021 as the base year, and the five-year and 10-year points are 2026 and 2031, respectively. However, utilities vary in their planning cycles, and some utilities use an earlier or later set of years in their reporting; the base year ranges from 2020 to 2022. For purposes of the statewide summary, Commerce aggregates all base-year data into a single value (2021) and does likewise for the five-year (2026) data and 10-year data (2031).

Interpretation of conservation and load data

An important principle of integrated resource planning is that all resources should be evaluated on a consistent basis. This includes different generating resources, such as wind and natural gas, as well as energy conservation measures and demand response resources. With energy conservation measures and demand response being analyzed and compared to supply-side options, utilities are able to determine whether customers are better served by increasing energy efficiency, demand reduction, or energy supply. Consequently, energy conservation measures are sometimes portrayed as a reduction in the utility's load and sometimes portrayed as resources available to meet load. This can lead to confusion in interpreting utility plans.

Here is how this potential confusion is resolved:

> Utilities report a base year load amount that reflects whatever conservation has occurred in the past. For the five-year and 10-year values, utilities are directed to report the load that they would expect to serve in the absence of any additional conservation savings. The report separately lists the conservation resources that the utility expects to acquire during the five-year and 10-year periods.
>
> For example, Avista reports that its load in 2022 (base year) was 680 average megawatts (aMW).[7] This figure represents the actual load of its customers in the base year. It reflects many years of conservation programs at Avista and would be significantly higher without those historical conservation achievements. For the five-year interval (2027), Avista forecasts a load of 692 aMW and conservation savings of 33 aMW.

[7] aMW, or average megawatt, is an amount of electric energy equal to one megawatt-hour per hour for an entire year, or 8,760 megawatt-hours.

The first number represents the load that Avista would expect if it achieved no conservation savings after the base year. Without additional conservation, its load would increase by 12 aMW, but with future conservation the forecast load with conservation decreases by 21 aMW for an adjusted total load of 659 aMW at the end of the five-year interval.

In summary, the amounts reported as load for the five-year and 10-year intervals are based on an assumption of no new conservation. The actual loads at these future time points are likely to be lower by the amount of energy conservation identified by each utility.

Results

The 2022 resource plans submitted to Commerce are summarized in Table 1-5 and Figures 1 and 3.

Table 1 presents utility report information in units of average-Megawatts (aMW) on statewide annual utility load and resources, including imports and exports, for the base year (2021), and the five and 10-year forecasts. The right two columns in the table illustrate the difference between the base year and the five and 10-year forecasts.

Table 1 also presents the composition of electric generation resources for the base year, and the five and 10-year forecasts.

Figure 1 presents the composition of electric generation resources for the five-year and 10-year forecasts.

Table 1 and Figure 1 show that utilities plan to continue relying mostly on Bonneville Power Administration (BPA), hydroelectric generation and thermal natural gas plants to meet electricity demand. The BPA resource is a blended resource and is typically 85% hydropower, 11% nuclear, and 4% unspecified market purchases. Figure 1 reveals that hydropower will remain the largest source of electricity for Washington utilities. While several consumer-owned utilities plan to remove natural gas from their resource portfolios in their five-year forecast, all the investor-owned utilities plan to maintain relatively steady amounts of natural gas in their resource portfolio.

Table 1: Washington's Projected Requirements and Resources - Annual Energy aMW

	Base Year	5-year forecast	10-year forecast	5-year change	10-year change
Requirements					
Loads	10,202	10,818	11,363	616	1,161
Exports	226	217	190	(9)	(36)
Energy Conservation Measures	-	(405)	(816)	(405)	(816)
Demand Response	0	(23)	(33)	(23)	(33)
Total Net Requirements	**10,428**	**10,607**	**10,704**	**179**	**276**
Resources					
Total BPA	4,360	4,492	4,669	132	309
Hydro	2,681	3,316	3,553	635	872

	Base Year	5-year forecast	10-year forecast	5-year change	10-year change
Thermal Natural Gas	2,692	2,563	2,433	(129)	(259)
Wind	638	1,070	1,026	432	388
Other Renewables	142	342	538	200	395
Net Short-Term Contracts	214	78	114	(136)	(100)
Net Long-Term Contracts	1,080	197	103	(883)	(977)
Other	37	44	77	7	40
Thermal Coal	726	156	67	(570)	(658)
Imports	89	56	51	(33)	(38)
Distributed Generation	5	11	18	6	13
Cogeneration	15	15	15	0	0
Undecided	-	1	13	1	13
Market Purchase	2			(2)	(2)
Total Resources	**12,680**	**12,341**	**12,676**	**(339)**	**(4)**
Load Resource Balance	**2,252**	**1,735**	**1,972**	**(517)**	**(280)**

Of note is that coal resources listed after 2025 are entirely attributable to PacifiCorp's integrated resource plan. PacifiCorp pro-rated its total system resources to Washington based on the ratio of Washington's energy usage to PacifiCorp's total system energy usage. In the company's April 13, 2023, submission, Washington is seeing a share of coal resources because PacifiCorp does not have a Washington-specific load and resource balance and therefore all resources (regardless of type) were pro-rated. This methodology notwithstanding, Washington will no longer receive either the costs or benefits from PacifiCorp's coal resources after 2025, in accordance with Washington Clean Energy Transformation Act (CETA) requirements and Washington Utilities and Transportation Commission (WUTC) orders.

Figure 1: Forecast Available Resources

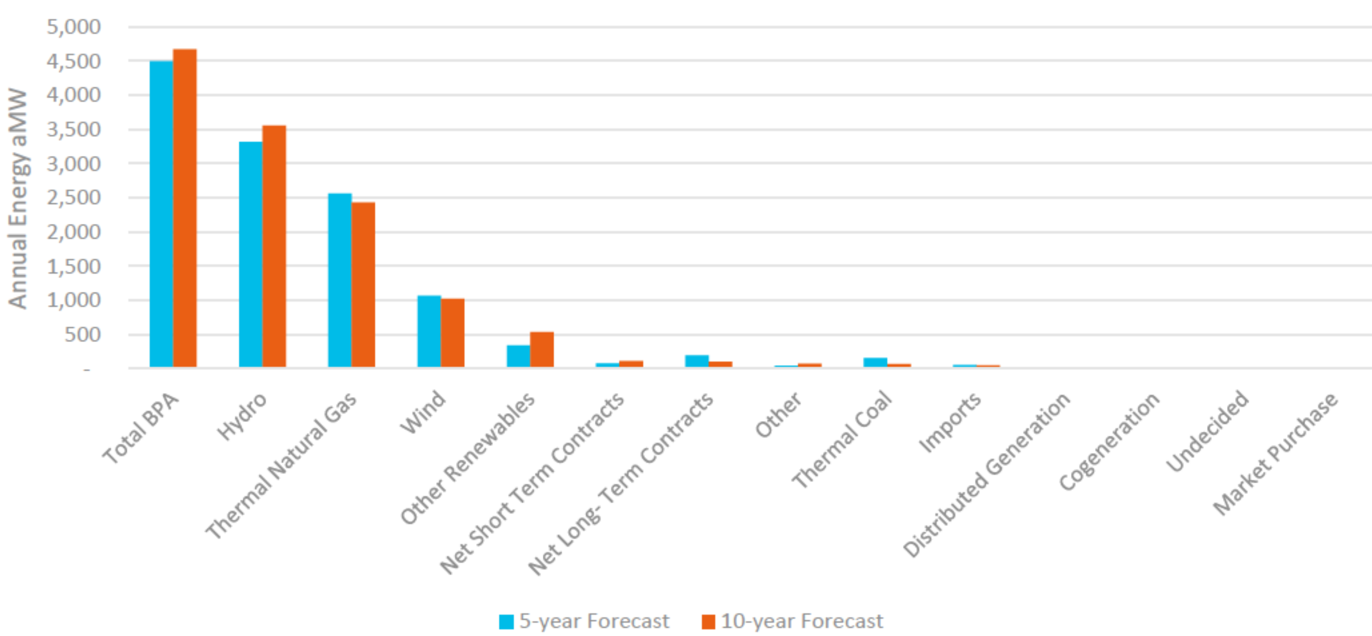

Table 2 presents in average-megawatts the differences between the 2022 and 2020 resource reports on statewide annual utility load and resources and the five and 10-year forecasts.

Table 2 shows a diminished contribution from coal-fired electricity generation in the forecast period, and an increased reliance on natural gas-fired generation, wind power, other renewables, and BPA resources.

The shift in electric generation resources shows progress towards meeting the requirements of the Clean Energy Transformation Act (CETA). CETA prohibits utilities from using coal generation after 2025.[8] It requires all retail sales of electricity to Washington be greenhouse gas neutral by 2030[9] and 100% non-emitting by 2045.[10]

Table 2: Difference between 2022 and 2020 Requirements and Resources - Annual Energy aMW

	Base Year	5-year Forecast	10-year Forecast
Requirements			
Loads	(105)	43	(9)
Exports	(107)	(40)	(1)
Energy Conservation Measures	-	88	(2)
Demand Response	-	(13)	(23)
Total Net Requirements	**(213)**	**78**	**(35)**
Resources			
Total BPA	(57)	212	265
Hydro	(379)	127	193
Thermal Natural Gas	606	675	690
Wind	119	395	448
Other Renewables	61	188	257
Net Short-Term Contracts	(32)	(243)	(221)
Net Long-Term Contracts	553	(302)	8
Other	42	49	71
Thermal Coal	(252)	(527)	(402)
Imports	(76)	2	(6)
Distributed Generation	2	4	5
Cogeneration	2	(0)	11
Undecided	-	(10)	(14)

[8] Section 19.405.030(1), Coal-fired resources-Depreciation schedule-Penalties. (2022, June 29). Retrieved from Revised Code of Washington: https://app.leg.wa.gov/RCW/default.aspx?cite=19.405.030
[9] Section 19.405.040(1), Greenhouse gas neutrality-Responsibilities for electric utilities-Energy transformation project criteria-Penalties. (2022, June 29). Retrieved from Revised Code of Washington: https://app.leg.wa.gov/RCW/default.aspx?cite=19.405.040
[10] Section 19.405.050(1), Clean energy implementation-Hydroelectric facilities-Special contracts. (2022, June 29). Retrieved from Revised Code of Washington: https://app.leg.wa.gov/RCW/default.aspx?cite=19.405.050

	Base Year	5-year Forecast	10-year Forecast
Market Purchase	(10)	(34)	(43)
Total Resources	**580**	**535**	**1,262**
Load Resource Balance	**792**	**459**	**1,297**

Most Washington utilities experience their annual peak load during the winter months. Table 3 presents utilities' aggregated report information for their highest estimated one-hour load during the winter season,[11] including imports and exports, for the base year (2021), and the five and 10-year forecasts. Because electricity demand tends to be higher during the winter season compared to other seasons, utilities rely more extensively on dispatchable thermal resources and short-term contracts to meet load during the winter season. Demand response is also an important resource during the winter, as this reduces the need for utilities to operate gas turbines or make market purchases during periods of very high demand. Utilities forecast reduced use of long-term contracts, coal, and BPA resources to meet summer peak and winter peak requirements in the five-year and 10-year forecasts.

Table 3: Washington Projected Requirements and Resources - Winter Capacity MW

	Base Year	5-year forecast	10-year forecast	5-year change	10-year change
Requirements					
Loads	12,721	13,623	14,640	902	1,919
Exports	263	188	162	(75)	(102)
Energy Conservation Measures		(524)	(1,006)	(524)	(1,006)
Demand Response		(202)	(387)	(202)	(387)
Total Net Requirements	**12,985**	**13,086**	**13,409**	**102**	**425**
Resources					
Hydro	3,225	4,595	5,146	1,370	1,920
Total BPA	3,762	3,506	3,650	(256)	(112)
Wind	233	310	323	77	90
Other Renewables	68	130	179	61	111
Thermal Natural Gas	3,175	2,849	3,258	(326)	83
Cogeneration	15	16	16	0	0
Thermal Coal	935	342	263	(593)	(672)
Other	20	112	244	92	224
Undecided	-	-	-	-	-
Imports	309	323	305	13	(5)
Distributed Generation	1	2	3	1	2
Net Short-Term Contracts	1,836	1,816	1,892	(20)	56

[11] Table 1 expressed in energy units of aMW, Table 3 in capacity units of MW.

	Base Year	5-year forecast	10-year forecast	5-year change	10-year change
Net Long-Term Contracts	1,396	114	70	(1,282)	(1,326)
Market Purchase				-	-
Total Resources	**14,976**	**14,114**	**15,349**	**(862)**	**372**
Load Resource Balance	**1,991**	**1,028**	**1,939**	**(964)**	**(52)**

Table 4 presents a time series of Commerce Utility Resource Plans. The information in the table presents aggregated annual utility loads (base year, five-year and 10-year) for the 2008 through 2022 Commerce reports. The forecast loads do not include the energy conservation measure (ECM) forecast by utilities. Figure 2 presents the information in Table 4 in a graphical format. Table 5 and Figure 3 present the aggregated annual utility loads (base-year, five-year and 10-year) and include energy conservation measures and demand response forecasts by utilities.

Table 4 and Table 5 and Figure 2 and Figure 3 show load growth forecasts by utilities for the five and 10-year out points have been trending down with each successive report. By comparing Figure 2 and Figure 3 it is evident that utility conservation programs significantly reduce aggregate load growth.

Table 4: Utility Report Time Series — Base Year and Forecast Loads Without Energy Conservation Measures

Utility Report Year	Base Year	Base Year, aMW	5-year Est.	5-year Est. aMW	10-year Est.	10-year Est. aMW
2008	2007	10,008	2012	11,304	2017	12,270
2010	2009	10,606	2014	11,737	2019	12,717
2012	2011	10,265	2016	11,264	2021	12,126
2014	2013	10,166	2018	11,502	2023	12,380
2016	2015	10,099	2020	10,875	2025	11,576
2018	2017	10,231	2022	10,816	2027	11,356
2020	2019	10,307	2024	10,775	2029	11,372
2022	2021	10,202	2026	10,818	2031	11,363

Figure 2: Utility Report Time Series — Base Year and Forecast Loads Without Energy Conservation Measures

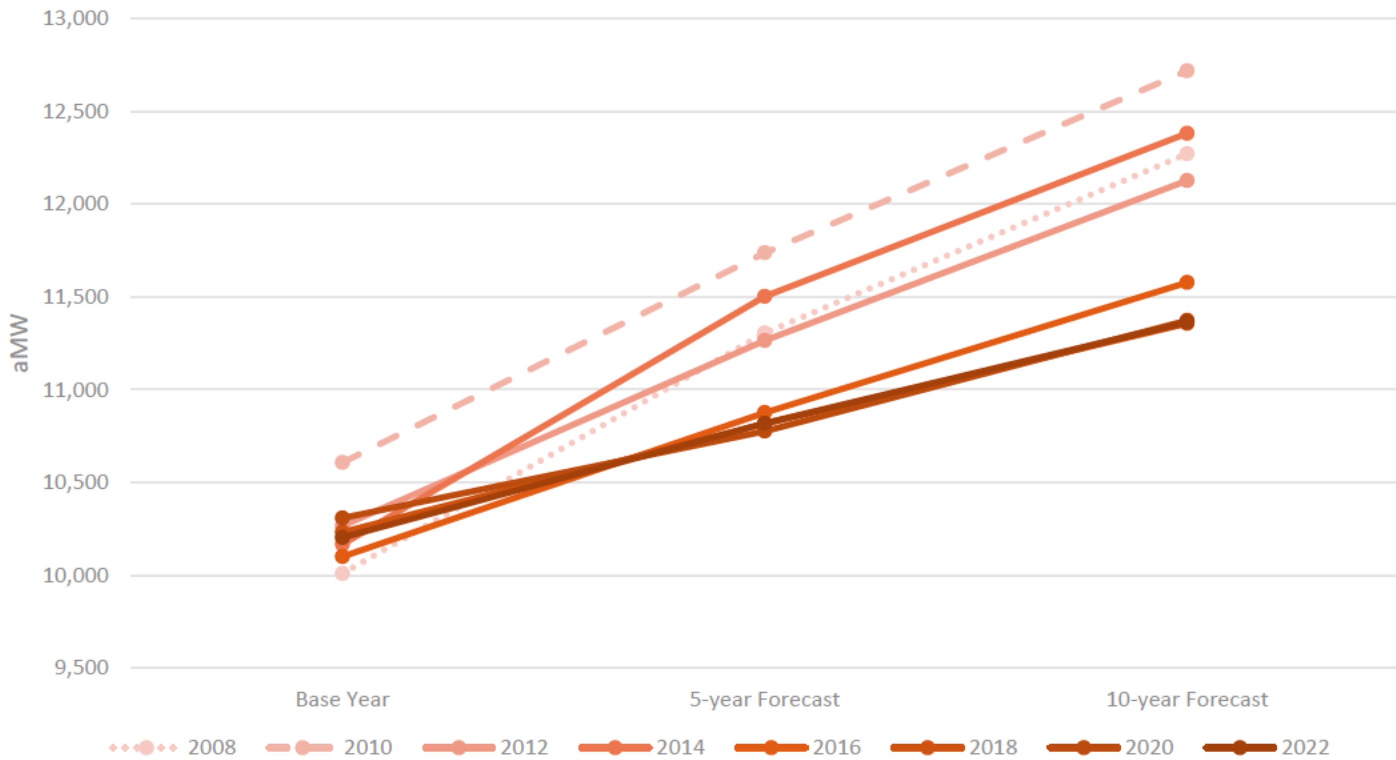

Table 5: Utility Report Time Series — Base Year and Forecast Loads with ECM and Demand Response

Utility Report Year	Base Year	Base Year, aMW	5-year Est.	5-year Est. aMW	10-year Est.	10-year Est. aMW
2008	2007	10,008	2012	10,890	2017	11,524
2010	2009	10,555	2014	11,145	2019	11,691
2012	2011	10,265	2016	10,692	2021	11,107
2014	2013	10,166	2018	11,017	2023	11,423
2016	2015	10,099	2020	10,347	2025	10,629
2018	2017	10,231	2022	10,345	2027	10,582
2020	2019	10,307	2024	10,272	2029	10,548
2022	2021	10,202	2026	10,389	2031	10,514

Figure 3: Utility Report Time Series — Base Year and Forecast Loads with ECM and Demand Response

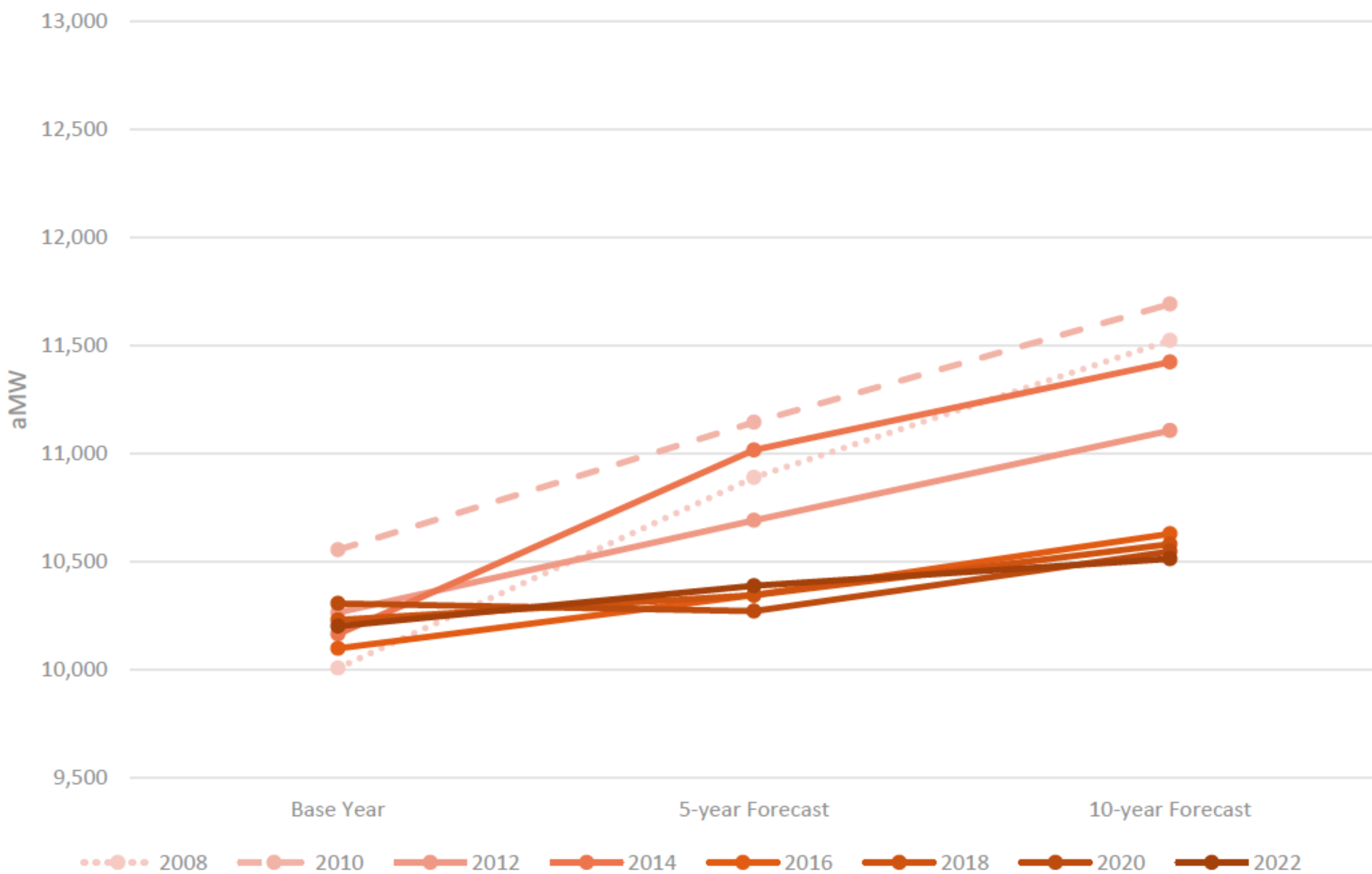

Table 6 presents the individual utility growth forecasts and the percent of load growth anticipated to be met by energy conservation measures. For example, Benton County PUD No 1 estimates a load growth of 14.2 aMW or 6.52% by 2031. Benton County PUD No 1 estimates 11.72 aMW of energy conservation measures by 2031, and 82.52% of that load growth will be met by energy conservation measures (11.72 aMW/14.2 aMW=82.52%). Several utilities (Chelan, Douglas, and Grant PUDs) are forecasting very high load growth rates over the next 10 years due to the growth of data centers, computing demand, and cryptocurrency mining. Chelan County PUD forecasts the average base case annual growth rate for High Density Loads, Cryptocurrency Loads, and Large Loads combined to be 31.88% for their 2023-2032 planning period. In comparison, Chelan County PUD expects its base case residential average annual growth rate to be 1.44% and its base case commercial sector average annual growth rate to be 1.97% during the same planning period.[12] As a result of data center proliferation and the growth of computing demand, especially artificial intelligence, Douglas PUD will experience significant increases in new data loads in the next several years as well. By 2029, new data load will increase from 22% of 2024 load to 58% of 2029 energy load.[13] For Grant County PUD, over the past the decade, industrial class load growth has made up an ever-increasing portion of their total retail load, and data centers have grown to dominate load growth in that sector.[14]

Table 6: Individual Utility Load Forecasts With and Without Conservation

Utility Name	Load Growth with No Conservation		% of Load Growth Met by Conservation	
	5-year Change %	10-year Change %	5-year Conservation	10-year Conservation
Alder Mutual Light Co, Inc	-2.91%	-2.91%	-5.12%	-5.12%
Asotin County PUD No 1	-0.22%	2.27%	0.00%	0.00%
Avista Corp	1.76%	2.65%	275.00%	372.22%
Benton County PUD No 1	2.21%	6.52%	108.46%	82.52%
Benton Rural Electric Assn	-9.18%	-8.28%	-9.40%	-10.43%
Big Bend Electric Coop, Inc	-4.62%	-2.39%	-10.24%	-19.81%
Blaine City Public Works	0.49%	1.14%	#N/A	#N/A
Centralia City Light	2.64%	2.65%	#N/A	#N/A
Chelan County PUD No 1	16.38%	22.25%	16.69%	31.12%
Chewelah Electric Dept	2.94%	2.96%	8.33%	8.29%
City of Cheney Light Dept	15.93%	22.63%	#N/A	#N/A
City of Coulee Dam Light Dept	4.84%	7.27%	14.76%	9.82%
City of McCleary Public Utility	3.85%	7.20%	2.11%	1.13%
City of Milton Electric Division	-0.27%	-0.07%	-44.63%	-178.78%
City of Sumas Electric Services	4.77%	2.28%	2.34%	4.88%
Clallam County PUD No 1	0.31%	0.32%	257.00%	251.45%
Clark County PUD No 1	4.65%	18.40%	#N/A	#N/A
Columbia Rural Elec Assn, Inc	2.80%	5.78%	#N/A	#N/A

12 Chelan County PUD. (2023, p. 15-16). Integrated Resource Plan Progress Report. Retrieved from https://www.chelanpud.org/docs/default-source/default-document-library/irp-2023-book.pdf
13 Douglas PUD. (2024, p. 14, 21-23). Integrated Resource Plan. Retrieved from https://douglaspud.org/wp-content/uploads/2024/02/2024-Draft-IRP.pdf
14 Grant County PUD. (2022, p.25). Integrated Resource Plan. Retrieved from https://www.grantpud.org/templates/galaxy/images/Exhibit_A_2022_Integrated_Resource_Plan.pdf

Utility Name	Load Growth with No Conservation		% of Load Growth Met by Conservation	
	5-year Change %	10-year Change %	5-year Conservation	10-year Conservation
Consolidated Irrigation District No 19	-29.94%	-29.94%	#N/A	#N/A
Cowlitz County PUD No 1	13.04%	20.26%	#N/A	#N/A
Douglas County PUD No 1	21.07%	36.99%	6.66%	8.53%
Eatonville Power & Light Dept	0.73%	1.39%	58.19%	30.61%
Ellensburg Energy Services Dept	1.20%	2.74%	3.49%	1.53%
Elmhurst Mutual Power & Light Co	1.65%	3.66%	33.86%	15.26%
Ferry County PUD No 1	-9.17%	-8.26%	-2.75%	-3.05%
Franklin County PUD No 1	29.74%	33.72%	#N/A	#N/A
Grant County PUD No 2	28.53%	44.52%	4.53%	6.47%
Grays Harbor County PUD No 1	-2.27%	-3.79%	-22.00%	-18.00%
Inland Power & Light Company	10.41%	21.90%	2.72%	2.93%
Jefferson County PUD No 1	2.49%	4.11%	23.00%	13.94%
Kalispel Tribal Utilities	20.05%	27.45%	0.00%	0.00%
Kittitas County PUD No 1	2.99%	8.03%	19.96%	7.43%
Klickitat County PUD No 1	4.77%	11.31%	#N/A	#N/A
Lakeview Light & Power	1.21%	2.23%	65.56%	35.63%
Lewis County PUD No 1	4.49%	7.69%	52.04%	96.94%
Mason County PUD No 1	-2.16%	-0.28%	-6.06%	-47.36%
Mason County PUD No 3	9.77%	16.92%	15.20%	24.96%
Modern Electric Water Company	0.74%	2.93%	157.74%	39.88%
Nespelem Valley Elec Coop, Inc	-0.07%	0.66%	-252.67%	27.55%
Ohop Mutual Light Company, Inc	-0.59%	-0.59%	-3.15%	-3.15%
Okanogan County Elec Coop, Inc	3.95%	16.38%	#N/A	#N/A
Okanogan County PUD No 1	1.05%	3.60%	0.00%	0.00%
Orcas Power & Light Coop	0.67%	4.08%	25.57%	4.18%
Pacific County PUD No 2	7.18%	10.22%	38.46%	24.32%
PacifiCorp	3.46%	9.07%	206.79%	139.63%
Parkland Light & Water Company	-0.09%	0.93%	-320.63%	29.33%
Pend Oreille County PUD No 1	3.75%	11.77%	#N/A	#N/A
Peninsula Light Company	-5.20%	-4.78%	-13.26%	-28.82%
Port Angeles City Light	-1.36%	-1.36%	-7.12%	-7.12%
Port of Seattle	6.66%	6.66%	15.93%	15.93%
Puget Sound Energy, Inc	5.88%	12.80%	144.90%	130.31%
Richland Energy Services	0.77%	1.77%	388.37%	504.04%
Seattle City Light	0.47%	2.99%	960.00%	265.63%
Skamania County PUD No 1	-4.08%	-2.15%	-0.88%	-1.68%
Snohomish County PUD No 1	1.87%	5.16%	183.80%	189.06%

Utility Name	Load Growth with No Conservation		% of Load Growth Met by Conservation	
	5-year Change %	10-year Change %	5-year Conservation	10-year Conservation
Steilacoom Public Works	-0.12%	2.30%	-10.97%	5.62%
Tacoma Power	1.51%	-3.70%	150.62%	-129.65%
Tanner Electric Coop	0.42%	3.19%	18.37%	2.44%
Town of Ruston Utility Dept	1.85%	-3.70%	#N/A	#N/A
Vera Irrigation District #15	-3.23%	-0.78%	-3.36%	-13.84%
Wahkiakum County PUD No 1	-1.96%	-0.50%	-1.89%	-7.46%
Whatcom County PUD No 1	14.43%	13.19%	0.00%	0.00%

The current round of utility resource plans indicates a continued reliance on energy conservation measures as the primary resource for balancing electricity supply and demand. The statewide aggregate growth in electricity demand is expected to be moderate with an average load growth of 3.15% over the five-year forecast and 6.16% over the 10-year forecast without conservation. The load growth projections may be conservative for 2022 because some of the utility resource plan results do not fully account for the impacts of climate change or new policies passed after 2021. Several utilities (Avista, Benton PUD, Seattle City Light, PacifiCorp and Puget Sound Energy) project that their energy conservation programs will result in more electricity savings than their projected amount of load growth. These utilities expect to experience negative growth in observed electric loads. With the majority of load growth met by energy conservation programs, new renewable resources primarily serve to replace retiring coal-fired generation and thermal natural gas generation.

Overgeneration

In 2013, the Legislature amended the resource planning statute to address concerns about the potential for "overgeneration" events.[15] The legislation required that utilities consider this potential in their planning "if applicable to the utility's resource portfolio," and required that Commerce include in this report an assessment of utility approaches to overgeneration.

The statute defines an overgeneration event as:

> *An event within an operating period of a balancing authority when the electricity supply, including generation from intermittent renewable resources, exceeds the demand for electricity for that utility's energy delivery obligations and when there is a negatively priced regional market.*

Overgeneration is also referred to as oversupply, and the consequence is generation curtailment. It might occur when high river flows and high wind volumes coincide. It might also occur when the hours of solar generation misaligns with peak electricity demand. The capacity of the hydroelectric system to store extra river flow is limited, and even the option of spilling water over the dams is restricted by fish mortality concerns. In these circumstances, the regional power system may have more electric generation from hydroelectric, wind, and solar resources than what is required to meet regional loads and export opportunities.

[15] Section 19.280.060, Department's duties—Report to the legislature. (2022, June 29). Retrieved from Revised Code of Washington: https://app.leg.wa.gov/RCW/default.aspx?cite=19.280.060

Since 2013, the Bonneville Power Administration has adopted an Oversupply Management Protocol, providing tools for the operators of the hydroelectric system and transmission grid to manage oversupply situations.[16] The implementation of this protocol has generally shifted the overgeneration issue from a planning concern to an operational concern.

In many cases, utilities did not find it necessary in their 2020-2022 resource plans to address overgeneration, or generation curtailment, as an issue separate from the more general assessment of generating resource alternatives.

Resource adequacy

Most utilities plan to meet load requirements in the lowest-cost, least-risk way by renewing BPA contracts (for slice or block products or shifting to a load following product), maximizing energy conservation measures, and implementing new demand response programs. Many consumer-owned utilities already have 80% or more renewable electric generation, and they plan to comply with CETA requirements between 2030 and 2045 using renewable energy credits.[17] With increased demand for renewables, some utilities, such as Clark PUD and Seattle City Light, have requested 100% clean block products from BPA. Some utilities, such as Centralia City Light, would like BPA to find a way to eliminate unspecified power purchases; otherwise, they would have to purchase renewable energy credits to cover the unspecified purchases by BPA to comply with CETA.[18]

Other strategies utilities reported considering include:

- Developing the Western Resource Adequacy Program
- Investigating dispatchable, renewable and non-emitting resources such as batteries, hydrogen, geothermal, and small modular nuclear reactors
- Diversifying the geographic location of their renewable resources
- Utilities reported transmission constraints as a key constraint to accessing cheap renewable resources.

There has been significant progress in the development of a Resource Adequacy Program; however, significant work remains in developing the Western Resource Adequacy Program. Grant PUD explains: "[T]he Western Resource Adequacy Program (WRAP), aims to set regional standards for planning methods and metrics, provide load and resource diversity savings, and establish a robust procurement process... There are many challenges that will need to be overcome for establishing a Resource Adequacy program unique to the Northwest, including the lack of an organized market administrator, the large number of consumer-owned utilities, the significant amount of hydropower resources and the size and role of Bonneville Power Administration (BPA). In addition, questions remain on how WRAP might coexist with energy imbalance and day-ahead markets."[19]

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[16] Oversupply. (n.d.). Retrieved from Bonneville Power Administration: https://www.bpa.gov/energy-and-services/transmission/oversupply

[17] Section 19.405.040(1) states that it is the policy of the state that all retail sales be greenhouse gas neutral by January 1, 2030, and that through December 31, 2044, an electric utilities may satisfy up to 20% of its compliance obligation using an alternative compliance option, such as unbundled renewable energy credits.

[18] Centralia City Light. (2022, p.34). 2022 Electric Utility Resource Plan Update. Retrieved from https://cityofcentralia.com/DocumentCenter/View/1938/2022-Electric-Utility-Resource-Plan-PDF?bidId=

[19] Grant Public Utility District. (2022, p.32). Integrated Resource Plan. Retrieved from https://www.grantpud.org/templates/galaxy/images/Exhibit_A_2022_Integrated_Resource_Plan.pdf

Regional resource forecasts

PNUCC 2022 Northwest Regional Forecast

The Pacific Northwest Utilities Conference Committee (PNUCC) is an electric utility association that compiles information on expected loads and resources of electric utilities in the Pacific Northwest. It includes the loads and resources of Washington utilities along with those of utilities in Oregon, Idaho and Montana.[20] Washington state is the largest state in the Northwest Regional Planning Area which is the area defined by the Pacific Northwest Electric Power Planning and Conservation Act.

The 2022 Northwest Regional Forecast (through 2032) highlighted three key themes:

- A significant transition from thermal generation to clean energy resources is underway in the Pacific Northwest and the rest of the Western Interconnection, with coal plant retirements and increasing adoption of variable clean energy resources. The transition in the Pacific Northwest in large part due to Washington's Clean Energy Transformation Act and Oregon's Renewable Porfolio Standard.[21]
- A variety of new policies that promote electrification such as Washington's Climate Commitment Act, Washington State's new building code standards, and Oregon's Climate Change Executive Order 20-40 are contributing to the challenges of electricity demand forecasting. The shift to a more variable clean power supply coinciding with growth in electricity demand due to electrification results in a growing need to address resource adequacy issues and increasing winter and summer peak deficits.
- Continued robust energy efficiency acquisition efforts and new demand response efforts by Northwest utilities.

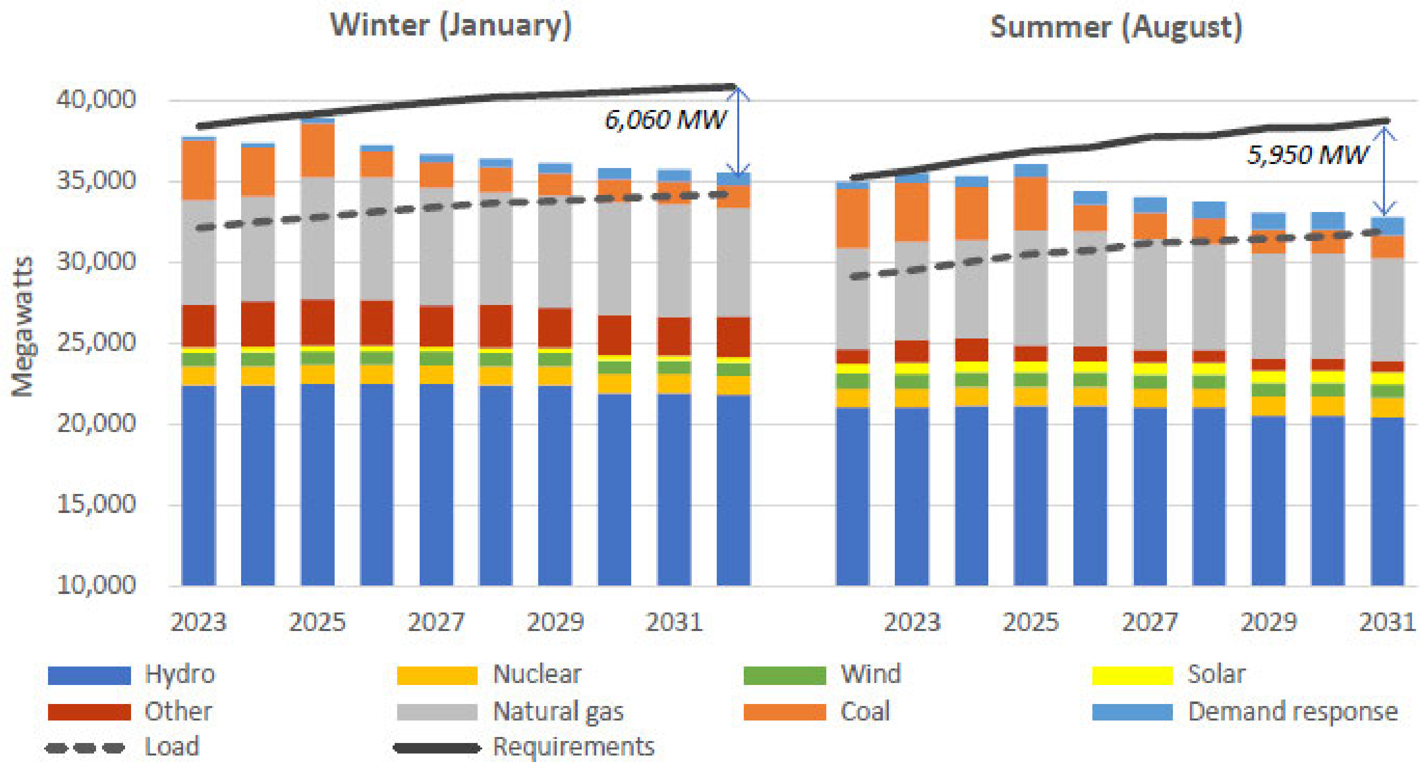
The report concluded that more regional utilities are expecting modest growth in retail loads through the forecast period compared to the previous year. Load growth is largely coming from new industrial loads that include server farms and a growing population in eastern Washington, Idaho, and western Montana. The load growth is diminished due to energy efficiency programs, as well as energy codes and standards. However, estimates of load growth may be conservative because many utilities are only just beginning to examine the implications of electrification and climate change in their load forecasts. In PNUCC's request for data, utilities representing just over 25% of load indicated that they factored in climate change, and utilities making up 30% of regional load are directly accounting for some electrification.[22] The inclusion of electrification in load forecasts will increase load estimates, and the inclusion of climate change impacts will increase summer load estimates while decreasing winter supply estimates.

PNUCC highlights winter-peaking requirements as a continuing concern. Additionally, as shown in

[20] Pacific Northwest Utilities Conference Committee. (2022). Northwest Regional Forecast of Power Loads and Resources 2022 through 2032. Retrieved from https://www.pnucc.org/wp-content/uploads/2022-PNUCC-Northwest-Regional-Forecast-final.pdf
[21] Idaho and Montana do not have any renewable portfolio standards. Montana's renewable portfolio standard of fifteen percent renewable energy by 2015 was repealed in 2021. Source: State Renewable Portfolio Standards and Goals. (2021). Retrieved from National Conference of State Legislatures: https://www.ncsl.org/energy/state-renewable-portfolio-standards-and-goals
[22] (Pacific Northwest Utilities Conference Committee, 2022, p. 6)

Figure 4, the summer peak deficit is widening to nearly match the expected winter peak deficit in the future. The region's projected peak demand is projected to exceed utilities' firm resources in every year of the planning period. The supply of winter peaking and summer peaking resources does not include out-of-region imports, the capacity of independent power projects within the Northwest or hydroelectric system capacity in excess of critical water conditions.

Figure 4: Northwest Utilities Peak Capacity Load/Resource



Source: Pacific Northwest Utilities Conference Committee

The compiled results from PNUCC indicate that the Northwest utilities collectively expect to have surplus energy resources for the 2022-23 operating years on an annual energy basis. The regional forecast shows an energy deficit starting in 2023-2024 (19 aMW) and continuing to grow through the end of the 10-year planning period (3,790 aMW). Much of the deficit is the result of the retirement of coal plants. Just over 2,100 MW of coal have already retired in the Northwest, with more to come. And by 2025, two coal plants[23] (almost 1,100 MW) will be converted to natural gas-fired generation.[24]

According to PNUCC, Northwest utilities made capacity additions of 58 MW in 2019 and are committed to adding nearly 1,647 MW of capacity from 2020 through 2025 -- primarily wind, solar, battery projects with one natural gas plant. PNUCC identifies a larger amount of planned resources in the region. Planned resources through 2032 are estimated at 9,447 MW of capacity and include 3,385 MW of wind, 2,130 MW of standalone solar, 2,541 MW of solar capacity with battery storage, as well as over 2,000 MW of dispatchable resources, such as natural gas and storage (for peak demand). However, they are not included in the forecast because they have less certainty from a financial or regulatory standpoint.

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[23] PacifiCorp is converting Jim Bridger 1 and 2 in Wyoming to natural gas in order to keep operating them while complying with federal regional haze requirements. Source: NewsData. (2023, August 25). PacifiCorp Coal Units Set for Conversion to Natural Gas This Fall. Retrieved from https://www.newsdata.com/clearing_up/supply_and_demand/pacificorp-coal-units-set-for-conversion-to-natural-gas-this-fall/article_9802600e-435f-11ee-9dba-a3fe639f5da2.html

[24] (Pacific Northwest Utilities Conference Committee, 2022, p. 4)

Pacific Northwest Power Supply Adequacy Assessment for 2027

The Northwest Power and Conservation Council , which is the region's premier power planning body, evaluated the adequacy of the Northwest electric power supply in 2023 and concluded that the 2027 regional power supply would be adequate if the region's utilities add the resources identified in the Council's most recent regional power plan. Power supply would not be adequate if the region relied solely on existing resources, existing reserve levels, and no new energy efficiency measures.

Traditionally, resource adequacy was assessed through the loss of load probability metric which is limited to 5%. However, this metric fails to indicate the shortfall magnitude, duration, or frequency. To better assess customer risk, the Council examined additional metrics and proposed standards for each one. These metrics are loss of load events (LOLEV), duration value at risk (VaR Duration), and peak (VaR Peak) and energy value at risk (VaR Energy).[25] If demand growth remains consistent with the plan's baseline forecast, then the power supply would be adequate with resources and reserves identified in the 2021 Power Plan's resource strategy.

However, if future electricity market supplies are significantly limited, if new policy commitments to electrification accelerate demand growth, or if major coal resources are retired earlier than expected without replacement, then additional resources and reserves will be required to maintain system adequacy. More work needs to be done to understand how the average load increase in the regional load forecast compare to the actual expected load growth driven by new policies implemented since the adoption of the 2021 Power Plan. Given the passage of recent electrification policies and recent global instability, the current resource strategy may be inadequate to ensure resource adequacy and reliability in 2027 based on the estimates of resource adequacy metrics.

This assessment also found that the 2021 Power Plan resource strategy is effective at eliminating nearly all summer shortfalls, when resource needs peak in the rest of the Western Interconnection (outside of the Pacific Northwest region).[26] Implementing the strategy does not eliminate winter shortfall events, but it does mitigate them by reducing shortfall event magnitude and shortening event duration to only a few hours during the morning and evening ramps.[27] New clean energy policies will result in market supply and demand dynamic changes because the hours of renewable generation will not always coincide with the hourly pattern of greatest energy need. Under the limited markets and high Western Electricity Coordinating Council (WECC) interconnection demand scenarios, summer market imports decrease in the morning and summer evening imports are eliminated. Under the limited markets and high WECC demand scenarios, the winter morning ramp period has increased imports. Transmission limitations within the Western grid may have a larger influence on market dynamics, as it may not be adequate to meet the import needs of California and Canada under certain scenarios.

[25] Northwest Power and Conservation Council. (2023, p.4). Pacific Northwest Power Supply Adequacy Assessment for 2027. Retrieved from https://www.nwcouncil.org/reports/2023-1/

[26] (Northwest Power and Conservation Council, 2023, p. 5). The Northwest Power Plan applies to the Pacific Northwest states (Washington, Oregon, Idaho, and Montana). The interconnected Western power grid encompasses 14 states, two Canadian provinces, and a portion of Mexico.

[27] (Northwest Power and Conservation Council, 2023, p. 29)

2022 Western Assessment of Resource Adequacy[28]

The WECC is a regional entity with authority delegated under the Federal Power Act to ensure a reliable and secure bulk power system in the Western Interconnection. As the only independent, interconnection-wide organization in the West, WECC creates and enforces reliability standards.

The Western Assessment of Resource Adequacy provides assessments for the Western Interconnection and five subregions. Washington is part of the Northwest Power Pool subregion. Over the next decade, entities will retire nearly 26 GW of resources, mostly coal and natural gas, while building close to 80 GW of new generation and energy storage resources, three-quarters of which will be solar, wind, and battery storage. The resource mix in 2032 will be very different and highly variable. This is because solar and wind resources have constantly changing energy outputs and limited dispatchability. Additionally, it is uncertain how electrification, energy efficiency, and new technologies will affect demand over the next decade. The assessment shows some near-term reduction in resource adequacy risk, but WECC foresees an increasing risk over the next 10 years. Not only is resource adequacy risk growing, but it is spreading throughout beyond the peak load seasons.

WECC uses two measures of resource adequacy: demand-at-risk indicator and planning reserve margin indicator. The demand-at risk indicator (DRI) is the number of hours in a year when demand is at risk. Planning reserve margin indicator (PRMI) is a measure of variability on the system. WECC presents major findings and recommendations to manage resource adequacy risks:

- **The increase in PRMI indicates that entities may need to plan for more reserves or take other actions to account for the increased variability.** Mitigation actions could include adding dispatchable resources; increasing demand management measures; participating in subregional cooperative efforts; supporting the research and development of new technology; and improving coordination of transmission planning and operation.
- **New challenges like supply chain disruption, skilled workforce shortages, and siting issues may impede or delay the build-out of new resources.** WECC recommends resource plans should include contingency plans to manage the risk of impediments to building planned resources. State commissions and regulatory bodies should continue to scrutinize integrated resource plans to ensure that utilities are planning for the increased risks.
- **All subregions rely on imports to help be resource adequate; however, the risk of wide-spread variability could create situations where the imports that entities depend on are not available.** WECC recommends that the Western Interconnection evaluate resource and transmission adequacy in a coordinated fashion through comprehensive wide-area system planning.
- **Uncertainty about future impacts to demand of electrification, energy efficiency, new technology, and other factors creates difficulties for load forecasting.** WECC recommends that some entities will need to evaluate and adapt their resource planning approaches to account for increased future uncertainty.

[28] Western Electricity Coordinating Council. (2022). Western Assessment of Resource Adequacy. Retrieved from https://www.wecc.org/Reliability/2022%20Western%20Assessment%20of%20Resource%20Adequacy.pdf

Appendix A: Utility Cover Sheets

Washington Electric Utility Loads and Resources Estimates reported to the Department of Commerce in 2022

Avista Utilities

Washington State Utility Integrated Resource Plan Year 2022									
Prepared by: Mike Hermanson									
		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		2022			2027			2032	
Period	Winter	Summer	Annual	Winter	Summer	Annual	Winter	Summer	Annual
Units	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)
Loads	1,086.00	1,019.00	680.00	1,135.00	1,037.00	692.00	1,186.00	1,056.00	698.00
Exports	36.00	5.00	19.00	0.00	0.00	0.00	0.00	0.00	0.00
Resources:									
Future Conservation/Efficiency				34.00	38.00	33.00	70.00	75.00	67.00
Demand Response				23.00	23.00		26.00	25.00	
Cogeneration									
Hydro	773.00	748.00	371.00	720.00	696.00	351.00	711.00	639.00	344.00
Wind	8.00	8.00	60.00	75.00	75.00	151.00	103.00	106.00	196.00
Other Renewables	31.00	37.00	31.00	31.00	37.00	31.00	31.00	37.00	31.00
Thermal - Natural Gas	576.00	478.00	425.00	483.00	403.00	370.00	483.00	403.00	370.00
Thermal - Coal	222.00	222.00	222.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Long Term Contracts	26.00	22.00	25.00	26.00	22.00	25.00	26.00	22.00	25.00
Net Short Term Contracts									
BPA									
Other									
Imports									
Distributed Generation									
Undecided									
Total Resources	**1,636.00**	**1,515.00**	**1,134.00**	**1,392.00**	**1,294.00**	**961.00**	**1,450.00**	**1,307.00**	**1,033.00**
Load Resource Balance	**514.00**	**491.00**	**435.00**	**257.00**	**257.00**	**269.00**	**264.00**	**251.00**	**335.00**

Date of Board/Commission Approval: N/A

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Loads are 1 in 2 expected values and do not include any consideration of planning margin. Reported loads and resources represent the Washington share of Avista's system. Resources include new resource selection in 2027 of 100 MW of NG CT new facilities and upgrades, 67 MW of wind, and 23 MW of DR. New Resources in addition to those selected in 2027 include 3 additional MW of DR, 44 MW of hydro, and an additional 28 MW of wind. These resource selections provide a resource balance commensurate with Avista planning parameters.

PUD No. 1 of Chelan County

Washington State Utility Integrated Resource Plan Year 2022									
Prepared by: Becky Keating									
		Base Year			**5 Year Estimate**			**10 Year Estimate**	
Estimate Year		**2020**			**2025**			**2030**	
Period	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**
Units	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**
Loads	446.00	243.00	204.50	522.93	274.73	238.00	547.16	289.01	250.00
Exports									
Resources:									
Future Conservation/Efficiency				11.93	6.73	5.59	30.16	17.01	14.16
Demand Response									
Cogeneration									
Hydro	419.00	220.00	189.00	770.00	386.00	338.00	1,227.00	603.00	532.00
Wind	0.37	0.33	2.58	1.38	0.76	2.25	1.38	0.76	2.25
Other Renewables									
Thermal - Natural Gas									
Thermal - Coal									
Net Long Term Contracts									
Net Short Term Contracts									
BPA									
Other									
Imports									
Distributed Generation									
Undecided									
Total Resources	**419.37**	**220.33**	**191.58**	**783.31**	**393.49**	**345.84**	**1,258.54**	**620.77**	**548.41**
Load Resource Balance	**-26.63**	**-22.67**	**-12.92**	**260.38**	**118.76**	**107.84**	**711.38**	**331.76**	**298.41**

Date of Board/Commission Approval: December 21

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Appendix B in Chelan PUD's IRP includes this cover sheet with supplemental information on loads and resources.

Clark Public Utilities

Washington State Utility Integrated Resource Plan Year 2022

Prepared by: Steve Andersen

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		2021			2026			2031	
Period	Winter	Summer	Annual	Winter	Summer	Annual	Winter	Summer	Annual
Units	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)
Loads	967.96	1,016.20	553.68	1,024.00		579.41	1,331.00		655.58
Exports									
Resources:									
Future Conservation/Efficiency									
Demand Response									
Cogeneration									
Hydro	5.00	5.00	1.75	80.00		51.74	80.00		51.74
Wind	6.00	0.00	16.31	9.00		18.13	9.00		18.00
Other Renewables									
Thermal - Natural Gas	255.40	203.80	221.80	265.00		227.16	265.00		102.00
Thermal - Coal									
Net Long Term Contracts									
Net Short Term Contracts	200.56	473.40	72.00						
BPA	506.00	340.00	323.74	554.00		363.96	762.00		500.48
Other				4.00		4.18	5.00		4.72
Imports									
Distributed Generation									
Undecided									
Total Resources	**972.96**	**1,022.20**	**635.59**	**912.00**	**0.00**	**665.17**	**1,121.00**	**0.00**	**676.94**
Load Resource Balance	**5.00**	**6.00**	**81.91**	**-112.00**	**0.00**	**85.76**	**-210.00**	**0.00**	**21.36**

Date of Board/Commission Approval: August 22

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Line 10: Historic 2021 actual winter and summer peak demands and annual energy. Projected 2026 and 2031 winter peak demands and annual energy. A summer peak demand forecast is not included in the IRP update. Line 16: Hydro includes the Packwood Hydroelectric Project (CPU receives an 18% share of project generation) and a future Power Purchase Agreement
Line 17: Wind is the Combine Hills II Wind Project (CPU receives 100% of project generation)
Line 19: Natural Gas is the River Road Generating Plant
Line 21: Net Short Term Contracts includes all historic market purchases
Line 24: Other is future market balancing purchases

Cowlitz PUD

Washington State Utility Integrated Resource Plan Year 2022

Prepared by: TEA

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		2021			2026			2031	
Period	Winter	Summer	Annual	Winter	Summer	Annual	Winter	Summer	Annual
Units	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)
Loads	725.03	608.54	515.24	893.34	780.77	582.41	977.36	846.58	619.63
Exports									
Resources:									
Future Conservation/Efficiency									
Demand Response									
Cogeneration									
Hydro	76.20	78.50	24.49	79.00	79.00	15.80	79.00	79.00	15.80
Wind	0.82	1.04	40.01	0.00	0.00	34.71	0.00	0.00	0.00
Other Renewables									
Thermal - Natural Gas									
Thermal - Coal									
Net Long Term Contracts									
Net Short Term Contracts				212.68	173.87		340.84	193.81	61.89
BPA	776.00	614.00	455.06	601.66	527.90	541.70	557.52	573.77	541.94
Other									
Imports									
Distributed Generation									
Undecided									
Total Resources	**853.02**	**693.54**	**519.56**	**893.34**	**780.77**	**592.21**	**977.36**	**846.58**	**619.63**
Load Resource Balance	**127.99**	**85.00**	**4.32**	**0.00**	**0.00**	**9.80**	**0.00**	**0.00**	**0.00**

Date of Board/Commission Approval: August 22

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Line 10: Base year seasonal peak loads are not weather adjusted. Actual summer peak occurred: 8/11/21 HE 19 Actual winter peak occurred: 12/27/21 HE 18; Annual average load is weather normalized
Line 13: Loads were forecasted using regression methodology that captured conservation effects and trends, therefore conservation is not captured as a separate line item
Line 16: Hydro resources include Swift No. 2, Wanapum, and Priest Rapids, Winter and Summer values represent actual average peak generation and the Annual value reflects the yearly average
Line 17: Wind resources include White Creek Wind, Nine Canyon Wind, and Harvest Wind--Peak MW represent wind actuals on winter and summer load peaks
Line 22 (Net Short Term Contracts): Future energy and capacity beyond the District portfolio will continue to be supplemented with market purchases on a short-term basis.
Line 23: Winter and Summer values for 2021 represent the maximum peak slice + block BPA power and the Annual value is based on actual average slice + block, for 2026 and 2031 critical water assumptions were used for the federal system, the deficits resulting from the critical water assumptions are captured in the Net Short Term Contracts (line 22) and would be purchased from the market.

Public Utility District No. 1 of Douglas County

Washington State Utility Integrated Resource Plan Year 2020 2022

Prepared by: Jeff Johnson

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		2021			2026			2031	
Period	Winter	Summer	Annual	Winter	Summer	Annual	Winter	Summer	Annual
Units	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)
Loads	239.00	179.00	142.56	289.40	209.20	172.60	319.50	226.50	195.30
Exports									
Resources:									
Future Conservation/Efficiency				2.00	2.00	2.00	4.50	4.50	4.50
Demand Response				5.00	5.00	1.00	10.00	10.00	2.00
Cogeneration									
Hydro	355.50	227.30	181.50	444.00	339.00	268.00	452.00	434.00	323.00
Wind	10.00	10.00	2.29	10.00	10.00	2.95	10.00	10.00	2.95
Other Renewables									
Thermal - Natural Gas									
Thermal - Coal									
Net Long Term Contracts	47.00	47.00	47.00						
Net Short Term Contracts									
BPA									
Other									
Imports									
Distributed Generation									
Undecided									
Total Resources	**412.50**	**284.30**	**230.79**	**461.00**	**356.00**	**273.95**	**476.50**	**458.50**	**332.45**
Load Resource Balance	**173.50**	**105.30**	**88.23**	**171.60**	**146.80**	**101.35**	**157.00**	**232.00**	**137.15**

Date of Board/Commission Approval: September 22

Public Utility District No. 2 of Grant County

Washington State Utility Integrated Resource Plan Year 2022

Prepared by: Lisa Stites

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		**2021**			**2026**			**2031**	
Period	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**
Units	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**
Loads	833.57	929.18	639.33	1,008.99	1,146.55	821.73	1,134.57	1,289.25	923.95
Exports									
Resources:									
Future Conservation/Efficiency				8.14	8.40	8.27	17.91	18.91	18.41
Demand Response									
Cogeneration									
Hydro	114.46	124.00	117.74	1,089.19	1,011.29	628.70	1,142.00	1,059.18	638.90
Wind	0.93	1.56	3.52	8.74	12.85	50.10	7.80	10.47	46.82
Other Renewables				62.95	82.30	93.85	114.40	149.41	210.57
Thermal - Natural Gas				198.00	198.00	11.51	270.00	270.00	5.91
Thermal - Coal									
Net Long Term Contracts	702.73	788.18	401.59						
Net Short Term Contracts			110.57			23.90			-2.06
BPA	15.44	15.44	5.90	15.44	15.44	5.40	15.44	15.44	5.40
Other									
Imports									
Distributed Generation									
Undecided									
Total Resources	**833.57**	**929.18**	**639.33**	**1,382.46**	**1,328.28**	**821.73**	**1,567.55**	**1,523.41**	**923.96**
Load Resource Balance	**0.00**	**0.00**	**0.00**	**373.47**	**181.73**	**0.00**	**432.98**	**234.16**	**0.00**

Date of Board/Commission Approval: August 22

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Line 10: Base year load is actual load for 2021
Line 18: Our other renewables includes both stand-alone solar PV and solar PV+battery hybrids

Lewis County PUD 1

Washington State Utility Integrated Resource Plan Year 2022

Prepared by: Luke Canfield

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		2021			2026			2031	
Period	Winter	Summer	Annual	Winter	Summer	Annual	Winter	Summer	Annual
Units	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)
Loads	213.08	148.36	114.63	239.34	154.40	119.78	239.34	158.35	123.45
Exports									
Resources:									
Future Conservation/Efficiency				4.30	2.60	2.68	14.40	9.50	8.55
Demand Response									
Cogeneration									
Hydro	5.12	4.52	1.19	5.12	4.52	1.19	5.12	4.52	1.19
Wind	1.80	1.40	1.60	1.80	1.40	1.60	1.80	1.40	1.60
Other Renewables									
Thermal - Natural Gas									
Thermal - Coal									
Net Long Term Contracts									
Net Short Term Contracts									
BPA	142.00	111.40	114.60	151.22	118.88	120.89	156.63	117.75	126.04
Other									
Imports									
Distributed Generation									
Undecided									
Total Resources	**148.92**	**117.32**	**117.39**	**162.44**	**127.40**	**126.36**	**177.95**	**133.17**	**137.38**
Load Resource Balance	**-64.16**	**-31.04**	**2.76**	**-76.90**	**-27.00**	**6.58**	**-61.39**	**-25.18**	**13.93**

Date of Board/Commission Approval: September 22

Grays Harbor PUD

Washington State Utility Integrated Resource Plan Year 2022

Prepared by: Shailesh Shere

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		**2021**			**2026**			**2031**	
Period	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**
Units	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**
Loads	235.00	143.00	132.00	224.00	138.00	129.00	219.00	136.00	127.00
Exports									
Resources:									
Future Conservation/Efficiency						0.66			0.90
Demand Response									
Cogeneration	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00
Hydro									
Wind	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
Other Renewables									
Thermal - Natural Gas	45.00	45.00	45.00						
Thermal - Coal									
Net Long Term Contracts									
Net Short Term Contracts									
BPA	170.00	129.00	135.70	170.00	129.00	135.00	170.00	129.00	135.00
Other									
Imports									
Distributed Generation									
Undecided									
Total Resources	**236.00**	**195.00**	**201.70**	**191.00**	**150.00**	**156.66**	**191.00**	**150.00**	**156.90**
Load Resource Balance	**1.00**	**52.00**	**69.70**	**-33.00**	**12.00**	**27.66**	**-28.00**	**14.00**	**29.90**

Date of Board/Commission Approval: September 6

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Line 13: Annual data from 2021 Conservation Potential Assessment.
Lines 15 and 17: Assumption Resource Power Contract's will be extended.
Line 23: Assumption we will purchase similar product to the current Slice/Regional Dialogue contract. Current contract expires 9/30/2028.

PacifiCorp

Washington State Utility Integrated Resource Plan Year 2022

Prepared by: Brian Osborn

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		2022			2027			2032	
Period	Winter	Summer	Annual	Winter	Summer	Annual	Winter	Summer	Annual
Units	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)
Loads	699.25	716.34	528.18	767.83	802.04	546.43	803.37	822.11	576.08
Exports	33.23	35.17	6.33	26.60	29.78	3.19	26.63	27.87	3.15
Resources:									
Future Conservation/Efficiency				30.96	74.95	37.74	47.94	120.30	66.88
Demand Response				50.20	61.53	10.75	28.92	27.94	11.32
Cogeneration									
Hydro	91.97	78.57	45.97	73.08	63.83	34.11	70.45	63.12	33.54
Wind	25.31	31.44	103.14	48.75	69.02	166.77	49.99	51.50	177.20
Other Renewables	8.26	31.94	46.61	6.39	48.50	99.45	5.63	11.31	178.56
Thermal - Natural Gas	218.67	192.50	102.65	213.81	187.26	98.54	190.33	172.98	98.88
Thermal - Coal	405.91	372.08	256.54	341.72	318.50	155.81	262.73	256.08	67.31
Net Long Term Contracts	0.00	0.00	6.98	0.00	0.00	0.10	0.00	0.00	0.10
Net Short Term Contracts	49.61	114.11	23.08	0.00	0.00	28.46	0.00	0.00	35.98
BPA									
Other	19.98	26.41	-1.40	108.16	108.68	2.71	238.77	234.65	35.35
Imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distributed Generation	0.21	5.57	2.46	0.71	7.45	3.54	1.25	14.58	6.83
Undecided									
Total Resources	**819.93**	**852.63**	**586.04**	**873.76**	**939.73**	**637.98**	**896.01**	**952.44**	**711.95**
Load Resource Balance	**87.44**	**101.11**	**51.53**	**79.33**	**107.92**	**88.35**	**66.01**	**102.46**	**132.72**

Date of Board/Commission Approval:

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Information is based on the 2021 Update Integrated Resource Plan filed with the Washington Utilities and Transportation Commission on March 31, 2022.
The Load Resource Balance in Capacity primarily reflects the 13% Planning Reserve Margin not included in Loads.

Puget Sound Energy

Washington State Utility Integrated Resource Plan Year 2022

Prepared by: Chris Schaefer

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		**2022**			**2027**			**2032**	
Period	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**
Units	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**
Loads	4,687.00	3,515.00	2,500.00	4,949.00	3,848.00	2,647.00	5,269.00	4,220.00	2,820.00
Exports	24.00	324.00	59.00	0.00	300.00	47.00	0.00	300.00	47.00
Resources:									
Future Conservation/Efficiency				383.00	188.00	213.00	693.00	335.00	417.00
Demand Response				89.00	89.00		198.00	198.00	
Cogeneration									
Hydro	743.00	774.00	514.00	762.00	808.00	505.00	757.00	801.00	504.00
Wind	118.00	118.00	295.00	113.00	113.00	485.00	129.00	129.00	475.00
Other Renewables	28.00	28.00	52.00	28.00	28.00	52.00	27.00	27.00	52.00
Thermal - Natural Gas	2,050.00	1,689.00	1,856.00	1,689.00	2,050.00	1,856.00	2,050.00	1,689.00	1,856.00
Thermal - Coal	307.00	307.00	247.00						
Net Long Term Contracts	612.00	612.00	534.00	63.00	63.00	107.00	44.00	44.00	45.00
Net Short Term Contracts	1,518.00	1,487.00		1,479.00	1,433.00		1,479.00	1,435.00	0.00
BPA									
Other									
Imports	303.00	303.00	50.00	303.00	303.00	50.00	303.00	303.00	50.00
Distributed Generation									
Undecided									
Total Resources	**5,679.00**	**5,318.00**	**3,548.00**	**4,909.00**	**5,075.00**	**3,268.00**	**5,680.00**	**4,961.00**	**3,399.00**
Load Resource Balance	**968.00**	**1,479.00**	**989.00**	**-40.00**	**927.00**	**574.00**	**411.00**	**441.00**	**532.00**

Date of Board/Commission Approval:

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Line 18: PSE's Other Renewables are Solar and Biomass. PSE's Integrated Resource Plan ("IRP") includes the least cost combination of conservation and supply-side resources to meet requirements per WAC 480-100-620. This information is also available in PSE's 2021 IRP, Appendix B, page 30, filed with the Washington Utilities and Transportation Commission ("WUTC") Docket UE-200304, filed April 20, 2021.

City of Richland

Washington State Utility Integrated Resource Plan Year 2022

Prepared by: Sandi Edgemon

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		2021			2026			2031	
Period	Winter	Summer	Annual	Winter	Summer	Annual	Winter	Summer	Annual
Units	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)
Loads	189.78	211.82	111.84	194.40	193.80	112.70	199.10	198.50	113.82
Exports									
Resources:									
Future Conservation/Efficiency				3.34	3.34	3.34	9.98	9.98	9.98
Demand Response				0.00	0.00	0.00	0.00	0.00	0.00
Cogeneration									
Hydro									
Wind									
Other Renewables	0.79	1.05	0.70	0.75	1.00	0.67	0.71	0.95	0.63
Thermal - Natural Gas									
Thermal - Coal									
Net Long Term Contracts	8.00	8.00	8.00	0.00	0.00	0	0.00	0.00	0
Net Short Term Contracts									
BPA	180.99	202.77	103.63	190.31	189.46	108.69	188.41	187.57	103.21
Other									
Imports									
Distributed Generation									
Undecided									
Total Resources	**189.78**	**211.82**	**112.33**	**194.40**	**193.80**	**112.70**	**199.10**	**198.50**	**113.82**
Load Resource Balance	**0.00**	**0.00**	**0.49**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Date of Board/Commission Approval: August 20

Seattle City Light (SCL)

Washington State Utility Integrated Resource Plan Year 2022

Prepared by: Paul Nissley

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		**2021**			**2026**			**2031**	
Period	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**
Units	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**
Loads			1,072.00			1,077.00			1,104.00
Exports			25.00						
Resources:									
Future Conservation/Efficiency						48.00			85.00
Demand Response				20.00	14.00		89.00	53.00	
Cogeneration									
Hydro			719.00			742.00			733.00
Wind			41.00			95.00			95.00
Other Renewables			12.00			64.00			64.00
Thermal - Natural Gas									
Thermal - Coal									
Net Long Term Contracts									
Net Short Term Contracts									
BPA			470.00			418.00			416.00
Other			37.00			37.00			37.00
Imports			31.00						
Distributed Generation						3.00			4.00
Undecided									
Total Resources	**0.00**	**0.00**	**1,310.00**	**20.00**	**14.00**	**1,407.00**	**89.00**	**53.00**	**1,434.00**
Load Resource Balance	**0.00**	**0.00**	**213.00**	**20.00**	**14.00**	**330.00**	**89.00**	**53.00**	**330.00**

Date of Board/Commission Approval: August 22

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Line 10: this row's 1072 aMW base year load is weather adjusted** (includes 3aMW OwnUse & 5.5% line loss). 2026 and 2031 load estimates don't include conservation. Line 11: this row's Exports include Lucky Peak contract, but no contract in place after 2025. Line 16: This row represents City Light's hydro resources and long-term hydro contracts. For purposes of 2026 & 2031 estimates, a hypothetical median hydro year was created based on individual median months from historical period 1999 to 2020.
Line 17: this row's Stateline wind contract expires in 2021; 95 aMW new Gorge wind resources planned in 2026.
Line 18:this row's Other renewables include landfill gas and sewage treatment plant digester gas (~13aMW in 2026 & 2031) and 51 aMW planned SE OR and/or WA utility solar by 2026.
Line 24: this row's Other includes SCL long term PPAs with BC Hydro classified as unspecified power. Line 25: this row's Imports include Lucky Peak exchange energy. Line 26: this row's estimated incremental distributed solar generation in Seattle associated w/ customer programs.**Annual estimates of weather normalized system load are computed by summing together the weather normalized monthly system loads. The monthly system load model is fit using 5 years of daily observed system load and temperature data. Additional effects like day of the week, holidays, annual level shifts, and a trigonometric seasonal component are also included to capture non-weather drivers. This isn't an exhaustive list of explanatory variables that could drive day-to-day changes in load, but it is sufficient to get an accurate estimate of the non-linear relationship between load and temperature which is the crux of the weather normalization process. To model the non-linear link between system load and temperature a Multivariate Adaptive Regression Spline (MARS) model is used to estimate a piece wise linear function. The MARS model selects break points in temperature to estimate the system response to changes in temperature

Public Utility District #1 of Snohomish County

Washington State Utility Integrated Resource Plan Year 2022

Prepared by: Landon Snyder

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		2021			2026			2031	
Period	Winter	Summer	Annual	Winter	Summer	Annual	Winter	Summer	Annual
Units	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)
Loads	946.89	663.73	784.42	948.90	685.07	799.11	977.19	710.02	824.93
Exports	170.16	158.59	116.51	161.74	212.78	166.86	135.25	167.03	140.19
Resources:									
Future Conservation/Efficiency				28.77	25.58	27.00	81.22	73.43	76.59
Demand Response				4.54	0.00	1.74	25.18	0.00	9.82
Cogeneration	2.29	1.63	2.06	2.78	1.87	2.34	2.78	1.87	2.34
Hydro	99.87	34.64	59.31	89.45	40.09	62.22	94.00	37.52	63.52
Wind	48.72	67.97	56.48	28.06	54.22	41.30	0.00	0.00	0.00
Other Renewables	0.03	0.14	0.09	0.45	1.48	0.98	0.45	1.48	0.98
Thermal - Natural Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Thermal - Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Long Term Contracts	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Short Term Contracts	25.00	0.00	8.33	50.00	0.00	16.67	0.00	0.00	0.00
BPA	940.35	714.36	772.56	905.21	768.34	810.03	906.77	753.48	806.41
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distributed Generation	0.79	3.58	2.10	1.38	6.27	3.69	2.04	9.27	5.46
Undecided	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Resources	**1,117.05**	**822.32**	**900.93**	**1,110.64**	**897.85**	**965.97**	**1,112.44**	**877.05**	**965.12**
Load Resource Balance	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Date of Board/Commission Approval: December 22

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

1. Not in the categories listed, so not in the table, Snohomish has identified a storage need of up to 70MW by 2031.
2. Snohomish plans to add 5MW of local, utility-scale solar by 2031. (Line 18)
3. Snohomish plans to offer Smart Rate programs to customers in conjunction with AMI meter rollout in the early 2020's, in order to achieve over 25MW of peak demand reduction by 2031. (Line 14)
4. Snohomish currently plans to let existing wind contracts expire at the end of their term without renewal (line 17)
5. Snohomish plans to add winter capacity via short-term contract from 2022-2026 (line 22)

Alder Mutual Light Co.

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	0.67	0.65	0.65
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response			
BPA Tier 1 (include BPA PF)	0.55	0.55	0.55
BPA Tier 2	0.13	0.10	0.10
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**0.67**	**0.65**	**0.65**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Asotin County PUD No 1

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	2021	2026	2031
Period	Annual	Annual	Annual
Units	(MWa)	(MWa)	(MWa)
Loads	0.63	0.58	0.58
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response			
BPA Tier 1 (include BPA PF)	0.57	0.57	0.57
BPA Tier 2	0.05	0.01	0.01
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**0.63**	**0.58**	**0.58**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Benton Rural Electric Association

Washington State Utility Resource Plan Year 2022			
Prepared by: BPA			
	Base Year	**5 Yr. Est.**	**10 Yr Est.**
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	71.37	64.82	65.46
Resources:			
Future Conservation/Efficiency		0.62	0.62
Demand Response			
BPA Tier 1 (include BPA PF)	59.34	59.66	59.66
BPA Tier 2	12.03	4.54	5.19
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**71.37**	**64.82**	**65.46**
Load Resource Balance	**0.00**	**0.00**	**0.00**

City of Centralia

Washington State Utility Resource Plan Year 2022			
Prepared by: David Hayes			
	Base Year	**5 Yr. Est.**	**10 Yr Est.**
Estimate Year	**2021**	**2027**	**2032**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	31.57	32.41	32.41
Resources:			
Future Conservation/Efficiency			
Demand Response			
BPA Tier 1 (include BPA PF)	23.98	24.37	24.37
BPA Tier 2	0.48	0.92	0.93
Non BPA:			
Co-generation			
Hydro (critical water)	7.11	7.11	7.11
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**31.57**	**32.41**	**32.41**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Date of Board/Commission Approval: August 22

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

SEE 2022 ELECTRIC UTILITY RESOURCE PLAN UPDATE

City of Cheney

Washington State Utility Resource Plan Year 2022			
Prepared by: BPA			
	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	15.82	18.34	19.40
Resources:			
Future Conservation/Efficiency			
Demand Response			
BPA Tier 1 (include BPA PF)	14.82	18.34	19.40
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)	1.00	0.00	0.00
Other			
Distributed Generation			
Undecided			
Total Resources	**15.82**	**18.34**	**19.40**
Load Resource Balance	**0.00**	**0.00**	**0.00**

City of Chewelah

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	2021	2026	2031
Period	Annual	Annual	Annual
Units	(MWa)	(MWa)	(MWa)
Loads	2.45	2.52	2.52
Resources:			
Future Conservation/Efficiency		0.01	0.01
Demand Response			
BPA Tier 1 (include BPA PF)	2.45	2.51	2.51
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**2.45**	**2.52**	**2.52**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Clallam County PUD No. 1

Washington State Utility Resource Plan Year 2022			
Prepared by: Tyler King			
	Base Year	**5 Yr. Est.**	**10 Yr Est.**
Estimate Year	**2020**	**2025**	**2030**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	77.23	77.47	77.48
Resources:			
Future Conservation/Efficiency		0.62	0.62
Demand Response			
BPA Tier 1 (include BPA PF)	75.62	76.03	76.03
BPA Tier 2	0.94	0.15	0.16
Non BPA:			
Co-generation			
Hydro (critical water)	0.67	0.67	0.67
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**77.23**	**77.47**	**77.48**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Date of Board/Commission Approval: August 22

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Data is reported using the Federal fiscal year (October through September). The base year is 2020 actual load. The 2025 and 2028 load forecasts are based on 2020 weather normalized actual load applied to BPA using a flat growth rate, including mandated conservation from the Energy Independence Act. The non-federal hydro resource "Line 17" is Clallam's share of the Packwood Lake project owned by Energy Northwest. We have current contracts for RECs to meet the 15% Washington State Renewable Energy Portfolio Standard through 2028. The PUD is planning a Demand Response pilot project within 5 years load shifting 0.10 aMW. The 10 year projected demand response is contingent on an estimated BPA demand rate, with the pilot project saving 0.80 aMW.

Columbia REA

Washington State Utility Resource Plan Year 2022			
Prepared by: Jim Cooper			
	Base Year	**5 Yr. Est.**	**10 Yr Est.**
Estimate Year			
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	42.54	43.73	45.00
Resources:			
Future Conservation/Efficiency			
Demand Response			
BPA Tier 1 (include BPA PF)	37.85	37.57	43.93
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)	1.07	1.07	1.07
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)	3.62	5.09	0.00
Other			
Distributed Generation			
Undecided			
Total Resources	**42.54**	**43.73**	**45.00**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Date of Board/Commission Approval: October 23

Consolidated Irrigation District

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	0.31	0.22	0.22
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response			
BPA Tier 1 (include BPA PF)	0.23	0.22	0.22
BPA Tier 2	0.08		
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**0.31**	**0.22**	**0.22**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Town of Coulee Dam

Washington State Utility Resource Plan Year 2022			
Prepared by: BPA			
	Base Year	**5 Yr. Est.**	**10 Yr Est.**
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	1.96	2.05	2.10
Resources:			
Future Conservation/Efficiency		0.01	0.01
Demand Response			
BPA Tier 1 (include BPA PF)	1.96	2.02	2.02
BPA Tier 2		0.02	0.07
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**1.96**	**2.05**	**2.10**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Date of Board/Commission Approval:

Town of Eatonville

Washington State Utility Resource Plan Year 2022			
Prepared by: BPA			
	Base Year	**5 Yr. Est.**	**10 Yr Est.**
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	3.29	3.31	3.33
Resources:			
Future Conservation/Efficiency		0.01	0.01
Demand Response			
BPA Tier 1 (include BPA PF)	3.29	3.30	3.32
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**3.29**	**3.31**	**3.33**
Load Resource Balance	**0.00**	**0.00**	**0.00**

City of Ellensburg

Washington State Utility Resource Plan Year 2022			
Prepared by: BPA			
	Base Year	**5 Yr. Est.**	**10 Yr Est.**
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	23.89	24.18	24.55
Resources:			
Future Conservation/Efficiency		0.01	0.01
Demand Response			
BPA Tier 1 (include BPA PF)	23.89	23.98	23.98
BPA Tier 2		0.19	0.55
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**23.89**	**24.18**	**24.55**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Elmhurst Mutual Power & Light Company

Washington State Utility Resource Plan Year 2022			
Prepared by: BPA			
	Base Year	**5 Yr. Est.**	**10 Yr Est.**
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	32.62	33.16	33.81
Resources:			
Future Conservation/Efficiency		0.18	0.18
Demand Response			
BPA Tier 1 (include BPA PF)	32.24	32.24	32.24
BPA Tier 2	0.38	0.74	1.39
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**32.62**	**33.16**	**33.81**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Ferry County PUD No 1

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	9.12	8.28	8.37
Resources:			
Future Conservation/Efficiency		0.02	0.02
Demand Response			
BPA Tier 1 (include BPA PF)	9.12	8.26	8.34
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**9.12**	**8.28**	**8.37**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Jefferson County PUD No 1

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	45.20	46.33	47.06
Resources:			
Future Conservation/Efficiency		0.26	0.26
Demand Response			
BPA Tier 1 (include BPA PF)	45.17	45.17	45.17
BPA Tier 2	0.03	0.90	1.63
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**45.20**	**46.33**	**47.06**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Inland Power & Light

Washington State Utility Resource Plan Year 2022			
Prepared by: Brian Hess			
	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	2021	2026	2031
Period	Annual	Annual	Annual
Units	(MWa)	(MWa)	(MWa)
Loads	127.53	140.80	155.46
Resources:			
Future Conservation/Efficiency		0.36	0.82
Demand Response			
BPA Tier 1 (include BPA PF)	104.89	104.89	120.70
BPA Tier 2	12.37	35.55	33.94
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)	10.27	0.00	0.00
Other			
Distributed Generation			
Undecided			
Total Resources	**127.53**	**140.80**	**155.46**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Starting in 2025, Inland Power & Light will supply all needed resources from BPA and transition away from any market purchases in order to better comply with CETA obligations.

Kalispel Indian Community of the Kalispel Reservation

Washington State Utility Resource Plan Year 2002

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	2021	2026	2031
Period	Annual	Annual	Annual
Units	(MWa)	(MWa)	(MWa)
Loads	3.44	4.13	4.38
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response			
BPA Tier 1 (include BPA PF)	3.44	4.07	4.07
BPA Tier 2		0.06	0.31
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	3.44	4.13	4.38
Load Resource Balance	0.00	0.00	0.00

Kittitas County PUD No. 1

Washington State Utility Resource Plan Year 2022			
Prepared by: EES Consulting			
	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	13.75	14.15	14.84
Resources:			
Future Conservation/Efficiency		0.08	0.08
Demand Response			
BPA Tier 1 (include BPA PF)	9.70	9.70	9.70
BPA Tier 2	2.74	2.79	3.20
Non BPA:			
Co-generation			
Hydro (critical water)	0.98	0.98	0.98
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation	0.33	0.60	0.88
Undecided			
Total Resources	**13.75**	**14.15**	**14.84**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Date of Board/Commission Approval: November 22

Public Utility District No. 1 of Klickitat County

Washington State Utility Resource Plan Year 2022			
Prepared by: Mike DeMott-Director of Finance and Power Management			
	Base Year	**5 Yr. Est.**	**10 Yr Est.**
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	60.32	63.20	67.14
Resources:			
Future Conservation/Efficiency			
Demand Response			
BPA Tier 1 (include BPA PF)	36.28	37.20	45.00
BPA Tier 2	10.74	21.60	17.74
Non BPA:			
Co-generation			
Hydro (critical water)	4.80	4.40	4.40
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)	8.50	0.00	0.00
Other			
Distributed Generation			
Undecided			
Total Resources	**60.32**	**63.20**	**67.14**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Lakeview Light & Power

Washington State Utility Resource Plan Year 2022

Prepared by: PBA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	2021	2026	2031
Period	Annual	Annual	Annual
Units	(MWa)	(MWa)	(MWa)
Loads	29.99	30.35	30.66
Resources:			
Future Conservation/Efficiency		0.24	0.24
Demand Response			
BPA Tier 1 (include BPA PF)	29.99	30.12	30.42
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**29.99**	**30.35**	**30.66**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Mason County PUD No. 1

Washington State Utility Resource Plan Year 2022			
Prepared by: BPA			
	Base Year	**5 Yr. Est.**	**10 Yr Est.**
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	10.69	10.45	10.66
Resources:			
Future Conservation/Efficiency		0.01	0.01
Demand Response			
BPA Tier 1 (include BPA PF)	8.85	8.99	8.99
BPA Tier 2	1.30	0.91	1.11
Non BPA:			
Co-generation			
Hydro (critical water)	0.54	0.54	0.54
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**10.69**	**10.45**	**10.66**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Mason PUD 3

Washington State Utility Resource Plan Year 2022			
Prepared by: Michele Patterson			
	Base Year	**5 Yr. Est.**	**10 Yr Est.**
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	80.76	88.65	94.42
Resources:			
Future Conservation/Efficiency		1.20	3.41
Demand Response		0.00	0.00
BPA Tier 1 (include BPA PF)	77.79	79.93	79.93
BPA Tier 2	0.00	5.04	0.00
Non BPA:			
Co-generation	0.00	0.00	0.00
Hydro (critical water)	0.97	0.66	0.66
Wind	1.97	1.80	0.00
Other Renewables	0.00	0.00	0.00
Thermal-Natural Gas	0.00	0.00	0.00
Thermal-Coal	0.00	0.00	0.00
Market Purchase (non BPA)	0.00	0.00	0.00
Other	0.00	0.00	0.00
Distributed Generation	0.02	0.02	0.02
Undecided	0.00	0.00	10.40
Total Resources	**80.76**	**88.65**	**94.42**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Date of Board/Commission Approval: August 22

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Based on federal fiscal year to align with BPA.
Line 5: actuals used for base year load; forecast not weather adjusted.
Line 20: distributed generation source is solar.
Line 21: decision to be made at a later date once 2028 BPA contract terms better understood.

City of McCleary

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	3.70	3.84	3.97
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response			
BPA Tier 1 (include BPA PF)	3.70	3.72	3.72
BPA Tier 2		0.12	0.25
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**3.70**	**3.84**	**3.97**
Load Resource Balance	**0.00**	**0.00**	**0.00**

City of Milton

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	6.63	6.62	6.63
Resources:			
Future Conservation/Efficiency		0.01	0.01
Demand Response			
BPA Tier 1 (include BPA PF)	6.63	6.61	6.62
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**6.63**	**6.62**	**6.63**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Modern Electric Water Company

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	26.88	27.08	27.67
Resources:			
Future Conservation/Efficiency		0.31	0.31
Demand Response			
BPA Tier 1 (include BPA PF)	26.29	26.29	26.29
BPA Tier 2	0.59	0.48	1.07
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**26.88**	**27.08**	**27.67**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Nespelem Valley Electric Cooperative Inc.

Washington State Utility Resource Plan Year 2022			
Prepared by: BPA			
	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	8.20	8.20	8.26
Resources:			
Future Conservation/Efficiency		0.02	0.02
Demand Response			
BPA Tier 1 (include BPA PF)	5.88	5.88	5.88
BPA Tier 2	2.32	2.30	2.36
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**8.20**	**8.20**	**8.26**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Okanogan County Electric Cooperative

Washington State Utility Resource Plan Year 2022

Prepared by: Jeff Kugel

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2022**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	8.85	9.20	10.30
Resources:			
Future Conservation/Efficiency			
Demand Response			
BPA Tier 1 (include BPA PF)	8.10	8.00	8.00
BPA Tier 2	0.56		
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)	0.19		
Other			
Distributed Generation			
Undecided		1.20	2.30
Total Resources	**8.85**	**9.20**	**10.30**
Load Resource Balance	**0.00**	**0.00**	**0.00**

PUD No. 1 of Okanogan County

Washington State Utility Resource Plan Year 2022

Prepared by: Ron Gadeberg

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	75.04	75.83	77.74
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response		0.00	0.00
BPA Tier 1 (include BPA PF)	45.00	45.00	45.00
BPA Tier 2	0.00	0.00	0.00
Non BPA:			
Co-generation	0.00	0.00	0.00
Hydro (critical water)	0.00	0.00	0.00
Wind	0.00	0.00	0.00
Other Renewables	0.00	0.00	0.00
Thermal-Natural Gas	0.00	0.00	0.00
Thermal-Coal	0.00	0.00	0.00
Market Purchase (non BPA)	30.04	30.83	32.74
Other	0.00	0.00	0.00
Distributed Generation	0.00	0.00	0.00
Undecided	0.00	0.00	0.00
Total Resources	**75.04**	**75.83**	**77.74**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Date of Board/Commission Approval: June 23

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Loads: Used Actual 2021 Loads at POD (Point of Delivery). Used Actual 2021 Resources at POD. Forecasted Load based on BPA approved load forecast. Forecasted Resources: BPA based on Block Slice Contract. Future load growth met via PGE Load following product.

Ohop Mutual Light Company

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	10.73	10.67	10.67
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response			
BPA Tier 1 (include BPA PF)	10.16	10.16	10.16
BPA Tier 2	0.57	0.51	0.51
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**10.73**	**10.67**	**10.67**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Orcas Power and Light Cooperative

Washington State Utility Resource Plan Year 2022			
Prepared by: RHS			
	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year			
Period	Annual	Annual	Annual
Units	(MWa)	(MWa)	(MWa)
Loads	26.47	26.64	27.55
Resources:			
Future Conservation/Efficiency		0.05	0.05
Demand Response		0.00	0.00
BPA Tier 1 (include BPA PF)	26.39	26.01	26.40
BPA Tier 2	0.00	0.00	0.00
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation	0.08	0.59	1.10
Undecided			
Total Resources	**26.47**	**26.64**	**27.55**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

No plans demand response at this point 2.) 5/10 year projections on load comes from BPA 3.)Distributed generation is solely solar

Pacific PUD #2

Washington State Utility Resource Plan Year 2022

Prepared by:

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	36.20	38.80	39.90
Resources:			
Future Conservation/Efficiency		1.00	0.90
Demand Response			
BPA Tier 1 (include BPA PF)	35.60	36.87	39.00
BPA Tier 2		0.93	
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)	2.00		
Other			
Distributed Generation			
Undecided			
Total Resources	**37.60**	**38.80**	**39.90**
Load Resource Balance	**1.40**	**0.00**	**0.00**

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

BPA has not set contract high water marks for new contract just yet.

Parkland Light & Water Company

Washington State Utility Resource Plan Year 2022			
Prepared by: BPA			
	Base Year	**5 Yr. Est.**	**10 Yr Est.**
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	13.49	13.48	13.62
Resources:			
Future Conservation/Efficiency		0.04	0.04
Demand Response			
BPA Tier 1 (include BPA PF)	13.49	13.45	13.58
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**13.49**	**13.48**	**13.62**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Pend Oreille PUD

Washington State Utility Resource Plan Year 2022

Prepared by: April Owen

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	34.40	35.69	38.45
Resources:			
Future Conservation/Efficiency			
Demand Response			
BPA Tier 1 (include BPA PF)	29.20	0.00	0.00
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)	94.90	94.90	94.90
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation	0.01	0.01	0.01
Undecided			
Total Resources	**124.11**	**94.91**	**94.91**
Load Resource Balance	**89.71**	**59.22**	**56.46**

Date of Board/Commission Approval: September 22

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Line 17: Pend Oreille PUD is anticipating it will sell approximately 54.00 of the 94.90 MWa reported Hydro as a wholesale product beginning in 2026.
Line 24: We have a limited amount of distributed generation, mostly in the form of solar. We are not expecting a material amount of growth in this area.
Pend Oreille PUD currently sells its length as a wholesale product. Loads reported are the District's base load and do not include cryptomining consumption of approximately 90 MWa.

City of Port Angeles

Washington State Utility Resource Plan Year 2022			
Prepared by: BPA			
	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	47.41	46.76	46.76
Resources:			
Future Conservation/Efficiency		0.05	0.05
Demand Response			
BPA Tier 1 (include BPA PF)	47.41	46.71	46.71
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**47.41**	**46.76**	**46.76**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Port of Seattle

Washington State Utility Resource Plan Year 2022			
Prepared by: BPA			
	Base Year	**5 Yr. Est.**	**10 Yr Est.**
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	15.83	16.89	16.89
Resources:			
Future Conservation/Efficiency		0.17	0.17
Demand Response			
BPA Tier 1 (include BPA PF)	15.83	16.72	16.72
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**15.83**	**16.89**	**16.89**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Town of Ruston

Washington State Utility Resource Plan Year 2022			
Prepared by: Rick Applegate			
	Base Year	**5 Yr. Est.**	**10 Yr Est.**
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	1.08	1.10	1.04
Resources:			
Future Conservation/Efficiency			
Demand Response			
BPA Tier 1 (include BPA PF)	0.79	0.80	0.74
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)	0.69	0.41	0.40
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**1.47**	**1.21**	**1.14**
Load Resource Balance	**0.39**	**0.11**	**0.10**

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

The Town of Ruston is a full requirements customer of Tacoma Power. As a result, the Resource Plan has been derived from the Tacoma Power IRP, scaled to load values for the Town of Ruston. The assumed load for Ruston is as follows: 2021 uses actual load for the calendar year; 2026 and 2031 reflect the same load growth percentage rates as forecast in the Tacoma Power IRP for the same periods.

Skamania County PUD No 1

Washington State Utility Resource Plan Year 2022			
Prepared by: BPA			
	Base Year	**5 Yr. Est.**	**10 Yr Est.**
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	16.68	16.00	16.32
Resources:			
Future Conservation/Efficiency		0.01	0.01
Demand Response			
BPA Tier 1 (include BPA PF)	15.91	15.91	15.91
BPA Tier 2	0.77	0.09	0.41
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**16.68**	**16.00**	**16.32**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Town of Steilacoom

Washington State Utility Resource Plan Year 2022			
Prepared by: BPA			
	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	4.65	4.64	4.75
Resources:			
Future Conservation/Efficiency		0.00	0.01
Demand Response			
BPA Tier 1 (include BPA PF)	4.65	4.64	4.75
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**4.65**	**4.64**	**4.75**
Load Resource Balance	**0.01**	**0.00**	**0.00**

City of Sumas

Washington State Utility Resource Plan Year 2022			
Prepared by: BPA			
	Base Year	**5 Yr. Est.**	**10 Yr Est.**
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	3.59	3.76	3.67
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response			
BPA Tier 1 (include BPA PF)	3.59	3.64	3.64
BPA Tier 2		0.11	0.03
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**3.59**	**3.76**	**3.67**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Tanner Electric Cooperative

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	11.57	11.62	11.94
Resources:			
Future Conservation/Efficiency		0.01	0.01
Demand Response			
BPA Tier 1 (include BPA PF)	11.03	11.03	11.03
BPA Tier 2	0.54	0.58	0.90
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**11.57**	**11.62**	**11.94**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Vera Water and Power

Washington State Utility Resource Plan Year 2022			
Prepared by: BPA			
	Base Year	**5 Yr. Est.**	**10 Yr Est.**
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	27.67	26.781	27.457
Resources:			
Future Conservation/Efficiency		0.03	0.03
Demand Response			
BPA Tier 1 (include BPA PF)	25.91	26.751	27.157
BPA Tier 2	0.77	0.00	0.27
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other*	1.00		
Distributed Generation			
Undecided			
Total Resources	**27.67**	**26.78**	**27.46**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Wahkiakum County PUD No 1

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	5.39	5.29	5.37
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response			
BPA Tier 1 (include BPA PF)	5.01	5.01	5.01
BPA Tier 2	0.39	0.28	0.36
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**5.39**	**5.29**	**5.37**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Whatcom County PUD No 1

Washington State Utility Resource Plan Year 2022			
Prepared by: BPA			
	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	26.45	30.27	29.94
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response			
BPA Tier 1 (include BPA PF)	26.45	26.83	26.83
BPA Tier 2		3.44	3.11
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**26.45**	**30.27**	**29.94**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Yakama Power

Washington State Utility Resource Plan Year 2022			
Prepared by: BPA			
	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	17.66	18.59	18.80
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response			
BPA Tier 1 (include BPA PF)	17.66	18.59	18.80
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**17.66**	**18.59**	**18.80**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Appendix B: Washington Utility Customer Count, Revenue, Sales, and Average Price[29]

2021 Utility Data

	Customers (Count)	Revenue (Thousand Dollars)	Retail Sales (Megawatthours)	Average Price (Cents/kWh)
Cooperatives				
Inland Power & Light Company	42,755	$62,455	977,541	6¢
Peninsula Light Company	34,707	$60,505	602,240	10¢
Elmhurst Mutual Power & Light Co	15,741	$19,527	287,017	7¢
Orcas Power & Light Coop	15,569	$32,011	219,743	15¢
Benton Rural Electric Assn	15,309	$42,519	592,182	7¢
Modern Electric Water Company	10,420	$14,926	224,121	7¢
Lakeview Light & Power	10,311	$23,531	252,098	9¢
Big Bend Electric Coop, Inc	9,686	$39,958	582,631	7¢
Columbia Rural Elec Assn, Inc	5,999	$33,350	381,765	9¢
Tanner Electric Coop	5,186	$12,316	95,867	13¢
Parkland Light & Water Company	4,603	$8,799	113,343	8¢
Ohop Mutual Light Company, Inc	4,591	$7,542	90,949	8¢
Okanogan County Elec Coop, Inc	3,952	$6,356	65,828	10¢
Nespelem Valley Elec Coop, Inc	1,536	$5,311	64,234	8¢
Clearwater Power Company	1,030	$2,305	22,054	10¢
Alder Mutual Light Co, Inc	315	$405	5,019	8¢
Kootenai Electric Cooperative	97	$245	2,807	9¢
Northern Lights, Inc	15	$15	117	13¢
Investor Owned				
Puget Sound Energy Inc	1,196,851	$2,367,219	23,282,858	10¢
Avista Corp	263,559	$568,172	5,730,590	10¢
PacifiCorp	134,816	$339,381	4,198,960	8¢
Municipal				
City of Seattle - (WA)	485,155	$952,665	8,922,444	11¢
City of Tacoma - (WA)	184,103	$380,881	4,642,537	8¢
City of Richland - (WA)	26,485	$74,590	950,951	8¢
City of Port Angeles - (WA)	11,864	$24,942	374,660	7¢
City of Centralia - (WA)	10,550	$26,480	266,777	10¢

[29] Energy Information Administration. (2023, October 5). Annual Electric Power Information Report. Retrieved from https://www.eia.gov/electricity/data/eia861/

	Customers (Count)	Revenue (Thousand Dollars)	Retail Sales (Megawatthours)	Average Price (Cents/kWh)
City of Ellensburg - (WA)	10,345	$18,148	206,175	9¢
City of Cheney - (WA)	5,879	$8,325	134,942	6¢
City of Blaine - (WA)	3,612	$6,853	81,074	8¢
City of Milton - (WA)	3,541	$4,989	55,790	9¢
Town of Steilacoom	2,990	$4,069	38,973	10¢
City of Chewelah	1,341	$2,001	21,433	9¢
Town of Eatonville - (WA)	1,278	$2,210	27,312	8¢
City of McCleary - (WA)	1,227	$2,892	32,390	9¢
City of Sumas - (WA)	1,050	$2,300	30,431	8¢
City of Coulee Dam - (WA)	605	$1,169	16,749	7¢
Town of Ruston - (WA)	575	$1,160	9,330	12¢
Public Utility Districts				
PUD No 1 of Asotin County	3	$18	302	6¢
PUD 1 of Snohomish County	367,096	$623,345	6,587,977	9¢
PUD No 1 of Clark County - (WA)	224,988	$381,092	4,675,496	8¢
PUD No 1 of Benton County	56,072	$130,786	1,807,315	7¢
PUD No 2 of Grant County	53,213	$231,937	5,382,366	4¢
PUD No 1 of Cowlitz County	52,217	$261,272	4,509,075	6¢
PUD No 1 of Chelan County	48,576	$80,373	1,984,267	4¢
PUD No 1 of Grays Harbor County	43,620	$107,549	1,164,781	9¢
PUD No 3 of Mason County	35,082	$71,024	675,366	11¢
PUD No 1 of Lewis County	33,873	$79,825	948,798	8¢
PUD No 1 of Clallam County	33,397	$68,656	651,819	11¢
PUD No 1 of Franklin County	28,824	$85,833	1,104,954	8¢
PUD No 1 of Okanogan County	21,663	$49,357	616,510	8¢
PUD No 1 of Jefferson County	20,440	$38,776	377,797	10¢
PUD No 2 of Pacific County	18,071	$25,814	309,414	8¢
PUD No 1 of Douglas County	16,779	$38,958	1,222,085	3¢
PUD No 1 of Klickitat County	13,696	$36,090	442,246	8¢
Vera Irrigation District #15	12,920	$19,233	234,126	8¢
PUD No 1 of Pend Oreille County	9,648	$20,298	275,483	7¢
PUD No 1 of Skamania Co	6,470	$14,079	127,678	11¢
PUD No 1 of Mason County	5,505	$9,711	81,779	12¢
PUD No 1 of Kittitas County	4,888	$11,687	110,501	11¢
PUD No 1 of Ferry County	3,700	$7,179	72,939	10¢
PUD No 1 of Wahkiakum County	2,685	$4,422	43,860	10¢
PUD No 1 of Whatcom County	1	$11,479	223,343	5¢

Appendix C: Glossary of Terms

Average Annual Energy: one megawatt is equal to one million watts. One million watts delivered continuously 24 hours a day for a year (8,760 hours) is called an average megawatt. The maximum amount of power a generating plant is capable of producing over the course of an average year is called its generating capability or average annual energy, expressed in average megawatts.

Cogeneration: the sequential production of electricity and useful thermal energy from a common fuel source.

Demand Response: the voluntary and temporary reduction in consumers' use of electricity when the power system is stressed. It includes voluntary demand response, demand response with paid incentives, time-of-use, and demand voltage reduction programs.

Distributed Generation: an eligible renewable resource where the facility or any integrated cluster of generating units has a generating capacity of not more than five megawatts.

Duration Value at Risk (VaR Duration): longest shortfall event for the 97.5th worst simulation year. VaR Duration sets a limit for shortfall duration during rare (once per 40 year) events. To calculate this metric, the duration of the longest shortfall event for each simulation year is recorded (or zero if there is no shortfall). The Duration VaR97.5 is the 97.5th highest duration from that record. Choosing the 97.5th percentile limits the risk of an excessively long shortfall event to no more than once per 40 years.

Energy Conservation Measures: any reduction in electric power consumption resulting from increases in the efficiency of energy use, production, or distribution.

Energy Value at Risk (VaR Energy): total annual shortfall energy for the 97.5th worst simulation year. VaR Energy set limits for the big energy shortfalls during rare (once per 40 year) events.

Loss of Load Probability (LOLP): traditionally, a power supply is deemed to be adequate when its annual Loss of Load Probability (LOLP) is 5% or less; that is, when the likelihood of having one or more shortfalls during an operating year is less than or equal to 5%. A 5% LOLP means that the simulated operation of the power supply yields only one year out of 20 with shortfalls.

Loss of Load Events (LOLEV): the expected number of shortfall events per year. A shortfall event is a set of contiguous hours of unserved demand. LOLEV is equal to the total number of shortfall events divided by the total number of simulation years.

Net short-term contracts/Market Purchases: refers to limited duration wholesale power purchase not to exceed one month, made by an electric utility for delivery to Washington retail electric customers for which the source of the power is not known at the time of entry into the transaction to procure the electricity.

Loads: electric loads include retail sales + line losses + utility needs. The base year includes existing conservation or demand reduction as a part of base year load. All projected electric loads (non-base year) are estimated before reductions from energy conservation measure programs or demand response program estimates. Additional future conservation and demand response are treated as resources to meet future load.

Peak Energy: highest estimated one-hour load for summer and winter, normalized for weather.

Peak Value at Risk (VaR Peak): highest single-hour shortfall for the 97.5th worst simulation year. VaR Peak set limits for occurrences of big energy shortfalls during rare (once per 40 year) events.

Resource Adequacy: the ability of the electricity system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components.

Renewable Resources: RCW 19.280, Electricity Utility Resource Plans, defines "renewable resources" as "electricity generation facilities fueled by: (a) Water; (b) wind; c) solar energy, (d) geothermal energy, (e) landfill gas, (f) biomass energy utilizing animal waste, solid organic fuels from wood, forest or field residues or dedicated energy crops that do not include wood pieces that have been treated with chemical preservatives such as creosote, pentachlorophenol, or copper-chrome-arsenic; (g) by-products of pulping or wood manufacturing processes, including but not limited to bark, wood chips, sawdust, and lignin in spent pulping liquors; (h) ocean thermal, wave or tidal power; and (i) gas from sewage treatment facilities."

Western Electricity Coordinating Council (WECC): 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.

Western Interconnection: the geographic area containing the synchronously operated electric grid in the western part of North America, which includes parts of Montana, Nebraska, New Mexico, South Dakota, Texas, Wyoming and Mexico and all of Arizona, California, Colorado, Idaho, Nevada, Oregon, Utah, Washington and the Canadian provinces of British Columbia and Alberta.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-89:
Washington Agencies Resource Adequacy Meeting Summaries (Compiled)

November 19, 2025

The Honorable Bob Ferguson
Governor of Washington
Office of the Governor
PO Box 40913
Olympia WA 98504-0913

The Honorable Sarah Bannister
Secretary of the Senate
312 Legislative Building
PO Box 40482
Olympia WA 98504-0482

The Honorable Bernard Dean
Chief Clerk of the House of Representatives
338 Legislative Building
PO Box 40482
Olympia WA 98504-0482

Re: Summary of the 2025 Long-term Resource Adequacy Meeting

Dear Governor Ferguson, Secretary Bannister, and Chief Clerk Dean,

We submit this attached summary of the 2025 long-term resource adequacy meeting held Sept. 22, 2025, as required by statute. This year, in response to public feedback to expand our schedule under RCW 19.280.065, we hosted three meetings: one each for summer readiness, long-term resource adequacy, and winter preparedness. The meeting agendas, recordings of each meeting, and presentation materials are available on the Department of Commerce webpage and the Utilities and Transportation Commission webpage.

Reliability assessments presented at the September 22 meeting indicated that the Northwest's electric grid meets national resource adequacy criteria over the near and medium terms under a broad range of operating conditions. As a region assessed as "normal risk," the Northwest has a low likelihood of electricity supply shortfall.

However, "normal risk" is not the same as "no risk." Although areas categorized as normal risk are expected to have sufficient resources for plausible extreme conditions, they are not immune to the effects of high-impact, low frequency weather events that affect demand and generation simultaneously. Presentations also indicated that normal conditions are shifting with the impacts of climate change, large new electricity uses like data centers and building and vehicle electrification. If significant new electricity usage materializes and more extreme weather continues, the grid could face reliability challenges. Presentations emphasized that no electric system is 100% resource adequate, and there is no resource that provides perfect capacity. We also underscore that it is important to incorporate risks associated with fossil generating resources, including fuel supply risk and weather-driven forced outages.

With this uncertainty, it is clear that utilities and policy makers must increase efforts to make customer energy demand more flexible, reduce delays in siting and interconnecting new clean energy projects, expand regional transmission capacity, and improve transparency and accuracy of load forecasts and planned resource additions. There is also a need to consider potential changes to the mix of generating resources with greater focus on the capacity and fuel requirements of the power system during critical periods, such as days of extreme cold combined with low hydroelectric and wind generation.

Lack of Clarity Surrounding New Load Growth
There is limited visibility into whether large customer (including data center) interconnection requests are duplicative or speculative, and utility-submitted data on planned resource additions are less predictable than in recent history.

Discussions at the meeting underscored that, under some forecasts presented, if the region did not add new generation capacity by 2030, it would have a resource gap equivalent to the current electricity requirements of the State of Oregon, approximately 9 gigawatts. Existing utility integrated resource plans (IRPs) show this gap closing. In addition, collaborative utility efforts, such as the Northwest Energy Efficiency Association's End-Use Load Flexibility project,[1] show progress on reducing peak electricity demand through grid-connected consumer products and dynamic services.

New Resource Challenges
We should be cautious of the assumptions behind the finding of adequacy. Bringing new resources online continues to be difficult due to:

- Changes in federal policy and corresponding increased costs,
- Lack of in-state and regional transmission capacity, and
- Permitting and interconnection challenges.

Voluntary Resource Adequacy Program Struggles
Shortly after our meeting, six utilities announced they would not join the Western Resource Adequacy Program (WRAP). This is an industry-led, voluntary regional resource adequacy program to help utilities share resources during scarcity. PacifiCorp, which serves approximately 141,000 customers in Washington, opted out of the program, while Avista and Puget Sound

[1] End-Use Load Flexibility - Northwest Energy Efficiency Alliance (NEEA).

Energy remain in. Reduced WRAP participation means that there will be fewer resources to share, and therefore the benefits of the program potentially diminish for Washington utilities and customers. Some utilities that have opted out of WRAP are now in talks to potentially create their own regional program. We continue to monitor this dynamic and encourage continued development and participation in regional resource adequacy initiatives.

Meanwhile, climate change is making extreme weather more frequent, posing the gravest threat to grid reliability. The experts who gathered at this meeting continue to stress that the increased severity and frequency of extreme weather events from climate change pose the greatest threat to resource adequacy.

We look forward to continuing to partner with you on this work.

Sincerely,

Brian J. Rybarik	Jennifer Grove
Chair	Assistant Director, Energy Division
WA Utilities and Transportation Commission	Washington Department of Commerce

Enclosure (1)
cc:

2025 Long-Term Resource Adequacy Meeting Summary

Introduction

On September 22, 2025, the Washington Utilities and Transportation Commission (UTC) and the Washington Department of Commerce (Commerce) convened a public meeting to review the adequacy of energy resources to serve the state's electricity needs and receive an update from regional experts and Washington utilities on the long-term resource adequacy of the electric grid. We convened this meeting and submit this summary in response to public feedback to expand our annual resource adequacy meeting under RCW 19.280.065 to three meetings: one meeting in the spring focused on summer readiness, one meeting in late summer to discuss long-term resource adequacy, and another in late fall to focus on winter preparedness.
RCW 19.280.065(1) says:

> At least once every twelve months, the department and the commission shall jointly convene a meeting of representatives of the investor-owned utilities and consumer-owned utilities, regional planning organizations, transmission operators, and other stakeholders to discuss the current, short-term, and long-term adequacy of energy resources to serve the state's electric needs, and address specific steps the utilities can take to coordinate planning in light of the significant changes to the Northwest's power system including, but not limited to, technological developments, retirements of legacy baseload power generation resources, and changes in laws and regulations affecting power supply options. The department and commission shall provide a summary of these meetings, including any specific action items, to the governor and legislature within sixty days of the meeting.

Maintaining an adequate supply of electricity is a core obligation of the utilities that provide electric service to Washington residents and businesses. State policy reinforces this obligation as Washington transforms its electric power system and economy, reducing and eventually eliminating emissions from fossil fuel combustion for electricity generation.[2]

The state's 100% clean electricity law, the Clean Energy Transformation Act,[3] includes requirements for utilities to establish specific standards for resource adequacy and incorporate those standards into their planning and compliance.[4] As utilities reduce reliance on fossil fuels and add renewable resources such as wind and solar, new approaches and resources will be required to maintain resource adequacy.

While resource adequacy is an obligation of each electric utility serving end-use customers in the state, it also is a shared responsibility of the overall electric power system and the entities that operate, plan, regulate, design, and fund that system.

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[2] Washington 2021 State Energy Strategy, page 119-120. https://commerce.wa.gov/energystrategy

[3] Chapter 19.405 RCW.

[4] RCW 19.280.030. This resource planning statute was amended by the CETA legislation to add explicit resource adequacy provisions.

The following summarizes the presentations and discussion at the September 2025 meeting.

Resource Adequacy 101—Energy Systems Integration Group
Energy Systems Integration Group (ESIG) is a non-profit organization and a leading source of expertise for energy systems around the world. ESIG described resource adequacy as "the ability of the electric system to supply firm demand at all times (up to some criteria)." This definition highlights two important aspects of resource adequacy.

- Resource adequacy refers to the ability to generate and move power over transmission lines to where it is needed; it does not include local distribution line disruptions.
- It is measured against criteria, such as a One-day-in-ten-years loss-of-load event, which determines an acceptable amount of risk of resource shortfall.

In other words, resource adequacy is the likelihood we will have enough power and transmission to meet electricity demand based on defined criteria. Changes in resource adequacy criteria may impact whether an electric system is deemed adequate. The industry is increasingly moving to multi-metric criteria to examine the adequacy of the electric system and the capacity contributions of individual resources to account for shifting resource adequacy risks, such as potential weather-related and fuel supply outages.

Key takeaways from the presentation were that no electric system is 100% resource adequate, and there is no resource that provides perfect capacity. Meeting resource adequacy will require utilities to develop diverse resource portfolios and secure transmission capacity necessary to meet multi-metric criteria. Utilities should continue to evaluate the adequacy of their resource portfolios as the region adds new loads. ESIG observed a system that was 100% adequate would be cost prohibitive.

ESIG offered a number of ways to improve resource adequacy while lowering system costs, including energy efficiency and demand response, expansion of regional transmission and energy markets, and adoption of a binding regional resource adequacy program, such as the WRAP, that would allow utilities to coordinate their diverse resources to avoid shortfalls.

Reliability Assessments — North American Electric Reliability Corporation and Western Electric Coordinating Council
The North American Electric Reliability Corporation (NERC) is the Electric Reliability Organization for North America. Its mission is to assure the effective reduction of risks to the reliability and security of the grid. It is subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. The Western Electricity Coordinating Council (WECC) is one of six regional entities under NERC that has authority delegated under the Federal Power Act to ensure a reliable and secure bulk power system throughout the Western Interconnection. WECC has the responsibility to create, monitor, and enforce reliability standards and promote activities, such as regional resource adequacy assessments, of the bulk power system in the Western Interconnection.

NERC presented its 2024 Long-Term Reliability Assessment (LTRA), as its 2025 LTRA was not yet complete at the time of the meeting. The LTRA found that unlike some parts of the United

States, which have an elevated risk of resource inadequacy, the Western Interconnection has a normal level of risk as of the 2024 assessment.

Study results show WECC is in the top one-third of all assessment areas for demand growth. Demand growth is being driven primarily by data centers, but also industrial onshoring and electrification of transportation and buildings. Meanwhile, resource projections reflect slower rates of additional resources being interconnected to the grid due to project delays and cancellations.

Data presented by WECC shows the Northwest adding 14 GW in new generation between 2026 and 2035. Nearly all these resource additions are intermittent power sources, and almost half of the generation comes from wind. Meanwhile, nearly 345 MW of generation over the same time period is planned to be retired, roughly 85% of which are clean resources. In the Northwest subregion, annual demand is expected to grow 24% between 2026 and 2035 with peak demand expected to increase by 20.6%.

The information that goes into the LTRA is aggregated from data provided by balancing authorities that collect and aggregate resource plans of utilities (not all utilities are balancing authorities). WECC explained they have been working more closely with balancing authorities and utilities to standardize and ensure the integrity of reporting to WECC.

Northwest Utilities Resource Adequacy Study — Energy and Environmental Economics, Inc.

Energy and Environmental Economics, Inc. (E3) is a nationally recognized consultant specializing in decarbonization and the clean energy transition, including climate policy analysis, integrated system planning, and asset valuation and strategy. E3 was retained by Pacific Northwest utilities and generation owners to evaluate resource adequacy in the Pacific Northwest today and in the future. The industry hired E3 to do a similar study prior to adoption of Washington's 100% clean electricity law, the Clean Energy Transformation Act (CETA), in 2019. The findings are similar.

The preliminary results of the 2025 study suggest the planned resource additions in utility IRPs are likely sufficient to meet the region's resource adequacy needs, but that meeting the pace of growth anticipated in utility IRPs will require annual resource additions equal to four to five times historic levels. The study finds the region experiencing significant headwinds due to permitting and interconnection delays, changes in federal policy, and higher costs. Without any new resource additions, the region would have a gap in resources beginning in 2026 and growing to 9 gigawatts by 2030, which is approximately the load of the state of Oregon. Data centers and the electrification of buildings and transportation are the principal contributors to load growth.

The study finds the most constraining reliability conditions are extended cold weather events in the winter during very low water years. The preliminary results suggest utilities will need to deploy some natural gas resources under the 2030 carbon neutral standard of CETA to meet demand during these extreme and infrequent conditions. The second phase of the study, expected by the end of this year, will evaluate resource options for meeting near-term and long-term resource adequacy and clean energy needs.

Update on Data Center Working Group under Governor's EO 25-05 — UTC and Commerce

UTC and Commerce provided an update on the Data Center Workgroup convened by the Department of Revenue and Governor's Office, in response to the Governor's Executive Order 25-05. Representatives from the UTC and Commerce provided a summary of each agency's priorities, which include:

- **Accurate load forecasting:** Speculation and duplicative load forecasts make it hard to forecast regional resource needs.
- **Conformance with state energy and climate laws:** Data center loads should comply with state clean energy and climate laws.
- **Load flexibility:** Data centers should exercise available load flexibility to help the electric grid during peak periods.
- **Leveraging tech investments in transmission and generation:** The state should work with hyperscalers who have immense experience deploying transmission and clean energy technologies and the funding needed to deploy them to the benefit of data centers and the overall electric grid.
- **Adequate resources to maintain reliability:** Utilities should not feel obligated to serve large loads if serving these loads threatens the resource adequacy and reliability of the electric grid.
- **Impacts on hydropower resources and fish populations:** Data center operations should not affect the operation of the hydropower system or fish populations.
- **Rate impacts:** Existing ratepayers should be insulated and protected against potential rate impacts of adding data centers to the electric grid.
- **Clean energy for economic development:** The development of data centers should support the growth of clean energy jobs.

Demand-side Resource Opportunities — Northwest Energy Efficiency Alliance and Tacoma Power

Northwest Energy Efficiency Alliance (NEEA) is an alliance of utilities and partners that pools resources and shares risks to transform the market for energy efficiency to the benefit of all consumers in the Northwest.

Recently NEEA announced that 10 regional utilities are funding an End-Use Load Flexibility initiative, exploring ways that grid-connected consumer products and dynamic services can fill regional winter-time power constraints within the next five years.

NEEA forecasts the project will deliver a 1-to-3-gigawatt resource to the region within the next four years, reducing the region's peak load by 10%. NEEA is developing its strategic and business plans for the 2026-2029 period, which include testing and refining projects and scaling and adapting utility load-flex programs by codifying best practices and providing tools to support market awareness.

Tacoma Power shared the potential for demand flexibility in its service territory and the technical and economic challenges of being an early adopter of demand response. The utility shared that industrial partners were often eager to participate in demand response programs. Residential customers have varied responses and often require intentional outreach before participating.

UTC
Washington Utilities and Transportation Commission

Washington State Department of Commerce

July 30, 2025

The Honorable Bob Ferguson, Governor of Washington
The Honorable Sarah Bannister, Secretary of the Senate
The Honorable Bernard Dean, Chief Clerk of the House

Re: Summary of the 2025 Summer Readiness Resource Adequacy Meeting

Dear Governor Ferguson and Members of the State Legislature:

It is our pleasure to provide the attached summary of a meeting held by the Department of Commerce and the Utilities and Transportation Commission on June 5, 2025, concerning resource adequacy, specifically focused on utility preparations to meet summer conditions, or summer readiness. We convened this meeting and submit this summary in response to public feedback to expand our annual resource adequacy meeting under RCW 19.280.065 to three meetings per year: one focused on summer readiness, another on long-term resource adequacy, and the third on winter preparedness. The meeting agenda, a recording of the meeting, and presentation materials from the first meeting are available on the Department of Commerce webpage and the Utilities and Transportation Commission webpage.

The expert assessments on resource adequacy presented at the summer readiness meeting conclude the Northwest has adequate resources to meet expected demand for electricity this summer and does not face a significant risk of outages under normal weather conditions. However, low snowpack and warmer and drier weather this summer pose an increased likelihood of wildfires and heat waves, especially in certain parts of the state. The Bonneville Power Administration (BPA) and Washington utilities reported they have the resources to meet customer and business demand and that short-term weather-related events are unlikely to impact the electric power system. That said, long duration heat waves and catastrophic wildfires across the West increase the risk of resource inadequacy and could severely strain the electric power system.

BPA and Washington utilities are taking steps to harden their systems against weather-related threats. The risk of the federal government no longer providing National Oceanic Atmospheric Administration (NOAA) weather data threatens the ability of weather experts and Washington utilities to identify weather-related threats to the electric power system.

The meeting included an update on the development of the Western Resource Adequacy Program (WRAP)—a utility-initiated effort to hold participating utilities accountable for maintaining reliable service while maximizing reliability benefits and cost savings of their diverse resources and loads. While acknowledging the challenges of implementing this program, we remain concerned that the industry is not moving fast enough to align itself with the contractual requirements of the program, and that some utilities have not committed to participating in the program. Nonetheless, we appreciate the commitment to WRAP implementation expressed by many utilities and the revised transition plan shared after our 2024 resource adequacy meeting.

Expert assessments of resource adequacy presented at this meeting highlight the need for the state and region to hasten efforts to increase transmission capacity and secure resources and strategies to meet medium-to-long-term load growth. These projects have long timelines and need to begin construction soon to be serviceable in the medium-to-long term. On the demand-side, a few utilities have started leveraging small demand response and virtual power plant programs to reduce peak demand on the power system. If scaled, these programs represent an immense opportunity to reduce peak demand. We look forward to taking a deeper dive into medium-and-long-term resource adequacy issues and policy opportunities at our next resource adequacy meeting, scheduled for Sept. 22, 2025.

This meeting's presentations highlight that the greatest near-term threat to resource adequacy is weather-related events, which continue to grow more severe and wide spread. We remain committed to monitoring resource adequacy and appreciate the continued engagement of the utility industry and consumer and environmental advocates, as our state continues to pursue resource adequacy while combatting climate change in an affordable and equitable manner.

Sincerely,

	Signed by: Jennifer Grove 7BBCBF83E1F34AE...
Brian Rybrik	Jennifer Grove
Chair	Assistant Director, Energy Division
WA Utilities and Transportation Commission	WA Department of Commerce

Attachment (1)

2025 Summer Readiness Resource Adequacy Meeting Summary

Introduction

On June 5, 2025, the Washington Utilities and Transportation Commission (UTC) and the Washington Department of Commerce (Commerce) convened a public meeting to review the adequacy of energy resources to serve the state's electricity needs and receive an update from regional experts and Washington utilities on their readiness for the summer of 2025.
We convened this meeting and submit this summary in response to public feedback to expand our annual resource adequacy meeting under RCW 19.280.065 to three annual meetings: one meeting in the spring focused on summer readiness, one meeting in late summer to discuss long-term resource adequacy, and another to be schedule in late fall to focus on winter preparedness. RCW 19.280.065(1) requires:

> At least once every twelve months, the department and the commission shall jointly convene a meeting of representatives of the investor-owned utilities and consumer-owned utilities, regional planning organizations, transmission operators, and other stakeholders to discuss the current, short-term, and long-term adequacy of energy resources to serve the state's electric needs, and address specific steps the utilities can take to coordinate planning in light of the significant changes to the Northwest's power system including, but not limited to, technological developments, retirements of legacy baseload power generation resources, and changes in laws and regulations affecting power supply options. The department and commission shall provide a summary of these meetings, including any specific action items, to the governor and legislature within sixty days of the meeting.

Maintaining an adequate supply of electricity is a core obligation of the utilities that provide electric service to the residents and businesses of Washington. State policy reinforces this obligation as Washington transforms its electric power system and economy, reducing and eventually eliminating emissions from fossil fuel combustion for electricity generation.[1]

The state's 100% clean electricity law, the Clean Energy Transformation Act,[2] includes requirements for utilities to establish specific standards for resource adequacy and incorporate those standards into their planning and compliance.[3] As utilities reduce reliance on coal-fired and gas-fired power plants and add renewable resources such as wind and solar, new approaches and resources will be required to maintain resource adequacy. It is equally important to incorporate risks associated with fossil generating resources, including fuel supply risk and weather-driven forced outage risk.

While resource adequacy is an obligation of each electric utility serving end use customers in the state, it also is a shared responsibility of the overall electric power system and the entities that operate, plan, regulate, design, and fund that system.

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[1] Washington 2021 State Energy Strategy, page 119-120. https://commerce.wa.gov/energystrategy
[2] Chapter 19.405 RCW.
[3] RCW 19.280.030. This resource planning statute was amended by the CETA legislation to add explicit resource adequacy provisions.

The following summarizes the presentations and discussion at the June 2025 meeting.

Summer Assessment—Western Electricity Coordinating Council (WECC)
The Western Electricity Coordinating Council (WECC) is a regional entity with authority delegated under the Federal Power Act to ensure a reliable and secure bulk power system throughout the Western Interconnection. WECC has the responsibility to create, monitor, and enforce reliability standards and promote activities, such as regional resource adequacy assessments, of the bulk power system in the Western Interconnection.

WECC presented findings from the 2025 North American Electric Reliability Corporation (NERC) Summer Reliability Assessment, and the WECC 2025 State of the Interconnection and 2025 Western Assessment of Resource Adequacy reports.

The assessments show the region has adequate resources in the short-term with weather-related events being the greatest threat to resource adequacy in the near term. The assessments show an unprecedented growth in regional resource demand in the medium to long term driven by large industrial loads, including data centers. The region needs to redouble efforts now to increase transmission capacity and generation resources to meet load growth and maintain resource adequacy over the medium-to-long term.

WECC shared that its assessments are informed by individual utility resource plans. These plans may in the aggregate overstate future resource needs, because large industrial loads, such as data centers, are counted multiple times if they submit interconnection requests across multiple utility service territories, which is common across the rapidly expanding data center industry. On the other hand, utility-submitted data currently lacks enough granularity to understand the status of projected new generation resources in utility IRPs. Improved transparency and consistency in utility reporting in response to these emerging industrial and resource adequacy trends is key to improving the precision of future WECC assessments.

Western Resource Adequacy Program — Western Power Pool
The Western Power Pool shared an update on the Western Resource Adequacy Program (WRAP). The program aims to transition individual utility resource adequacy approaches to a single resource adequacy standard and program to make it easier for utilities to share energy in times of need. A uniform resource adequacy standard will increase transparency into regional needs and help the region utilize diverse resources and loads to reduce overall capacity needs among participating utilities.

WRAP remains in a non-binding phase. During this phase, utilities submit data and view their resource obligations, which helps identify whether they have enough contracted capacity to comply with program requirements. This past year, the program added an option to allow participants with resource needs to "raise their hand" to enlist the help of other members with excess resources. There is no obligation to offer help and no penalties for non-compliance with program requirements during the non-binding phase.

Summer Readiness — Bonneville Power Administration

The Bonneville Power Administration (BPA) is obligated under the Pacific Northwest Electric Power Planning and Conservation Act to assure the adequate supply of power to its load-following customers. Those obligations are satisfied through 20-year contracts due to be updated in 2028. Utilities that elect slice or block contracts retain responsibility for their own resource adequacy.

BPA reported that it has adequate contracted resources to meet WRAP requirements and plans to join the binding phase of the program at program launch in the winter of 2027-2028. BPA anticipates reduced stream flow with this past winter's snowpack concentrated in areas of its system with less generation but expects minimal risks to its system given current hydraulic forecasts. BPA shared that its power system is well positioned to respond to short-term weather events, but longer-term weather events could put stress on its system.

Current conditions and Summer Outlook — Washington State Climate Office

The Washington State Climate Office (WASCO) housed at the University of Washington monitors and forecasts climate trends, provides training and capacity building, houses data and information resources on Washington's current and past climate, and conducts applied research on the climate and its impacts to Washington residents.

WASCO reported that this past winter was drier than normal with low precipitation leaving little snowpack for multiple years in a row. Snow sites are melting two-to-four weeks faster than usual, compounding precipitation deficits and the risk of wildfires this summer. An emergency drought declaration has already been issued for Yakima County and drought advisories have been issued for seven other counties. Weather forecasts indicate a higher likelihood that this summer will be warmer and drier than normal conditions expected, leaving our state at an elevated risk of wildfires and more frequent, longer-duration heat waves through September.

Summer Readiness — Puget Sound Energy

Puget Sound Energy (PSE) reported that the utility is participating in WRAP and plans to enter the binding phase of the program in the Winter of 2027-2028. PSE reported the utility has enough resources to meet peak summer demand and plans in place to coordinate with transmission providers to deliver power to customers during heat events. The utility holds daily coordination calls on system conditions between real-time power merchants and PSE's load office operations and has backup fuel (diesel) in place for natural gas fired generation if needed.

PSE provided information about the impact of its nascent demand response and virtual power plant programs in reducing load to maintain resource adequacy. PSE intends to build on the success of its demand response and virtual programs going forward.

Summer Readiness: System Operations Overview — Avista

Avista expects to meet resource adequacy this summer. Avista has broadened its transmission portfolio with BPA and added new transmission capacity on its own lines. The utility sees wildfires as the largest risk to resource adequacy this summer. In partnership with the Department of Natural Resources and local fire responders, Avista has newly installed cameras across its service territory to detect smoke and send alerts to Avista and local fire responders. In addition, Avista is adding weather stations to help the utility better understand and manage risks to its system.

Wildfire and Summer Readiness — PacifiCorp
PacifiCorp acknowledged higher than expected wildfire risk in its service territory in Yakima County. The utility reported that across its multi-state service territory it is investing $2 billion to improve its situational awareness, harden its electric grid, and improve operations to respond to weather-related threats and outages. This includes new protocols to improve communications with customers. In addition, the utility reported it is investing 75 GW in natural gas resources across its multi-state footprint.

PacifiCorp shared that its newly energized Gateway South transmission project from Wyoming to Salt Lake City has loosened up congestion on its transmission system and allowed additional wind resources onto its system. The utility reported it has resources to meet the resource adequacy needs of Washington customers and businesses, but extreme heat with little decrease in nightly temperatures across the Pacific Northwest, Desert Southwest and California would cause extremely high loads and strain its system.

Summer Readiness — Public Generating Pool
The Public Generating Pool (PGP) is composed of eight publicly owned electric utilities in Washington and one electric utility in Oregon. The Washington utilities in PGP include Seattle City Light, Snohomish County Public Utility District (PUD), Tacoma Power, Clark County PUD, Chelan County PUD, Grant County PUD, Lewis County PUD, and Cowlitz County PUD. These utilities operate non-federal assets and purchase 35% of their power from BPA.
PGP reported its member utilities are seeing near average hydro levels and did not have anything to flag for the summer of 2025. PGP is concerned that the region will grow more dependent on imported power and laments the lack of a regional summer preparedness dashboard, which is common in parts of the county with regional transmission organizations.

Public Comment
Christina Wyatt of Big Bend Electric Cooperative shared that as a Bonneville Customer in multiple balancing authorities Big Bend does not have any real time operational signals and there is a lack of fiber to implement demand response programs. She said that 50% of Big Bend's customers are irrigation customers and a demand response program would require them to shutoff power, which would impact food security.

Lauren McCloy of the Northwest Energy Coalition (NWEC) shared her observations from the meeting. She highlighted how the presentations stressed the importance of transmission to resource adequacy and demand response. NWEC views demand response as a low-cost way to meet the capacity needs of the region and encourages the region to continue to investigate how to best integrate demand response on the grid and pilot projects to develop and scale demand response programs. NWEC advocated for everyone to continue to encourage the federal government to keep data on water levels in the public realm.

Blake Scherer of Benton PUD commented that "the continued implementation of CETA is in itself a risk to utility resource adequacy and affordability, especially penalizing dispatchable natural gas resources and promoting the overbuild of non-dispatchable, transmission-dependent, land-intensive wind and solar resources." He said CETA legislation allows CETA to suspend implementation of the law or exempt a utility from paying penalties if Commerce finds RCW 19.405.080 demonstrates adverse system reliability impacts due to CETA[4]. The first report said it was too early to tell if CETA was impacting system reliability. The next report is due in July of 2028.

Nicolas Garcia of the Washington Public Utility District Association (WPUDA) stressed that resource adequacy has a real economic impact to households. Resource adequacy challenges can lead to high costs being passed onto customers, especially low-income customers.

[4] We include this statement to reflect public comments provided at the workshop but note that this comment does not accurately state the provisions of law related to temporary suspension of the clean electricity standards. CETA provides a temporary exemption provision in RCW 19.405.090(3) and (5) and provides that the governing body of a consumer-owned utility may authorize a temporary exemption based on factors specified in the statute, without reference to the assessment made by Commerce under RCW 19.405.080.

December 31, 2025

The Honorable Bob Ferguson, Governor of Washington
The Honorable Sarah Bannister, Secretary of the Senate
The Honorable Bernard Dean, Chief Clerk of the House

Re: Summary of the 2025 Winter Preparedness Resource Adequacy Meeting

Dear Governor Ferguson and Members of the State Legislature,

Please find the attached summary of the 2025 winter preparedness resource adequacy meeting held November 4, 2025. This year, in response to public feedback, we expanded our annual resource adequacy meeting under RCW 19.280.065 to three gatherings: one each for summer readiness, long-term resource adequacy, and winter preparedness. The meeting agenda, recording, and presentation materials are available on the Department of Commerce webpage and the Utilities and Transportation Commission webpage.

Winter reliability assessments, presented by regional resource adequacy experts, the North American Electric Reliability Corporation and Western Electricity Coordinating Council, indicate the Northwest's electric grid meets national resource adequacy criteria under normal conditions this winter. Extreme weather poses an elevated risk of short-duration outages absent additional measures, such as utilities following their emergency policies and procedures or firing up their backup generators. The Bonneville Power Administration and Washington utilities do not forecast outages this winter.

At the November 4 meeting, the Bonneville Power Administration and utilities shared the steps they are taking in preparation for the season. This includes daily monitoring of weather conditions, regular calls with reliability coordinators and fuel suppliers, maintenance of the system, and updates to their operations and emergency planning procedures. Utilities reported they have maximized hydro and natural gas storage ahead of winter and ensured facilities are operating properly. Some, such as Seattle City Light and Puget Sound Energy, noted voluntary customer curtailment programs intended to help offset electricity demand if needed.

The meeting highlighted the need for coordination between the natural gas system and the electric system to ensure a reliable energy supply throughout winter. The Northwest Gas Association and Pacific Northwest Utilities Conference Committee discussed collaboration between the electric and gas industries to prepare for winter, as well as broader efforts to bring utility leaders, regulators, state policymakers, power producers, and other stakeholders together, for the purposes of better cross-sector planning and operations. This ensures discussion around the increased interdependence of gas and electric systems as the region continues its transition to clean energy and state-level climate goals. We appreciate seeing natural gas and electric utilities working together to ensure affordable, reliable, and equitable services for Washington customers.

Preparing for this winter
Washington has already seen some extreme weather as the winter season begins. Utilities can take near-term steps to preserve reliable service in case of extreme weather. These include:

- Ensuring customers' backup generators are in service and ready to be deployed,
- Ensuring the industry's emergency and curtailment plans and procedures are in place, and
- Coordinated planning and response between electric and natural gas systems.

Preparing for future winters
While this meeting focused on readiness for winter 2025-2026, there is a clear need for concerted action to prepare for future winters. Washington law provides utilities with flexibility to use gas-fired generating facilities and, if needed, to expand gas-fired capacity to meet winter peaks. In the meantime, Washington must do more to streamline siting and permitting, add in-state and out-of-state transmission capacity, proactively pursue transmission enhancements and expansions and demand flexibility, and improve resource forecasting for large new loads, such as data centers and advanced manufacturing facilities.

Our energy system is deeply interconnected, and every aspect is vulnerable to extreme weather events fueled by climate change. We remain committed to working with our natural gas and electric utility partners to further our joint efforts to maximize the reliability and affordability of our state's energy system as we decarbonize our economy.

Sincerely,

Brian J. Rybarik
Chair
WA Utilities and Transportation Commission

Jennifer Grove
Assistant Director, Energy Division
WA Department of Commerce

Attachment (1)

2025 Winter Preparedness Adequacy Meeting Summary

Introduction

On November 4, 2025, the Washington Utilities and Transportation Commission (UTC) and the Washington Department of Commerce (Commerce) convened a public meeting to review the adequacy of energy resources to serve the state's electricity and natural gas needs.

We convened this meeting and submit this summary in response to public feedback to expand our annual resource adequacy meeting under RCW 19.280.065 to three annual meetings: one meeting in the spring focused on summer readiness, one meeting in late summer to discuss long-term resource adequacy, and another in late fall to focus on winter preparedness.

RCW 19.280.065(1) says:

> At least once every twelve months, the department and the commission shall jointly convene a meeting of representatives of the investor-owned utilities and consumer-owned utilities, regional planning organizations, transmission operators, and other stakeholders to discuss the current, short-term, and long-term adequacy of energy resources to serve the state's electric needs, and address specific steps the utilities can take to coordinate planning in light of the significant changes to the Northwest's power system including, but not limited to, technological developments, retirements of legacy baseload power generation resources, and changes in laws and regulations affecting power supply options. The department and commission shall provide a summary of these meetings, including any specific action items, to the governor and legislature within sixty days of the meeting.

Maintaining an adequate supply is a core obligation of the utilities that provide energy service to the residents and businesses of Washington. State policy reinforces this obligation as Washington transforms its electric power system and economy, reducing and eventually eliminating emissions from fossil fuel combustion for electricity generation.[1]

The state's 100% clean electricity law, the Clean Energy Transformation Act,[2] includes requirements for utilities to establish specific standards for resource adequacy and incorporate those standards into their planning and compliance.[3] As utilities reduce reliance on coal-fired and gas-fired power plants and add renewable resources such as wind and solar, new approaches and resources will be required to maintain resource adequacy. Utilities must also incorporate equally-important risks associated with fossil generating resources, including fuel supply risk and weather-driven forced outage risk.

While resource adequacy is an obligation of each electric utility serving end-use customers in the state, it also is a shared responsibility of the overall energy system and the entities that operate, plan, regulate, design, and fund that system.

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[1] Washington 2021 State Energy Strategy, page 119-120. https://commerce.wa.gov/energystrategy

[2] Chapter 19.405 RCW.

[3] RCW 19.280.030. This resource planning statute was amended by the CETA legislation to add explicit resource adequacy provisions.

Northwest Gas Association (NWGA)—Gas-Electric Integration and Regional Winter Readiness

NWGA represents the Pacific Northwest gas industry, which includes regional natural gas distribution companies and pipeline operators. Natural gas is used for space and water heating, and process heat for industrial applications. In addition, natural gas is used to generate electricity and, in some cases, provides feedstock for other products.

Natural gas and electric systems operate differently. Electrons move instantly and operate at a frequency and not at a speed. The legacy electric grid had no inherent way to store electricity. Meanwhile, natural gas molecules move at about 25 miles an hour, and the natural gas pipeline serves as inherent storage with the packing and drafting of gas molecules. When the electric system experiences systemwide outages, the system can be restored in segments, with power returning when each segment is energized. By comparison, when the gas system experiences a system outage, the system requires door-to-door service to turn off service, and then again for restoration when gas is flowing again.

Today the Pacific Northwest natural gas pipeline system delivers 33 percent more gas than 25 years ago. The majority of the gas, 75 percent, is weather-dependent, used in the winter and summer months. During winter peaks, gas supplies can supply over 75 percent of the total energy customers use in Oregon and Washington. To ensure the gas system can meet this demand, natural gas utilities and suppliers conduct long-term plans that consider pipeline constraints, contract terms, policies, and local distribution, consumption, and generation analyzed in tandem to determine contract needs.

Many natural gas utilities and suppliers participate in mutual assistance agreements, such as the Northwest Mutual Assistance Agreement (NWMAA), to maintain the natural gas system. NWMAA is a voluntary collaboration among entities that control natural gas assets in the Northwest, primarily focused on enhancing reliability during emergencies, such as by providing neighbors with gas. Many utilities have daily communication between gas suppliers and system operators, conduct simulated emergency scenario simulations, and have some level of generation that can switch to secondary fuel, such as fuel oil. Lastly, members of Reliability Coordinator (RC) West, the California Independent System Operator's electricity reliability coordinator in the western US, convene ahead of winter to prepare for regional cold weather events.

Winter Reliability and Electric-Gas Coordination—North American Electric Reliability Corporation (NERC) and Western Electricity Coordination Council (WECC)

NERC is the Electric Reliability Organization for North America, with a mission to assure the effective reduction of risks to reliability and security of the grid. NERC is subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. WECC is one of six regional entities under NERC that has authority delegated under the Federal Power Act to ensure a reliable and secure bulk power system throughout the Western Interconnection. WECC has the responsibility to create, monitor, and enforce reliability standards and promote activities, such as regional resource adequacy assessments, of the bulk power system in the Western Interconnection.

WECC's Winter Reliability Assessment finds long duration cold snaps are the primary concern for grid reliability in the Northwest, British Columbia, and Alberta. Low temperatures can lead to elevated demand, reduced output from renewable and fossil generation facilities, gas delivery constraints, and unplanned transmission and generation outages. The Pacific Northwest is one of a handful regions that face an elevated risk[4] of operating reserves or energy shortfalls in instances of a regionwide cold snap, in which case the region would need to take additional steps, such as running back-up generators or importing power from other regions, to maintain services.

Utilities in the WECC flagged survey responses to NERC that there should be an increased emphasis on regional gas-electric coordination, stressing the need to continue regional tabletop exercises between gas and electric operators to simulate emergency scenarios and improve readiness. Utilities in the West also reported updating pipeline operation logic and expedited emergency protocols, as well as deployment of limited duration battery energy storage systems to increase capacity on the grid.

Winter Preparedness—PacifiCorp

PacifiCorp is an investor-owned electric utility. It serves 141,000 customers in Washington, and a total of 2.1 million customers across Washington, Oregon, Idaho, California, Utah, and Wyoming.

PacifiCorp's Pacific Northwest service territory is winter-peaking, and its southwest is summer-peaking. Based on National Oceanic and Atmospheric Administration (NOAA) weather forecasts from September 2025, the utility anticipates average temperatures in most of the Northwest in October through December, below average temperatures in most of the Northwest in January through March, and above average temperatures in the Southwest portions of WECC throughout winter. PacifiCorp plans to take advantage of its transmission system and regional generation and load diversity to move energy across its Northwest and Southwest territories to meet its Northwest load this winter.

PacifiCorp's operational planning for winter readiness includes securing and maintaining firm gas transportation and power transmission contracts for its electric generation fleet, improved operational coordination between the generation fleet and the natural gas system, extensive winter scenario modeling, and leveraging storage, flexible resources, and regional markets.

Bonneville Power Administration (BPA)

BPA is obligated under the Pacific Northwest Electric Power Planning and Conservation Act to assure the adequate supply of power to its load-following customers. Those obligations are satisfied through 20-year contracts due to be updated in 2028. Utilities that elect slice or block contracts retain responsibility for their own resource adequacy.

BPA is not forecasting any unusual system outages during this winter and has regular capability to meet load during short-term cold snaps. Long-duration cold snaps would introduce more

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[4] Elevated risk is an indication of insufficient operating reserves or energy shortfalls in above-normal peak-day demand or outages.

uncertainty and risk to the reliability of BPA's system. Fish passage constraints are currently uncertain and could impact BPA's ability to respond to extreme weather events in March, but BPA observed that extreme weather events in March are rare.

Seattle City Light (SCL)

SCL delivers electricity to approximately 513,500 customers in Seattle and a handful of surrounding communities. SCL expects this winter to be wetter and cooler with healthier snowpacks; however, these weather patterns could make polar vortex events more likely in mid-to-late winter as the polar jet stream weakens. SCL shared it has outage and water management procedures, and has maximized capacity of its system and conserved its hydro storage for use in peak winter events. The utility practices proactive forward hedging when necessary to ensure resource availability and closely monitors weather forecasts.

SCL also has implemented a new large industrial curtailment program, in which large industrial customers can receive incentives to curtail their load during key events. The events in this program are scheduled a day ahead for a 24-hour period, and there are no limits on the number of times the utility can call for industrial customers to curtail. Incentives for participating are based on the day-ahead market value of electricity.

NW Natural Gas (NWN)

NWN plans for all resources to be available at their maximum output. The utility shared that regional natural gas prices are still highly volatile, and cold weather can lead to infrastructure constraints and higher prices. While national natural gas production reached record highs in 2025, NW Natural Gas noted new liquified natural gas (LNG) export facilities are coming online, driving higher demand. Meanwhile, natural gas use for electric power generation remains high.

Cascade Natural Gas (Cascade)

Cascade shared that at 100 percent demand on its system it can meet approximately 53 percent of peak day needs with its storage resources. Total storage capacity accounts for approximately 14.75 percent of winter demand, and winter demand is approximately 68 percent of its annual demand. It has eight natural gas generation plants behind its system, highlighting the importance of gas and electric coordination efforts.

Avista

Avista reported it has prepared for the winter through diversifying their electric and gas portfolio, grid maintenance, regular winter prep calls with natural gas suppliers, increasing planning reserve margins, internal planning, refueling storage facilities, and participation in mutual assistance check-ins.

Avista participated in a NWGA and Pacific Northwest Utilities Conference Committee (PNUCC) symposium created to discuss gas-electric coordination issues, including a tabletop exercise to practice coordination during key events. The utility highlighted that sustained regional cold fronts, bulk electric or gas system issues, or regional transfer constraints could lead to high prices for customers.

Avista is continuing to explore multiple winter strategies. These include requesting customers to conserve, diversifying energy supply, conducting full system integrated resource planning, evaluating back up fuel supplies, exploring the need for regional infrastructure, continuing to evolve gas and electric coordination, and participating in regional resource adequacy initiatives and electricity markets.

Puget Sound Energy

Puget Sound Energy serves over 1.2 million electric customers and nearly 900,000 natural gas customers primarily in Western Washington. Winter readiness and energy emergency operations contingency plans span both its gas system and electric system.

On its gas system, PSE has a comprehensive cold weather action plan based on peak morning forecasts. The plan includes its LNG peak shaving plant, compressed natural gas injection sites, bypassing operations at key locations, and interruptible customer curtailment. Gas projects target specific inventories prior to winter peak season and PSE validates power plant readiness through vaporization test runs. Gas emergency contingency plans include participation in the NWMAA, curtailable interruptible loads, requests for customer conservation, and curtailment of firm sales customers through system isolation.

Winter readiness on PSE's electric system begins with resources and capacity contracts established to meet winter planning targets. The utility holds weekly collaborative meetings with PSE meteorologists to ensure early awareness of weather. The Cold Weather Action Plan ensures preparedness for high energy usage days, and electric system and transmission studies ensure reliability. Early and ongoing conservation efforts further reduce peak needs. Electric emergency contingency plans include energy supply monitoring alerts, planning reserve margins, contingency reserve obligations, emergency operations and energy agency plans.

Key Findings from Gas-Electric Integration Literature Review and Regional Symposium—NWGA and PNUCC

PNUCC is a not-for-profit trade association of consumer-owned and investor-owned electric utilities and other power industry partners that share a common interest in the efficacy and reliability of the Northwest power system. PNUCC and NWGA shared their gas-electric coordination initiative, which aims to underscore and strengthen collaboration in maintaining a reliable, affordable, and resilient energy future between the electric and gas sectors.

The initiative began with a literature review of regional energy studies, which underscored the need for better coordination between gas and electric systems. To this end, PNUCC, NWGA, Western Power Pool, and the Public Generating Pool convened a symposium of utility leaders, regulators, state policymakers, power producers, and other key stakeholders to discuss key opportunities and challenges. Key themes from the symposium include a need to (1) establish cross-sector coordination forums to align planning and share data; (2) jointly plan for load growth and peak mitigation, particularly around hybrid systems; (3) integrate models and metrics to stress-test system resilience; and (4) align regulatory frameworks to support long-term, co-optimized planning.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))	Order No. 202-25-11

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 1-90:
E3 Resource Adequacy Phase 1 Presentation

Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results

Washington Utilities and Transportation Commission
Washington Department of Commerce

Resource Adequacy Meeting, RCW 19.280.065, Docket UE-210096

September 22, 2025

Lacey, Washington

Energy+Environmental Economics

Arne Olson, Sr. Partner
Aaron Burdick, Director
Charles Li, Sr. Managing Consultant
Bill Wheatle, Managing Consultant
Pedro de Vasconcellos Oporto, Sr. Consultant
Hugh Somerset, Sr. Consultant

Overview of Phase 1

E3 was retained by regional utilities and generation owners to evaluate the state of resource adequacy in the Pacific Northwest today and into the future. Key findings of Phase 1:

1. **Accelerated load growth and continued retirements create a resource gap beginning in 2026 and growing to *9 GW by 2030***
   - 9 GW is approximately the load of the state of Oregon
2. **Preferred resources such as wind, solar and batteries make only *small contributions* to meeting resource adequacy needs**
3. ***Timely development of all resources is extremely challenging* due to permitting and interconnection delays, federal policy headwinds, and cost pressures**

STUDY SPONSORS

- Puget Sound Energy
- Public Generating Pool
  - Chelan Public Utility District
  - Clark Public Utility District
  - Cowlitz Public Utility District
  - Eugene Water & Electric Board
  - Grant Public Utility District
  - Lewis Public Utility District
  - Seattle City Light
  - Snohomish Public Utility District
  - Tacoma Power
- Avista Corporation
- Benton Public Utility District
- Douglas Public Utility District
- Emerald People's Utility District
- Franklin Public Utility District
- Idaho Power
- Klickitat Public Utility District
- Mason Public Utility District No. 3
- Northwest & Intermountain Power Producers Coalition
- NorthWestern Energy
- Okanogan Public Utility District
- Pacific Public Utility District
- Portland General Electric

Who is E3?

Our Practice Areas

+ E3 is the **largest consulting firm** focused on the clean energy transition in North America
+ E3 is a recognized **thought leader** on decarbonization and clean energy transition topics
+ E3 has **three major practice areas** covering energy systems from bulk grid to behind the meter

Climate Pathways / Policy Analysis

- Climate and energy policy analysis
- Long-term energy & climate scenarios
- Electrification and low-carbon fuels
- Future of gas

Asset Valuation & Strategy

- Asset valuation and due diligence
- Strategic advisory
- Energy market price forecasting
- Market design
- Transmission planning

Integrated System Planning

- Integrated resource planning for electric systems: reliability and resource mix
- Planning for utility and state RPS + GHG targets
- Utility planning and procurement decisions

Economy-wide energy systems — Bulk grid power systems — Grid edge & behind-the-meter

E3 has extensive experience planning for deeply-decarbonized power systems for a wide range of clients

+ State agencies

- **California:** E3 provides technical support and advisory services to the CPUC in administration of the state's IRP program, to CARB in implementation of AB32 "cap-and-trade" program, and to the CEC on a variety of research topics including compliance with SB100
- **New York State Climate Act Scoping Plan:** E3 supports NYSERDA with technical analysis of pathways to achieve economy-wide carbon neutrality by 2050 including 100x40 in the power sector
- **Illinois:** E3 supports the Illinois Power Authority and Commerce Commission on a variety of topics including resource adequacy, procurement, and renewable energy transmission studies
- **Massachusetts Department of Energy Resources:** Evaluating the benefits of long-duration energy storage and other topics

+ Utilities

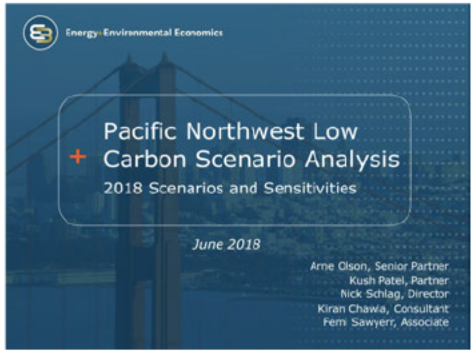
- **E3 has provided IRP support to dozens of utilities** including Puget Sound Energy, Eugene Water and Electric Board, Sacramento Municipal Utilities District, Arizona Public Service, Salt River Project, NV Energy, Public Service Company of New Mexico, El Paso Electric, Xcel Energy, Black Hills Energy, Hawaiian Electric Company, Omaha Public Power District, Florida Power & Light, Tampa Electric Company, Nova Scotia Power, New Brunswick Power, and others

+ Non-profits

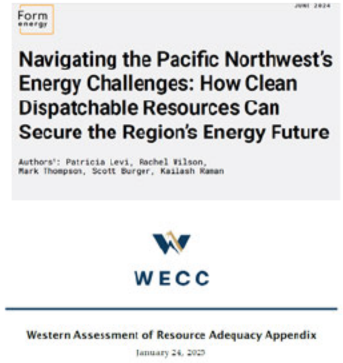
- E3 has advised **environmental advocacy organizations** including the Natural Resources Defense Council, Environmental Defense Fund, The Nature Conservancy, Clean Air Task Force, EarthJustice, World Resources Institute, Climate Solutions, and others

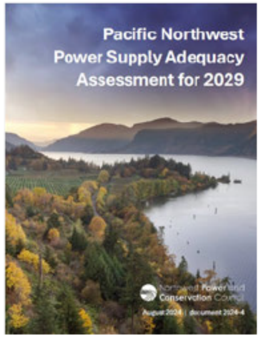
Resource Adequacy and the Energy Transition: Project Background

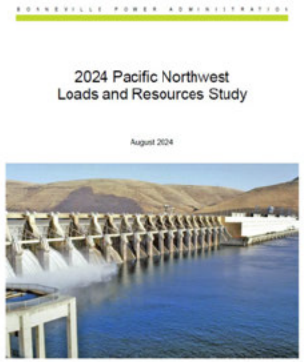
Prior E3 Studies in the Pacific Northwest



Recent PNW Regional Studies and Forecasts



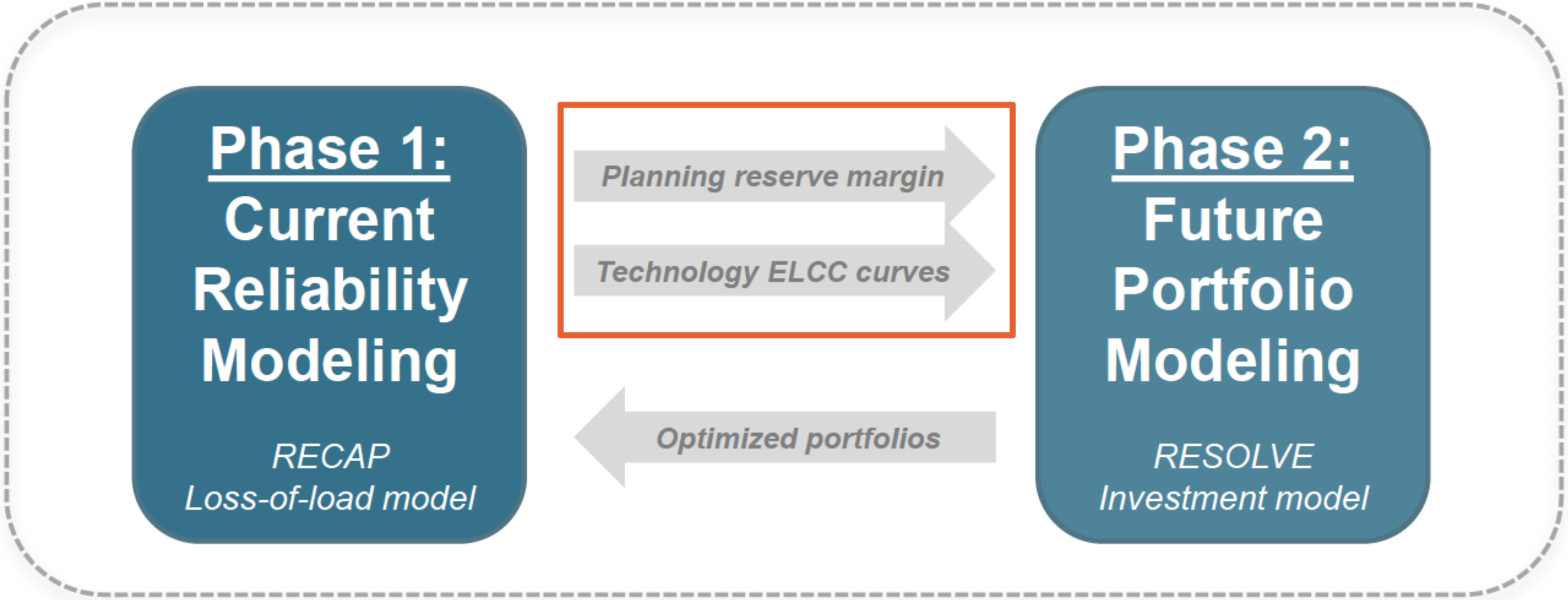




- **Prior E3 studies found that the Pacific Northwest faces *immediate and growing* resource adequacy challenges**
- **Much has happened over the past six years that might change the regional resource adequacy picture**
- **Current study objectives:**
  - Evaluate current load-resource balance
  - Examine the role of various technologies including flexible loads and firm generation for ensuring reliability
  - Identify potential barriers that may prevent the region from meeting its goals in the future

Study uses a two-phased modeling approach

+ **The modeling approach pairs detailed loss-of-load-probability modeling with capacity expansion modeling to provide a robust perspective on system reliability and cost under aggressive clean energy targets**

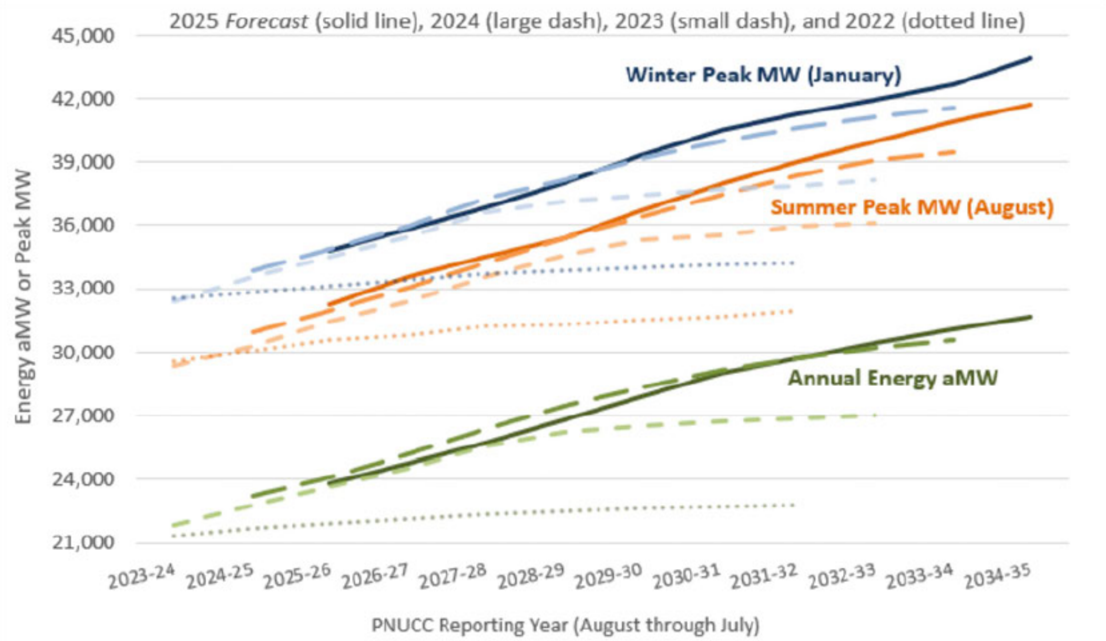


Key Study Topics:

1. Near-term resource adequacy picture
2. Barriers to new resource development
3. How to maintain long-term resource adequacy on a transitioning grid
4. Potential role for DSM and emerging "clean firm" resources
5. Stranding risk for near-term capacity resources

Regional load forecasts continue to increase due to AC adoption, electric vehicles, and data centers

PNUCC 2025 Northwest Regional Forecast
Energy aMW or Peak MW Forecast



Growth Rates

Energy	10 year
2025 Forecast	3.2%
2024 Forecast	3.1%
2023 Forecast	2.4%
2022 Forecast	0.9%

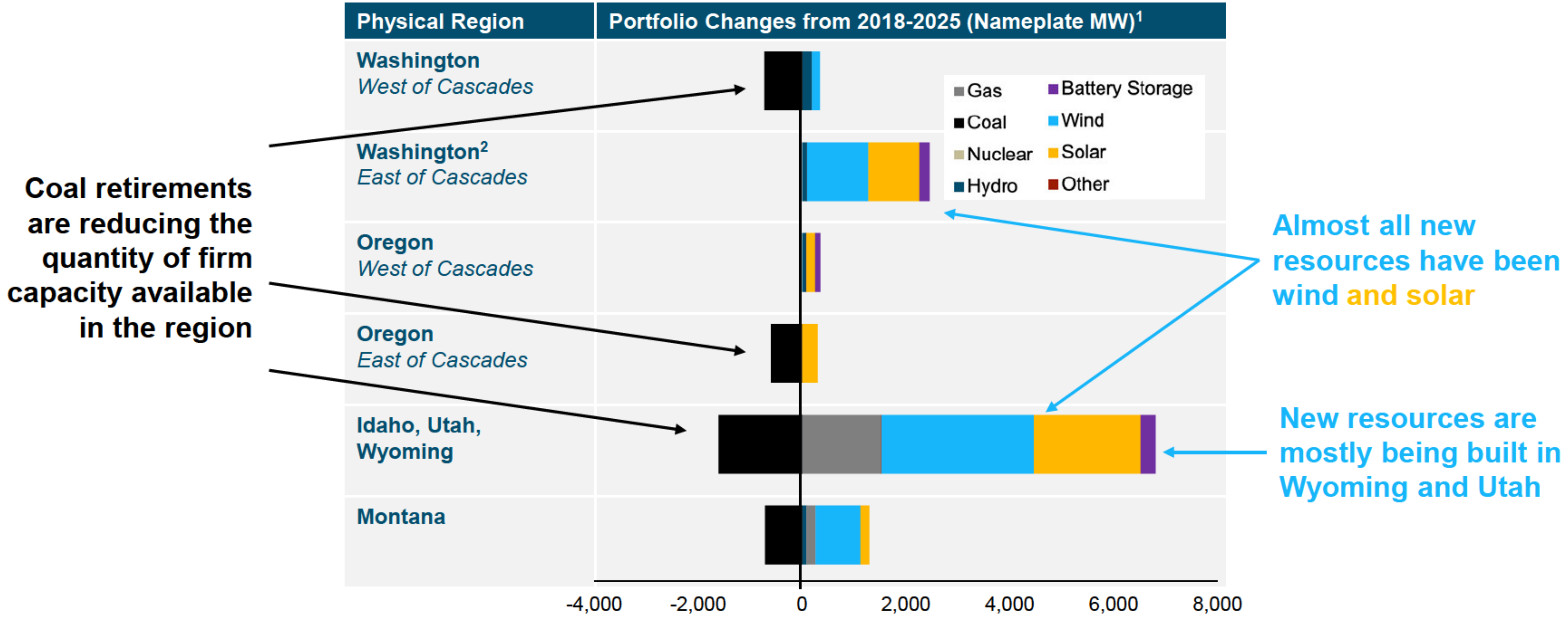
Summer Peak	10 year
2025 Forecast	2.9%
2024 Forecast	2.7%
2023 Forecast	2.3%
2022 Forecast	1.0%

Winter Peak	10 year
2025 Forecast	2.6%
2024 Forecast	2.3%
2023 Forecast	1.8%
2022 Forecast	0.7%

+ **Load growth acceleration is attributable to multiple distinct drivers, despite impact of energy efficiency**

Driver	Near-term Impact
Economywide **energy efficiency**	Small load reductions in both seasons
Higher-than-expected **air conditioning adoption** after recent heat waves	Small-medium peak load growth in the summer
Policy-driven **electric vehicle adoption**	Medium peak load growth in both seasons
Population growth and new building construction	Medium peak load growth in both seasons
Anticipated **data center** interconnection	Large average and peak load growth in both seasons

New resource additions have been slow, and located primarily outside of Washington and Oregon



1. Based on WECC 2034 ADS and recent retirements)

The Greater Northwest faces a supply deficit in 2026 which grows to 8,700 MW by 2030

- **Load growth and retirements mean the region faces a power supply shortfall in 2026**
  - The region currently relies on imports to maintain reliability
- **Nearly 9,000 MW of new capacity is needed by 2030**
- **Projects currently in active development account for only 3,000 MW of new capacity**
  - 850 MW are coal-to-gas conversions
  - 260 MW are hydro upgrades

Greater Northwest
Total Resource Need and Effective Capacity Contribution from Planned Resources (MW)

** Total Resource Need includes peak load + planning reserve margin as well as obligation to serve the Columbia River Treaty Regime*

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Greater Northwest
Total Resource Need and Effective Capacity Contribution from Planned Resources (MW)

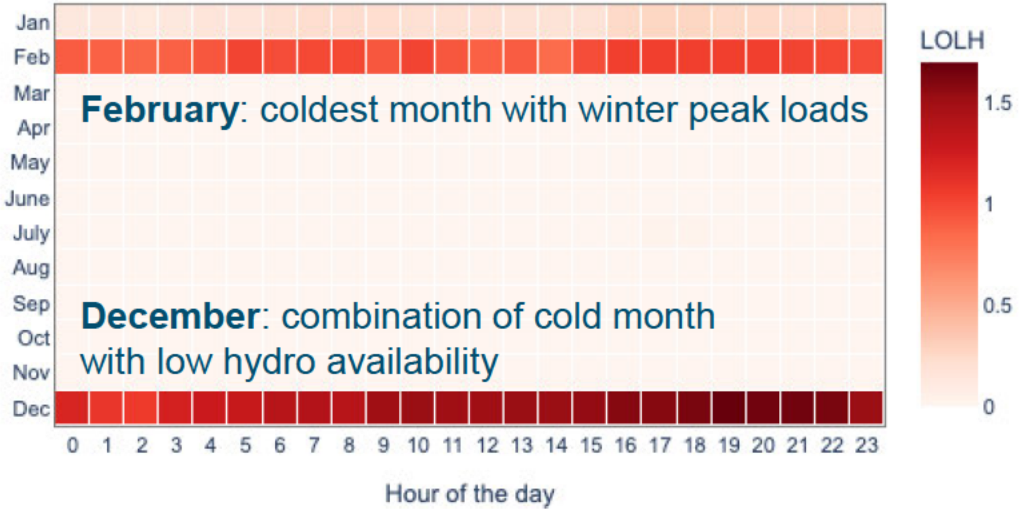
System Needs (MW)	2025	2026	2027	2028	2029	2030
Total Resource Need*	49,245	50,737	52,499	54,184	55,879	57,195
Existing Portfolio w/ Retirements	46,716	45,666	45,395	45,388	45,098	44,757
Firm Imports	3,750	3,750	3,750	3,750	3,750	3,750
Reliability Position Surplus (+) / Shortfall (-)	**+1,221**	**-1,321**	**-3,354**	**-5,046**	**-7,031**	**-8,689**
ELCC from "In-Development" Firm Resources	-	296	407	580	770	1,114
ELCC from "In-Development" Wind, Solar and Battery projects	-	645	1,015	1,316	1,508	1,934

** Total Resource Need includes peak load + planning reserve margin as well as obligation to serve the Columbia River Treaty Regime*

The most constraining reliability conditions are extended wintertime cold weather events during very low water years

- Most loss-of-load events occurring during the coldest winter months
- Many events exceed 50 hours in duration with some exceeding 100 hours due to energy shortfalls in dry years

Average Loss-of-Load Hours (LOLH) by Month x Hour*

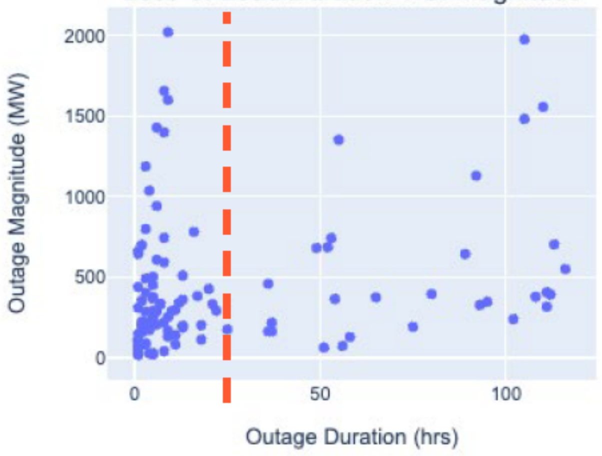


* Metrics + heatmap shown without firm imports

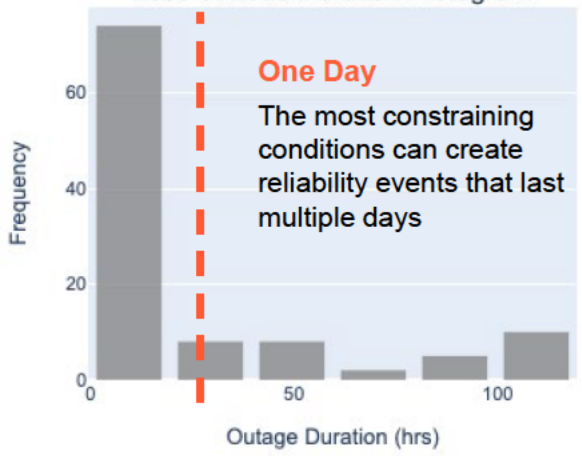
Greater Northwest, tuned to 1-day-in-10-year standard

Distribution of Loss-of-Load Events across over 2,500 years of simulated load, hydro, and renewable conditions

Loss-of-Load Duration V.S. Magnitude



Loss-of-Load Duration Histogram

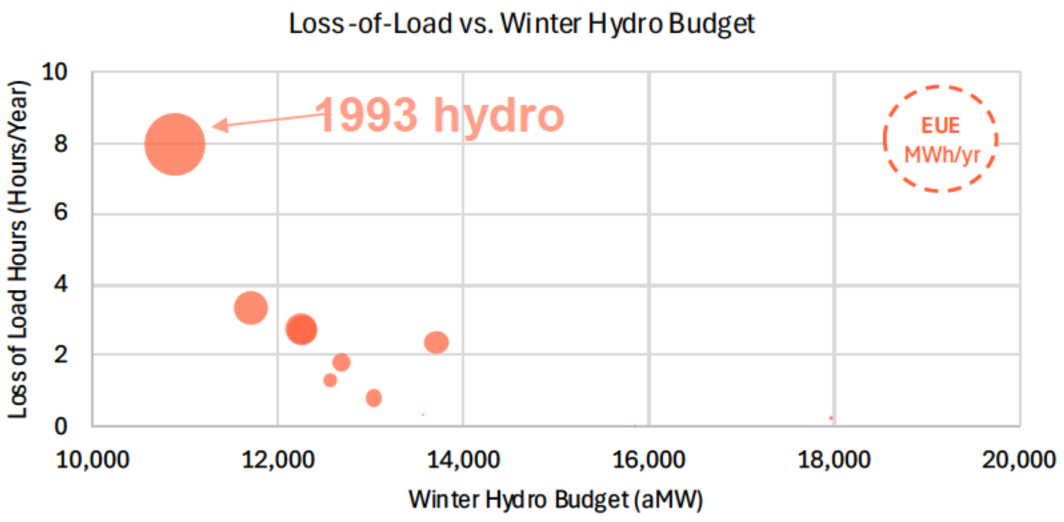


Addressing these events requires resources that can deliver energy over long periods of time

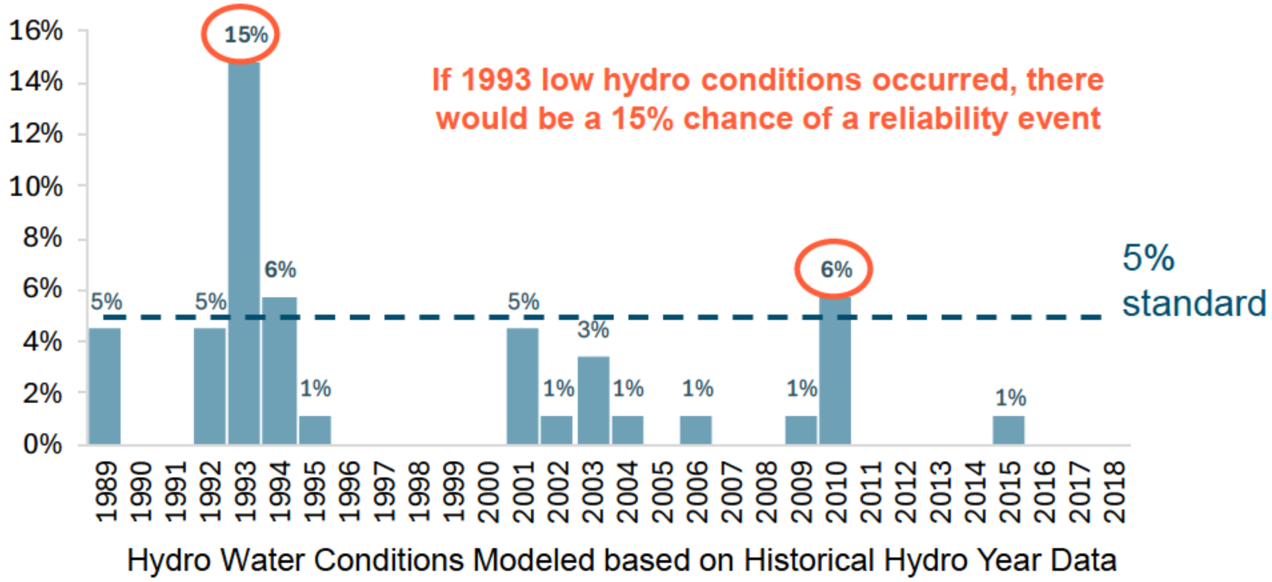
Energy shortfalls that occur during low hydro years contribute significantly to resource adequacy events

+ Loss of load events are concentrated during the lowest hydro years (1989, 1990, 1992, 1993, 1994, 2001, 2010)
+ January 2024 conditions were consistent with the very low hydro years simulated here

2025 Average Loss-of-Load Hours (LOLH) and Expected Unserved Energy (EUE) by Hydro Year



2025 Loss-of-Load Probability (LOLP) by Hydro Year

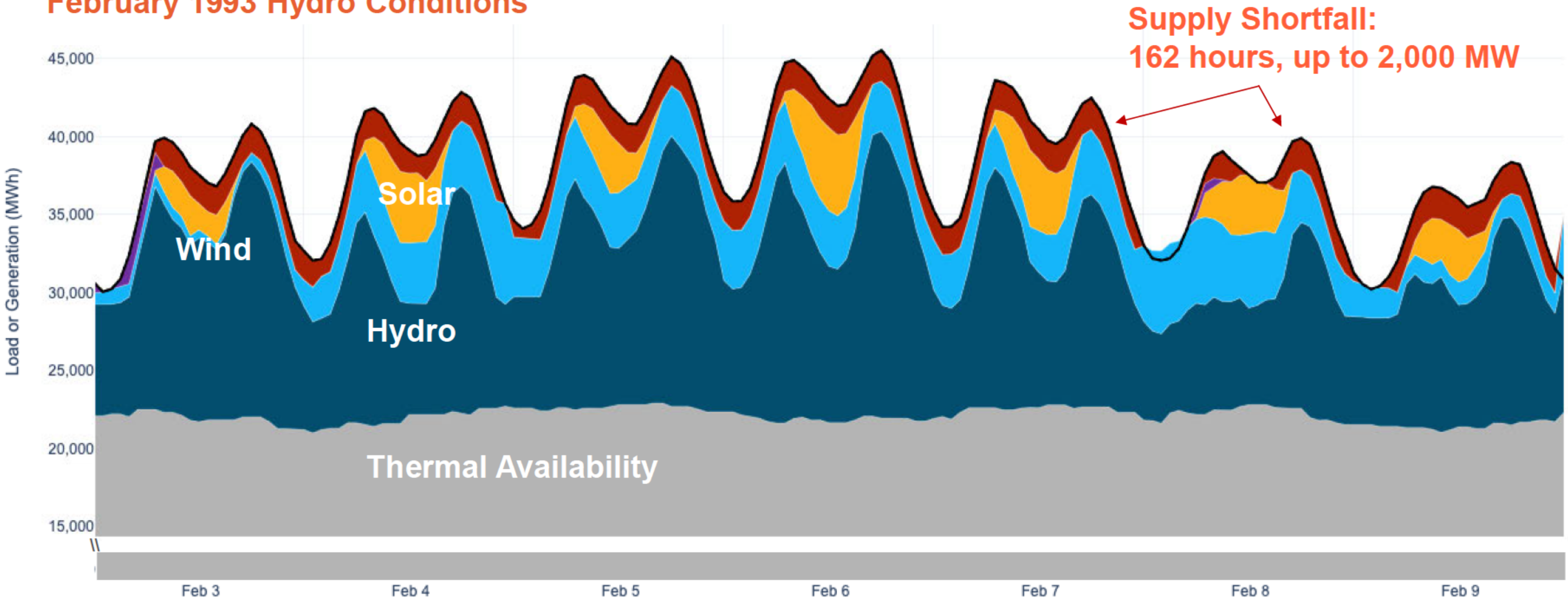


Analysis used BPA hydro simulations for 30-year period from 1989-2018

Resource availability example: February 2014 load conditions combined with 1993 hydro conditions

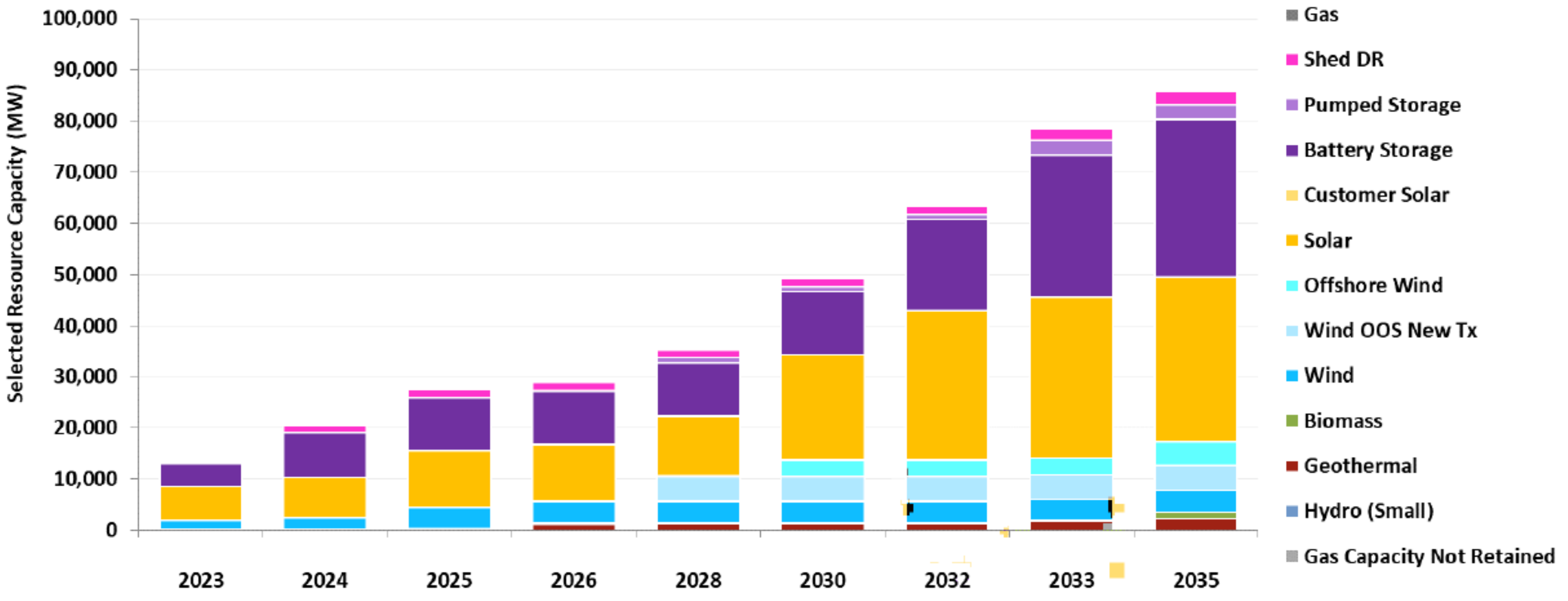
Greater Northwest 2025, RECAP simulated energy-limited event

February 1993 Hydro Conditions

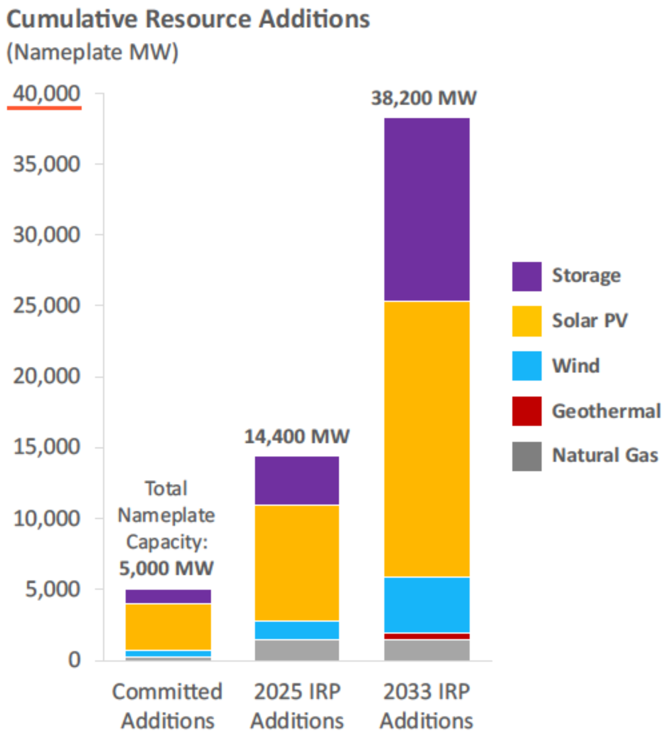


Regional comparison: solar and batteries provide high capacity value in summer-peaking regions like the Southwest

California is planning to build 50 GW of solar and storage resources by 2035 and 100 GW by 2040 (on top of 50 GW installed in 2025)



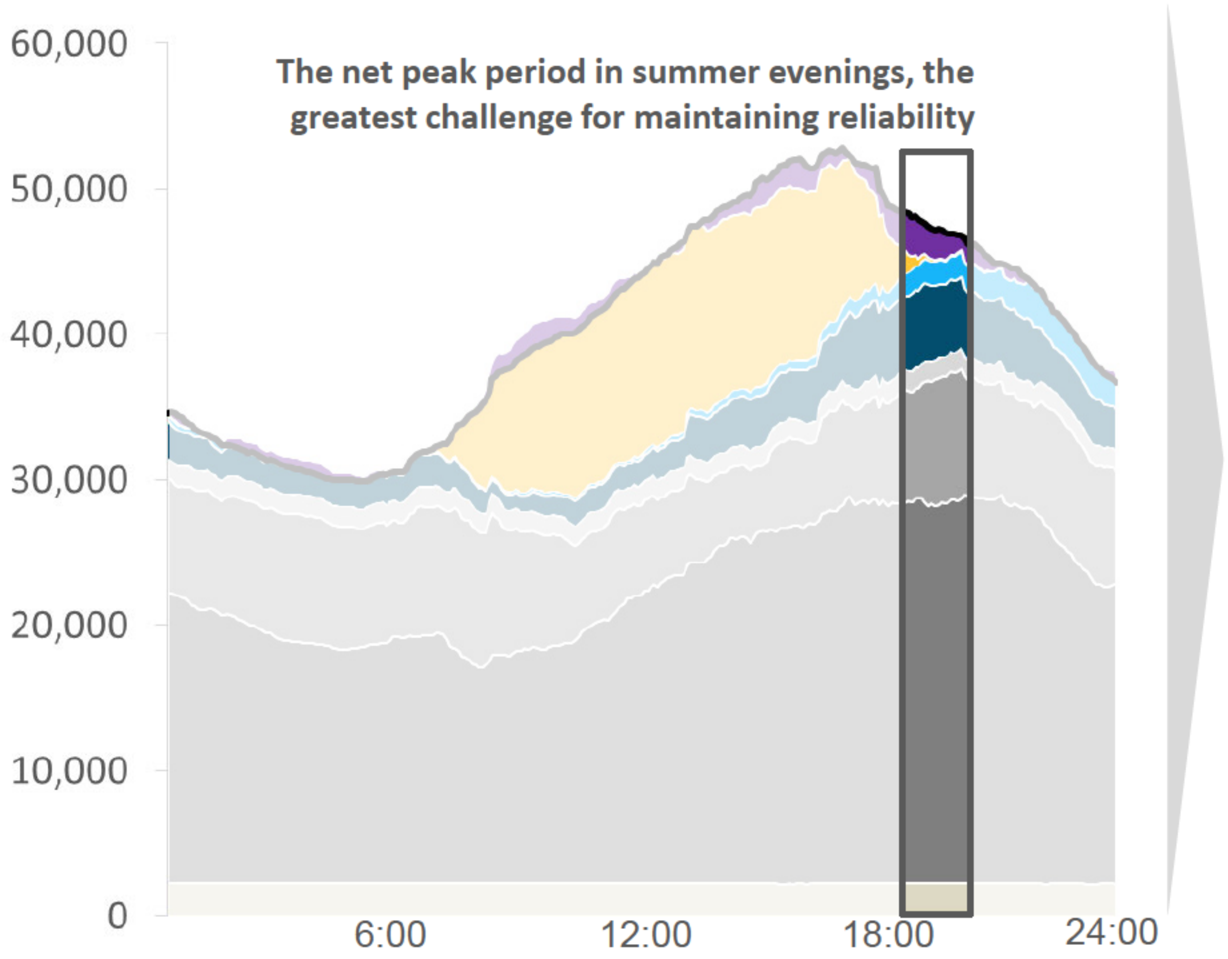
Desert Southwest is planning to build 30 GW of solar and storage resources through 2033



Regional comparison: California's most recent near reliability event was during a historic heatwave in September 2022

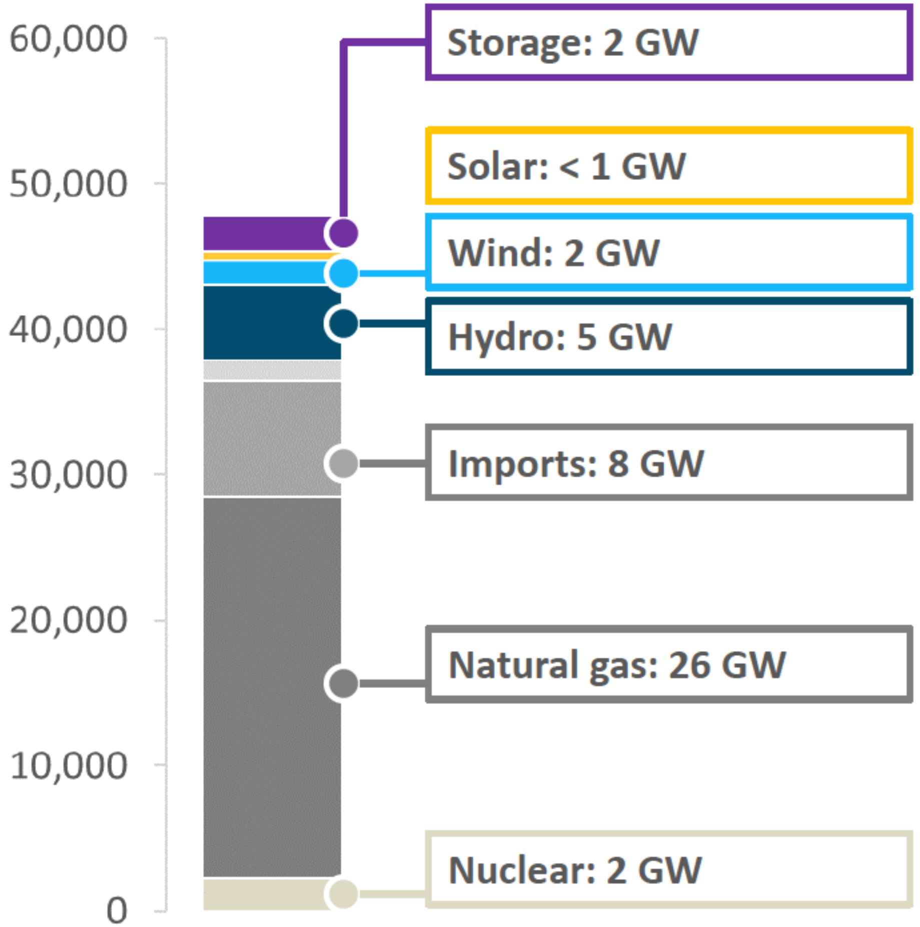
CAISO System Operations on September 6, 2022

(MW)



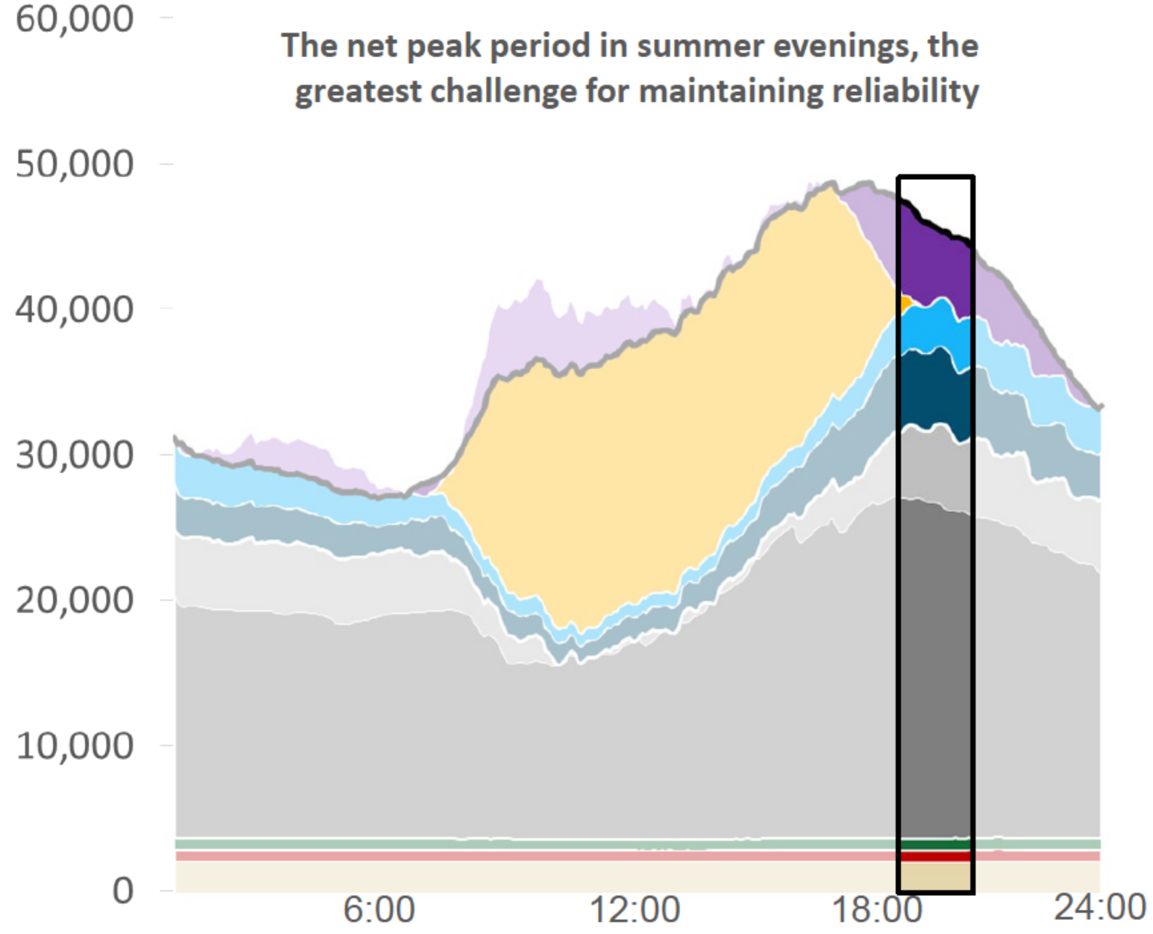
Generation During Hour of Highest Net Load

(MW)

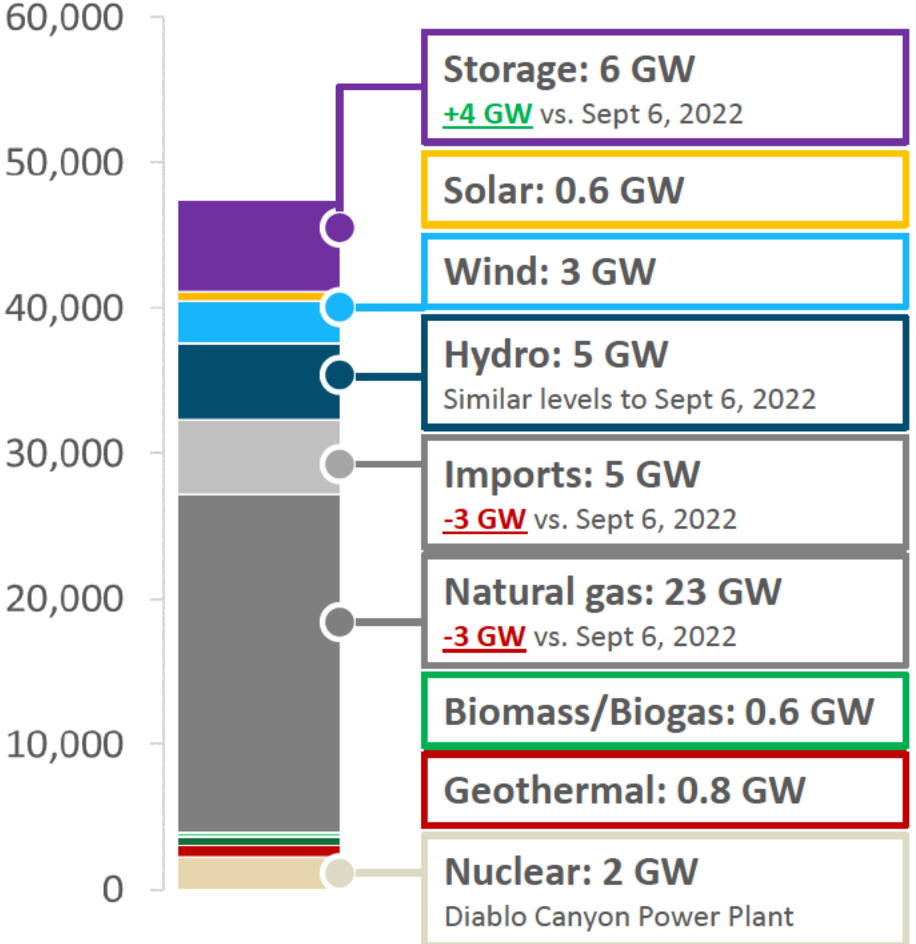


Regional comparison: Significant additions of batteries helped make the next September heatwave in 2024 a non-event

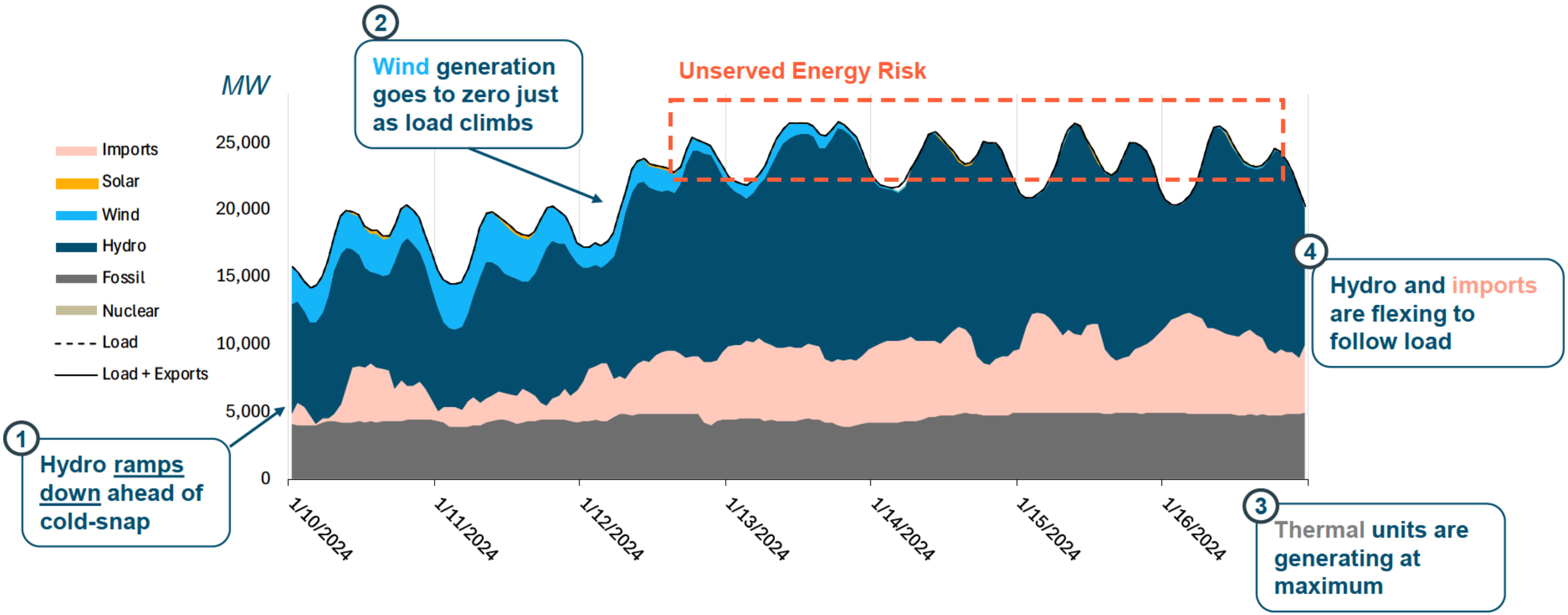
CAISO System Operations on September 5, 2024
(MW)



Generation During Hour of Highest Net Load
(MW)



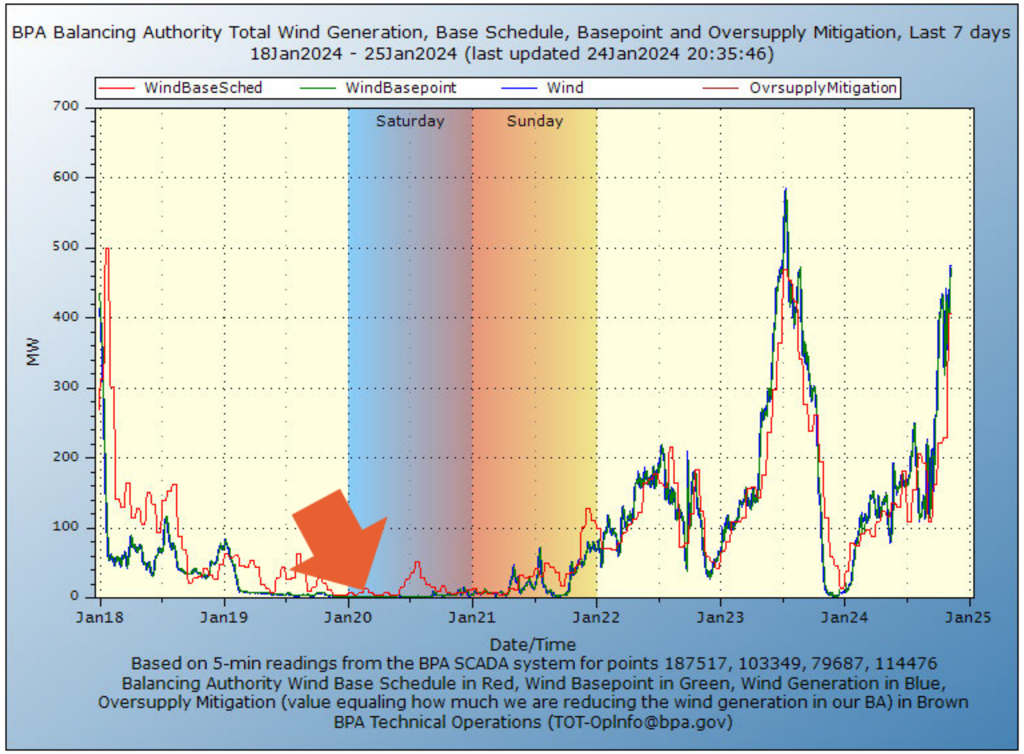
Regional comparison: The Northwest's most recent near reliability event was the multi-day January 2024 cold snap



Source: EIA, BPA

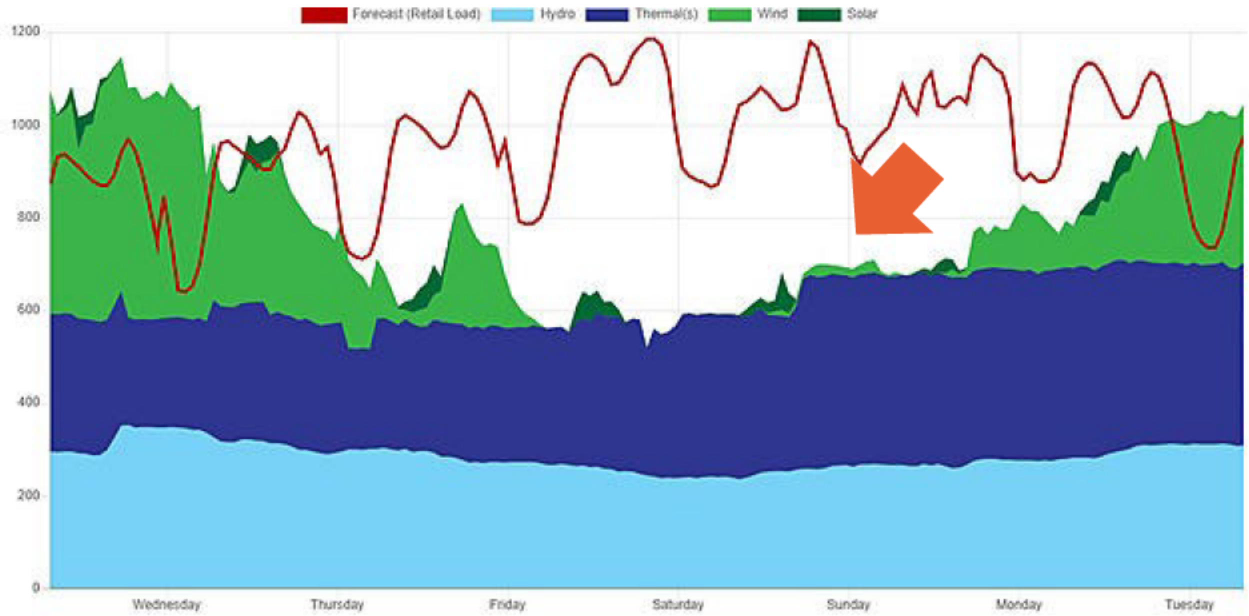
Northwest wind produced at very low levels during most of the January 2024 cold weather event

BPA: Almost no wind production on January 15-17 and 19-21



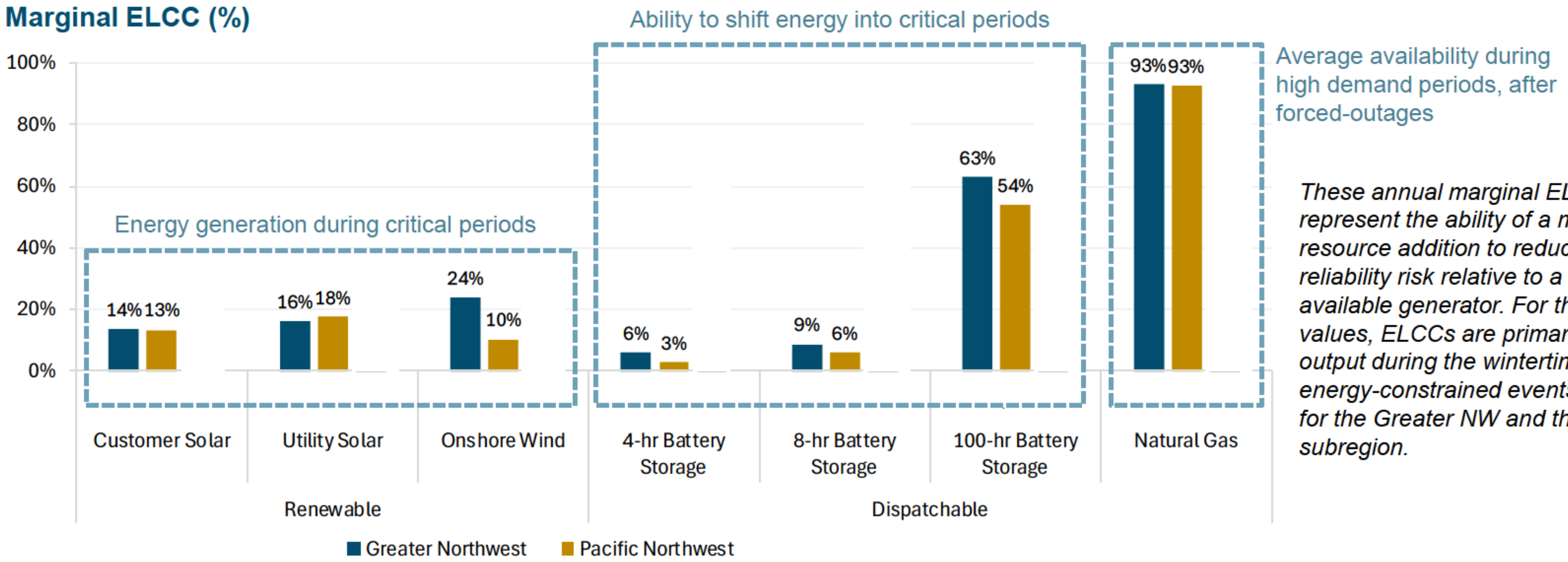
Average Jan 13: **567 MW**
Average Jan 15 5:00 AM – Jan 17 10:00 AM: **8 MW**

NorthWestern Energy: Almost no wind production on January 12-14



Low temperature records set on January 13 in Portland (12 degrees) and Seattle (16 degrees)

Resource reliability value depends on ability to supply energy during multi-day cold snaps under low hydro conditions



These annual marginal ELCC values represent the ability of a marginal resource addition to reduce region-wide reliability risk relative to a firm, always available generator. For these 2025 values, ELCCs are primarily a function of output during the wintertime multi-day energy-constrained events that define risk for the Greater NW and the PNW subregion.

+ **Solar and wind have low capacity factor during reliability events → 10-24% of nameplate**
+ **Short-duration energy storage cannot charge during most energy-constrained events → 3-9%**
+ **Natural gas plants with firm fuel can run when needed → 93%**

Energy storage and flexible loads can be valuable if matched to the duration of the reliability event

+ **Short-duration storage and demand response solutions do not have high reliability value**
+ **Multi-day response is valuable but more difficult to source**

	Duration (hours)	# of Calls per year	2030 Marginal ELCC
Energy Storage	4		6%
	8		9%
	100		**63%**
Load-shed Demand Response	6	12	18%
	12	10	30%
	24	8	44%
	48	6	**54%**
	72	4	**57%**
	120	2	**61%**

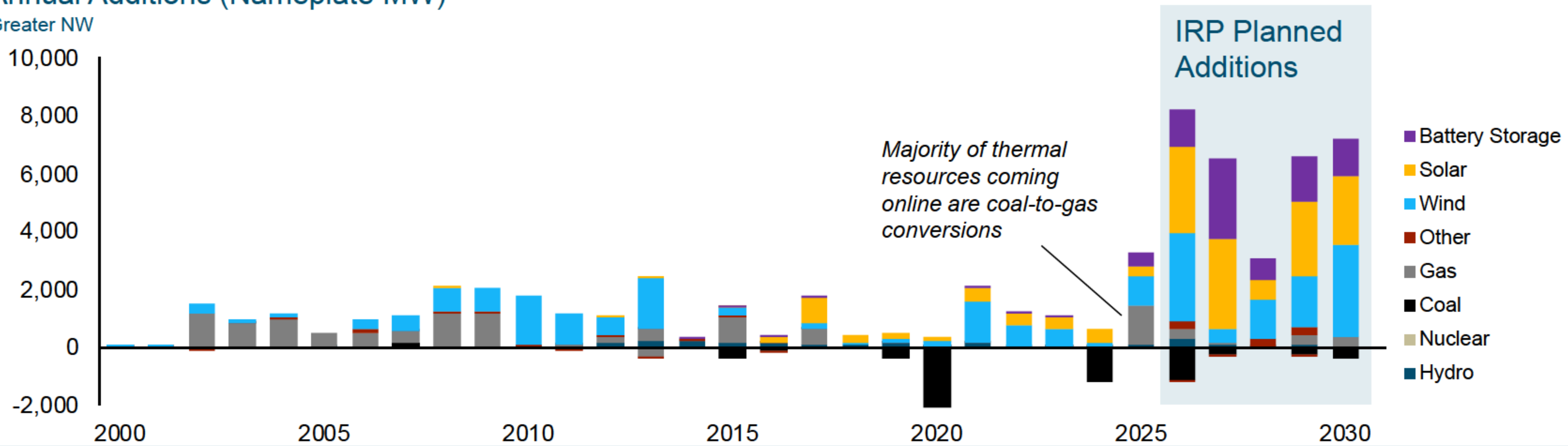
The rate of new resource additions required to meet resource adequacy needs in the next five years is unprecedented

+ **Meeting the pace of growth anticipated in utility IRPs would require annual resource additions equal to 4-5x historical levels**
+ **Project development is currently experiencing significant headwinds due to changes in federal policy and higher costs**

Retirements and New Installed Capacity Additions by Year

Annual Additions (Nameplate MW)

Greater NW



Utility + developers identified transmission, accreditation uncertainty, and new firm capacity barriers as key challenges

Key challenge	Findings from stakeholder interviews	Potential Solutions
1. Transmission access faces physical and institutional constraints	• Separate procurement and transmission planning processes leading to chicken-and-egg challenges • Lack of firm transmission rights for new resources • Difficult terrain and siting challenges	• **Improve regional transmission planning and interconnection processes**
2. Uncertain capacity accreditation metrics	• **WRAP is voluntary** and has not yet become binding • **Accreditation metrics are uncertain**	• **Strengthen the WRAP program with fundamentals-based capacity accreditation**
3. Barriers to building new RA capacity	• Utilities are likely to be challenged by the **sheer volume** of new resources in their IRPs • Existing clean resources make limited contributions to resource adequacy and **"clean firm" options are not yet commercially available** • Natural gas is the only viable near-term firm capacity option, yet siting new gas plants is extremely challenging and may create **stranded asset risks**	• **New firm resources may be needed** if they do not set the region back on long-term carbon reduction goals • **"Clean firm" resources may need policy support to** speed commercialization

Key findings of Phase 1:

1. **Accelerated load growth and continued retirements create a resource gap beginning in 2026 and growing to *9 GW by 2030***
   - 9 GW is approximately the load of the state of Oregon
2. **Preferred resources such as wind, solar and batteries make only *small contributions* to meeting resource adequacy needs**
3. ***Timely development of all resources is extremely challenging* due to permitting and interconnection delays, federal policy headwinds, and cost pressures**

Phase 2 will evaluate resource options for meeting near-term and long-term resource adequacy and clean energy needs

	Scenario	RA contributions	Additional considerations
Mature	Solar	Low and declining ELCCs	Variable energy resource
	Onshore wind	Declining ELCCs	Variable energy resource
	Natural gas	Firm	Carbon emitting, requires pipeline infrastructure
	Biomass/biodiesel	Firm	Uncertain fuel availability and cost
	Short-duration storage (4-8 hr li-ion)	Declining ELCCs	ELCC saturation impacted by hydro fleet interactions
	Long duration storage (10-12 hr pumped hydro)	Declining ELCCs	ELCC saturation impacted by hydro fleet interactions
	Geothermal	Limited potential	High cost per kWh and limited PacNW sites
	Energy efficiency	Limited potential vs. cost	Can reduce new load but cannot serve existing load
	Demand response	Declining ELCCs	Duration and use limited
Emerging	Floating offshore wind	Declining ELCCs	High enabling infrastructure costs + long timelines
	Natural gas to H2 retrofits	Firm	High enabling infrastructure costs + long timelines
	New dual fuel gas + H2-ready plants	Firm	High enabling infrastructure costs
	New H2-only plants	Firm	High enabling infrastructure costs + long timelines
	Gas w/ 90-100% carbon capture and storage	Firm	High enabling infrastructure costs + long timelines
	Nuclear small modular reactors	Firm	Uncertain costs + long timelines
	Enhanced geothermal	Firm	Uncertain costs and potential
	Multi-day storage (100 hr)	Slower declining ELCCs	Uncertain costs, high round-trip energy losses
	Direct air capture	n/a	Can offset emitting gas that serves RA needs

Note: emerging technologies face cost uncertainty, unclear commercialization timelines, and/or high enabling infrastructure needs

Thank you!

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