

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Order No. 202-25-14

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

Filed January 28, 2026

Exhibit 1-151:
WECC Contingency Reserve Whitepaper



WECC-0142 BAL-002-WECC-3

Contingency Reserve

Request to Retire

WECC-0142 Drafting Team

01/21/2025

WECC-0142 BAL-002-WECC-3—Contingency Reserve—Request to Retire**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](https://www.nerc.com/pa/Stand/Resources/Documents/FERC'S%20Criteria%20for%20Approving%20Reliability%20Standards%20from%20Order%20672.pdf)

² FERC Order 740, Remand.



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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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WECC-0142 BAL-002-WECC-3—Contingency Reserve—Request to Retire**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.



WECC-0142 BAL-002-WECC-3—Contingency Reserve—Request to Retire**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

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



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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 Group¹⁷ 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



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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

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)

²⁴FERC 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.

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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.



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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.

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.



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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*.

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).



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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

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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



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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.



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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.



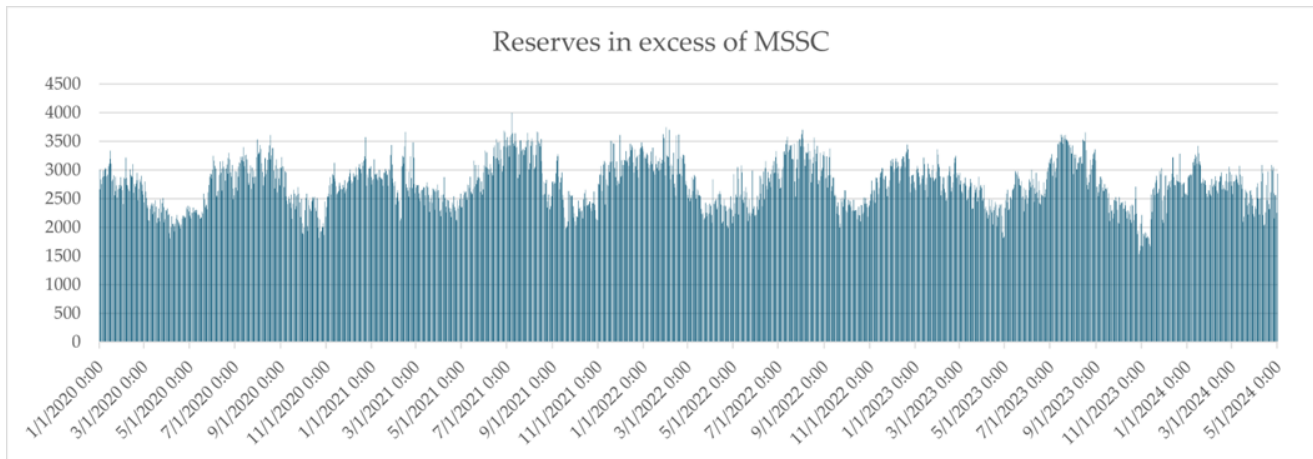
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Figure 2: Reserves in excess of MSSC; January 1, 2020, through May 1, 2024

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



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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



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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: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Order No. 202-25-14

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

Filed January 28, 2026

Exhibit 1-152:
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

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Order No. 202-25-14

Exhibit to
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Public Interest Organizations

Filed January 28, 2026

Exhibit 1-153:
WECC Reliability Assessment Webpage

[LOGIN](#)

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.

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Reliability Assessments

- Interregional Transfer Capability Study

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Exhibit 1-154:
Wash. Commerce Util. Res. Planning Report (compiled 2022 & 2024)

Washington State Electric Utility Resource Planning



2022 Report

April 2024

Report to the Legislature

Director Mike Fong

ENERGY

v3.4

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.

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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 load⁵ and resources and may be submitted only if the utility has fewer than 25,000 customers and is a full requirements customer⁶ 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](#)).

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

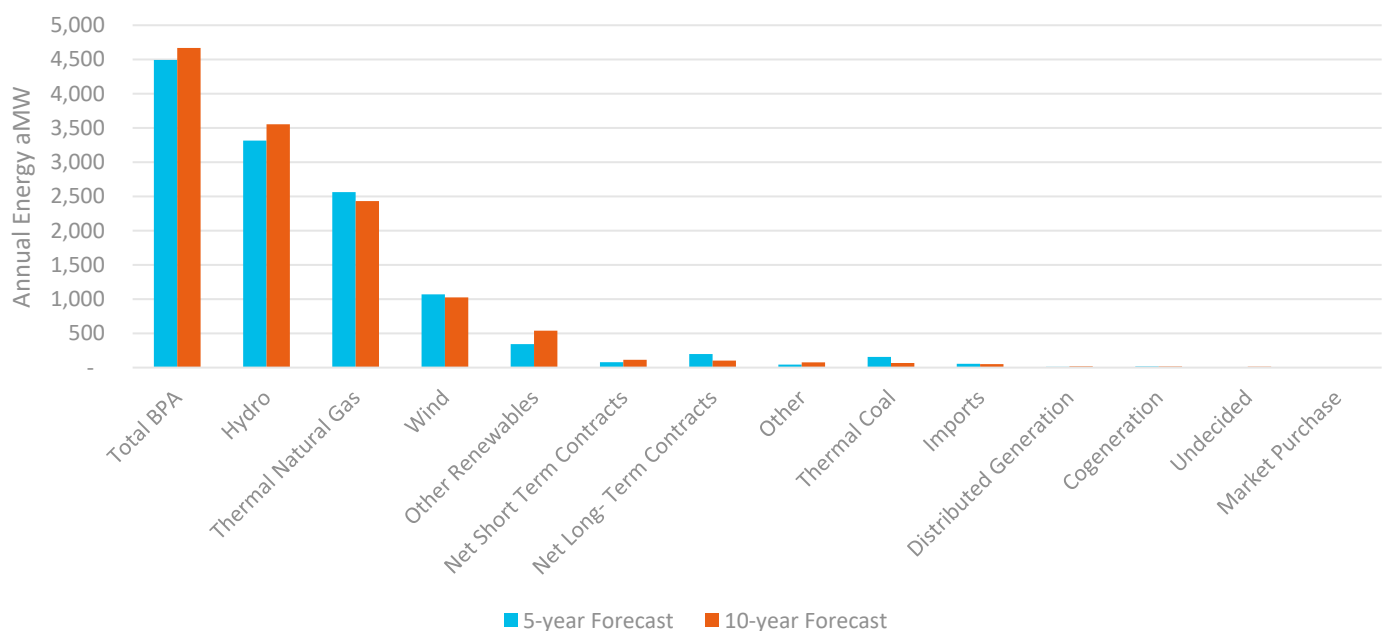


Table 2 presents in average-megawatts the differences between the 2022 and 2020 resource reports on statewide annual utility load and resources and the five and 10-year forecasts.

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 2030⁹ 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

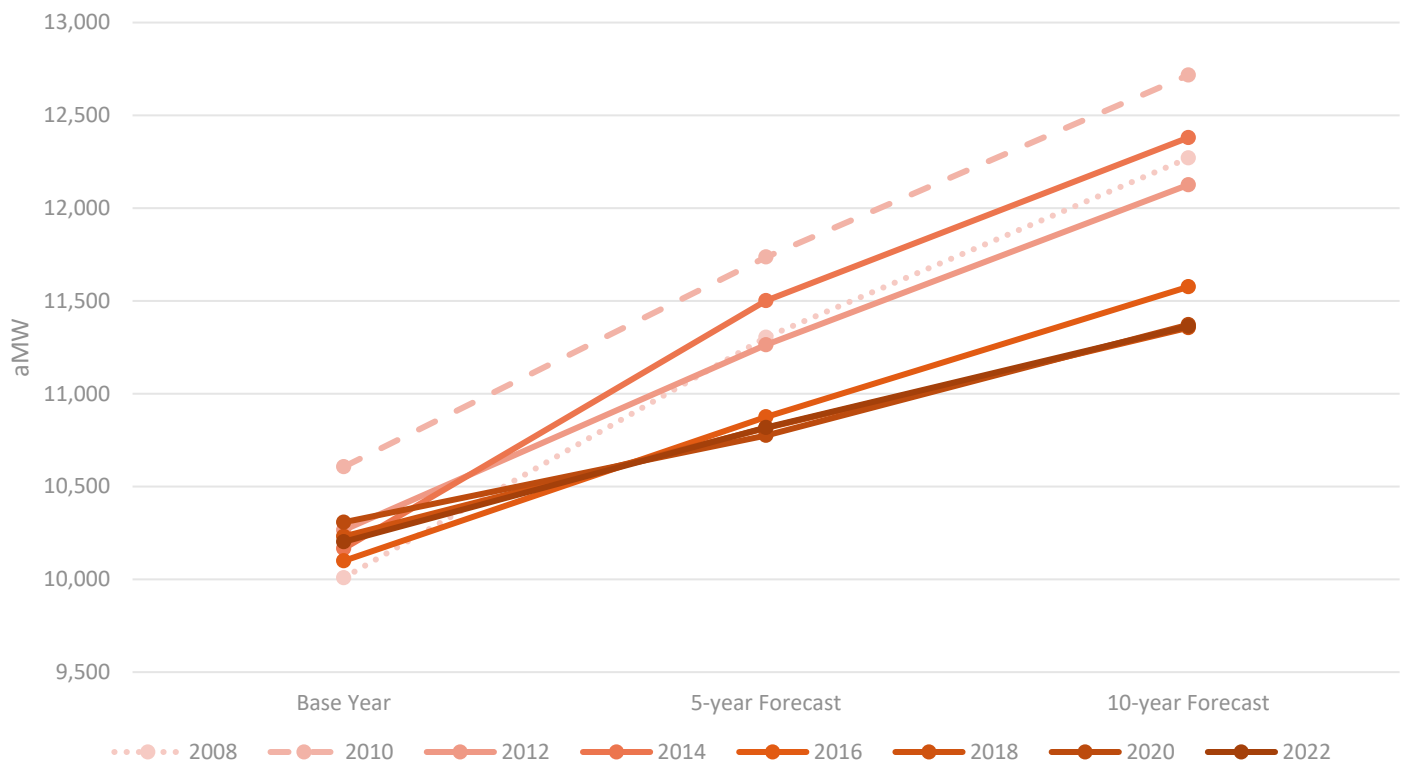


Table 5: Utility Report Time Series – Base Year and Forecast Loads with ECM and Demand Response

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

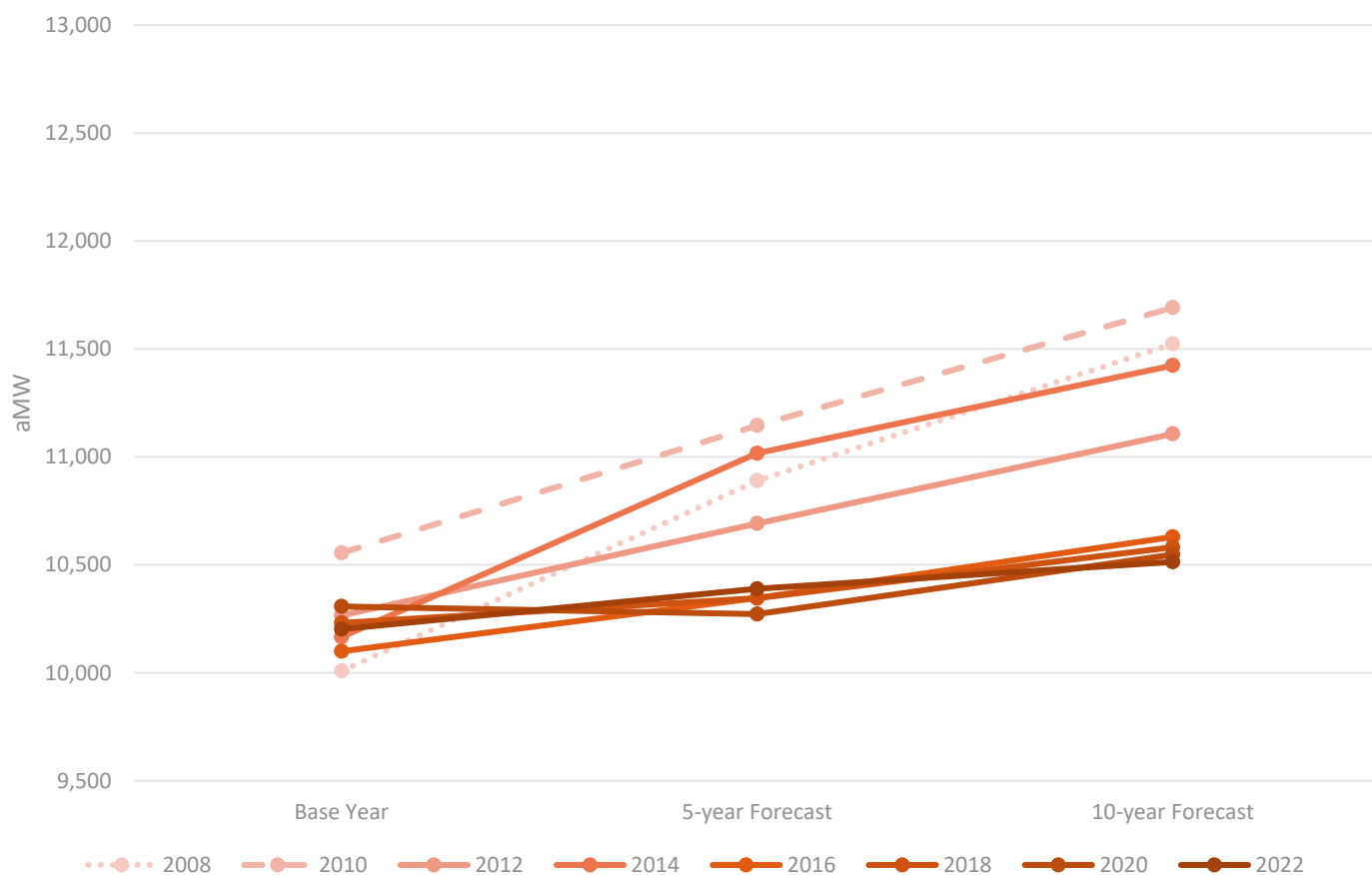


Table 6 presents the individual utility growth forecasts and the percent of load growth anticipated to be met by energy conservation measures. For example, Benton County PUD No 1 estimates a load growth of 14.2 aMW or 6.52% by 2031. Benton County PUD No 1 estimates 11.72 aMW of energy conservation measures 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://douglasrud.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

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 Portfolio 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

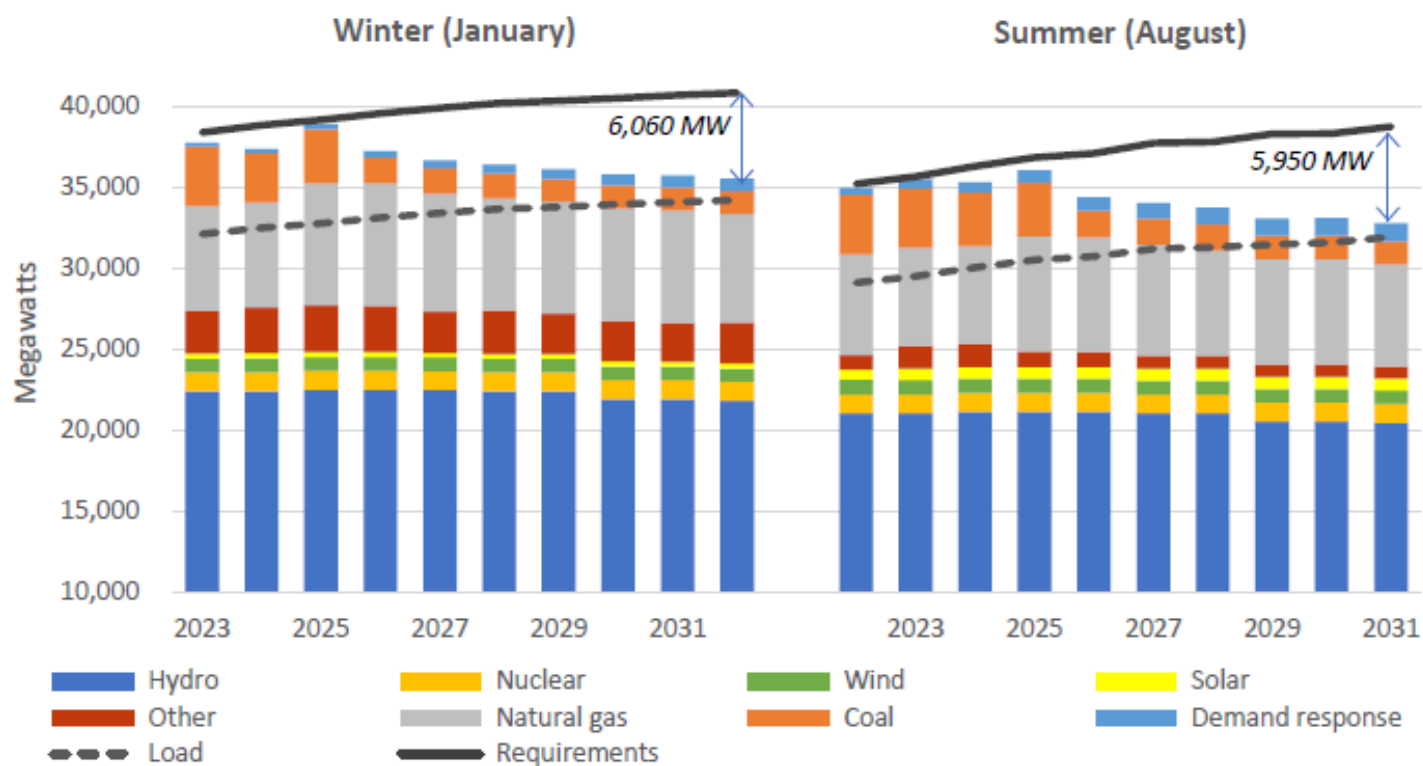
²⁰ Pacific Northwest Utilities Conference Committee. (2022). Northwest Regional Forecast of Power Loads and Resources 2022 through 2032. Retrieved from <https://www.pnucc.org/wp-content/uploads/2022-PNUCC-Northwest-Regional-Forecast-final.pdf>

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 plants²³ (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.

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/pacificcorp-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.nwccouncil.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 Adequacy²⁸

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.

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

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 Price²⁹

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: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Order No. 202-25-14

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

Filed January 28, 2026

Exhibit 1-155:
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 \(NEEA\).](#)

The Honorable Bob Ferguson
The Honorable Sarah Bannister
The Honorable Bernard Dean
November 19, 2025
Page 3

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
Chair
WA Utilities and Transportation Commission



Jennifer Grove
Assistant Director, Energy Division
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.

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.



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

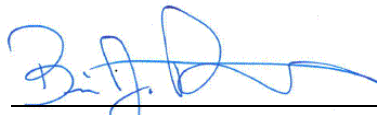
The Honorable Bob Ferguson
The Honorable Sarah Bannister
The Honorable Bernard Dean, Chief Clerk of the House
July 30, 2025
Page 2

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,



Brian Rybrik
Chair
WA Utilities and Transportation Commission

Signed by:



Jennifer Grove
Assistant Director, Energy Division
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.

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.

2025 Summer Readiness Resource Adequacy Meeting Summary

Page No. 2

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

2025 Summer Readiness Resource Adequacy Meeting Summary

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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 country 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 (NWECC) shared her observations from the meeting. She highlighted how the presentations stressed the importance of transmission to resource adequacy and demand response. NWECC 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. NWECC 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

2025 Summer Readiness Resource Adequacy Meeting Summary

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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 CETA⁴. 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

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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

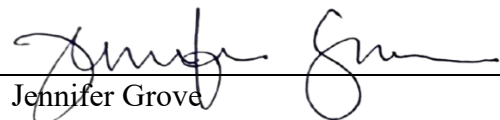
While this meeting focused on readiness for winter 2025-2026, there is a clear need for concerted action to prepare for future winters. Washington law provides utilities with flexibility to use gas-fired generating facilities and, if needed, to expand gas-fired capacity to meet winter peaks. In the meantime, 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.

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 of regions that face an elevated risk⁴ 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

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: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Order No. 202-25-14

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

Filed January 28, 2026

Exhibit 1-156:
Wash. Dep't of Commerce Summary of Utilities' 2024 IRPs (Dec. 1, 2025)



Washington State Electric Utility Resource Planning

2024 Report

December 2025

Report to the Legislature

Director Joe Nguyễn

 ENERGY POLICY OFFICE

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For people with disabilities, this report is available on request in other formats. To submit a request, please call 7-1-1 and ask to be connected to 360-725-4000.

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Executive summary

Overview

[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

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](#).

Key findings

This report collects and summarizes data from Washington state utilities' 2024 resource plans. The 2024 Utility Resource Plan Report summarizes the findings of Washington state load and resource information for a 10-year planning cycle — with most utilities using 2023 as the base year. This report does not reflect state or federal policy changes post-2024. Key findings of the 2024 Utility Resource Plan report are:

- Utilities plan to reduce their use of coal-fired electricity generation and market purchases serving Washington retail customers in the forecast periods, and to increase their use of hydropower, wind power, and utility-scale solar. Hydropower will remain the dominant source of electric for Washington utilities over the 10-year forecast period.
- Following successive years of stagnant or declining load forecasts, many utilities anticipate modest load growth driven by population growth and transportation and building electrification over the next five to ten years. In addition, the Mid-Columbia utilities (Grant, Douglas, and Chelan public utility districts) forecast significant load growth from data centers.
- Utilities anticipate a decline in savings potential from energy efficiency and conservation compared to past resource plans due to building and appliance codes and standards, market saturation of efficient technologies, and load growth from electrification.

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), pursuing new renewable resources, and maximizing energy conservation measures. While several consumer-owned utilities plan to remove natural gas from their resource portfolios in the next five and ten years, investor-owned utilities plan to maintain relatively steady amounts of natural gas in their resource portfolio.

¹ Section 19.280.060, Department's duties—Report to the legislature. (2025). Retrieved from Revised Code of Washington: <https://app.leg.wa.gov/RCW/default.aspx?cite=19.280.060>.

Assessments of resource adequacy from regional experts conclude the Northwest has adequate resources to meet current demand for electricity and does not face a significant risk of outages in the near term. However, these assessments assume the industry will be able to execute their planned capacity expansions. Confidence in these assessments is also limited by the increasing level of uncertainty that planners face about future demand for electricity. The sources of this uncertainty include the added volatility of our weather, the pace of consumer conversion to electricity for transportation, heating and other end uses, changing federal and state policies, and the growing energy demands of data centers.

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. 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. 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 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.

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 to 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.² 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 ninth report since the Legislature enacted the resource planning law in 2006. This report collects and summarizes data from Washington state utilities' 2024 resource plans. Data collection was completed in early 2025.

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 load³ and resources and may be submitted only if the utility has fewer than 25,000 customers or is a full requirements customer⁴ 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 utility submittals 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. The Legislature has asked Commerce to provide this review and oversight of the resource planning process so that they can understand and assist in meeting the state's electricity needs.

This report summarizes the electricity loads and resources reported by Washington utilities in their 2024 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, i.e. "hydropower" or "market purchase." 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](#)). It also does not evaluate the impacts of new state or federal policies after 2024 which may contradict the assumptions utilized in the utility resource plans, regional resource adequacy assessments, or regional forecasts summarized in this report.

² [Chapter 19.280, Electric Utility Resource Plans](#). (2025). Retrieved from Revised Code of Washington

³ 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.

⁴ "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 61⁵ utilities. The individual reports are presented in Appendix A: Utility cover sheets. A summary of electricity sales to customers is presented in Appendix B: Washington utility customer count, revenue, sales, and average price. A glossary of terms is provided in Appendix C: Glossary of terms.

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. As mentioned previously, 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 2024, most utilities used 2023 as the base year, and the five-year and 10-year points are 2028 and 2033, 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 2022 to 2024. For purposes of the statewide summary, Commerce aggregates all base-year data into a single value (2023) and does likewise for the five-year (2028) data and 10-year data (2033).

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 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, demand response, and behind-the-meter solar (BTM solar). The report separately lists the conservation resources, demand response, and BTM solar that the utility expects during the five-year and 10-year periods.

⁵ Commerce did not receive a resource plan coversheet from Consolidated Irrigation District #19 for 2024.

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

Results

The 2024 resource plans submitted to Commerce are summarized in Table 1-4 and Figures 1-2.

Table 1 presents utility report information in units of average-Megawatts (aMW)⁶ on statewide annual utility load and resources, including imports and exports, for the base year (2023), 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. Table 1 shows the five and 10-year forecast for load growth is nearly double the amount presented from two years ago, most of which comes from data center load growth in Chelan, Grant, and Douglas counties.

In this year of reporting, Commerce asked utilities to disaggregate "other renewable resources." We can see that the use of biomass and utility-scale solar was nearly equal in the base year (55 and 56 aMW respectively), but utilities are expecting substantial growth in utility-scale solar in the next five to 10 years as the use of biomass resources remains steady.

Table 1: Washington's projected requirements and resources - annual energy aMW

Requirements	Base Year	5-year Forecast	10-year Forecast	5-year Change	10-year Change
Loads	10,189	11,316	12,245	1,128	2,057
Exports	746	513	423	(234)	(323)
Energy Conservation Measures	No data	(336)	(790)	(336)	(790)
Demand Response	No data	(42)	(57)	(42)	(57)
BTM Solar	0	(26)	(52)	(26)	(52)
Total Net Requirements	10,935	11,425	11,770	490	835

Resources	Base Year	5-year Forecast	10-year Forecast	5-year Change	10-year Change
Total BPA	4,511	4,844	4,985	333	474
Hydro	3,044	3,513	3,878	469	834
Thermal Natural Gas	1,101	1,206	855	105	(246)
Market Purchases	934	327	132	(607)	(802)
Thermal Coal	450	No data	No data	(450)	(450)
Other	850	196	161	(654)	(689)
Wind	811	1,059	1,625	248	814
Imports	237	259	301	22	64
Cogeneration	2	2	2	No data	No data
Biomass	55	62	62	7	7

⁶ 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.

Resources	Base Year	5-year Forecast	10-year Forecast	5-year Change	10-year Change
Utility-scale Solar	56	363	499	307	443
Other Distributed Renewables	25	25	25	(0)	(0)
Geothermal	2	2	102	(0)	99
Landfill Gas	1	7	9	6	8
Undecided	No data	175	94	175	94
FTM Distributed Solar	No data	1	1	1	1
Nuclear	No data	No data	24	No data	24
Biogas	No data	No data	No data	No data	No data
Total Resources	12,079	12,446	13,654	367	1,575
Load Resource Balance	1,144	1,021	1,884	(123)	740

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.

While several consumer-owned utilities plan to remove natural gas from their resource portfolios in their five-year forecast, all the investor-owned utilities forecast relatively steady amounts of natural gas in their resource portfolios. For the first time since reporting started, Washington utilities forecast that wind power will surpass thermal natural gas plants in meeting their 10-year resource need.

Figure 1: Forecast available resources

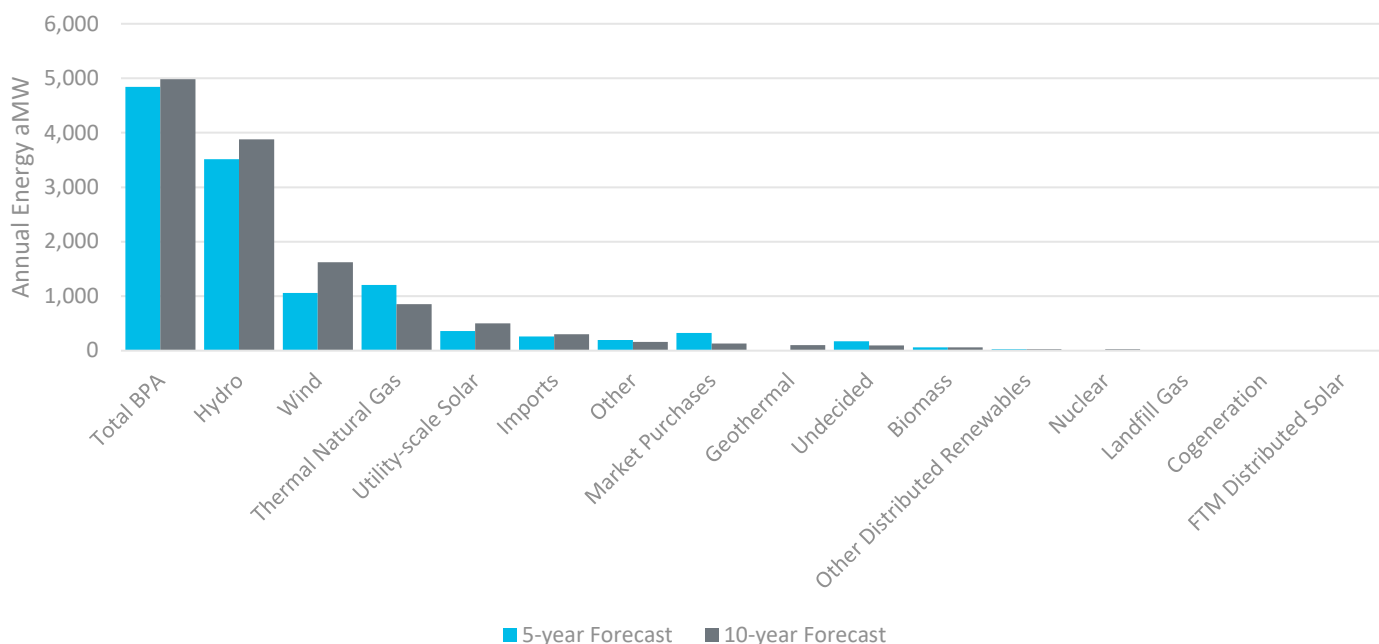


Table 2 presents in average-megawatts the differences between the 2022 and 2024 resource reports on statewide annual utility load and resources and the five and 10-year forecasts. Table 2 shows a diminished contribution from

coal-fired electricity generation and natural gas-fired generation in the forecast period, and an increased reliance on BPA resources, hydropower, wind, imports, and other renewables.

Table 2: Difference between 2024 and 2022 requirements and resources – annual energy aMW

Requirements	Base Year	5-year Forecast	10-year Forecast
Loads	(14)	499	882
Exports	520	295	233
Energy Conservation Measures	No data	(70)	(26)
Demand Response	No data	18	24
BTM Solar	No data	26	52
Total Net Requirements	507	819	1,066

Resources	Base Year	5-year Forecast	10-year Forecast
Total BPA	151	352	316
Hydro	363	197	325
Thermal Natural Gas	(1,591)	(1,357)	(1,578)
Market Purchases	718	249	18
Other	(266)	(44)	(19)
Wind	173	(11)	599
Thermal Coal	(275)	(156)	(67)
Imports	148	203	250
Other Renewables	(29)	91	127
Distributed Generation	20	39	57
Cogeneration	(13)	(13)	(13)
Undecided	No data	174	82
Nuclear	No data	No data	24
Total Resources	(454)	28	685
Load Resource Balance	(961)	(791)	(380)

The shift in electric generation resources suggests progress towards meeting the requirements of the Clean Energy Transformation Act (CETA). CETA prohibits utilities from using coal generation after 2025.⁷ CETA requires all retail sales of electricity to Washington be greenhouse gas neutral by 2030⁸ and 100% non-emitting by 2045.⁹

⁷ [Section 19.405.030\(1\), Coal-fired resources-Depreciation schedule-Penalties](#). (2025). Retrieved from Revised Code of Washington.

⁸ [Section 19.405.040\(1\), Greenhouse gas neutrality-Responsibilities for electric utilities-Energy transformation project criteria-Penalties](#). (2025). Retrieved from Revised Code of Washington.

⁹ [Section 19.405.050\(1\), Clean energy implementation-Hydroelectric facilities-Special contracts](#). (2025). Retrieved from Revised Code of Washington.

Table 3 presents utilities' aggregated report information for their highest estimated one-hour load during the winter season,¹⁰ including imports and exports, for the base year (2023), and the five and 10-year forecasts. In the past, utilities forecasted more reliance on market purchases to meet peak demand, but utilities are increasingly aiming to decrease their reliance on short-term wholesale electricity markets (market purchases). The availability of dispatchable generation resources is declining and market power prices and volatility is increasing, especially during peak demand periods when prices can be high and supply uncertain.¹¹ Utilities are exploring various solutions, including demand response programs, energy efficiency measures, and new generation resources.

Table 3: Washington projected requirements and resources – winter capacity MW

Requirements	Base Year	5-year forecast	10-year forecast	5-year change	10-year change
Loads	14,584	15,976	17,224	1,391	2,640
Exports	1,093	802	741	(291)	(352)
Energy Conservation Measures	No data	(404)	(896)	(404)	(896)
Demand Response	No data	(387)	(526)	(387)	(526)
BTM Solar	0	(12)	(16)	(12)	(16)
Total Net Requirements	15,678	15,975	16,526	297	848

Resources	Base Year	5-year forecast	10-year forecast	5-year change	10-year change
Hydro	5,171	6,195	6,750	1,024	1,578
Total BPA	4,334	4,725	4,808	391	474
Thermal Natural Gas	3,182	3,008	3,001	(174)	(181)
Other	1,878	1,300	1,340	(578)	(538)
Market Purchases	1,598	225	200	(1,373)	(1,398)
Wind	770	1,420	1,953	649	1,183
Imports	654	526	584	(128)	(70)
Thermal Coal	596	No data	No data	(596)	(596)
Biomass	59	66	66	7	7
Other Distributed Renewables	26	26	26	No data	No data
Utility-scale Solar	20	527	544	507	524
Cogeneration	5	90	90	85	85
Landfill Gas	2	8	11	6	9
Geothermal	2	2	102	(0)	100
Undecided	No data	80	No data	80	No data
Nuclear	No data	No data	30	No data	30
FTM Distributed Solar	No data	0	0	0	0
Biogas	No data	No data	No data	No data	No data

¹⁰ Table 1 expressed in energy units of aMW, Table 3 in capacity units of MW.

¹¹ Puget Sound Energy. (2023, Chapter 1, p. 5). Electric Progress Report.

Resources	Base Year	5-year forecast	10-year forecast	5-year change	10-year change
Total Resources	18,297	19,000	20,943	703	2,646
Load Resource Balance	2,619	3,025	4,417	405	1,798

Most Washington utilities experience their annual peak load during the winter months; however, due to climate change, utilities anticipate less heating required in the winter and more cooling required during the summer. Table 4 presents utilities' aggregated report information for their highest estimated one-hour load during the summer season, including imports and exports, for the base year (2023), and the five and 10-year forecasts.

Warmer average summer temperatures and more frequent and intense heat waves are leading to increased demand for air conditioning and cooling, directly driving up electricity consumption during summer peak hours. For instance, Puget Sound Energy (PSE) noted that incorporating climate change data into their demand forecast resulted in increased summer peak temperatures and thus, increased summer demand.¹² Avista anticipates needing to prepare for a near-term future as a dual summer and winter peaking utility due to these trends.¹³

Table 4: Washington projected requirements and resources - summer Capacity MW

Requirements	Base Year	5-year forecast	10-year forecast	5-year change	10-year change
Loads	11,996	13,911	15,517	1,915	3,520
Exports	1,427	1,385	1,295	(42)	(133)
Energy Conservation Measures	No data	(392)	(854)	(392)	(854)
Demand Response	No data	(400)	(539)	(400)	(539)
BTM Solar	0	(83)	(122)	(83)	(122)
Total Net Requirements	13,424	14,421	15,296	998	1,872

Resources	Base Year	5-year forecast	10-year forecast	5-year change	10-year change
Hydro	5,392	6,262	6,509	870	1,117
Total BPA	3,301	3,421	3,582	120	281
Thermal Natural Gas	2,681	2,515	2,508	(166)	(173)
Other	1,541	1,249	1,248	(292)	(293)
Market Purchases	1,778	248	200	(1,530)	(1,578)
Wind	547	1,216	1,759	669	1,212
Imports	282	222	280	(60)	(2)
Thermal Coal	595	No data	No data	(595)	(595)
Biomass	59	66	66	7	7
Other Distributed Renewables	22	22	22	No data	No data
Utility-scale Solar	84	966	1,022	882	938

¹² Puget Sound Energy. (2023, Chapter 3, p. 14). Electric Progress Report.

¹³ Avista. (2023, Chapter 2, p. 21). Electric Integrated Resource Plan.

Resources	Base Year	5-year forecast	10-year forecast	5-year change	10-year change
Cogeneration	4	4	89	No data	85
Landfill Gas	2	9	11	7	9
Geothermal	2	2	102	(0)	100
Undecided	No data	128	No data	128	No data
Nuclear	No data	No data	31	No data	31
FTM Distributed Solar	No data	1	2	1	2
Biogas	No data	No data	No data	No data	No data
Total Resources	16,290	17,206	18,946	916	2,656
Load Resource Balance	2,866	2,784	3,649	(82)	783

Figure 2 shows Washington utilities' 10-year (2033) projected resources by utility ownership type. Most consumer-owned utilities (public utility districts, municipal, and cooperatives) rely predominantly on BPA resources and hydropower; however, municipal utilities forecast a higher use of wind power and energy conservation measures than other consumer-owned utilities. Investor-owned utilities plan to rely on baseload natural gas generation for approximately 20% of their 10-year projected resources; however, they plan to reduce their natural gas generation by approximately 16% compared to the base year of 2023.

Figure 2: Washington 10-year projected resources by utility ownership type

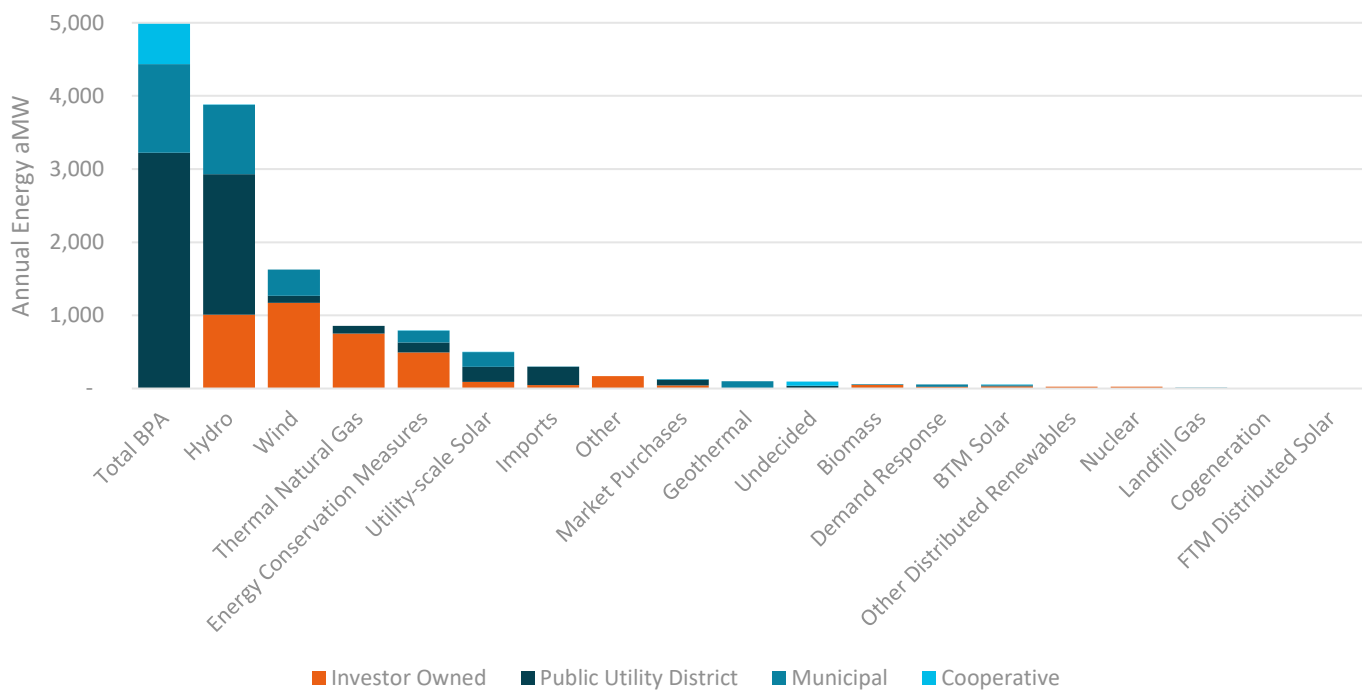


Table 5 presents a time series of Commerce Utility Resource Plans. The information in the table presents aggregated annual utility loads (base year, five-year and 10-year) for the 2008 through 2024 Commerce reports. The forecast loads do not include the energy conservation measure (ECM) forecast by utilities. Figure 3 presents the information in Table 5 in a graphical format. Table 6 and Figure 4 present the aggregated annual utility loads (base-year, five-year and 10-year) and include energy conservation measures (ECM), demand response (DR), and behind-the-meter (BTM) solar forecasts by utilities.

Table 5 and 6 and Figure 3 and 4 show load growth forecasts by utilities for the five and 10-year points which have typically trended down with each successive report; however, this year, the forecasts do not follow the trend. This is due to new high load growth rates from factors, such as data center growth, population growth, and electrification.

The Mid-Columbia utilities, Grant, Chelan, and Douglas PUDs, are forecasting high load growth rates due to the growth of data centers, computing demand, cryptocurrency mining, and industrial load.

Chelan County PUD forecasts a very high average annual growth rate of 31.71%, 31.88%, and 32.23% for High Density Loads¹⁴, cryptocurrency processing, and large loads during the planning period.¹⁵

For Grant County PUD, over the past the twenty years, 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. Industrial loads have transitioned from a 28% share twenty years ago to a 47% share of total Grant PUD load today.¹⁶

Over the last decade, Douglas PUD experienced a load growth of 76% principally due to large loads.¹⁷ Douglas PUD expects elevated levels of load growth to continue. Douglas PUD reports it has instituted a number of policies to curb risk associated with data loads. One of these policies requires large contract customers to enter into special contracts that mitigate risk associated with transmission and distribution build-out by requiring customers to pay for all required infrastructure upgrades upfront.¹⁸

Other utilities are also predicting increasing load growth (though not at the very high rates from data centers, computing demand, cryptocurrency mining, and industrial and manufacturing growth) due to electrification of buildings and transportation and population growth. Clark Public Utilities (CPU) projects an average year-over-year load growth of 1.98%, with a high scenario reaching 3.12% for 2025-2044. The load forecast in CPU's study incorporates additional load growth due to building and vehicle electrification beyond what has been seen historically. Over the study period, CPU shifts from a predominantly winter-peaking utility to a summer-peaking utility. CPU is currently forecast to have sufficient resources available to meet average energy demand through 2035. However, on a capacity basis, CPU is currently at a deficit and is projected to grow that deficit to roughly 750 MW of summer capacity and 500 MW of winter capacity by the end of the study period absent additional resource procurement. That deficit is partially exacerbated by the additional capacity required to comply with the Western Resource Adequacy Program (WRAP), which is modeled to take effect in November 2027.¹⁹ Moreover, Puget Sound Energy (PSE) primarily serves residential and commercial customers, and it expects energy demand to grow an average rate of 1.8 percent annually from 2024-2045.²⁰ Rising customers and electric vehicle counts drive most of the growth in energy demand for PSE. This demand growth is partially, but not entirely, offset by decreasing residential heating energy demand – a consequence of adopting trended normal temperatures consistent with climate change impacts.

Table 5: Utility report time series – base year and forecast loads without ECM

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

¹⁴ These are typically server farms and similar technological operations.

¹⁵ Chelan PUD. (2023, p. 15-16). Integrated Resource Plan Progress Report.

¹⁶ Grant PUD. (2024, p. 54). Integrated Resource Plan.

¹⁷ Douglas PUD. (2024, p. 6). Integrated Resource Plan Update.

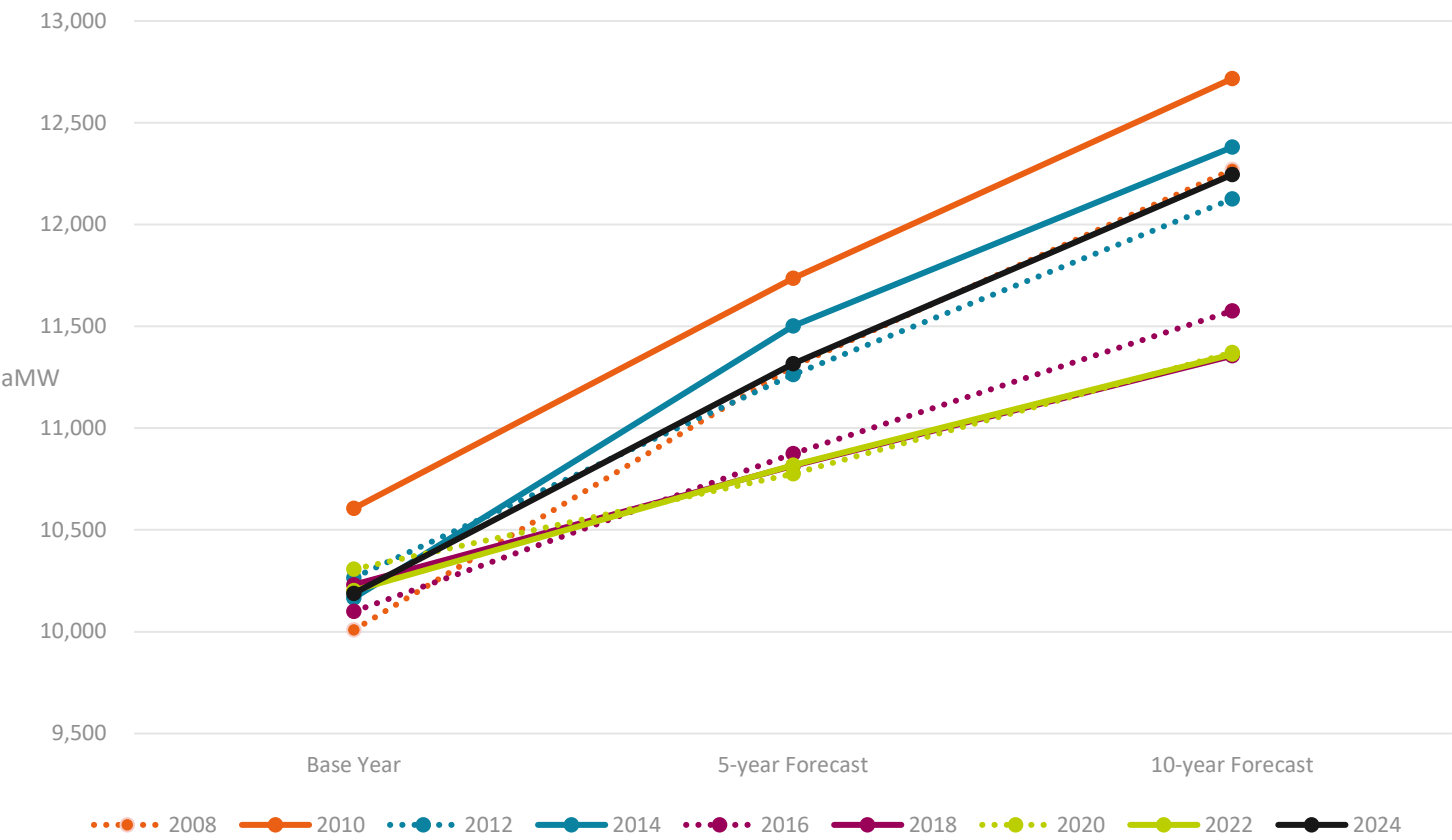
¹⁸ Douglas PUD. (2024, p. 7). Integrated Resource Plan Update.

¹⁹ Clark Public Utilities. (2024, p. 6). Integrated Resource Plan.

²⁰ Puget Sound Energy. (2023, Chapter 6, p. 1). Electric Progress Report.

Utility Report Year	Base Year	Base Year, aMW	5-year Est.	5-year Est. aMW	10-year Est.	10-year Est. aMW
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
2024	2023	10,189	2028	11,316	2033	12,245

Figure 3: Utility report time series – base year and forecast loads without ECM



By comparing, Table 5 and 6 as well as Figure 3 and 4 it is evident that utility conservation programs significantly reduce aggregate load growth.

Table 6: Utility report time series – base year and forecast loads with ECM, DR, and BTM solar

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
2024	2023	10,189	2028	10,912	2033	11,347

Figure 4: Utility report time series – base year and forecast loads with ECM, DR, and BTM solar

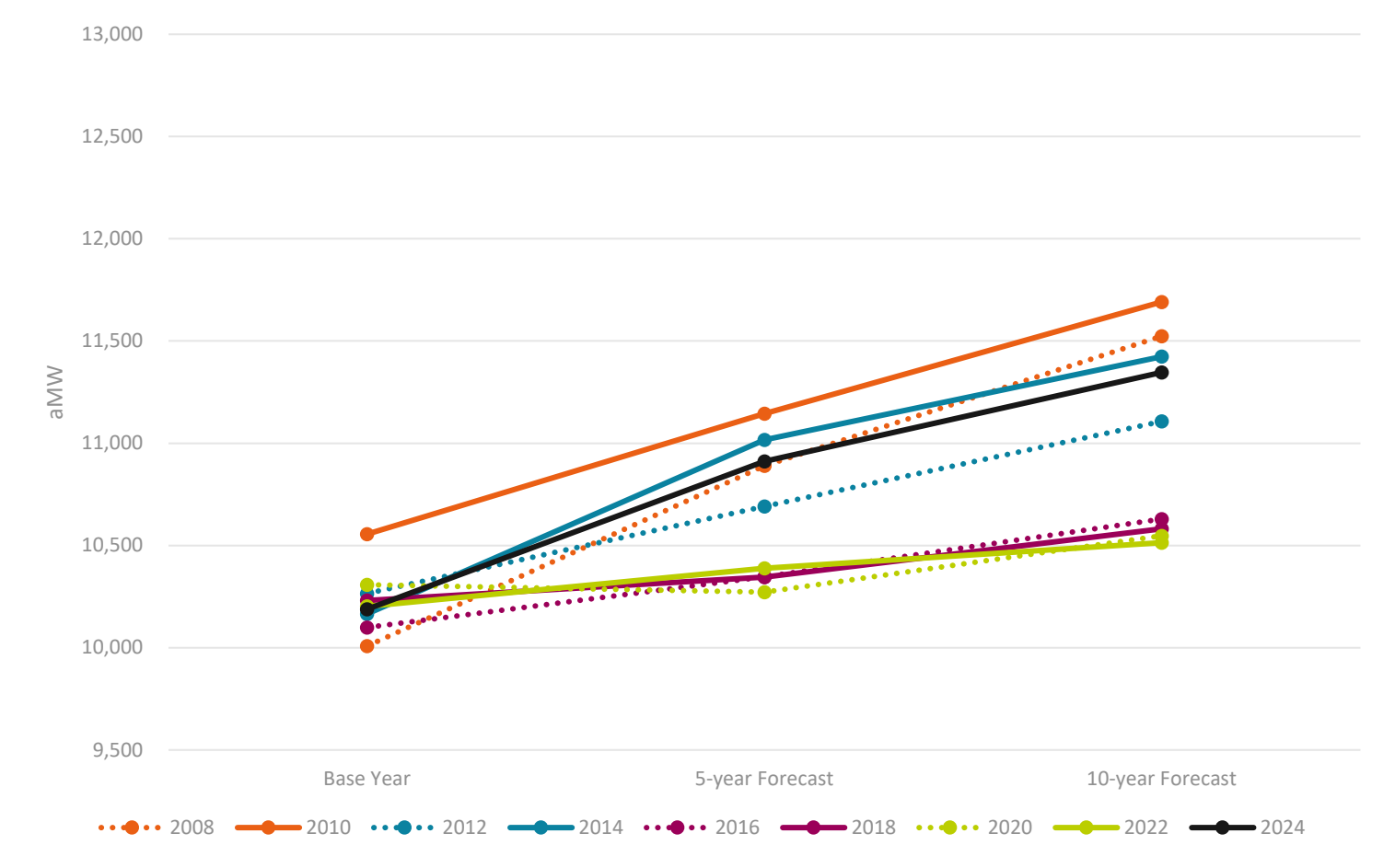


Table 7 presents the individual utility growth forecasts and the percentage of load growth anticipated to be met by energy conservation measures. The average load growth with no conservation across utilities has more than doubled compared to the 2022 resource plan report. The average 5-year load growth with no conservation increased from 3.2% in 2022 to 8.5% in 2024, and the average 10-year load growth with no conservation increased from 6.2% in 2022 to 15.5% in 2024. Most of this load growth comes from data centers, computing demand, and cryptocurrency mining in the service territories of Chelan County PUD, Douglas County PUD, and Grant County PUD.

Table 7: Individual utility load forecasts without conservation and with conservation

Utility Name	5-year load growth change % without conservation	10-year load growth change % without conservation	5-year load growth change % met by conservation	10-year load growth change % met by conservation
Asotin County PUD No. 1	6.01%	6.20%	0.00%	0.00%
Avista	6.12%	12.81%	47.63%	45.71%
Benton County PUD No. 1	-0.95%	2.34%	-239.74%	194.86%
Benton Rural Electric Assn	2.84%	7.27%	0.00%	0.00%
Big Bend Electric Cooperative	9.16%	11.60%	3.81%	3.01%
Blaine, City of	34.09%	46.81%	0.21%	0.15%
Centralia, City of	7.94%	9.23%	0.00%	0.00%
Chelan County PUD No.1	72.93%	140.13%	4.98%	6.36%
Cheney, City of	3.63%	7.19%	3.39%	1.71%
Chewelah, City of	-0.49%	-0.45%	-80.35%	-87.70%
Clallam County PUD No. 1	3.33%	8.13%	134.19%	109.77%
Clark Public Utilities	3.62%	12.50%	0.00%	0.00%
Columbia REA	0.74%	4.86%	0.00%	0.00%
Coulee Dam, Town of	1.02%	3.47%	0.00%	0.00%
Cowlitz County PUD No. 1	31.61%	32.21%	0.00%	0.00%
Douglas County PUD No. 1	106.98%	171.13%	0.00%	0.00%
Eatonville, Town of	0.00%	0.00%	0.00%	0.00%
Ellensburg, City of	8.29%	9.79%	5.76%	4.88%
Elmhurst Mutual Power and Light Company	0.72%	2.35%	150.00%	46.15%
Ferry County PUD	-1.07%	1.15%	-9.46%	8.79%
Franklin County PUD No. 1	23.87%	32.56%	0.00%	0.00%
Grant County PUD No. 2	37.89%	54.16%	2.50%	4.21%
Grays Harbor County PUD No. 1	9.33%	7.40%	0.00%	0.00%
Inland Power and Light	11.24%	21.75%	0.00%	0.00%
Jefferson County PUD No. 1	1.59%	2.84%	31.05%	17.35%

Utility Name	5-year load growth change % without conservation	10-year load growth change % without conservation	5-year load growth change % met by conservation	10-year load growth change % met by conservation
Kalispel Tribal Utilities	25.31%	32.70%	0.00%	0.00%
Kittitas County PUD No. 1	10.87%	21.01%	2.00%	1.03%
Klickitat County PUD No. 1	-3.44%	3.23%	0.00%	0.00%
Lakeview Light & Power	1.83%	2.86%	21.82%	13.95%
Lewis County PUD No. 1	2.93%	8.07%	0.00%	0.00%
Mason County PUD No. 1	2.26%	4.20%	0.00%	0.00%
Mason County PUD No. 3	7.82%	16.30%	21.08%	10.42%
McCleary, City of	4.47%	5.83%	0.00%	0.00%
Milton, City of	-0.06%	0.16%	-775.00%	281.82%
Modern Electric	-0.20%	2.14%	-126.68%	11.88%
Nespelem Valley Electric Cooprative	4.99%	7.09%	0.00%	0.00%
Ohop Mutual Light Company	3.22%	7.95%	14.03%	5.68%
Okanogan County Electric Cooperative	9.41%	16.15%	0.00%	0.00%
Okanogan County PUD No. 1	4.73%	8.45%	0.00%	0.00%
Orcas Power and Light Cooperative	6.34%	8.82%	0.00%	0.00%
Pacific County PUD No. 2	2.75%	5.23%	50.00%	21.05%
PacifiCorp	9.82%	15.91%	72.64%	80.89%
Parkland Light and Water Company	1.42%	2.39%	10.47%	6.23%
Pend Oreille PUD	-58.45%	-56.90%	0.00%	0.00%
Peninsula Light	-4.67%	-4.14%	-14.62%	-16.50%
Port Angeles, City of	5.02%	6.70%	28.51%	43.42%
Puget Sound Energy	1.68%	4.61%	369.23%	363.55%
Richland, City of	11.05%	16.16%	26.78%	66.31%
Seattle City Light	8.62%	19.37%	52.69%	44.02%
Seattle, Port of	2.53%	23.11%	31.90%	3.50%
Skamania County PUD No. 1	5.62%	9.05%	1.05%	0.65%
Snohomish County PUD No. 1	9.56%	25.45%	42.27%	40.96%
Steilacoom, Town of	4.75%	7.01%	5.71%	3.87%
Sumas, City of	4.85%	4.85%	11.11%	11.11%
Tacoma Power	-2.78%	1.99%	-154.95%	478.49%
Tanner Electric	18.69%	21.78%	0.89%	0.77%
Vera Water and Power	3.52%	7.02%	4.93%	2.47%
Wahkiakum County PUD No. 1	8.10%	11.96%	0.00%	0.00%
Whatcom County PUD No. 1	10.51%	47.71%	0.00%	0.00%

Utility Name	5-year load growth change % without conservation	10-year load growth change % without conservation	5-year load growth change % met by conservation	10-year load growth change % met by conservation
Yakama Power	4.71%	6.01%	5.88%	4.61%
Average	8.47%	15.46%	-4.07%	30.59%

Energy efficiency and conservation (also referred to as energy conservation measures) is a fundamental resource for utilities in their long-term planning, but utilities are anticipating energy efficiency and conservation to contribute less towards meeting load growth. Projected load growth across utilities is also greater than prior resource plans due to the incorporation of new load growth projections due to building and transportation electrification. For instance, Avista anticipates that energy conservation measures will meet a significant portion of future load growth, although the percentage may be lower than in previous forecasts due to factors like electric transportation, building electrification, and market saturation of efficient technologies. Energy conservation measures meet more than 27% of all future load growth for Avista, where prior IRP forecasts found energy conservation measures met nearly 70% of future load growth.²¹

Several utilities are actively exploring and implementing demand response programs, specifically targeting large load customers, including data centers and cryptocurrency miners, to manage peak demand. For instance, Grant PUD is currently operating a pilot demand response program aimed at high load factor customers, including cryptocurrency miners. They are also considering direct load curtailment for irrigation customers. Grant PUD anticipates these programs can help reduce near-term capacity shortfalls and compete with storage and peaking assets. They estimate 30 to 50 MW could be available through these DR programs by 2026.²² Tacoma Power is testing demand response as a potential resource option under scenarios where they anticipate capacity shortfalls. They have considered generic demand response resources that either shift usage or are called upon during peak events, equivalent to approximately 20 to 30 MW by the late 2030s.²³ In 2024, Clark Public Utilities (CPU) launched an industrial demand response incentive pilot program allowing qualified customers to nominate load reductions during a demand response event. CPU plans to continue expanding demand response programs as they become more cost-effective and with the adoption of Advanced Metering Infrastructure (AMI).²⁴

Overgeneration

In 2013, the Legislature amended the resource planning statute to address concerns about the potential for “overgeneration” events.²⁵ 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:

²¹ Avista. (2023, Chapter 9, p. 7). Electric Integrated Resource Plan.

²² Grant PUD. (2024, p. 77). Integrated Resource Plan.

²³ Tacoma Power. (2024, p. 39-40). Integrated Resource Plan.

²⁴ Clark Public Utilities. (2024, p. 74). Integrated Resource Plan.

²⁵ [Section 19.280.060, Department’s duties—Report to the legislature](#). (2025). Retrieved from Revised Code of Washington.

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. It might occur when high river flows and high wind volumes coincide with low load. It might also occur when the hours of solar generation misalign 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. This oversupply results in negatively priced spot market prices. The consequence is that a utility must pay another entity to take unwanted power or generation is curtailed. Many wind generators receive federal incentive credits and/or payments based upon their wind production, and they can sell the RECs from this generation. Thus, these generators can withstand some degree of negative pricing and still make a profit.²⁶

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.²⁷ In the Northwest, the BPA has business practices that push the burden of oversupply back to the market and away from themselves. These practices include not selling at negative prices until spilled water reaches dissolved gas limits, holding renewable generators to a fixed schedule, not accepting unplanned surplus, and canceling transmission loss returns.²⁸ 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 2022-2024 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 and response programs.

Many consumer-owned utilities already have 80% or more renewable generation, and they plan to comply with CETA requirements between 2030 and 2045 using clean energy credits. With the emergence of the Western Resource Adequacy Program (WRAP) and increased reliance on regional markets for power, some utilities, such as Snohomish PUD and Benton PUD, are moving to BPA load-following customers to rely on BPA to ensure resource adequacy.

Other strategies utilities reported considering include:

- Developing WRAP
- 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

²⁶ Chelan PUD. (2023, p. 24-25). Integrated Resource Plan Progress Report.

²⁷ [Oversupply](#). (n.d.). Retrieved from Bonneville Power Administration.

²⁸ Chelan PUD. (2023, p. 25). Integrated Resource Plan Progress Report.

- Enhancing the capacity of their transmission lines

Regional resource adequacy forecasts

Commerce and the Utilities and Transportation Commission (UTC) regularly review regional resource adequacy assessments and other load forecasts and scenario studies,²⁹ and convene an annual meeting with regional resource adequacy experts, utilities, and other stakeholders per [RCW 19.280.065](#).

The joint meeting between the UTC and Commerce in September 2024 found assessments of resource adequacy from regional experts show the Northwest has adequate resources to meet current demand for electricity and does not face a significant risk of outages in the near term.³⁰ However, these assessments assume the industry will be able to execute their planned capacity expansions. Confidence in these assessments is also limited by the increasing level of uncertainty that planners face about future demand for electricity. The sources of this uncertainty include the added volatility of our weather, the pace of consumer conversion to electricity for transportation, heating and other end uses, and the growing energy demands of data centers. Common themes across resource adequacy assessments and other regional load forecasts and scenario studies include:

- Participation of utilities in WRAP is crucial for the future of regional resource adequacy
- Limited transmission capacity is a key binding constraint that once addressed would enable utilities to more efficiently access a diverse set of cost-effective resources from across the West, mitigate weather disruptions, and enhance regional resource adequacy
- Demand-side management and virtual power plants have significant potential to shave peak load and maintain resource adequacy
- Traditional battery storage technologies can help enable the smooth integration of intermittent renewables onto the electric grid while emerging long duration storage technologies can support the electric grid for multiple days during potential natural gas supply or electric generation disruptions
- Emerging technologies, such as green hydrogen and enhanced geothermal, show promise as firm power supplies free of greenhouse gas emissions
- High data center load growth and lower than expected energy efficiency scenarios would place severe resource demands on the grid and put the adequacy of the electric grid at risk
- The region needs to steadfastly permit, site, and build resources to maintain current levels of resource adequacy over the medium-to-long term

Conclusion

The 2024 Washington State Electric Utility Resource Planning report reveals modest load growth increasingly met by clean energy resources. Utilities plan to cut coal and market purchases, and increase use of hydropower, wind, and solar.

After years of declining or stagnant load forecasts, utilities across the state project modest load growth from population increases and electrification. Alongside this general assessment, substantial load growth was forecasted by Grant, Douglas, Chelan PUDs, driven by potential data center electricity needs.

To meet these demands, consumer-owned utilities are focusing on renewing their Bonneville Power Administration (BPA) contracts, and both consumer-owned utilities and investor-owned utilities are developing new renewables

²⁹ These studies include but are not limited to: the Western Electricity Coordinating Council Resource Assessment of Resource Adequacy, the Pacific Northwest Power and Conservation Council Power Supply and Adequacy Assessment, and Pacific Northwest Utilities Conference Committee Northwest Regional Forecast, the latter of which is not a resource adequacy assessment.

³⁰ [2024 Resource Adequacy Letter and Summary](#); [Western Assessment of Resource Adequacy 2024](#).

and maximizing conservation. While many consumer-owned utilities plan to phase out natural gas, investor-owned utilities project stable usage. Wind power is notably forecasted to surpass natural gas within ten years, advancing Clean Energy Transformation Act (CETA) goals. Some utilities are preparing for dual winter and summer peaks due to increased summer temperatures and household cooling demands driven by climate change. Regional assessments indicate adequate resources to meet loads in the near term, but maintaining resource adequacy depends on successful capacity expansions and increased regional cooperation between utilities.

The 2024 report presents several other developments since the 2022 legislative report:

- Incorporation of climate change and electrification modelling: The resource plans summarized in the 2024 report more thoroughly accounted for the impacts of climate change and electrification. These changes resulted in a shift in peak demand for some utilities and modest load growth for many utilities.
- Energy conservation contribution: The 2024 report offers a more cautious outlook on the incremental contribution of energy conservation measures (ECM) to meet future load growth compared to 2022. Planned five-year ECM is 70 aMW lower than the 2022 report's anticipation for that period.
- Reduced market reliance for peak demand: The 2024 report indicates utilities have a stronger intent to reduce reliance on short-term wholesale market purchases for peak demand, a shift from earlier forecasts where such purchases were more prominent in peak capacity strategies.
- Load resource balance: The 2024 report projects a tighter (lower) load-resource balance (surplus) for base, five-year, and ten-year forecasts compared to 2022's anticipated balances, suggesting a closer but adequate margin between expected resources and requirements.

Finally, this report points to a continued need to improve clean energy siting and permitting processes and enhance transmission capacity in Washington and across the Western Interconnection. Increased deployment of demand-side management, virtual power plants, and traditional battery storage systems, accompanied by emerging technologies and utility participation in the Western Regional Adequacy Program (WRAP), are additional actions that would further resource adequacy and the clean energy transition.

Appendix A: Utility cover sheets

Washington Electric Utility Loads and Resources Estimates reported to the Department of Commerce in 2024 are available in this Excel workbook.

Appendix B: Washington utility customer count, revenue, sales, and average price³¹

Behind the Meter	Customers (Count)	Revenue (Thousand Dollars)	Retail Sales (Megawatthours)	Average Price (Cents/kWh)
Tesla Inc.	99	\$67	608	11¢
Sunnova	60	\$11	64	17¢

Cooperative	Customers (Count)	Revenue (Thousand Dollars)	Retail Sales (Megawatthours)	Average Price (Cents/kWh)
Inland Power & Light Company	44,400	\$85,033	1,016,225	8¢
Peninsula Light Company	35,429	\$60,993	624,171	10¢
Elmhurst Mutual Power & Light Co	16,037	\$21,137	279,846	8¢
Benton Rural Electric Assn	15,962	\$44,938	620,972	7¢
Orcas Power & Light Coop	15,855	\$36,214	214,371	17¢
Modern Electric Water Company	10,615	\$15,619	227,881	7¢
Lakeview Light & Power	10,481	\$23,781	251,778	9¢
Big Bend Electric Coop, Inc	9,946	\$42,454	564,937	8¢
Columbia Rural Elec Assn, Inc	6,490	\$33,210	367,976	9¢
Tanner Electric Coop	5,317	\$12,949	99,247	13¢
Ohop Mutual Light Company, Inc	5,017	\$8,438	98,989	9¢
Parkland Light & Water Company	4,591	\$9,005	117,676	8¢
Okanogan County Elec Coop, Inc	4,143	\$6,798	67,139	10¢
Yakama Power	2,298	\$7,004	95,343	7¢
Nespelem Valley Elec Coop, Inc	1,538	\$5,535	59,863	9¢
Clearwater Power Company	1,046	\$2,326	21,443	11¢
Kootenai Electric Cooperative	98	\$267	2,626	10¢
Northern Lights, Inc	15	\$30	252	12¢

³¹ Energy Information Administration. (2023). [Annual Electric Power Information Report](#).

Federal	Customers (Count)	Revenue (Thousand Dollars)	Retail Sales (Megawatthours)	Average Price (Cents/kWh)
Bonneville Power Administration	10	\$31,985	1,195,413	3¢

Investor owned	Customers (Count)	Revenue (Thousand Dollars)	Retail Sales (Megawatthours)	Average Price (Cents/kWh)
Puget Sound Energy Inc	1,223,225	\$2,753,519	23,436,236	12¢
Avista Corp	270,433	\$610,155	5,739,294	11¢
PacifiCorp	136,363	\$387,829	3,850,048	10¢

Municipal	Customers (Count)	Revenue (Thousand Dollars)	Retail Sales (Megawatthours)	Average Price (Cents/kWh)
City of Seattle - (WA)	503,221	\$1,048,523	9,228,431	11¢
City of Tacoma - (WA)	196,833	\$410,927	4,552,573	9¢
City of Richland - (WA)	27,048	\$77,437	997,726	8¢
City of Port Angeles - (WA)	11,018	\$27,557	396,839	7¢
City of Centralia - (WA)	10,701	\$26,675	265,359	10¢
City of Ellensburg - (WA)	10,582	\$19,101	221,650	9¢
City of Cheney - (WA)	6,007	\$8,359	148,111	6¢
Town of Steilacoom	3,782	\$4,335	38,733	11¢
City of Blaine - (WA)	3,766	\$7,244	83,974	9¢
City of Milton - (WA)	3,593	\$5,964	55,110	11¢
City of Chewelah	1,363	\$2,115	24,088	9¢
Town of Eatonville - (WA)	1,278	\$2,302	28,247	8¢
City of McCleary - (WA)	1,194	\$3,752	31,649	12¢
City of Sumas - (WA)	1,028	\$2,582	31,283	8¢
Town of Ruston - (WA)	622	\$1,368	10,382	13¢
City of Coulee Dam - (WA)	602	\$1,243	16,701	7¢
PUD No 1 of Asotin County	3	\$14	245	6¢

Political subdivision	Customers (Count)	Revenue (Thousand Dollars)	Retail Sales (Megawatthours)	Average Price (Cents/kWh)
PUD No 1 of Snohomish County	377,261	\$668,410	6,794,876	10¢
PUD No 1 of Clark County - (WA)	235,481	\$392,180	4,785,718	8¢
PUD No 1 of Benton County	57,263	\$134,664	1,838,441	7¢
PUD No 2 of Grant County	55,012	\$269,355	5,958,946	5¢
PUD No 1 of Cowlitz County	53,155	\$232,091	4,104,045	6¢
PUD No 1 of Chelan County	49,579	\$67,197	1,876,426	4¢
PUD No 1 of Grays Harbor County	45,223	\$106,199	930,270	11¢
PUD No 3 of Mason County	35,985	\$80,923	695,379	12¢
PUD No 1 of Lewis County	34,809	\$81,808	964,301	8¢
PUD No 1 of Clallam County	33,931	\$72,147	665,293	11¢
PUD No 1 of Franklin County	29,428	\$87,670	1,103,231	8¢
PUD No 1 of Okanogan County	22,018	\$53,592	633,607	8¢
PUD No 1 of Jefferson County	20,873	\$42,250	391,951	11¢
PUD No 2 of Pacific County	18,338	\$27,693	315,430	9¢
PUD No 1 of Douglas County	17,364	\$53,512	1,345,707	4¢
PUD No 1 of Klickitat County	14,111	\$38,965	441,885	9¢
Vera Irrigation District #15	13,509	\$20,325	239,014	9¢
PUD No 1 of Pend Oreille County	10,008	\$53,256	695,193	8¢
PUD No 1 of Skamania Co	6,571	\$15,873	137,082	12¢
PUD No 1 of Mason County	5,610	\$10,251	83,748	12¢
PUD No 1 of Ferry County	3,783	\$7,784	80,287	10¢
PUD No 1 of Kittitas County	3,771	\$12,800	112,794	11¢
PUD No 1 of Wahkiakum County	2,776	\$4,638	46,164	10¢
PUD No 1 of Whatcom County	1	\$10,206	229,343	4¢

Retail power marketer	Customers (Count)	Revenue (Thousand Dollars)	Retail Sales (Megawatthours)	Average Price (Cents/kWh)
Shell Energy North America (US), L.P.	3	\$33,821	486,097	7¢
BP Energy Company	2	\$82,247	830,991	10¢
Brookfield Renewable Energy Marketing US LLC	1	\$19,697	361,074	5¢
Avangrid Renewables	1	\$1,019	32,879	3¢
Calpine Energy Solutions, LLC	1	\$970	8,012	12¢

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.

Behind-the-meter (BTM) solar: refers to customer-sited solar energy panels. BTM solar includes the expected generating capability that is customer-owned, utility-owned, and third-party owned.

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 VaR_{97.5} 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 (also referred to as conservation and efficiency resources): 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.

Front-of-the-meter (FTM) distributed solar: refers to solar power that is located on the distribution system or any subsystem of the distribution system.

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.”

Utility-scale solar: refers to a large-scale solar power project that is interconnected to the transmission system.

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.

Western Resource Adequacy Program (WRAP): The Western Resource Adequacy Program (WRAP) is the first regional reliability planning and compliance program in the history of the West.

It will deliver a region-wide approach for assessing and addressing resource adequacy and provide an important step forward for reliability in the region.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Order No. 202-25-14

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

Filed January 28, 2026

Exhibit 1-157:
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
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Charles Li, Sr. Managing Consultant
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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



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

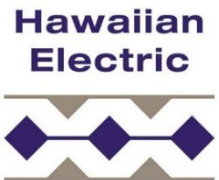
- **California:** E3 provides technical support and advisory services to the CPUC in administration of the state's IRP program, to CARB in implementation of AB32 "cap-and-trade" program, and to the CEC on a variety of research topics including compliance with SB100
- **New York State Climate Act Scoping 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

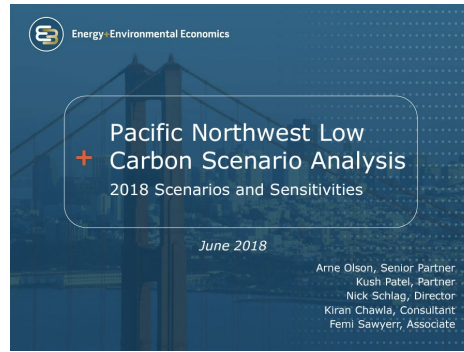
+ Non-profits

- 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



Resource Adequacy in the Pacific Northwest

March 2019

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+ 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

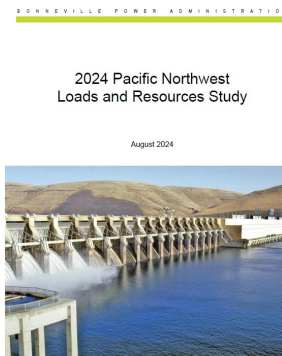
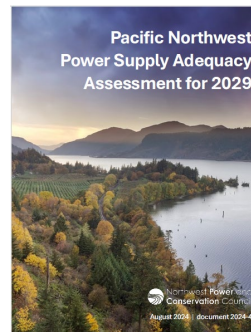
+ Current study objectives:

- 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

Recent PNW Regional Studies and Forecasts

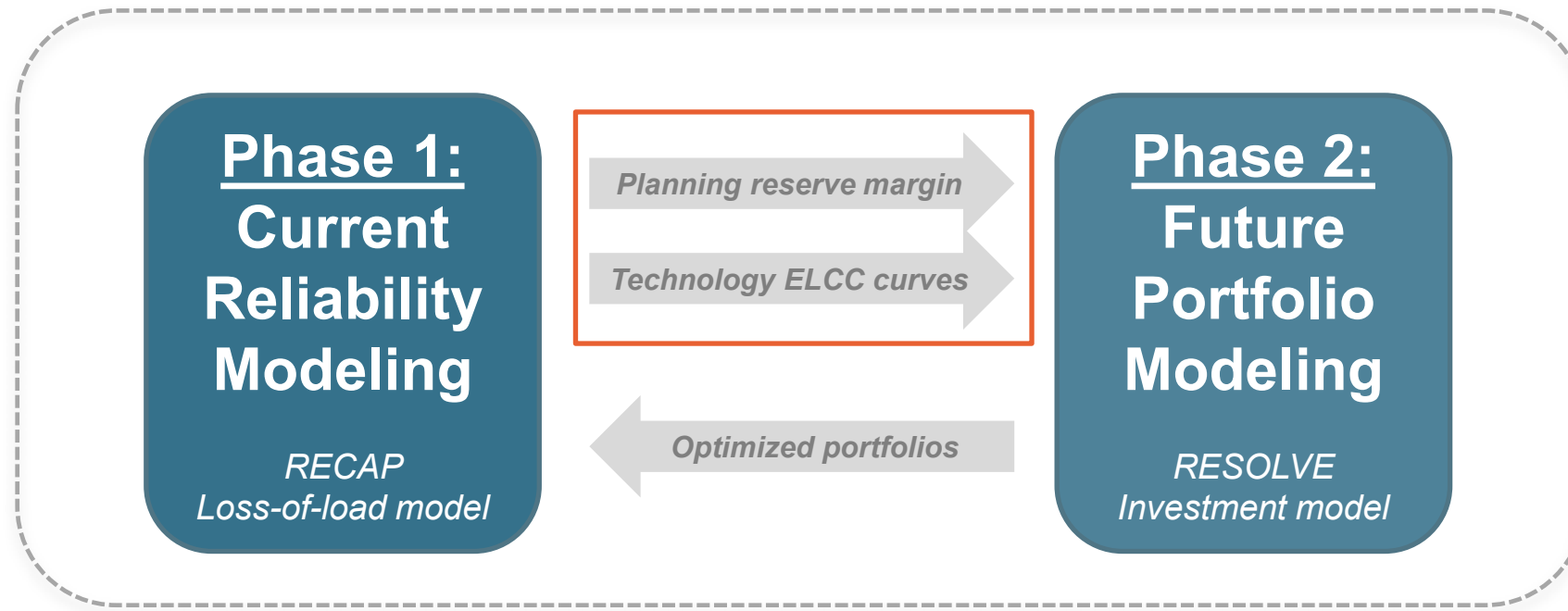


Western Assessment of Resource Adequacy Appendix
January 24, 2025



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

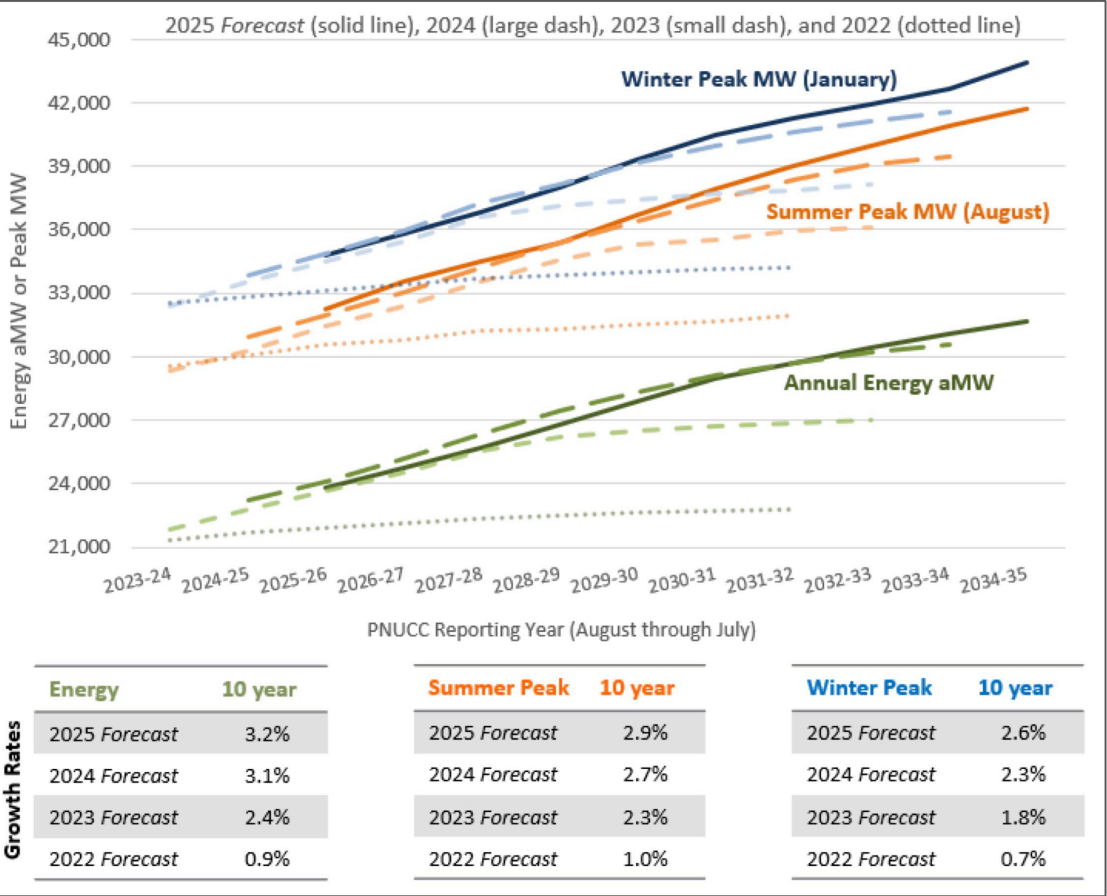


Key Study Topics:

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

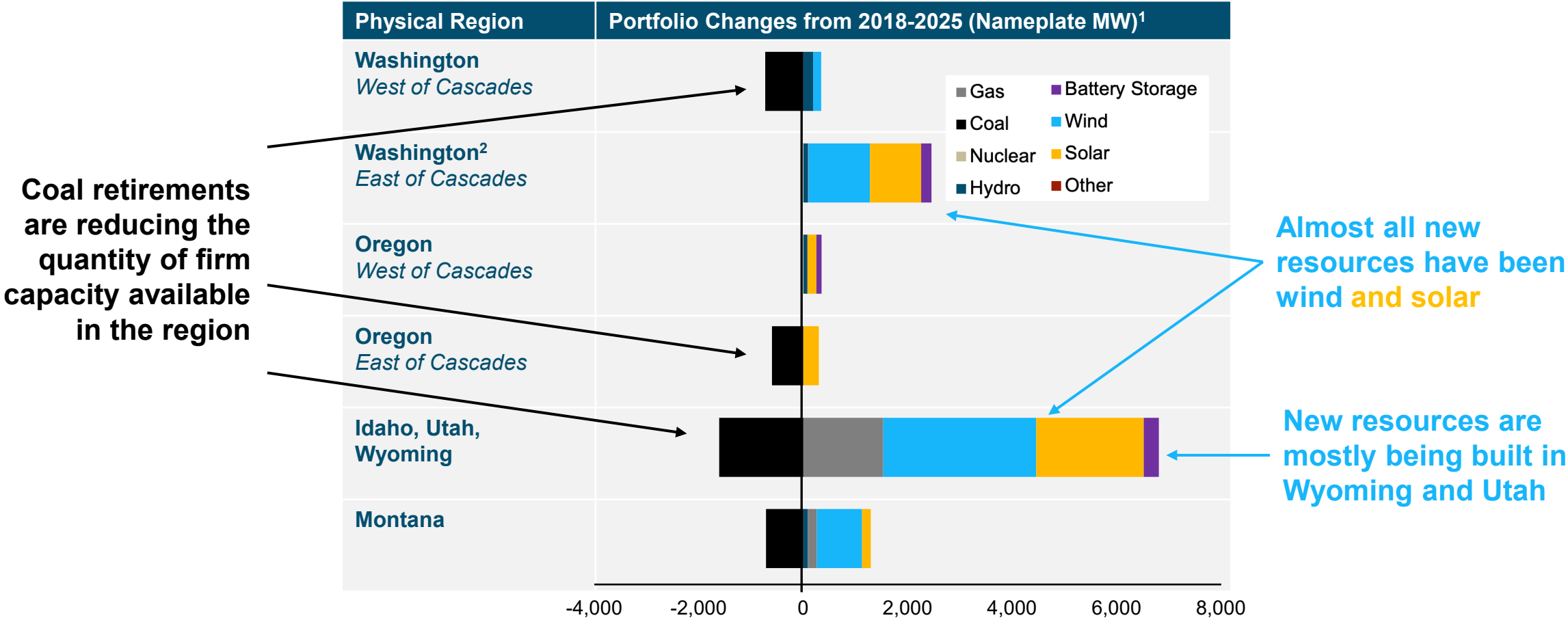
PNUCC 2025 Northwest Regional Forecast Energy aMW or Peak MW Forecast



+ 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

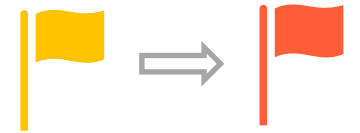
New resource additions have been slow, and located primarily outside of Washington and Oregon



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

Greater Northwest

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

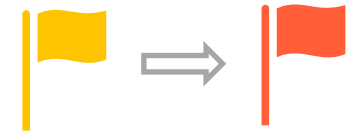
+ Nearly 9,000 MW of new capacity is needed by 2030

+ 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

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

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



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+ 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)

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

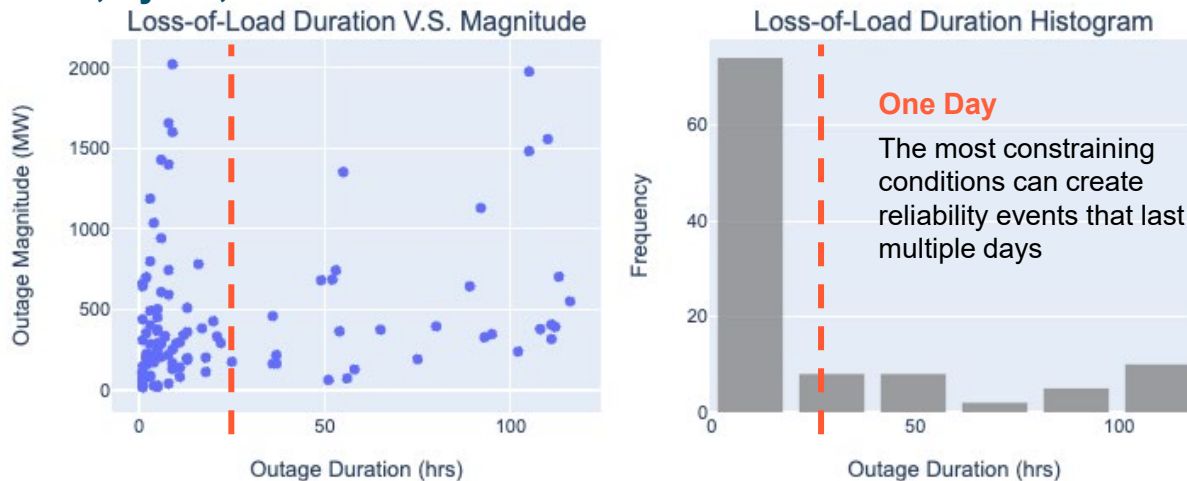
The most constraining reliability conditions are extended wintertime cold weather events during very low water years



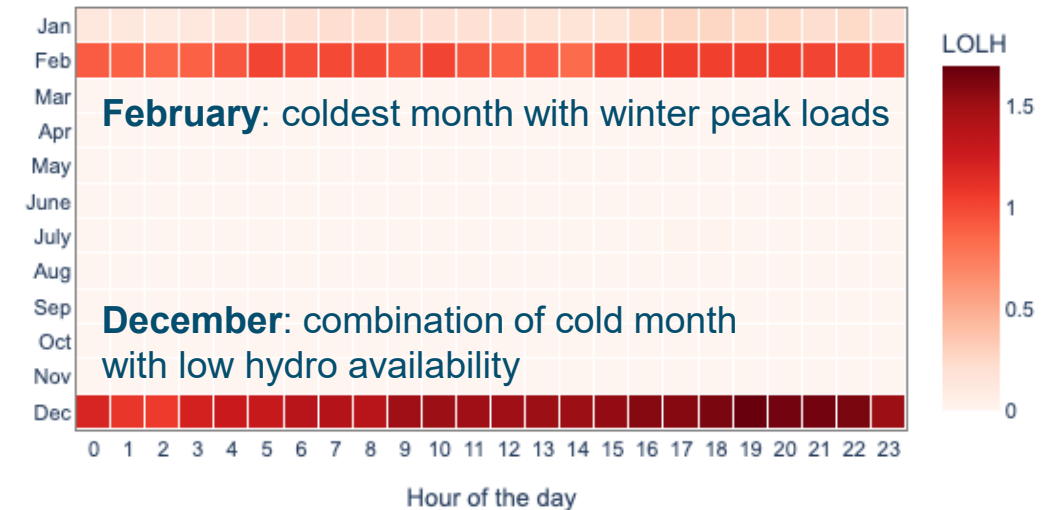
- + Most loss-of-load events occurring during the coldest winter months
- + Many events exceed 50 hours in duration with some exceeding 100 hours due to energy shortfalls in dry years

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



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



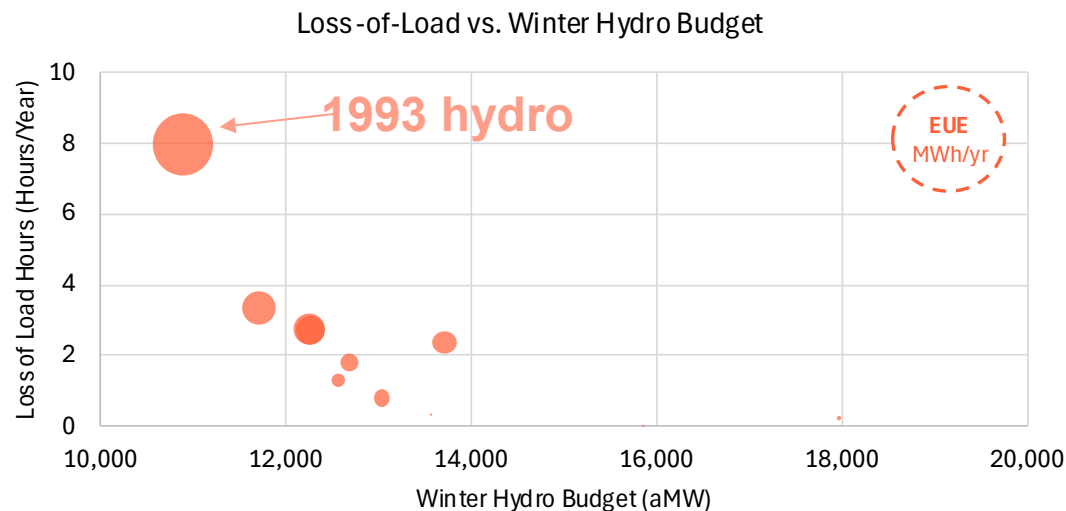
* Metrics + heatmap shown without firm imports

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

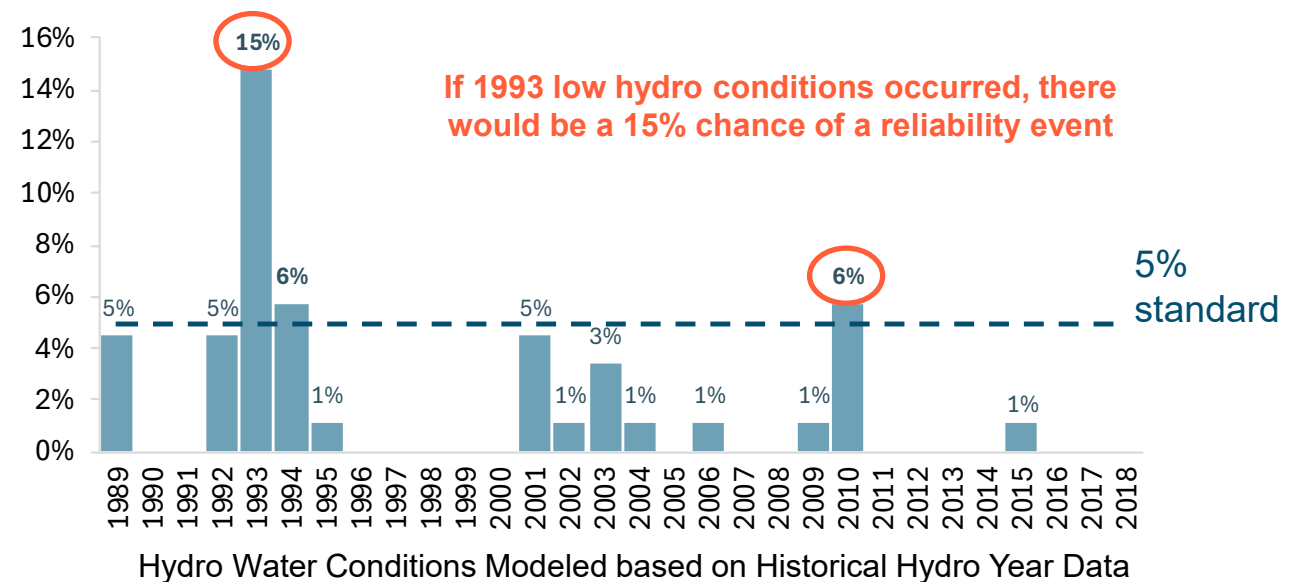
Energy shortfalls that occur during low hydro years contribute significantly to resource adequacy events

- + 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

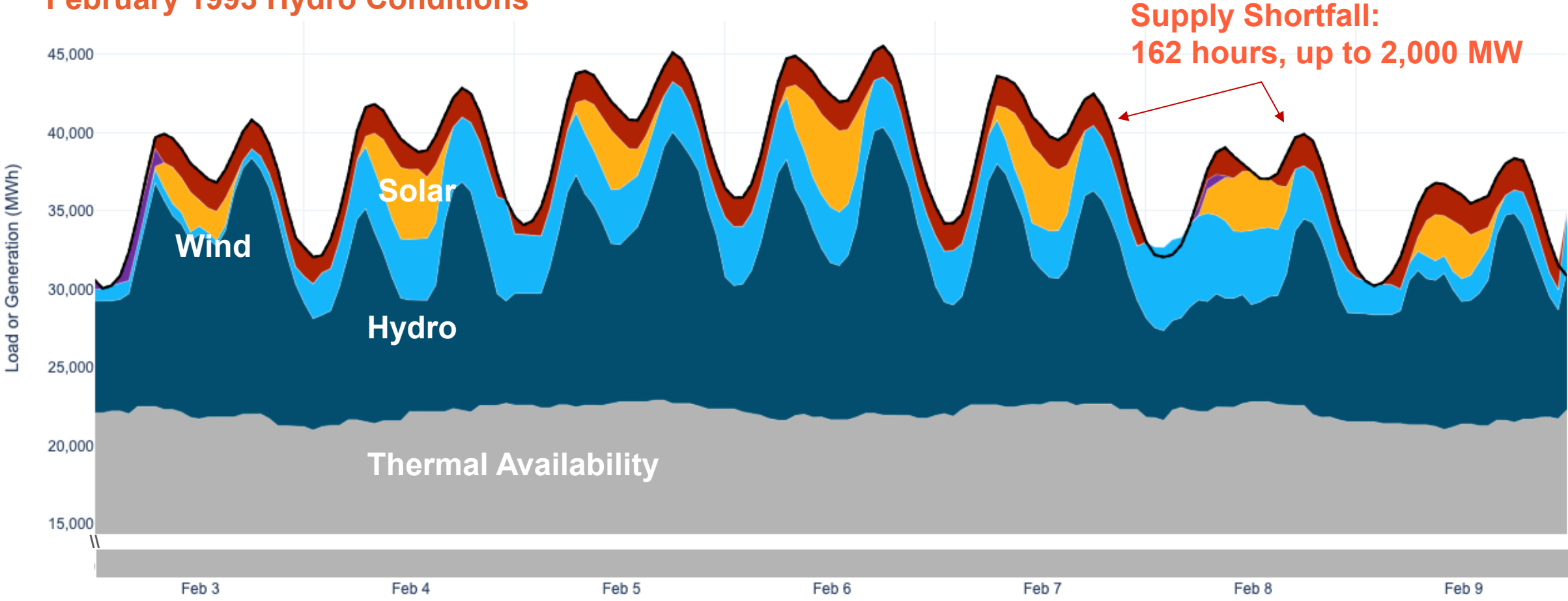




Resource availability example: February 2014 load conditions combined with 1993 hydro conditions

Greater Northwest 2025, RECAP simulated energy-limited event

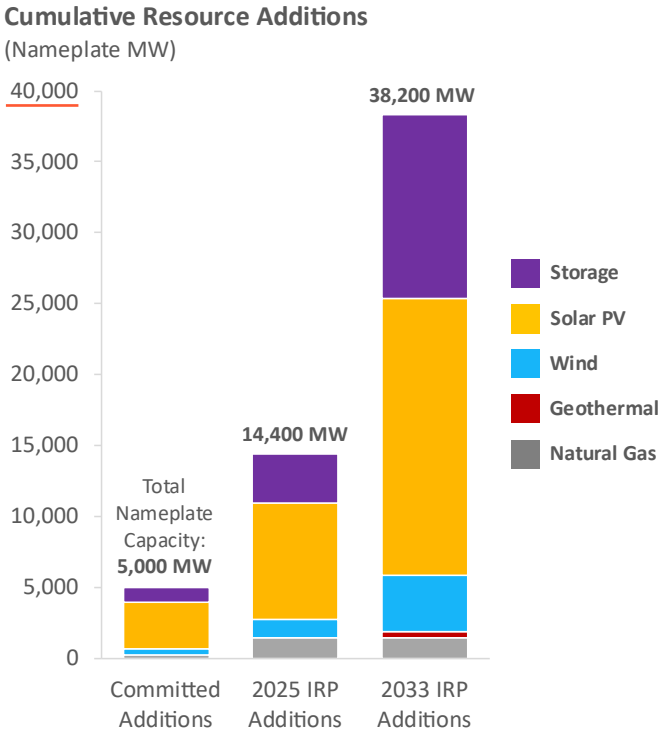
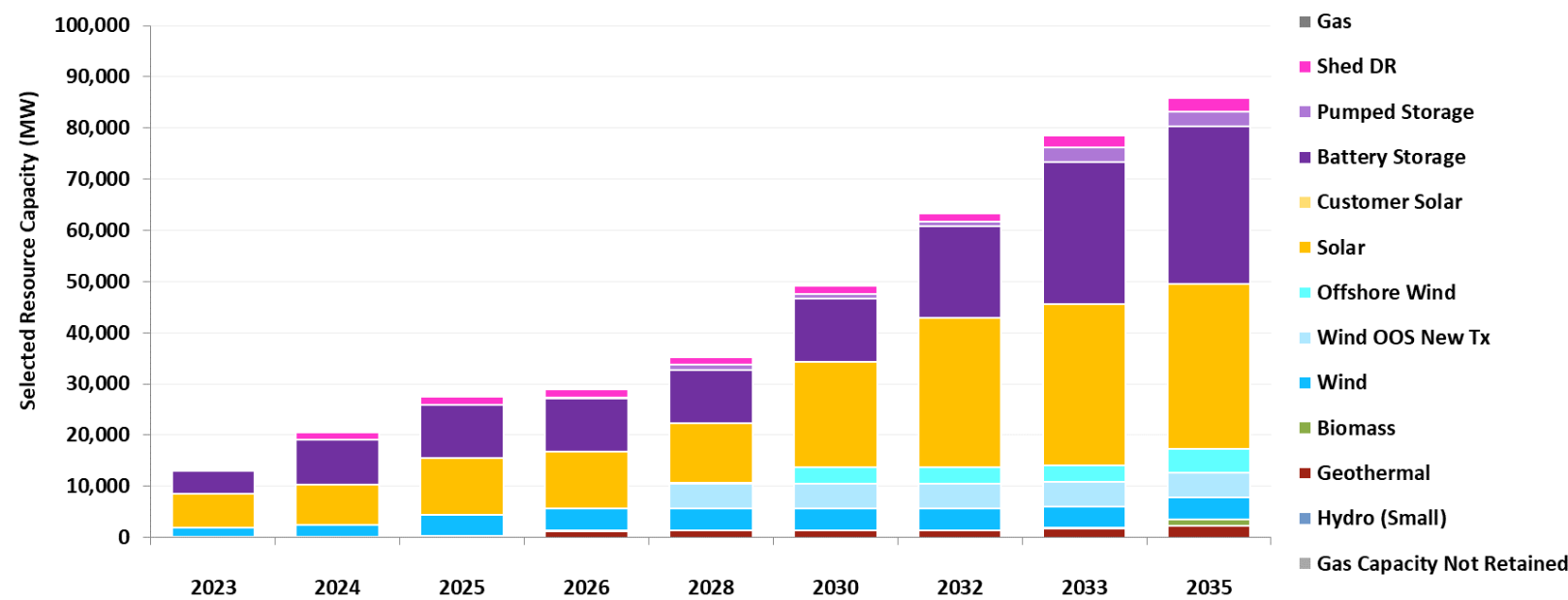
February 1993 Hydro Conditions



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

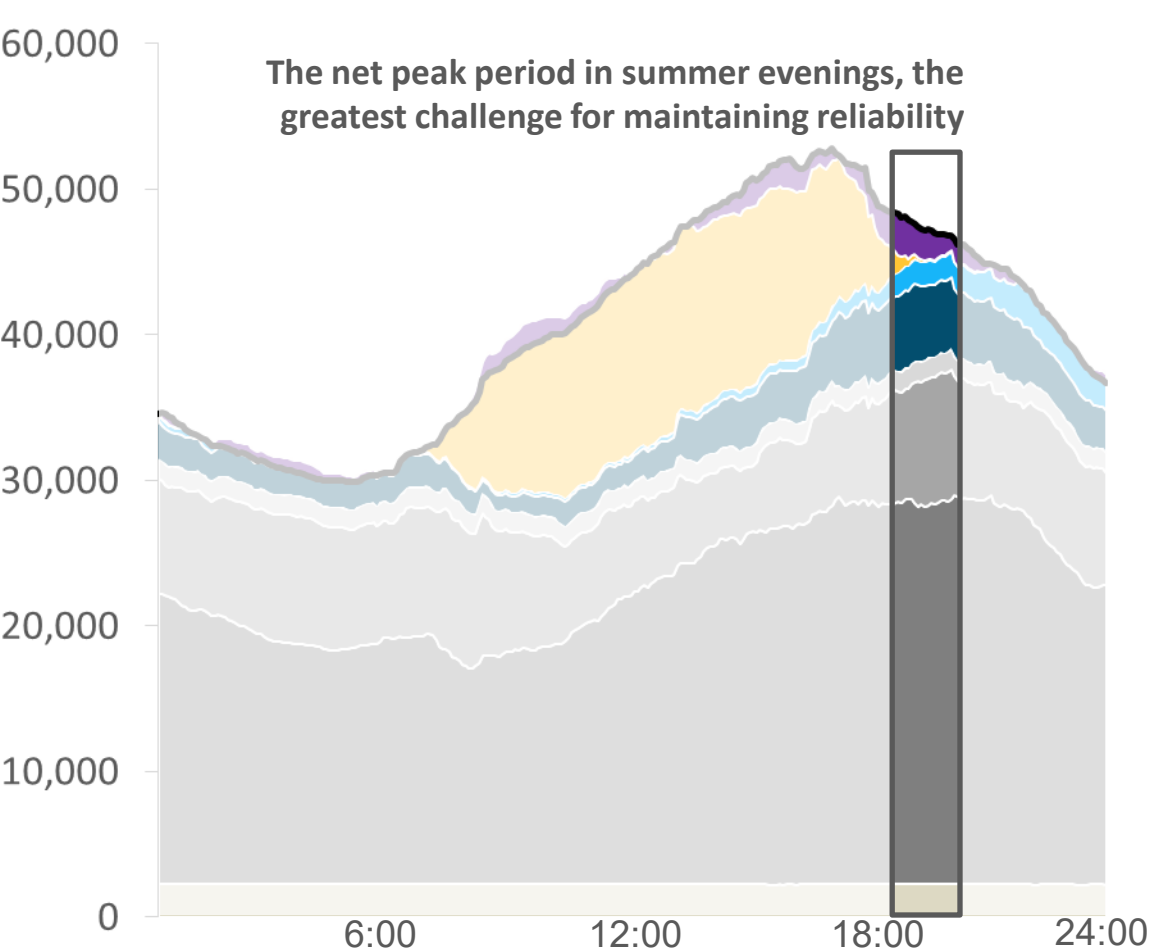
California is planning to build 50 GW of solar and storage resources by 2035 and 100 GW by 2040 (on top of 50 GW installed in 2025)

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

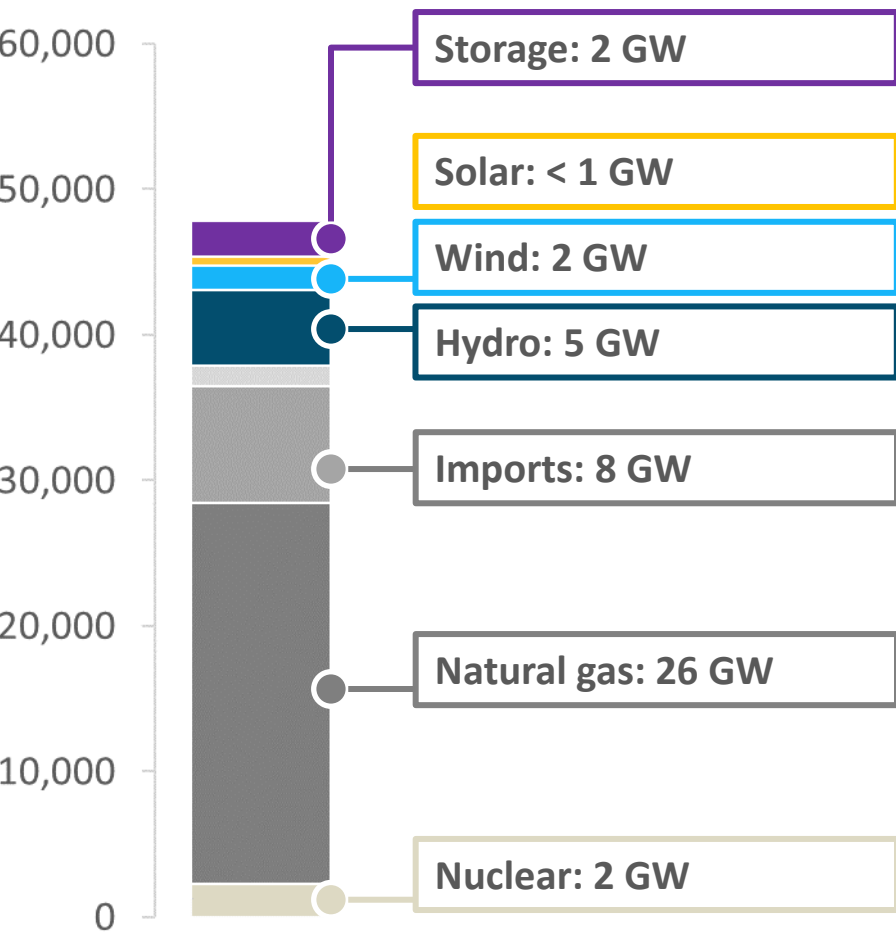


Regional comparison: California's most recent near reliability event was during a historic heatwave in September 2022

CAISO System Operations on September 6, 2022
(MW)

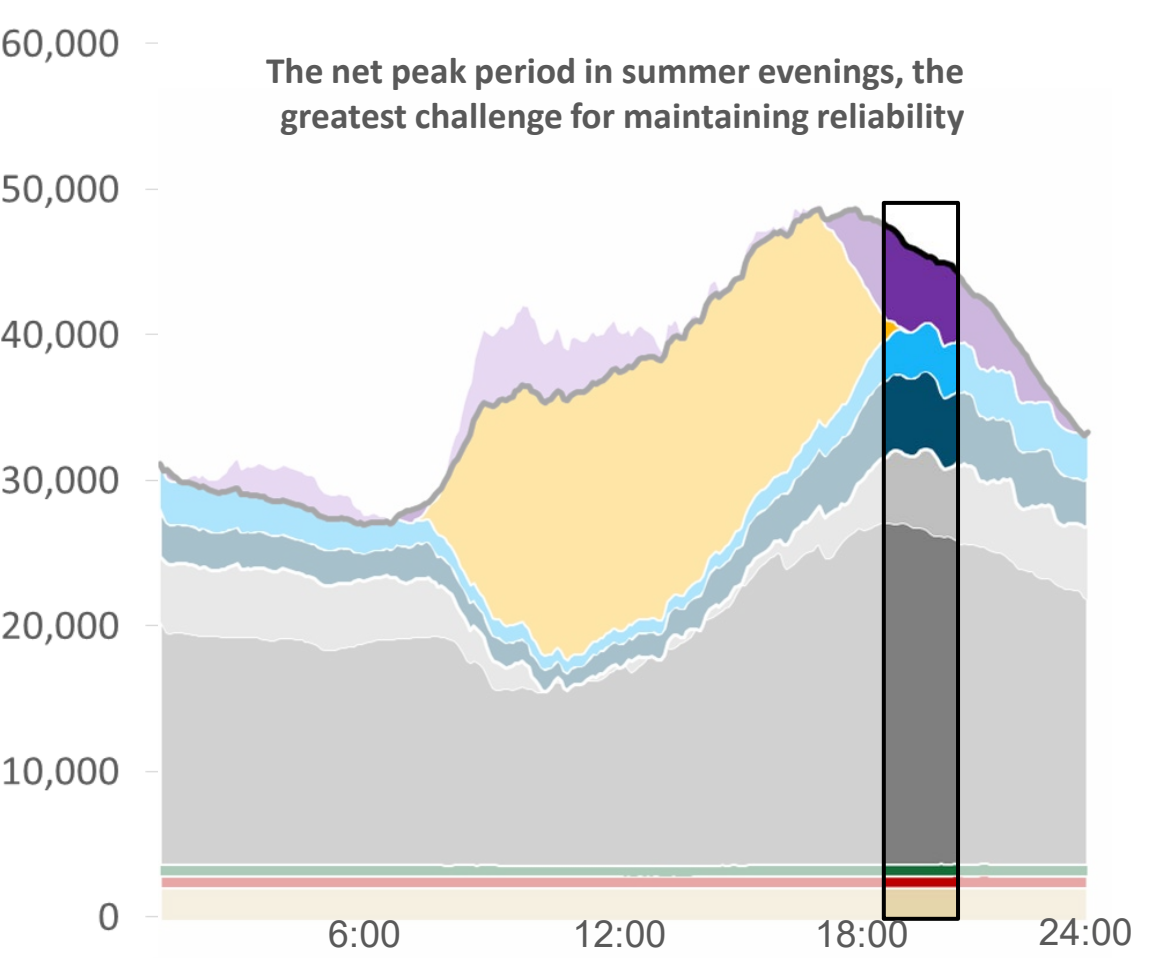


Generation During Hour of Highest Net Load
(MW)

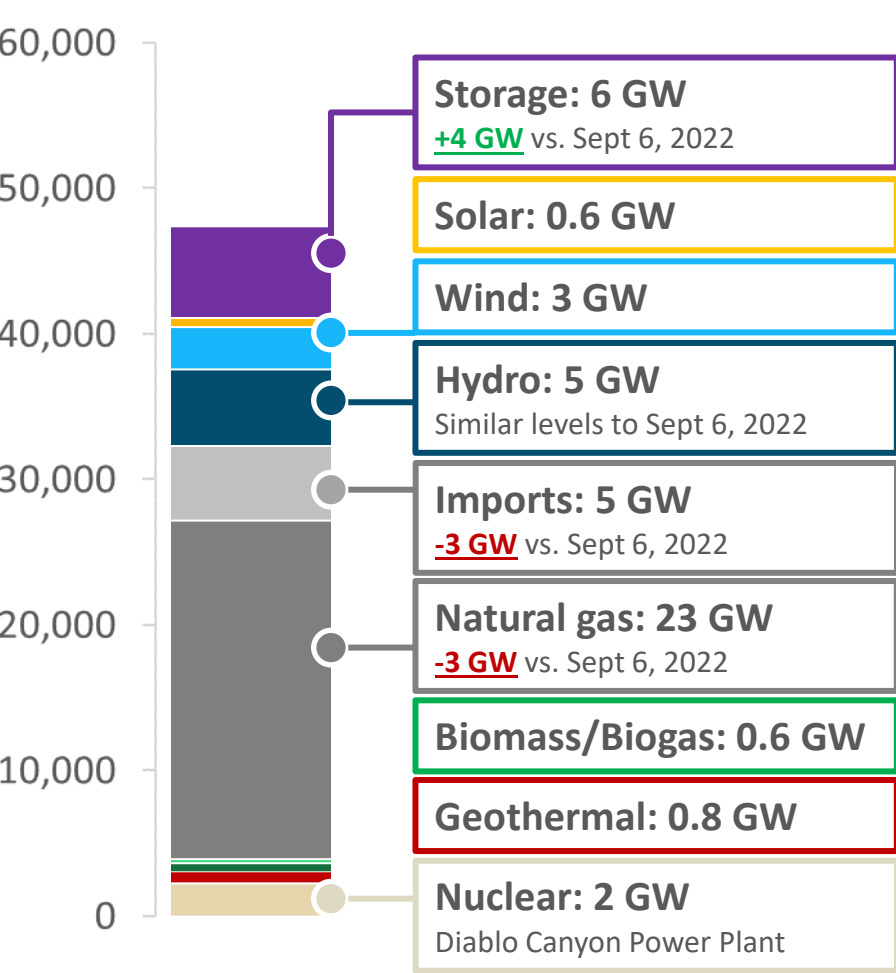


Regional comparison: Significant additions of batteries helped make the next September heatwave in 2024 a non-event

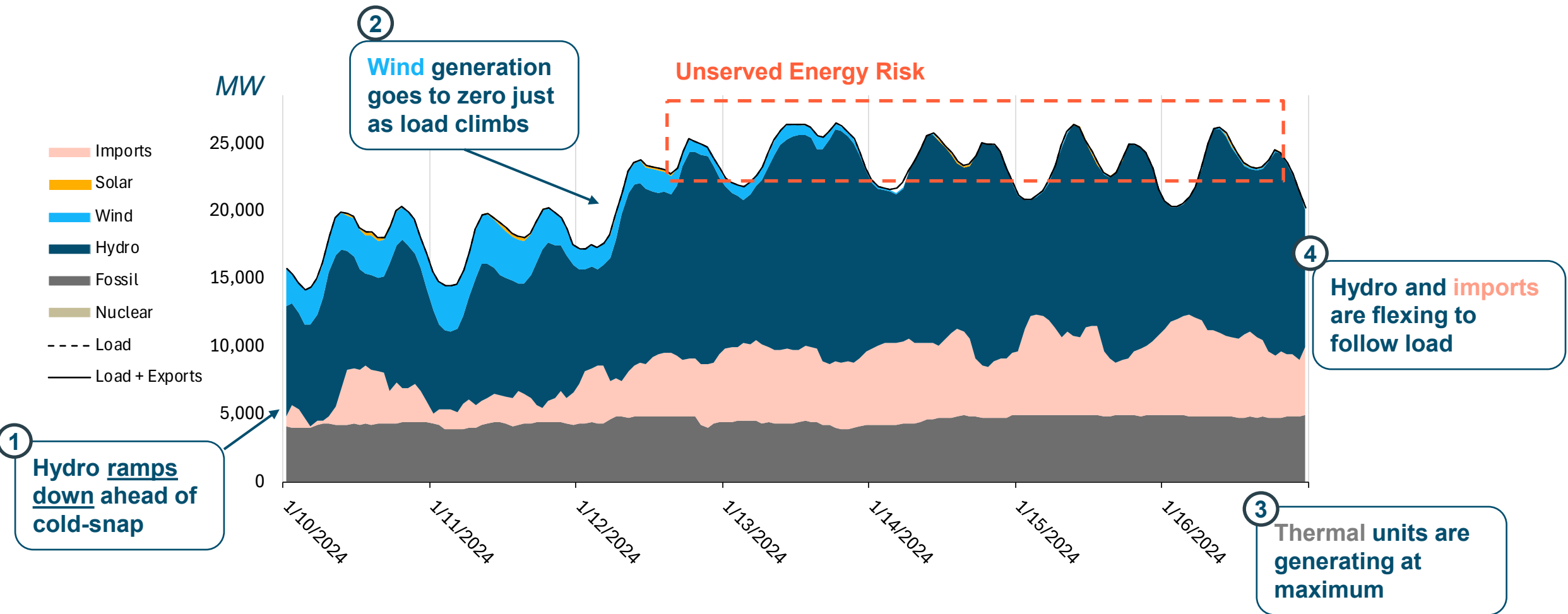
CAISO System Operations on September 5, 2024
(MW)



Generation During Hour of Highest Net Load
(MW)

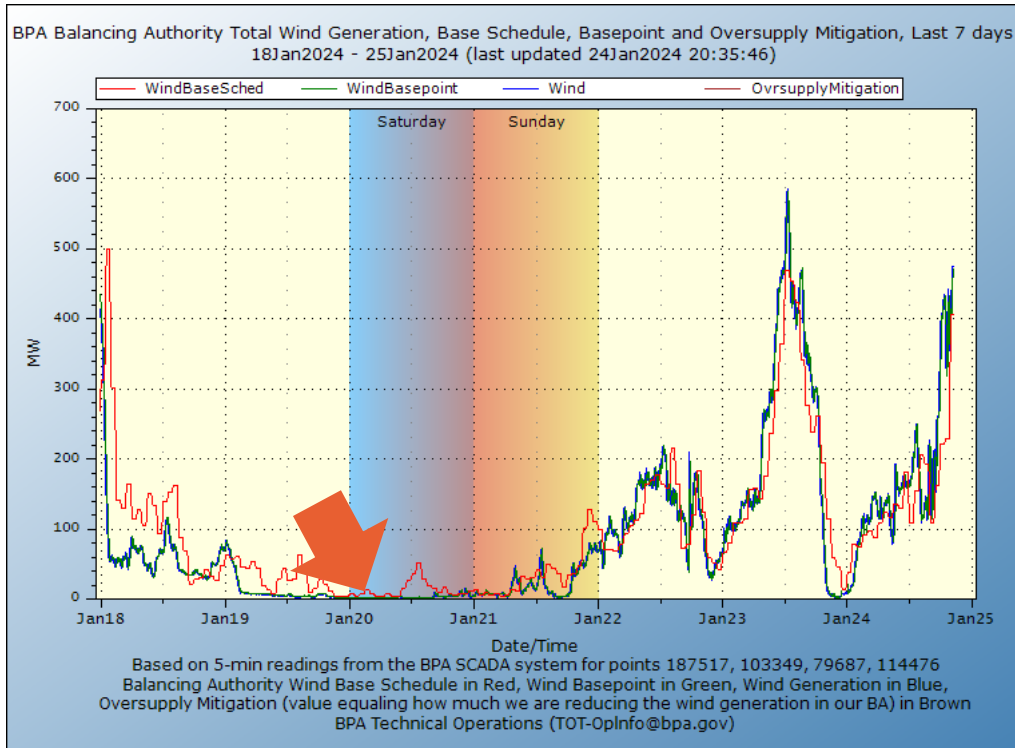


Regional comparison: The Northwest's most recent near reliability event was the multi-day January 2024 cold snap



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

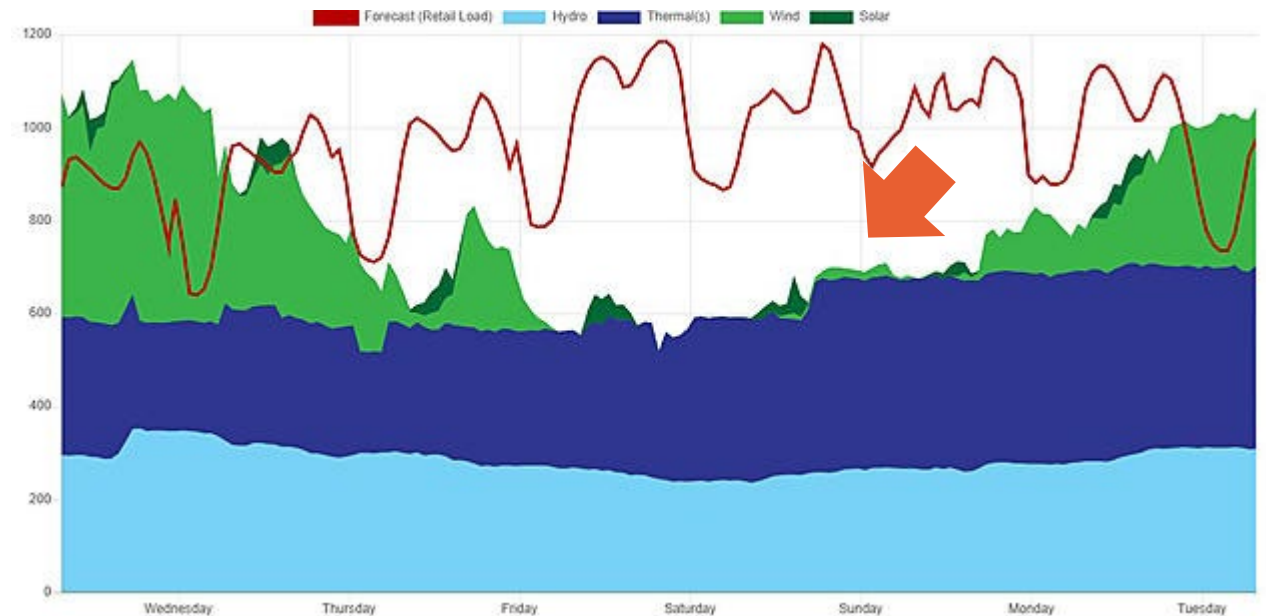
BPA: Almost no wind production on January 15-17 and 19-21



Average Jan 13: **567 MW**

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

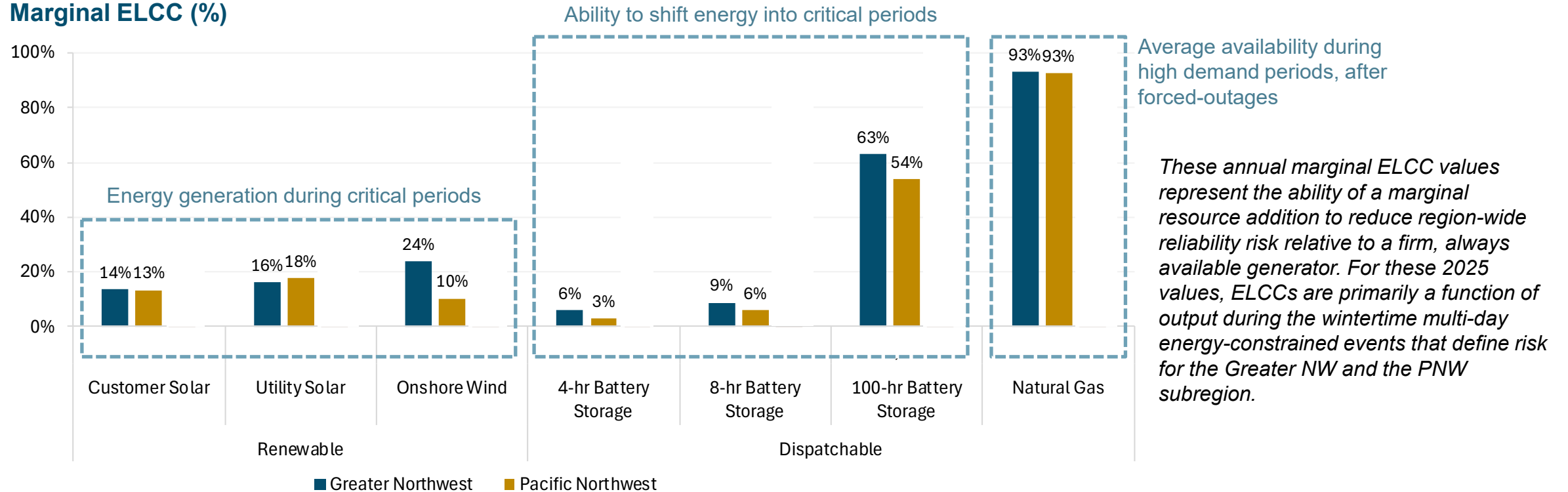
NorthWestern Energy: Almost no wind production on January 12-14



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

Marginal ELCC (%)



- + 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%

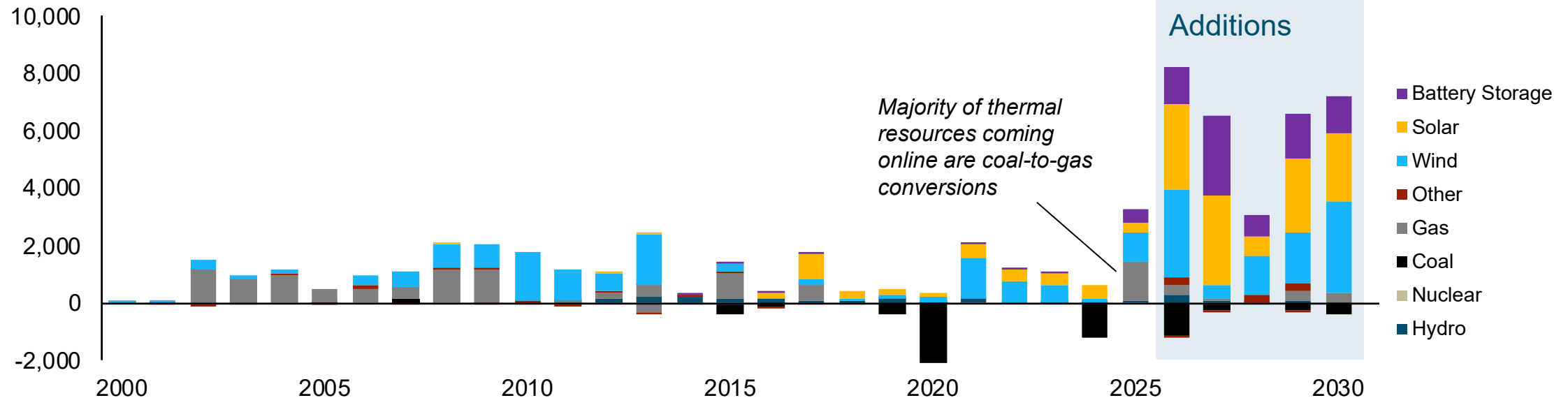
The rate of new resource additions required to meet resource adequacy needs in the next five years is unprecedented

- + 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	• <u>WRAP is voluntary</u> and has not yet become binding • <u>Accreditation metrics are uncertain</u>	• Strengthen the WRAP program with fundamentals-based capacity accreditation
3. Barriers to building new RA capacity	• Utilities are likely to be challenged by the <u>sheer volume</u> of new resources in their IRPs • Existing clean resources make limited contributions to resource adequacy and <u>“clean firm” options are not yet commercially available</u> • Natural gas is the only viable near-term firm capacity option, yet siting new gas plants is extremely challenging and may create <u>stranded asset risks</u>	• 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

Thank you!

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Energy+Environmental Economics

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Bill Wheatle, Managing Consultant
Pedro de Vasconcellos Oporto, Sr. Consultant
Hugh Somerset, Sr. Consultant

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-25-14
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
<u>PacifiCorp, and Xcel Energy</u>	)	

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

Filed January 28, 2026

Exhibit 1-158:
Sylvan & GridLab Independent Evaluation of E3 Presentation

Near-term winter resource adequacy challenges in the Pacific Northwest

A review of E3's Northwest RA Study Phase 1 and independent evaluation of near-term winter challenges



Sylvan Energy Analytics
January 2026

This work was sponsored by  GridLAB

Who we are



Sylvan Energy Analytics is a boutique energy consulting and software firm based in Portland, Oregon.

We specialize in integrated resource planning, capacity expansion and production cost modeling, resource adequacy, clean energy policy, and utility regulation.



GridLab is a non-profit public interest organization with a mission to provide expertise to enable grid transformation.

GridLab and Sylvan have collaborated on open-source resource adequacy analysis, clean energy planning, and novel resource portfolio optimization techniques.

Background

- In the Fall of 2025, Energy & Environmental Economics (E3) released Phase 1 results of a study examining resource adequacy in the Pacific Northwest
 - The study was sponsored by most of the electric utilities operating in the Pacific Northwest
 - It projected a 9 GW shortfall by 2030 across the “Greater NW,” with the potential for multiday supply shortages during winter cold events and shortages as soon as 2026
 - Phase 1 results suggested limited ability for clean resources (wind, solar, and short duration battery storage) to meet the identified needs
 - Phase 2 is underway and is expected to be released in early 2026
- Given the urgency of the Phase 1 findings, Sylvan was engaged by GridLab to review E3’s analysis and findings and identify near-term opportunities to support regional RA



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
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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

We would like to thank E3 and the study sponsors for their time and attention in answering our questions

Overview

Problem statement: If we take the E3 study Phase 1 results at face value, the region needs solutions well before significant amounts of new infrastructure can come online

Objective: Understand what drove E3's Phase 1 findings and explore the potential contributions of near-term solutions that may not be considered in Phase 2 of their analysis

Scope:

- Conduct a methodological review in key areas that could impact RA results, including large load flexibility, hydro dispatch flexibility, imports & coordination with California, and retirements & conversions
- Conduct an independent evaluation of the near-term winter RA challenge in the Pacific Northwest
 - Develop multiple load scenarios based on recent load trends and various projections of future data center demand
 - Examine winter resource adequacy challenges in 2030 based on the weather and hydro conditions experienced in January 2024 (the most recent example of highly constrained winter conditions in the Pacific Northwest)
- Identify near-term opportunities to support regional resource adequacy based on findings



Executive Summary

High level findings from methodological review

Focus area	Findings of methodological review	Potential impact to near-term RA needs
Large load flexibility	Large load flexibility was not considered in Phase 1 and is not scoped into Phase 2	High
Hydro flexibility	- E3 study may underestimate weekly energy shifting available from hydro dispatch - E3's load following hydro dispatch assumption may overlook contributions from short-duration storage	Uncertain (requires further study)
Imports and coordination with California	- E3 study assumptions may slightly underestimate import winter capability - Winter import capability is limited by transmission, not generation (California has several GWs of unused gas capacity available during PNW winter events)	Low
Retirements and conversions	- Phase 1 results slightly overstated RA challenges by treating coal-to-gas conversions as retirements in initial need evaluation - E3 study Phase 1 did not include Centralia coal-to-gas conversion (it had not yet been announced)	Low-to-moderate

High level findings from methodological review

Focus area	Findings of methodological review	Potential impact to near-term RA needs
Large load flexibility	• Large load flexibility was not considered in Phase 1 and is not scoped into Phase 2	High

Because of the high potential near-term impact of large load flexibility, most of our analysis focuses on these two highly related questions:

1. How much of the projected need is being driven by data centers (i.e., “new large loads”)?
2. What is the potential for management of new large loads to avoid the most catastrophic consequences of potential supply shortages during extreme weather conditions?

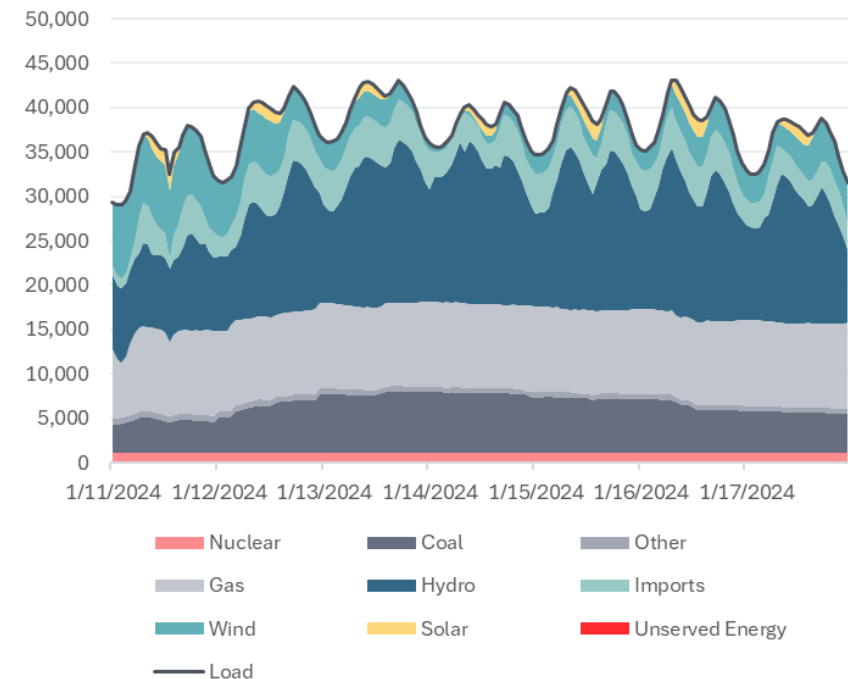
Independent evaluation approach

To better understand the nature of the near-term winter resource adequacy risk in the Northwest and the potential impact of new large loads, we examined how the recent January 2024 winter event might unfold if experienced in 2030 under various scenarios.

GridPath dispatch simulation approach:

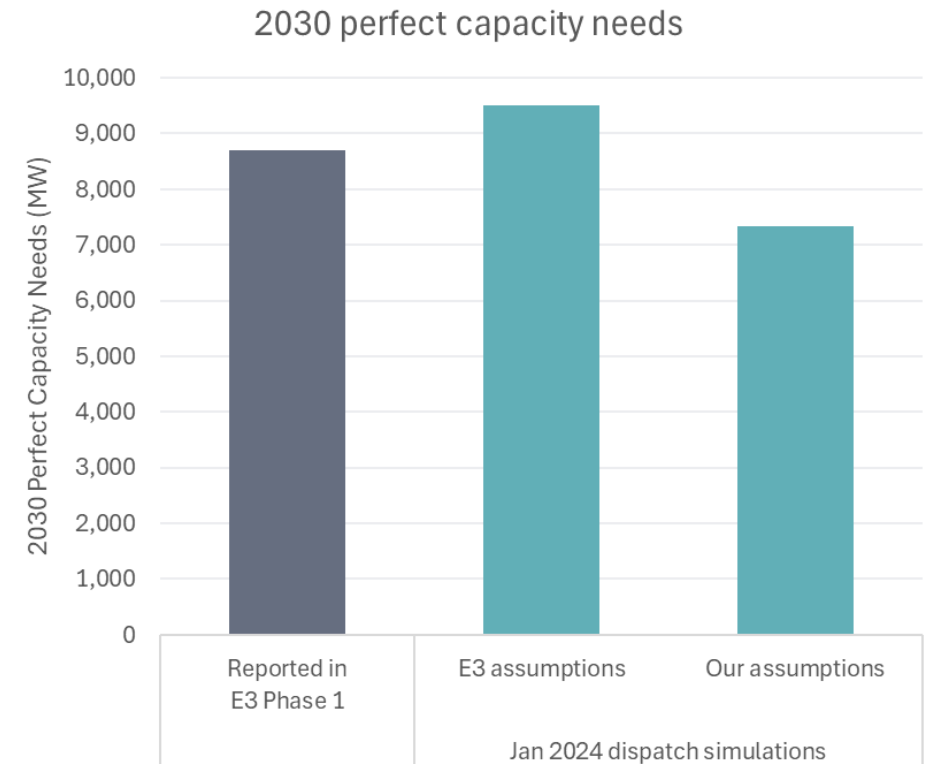
1. Developed dispatch simulation for the “Greater NW” that replicated the weather and hydro conditions from January 2024
2. Ran a benchmark simulation with 2024 historical loads to assess reasonableness of assumptions/constraints
3. Adjusted loads and resources to approximate the 2030 system
4. Identified perfect capacity needs and potential customer outages if unfilled
5. Layered in short-term solutions
 - Resources in development
 - Emergency large load management
 - Additional proposed clean resources

Simulated dispatch in January 2024 benchmarking run



Validating our approach to estimating 2030 winter risk

- To validate our approach, we compared our findings to the Phase 1 reported capacity need in 2030 in two ways:
 - **E3 assumptions:** uses E3's import assumptions (3,750 MW) and coal-to-gas accounting (coal units are retired)
 - **Our assumptions:** uses our import assumptions and our coal-to-gas accounting (coal units are converted to gas), except Centralia 2
- Both simulations assumed loads approximately reflect E3's forecasted load growth rates
- Our dispatch analysis generally corroborates E3's findings when using their load growth rates and gives us confidence that January 2024 conditions serve as a reasonable proxy for estimating winter RA needs
- Differences in import assumptions and coal-to-gas accounting reduce the magnitude of the identified need, but it remains substantial under E3's projected load growth



Alternative 2030 load scenarios

We combined various organic growth and data center load scenarios to explore alternative load growth futures (ranging from 1.5% to 3.2% average annual growth through 2030)

Scenario	Organic Load Growth	Data Center Demand	Total annual average growth rate through 2030
E3 Forecast	High/E3 (~1.8%)	Low/E3 (1,700 MWa)	~2.8%
Baseline Scenario	Baseline (1.4%)	Baseline (3,700 MWa)	3.2%
Low Tech Scenario	Baseline (1.4%)	Low/E3 (1,700 MWa)	2.2%
Low Electrification Scenario	Low (0.9%)	Baseline (3,700 MWa)	2.6%
Low Growth Scenario	Low (0.9%)	Low/E3 (1,700 MWa)	1.5%
<i>Historical growth in electricity sales (2019-2024, excluding 2020)</i>			1.3%

All alternative load scenarios envision accelerated load growth relative to the last 6 years

High level findings from independent evaluation

1. The scale and nature of the winter resource adequacy challenge in the Pacific Northwest depends strongly on future load growth, which remains highly uncertain due to both data center demand and electrification trends
2. Large load flexibility could mitigate most or all near-term winter resource adequacy needs under most load scenarios
3. Sustained development of clean resources is well-suited to meeting organic (i.e., non-data center) load growth in the region unless electrification accelerates faster than recent load growth trends suggest
4. Supporting reliable winter data center operations in the Pacific Northwest will likely require resources with more energy availability during challenging winter events
5. In the near term, the ability to curtail large loads first during emergency events can protect other customers from the most catastrophic health and safety consequences of supply shortages
6. In the long term, the need for dispatchable or baseload solutions is not a question of if, but when

Finding #1. The scale and nature of the winter resource adequacy challenge in the Pacific Northwest depends strongly on future load growth, which remains highly uncertain due to both data center demand and electrification trends

We estimate winter capacity needs in 2030 of 1.0 GW – 4.9 GW after accounting for coal-to-gas conversions and resources in development

	Estimated winter perfect capacity needs in 2030 across load scenarios (based on January 2024 weather & hydro conditions)					Reported by E3 in Phase 1
	Low Growth (1.5% AGR)	Low Electrification (2.6% AGR)	Low Tech (2.2% AGR)	Baseline (3.2% AGR)	Approximation of E3 Forecast	
With no new resources	2.9 GW	5.0 GW	4.7 GW	6.8 GW	6.7 GW	8.7 GW
+ Resources in development	1.0 GW	3.1 GW	2.8 GW	4.9 GW	4.8 GW	5.6 GW

Notes: Our estimated capacity needs with no new resources include the impacts of coal-to-gas conversions, including Centralia 2. E3's reported capacity needs with no new resources assume coal units are retired, rather than converted to gas. We estimate this accounts for approximately 1.5 GW of the 8.7 GW of need identified by E3. E3's reported capacity needs with resources in development include coal-to-gas conversions, except for Centralia 2.

Finding #2. Large load flexibility could mitigate most or all near-term winter resource adequacy needs under most load scenarios

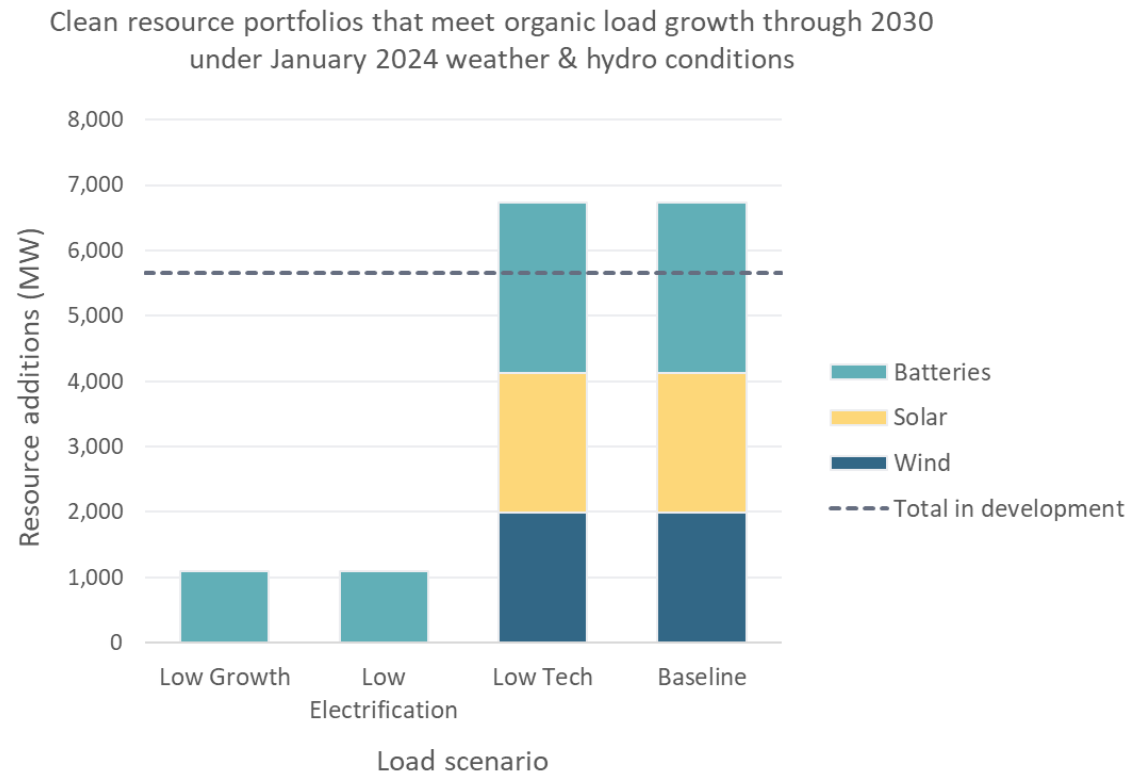
We estimate winter capacity needs in 2030 of 0.0 GW – 3.1 GW to avoid supply shortages if large loads are managed during the most critical winter weather events

	Estimated winter perfect capacity needs in 2030 across load scenarios (based on January 2024 weather & hydro conditions)					Reported by E3 in Phase 1
	Low Growth (1.5% AGR)	Low Electrification (2.6% AGR)	Low Tech (2.2% AGR)	Baseline (3.2% AGR)	Approximation of E3 Forecast	
With no new resources	2.9 GW	5.0 GW	4.7 GW	6.8 GW	6.7 GW	8.7 GW
+ Resources in development	1.0 GW	3.1 GW	2.8 GW	4.9 GW	4.8 GW	5.6 GW
+ Large load flexibility	0.0 GW	0.0 GW	1.1 GW	1.2 GW	3.1 GW	NA

Notes: Our estimated capacity needs with no new resources include the impacts of coal-to-gas conversions, including Centralia 2. E3's reported capacity needs with no new resources assume coal units are retired, rather than converted to gas. We estimate this accounts for approximately 1.5 GW of the 8.7 GW of need identified by E3. E3's reported capacity needs with resources in development include coal-to-gas conversions, except for Centralia 2.

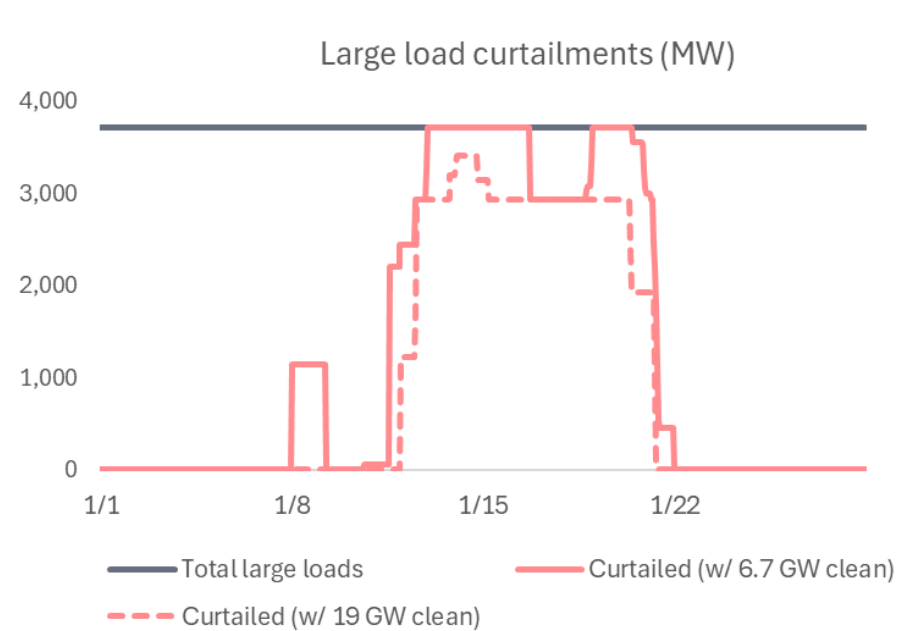
Finding #3. Sustained development of clean resources is well-suited to meeting organic (i.e., non-data center) load growth in the region unless electrification accelerates faster than recent load growth trends suggest

- We estimate that less than 7 GW of new wind, solar, and batteries are adequate to avoid supply shortages among non-data center customers under January 2024 weather & hydro conditions in 2030 across our four load scenarios
- Under the E3 Load Forecast Approximation (with more electrification and fewer data centers than our load scenarios), supply shortages cannot be avoided even if all proposed clean resources (19 GW) come online by 2030



Finding #4. Supporting reliable winter data center operations in the Pacific Northwest will likely require resources with more energy availability during challenging winter events

Without these additional resources, we estimate that large load curtailments could range from 0 hours to 9 days under January 2024 weather & hydro conditions, depending on the load scenario and clean resource buildout



Load scenario	Large load curtailments in 2030 under January 2024 weather & hydro conditions
Low Growth	0 hrs
Low Electrification	2.5 - 4.6 days
Low Tech	2.3 - 6.2 days
Baseline	7.0 - 9.3 days

Note: Clean resource additions range from the greater of the resources under development and the resources needed to meet organic load growth to all proposed clean resources as of December 2024 (19 GW)

Finding #5. In the near term, the ability to curtail large loads first during emergency events can protect other customers from the most catastrophic health and safety consequences of supply shortages

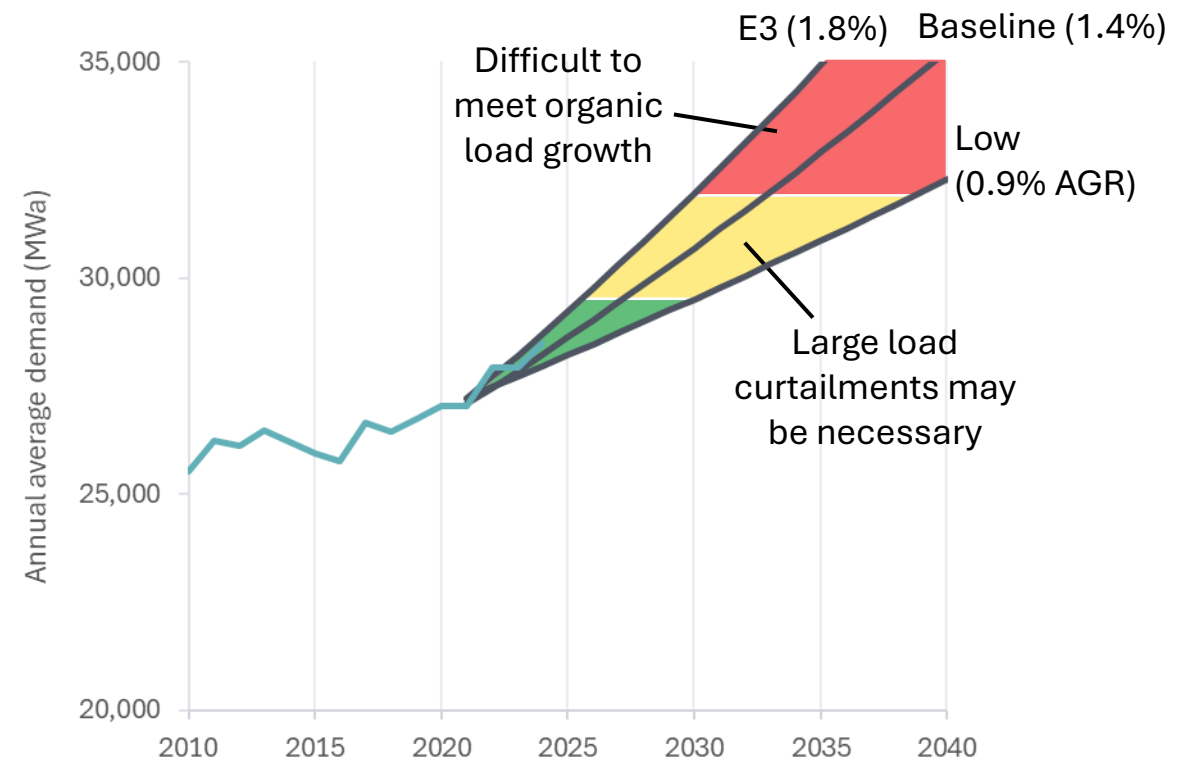
We estimate that large load management could reduce average outages among other customers during critical winter weather conditions from 19 hours to 0.1 hours (assuming only resources already in development come online by 2030)

Average customer outage duration in 2030 during January 2024 weather/hydro event under Baseline Load Scenario (assuming only resources already in development come online)		
Strategy	Existing customers	New large loads
Curtail equally across large loads and other customers	19 hrs	19 hrs
Prioritize large load curtailment before other customers	0.1 hrs	225 hrs (about 10 days)

Finding #6. In the long term, the need for dispatchable or baseload solutions is not a question of if, but when

- When the region faces the most daunting challenges encountered in our simulations will depend on future load growth (which will depend on economic conditions, electrification, and energy efficiency)
- Pushing these needs out in time creates opportunities for emerging clean technologies to be part of the solution

Extrapolated* organic load growth trajectories and resource adequacy challenges



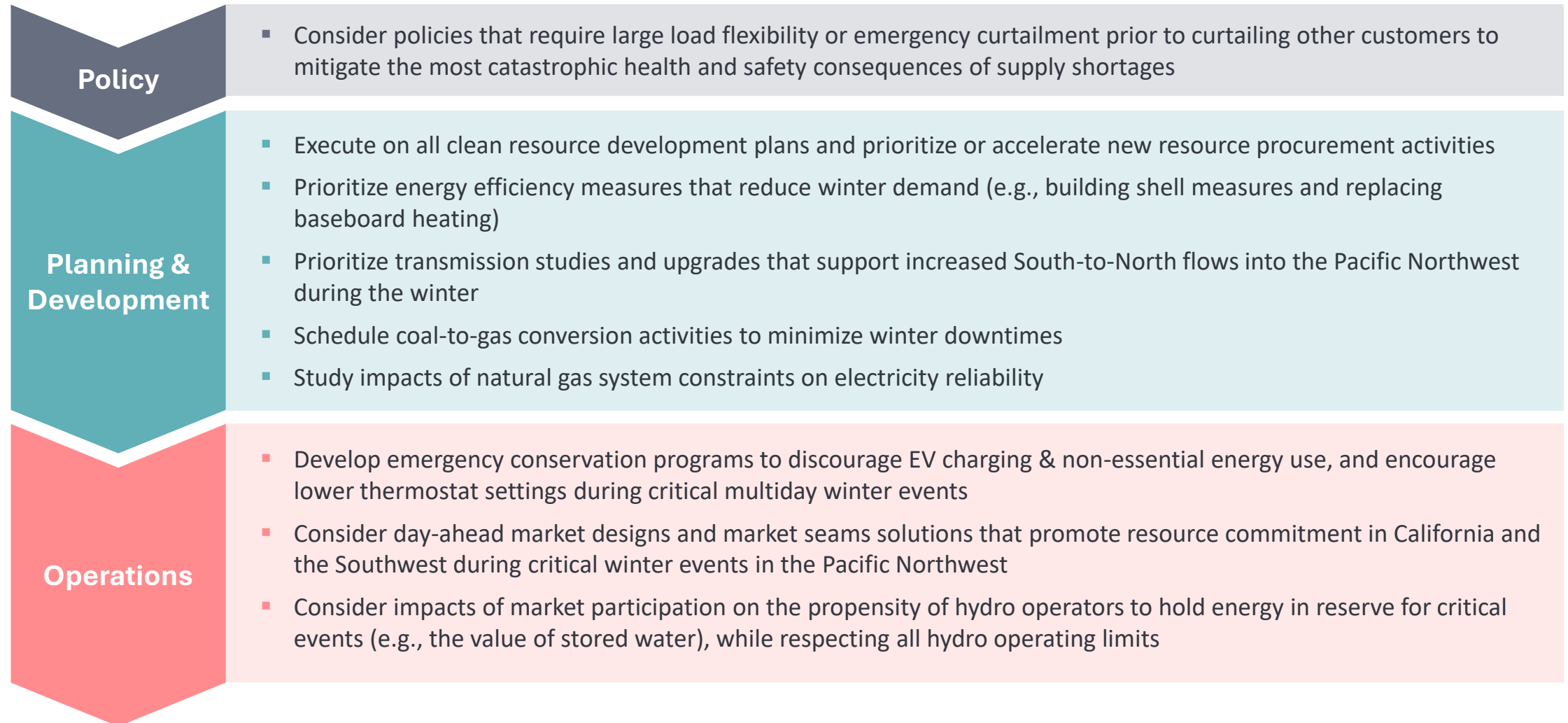


Cape Lookout State Park, Oregon Coast (source: www.oregonlive.com)

An opportunity to drive innovation

- If subject to flexibility requirements, data center customers will face the most daunting long-duration reliability challenges first and will have an incentive to solve them
- With a desire to move quickly and larger risk appetites than regulated utilities, data center customers could drive innovation in the next generation of clean technologies that serve longer duration needs, accelerating adoption, and driving down costs
- Flexibility requirements can also be leveraged to facilitate more rapid interconnection until new technologies become available

Near-term opportunities identified to support regional RA





Analytical Details

Evaluation approach

To better understand the nature of the near-term winter resource adequacy risk in the Northwest and the potential impact of new large loads, we examined how the recent January 2024 winter event might unfold if experienced in 2030 under various scenarios.

GridPath dispatch simulation approach:

1. Developed dispatch simulation for the Pacific Northwest that replicated the weather and hydro conditions from January 2024
2. Ran a benchmark simulation with 2024 historical loads to assess reasonableness of assumptions/constraints
3. Adjusted loads and resources to approximate the 2030 system
4. Identified perfect capacity needs and potential customer outages if unfilled
5. Layered in short-term solutions
 - Resources in development
 - Emergency large load management
 - Additional proposed clean resources

Some technical notes

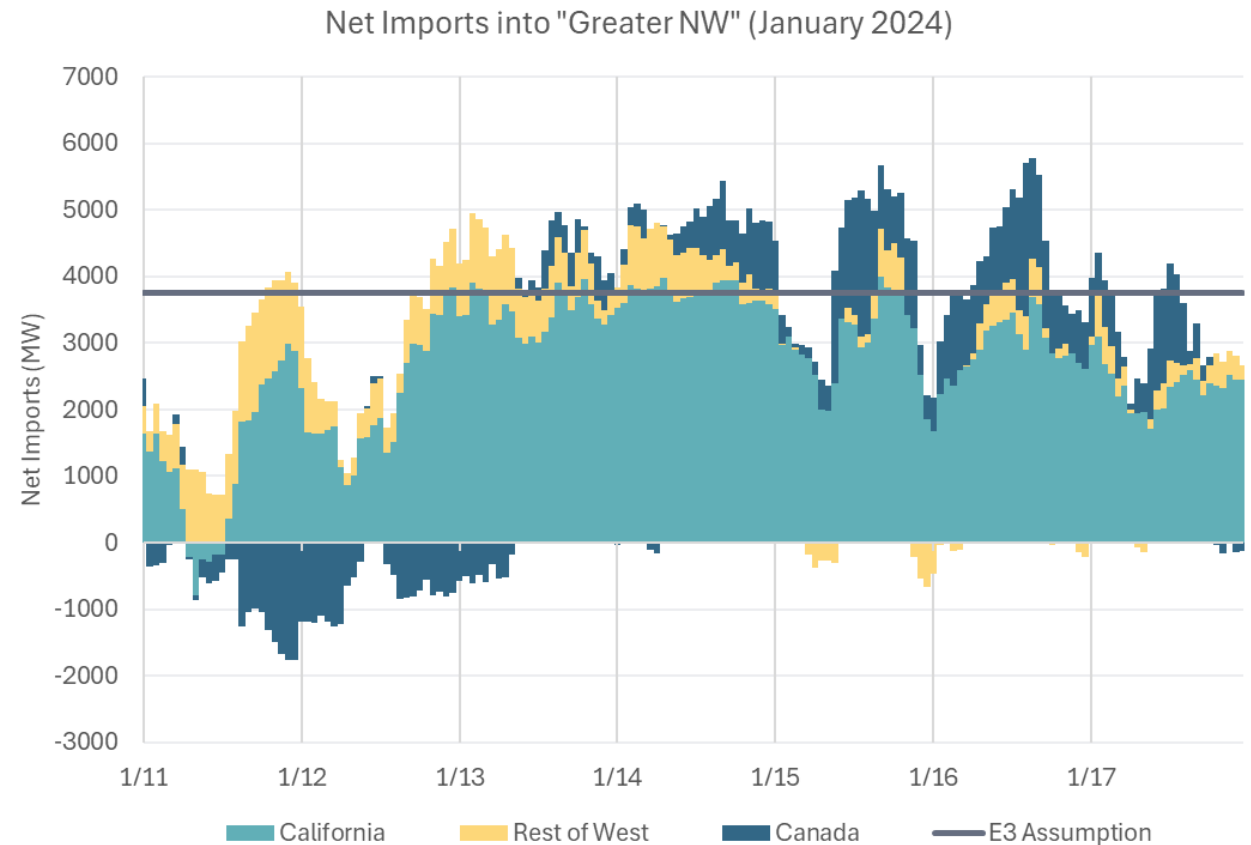
- We did not model full economics due to limited time and data availability, so results are more indicative of what the system *could* do vs. what it *would* economically do
- We have not fully reconciled our “Greater NW” footprint with E3’s due to time and data limitations. Loads and resources likely differ between the analyses and load comparisons focus on load growth rates rather than total loads to account for these differences
- Perfect capacity needs were identified by minimizing the maximum observed unserved energy across the month
- Potential customer outages were identified by equally penalizing total and maximum unserved energy to better reflect operations

Key assumptions

	Our analysis	E3 study
Footprint	BAs in OR, WA, ID, MT + PACE	BAs in OR, WA, ID, MT (excluding WAUW) + PACE
Hydro dispatch	Optimized with weekly energy budgets, minimum, maximum, and ramping constraints based on Jan 2024 hydro dispatch; unconstrained energy shifting allowed between weeks 2 & 3	Load-following heuristic with weekly budgets with up to 5% inter-week energy shifting, minimum and maximum levels based on historical min/max as a function of energy budget
Transmission constraints	2024 benchmark: Constrained flows between PACE and PNW based on high and low observations across January 2024 historical observations 2030 simulations: Added 1,000 MW bidirectional capacity associated with B2H by 2030 (total in 2030: -1,150 MW to +3,410 MW)	None in RA analysis (zonal results are from separate simulations, each assuming a copper plate)
Import constraints	<u>Total: 5,000 MW</u> Into PNW zone (excluding Canada): 3,000 MW Canada to PNW: 1,000 MW Into PACE: 1,000 MW	<u>Total: 3,750 MW</u>
Canadian entitlement	2024 benchmark: 660 MWa net exports into Canada across the month, but allowing Canadian storage to also support imports in any given hour 2030 simulations: Same, but net exports reduced to 590 MWa	590 MW exports to Canada in all hours, no accounting for Canadian storage or import capability from Canada
2030 baseline resource fleet	Existing based on operational resources as of January 2024 (EIA 930), in development resources based on 2024 EIA 860 Dave Johnston 3 retired Coal-to-gas conversions of Centralia 2, Dave Johnston 1 & 2, Naughton 1 & 2	Existing and in development resources based on WECC ADS Dave Johnston 3 and <u>Centralia 2 retired</u> Coal-to-gas conversions of Dave Johnston 1 & 2, Naughton 1 & 2 (however in initial need evaluation, these are retired)
2030 Load	Four load scenarios that combine different outlooks for organic load growth and data center demand, plus a load scenario that approximates E3's forecasted load growth	PATHWAYS-based bottom-up loads with adjustments and internal data center forecast

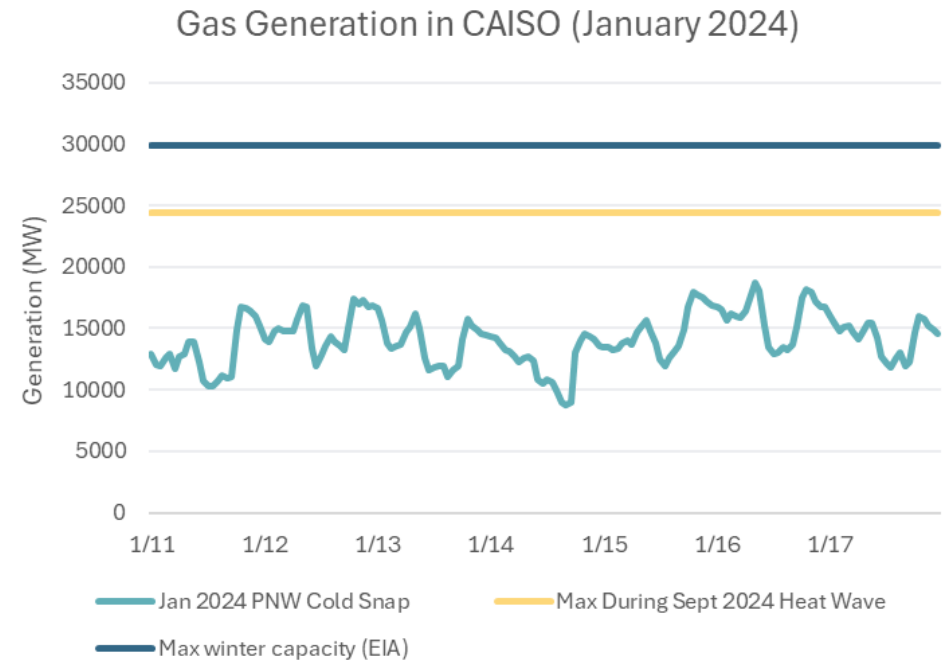
Winter import constraints

- The E3 study assumes 3,750 MW of imports are available in all hours based on imports during the January 2024 cold event
- Net imports into the “Greater NW” exceeded 3,750 MW in 102 hours in January 2024 and exceeded 5,000 MW in the most constrained hours
- The 3,750 MW limit aligns well with imports from California during the event, but may neglect additional import capability from Canada and the rest of the West



Transmission, not available supply, limited imports

- Much of the gas fleet in California went unused during the January 2024 event (i.e., there was not a shortage of regional generating capacity in the West)
- However, South-to-North transmission flows between California and the Pacific Northwest were constrained by operating limits
- South-to-North operating limits on COI and PDCI are tighter than North-to-South limits
 - Max N-to-S during Sept 2024 heatwave: ~5,500 MW
 - Max S-to-N during Jan 2024 cold snap: ~3,800 MW



Near-term opportunities to support increased imports during winter events:

- Prioritize transmission studies and upgrades that support increased S-to-N flows into the PNW during the winter
- Consider day-ahead market designs and market seams solutions that promote resource commitment in California and the Southwest during critical winter events in the Pacific Northwest

Hydropower dispatch

Study review:

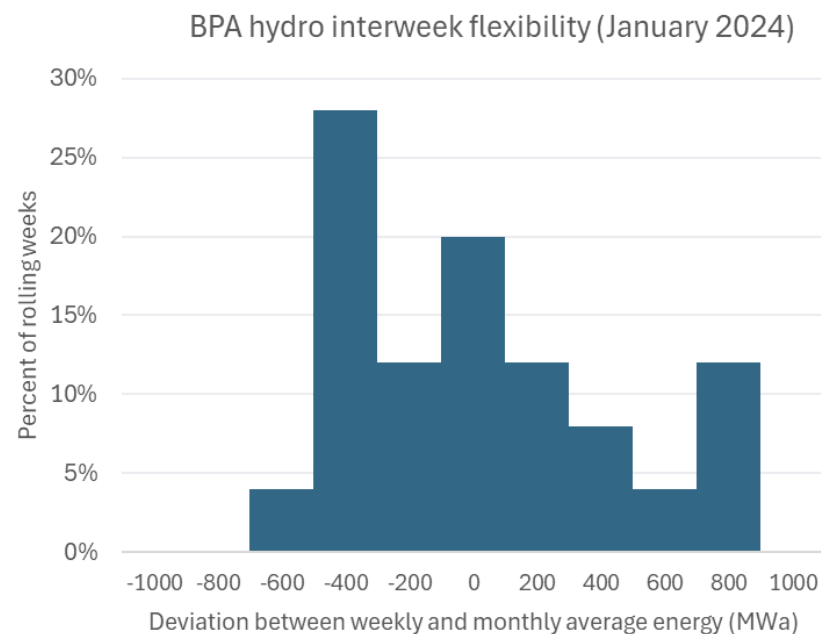
- E3 confirmed that they use a load-following heuristic to estimate hydro dispatch in each week and they allow 5% of weekly hydro energy to shift between weeks
- Heuristic dispatch may underestimate the potential of the hydro system to support resource adequacy and may overlook opportunities to co-optimize between hydro and other resources, including short-duration batteries
- Analysis into BPA hydro dispatch in January 2024 suggests that any given week could have access to as much as 880 MWa (14%) of additional hydro beyond the monthly average energy

Outstanding substantives questions:

- How do hydro operators value stored water when dispatching their hydro fleets? Does it adequately account for the value of supporting winter reliability over longer timescales (i.e., future days, weeks, or months) or is hydro dispatch over-optimized for short-term economics?
- How will day-ahead market participation affect this tradeoff between short-term revenues and winter reliability value?

Near-term opportunity:

- Consider impacts of market participation on the propensity of hydro operators to hold energy in reserve for critical events (e.g., the value of stored water), while respecting all hydro operating limits



Retirements and conversions

Study review:

- E3 confirmed the 8,689 MW identified need assumes that coal plants retire instead of undergoing coal-to-gas conversions
 - E3 analysis suggests that capacity needs could be 850 MW smaller with coal-to-gas conversions included

Our approach:

- Include all announced coal-to-gas conversions to avoid overstating incremental needs
 - While conducting the analysis, Transalta announced the conversion of Centralia 2 to gas. This update was incorporated into our final simulations.

Outstanding substantive question:

- Some of PacifiCorp's coal-to-gas conversion plans suggest winter downtimes, which may be avoidable by pushing the schedule out or accelerating it by a matter of months. How does winter reliability factor into scheduling for coal-to-gas conversions?

Near-term opportunity:

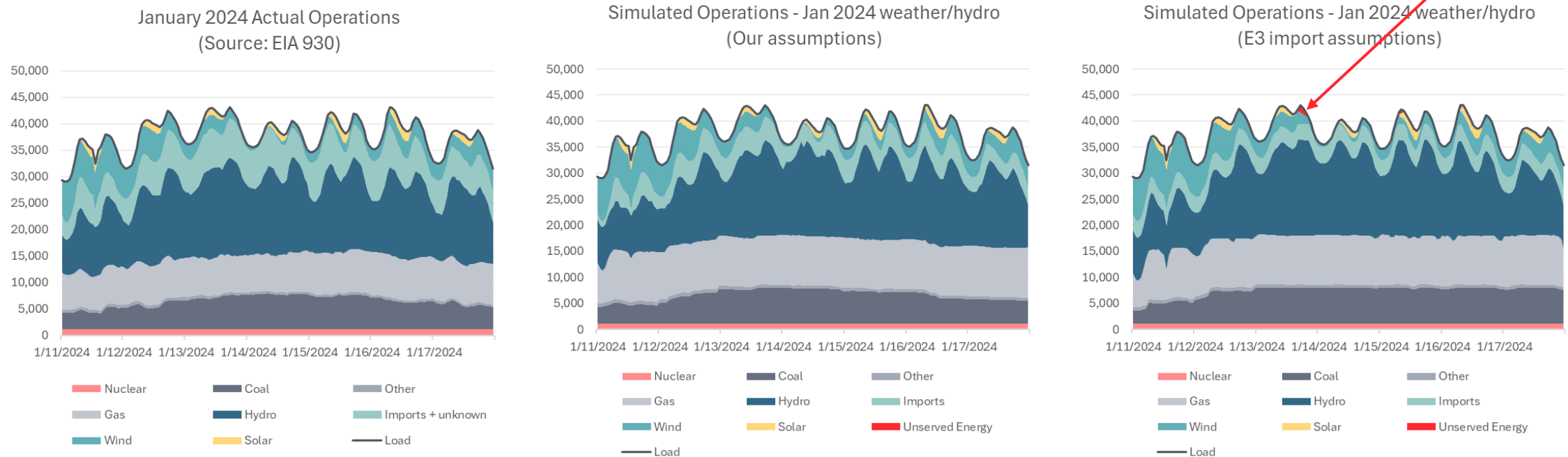
- Schedule coal-to-gas conversion activities to minimize winter downtimes

	Winter Capacity	E3 initial need evaluation	Our analysis
Dave Johnston 1	99 MW	Retired	Converted to gas
Dave Johnston 2	106 MW	Retired	Converted to gas
Dave Johnston 3	220 MW	Retired	Retired
Naughton 1	156 MW	Retired	Converted to gas
Naughton 2	201 MW	Retired	Converted to gas
Centralia 2	670 MW	Retired	Converted to gas
Total retired		1,452 MW	220 MW
Total converted to gas		0 MW	1,232 MW

2024 benchmarking

- Tested reasonableness of assumptions by simulating January 2024 dispatch

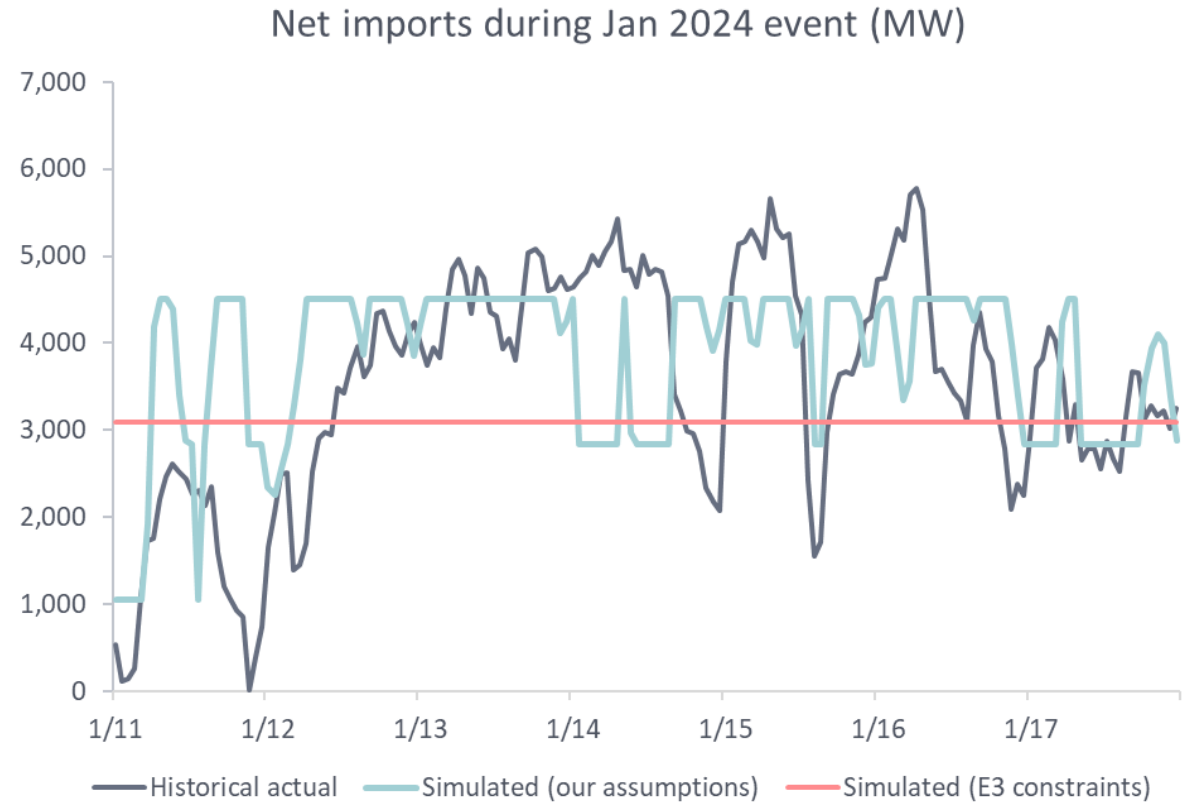
Applying E3 import constraint yields shortages in 11 hrs, up to 1,400 MW



*Actual and simulated operations have different classifications for some resources that are interconnected to BPA, but not reported by BPA (or other BAs) in EIA 930. These resources are simulated explicitly and grouped by technology in the simulated operations plots, but fall within “Imports + unknown” in the actual operations plot (on the left)

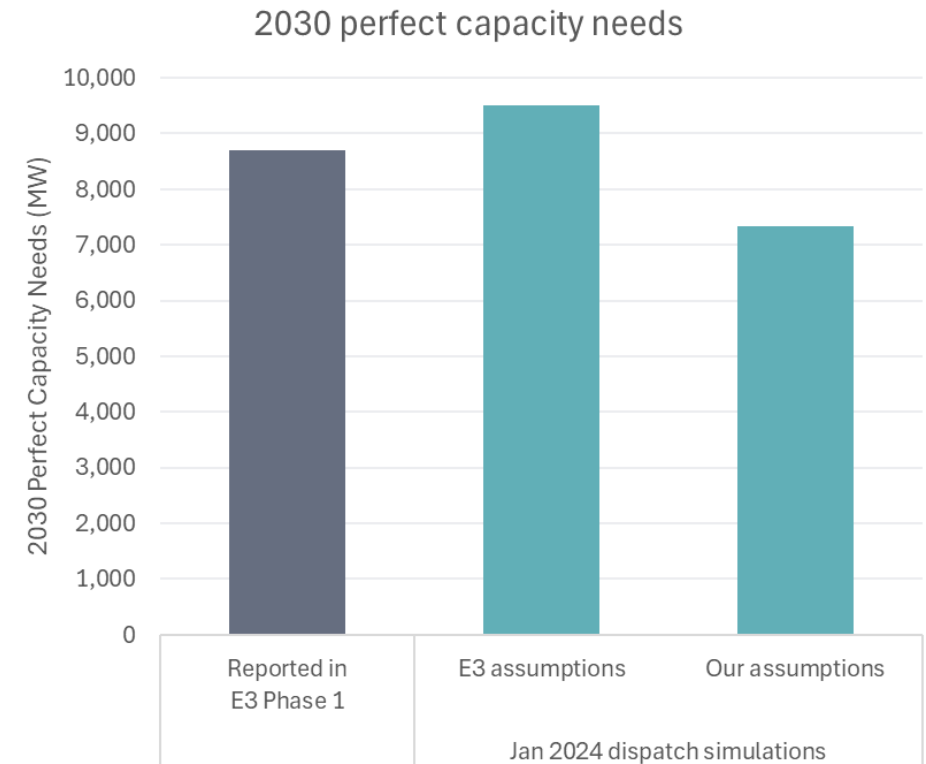
2024 benchmarking

- Additional imports in our assumptions are adequate to clear unserved energy in Jan 2024 benchmarking exercise
- Average net imports between 1/11 and 1/17 are similar across historical actuals and simulations:
 - Historical actuals: 3,508 MW
 - Dispatch simulation with our assumptions: 3,811 MW
 - Dispatch simulation with E3 constraints: 3,090 MW
- Reminder: simulations reflect system capability, not fully economic dispatch



Validating our approach to estimating 2030 winter risk

- To validate our approach, we compared our findings to the Phase 1 reported capacity need in 2030 in two ways:
 - **E3 assumptions:** uses E3's import assumptions (3,750 MW) and coal-to-gas accounting (coal units are retired)
 - **Our assumptions:** uses our import assumptions and our coal-to-gas accounting (coal units are converted to gas, except Centralia 2)
- Both simulations assumed loads approximately reflect E3's forecasted load growth rates
- Our dispatch analysis generally corroborates E3's findings when using their load growth rates and gives us confidence that January 2024 conditions serve as a reasonable proxy for estimating winter RA needs
- Differences in import assumptions and coal-to-gas accounting reduce the magnitude of the identified need, but it remains substantial under E3's projected load growth



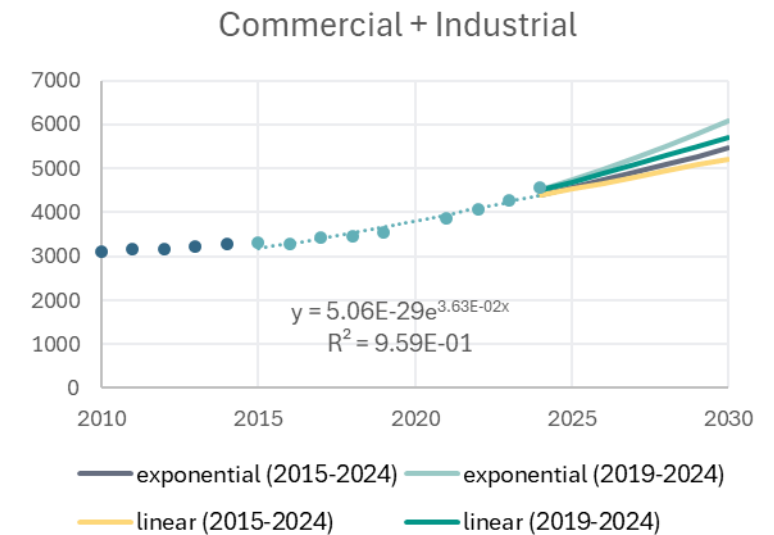
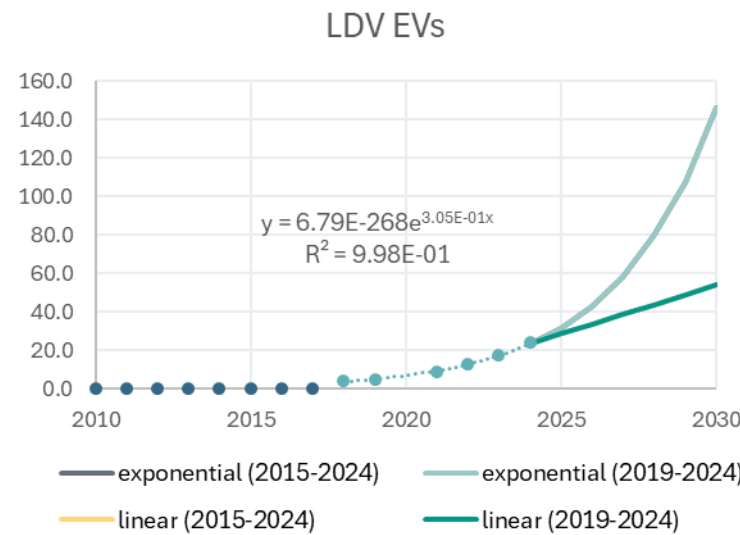
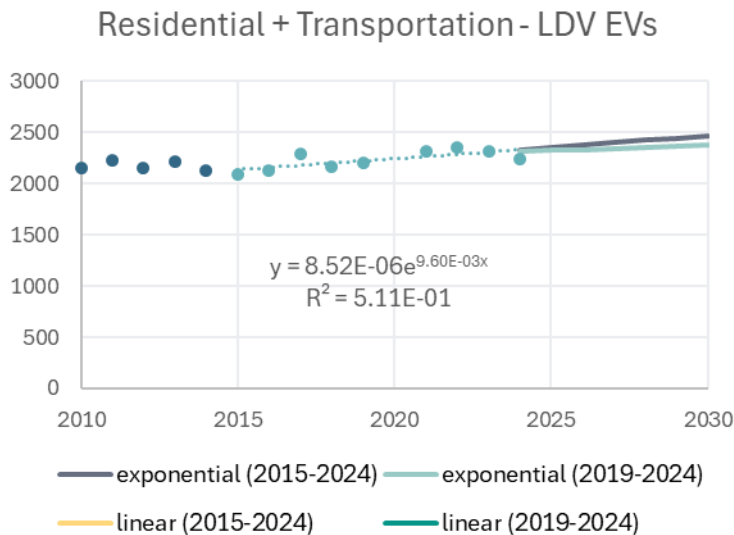
Electricity demand scenarios for 2030

- The E3 study relies on E3's internal load forecast, which comes from their bottom-up PATHWAYS model and internal data center demand forecasts
- E3's annual energy tracks closely with PNUCC's 2025 forecast (with aligned footprints), which is based on utility forecasts and projects 3.2% annual growth
- Data centers vs. electrification
 - E3 suggests that their forecast includes higher EV and electric space heating than the PNUCC forecast, which is potentially offset by a lower data center forecast
 - PNUCC has not collected information from their members to clearly distinguish between organic load growth and data center loads
- To understand the sensitivity of 2030 resource needs to future load growth and data center flexibility, Sylvan developed additional top-down load growth scenarios from available public data

Estimating organic load growth trends

- “Organic” load growth includes everything but new large loads (i.e., includes electrification)
- We estimated plausible ranges of sector-specific loads by fitting linear and exponential functions to recent historical sector-specific loads
- Data sources: EIA historical sales by sector and state, EIA historical LDV EV electricity consumption by state

Example: estimation of organic load growth trends in Oregon



Organic load growth scenarios

- **Baseline organic load growth:** upper bounds of residential and electric vehicle extrapolated trends, plus lower bound of commercial & industrial extrapolated trends (attributes any acceleration of C&I load growth to data centers)
 - Falls between NWPCC “Mixed bag” and “Persistent high growth” load scenarios (excluding data center and H₂ demands)
- **Low organic load growth:** lower bounds of residential and electric vehicle extrapolated trends, plus lower bound of commercial & industrial extrapolated trends (attributes any acceleration of C&I load growth to data centers)
 - Falls just below NWPCC “Mixed bag” load scenario (excluding data center and H₂ demands)
- Note: comparisons are high level and indicative, as footprints vary between forecasts and NWPCC loads assume fixed energy efficiency

Scenario	Average annual organic growth rate through 2030
NWPCC ² “Persistent high growth”	~1.9%
E3 Forecast ¹	~1.8%
Baseline Organic Growth	1.4%
NWPCC ² “Mixed bag”	~1.0%
Low Organic Growth	0.9%
NWPCC ² “Persistent low growth”	~-0.1%

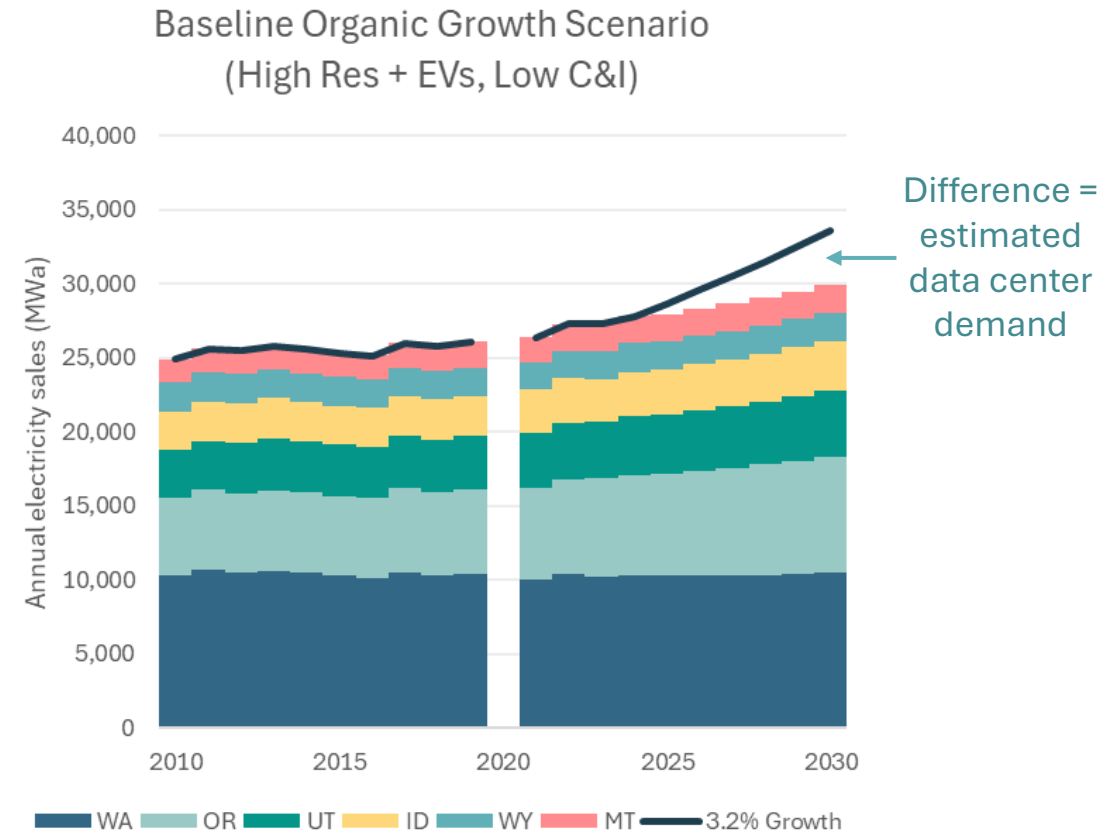
¹E3 organic growth rate between 2025 and 2030 estimated by subtracting data center demand from total forecasted Greater NW demand reported on slide 24 of Phase 1 Executive Summary

²NWPCC growth rates between 2025 and 2030 estimated by subtracting data center and H₂ demand on slide 33 from total forecasted demand scenarios on slide 46 of the Ninth Plan Demand Forecast Part 2 (https://www.nwcouncil.org/fs/19380/2025_0429_2.pdf)

Data center demand scenarios

- **Baseline data center demand:** estimated as the difference between the organic load growth forecast and 3.2% total load growth reported by PNUCC
 - Higher than E3 forecast, between Mid and High forecasts from the NWPCC
- **Low data center demand:** E3 data center forecast

Scenario	PNW MWa (WA, OR, ID, MT)	“Greater NW” MWa (PNW + UT + WY)
Baseline Scenario	2,931	3,717
Low Scenario (E3 Data Center forecast)	1,100	1,700
NWPCC Low Tech Load	~1,400	NA
NWPCC Mid Tech Load	~2,200	NA
NWPCC High Tech Load	~4,600	NA



Alternative 2030 load scenarios

We combined various organic growth and data center load scenarios to explore alternative load growth futures (ranging from 1.5% to 3.2% average annual growth through 2030)

Scenario	Organic Load Growth	Data Center Demand	Total annual average growth rate through 2030
E3 Forecast	High/E3 (~1.8%)	Low/E3 (1,700 MWa)	~2.8%
Baseline Scenario	Baseline (1.4%)	Baseline (3,700 MWa)	3.2%
Low Tech Scenario	Baseline (1.4%)	Low/E3 (1,700 MWa)	2.2%
Low Electrification Scenario	Low (0.9%)	Baseline (3,700 MWa)	2.6%
Low Growth Scenario	Low (0.9%)	Low/E3 (1,700 MWa)	1.5%
<i>Historical growth in electricity sales (2019-2024, excluding 2020)</i>			1.3%

All alternative load scenarios envision accelerated load growth relative to the last 6 years



Detailed findings

- Resource needs under January 2024 weather/hydro conditions across the 2030 load scenarios
 - With no incremental resources
 - With resources in development as of December 2024 and Centralia 2 coal-to-gas conversion
 - With emergency large load curtailment
- Outage risk to customers with and without large load curtailments
- Contributions of clean energy resources in development and potential from additional proposed clean resources
- High level insights on load uncertainty and how quickly the region may face the most daunting challenges



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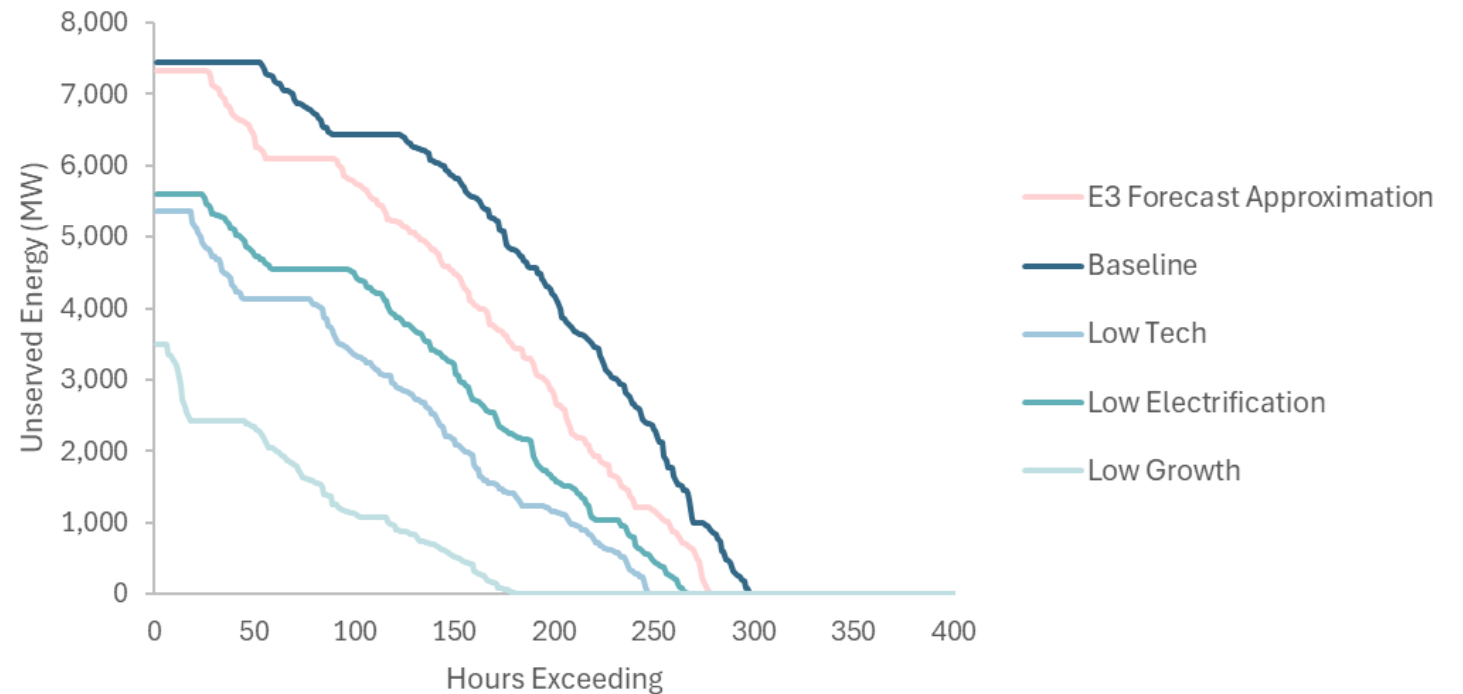
Our findings generally corroborate E3's high level problem statement

Across all load scenarios, unserved energy is observed in large quantities and in several hours if there are no resource additions through 2030, similar to E3's findings

Notes:

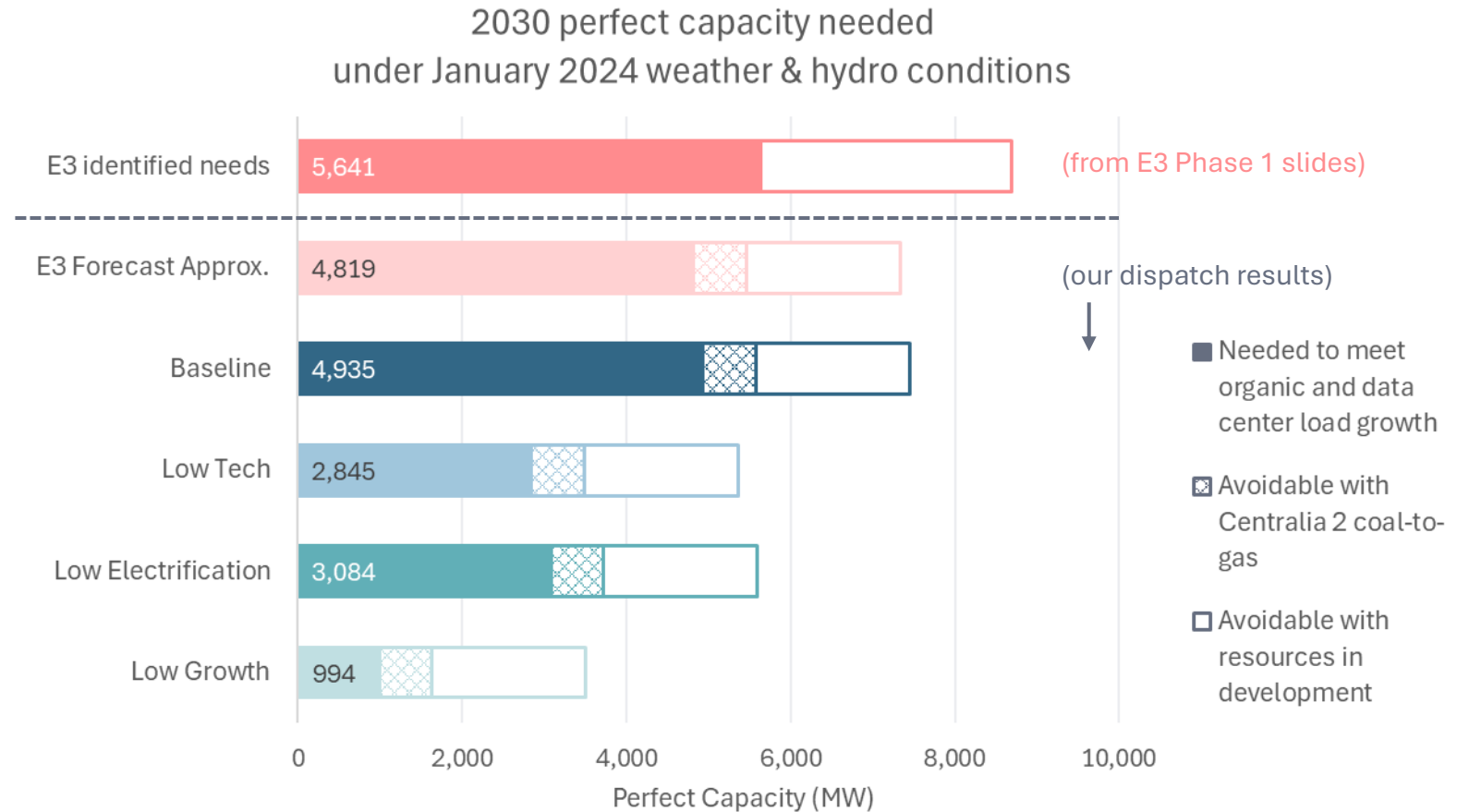
- These results are based on “operational” runs, in which both total and maximum unserved energy are penalized
- Perfect capacity needs (coming up on the next slide) are calculated by minimizing the maximum unserved energy, which can be lower than the maximum values shown on this slide

Simulated unserved energy (sorted from high to low) with no resource additions, before Centralia 2 coal-to-gas conversion



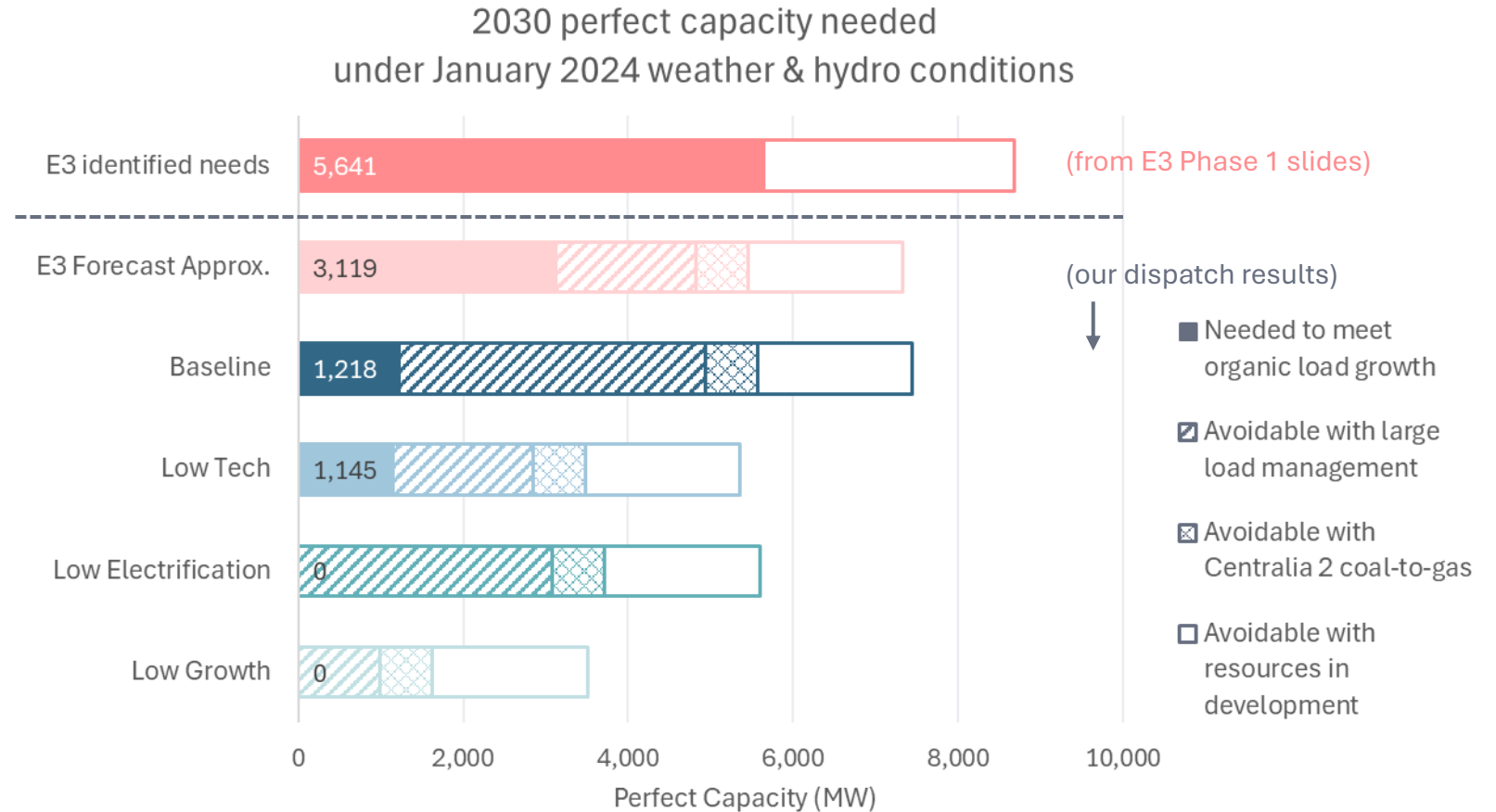
How sensitive are 2030 resource adequacy needs to future load growth?

- No analysis can predict the future and resource needs in 2030 remain highly uncertain, due both to new large loads and electrification trends
- After accounting for resources already under construction or with regulatory approvals in place as of December 2024 according to EIA 860 (“in development”) and coal-to-gas conversion of Centralia 2, estimated remaining 2030 needs range from 1 GW to 5 GW of “perfect capacity” across load scenarios

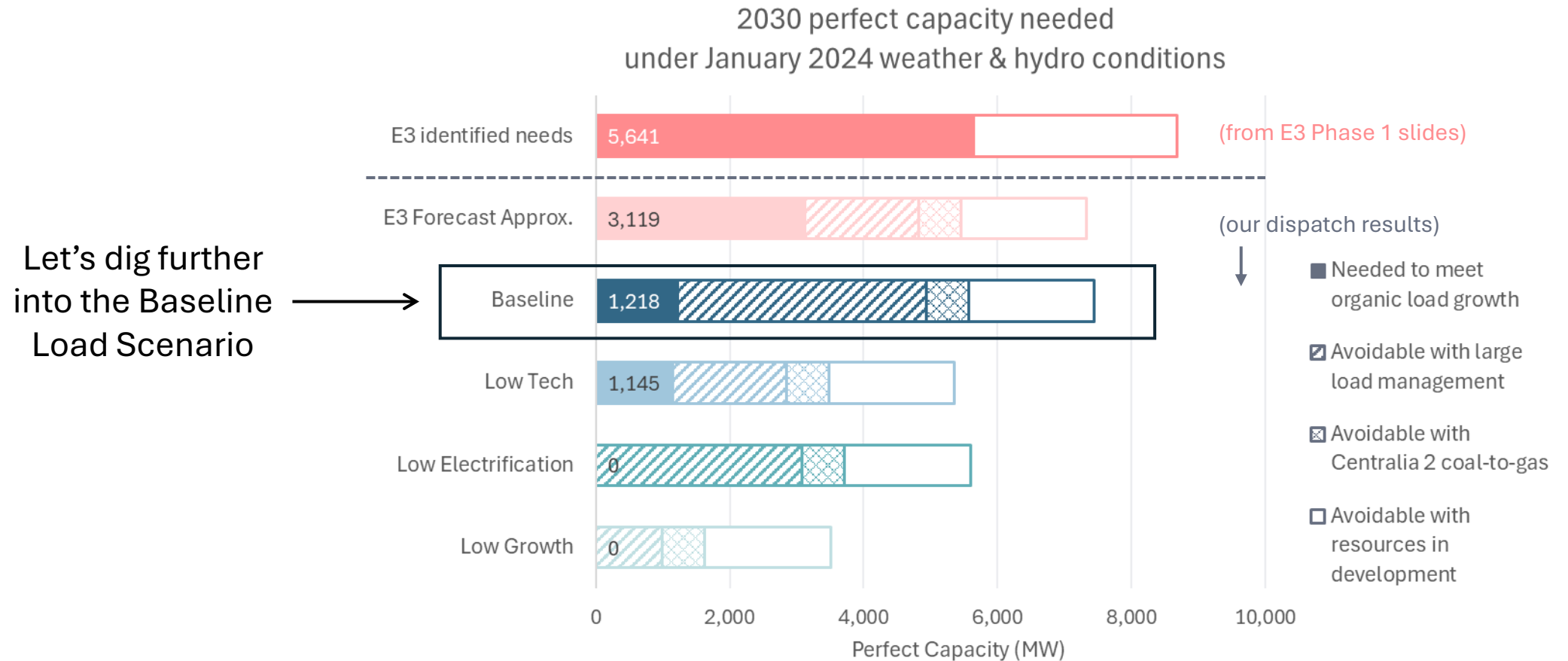


"Connect and manage" for large loads and resource adequacy

- Large loads, which remain highly uncertain in terms of both whether they will materialize and how long they will persist on the grid, are a key driver of near-term needs
- If large loads are interconnected before adequate supply is secured, emergency large load curtailment during extreme weather could mitigate risks to other customers, similar to new requirements in Texas
- If large loads can be managed during extreme weather events, estimated remaining 2030 needs range from 0 GW to 3 GW, depending on organic load growth (including electrification)



"Connect and manage" for large loads and resource adequacy in the Baseline Scenario



Supply shortages from the customer's perspective

If no additional resources are secured beyond those already in development, what does the shortage under the Baseline Scenario look like from the customer perspective during this event?

Average customer outage duration in 2030 during January 2024 weather/hydro event under Baseline Load Scenario

Strategy	Existing customers	New large loads
Curtail equally across large loads and other customers	19 hrs	19 hrs
Prioritize large load curtailment before other customers	0.1 hrs	225 hrs (about 10 days)

Near-term opportunity:

- Consider policies that require large load flexibility or emergency curtailment prior to curtailing other customers to mitigate the most catastrophic health and safety consequences of supply shortages
 - Could be paired with bring-your-own generation strategies
 - Could enable more rapid interconnection

*Resources in development were either under construction or had final regulatory approvals in place as of December 2024



Detailed findings

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 - With no incremental resources
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- Outage risk to customers under across the load scenarios with and without large load curtailments
- Contributions of clean energy resources in development and potential from additional proposed clean resources
- High level insights on load uncertainty and how quickly the region may face the most daunting challenges

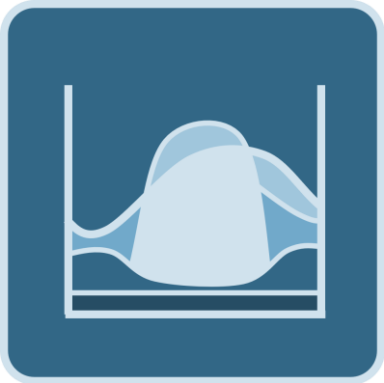
Addressing supply shortages with new clean resources

- Next, we allowed the model to select additional resources from projects that were proposed but did not have regulatory approvals (as of December 2024) to meet demand across the January 2024 weather/hydro conditions under the Baseline Load Scenario
 - A. To meet organic load growth; and
 - B. To meet all load growth, including data center demand
- Findings are broadly indicative
 - Resource costs were high level and imprecise (i.e., these are not optimal selections)
 - Assumed proposed projects have the same hourly availability as existing projects by technology and zone (i.e., understates diversity benefits)

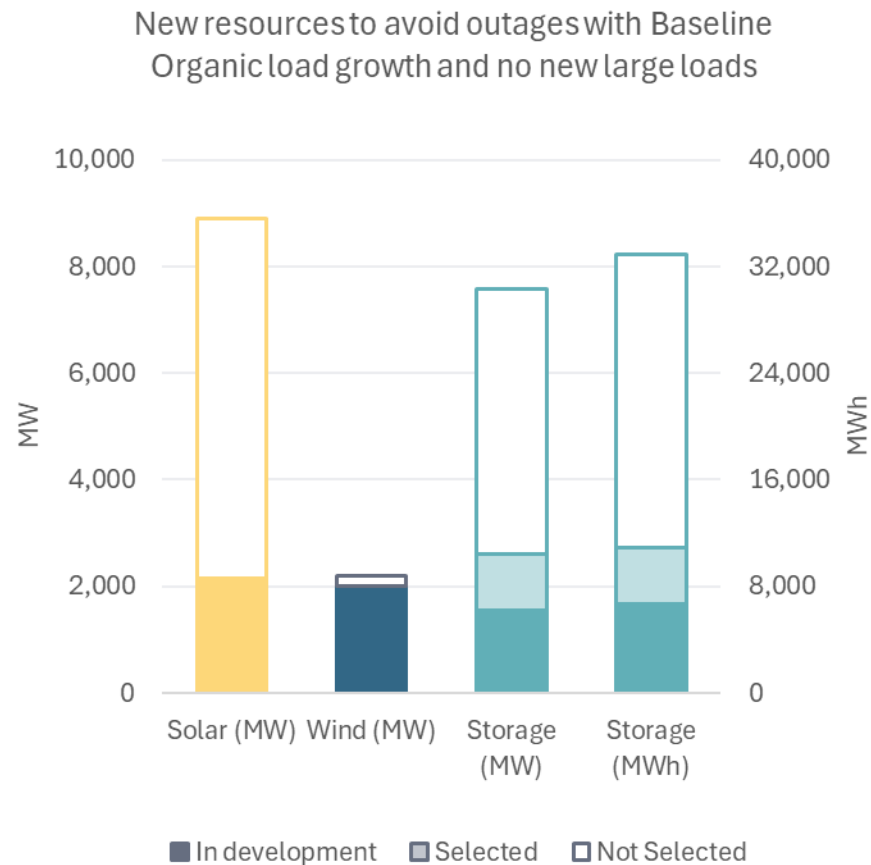
**Blended
production
cost/capacity
expansion mode**



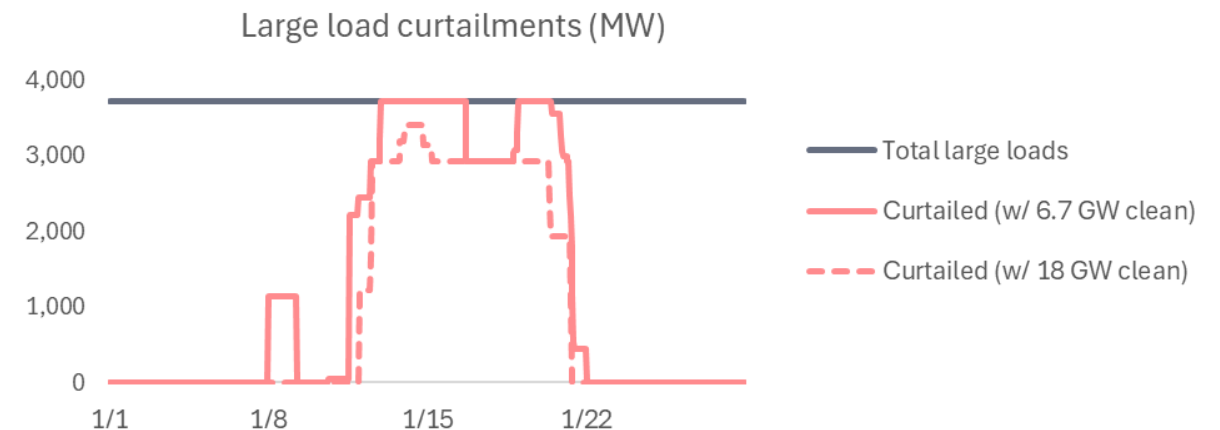
Incorporates investment variables directly into production cost problem to probe resource needs and identify potential solutions



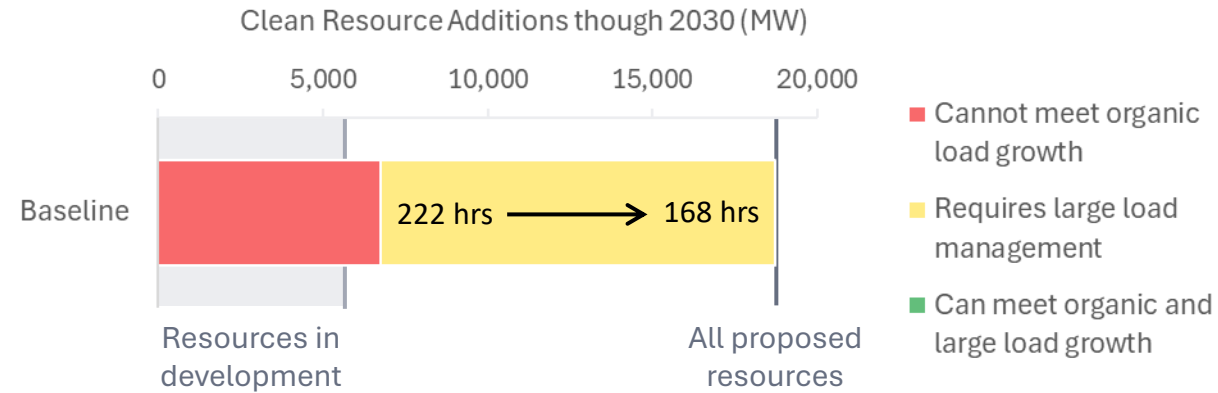
Clean resource additions and large load management in the Baseline scenario



- Clean resources in development (5.7 GW) plus 1 GW of additional short duration storage were adequate to meet Baseline Organic load growth during this event
- With these additional selected resources: large loads experienced 222 hrs (9.25 days) of outages during the event
- When all proposed clean resources were included (19 GW total): large loads still experienced 168 hrs (7 days) of outages during the event

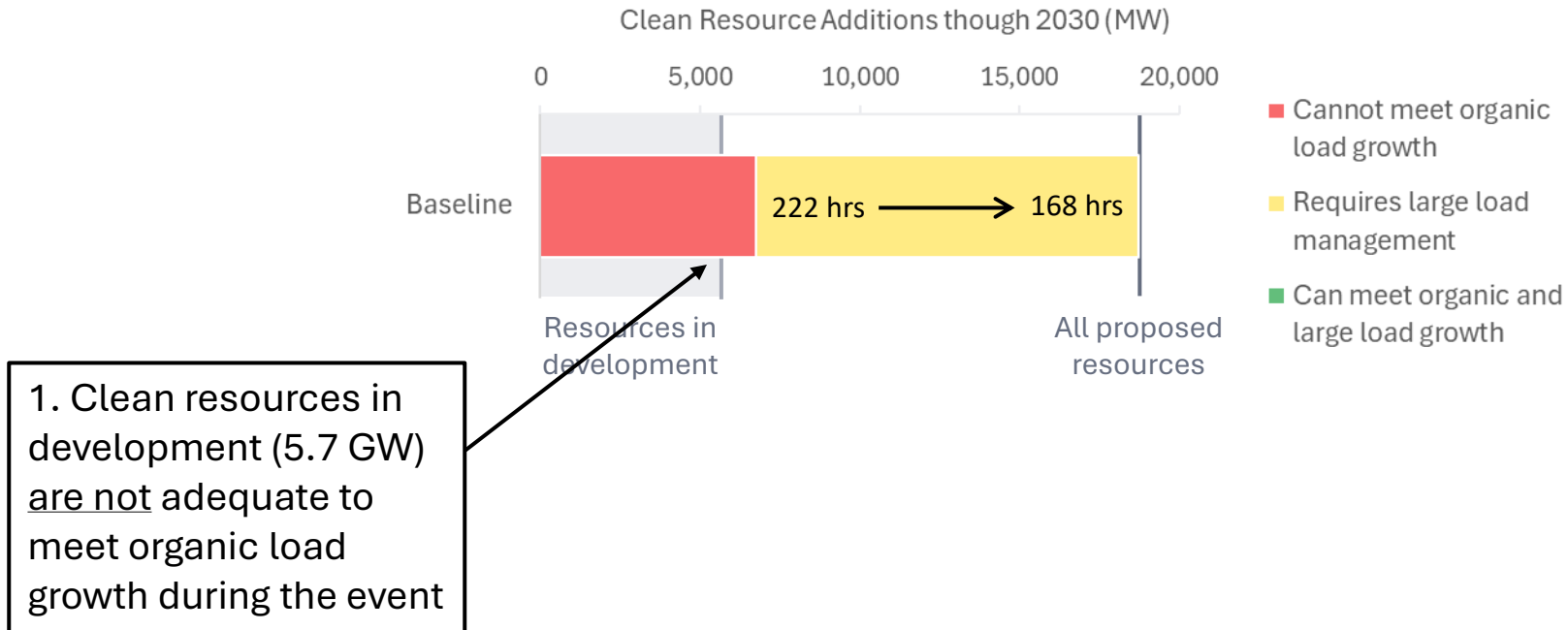


Clean resource additions and large load management across the scenarios

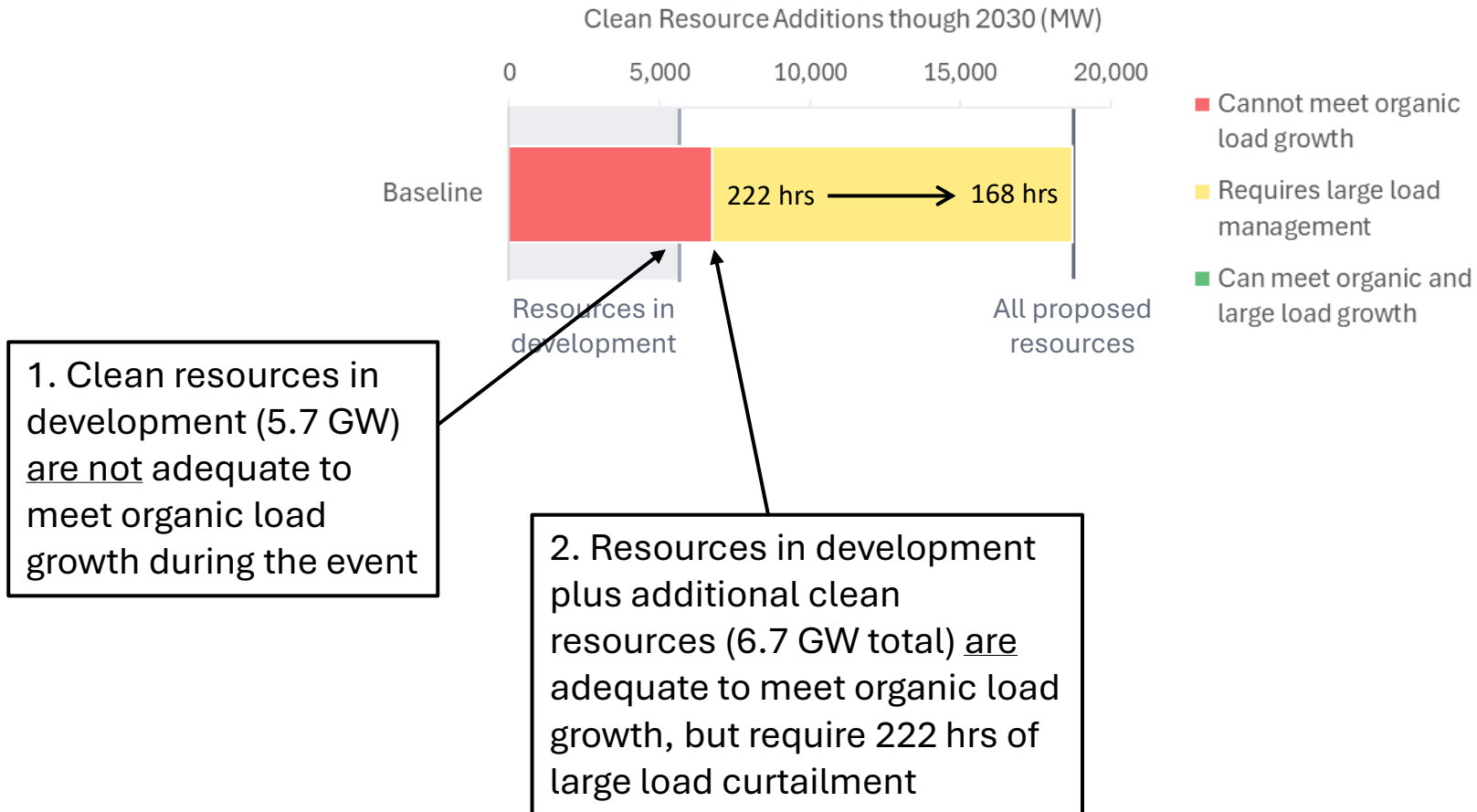


To compare across scenarios, we'll introduce a short-hand for the contributions of new clean resources toward meeting load growth and avoiding large load curtailments

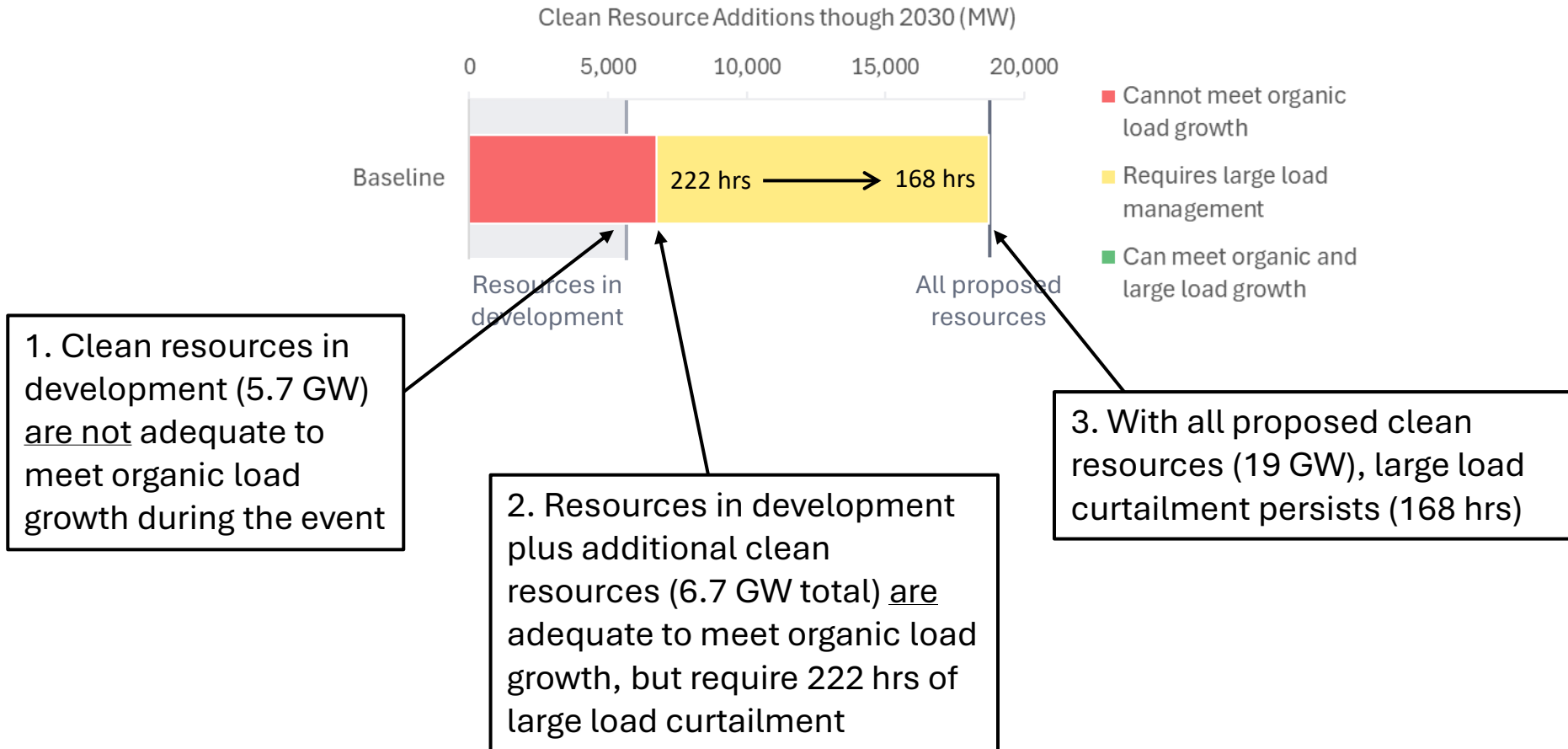
Clean resource additions and large load management across the scenarios



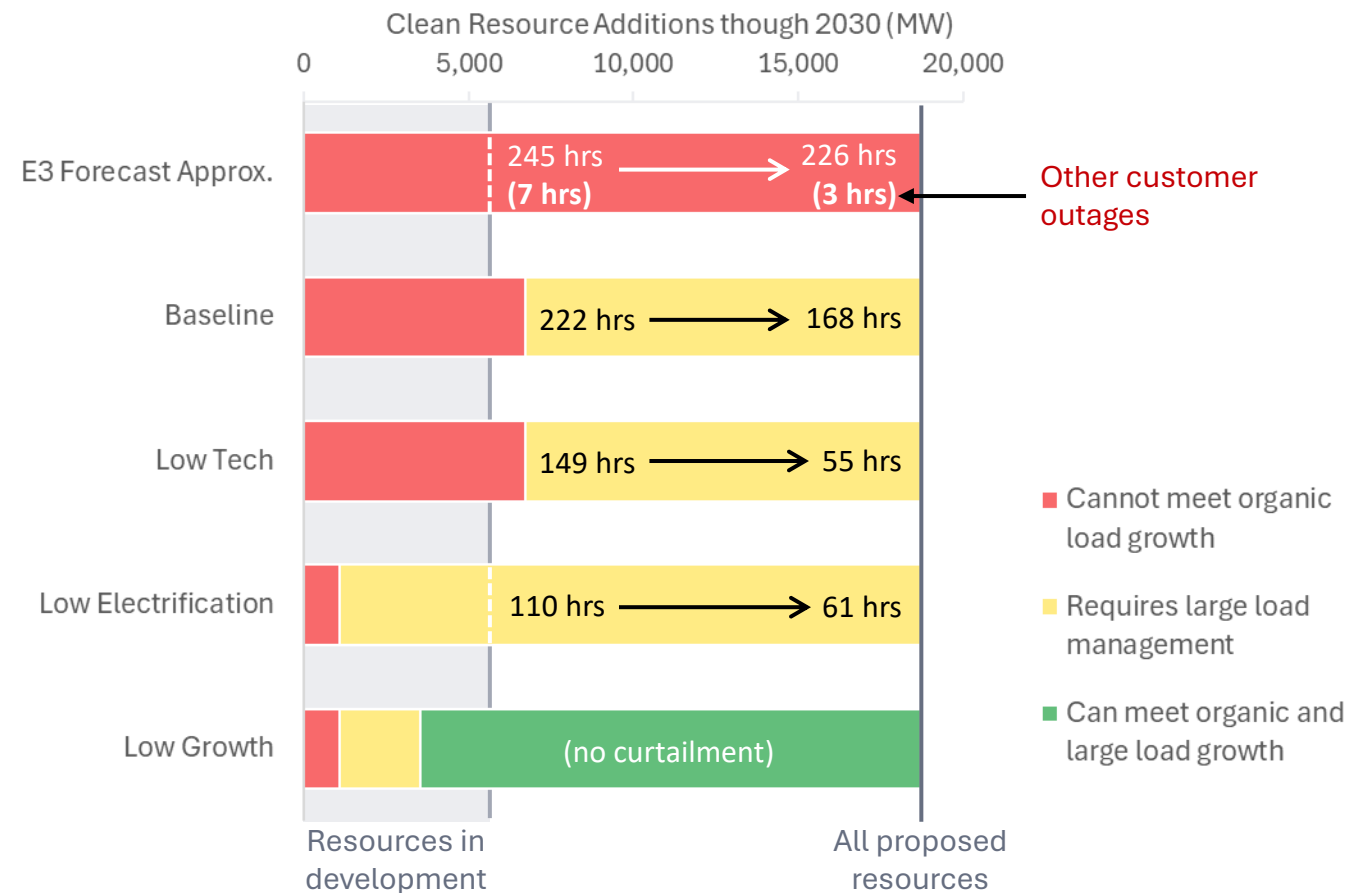
Clean resource additions and large load management across the scenarios



Clean resource additions and large load management across the scenarios



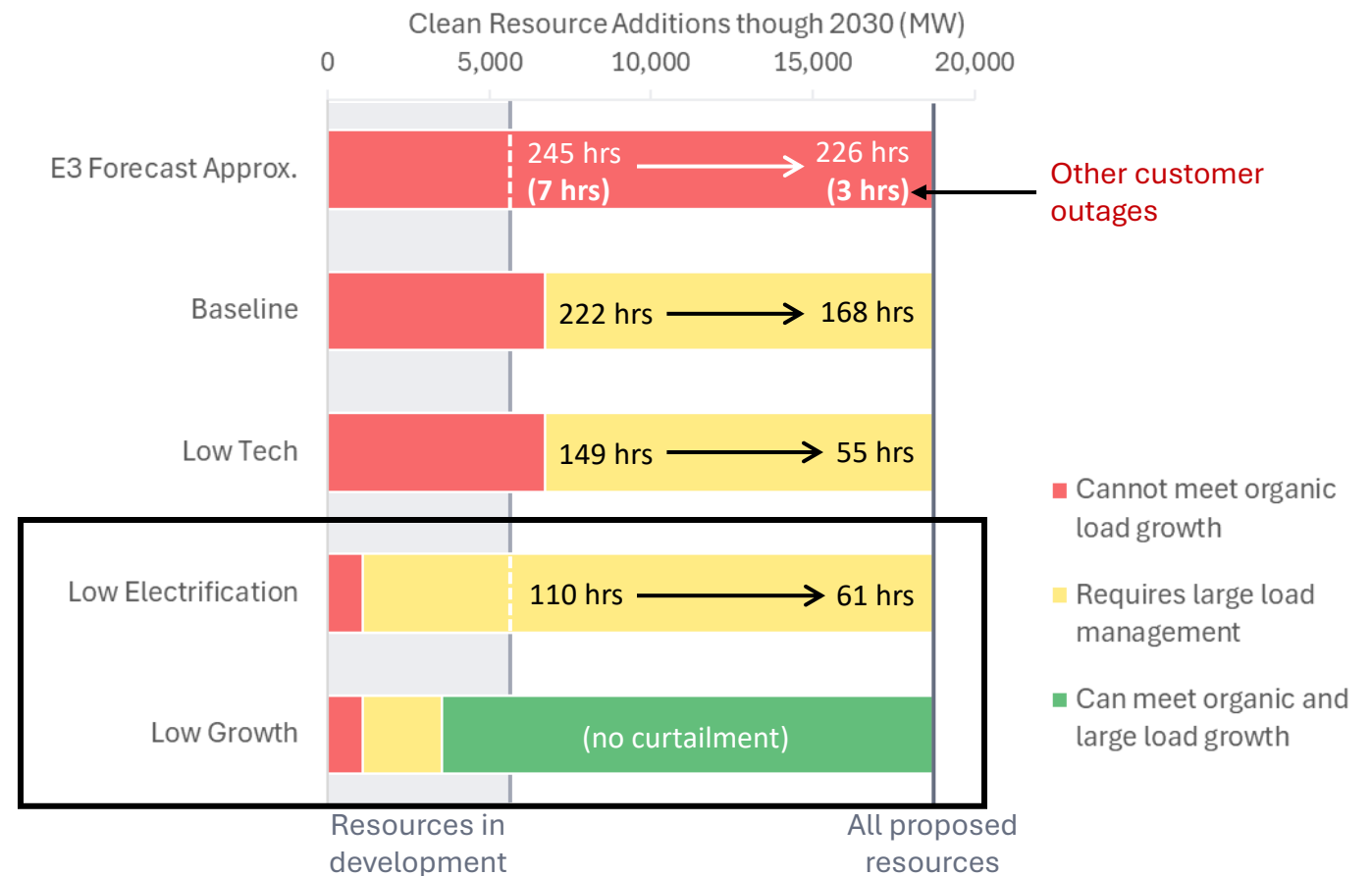
Clean resource additions and large load management across the scenarios



Clean resource additions and large load management across the scenarios

In scenarios without accelerated electrification (Low Electrification and Low Growth):

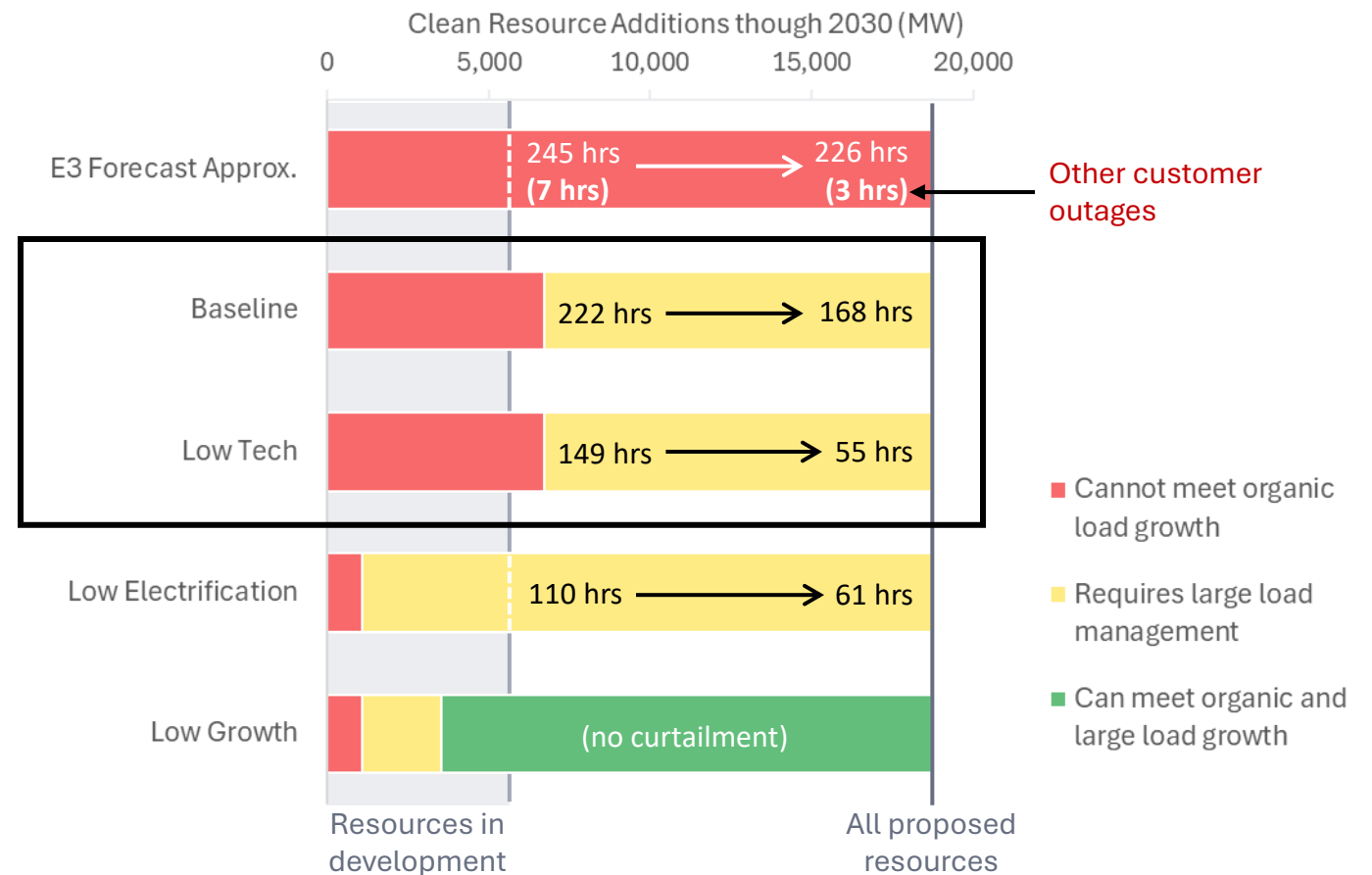
- Clean resources in development are adequate to meet organic load growth during this event
- Large load curtailment will depend on how many large loads materialize and whether they bring additional resources (simulations range from 0 hrs to 110 hrs)



Clean resource additions and large load management across the scenarios

In scenarios that project 1.4% annual organic load growth (Baseline and Low Tech):

- Clean resources in development plus a relatively small amount of incremental resources are adequate to meet organic load growth during this event
- Large load curtailment will depend on how many large loads materialize and whether they bring additional resources (simulations range from 55 hrs to 222 hrs)



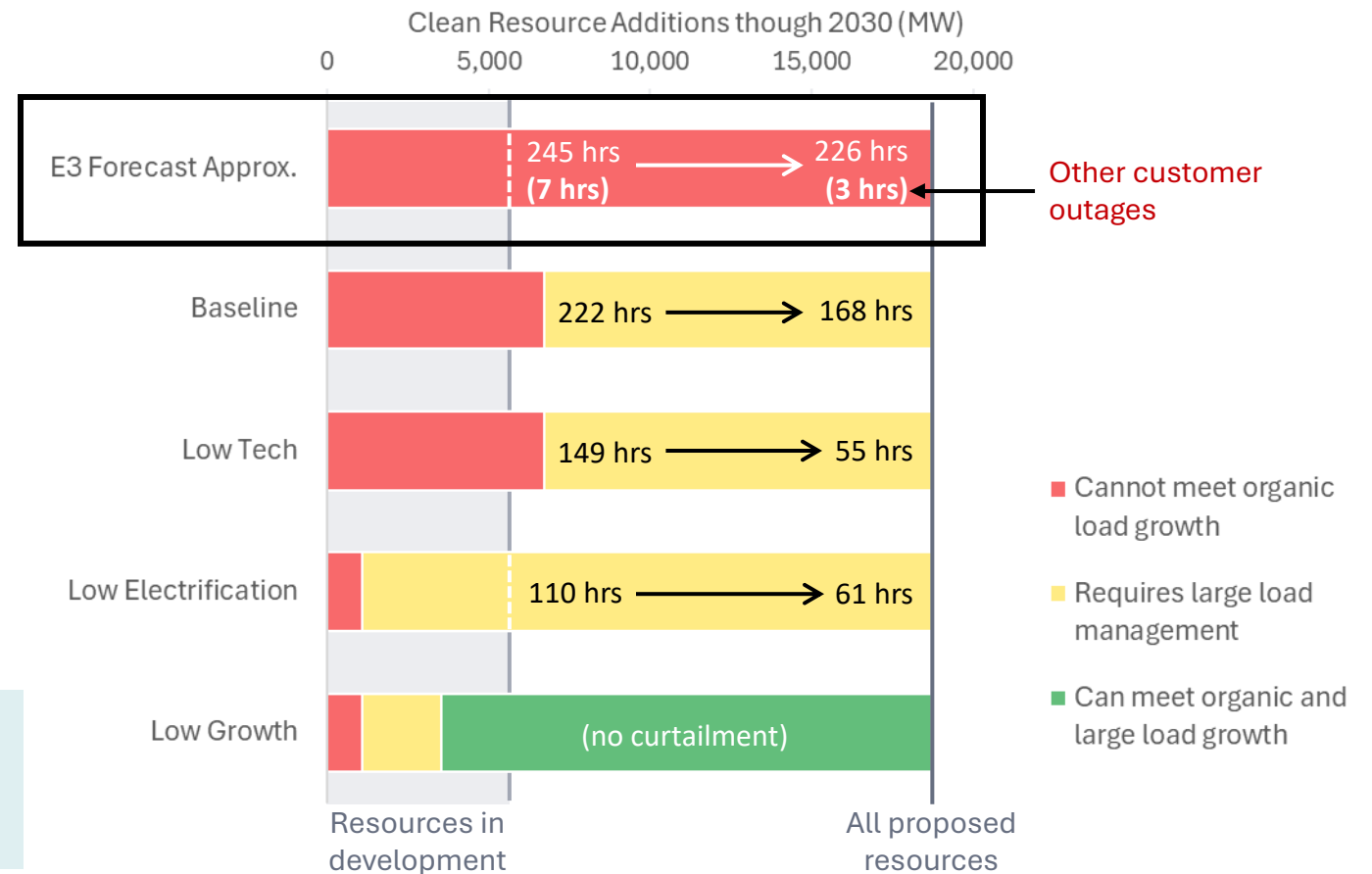
Clean resource additions and large load management across the scenarios

Under E3's load growth scenario, which includes more rapid electrification and relatively low data center demand, the region is in a real bind!

- Resource needs to meet organic growth exceed the quantity of proposed clean projects (19 GW)
- Large load curtailments exceed 100 hrs and other customers may experience rolling brown outs even with large load curtailments unless additional resources can come online
- New gas has been discussed as a solution to this challenge, but the gas system was constrained during the January 2024 event as well

Near-term opportunity:

- Study impacts of regional natural gas system constraints on regional electricity reliability

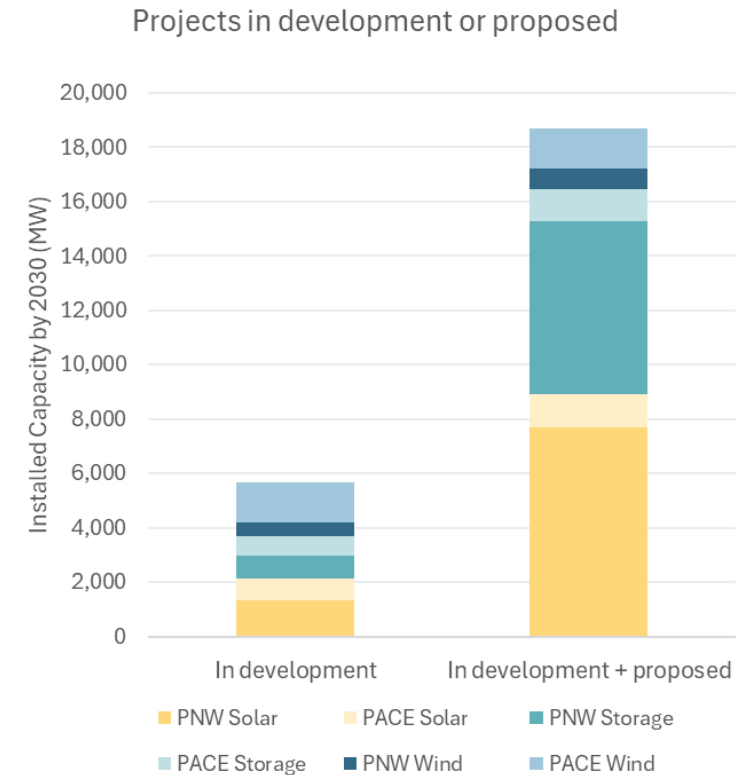


Winter portfolio ELCCs of new clean resources

Winter portfolio ELCCs estimated by calculating avoided perfect capacity during Jan 2024 weather/hydro event (not representative of summer contributions)

Baseline Load Scenario	Installed capacity (MW)	Avoided Perfect Capacity in Jan 2024 conditions (MW)	Approx. Winter Portfolio ELCC
All clean resources in development	5,666	1,875	33%
Additional clean resources pending approvals	13,009	2,473	19%
Total	18,675	4,348	23%

(Calculated before Centralia 2 coal-to-gas conversion and large load curtailments)

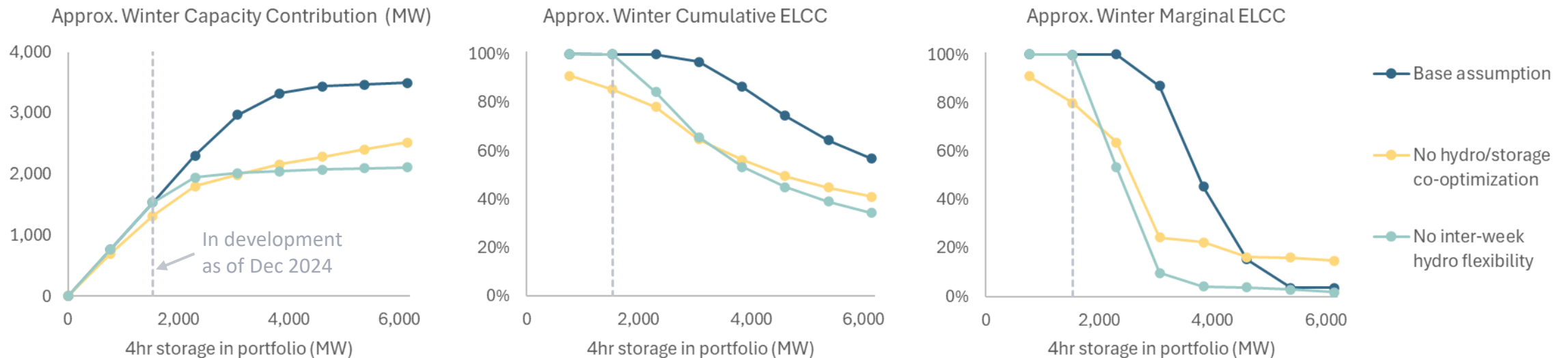


Near-term opportunity:

- Execute on all clean resource development plans and prioritize or accelerate new resource procurement activities

Winter ELCCs of 4hr storage

- Winter ELCCs for 4hr storage could depend strongly on how the hydro system is operated and modeled
- Two assumptions could lead to lower ELCCs and more rapid saturation of short duration storage than our analysis observes
 - Overly constraining the ability to hold water in preparation for a forecasted or potential future weather event
 - Load-following or net load-following hydro dispatch that is not co-optimized with battery storage dispatch



Notes:

- Approximate winter capacity contributions were calculated as the reduction in capacity need during January 2024 weather & hydro conditions under the Baseline load scenario, with wind and solar that is in development and Centralia 2 coal-to-gas conversion
- These values do not account for contributions to resource adequacy in the summer and may not be applicable to individual utilities with unique constraints
- After conducting the analysis, we found that 332 MW of batteries came online in 2024, which were not included in the baseline dispatch simulations because they were not in January 2024 EIA 930 data. This analysis suggests these additional batteries would have reduced capacity needs in all simulations by about 330 MW.

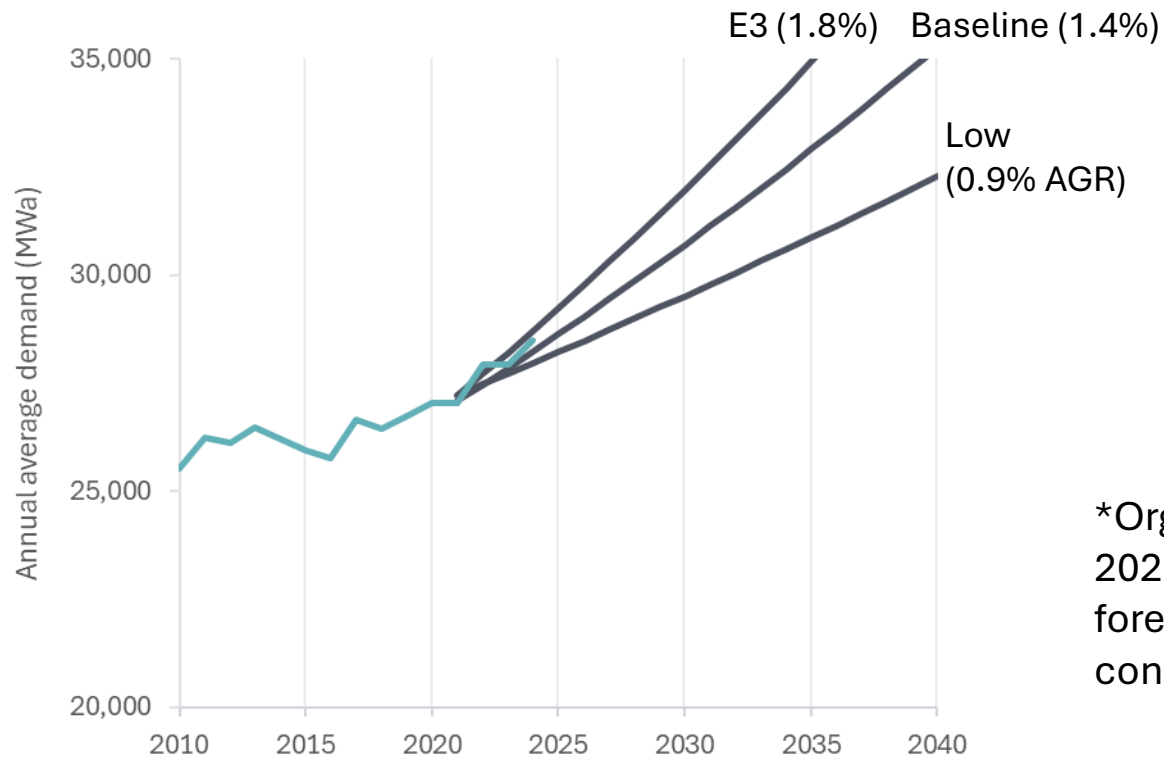


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The need for dispatchable or baseload solutions is not a question of if, but when

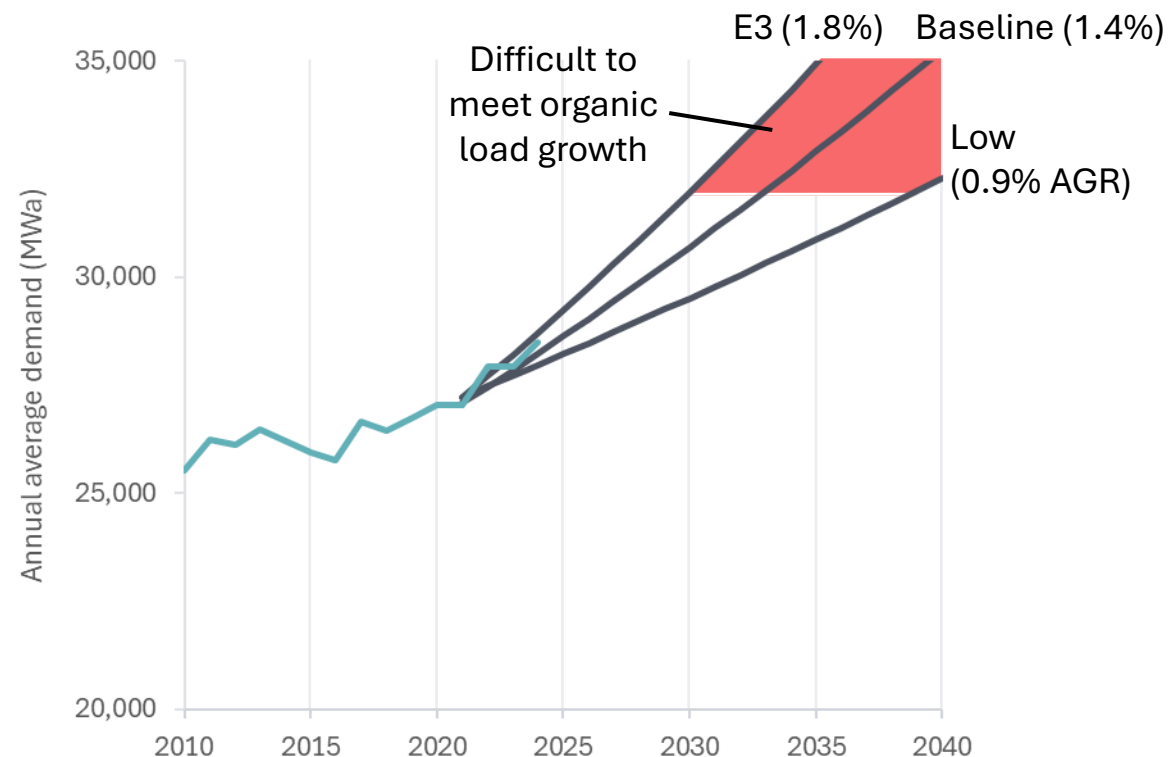
Extrapolated* organic load growth trajectories



*Organic load growth trajectories estimated by applying the 2025-2030 average annual organic load growth rate from each forecast to 2031-2040. This exercise is indicative and conceptual and may not align with actual load forecasts.

The need for dispatchable or baseload solutions is not a question of if, but when

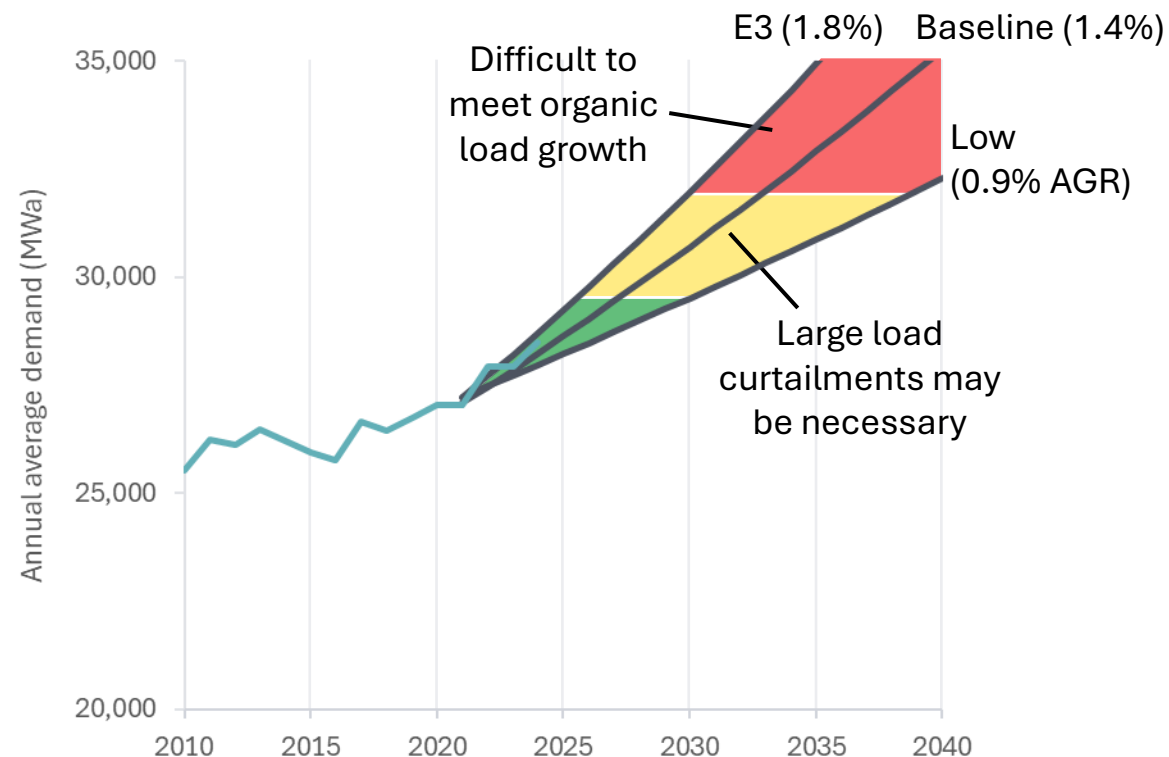
Extrapolated* organic load growth trajectories and resource adequacy challenges



- When the region faces the most daunting challenges encountered in our simulations will depend on future load growth (which will depend on economic conditions, electrification, and energy efficiency):
 - E3 Forecast: By 2030
 - Extrapolated Baseline Forecast: Roughly early 2030s
 - Extrapolated Low Growth Forecast: Roughly late 2030s
- Pushing these needs out in time creates opportunities for emerging clean technologies to be part of the solution

The need for dispatchable or baseload solutions is not a question of if, but when

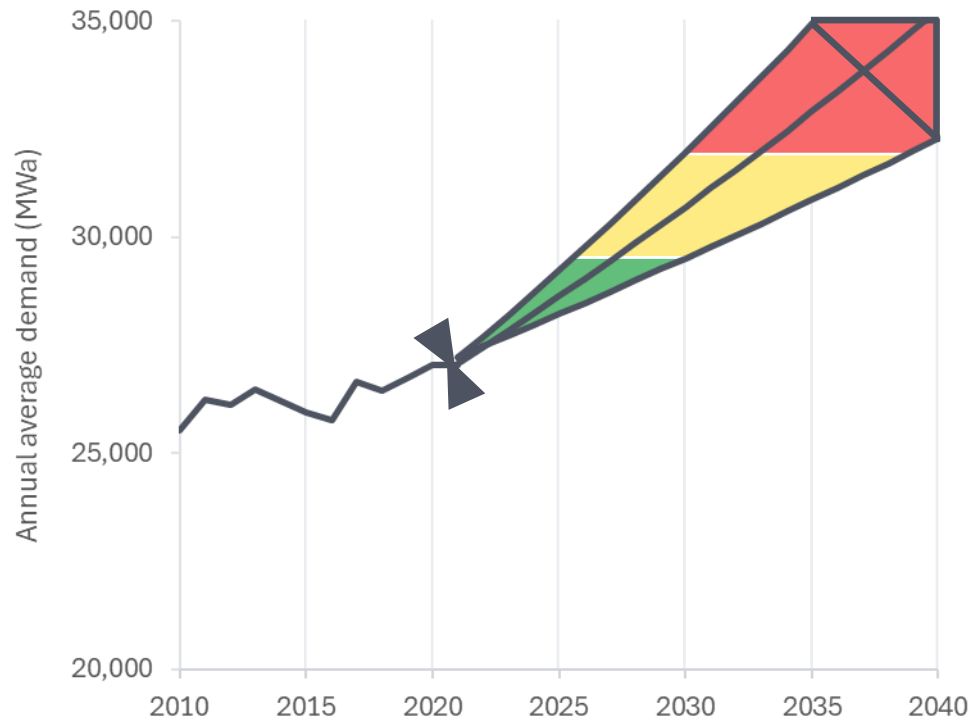
Extrapolated* organic load growth trajectories and resource adequacy challenges



- When the region faces the most daunting challenges encountered in our simulations will depend on future load growth (which will depend on economic conditions, electrification, and energy efficiency):
 - E3 Forecast: By 2030
 - Extrapolated Baseline Forecast: Roughly early 2030s
 - Extrapolated Low Growth Forecast: Roughly late 2030s
- Pushing these needs out in time creates opportunities for emerging clean technologies to be part of the solution
- Large load flexibility requirements provide a crucial backstop across the scenarios

"A kite only flies when it's tethered"

-Victor Robert Lee



We can't control the wind (or the economy), but we have some tethers on the demand side that could buy the region some time

Near-term opportunities:

- Develop emergency conservation programs to discourage EV charging & non-essential energy use, and encourage lower thermostat settings during critical multiday winter events
- Prioritize energy efficiency measures that reduce winter demand (e.g., building shell measures and replacing baseboard heating)



Cape Lookout State Park, Oregon Coast (source: www.oregonlive.com)

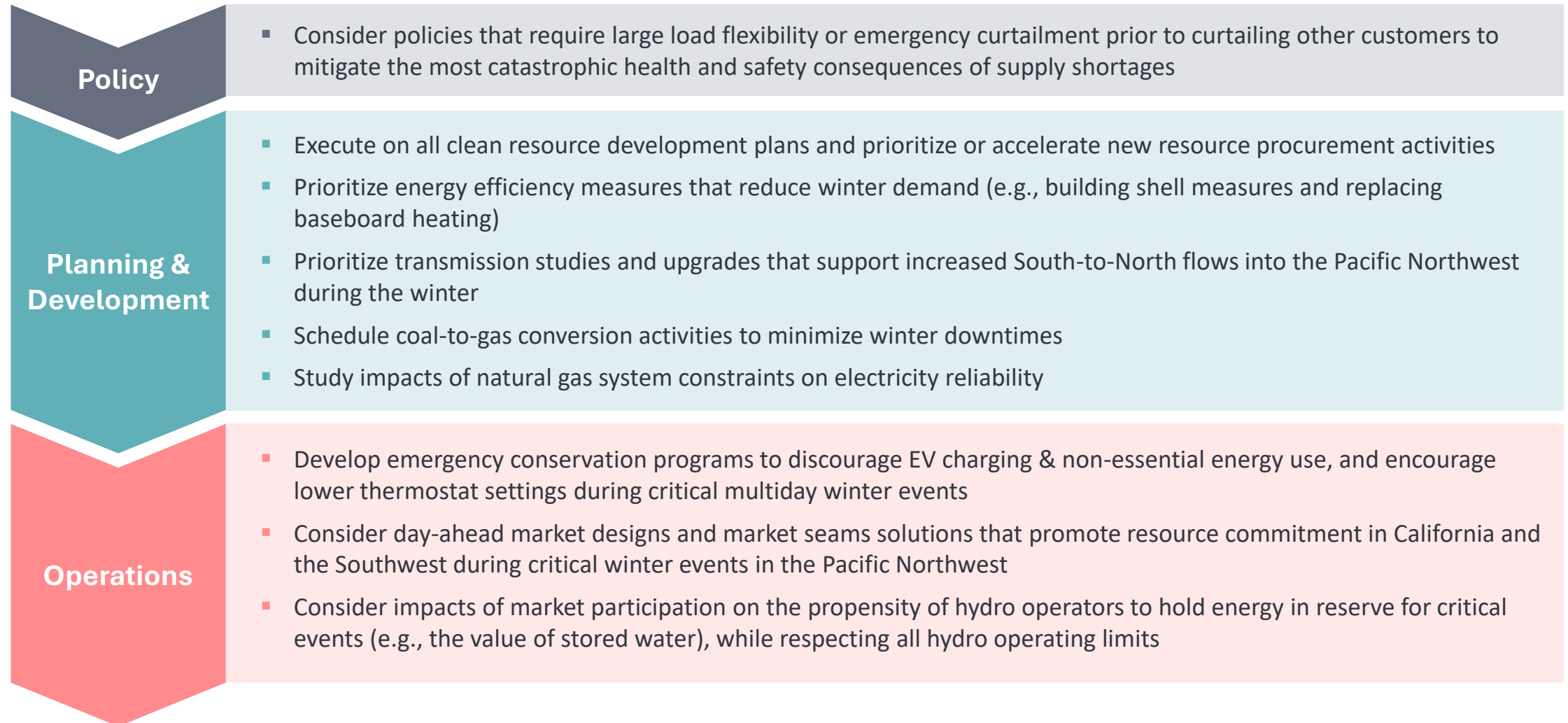
An opportunity to drive innovation

- If subject to flexibility requirements, data center customers will face the most daunting long-duration reliability challenges first and will have an incentive to solve them
- With a desire to move quickly and larger risk appetites than regulated utilities, data center customers could drive innovation in the next generation of clean technologies that serve longer duration needs, accelerating adoption, and driving down costs
- Flexibility requirements can also be leveraged to facilitate more rapid interconnection until new technologies become available

High level findings from independent evaluation

1. The scale and nature of the winter resource adequacy challenge in the Pacific Northwest depends strongly on future load growth, which remains highly uncertain due to both data center demand and electrification trends
2. Large load flexibility could mitigate most or all near-term winter resource adequacy needs under most load scenarios
3. Sustained development of clean resources is well-suited to meeting organic (i.e., non-data center) load growth in the region unless electrification accelerates faster than recent load growth trends suggest
4. Supporting reliable winter data center operations in the Pacific Northwest will likely require resources with more energy availability during challenging winter events
5. In the near term, the ability to curtail large loads first during emergency events can protect other customers from the most catastrophic health and safety consequences of supply shortages
6. In the long term, the need for dispatchable or baseload solutions is not a question of if, but when

Near-term opportunities identified to support regional RA





Cape Lookout State Park, Oregon Coast (source: www.oregonlive.com)

Thank you!

For more information, contact:
elaine@sylvan.energy

SYLVAN
ENERGY ANALYTICS

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Order No. 202-25-14

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

Filed January 28, 2026

Exhibit 1-159:
Email Correspondence with E3

From: [Brad Cebulko](#)
To: [Arne Olson](#); [Fred Heutte](#)
Cc: [Laura Burford](#); [Michael Lenoff](#); [Erik Olson](#); [Edward Burgess](#)
Subject: Re: E3 NW RA study and Centralia
Date: Friday, January 9, 2026 6:57:25 PM

External Sender

Thank you, Arne.

Brad Cebulko

m: 317.519.3165

From: Arne Olson <arne@ethree.com>
Sent: Friday, January 9, 2026 3:43 PM
To: Brad Cebulko <bcebulko@currentenergy.group>; Fred Heutte <fred@nwenergy.org>
Cc: Laura Burford <LBurford@currentenergy.group>; Michael Lenoff <mleoff@earthjustice.org>; Erik Olson <eolson@currentenergy.group>; Edward Burgess <eburgess@currentenergy.group>
Subject: Re: E3 NW RA study and Centralia

Yes everything that I didn't comment on is correct

Sent from my Verizon, Samsung Galaxy smartphone
Get [Outlook for Android](#)

From: Brad Cebulko <bcebulko@currentenergy.group>
Sent: Friday, January 9, 2026 3:35:46 PM
To: Arne Olson <arne@ethree.com>; Fred Heutte <fred@nwenergy.org>
Cc: Laura Burford <LBurford@currentenergy.group>; Michael Lenoff <mleoff@earthjustice.org>; Erik Olson <eolson@currentenergy.group>; Edward Burgess <eburgess@currentenergy.group>
Subject: Re: E3 NW RA study and Centralia

Arne,

I really appreciate the response as well as the data. Thank you. I have one final point of clarification. I understand your response as confirming the accuracy of our summary, subject to the qualifications and information you provided. Please let me know if that understanding is incorrect.

Have a great weekend.

Brad Cebulko

m: 317.519.3165

From: Arne Olson <arne@ethree.com>

Sent: Thursday, January 8, 2026 7:26 PM

To: Brad Cebulko <bcebulko@currentenergy.group>; Fred Heutte <fred@nwenergy.org>

Cc: Laura Burford <LBurford@currentenergy.group>; Michael Lenoff <mleoff@earthjustice.org>; Erik Olson <eolson@currentenergy.group>; Edward Burgess <eburgess@currentenergy.group>

Subject: RE: E3 NW RA study and Centralia

Hi Brad,

Thanks for this summary. I have placed some answers below in red. Also please see the attached spreadsheet with the data that was requested.

Please let me know if I can answer any other questions for you.

Best,

Arne

From: Brad Cebulko <bcebulko@currentenergy.group>

Sent: Friday, January 2, 2026 12:22 PM

To: Arne Olson <arne@ethree.com>; Fred Heutte <fred@nwenergy.org>

Cc: Laura Burford <LBurford@currentenergy.group>; Michael Lenoff <mleoff@earthjustice.org>; Erik Olson <eolson@currentenergy.group>; Edward Burgess <eburgess@currentenergy.group>

Subject: Re: E3 NW RA study and Centralia

Arne,

Thank you again for speaking with us on Wednesday, December 31. We appreciate you taking the time to discuss your September 2025 presentation on resource adequacy to the Washington Utilities and Transportation Commission and the Washington Department of Commerce. We also appreciate your efforts to locate and share information on Canadian entitlements, the list of in-development resources, and achieved LOLE values. Thank you for your assistance. My understanding is that your anticipated timing works, as the deadline for making use of the materials would be early the following week.

To confirm the accuracy of our notes from the Wednesday call, my colleagues and I have summarized our understanding below. Would you please let us know if the notes below are accurate and if any modifications to the below are appropriate? If possible, we'd be happy to receive this response in advance of the other materials, but also understand your schedule may get in the way.

- The “Greater Northwest” region evaluated in the presentation includes all of the traditional NW Power Act Northwest (Washington, Oregon, Idaho and western Montana) plus all of NorthWestern Energy and PAC-East.
- Slide 10 of the presentation is based on the following inputs:

- Each year shown in the table is a water year beginning October 1. So, for instance, “2026” refers to the year from October 1, 2025 through September 30, 2026.
- The “peak load” used to calculate “Total Resource Need” was developed by E3’s own load forecast. To forecast data center demand, including whether data centers will reduce load at times of peak demand, E3 used figures from utilities’ integrated resource plans.
- The “planning reserve margin” used to calculate “Total Resource Need” was calculated to achieve a loss of load expectation of one event-day per decade (i.e., the 1-in-10 LOLE standard). E3 used its own loss-of-load expectation model to calculate the planning reserve margin.
- The “Existing Portfolio w/ Retirements” assigns value to individual resources based on E3’s own set of capacity accreditation values that were developed using E3’s calculations of resource types’ marginal effective load carrying capacity.
- E3’s August whitepaper explains E3’s accreditation approach.
- Centralia is modeled as retired for all study years. In other words, the study attributes 0 MW to Centralia and does not model the proposed coal-to-gas conversion of Centralia scheduled to be completed in 2028.
- The “firm imports” of 3,750 MW each year is calculated by looking to the 2,500 MW figure that the Northwest Power and Conservation Council uses for a smaller region than the region E3 studies for the presentation. E3 added to the 2,500 MW figure to account for the larger region. E3 was intentionally conservative in setting the 3,750 MW figure. The 3,750 MW figure is not intended to represent the maximum import capability of the region E3 studied.
- The quantum of “in-development” Firm, Wind, Solar, and Battery resources are sourced from WECC’s Anchor Data Set, after accreditation using E3’s calculations of resource types’ effective load carrying capacity. The quantum of “in-development” resources does not include planned resources in utilities’ integrated resource plans shown on slide 21. To confirm whether the “in-development” resources are in service, one can investigate the status of resources shown in the WECC Anchor Data Set, including by reference to press releases.
- With regard to the “Reliability Positions” shown on slide 10:
 - The “Surplus” or “Shortfall” does not include the “in-development” resources. So, for instance, including the “in-development” resources for 2026 improves the calculated Reliability Position from a shortfall of 1,321 MW to a shortfall of 380 MW.

- Any electric system will have some level of resource adequacy risk. The “Surplus” or “Shortfall” shows whether the region has more or fewer resources needed to achieve, in E3’s model, the target risk threshold of a loss of load expectation of one event-day in ten years. A shortfall indicates that the region has higher risk of loss of load than the one event-day in ten years standard. A surplus indicates that the region has lower risk of loss of load than the one event-day in ten years standard.
- The “Surplus” or “Shortfall” does not show whether the region has insufficient resources to meet forecasted peak load.

THE ‘SURPLUS’ OR ‘SHORTFALL’ SHOWS WHETHER THE REGION HAS SUFFICIENT RESOURCES TO MEET FORECASTED PEAK LOAD PLUS THE PLANNING RESERVE MARGIN NEEDED TO ACHIEVE THE 0.1 LOLE RESOURCE ADEQUACY STANDARD.

- For 2026, the risk in the studied region is slightly elevated above the target risk.
- The planned resources in utilities’ integrated resource plans shown on slide 21 are enough to meet the shortfalls shown on slide 10 for all years studied.
- Data center flexibility, such as reductions in demand during times of peak demand, can help address the calculated shortfalls.
- Slide 12 indicates that there is essentially no LOLE risk in the year 2025 unless there is a “bad” water year. Will you please clarify whether Slide 12 represents water year 2025 (October 1, 2024 – September 30, 2025)?

CORRECT

- The study finds that the greatest risk to the system is during low hydro years and the evidence, as of December 31, 2025, does not indicate we are in a low hydro year.
- With regard to the presentation’s fit to current conditions:
 - The presentation is based on a probabilistic model incorporating 30 years of past weather and hydrological conditions. The model does not reflect actual weather and hydrological conditions presently existing for this winter, such as La Niña. Similarly, the model does not reflect weather and hydrological forecasts for this winter.

THE MODEL CONSIDERS 30 HYDRO YEARS (1989-2018) AND 44 TEMPERATURE YEARS (1979-2022). THE HYDRO YEARS AND LOAD YEARS ARE PAIRED RANDOMLY USING MONTE CARLO DRAWS.

- To gauge the extent to which the model represents current conditions, the key factors are: (1) weather forecasts; (2) hydrological conditions; (3) load conditions; and (4) resource additions and retirements. Thus, for instance, if prevailing and forecasted hydrological conditions are stronger than the average conditions observed in the 30-year dataset used for the model, and holding constant other factors, the “Reliability Position” shown on

slide 10 likely underestimates the actual reliability position in the region. The same goes for a winter weather forecast that is milder than the average weather observed over the thirty-year dataset used for the model.

- Flexibility of data center demand, such as reductions in demand during times of peak load, is one way to help address the shortfalls shown on slide 10.

CORRECT, HOWEVER, DATA CENTER "LOAD FLEXIBILITY" IS OFTEN ACHIEVED WITH ONSITE GENERATION. THIS WOULD MOVE THE PROBLEM FROM ONE SIDE OF THE METER TO THE OTHER, BUT WOULDN'T ELIMINATE THE NEED TO BUILD THE RESOURCES SUBJECT TO THE SUPPLY CHAIN AND OTHER CHALLENGES. TRUE FLEXIBILITY OF COMPUTE LOAD WOULD BE A SIGNIFICANT NEW RESOURCE BUT WE HAVE NOT YET SEEN EVIDENCE OF THIS AT SCALE.

- The Department of Energy's December 16, 2025 Order No. 202-25-11 to Transalta is counterproductive and risks harming reliability in the studied region to the extent the order delays the conversion of Centralia Unit 2 to gas. The order need not be renewed in March 2026 to address the Reliability Positions shown on slide 10 of the presentation.

Please let me know if you have any clarifying questions. Thank you again, and Happy New Year.

Brad Cebulko

m: 317.519.3165

From: Arne Olson <arne@ethree.com>

Sent: Wednesday, December 31, 2025 6:32 PM

To: Brad Cebulko <bcebulo@currentenergy.group>; Fred Heutte <fred@nwenergy.org>

Cc: Laura Burford <LBurford@currentenergy.group>; Michael Lenoff <mlenoff@earthjustice.org>; Erik Olson <eolson@currentenergy.group>

Subject: RE: E3 NW RA study and Centralia

Hi all, thanks for the good questions this morning. Just following up to let you know that, given the holidays and some upcoming deadlines, we will aim to get you the information you requested by late next week. The information we are digging up is:

- Details on how we are modeling the Canadian Entitlement
- List of the "in-development" resources through 2030
- Achieved LOLE values for each year through 2030

Let me know if there is any additional information you might need, and also if there is any impending deadline that we should be aware of.

Also, here is a link to E3's newest resource adequacy white paper.

<https://www.ethree.com/new-framework-resource-adequacy/>

As I mentioned during our call, it's intended to be a detailed guidebook for how to evaluate resource adequacy needs across markets and vertically integrated systems. Happy to answer any questions you might have about the white paper, or if any other questions come up about our current NW study.

Happy New Year!

Arne

-----Original Appointment-----

From: Arne Olson

Sent: Monday, December 29, 2025 2:08 PM

To: Arne Olson; Brad Cebulko; Fred Heutte

Cc: Laura Burford; Michael Lenoff; Erik Olson

Subject: E3 NW RA study and Centralia

When: Wednesday, December 31, 2025 8:00 AM-8:25 AM (UTC-08:00) Pacific Time (US & Canada).

Where: Microsoft Teams Meeting

Microsoft Teams [Need help?](#)

[Join the meeting now](#)

Meeting ID: 256 665 160 678 92

Passcode: Ei7NT9X3

For organizers: [Meeting options](#)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-25-14
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
<u>PacifiCorp, and Xcel Energy</u>	)	

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

Filed January 28, 2026

Exhibit 1-159a:
E3's Attachment to Email Correspondence with E3

Columbia River Treaty Regime

Sources

<https://www.state.gov/bureau-of-western-hemisphere-affairs/details-about-the-key-elements-agreed-between-the-united-states-and-canada-regarding-modernization-of-the-columbia-river-treaty-regime>

(Table 1.) <https://www.congress.gov/crs-product/R43287>

Year	Capacity (MW) ¹	Generation (MW) ²
2024 (Baseline)	1,141	454
2025-2029	660	305
2030	590	278
2031	573	225
2032	565	225
2033	558	225
2034-2044	550	225

How it is modeled

The capacity component of the treaty (1) was interpreted as the capacity BC is able to access and demand at any point in time. After consulting with BPA, we also interpret that BC could demand this amount for a sustained long period of time, such as for two weeks or more, without violating the generation amounts of the treaty (2) which is itself interpreted as the annual average energy for the treaty. This means the treaty's capacity could be requested for longer than the reliability risk periods and present a firm requirement. **Therefore, the capacity component of the treaty was modeled as a firm obligation which increases the region's total reliability need by the same amount in MWs.**

Year	Firm Obligation, MW
2025	660
2026	660
2027	660
2028	660
2029	660
2030	590

In-Development Resources

Sources

<https://www.wecc.org/program-areas/reliability-planning-performance-analysis/reliability-modeling/anchor-data-set-ads>

<https://www.pacificorp.com/energy/integrated-resource-plan.html>

Plant-level list in-development resources within the Greater Northwest Study Region with commission dates between 2025-2030. In-development resources are WECC ADS 2034 facilities with confirmed project location, project name, and can be verified online. In-development resources include coal-to-gas plant conversions in PacifiCorp's 2025 IRP. Plants with commission dates before January 1 are considered available in the study year. Each resource is assigned to a Transmission Zone based on physical location within the Greater Northwest for zonal modeling.

Annual Capacity Additions (Nameplate MW)						
	2025	2026	2027	2028	2029	2030
Hydro	99	251	78	2	91	-
Nuclear	-	-	-	-	-	-
Coal	-	-	-	-	-	-
Gas	1,339	357	-	-	205	360
Other	-	-	-	-	-	-
Wind	1,026	1,126	460	-	-	-
Solar	344	1,396	125	-	-	-
BTM Solar	-	-	-	-	-	-
Battery Storage	460	545	-	-	-	-
Demand Response	-	-	-	-	-	-
Total	3,267	3,676	663	2	296	360

Total
522
-
-
2,261
-
2,611
1,866
-
1,005
-
8,264

Source	GeneratorKey	Name	State	County	Transmission Zone	Rated Capacity (Nameplate MW)	Resource Type	Balancing Authority	Commission Date	First Available Year
ADS 2034	2177	Meyers Falls 1 HY	WA	NA	PNW_NE	1	Hydro	AVA	12/31/2024	2025
ADS 2034	2197	Upper Falls Post St 1 HY	WA	NA	PNW_NE	10	Hydro	AVA	1/4/2026	2027
ADS 2034	2393	Cedar Falls 2 HY	WA	NA	PNW_NW	15	Hydro	PSEI	1/1/2026	2027
ADS 2034	2394	Cedar Falls 1 HY	WA	NA	PNW_NW	15	Hydro	PSEI	1/1/2026	2027
ADS 2034	3472	Thompson Falls 2 HY	MT	NA	Inland_NW	5	Hydro	NWMT	6/1/2025	2026
ADS 2034	3479	Thompson Falls 6 HY	MT	NA	Inland_NW	5	Hydro	NWMT	12/1/2024	2025
ADS 2034	3480	Thompson Falls 5 HY	MT	NA	Inland_NW	5	Hydro	NWMT	12/1/2024	2025
ADS 2034	3481	Thompson Falls 4 HY	MT	NA	Inland_NW	5	Hydro	NWMT	3/31/2025	2026
ADS 2034	3486	Holter 4 HY	MT	Lewis&Clark	Inland_NW	10	Hydro	NWMT	6/15/2025	2026
ADS 2034	3487	Holter 3 HY	MT	Lewis&Clark	Inland_NW	10	Hydro	NWMT	7/1/2025	2026
ADS 2034	3488	Holter 2 HY	MT	Lewis&Clark	Inland_NW	10	Hydro	NWMT	8/25/2025	2026
ADS 2034	3489	Ryan 6 HY	MT	NA	Inland_NW	8	Hydro	NWMT	1/1/2025	2026
ADS 2034	3490	Ryan 5 HY	MT	NA	Inland_NW	8	Hydro	NWMT	3/9/2025	2026
ADS 2034	3515	Ryan 3 HY	MT	NA	Inland_NW	8	Hydro	NWMT	12/1/2024	2025
ADS 2034	3517	Ryan 1 HY	MT	NA	Inland_NW	8	Hydro	NWMT	12/1/2024	2025
ADS 2034	3531	Holter 1 HY	MT	Lewis&Clark	Inland_NW	10	Hydro	NWMT	12/1/2025	2026
ADS 2034	3537	Thompson Falls 3 HY	MT	NA	Inland_NW	5	Hydro	NWMT	4/1/2025	2026
ADS 2034	3539	Thompson Falls 1 HY	MT	NA	Inland_NW	5	Hydro	NWMT	6/1/2025	2026
ADS 2034	4925	Boundary 1 HY	WA	NA	PNW_NW	158	Hydro	SCL	8/1/2025	2026
ADS 2034	4966	Long Lake 1	WA	Lincoln	PNW_NE	9	Hydro	AVA	12/31/2024	2025
ADS 2034	7473	Lagrande 2 HY	WA	NA	PNW_NW	6	Hydro	TPWR	1/1/2024	2025
ADS 2034	7474	Lagrande 3 HY	WA	NA	PNW_NW	6	Hydro	TPWR	1/1/2024	2025
ADS 2034	7475	Lagrande 4 HY	WA	NA	PNW_NW	6	Hydro	TPWR	1/1/2024	2025
ADS 2034	7606	Long Lake 2	WA	Lincoln	PNW_NE	9	Hydro	AVA	12/31/2024	2025
ADS 2034	7607	Long Lake 3 HY	WA	NA	PNW_NE	18	Hydro	AVA	12/1/2025	2026
ADS 2034	7608	Long Lake 4 HY	WA	NA	PNW_NE	18	Hydro	AVA	1/1/2028	2029
ADS 2034	8613	Ryan 2 HY	MT	Cascade	Inland_NW	9	Hydro	NWMT	12/13/2024	2025
ADS 2034	8614	Ryan 4 HY	MT	Cascade	Inland_NW	9	Hydro	NWMT	12/31/2024	2025
ADS 2034	9698	Gorge 1 HY	WA	NA	PNW_NW	37	Hydro	SCL	1/1/2028	2029
ADS 2034	9699	Gorge 2 HY	WA	NA	PNW_NW	37	Hydro	SCL	1/1/2028	2029
ADS 2034	18045	Boswell Springs Wind WT	WY	Sweetwater	Central_West	320	Wind	PACE	4/1/2024	2025
ADS 2034	18048	Cedar Creek Wind WT	ID	Power	Central_West	152	Wind	PACE	4/1/2024	2025
ADS 2034	18179	Hauser Agg HY	MT	Lewis&Clark	Inland_NW	17	Hydro	NWMT	12/31/2024	2025
ADS 2034	18210	Uinta Agg HY	UT	Uintah	Central_West	1	Hydro	PACE	12/1/2025	2026
ADS 2034	18218	Utility Solar+Storage - PV - S-O	OR	NA	PNW_SW	1	Battery Storage	PACW	1/1/2024	2025
ADS 2034	18224	Big Fork 1 HY	MT	Flathead	PNW_NE	2	Hydro	BPAT	1/1/2027	2028
ADS 2034	18345	Glen Canyon Solar A PV-T	UT	Kane	Central_West	95	Solar	PACE	1/1/2024	2025
ADS 2034	19147	Tower Rd Solar PV-T	OR	Morrow	PNW_NE	120	Solar	BPAT	12/1/2024	2026
ADS 2034	19260	Farmers Irrigation District Coppel	OR	Hood River	PNW_SW	2	Hydro	PACW	1/1/2026	2027
ADS 2034	20916	Oregon Trail Solar PV-T	OR	Gilliam	PNW_NE	41	Solar	BPAT	12/31/2025	2026
ADS 2034	20917	Green River Energy Center PV-	UT	Emery	Central_West	400	Solar	PACE	6/15/2025	2026
ADS 2034	20962	Cedar Springs Wind IV WT	WY	NA	Central_West	350	Wind	PACE	12/31/2024	2025

ADS 2034		20963	Anticline Wind WT	WY	NA	Central West		101	Wind	PACE		12/31/2024	2025
ADS 2034		20964	Two Rivers Wind LLCWT	WY	Carbon	Central West		280	Wind	PACE		3/31/2025	2026
ADS 2034		21121	Franklin BESS paired with Solar	ID	Twin Falls	Central West		60	Battery Storage	IPCO		6/1/2024	2025
ADS 2034		21163	Oregon Trail BESS BA	OR	Gilliam	PNW NE		41	Battery Storage	BPAT		12/31/2025	2026
ADS 2034		21164	Tower Rd BESS BA	OR	Morrow	PNW NE		60	Battery Storage	BPAT		12/31/2025	2026
ADS 2034		21215	Jim Bridger 1 ST	WY	Sweetwater	Central West		578	Gas	PACE		4/1/2024	2025
ADS 2034		21216	Jim Bridger 2 ST	WY	Sweetwater	Central West		586	Gas	PACE		4/1/2024	2025
ADS 2034		21401	Yellowstone County Generating	MT	Yellowstone	Inland NW		10	Gas	NWMT		5/15/2024	2025
ADS 2034		21402	Yellowstone County Generating	MT	Yellowstone	Inland NW		10	Gas	NWMT		5/15/2024	2025
ADS 2034		21403	Yellowstone County Generating	MT	Yellowstone	Inland NW		10	Gas	NWMT		5/15/2024	2025
ADS 2034		21404	Yellowstone County Generating	MT	Yellowstone	Inland NW		10	Gas	NWMT		5/15/2024	2025
ADS 2034		21405	Yellowstone County Generating	MT	Yellowstone	Inland NW		10	Gas	NWMT		5/15/2024	2025
ADS 2034		21406	Yellowstone County Generating	MT	Yellowstone	Inland NW		10	Gas	NWMT		5/15/2024	2025
ADS 2034		21407	Yellowstone County Generating	MT	Yellowstone	Inland NW		10	Gas	NWMT		5/15/2024	2025
ADS 2034		21408	Yellowstone County Generating	MT	Yellowstone	Inland NW		10	Gas	NWMT		5/15/2024	2025
ADS 2034		21409	Yellowstone County Generating	MT	Yellowstone	Inland NW		10	Gas	NWMT		5/15/2024	2025
ADS 2034		21410	Yellowstone County Generating	MT	Yellowstone	Inland NW		10	Gas	NWMT		5/15/2024	2025
ADS 2034		21411	Yellowstone County Generating	MT	Yellowstone	Inland NW		10	Gas	NWMT		5/15/2024	2025
ADS 2034		21412	Yellowstone County Generating	MT	Yellowstone	Inland NW		10	Gas	NWMT		5/15/2024	2025
ADS 2034		21413	Yellowstone County Generating	MT	Yellowstone	Inland NW		10	Gas	NWMT		5/15/2024	2025
ADS 2034		21414	Yellowstone County Generating	MT	Yellowstone	Inland NW		10	Gas	NWMT		5/15/2024	2025
ADS 2034		21415	Yellowstone County Generating	MT	Yellowstone	Inland NW		10	Gas	NWMT		5/15/2024	2025
ADS 2034		21416	Yellowstone County Generating	MT	Yellowstone	Inland NW		10	Gas	NWMT		5/15/2024	2025
ADS 2034		21417	Yellowstone County Generating	MT	Yellowstone	Inland NW		10	Gas	NWMT		5/15/2024	2025
ADS 2034		21418	Yellowstone County Generating	MT	Yellowstone	Inland NW		10	Gas	NWMT		5/15/2024	2025
ADS 2034		21423	DaveJohnston 1 1 ST	WY	Converse	Central West		99	Gas	PACE		1/1/2029	2029
ADS 2034		21432	Naughton 1 (natural gas conver	WY	Lincoln	Central West		156	Gas	PACE		1/1/2026	2026
ADS 2034		21433	Naughton 2 (natural gas conver	WY	Lincoln	Central West		201	Gas	PACE		1/1/2026	2026
ADS 2034		21678	Additional Hemingway Standalo	ID	Owyhee	Central West		36	Battery Storage	IPCO		6/1/2024	2025
ADS 2034		21679	Elmore Distributed BESS BA	ID	Elmore	Central West		3	Battery Storage	IPCO		6/1/2024	2025
ADS 2034		21680	Happy Valley BESS I 1 BA	ID	Canyon	Central West		39	Battery Storage	IPCO		6/1/2025	2026
ADS 2034		21681	Happy Valley BESS II 1 BA	ID	Canyon	Central West		39	Battery Storage	IPCO		6/1/2025	2026
ADS 2034		21682	Kuna BESS 1 BA	ID	Ada	Central West		150	Battery Storage	IPCO		6/1/2025	2026
ADS 2034		21683	Melba Distributed BESS BA	ID	Canyon	Central West		2	Battery Storage	IPCO		6/1/2024	2025
ADS 2034		21735	Parowan Solar BA	UT	Iron	Central West		58	Battery Storage	PACE		12/1/2024	2025
ADS 2034		21749	Pump Storage - West 1 PS	OR	Douglas	PNW SW		35	Hydro	PACW		1/1/2026	2027
ADS 2034		21752	Coffee Creek 1 BA	OR	Washington	PNW NE		17	Battery Storage	BPAT		6/1/2025	2026
ADS 2034		21753	Constable BESS 1 BA	OR	Washington	PNW SW		100	Battery Storage	BPAT		12/31/2024	2025
ADS 2034		21754	Seaside BESS 1 BA	OR	Multnomah	PNW SW		200	Battery Storage	BPAT		6/1/2025	2026
ADS 2034		21755	Troutdale BESS 1 BA	OR	Multnomah	PNW NE		200	Battery Storage	BPAT		12/31/2024	2025
ADS 2034		22116	Pleasant Valley Solar II 1 PV-T	ID	Ada	Central West		125	Solar	IPCO		12/1/2026	2027
ADS 2034		22212	Arco Wind WT	ID	Bonneville	Central West		360	Wind	PACE		12/1/2026	2027
ADS 2034		22215	Faraday Solar B LLC PV-T	UT	Utah	Central West		525	Solar	PACE		9/30/2025	2026
ADS 2034		22217	Hornshadow Solar II LLC PV-T	UT	Emery	Central West		200	Solar	PACE		6/30/2025	2026
ADS 2034		22218	Hornshadow Solar LLC PV-T	UT	Emery	Central West		100	Solar	PACE		6/30/2025	2026
ADS 2034		22220	Parowan Solar PV-T	UT	Iron	Central West		58	Solar	PACE		12/1/2024	2025
ADS 2034		22231	Rock Creek I Wind 32 WT	WY	Carbon	Central West		195	Wind	PACE		6/1/2025	2026
ADS 2034		22232	Rock Creek II Wind 66 WT	WY	Albany	Central West		403	Wind	PACE		9/1/2025	2026
ADS 2034		22256	Buckaroo Solar 1 PV-T	OR	Pendleton	PNW SW		2	Solar	PACW		9/30/2025	2026
ADS 2034		22257	Buckaroo Solar 2 PV-T	OR	Pendleton	PNW SW		3	Solar	PACW		9/30/2025	2026
ADS 2034		22262	Antelope Creek Solar LLC PV-T	OR	Jackson	PNW SW		2	Solar	PACW		4/19/2024	2025
ADS 2034		22264	Black Rock Solar PV-T	WA	Yakima	PNW NE		100	Solar	BPAT		1/1/2024	2025
ADS 2034		22267	Green Solar LLC PV-T	OR	Culver	PNW SW		3	Solar	TH Malin		3/15/2024	2025
ADS 2034		22268	High Top Solar PV-T	WA	Yakima	PNW NE		80	Solar	BPAT		4/1/2024	2025
ADS 2034		22270	Orchard Knob Solar PV-T	OR	Polk	PNW NE		2	Solar	BPAT		2/23/2024	2025
ADS 2034		22274	Pilot Rock Solar I PV-T	OR	Umatilla	PNW SW		2	Solar	PACW		9/30/2025	2026
ADS 2034		22275	Pilot Rock Solar II PV-T	OR	Umatilla	PNW SW		3	Solar	PACW		9/30/2025	2026
ADS 2034		22276	Pine Grove Solar LLC PV-T	OR	Klamath	PNW SW		1	Solar	TH Malin		2/16/2024	2025
ADS 2034		22281	Sunset Ridge Solar LLC PV	OR	Klamath	PNW SW		2	Solar	TH Malin		7/25/2024	2025
ADS 2034		22292	Clearwater II 37 WT	MT	Custer	Central West		103	Wind	PACE		1/2/2024	2025
ADS 2034		22323	BHCE 100 MW Wind WT	CO	TBD	PNW NE		100	Wind	BPAT		1/1/2026	2027
ADS 2034		22340	Beaver Creek 1 WT	MT	Gallatin	Inland NW		248	Wind	NWMT		3/1/2025	2026
ADS 2034		22487	Sprague Hydro (North Fork) 1 H	OR	Klamath	PNW SW		1	Hydro	PACW		1/1/2024	2025
ADS 2034		22546	Wallowa Falls 1 HY	OR	NA	PNW SW		1	Hydro	PACW		1/1/2026	2027
ADS 2034		22567	DaveJohnston 2 2 ST	WY	Converse	Central West		106	Gas	PACE		1/1/2029	2029
Pacificorp 2025 IRP	Pacificorp 2025 IRP	E3 Dave Johnston 4 Coal-to-Ga	WY	Converse	Central West			360	Gas	PACE		12/31/2029	2030

Greater Northwest System Metrics

	Unit	2025	2026	2027	2028	2029	2030
Total Resource Need*	MW	49,245	50,737	52,499	54,184	55,879	57,195
Existing Portfolio w/ Retirements**	MW	46,716	45,666	45,395	45,388	45,098	44,757
Firm Imports	MW	3,750	3,750	3,750	3,750	3,750	3,750
Reliability Position							
before Resource Additions	MW	1,221	-1,321	-3,354	-5,046	-7,031	-8,689
Surplus (+) / Shortfall (-)							
"In-Development"*** Firm Resources	MW	0	296	407	580	770	1,114
"In-Development" Wind, Solar and Battery projects	MW	0	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

** Does not include new gas capacity from converted coal units, only the coal retirements. New gas capacity from conversion categorized as "In-Development" below. Still includes retirement of Centralia 2, at 687 MW of effective firm capacity.

*** In-development resources are WECC ADS 2034 facilities with confirmed project location, project name, and can be verified online. Includes new gas capacity from the conversion of coal units. Does not include repowering of Centralia 2 as a gas unit.

System Metrics including "In-Development" Resources	Unit	2025	2026	2027	2028	2029	2030
Reliability Position							
with "In-Development" Resources	MW	1,221	-380	-1,932	-3,150	-4,753	-5,641
Surplus (+) / Shortfall (-)							
Loss-of-Load Expectation	MWh/year	63	1,212	6,987	20,398	58,132	98,067
	Hours/year	0.14	1.65	5.58	14.70	36.43	56.57
	Days/year	0.01	0.15	0.68	1.77	4.14	6.01
	% chance/year	0.3%	5.2%	21.0%	40.5%	59.4%	67.5%

Greater Northwest System Metrics

	Unit	2025	2026
Total Resource Need*	MW	49,245	50,737
Existing Portfolio w/ Retirements**	MW	46,716	45,666
Firm Imports	MW	3,750	3,750
Reliability Position			
before Resource Additions	MW	1,221	-1,321
Surplus (+) / Shortfall (-)			
"In-Development"*** Firm Resources	MW	0	296
"In-Development" Wind, Solar and Battery projects	MW	0	645

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

**Does not include new gas capacity from converted coal units, only the coal retirements. New gas capacity from

** In-development resources are WECC ADS 2034 facilities with confirmed project location, project name, and cost

System Metrics including "In-Development"	Unit	2025	2026
Resources			
Reliability Position			
with "In-Development" Resources	MW	1,221	-380
Surplus (+) / Shortfall (-)			
	MWh/year	63	1,212
	Hours/year	0.14	1.65
	Days/year	0.01	0.15
Loss-of-Load Expectation	% chance/year	0.3%	5.2%

2027	2028	2029	2030
52,499	54,184	55,879	57,195
45,395	45,388	45,098	44,757
3,750	3,750	3,750	3,750
-3,354	-5,046	-7,031	-8,689
407	580	770	1,114
1,015	1,316	1,508	1,934

o River Treaty Regime

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2027	2028	2029	2030
-1,932	-3,150	-4,753	-5,641
6,987	20,398	58,132	98,067
5.58	14.70	36.43	56.57
0.68	1.77	4.14	6.01
21.0%	40.5%	59.4%	67.5%

ilia 2 as a gas unit.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Order No. 202-25-14

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

Filed January 28, 2026

Exhibit 1-160:
Clean Air Task Force Toll from Coal

Craig

Moffat, Colorado

Owner MidAmerican Energy Holdings Co, 12.9%, Salt River Project, 12%, Salt River Project, 19.3%, Tri-State G & T Assn Inc, 49.3%, Xcel Energy Inc, 6.5%

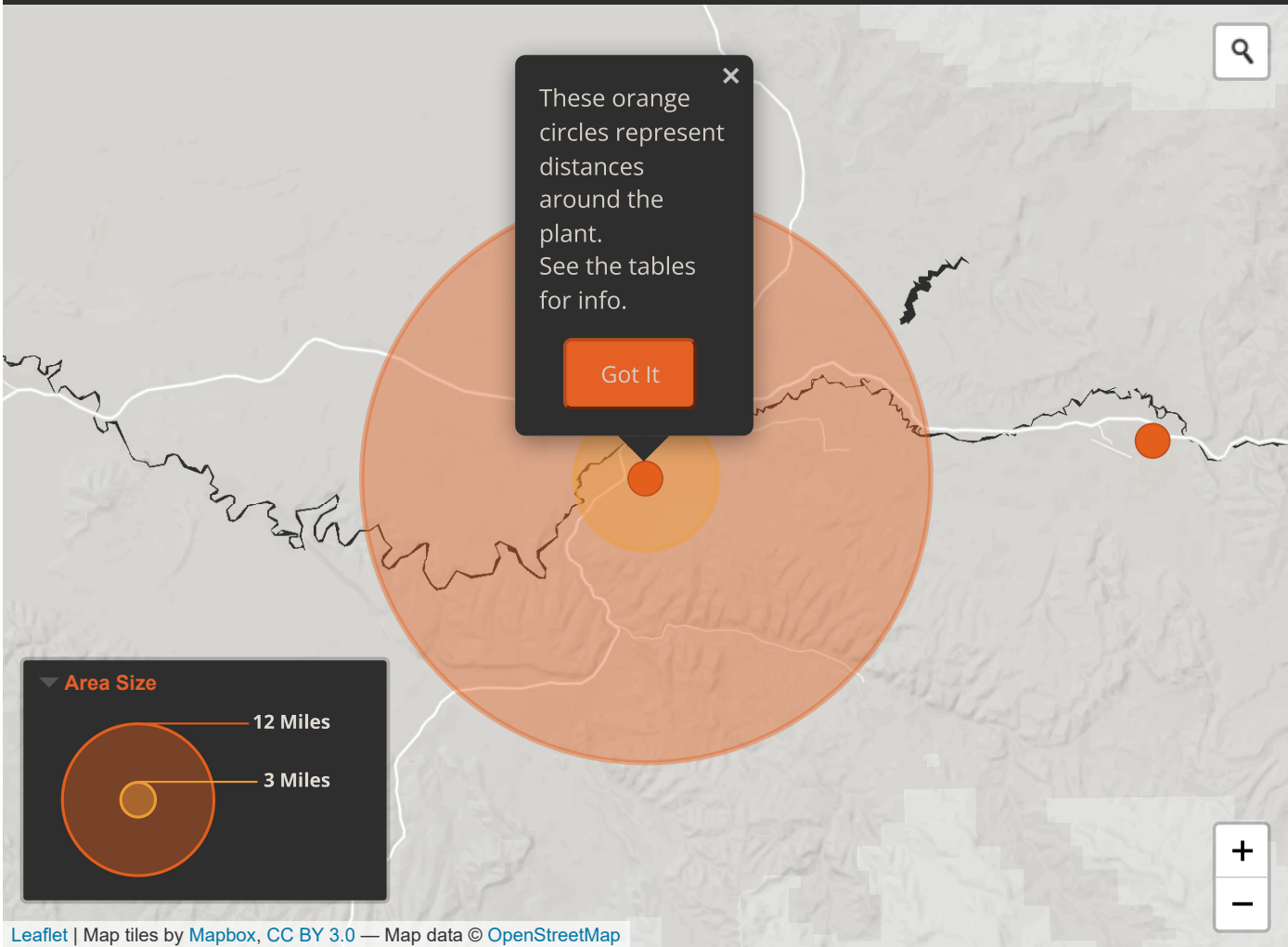
Size of Plant 1,304 MW

In Service Date 1979-1984

SO₂ Emissions 3,018 tons per year

NO_x Emissions 7,985 tons per year

CO₂ Emissions 9,181,677 tons per year



Health Impacts

(per year)

Deaths 21

Hospital Admissions 2

Asthma ER Visits 5

Heart Attacks 8

At Risk Population

	3 Miles	12 Miles
Population	410	12,135

Acute Bronchitis 14
Asthma Attacks 270
Work Loss Days 1,234

Number of Children	123	3,642
Number of Schools	--	13
Hospitals	--	1
Nursing Homes	0	1
Places of Worship	--	1
People of Color vs State Average	8% vs. 30%	18% vs. 30%
Poverty Rate vs State Average	4% vs. 13%	11% vs. 13%



CLEAN AIR
TASK FORCE

Methodology

Powered by ZevRoss
Spatial Analysis



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
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Order No. 202-25-14

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Filed January 28, 2026

Exhibit 1-161
SPP West Press Release

March 20, 2025

SPP first RTO to operate in both interconnections with tariff approval

LITTLE ROCK, ARK. — Southwest Power Pool (SPP) will soon be the first regional transmission organization (RTO) in the U.S. to provide full services in both the Eastern and Western Interconnections of the nation's power grid. On March 20, the Federal Energy Regulatory Commission (FERC) unanimously approved Southwest Power Pool's amended tariff that includes provisions enabling Western members to join the RTO. The Commission's approval paves the way for seven Western entities, all of whom are participants in SPP's Western Energy Imbalance Service (WEIS) market today, to begin participating in SPP's Integrated Marketplace, transmission planning, reliability coordination and other RTO services beginning in April 2026.

On June 4, 2024, SPP **filed its amended tariff with FERC** to accommodate requirements for Western entities pursuing RTO membership or increased participation as part of the expansion of the SPP RTO: Basin Electric Power Cooperative; Colorado Springs Utilities; Deseret Power Electric Cooperative; the Municipal Energy Agency of Nebraska (MEAN); Platte River Power Authority; Tri-State Generation and Transmission Association; and the Western Area Power Administration Colorado River Storage Project, Rocky Mountain and Upper Great Plains regions.

"I am pleased to announce FERC's approval of the amended RTO tariff," said Barbara Sugg, SPP president and CEO. "Expanding the RTO into the Western Interconnection is an exciting step in SPP's growth, bringing value to new and existing members while enhancing reliability in both interconnections."

The expansion of the RTO is part of Aspire 2026, SPP's five-year strategic plan, which details opportunities to fully integrate Western facilities into SPP's existing market system in a way that creates meaningful, equitable value for new and existing members.

"The Western expansion of the SPP RTO bolsters reliability and resiliency for our members as we grow and diversify our resource portfolio while reducing emissions," said Tri-State Generation and Transmission Association CEO Duane Highley. "We greatly value the full benefits of the SPP RTO, including day-ahead and ancillary services markets, efficient regional transmission planning, a common transmission tariff and participatory governance model that help us to further reduce costs for our members across the West. Prior to SPP RTO West entry, we will be making a filing with our state regulators highlighting these market benefits."

"SPP's RTO expansion into the Western Interconnect will help us to reduce our overall carbon footprint for MEAN's power resources through the economic dispatch of a wholesale power market and maximizing operational efficiencies of renewable resources," said MEAN Director of Wholesale Operations Brad Hans. "As a

member of SPP's RTO in the Eastern Interconnect for several years, MEAN recognizes the benefits of participating in that market and the energy cost savings it provides as well as SPP's member-driven business model."

"In 2018, when we outlined our plan to pursue a noncarbon energy portfolio, it was very clear to us that an integral component to this plan was to join a power market," shares Jason Frisbie, CEO and general manager of Platte River Power Authority. "Over the last seven years our teams across the organization have been dedicated to this effort working closely with SPP to be ready for the moment we join the RTO, which will help us integrate more renewable energy onto our system and manage our energy costs."

"With the complexities of today's energy industry and the regulations that define it, an adaptable electric grid with access to both local and regional resources is essential for managing customer costs and maintaining service reliability," said Colorado Springs Utilities Chief Executive Officer Travas Deal. "We strongly believe the SPP RTO will help us achieve this goal, while also connecting us with vital transmission resources as we pursue new and cleaner forms of electric generation. So, FERC's approval of the amended tariff is very encouraging for us and our customers as we implement our Sustainable Energy Plan."

SPP is working with additional Western utilities who have expressed interest in joining the RTO once this initial expansion is complete.

Separately, SPP is developing Markets+, another market designed to bring significant incremental value to the Western Interconnection. SPP received **FERC's approval of the Markets+ tariff** in January, and is working with interested parties to finalize plans to fund the market's development and launch. With the addition of Markets+, SPP will have a solid presence in the West, operating two markets and serving as the program administrator for the Western Power Pool's Western Resource Adequacy Program (WRAP).

"Multiple markets maximize value for all participants," said Sugg. "SPP has operated a Western market since 2021, and with the expansion of the RTO's Integrated Marketplace in 2026 and launch of Markets+ in 2027, we're looking forward to bringing additional affordability, reliability, equity and sustainability to the West."

SPP first earned FERC's approval as an RTO in October 2004, and over the last two decades has expanded its RTO footprint in the Eastern Interconnection from eight to 14 states. This expansion would grow SPP's RTO service territory to encompass all or part of 17 states. SPP has been engaged with parties interested in **evaluating** the benefits and requirements of RTO membership in the Western Interconnection since Oct. 20, 2020. The SPP board of directors **approved** the initial RTO expansion terms and conditions in July 2021, the DC tie terms and conditions in July 2022 and the WAPA Colorado River Storage Project terms and conditions in January 2023. The expansion of the SPP RTO is scheduled to go live April 1, 2026.

Meghan Sever, 501-482-2393, msever@spp.org

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
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Order No. 202-25-14

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Public Interest Organizations

Filed January 28, 2026

Exhibit 1-162
EIA Generating Unit Annual Capital and Life Extension Costs Analysis



Independent Statistics & Analysis

U.S. Energy Information
Administration

Generating Unit Annual Capital and Life Extension Costs Analysis

December 2019



This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the Department of Energy or other Federal agencies.

Generating Unit Annual Capital and Life Extension Costs Analysis

In a period of accelerating retirements of electric power generators, EIA sought to revisit its assumptions of age-related generation costs. EIA commissioned Sargent & Lundy (S&L) to evaluate capital expenditures (CAPEX) and operations and maintenance (O&M) costs for non-nuclear generating units, with a particular emphasis on how costs of coal and other fossil-fueled plants change over time. The following report represents S&L's findings. A separate EIA report, *Updates to Cost Assumptions in the Electricity Market Module (EMM) of the National Energy Modeling System (NEMS)*,¹ details subsequent updates to the EMM module.

The following report was accepted by EIA in fulfillment of contract number DE-EI0003250. All views expressed in this report are solely those of the contractor and acceptance of the report in fulfillment of contractual obligations does not imply agreement with nor endorsement of the findings contained herein. Responsibility for accuracy of the information contained in this report lies with the contractor. Although intended to be used to inform the updating of EIA's EMM module of NEMS, EIA is not obligated to modify any of its models or data in accordance with the findings of this report.

¹ <https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/addendum.pdf>



55 East Monroe Street
Chicago, Illinois 60603-5780

FINAL

Generating Unit Annual Capital and Life Extension Costs Analysis

Final Report on Modeling Aging-Related
Capital and O&M Costs

Prepared for



U.S. Energy Information Administration

SL-014201
May 2018

LEGAL NOTICE

This report (“Deliverable”) was prepared by Sargent & Lundy, L.L.C. (“Sargent & Lundy”), expressly for the sole use of U.S. Energy Information Administration (“Client”) in accordance with the agreement between Sargent & Lundy and Client. This Deliverable was prepared using the degree of skill and care ordinarily exercised by engineers practicing under similar circumstances. Client acknowledges: (1) Sargent & Lundy prepared this Deliverable subject to the particular scope limitations, budgetary and time constraints, and business objectives of the Client; (2) information and data provided by others may not have been independently verified by Sargent & Lundy; and (3) the information and data contained in this Deliverable are time sensitive and changes in the data, applicable codes, standards, and acceptable engineering practices may invalidate the findings of this Deliverable. Any use or reliance upon this Deliverable by third parties shall be at their sole risk.

Sargent & Lundy is a full-service architect-engineering firm that has been dedicated exclusively to the electric power industry for over 125 years. Sargent & Lundy has provided comprehensive planning, development, permitting, technical and financial consulting, engineering, design, construction management, and commissioning services for electric power generation and power delivery projects—1,557 clients in 88 countries worldwide—since its founding in 1891. Having designed 958 power plants, totaling 140,667 MW of electric generation capacity, Sargent & Lundy is regarded as one of the oldest, largest, and most experienced power generation engineering companies in the U.S.

Sargent & Lundy's roles on electric power generation projects include full-design architect-engineer, owner's engineer, lender's independent engineer/technical advisor, and consultant. Our services include specialized technical advisory and consulting services to complete engineering and program management, encompassing procurement, construction management, technology transfer, and assistance with construction. Sargent & Lundy provides professional consulting, engineering, and design services throughout the lifecycle of power generation projects, from project concept and development, through detailed design and procurement, to construction and operation.

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ACRONYMS AND ABBREVIATIONS

Term	Definition or Clarification
2017\$	2017 dollars
A&G	Administrative and general
AEO	<i>Annual Energy Outlook</i>
ARIMA	Autoregressive integrated moving average
ATB	Annual Technology Baseline
CAPEX	Capital expenditures
CC	Combined cycle
CF	Capacity factor
COD	Commercial operation date
CT	Combustion turbine
DOE	Department of Energy
EIA	Energy Information Administration
EMM	Electricity Market Module
ESP	Electrostatic precipitator
FERC	Federal Energy Regulatory Commission
FERC Form 1	FERC Form No. 1
FGD	Flue gas desulfurization
Hg	Mercury
HP	High pressure
ID	Identifier or induced draft
IP	Intermediate pressure
IPP	Independent power producer
IRENA	International Renewable Energy Agency

ACRONYMS AND ABBREVIATIONS

Term	Definition or Clarification
kW	Kilowatts
kW-yr	Kilowatt-years
LCOE	Levelized cost of electricity
LP	Low pressure
MMRA	Major maintenance reserve account
MW	Megawatts
MWh	Megawatt-hours
NO _x	Nitrogen oxide
NREL	National Renewable Energy Laboratory
OEA	Office of Energy Analysis
O&M	Operations and maintenance
PM	Particulate matter
PV	Photovoltaic
R ²	R-squared
Sargent & Lundy	Sargent & Lundy LLC
SO ₂	Sulfur dioxide
TCP	Total Cost of Plant

EXECUTIVE SUMMARY

IDENTIFYING IMPACTS OF AGING ON GENERATION COST AND OPERATION

Sargent & Lundy LLC (Sargent & Lundy) was engaged by the Office of Energy Analysis (OEA) of the U.S. Energy Information Administration (EIA), an agency within the U.S. Department of Energy (DOE), to conduct a study to improve the ability of the Electricity Market Module (EMM) to represent the changing landscape of electricity generation and to more accurately represent costs, which will improve projections for generating capacity, generator dispatch, and electricity prices. The EMM is a submodule within the EIA's National Energy Modeling System (NEMS), a computer-based energy supply modeling system that is used for the EIA's *Annual Energy Outlook* (AEO) and other analyses.

In particular, the purpose of this study was to provide information that may enable the EIA to more accurately represent costs associated with operation of the existing fleet of U.S. generators as they age. This includes capital expenditures (CAPEX) related to ongoing operations as well as potential increases in operations and maintenance (O&M) costs attributable to declining performance due to aging.

The primary focus of our analysis was existing fossil fuel generators. The study also included existing wind, solar, hydro, and other renewable generators. The work scope did not include analysis of nuclear units.

The generating capacity types represented in the EMM that were included in our analysis comprised:

- Coal steam plants
- Gas/oil steam plants
- Gas/oil combined-cycle (CC) plants
- Gas/oil combustion turbines (CTs)
- Conventional hydropower
- Pumped storage – hydraulic turbine reversible
- Solar thermal – central tower
- Solar photovoltaic (PV) – single-axis tracking
- Geothermal
- Wind

For most types of generators evaluated, we did not find a statistically significant relationship between plant age and costs (both CAPEX and O&M). CAPEX spending over the life of each plant represents a series of capital projects—rather than a single life extension project—that includes both discretionary spending and

vendor-specified spending. For discretionary spending, different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances. Vendor-specified spending is primarily for major maintenance, typically based on cumulative hours of operation and/or cumulative starts, and more commonly applied to gas/oil CC and CT plants. We did, however, find a statistically significant relationship between age and CAPEX spending for fossil steam coal generators with flue gas desulfurization (FGD) equipment, and between age and O&M spending for conventional hydroelectric plants and wind turbines. We also found age and CAPEX spending to be significantly correlated for CC and CT plants, although measured in terms of operating hours or starts, rather than years. Table ES-1 summarizes the variables found to have a significant effect on annual changes in real spending per kilowatt (kW) for each generator type. We recommend the EIA incorporate these variables in the EMM representation of CAPEX and O&M.

Table ES-1 — Variables Affecting Annual Changes in Real Spending per kW

Generating Capacity	CAPEX Spending	O&M Spending
Coal Steam Plants	Age and FGD (see Table ES-3)	-
Gas/Oil Steam Plants	Capacity (see Table ES-5)	-
Gas/Oil Combined-Cycle Plants	Operating Hours (see Table ES-7)	-
Gas/Oil Combustion Turbines	Starts (see Table ES-7)	-
Conventional Hydropower	-	Age (Regression Equation)
Pumped Storage – Hydraulic Turbine Reversible	-	-
Solar Thermal – Central Tower	-	-
Solar Photovoltaic – Single-Axis Tracking	-	-
Geothermal	-	-
Wind	Capacity (see Table ES-11)	Age (Regression Equation)

While we did not find a consistent relationship between aging and CAPEX and O&M costs, changes in performance-related factors and external market conditions are also related to changes in these costs over time. Examples of these factors and conditions include the following:

- Plant efficiency (heat rate)
- Capacity degradation
- Outage rates
- Market prices (electricity, fuel)

These factors and conditions were not part of the scope of our study. We recommend the EIA consider studying these in the future.

MODELING IMPACTS OF AGING IN EIA PROJECTIONS

Existing Treatment of Aging in EIA's Electricity Market Module

The EMM currently accounts for power plant aging through a one-time step increase in annual CAPEX that is intended to extend the life or preserve the performance of an existing generator. In the EMM, costs for plant O&M do not vary with plant age.

As modeled in the EMM, a generating unit is assumed to retire if the expected revenues from the generator are not sufficient to cover the annual going-forward costs and if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, O&M costs, and annual CAPEX. The average annual CAPEX in the EMM is \$0.18 per kilowatt-year (/kW-year) for existing CC plants, \$9/kW-year for existing gas/oil steam plants, and \$18/kW-year for existing coal plants (in constant 2017 dollars). These amounts are increased to \$7.25/kW-year, \$16/kW-year, and \$25/kW-year, respectively, after a plant reaches 30 years of age.¹ The average annual CAPEX in the EMM for existing CT plants is \$1.52/kW-year with no life extension costs. The other generating technologies in the EMM are not currently modeled with either CAPEX or life extension costs.

Need for Update to EIA's Treatment of Aging

The existing CAPEX values in the EMM were derived from yearly changes in plant in service accounts reported on the Federal Energy Regulatory Commission (FERC) Form No. 1 ("FERC Form 1").² The O&M costs in the EMM are also derived from FERC Form 1. However, FERC Form 1 does not cover merchant power plants or independent power producers (IPPs), leaving a large gap in the data. For example, out of approximately 35,000 generating units in the U.S., roughly 21,000 (60%) are IPPs. The EIA currently extrapolates data from FERC Form 1 to represent all plants covered in the EMM.

Sargent & Lundy's update to the EMM treatment of aging examined the potential adaptation of the EMM to represent changes in age-related spending patterns by various methods. This examination required the following steps:

¹ Internal communication with EIA, February 2018.

² FERC Form 1 is an annual regulatory requirement for major electric utilities, licensees, and others designed to collect non-confidential financial and operational information.

1. Gathering of in-house data from independent power projects and other plants, in addition to FERC Form 1 data.
2. Incorporation of O&M and capital spending forecasts by plant owners and operators with firsthand knowledge of plant operating history and future needs, thereby extending the range of plant operating years over which to characterize spending, compared with FERC Form 1 data that is limited to historical data.
3. Removal of capital spending for major modifications relating to environmental compliance, which would be modeled on a case-specific basis.
4. Identification of the most significant variables affecting age-related spending from commonly reported plant data—such as plant capacity (kW), annual generation (megawatt-hours [MWh]), age, fuel type, emission controls, and regulatory environment—using regression analysis.
5. Representation of age-related costs as either fixed (\$/kW-year) or variable (\$/MWh) according to generating technology and typical maintenance practices.
6. Application of capital spending and/or age-related costs to the EMM representations of long-term fixed O&M, variable O&M, and ongoing capital spending for each generating technology.

The assessment methodology used by Sargent & Lundy for the EMM update included an in-depth process of data validation, data normalization, and statistical testing, which is described in detail in Section 2.

ANALYSIS OF AGING IMPACTS IN PUBLICLY-REPORTED COST INFORMATION

Cost Breakdowns in Reported Data

Our analysis required an understanding of the cost breakdowns in the reported data between 1) capitalized (CAPEX) and expensed (O&M) cost components and 2) fixed O&M and variable O&M cost components. From a system modeling perspective, CAPEX and fixed O&M costs are typically expressed in \$/kW-year, while variable O&M is typically expressed in \$/MWh. Normalized cost breakdowns in these units are necessary for compatibility with the EMM.

The reporting formats of our in-house data and the FERC Form 1 data have a clear delineation between CAPEX and O&M. However, while the in-house data often contains an explicit breakdown between fixed and variable O&M, the FERC Form 1 accounts for O&M are not categorized as such. Rather, the reported O&M costs in a given account are the combined fixed and variable costs at the reported generating output. Thus, the variable O&M component cannot be clearly delineated from the total reported O&M in the FERC Form 1 data.

O&M costs for the following technologies are essentially all fixed: solar thermal (central tower), solar PV (single-axis tracking), geothermal, and wind. By definition, fixed O&M costs are independent of plant generation, so they are expressed in \$/kW-year.

O&M costs for the following technologies include a significant variable component: coal steam, gas/oil steam, gas/oil CC, gas/oil CTs, conventional hydropower, and pumped storage (hydraulic turbine reversible). By definition, variable O&M costs are proportional to plant generation and are typically expressed in \$/MWh.

As mentioned, the variable O&M components cannot be clearly delineated from the total reported O&M costs. For this assessment, the variable components were combined with the fixed components and expressed in \$/kW-year. The combined total O&M was found to correspond to the combined total O&M representation in the EMM, which includes a \$/MWh variable O&M breakout, as presented in the subsections below.

CAPEX spending values, expressed in \$/kW-year, were derived from the new dataset as an additive to the EMM O&M costs and as replacements for the existing EMM CAPEX representation for all technologies, except for gas/oil CC and gas/oil CTs. CAPEX spending for gas/oil CC and gas/oil CTs was found to be primarily for major maintenance events, which are already represented as a \$/MWh variable O&M cost in the EMM.

Data Compilation

The data compilation for this analysis consisted of the following annual plant data (any available data from 1980 to 2060, historical or forecasted by plant owner):

- Plant megawatts (MW) (summer)
- Annual MWh
- Annual O&M (from FERC Form 1)
- Annual O&M (from other sources)
- Annual CAPEX (from FERC Form 1)
- Annual CAPEX (from other sources)
- Annual environmental compliance costs

All available and validated cost data over the plant operating life, historical or forecasted, was normalized as follows for each plant:

- Annual O&M in 2017 \$/kW-year versus age (years from commercial operation date [COD])
- Annual CAPEX in 2017 \$/kW-year versus age (years from COD)
- Annual O&M + CAPEX in 2017 \$/kW-year versus age (years from COD)

In all cases, the yearly values are expressed in constant 2017 price levels and would increase annually with the inflation rate.

IDENTIFYING CHANGES IN SPENDING PATTERNS OVER PLANT LIFE

Differences in Spending Approach by Plant Type

CAPEX spending over the life of each plant represents a series of capital projects throughout the plant life, rather than a single life extension project. This consists of both discretionary spending and vendor-specified spending, examples of which are as follows:

- Discretionary spending is notable for most coal steam and gas/oil steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances. Typical industry-standard frequencies for repairs and replacements of major equipment within a coal plant are not absolute, but rather indicative of when a coal plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair.
- Vendor-specified major maintenance spending, such as commonly applied to gas/oil CC and gas/oil CTs, is based on cumulative hours of operation and/or cumulative starts. Implicitly, CAPEX spending for CC and CT plants is age-related and vendor-specified, and may be expressed as an equivalent \$/MWh value, which covers:
 - Major maintenance costs for periodic combustion inspections, hot gas path inspections, and major overhauls account for nearly all of the CAPEX expenditures. Many plant owners choose to capitalize major maintenance expenditures. As these expenditures normally follow the equipment vendor's recommendations, they maintain plant performance and extend the plant life.
 - Major one-time costs include rotor replacement, typically at about 150,000 equivalent operating hours, 7,000 equivalent starts, or within the first 30 years of plant operation. These costs are captured within the dataset. As gas turbines age, major maintenance parts often become available from third-party suppliers at a discounted price.

Potential Benefits of CAPEX and O&M Spending on Future Spending

CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

Potential Impacts of Plant Age on Future Spending

The spending characteristics described in the previous subsections are evident in the datasets, which reveal significant variability in plant spending as a function of age. Sargent & Lundy's evaluation therefore examined additional variables that might explain some of the variability in age-related spending: plant capacity (MW), capacity factor, external market conditions, regulatory environment, fuel characteristics, and FGD. These additional variables and their effects are described in the following subsections.

Effect of Plant Capacity (MW)

The effect of plant MW capacity on age-related spending, expressed in \$/kW-year, was examined by breaking the dataset into separate plant size categories, summarized as follows:

• Coal Steam ▪ All MW ▪ < 500 MW ▪ 500 MW – 1,000 MW ▪ 1,000 MW – 2,000 MW ▪ > 2,000 MW • Gas/Oil CC ▪ All MW ▪ < 500 MW ▪ 500 MW – 1,000 MW ▪ > 1,000 MW • Conventional Hydroelectric ▪ All MW ▪ < 100 MW ▪ 100 MW – 500 MW ▪ > 500 MW • Solar Photovoltaic ▪ < 5 MW ▪ > 5 MW	• Gas/Oil Steam ▪ < 500 MW ▪ 500 MW – 1,000 MW ▪ > 1,000 MW • Gas/Oil CT ▪ All MW ▪ < 100 MW ▪ 100 MW – 300 MW • Pumped Hydroelectric Storage ▪ All MW ▪ < 100 MW ▪ 100 MW – 500 MW ▪ > 500 MW • Wind Turbine ▪ All MW ▪ < 100 MW ▪ 100 MW – 200 MW ▪ > 200 MW

For some of the MW breakdowns above, the age coefficient in the regression analysis of CAPEX or O&M was found to be statistically significant. For the other MW breakdowns, an average value by age group was found to be more appropriate (see Table ES-1).

Effect of Plant Capacity Factor

CAPEX and O&M spending for the coal steam plants increased significantly with age when expressed on a \$/MWh basis. This was primarily a result of significant declines in plant capacity factors over time, as shown in Figure ES-1. A similar decline also occurred with the gas/oil steam plants, as shown in Figure ES-2.

Figure ES-1 — Capacity Factor vs. Age for All Coal Plants

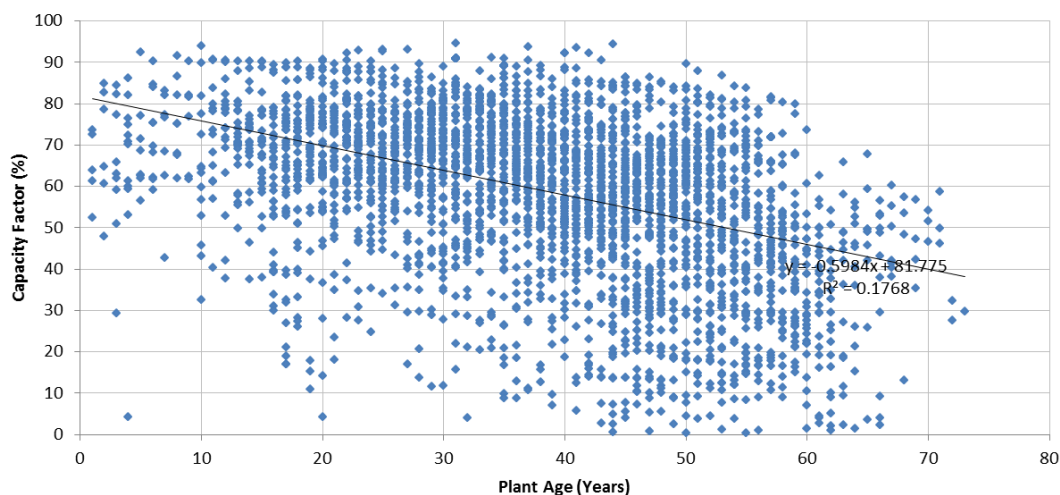
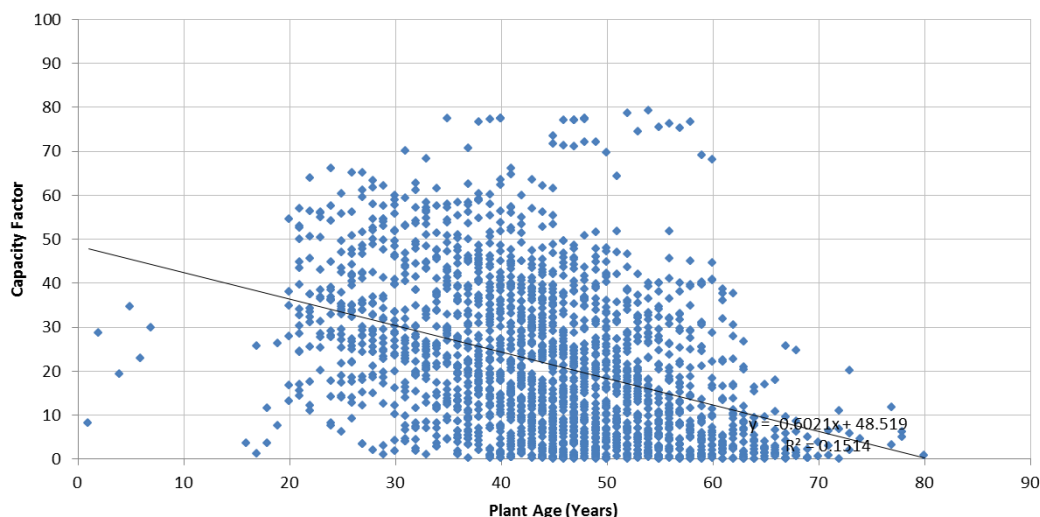


Figure ES-2 — Capacity Factor vs. Age for All Gas/Oil Steam Plants



Effect of External Market Conditions

The declining capacity factors with age, shown above, may have been a result of external market conditions and/or declining plant performance. These are areas for further exploration.

External market conditions over the same time period that may have contributed to lower capacity factors for coal steam and gas/oil steam plants include:

- Competition with lower gas prices and more efficient gas turbines
- Competition with renewable energy having lower dispatch costs
- Lower load growth due to increased amounts of energy efficiency and distributed resources

For some coal steam and gas/oil steam plants, the decline in capacity factor was also a result of less efficient heat rates, increased component failures, and increased outage rates over time. A major contributor to this decline in performance is often a result of increased cycling operation. Increased cycling leads to higher O&M and CAPEX spending over time.³

External market conditions may have also reduced the number of data points with higher age-related spending, due to plant retirements. The least efficient coal steam and gas/oil steam plants would likely retire under the following circumstances:

- Lower efficiency may contribute to less frequent dispatch and more cycling, leading to more component failures and higher spending
- Less frequent dispatch reduces hours of operation and power sales
- Lower power sales income may not adequately cover plant fixed costs

Some of the older coal steam plants (23 in this data sample) maintained consistently high capacity factors throughout their plant lives, with no real increase in spending. These high capacity factor plants had an installed capacity ranging from 70 MW to 2,400 MW, with an average of 850 MW and an average COD of 1961. These plants are slightly larger and older, on average, than the entire dataset of coal steam plants, which have an average installed capacity of 720 MW and an average COD of 1964. Table ES-2 shows the average capacity factors and O&M and CAPEX spending for the entire dataset of coal steam plants compared with the older consistently high capacity factor plants.

³ Kumar, N., Besuner, P., Lefton, S., and Agan, D., *Power Plant Cycling Costs*, National Renewable Energy Laboratory, April 2012.

Table ES-2 — High Capacity Factor Coal Plants – Spending Comparison

	Average – All Years	Years 1-20	Years 20-40	Years 40-80
Capacity Factor – All Plants	59.1%	66.8%	64.5%	52.9%
Capacity Factor – High CF Plants	74.0%	-	72.8%	74.4%
O&M – All Plants (2017 \$/kW-yr)	46.01	53.90	40.06	48.77
CAPEX – All Plants (2017 \$/kW-yr)	22.78	17.92	26.20	21.25
Total – All Plants (2017 \$/kW-yr)	68.67	71.86	66.25	69.82
O&M – High CF Plants (2017 \$/kW-yr)	36.65	-	31.07	38.78
CAPEX – High CF Plants (2017 \$/kW-yr)	20.26	-	23.13	19.16
Total – High CF Plants (2017 \$/kW-yr)	57.02	-	54.20	58.10

Market conditions at the older, high capacity factor plants may have led to fewer competing resources, which would support higher levels of dispatch and higher capacity factors. In addition, lower cycling requirements at those plants would have reduced spending requirements.

Effect of Regulatory Environment

Owners of coal steam plants in deregulated states were found to have no aversion to capital spending compared to plant owners in regulated states. Some of the difference may be due to higher labor costs in many of the deregulated states. This is the opposite of what would be expected, whereby plant owners in a deregulated environment would have a greater incentive to reduce O&M costs that cannot be passed through to ratepayers. The higher O&M spending is likely a result of other factors, such as higher average labor costs in deregulated states, which tend to have a higher percentage of union labor compared with regulated states. Therefore, the net effect of regulatory status on average O&M spending was not apparent at this level of detail.

Effect of Fuel Characteristics

Sargent & Lundy's regression analysis compared CAPEX spending for coal steam plants with bituminous and subbituminous coal types. The results indicate that average CAPEX spending is not likely affected by coal type at a high-level designation (i.e., bituminous/subbituminous) without more detailed coal specifications.

Effect of Flue Gas Desulfurization

The regression analysis indicated a significant difference in CAPEX spending for coal plants with FGD. The corrosive environment of chemicals and reagents significantly reduces the life of equipment such as pumps, mills, nozzles, valves, etc. These components must be replaced more frequently than at plants without FGD.

PROPOSED UPDATES TO EMM METHODOLOGY

The EMM captures changes in age-related spending patterns through multiple cost categories: CAPEX, O&M, fuel, energy sales, and capacity sales. The updates below relate only to the CAPEX and O&M. The focus of the work scope was to more accurately represent power plant aging impacts on CAPEX and O&M. Detailed derivations of fixed and variable O&M costs for the EMM were not part of the work scope.

Sargent & Lundy’s recommended updates to the fixed and variable O&M costs and CAPEX in the EMM for each generating technology are summarized in the tables below. Values are in constant 2017 price levels and are incurred in every year of plant operation, starting from commercial operation through plant retirement. In all cases, the yearly values would increase annually with the inflation rate.

Coal Steam

Sargent & Lundy’s analysis of the coal steam dataset (Appendix A) identified two significant variables affecting annual changes in real CAPEX spending (on a constant \$/kW-year basis): age and FGD. Variables not having a significant effect on annual changes in real CAPEX spending (on a constant \$/kW-year basis) were: plant capacity (kW), fuel type, and regulatory environment. When CAPEX spending was expressed on a constant \$/MWh basis, it was significantly related to age, primarily as a result of declining MWh generation with age.

Table ES-3 compares the new CAPEX values derived from the coal steam dataset with the CAPEX values currently used in the EMM. The new CAPEX values are similar in magnitude with the current EMM values over the long term, except that the new values follow a continuous pattern rather than a step pattern. As discussed below, the new values include life extension projects that occur throughout the plant life, including the first 30 years of operation.

Table ES-3 — Coal Steam CAPEX Results – All MW, All Capacity Factors

Net Total CAPEX (2017 \$/kW-year)	\$/kW-yr (Years 1-10)	\$/kW-yr (Years 10-20)	\$/kW-yr (Years 20-30)	\$/kW-yr (Years 30-40)	\$/kW-yr (Years 40-50)	\$/kW-yr (Years 50-60)	\$/kW-yr (Years 60-70)	\$/kW-yr (Years 70-80)
New Value – No FGD*	17.16	18.42	19.68	20.94	22.20	23.46	24.72	25.98
New Value – with FGD*	22.84	24.10	25.36	26.62	27.88	29.14	30.40	31.66
Existing EMM Value	17.55	17.55	17.55	24.62	24.62	24.62	24.62	24.62

*Calculated to the midpoint of the given age band.

“Life extension costs” in the existing CAPEX values are covered by the step increase after year 30. Life extension costs in the new CAPEX values are distributed throughout the plant life. This is a result of

discretionary spending, which is a common practice for most coal steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

Typical industry-standard frequencies for repairs and replacement of major equipment within a coal plant are not absolute, but rather indicative of when a coal plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair.

The new values also account for CAPEX relating to FGD. An FGD system tends to be capital-intensive to own and operate. The corrosive environment of chemicals and reagents significantly reduces the life of equipment such as pumps, mills, nozzles, valves, etc. These components must be replaced more frequently than at plants without FGD.

O&M costs for the coal steam plants include a significant variable component. By definition, variable O&M costs are proportional to plant generation and are typically expressed in \$/MWh. As previously mentioned, the variable O&M component cannot be clearly delineated from the total reported O&M in the FERC Form 1 data. For this assessment, the variable component was combined with the fixed component and expressed in \$/kW-year. The combined total O&M in the coal steam plant dataset for this analysis was found to be nearly equivalent to the existing combined total O&M representation in the EMM, which already includes the necessary \$/MWh variable O&M breakout (see Table ES-4).

Table ES-4 — Coal Steam O&M Comparison with Existing EMM

	Fixed O&M (2017 \$/kW-yr)	Variable O&M (2017 \$/MWh)*	Variable O&M (2017 \$/kW-yr)**	Total O&M (2017 \$/kW-yr)**
Coal Steam Dataset Results – All Plants	36.81	1.78	9.20	46.01
< 500 MW	44.21	1.78	9.20	53.41
500 MW – 1,000 MW	34.02	1.78	9.20	43.22
1,000 MW – 2,000 MW	28.52	1.78	9.20	37.72
> 2,000 MW	33.27	1.78	9.20	42.47
Existing EMM Value***	40.63	1.78	9.20	49.83

*Fixed and variable split is estimated using the existing EMM variable O&M cost of \$1.78/MWh.

**Calculated at the coal steam dataset average capacity factor of 59%.

***Source: Internal communication with EIA, February 2018.

Gas/Oil Steam

The analysis of the gas/oil steam dataset (Appendix B) identified only one significant variable affecting annual changes in real CAPEX spending (on a constant \$/kW-year basis): plant capacity (kW). That is, CAPEX was lower on a \$/kW-year basis for larger plant sizes due to economies of scale. When CAPEX spending was expressed on a constant \$/MWh basis, it was significantly related to age, primarily as a result of declining MWh generation with age.

Table ES-5 compares the new CAPEX values derived from the gas/oil steam dataset with the CAPEX values currently used in the EMM. The new CAPEX values are similar in magnitude with the current EMM values over the long term, except that the new values follow a continuous pattern rather than a step pattern. As discussed below, the new values include life extension projects that occur throughout the plant life, including the first 30 years of operation.

Table ES-5 — Gas/Oil Steam CAPEX Results

Plant Size	Net Total CAPEX (2017 \$/kW-year)	
	Years 1-30	Years 30-80
Gas/Oil Steam Dataset Results – All Plants	15.96	15.96
New Value: < 500 MW	18.86	18.86
New Value: 500 MW – 1,000 MW	11.57	11.57
New Value: > 1,000 MW	10.82	10.82
Existing EMM Value	9.14	16.21

“Life extension costs” in the existing CAPEX values are covered by the step increase after year 30. Life extension costs in the new CAPEX values are distributed throughout the plant life. This is a result of discretionary spending, which is a common practice for most gas/oil steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

Typical industry-standard frequencies for repairs and replacement of major equipment within a gas/oil steam plant are not absolute, but rather indicative of when a gas/oil steam plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair.

Typical industry-standard frequencies for repairs and replacement of major equipment are similar to those of coal units, as presented in the previous section.

The use of a constant annual value on the modeling of annual CAPEX would be similar to representing a major maintenance reserve account (MMRA), which is commonly used for non-recourse financing of power projects. MMRA's are usually required by power project lenders over the tenor of debt as protection against maintenance spending uncertainty. An MMRA is typically funded by annual contributions drawn from a project's cash flow, sometimes as a uniform annual amount. Annual contribution levels are based on estimated long-term maintenance expenditure patterns. Over the long term, annual contributions represent a smoothed version of irregular actual annual values.

The use of a long-term average value also recognizes the inherent variability in long-term spending patterns for any given plant. Since the EMM is a large-scale model, it is conceptually designed to represent plant types as averages rather than as individual plants. When summed across a large number of plants in a utility system, some of the variability in annual expenditure patterns would tend to even out. The level of accuracy between average values and year-specific values for a given plant type is nearly equivalent in large-scale models.

O&M costs for the gas/oil steam plants include a significant variable component, although typically smaller than coal units. The combined total O&M in the gas/oil steam plant dataset for this analysis was found to be somewhat lower than the existing combined total O&M representation in the EMM, which already includes the necessary \$/MWh variable O&M breakout (see Table ES-6). However, the variable O&M of \$8.23/MWh in the EMM is much higher than values Sargent & Lundy has observed in actual gas/oil steam plants and should not be higher than the variable O&M of \$1.78/MWh in the EMM used for the coal units.

Table ES-6 — Gas/Oil Steam O&M Comparison with Existing EMM

	Fixed O&M (2017 \$/kW-yr)	Variable O&M (2017 \$/MWh)*	Variable O&M (2017 \$/kW-yr)**	Total O&M (2017 \$/kW-yr)**
Gas/Oil Steam Dataset Results – All Plants	24.68	1.00	1.84	26.52
< 500 MW	29.73	1.00	1.84	31.57
500 MW – 1,000 MW	17.98	1.00	1.84	19.82
> 1,000 MW	14.51	1.00	1.84	16.35
Existing EMM Value***	19.68	8.23	15.14	34.82

*Fixed and variable split is estimated using an approximate value for variable O&M of \$1.00/MWh based on confidential projects.

**Calculated at the gas/oil steam dataset average capacity factor of 21%.

***Source: Internal communication with EIA, February 2018.

Gas/Oil Combined Cycle and Gas/Oil Combustion Turbine

As with coal steam and gas/oil steam plants, CAPEX spending for gas/oil CC and gas/oil CT plants represents a series of capital projects throughout the plant life, which include projects for “life extension.” Most CAPEX spending for gas/oil CC and gas/oil CT plants is for vendor-specified major maintenance events. Other CAPEX spending, other than for emission control retrofits, is relatively minor.

Vendor-specified major maintenance spending is based on cumulative hours of operation and/or cumulative starts. Implicitly, CAPEX spending for CC and CT plants is age-related and vendor-specified, and may be expressed as an equivalent \$/MWh value, which covers:

- Major maintenance costs for periodic combustion inspections, hot gas path inspections, and major overhauls account for nearly all of the CAPEX expenditures. Many plant owners choose to capitalize major maintenance expenditures. As these expenditures normally follow the equipment vendor’s recommendations, they maintain plant performance and extend the plant life.
- Major one-time costs include rotor replacement, typically at about 150,000 equivalent operating hours, 7,000 equivalent starts, or within the first 30 years of plant operation. These costs are captured within the dataset. As gas turbines age, major maintenance parts often become available from third-party suppliers at a discounted price.

As with MMRAAs described in the previous subsection, major maintenance contracts are priced according to smoothed versions of irregular long-term expenditure patterns. Apart from adjustments for operating conditions, major maintenance (and nearly all of the CAPEX) is effectively priced as an equal annual value, expressed in constant \$/MWh with annual escalation.

Table ES-7 compares the new CAPEX and O&M values derived from the gas/oil CC and CT datasets with the values currently used in the EMM. As indicated above, the combined CAPEX and O&M values in the datasets would be expected to correspond to the combined CAPEX and O&M in the EMM, with most of the CAPEX in the EMM represented as variable O&M. However, some of the EMM values are higher than values Sargent & Lundy has observed in actual CC and CT plants, as detailed below:

- The EMM fixed and variable O&M costs for CC plants are reasonable for smaller CC installations (< 500 MW) but high for larger plants.
- The EMM CAPEX addition of \$7/kW-year after 30 years of operation should not be represented as a fixed cost. As previously mentioned, age-related costs would be built into the \$/MWh variable O&M and would be a function of cumulative operating hours rather than operating years.

- The EMM fixed and variable O&M costs for CT plants are high for all plant sizes. Since most CT plants operate as peaking plants with low capacity factors, the variable O&M component is likely to be based on equivalent starts rather than equivalent operating hours.

Table ES-7 — Gas/Oil CC and CT CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 \$/kW-yr)	Variable O&M (2017 \$/MWh)*	Variable O&M (2017 \$/kW-yr)*	Total O&M (2017 \$/kW-yr)*	CAPEX (2017 \$/kW-yr)	Total O&M and CAPEX (2017 \$/kW-yr)**
CC Dataset Results (All Plants)	13.08	3.91	(included in CAPEX)	13.08	15.76	28.84
< 500 MW	15.62	4.31	(included in CAPEX)	15.62	17.38	33.00
500 MW – 1,000 MW	9.27	3.42	(included in CAPEX)	9.27	13.78	23.05
> 1,000 MW	11.68	3.37	(included in CAPEX)	11.68	13.57	25.25
Existing EMM Value**	27.52	2.64	10.64	38.16	0.18; 7.25 (after year 30)	38.34; 45.41 (after year 30)
CT Dataset Results (All Plants)	5.33	(starts based)	(included in CAPEX)	5.33	6.90	12.23
< 100 MW	5.96	(starts based)	(included in CAPEX)	5.96	9.00	14.96
100 MW – 300 MW	6.43	(starts based)	(included in CAPEX)	6.43	6.18	12.61
> 300 MW	3.99	(starts based)	(included in CAPEX)	3.99	6.95	10.94
Existing EMM Value***	12.60	14.63	5.13	17.73	1.52	19.25

*Fixed and variable split is estimated, assuming all CAPEX costs are represented as variable O&M, either hours-based (\$/MWh) or starts-based (\$/start).

**Calculated at the dataset average capacity factor of 46% for CC and 4% for CT.

***Source: Internal communication with EIA, February 2018.

Conventional Hydroelectric

Overall, the conventional hydroelectric dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size. The average CAPEX value over all operating years is \$22.56/kW-year. The dataset does support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

Annual O&M spending in 2017 \$/kW-year = 22.360 + (0.073 × age)

The CAPEX and O&M values derived from the conventional hydroelectric dataset are significantly higher than the existing values used in the EMM (Table ES-8) and outside the range of values published in the AEO⁴ and by the International Renewable Energy Agency (IRENA).⁵ The reasons for this discrepancy are not known without having the data sample used for the EMM values. It appears that the EMM does not currently account for CAPEX or life extension expenditures for conventional hydroelectric.

Table ES-8 — Hydroelectric CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 \$/kW-yr)	Variable O&M (2017 \$/MWh)	CAPEX (2017 \$/kW-yr)	Total O&M and CAPEX (2017 \$/kW-yr)
Conventional Hydroelectric Dataset Results – All Plants	22.00	-	22.56	44.56
Existing EMM Value*	14.58	0.00	0.00	14.58

*Source: Internal communication with EIA, February 2018.

Pumped Storage

Overall, the pumped storage dataset does not support any age-related CAPEX or O&M spending trend across the full data and on any of the subsets by plant size. The average value over all operating years is \$14.83/kW-year for CAPEX and \$23.63/kW-year for O&M (Table ES-9). The existing values used in the EMM are not available.

Table ES-9 — Pumped Storage CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 \$/kW-yr)	Variable O&M (2017 \$/MWh)	CAPEX (2017 \$/kW-yr)	Total O&M and CAPEX (2017 \$/kW-yr)
Pumped Storage Dataset Results – All Plants	23.63	-	14.83	38.46
Existing EMM Value	N/A	N/A	N/A	N/A

Solar Photovoltaic

The solar PV dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size. Sargent & Lundy notes that the average change in the “Total Cost of Plant” (TCP) reported in the FERC data for the limited usable dataset (15 sites not filtered out) is approximately \$26/kW-year. However, due to the limited dataset, lack of clarity on what qualifies as a change to the TCP, and general lack of

⁴ Energy Information Administration, *Annual Energy Outlook 2018*, Cost and Performance Characteristics (Table 8.2), February 2018.

⁵ International Renewable Energy Agency, *Renewable Energy Technologies: Cost Analysis Series, Hydropower*, June 2012.

consistency in the FERC capital cost data provided, Sargent & Lundy advises that caution be taken when trying to establish any definitive solar PV capital cost trends from the FERC data.

The solar PV dataset appears to support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, based upon closer inspection of the data, a more appropriate predictor of O&M spending for this dataset would be a simple average across all years. This determination is based on the lack of data points for plants over 10 years old.

When considering the average O&M costs per plant as a single data point and then averaging those values, Sargent & Lundy calculated an average O&M cost of \$75/kW-year from the FERC data for sites under 5 MW. Using the same method, an average O&M cost of \$15/kW-year was calculated from the FERC data for sites over 5 MW.

By comparison, the EMM uses an average O&M value of \$28.47/kW-year for all solar PV plants and an average CAPEX value of zero. Neither dataset captures the most recent trends in solar PV technology due to rapid changes in cost, size, and efficiency.

Solar Thermal

There are no solar thermal power plants that report operating data in FERC Form 1. Industry-wide, there are a limited number of solar thermal projects; a majority of which have been constructed within the last 10 years—the exception being small test facilities and the Solar Energy Generating Systems (SEGS) plants built in the 1980s.

Geothermal

Overall, the geothermal dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size. Instead, we recommend a simple average be used across the full age range. Sargent & Lundy recommends using the indicated \$/kW-year average in Table ES-10 for O&M and CAPEX spending. As shown in the table, it appears the EMM does not currently account for CAPEX or life extension expenditures for geothermal plants.

Table ES-10 — Geothermal CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 \$/kW-yr)	Variable O&M (2017 \$/MWh)	CAPEX (2017 \$/kW-yr)	Total O&M and CAPEX (2017 \$/kW-yr)
Geothermal Dataset Results – All Plants	157.10	-	40.94	198.04
Existing EMM Value**	91.66	0.00	0.00	91.66

**Source: Internal communication with EIA, February 2018.

Wind

The dataset supports age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equations shown in Table ES-11. Age was not a significant predictor of CAPEX spending, although CAPEX was found to vary significantly as a function of capacity (kW). That is, CAPEX was lower on a \$/kW-year basis for larger plant sizes due to economies of scale.

The CAPEX and O&M values derived from the wind dataset are significantly higher than the existing values used in the EMM. The reasons for this discrepancy are not known without having the data sample used for the EMM values. Neither data sample is stratified by wind technology or turbine size. Neither dataset captures the most recent trends in wind turbine technology due to rapid changes in cost, size, and efficiency.

Table ES-11 — Wind CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 \$/kW-yr)	Variable O&M (2017 \$/MWh)	CAPEX (2017 \$/kW-yr)
Wind Dataset Results – All Plants	$31.66 + (1.22 \times \text{age})$	0.00	18.29
< 100 MW	$39.08 + (1.12 \times \text{age})$	0.00	20.48
100 MW – 200 MW	$23.80 + (1.17 \times \text{age})$	0.00	16.93
> 200 MW	$26.78 + (0.92 \times \text{age})$	0.00	13.48
Existing EMM Value*	29.31	0.00	0.00

*Source: Internal communication with EIA, February 2018.

RECOMMENDED AREAS FOR FURTHER STUDY

Based on our analyses performed for the update to the EMM treatment of age-related spending, Sargent & Lundy identified several areas that warrant further study, including:

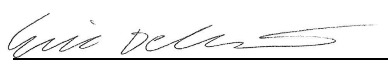
- Impact of regional labor cost differences versus the effects of a regulated/deregulated environment;
- Compatibility of EMM plant technology and size breakdowns and fixed/variable O&M cost breakdowns with proposed EMM updates;
- Identification of the factors supporting consistently high capacity factors over the plant lives at particular coal units; and
- Impact of aging on plant performance (heat rates, capacity derates, etc.). If capacity factors decline, regardless of the causes, this includes examining the impact of the lower capacity factors on plant costs and performance.

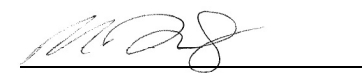
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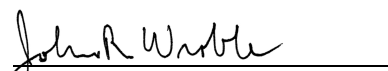

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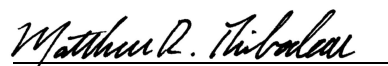

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1. INTRODUCTION

Sargent & Lundy LLC (Sargent & Lundy) was engaged by the Office of Energy Analysis (OEA) of the U.S. Energy Information Administration (EIA), an agency within the U.S. Department of Energy (DOE), to conduct a study to improve the ability of the Electricity Market Module (EMM) to represent the changing landscape of electricity generation and to more accurately represent costs, which will improve projections for generating capacity, generator dispatch, and electricity prices. The EMM is a submodule within the EIA's National Energy Modeling System (NEMS), a computer-based energy supply modeling system that is used for the EIA's *Annual Energy Outlook* (AEO) and other analyses.

In particular, the purpose of this study was to provide information that may enable the EIA to more accurately represent costs associated with operation of the existing fleet of U.S. generators as they age. This includes capital expenditures (CAPEX) related to ongoing operations as well as potential increases in operations and maintenance (O&M) costs attributable to declining performance due to aging.

The primary focus of our analysis was existing fossil fuel generators. The study also included existing wind, solar, hydro, and other renewable generators. The work scope did not include analysis of nuclear units.

The generating capacity types represented in the EMM that were included in our analysis comprised:

- Coal steam plants
- Gas/oil steam plants
- Gas/oil combined-cycle (CC) plants
- Gas/oil combustion turbines (CTs)
- Conventional hydropower
- Pumped storage – hydraulic turbine reversible
- Solar thermal – central tower
- Solar photovoltaic (PV) – single-axis tracking
- Geothermal
- Wind

This final report is the fourth milestone task of the EMM update project, which is organized as follows:

- Task 1 – Analysis of publicly available information for use in estimating capital costs related to ongoing operations for specified plant types.

- Task 2 – Analysis of publicly available information for use in estimating changes in O&M expenditures due to aging for specified plant types.
- Task 3 – Interim report on assembled aging-related capital and O&M costs.
- Task 4 – Final report on modeling aging-related capital and O&M costs.

2. ASSESSMENT METHODOLOGY

2.1 BACKGROUND

The EMM currently accounts for power plant aging through a one-time step increase in annual CAPEX. These added expenditures are intended to extend the life or preserve the performance of an existing generator, including repowering, major repairs or retrofits, and/or covering increases in maintenance required to mitigate the adverse effects of aging, including any decreases in plant performance. The portion of the annual CAPEX associated with the step increase is referred to as “life extension costs.”

As modeled in the EMM, a generating unit is assumed to retire if the expected revenues from the generator are not sufficient to cover the annual going-forward costs and if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, O&M costs, and annual CAPEX. The average annual CAPEX in the EMM is \$0.18 per kilowatt-year (/kW-year) for existing CC plants, \$9/kW-year for existing gas/oil steam plants, and \$18/kW-year for existing coal plants (in constant 2017 dollars). These amounts are increased to \$7.25/kW-year, \$16/kW-year, and \$25/kW-year, respectively, after a plant reaches 30 years of age.⁶ The average annual CAPEX in the EMM for existing CT plants is \$1.52/kW-year with no life extension costs. The other generating technologies in the EMM are not currently modeled with either CAPEX or life extension costs.

The existing CAPEX values in the EMM were derived from yearly changes in plant in service accounts reported on the Federal Energy Regulatory Commission (FERC) Form No. 1 (“FERC Form 1”).⁷ The O&M costs in the EMM are also derived from FERC Form 1. However, FERC Form 1 does not cover merchant power plants or independent power producers (IPPs), leaving a large gap in the data. For example, out of approximately 35,000 generating units in the U.S., roughly 21,000 (60%) are IPPs. The EIA currently extrapolates data from FERC Form 1 to represent all plants covered in the EMM.

Sargent & Lundy’s update to the EMM treatment of aging examined the potential adaptation of the EMM to represent changes in age-related spending patterns by various methods. This examination required the following steps:

1. Gathering of in-house data from independent power projects and other plants, in addition to FERC Form 1 data.

⁶ Internal communication with EIA, February 2018.

⁷ FERC Form 1 is an annual regulatory requirement for major electric utilities, licensees, and others designed to collect non-confidential financial and operational information.

2. Incorporation of O&M and capital spending forecasts by plant owners and operators with firsthand knowledge of plant operating history and future needs, thereby extending the range of plant operating years over which to characterize spending, compared with FERC Form 1 data that is limited to historical data.
3. Removal of capital spending for major modifications relating to environmental compliance, which would be modeled on a case-specific basis.
4. Identification of the most significant variables affecting age-related spending from commonly reported plant data—such as plant capacity (kW), annual generation (megawatt-hours [MWh]), age, fuel type, emission controls, and regulatory environment—using regression analysis.
5. Representation of age-related costs as either fixed (\$/kW-year) or variable (\$/MWh) according to generating technology and typical maintenance practices.
6. Application of capital spending and/or age-related costs to the EMM representations of long-term fixed O&M, variable O&M, and ongoing capital spending for each generating technology.

The assessment methodology used by Sargent & Lundy for the EMM update included an in-depth process of data validation, data normalization, and statistical testing, which is described in detail in the following subsections.

2.2 SOURCES OF COST INFORMATION

2.2.1 FERC Form 1 Data

Sargent & Lundy reviewed the FERC Form 1 data through 2016, financial information available from other publicly available sources, and detailed in-house project information with which we are familiar. We assembled a sufficient volume of source material for each technology in order to characterize the distribution of capital and O&M expenditures over the life of a plant.

We obtained the FERC Form 1 data via ABB's Velocity Suite EV Power database. Using the available FERC Form 1 data, we assessed and summarized the "Cost of Plant" components of the data by major plant type category. The "Cost of Plant" components include the following categories of "Electric Plant in Service" accounts in FERC Form 1 data, which have been reported annually since the database's inception:

- Steam Power Generation – Cost of Plant
 - 310 Land and land rights.
 - 311 Structures and improvements.

- 312 Boiler plant equipment.
- 313 Engines and engine-driven generators.
- 314 Turbo generator units.
- 315 Accessory electric equipment.
- 316 Miscellaneous power plant equipment
- 317 Asset retirement costs for steam production plant.
- Hydraulic Power Generation – Cost of Plant
 - 330 Land and land rights.
 - 331 Structures and improvements.
 - 332 Reservoirs, dams, and waterways.
 - 333 Water wheels, turbines, and generators.
 - 334 Accessory electric equipment.
 - 335 Miscellaneous power plant equipment.
 - 336 Roads, railroads, and bridges.
 - 337 Asset retirement costs for hydraulic production plant.
- Other Power Generation – Cost of Plant
 - 340 Land and land rights.
 - 341 Structures and improvements.
 - 342 Fuel holders, producers, and accessories.
 - 343 Prime movers.
 - 344 Generators.
 - 345 Accessory electric equipment.
 - 346 Miscellaneous power plant equipment.
 - 347 Asset retirement costs for other production plant.

The sum of these components includes the original construction cost and all ongoing CAPEX. Therefore, each annual FERC Form 1 submittal includes the cumulative additions to the “Total Cost of Plant” (TCP). Annual changes in the TCP between each submittal year give an indication of the amount of CAPEX for the given year. Sargent & Lundy assessed and summarized these annual changes to derive age-related CAPEX, as discussed in the following subsections.

Sargent & Lundy also assessed and summarized the annual O&M expenditures for each technology as reported under the “Electric Operation and Maintenance Expenses” accounts in FERC Form 1:

- Steam Power Generation – O&M
 - 500 Operation supervision and engineering.
 - 502 Steam expenses.
 - 505 Electric expenses.
 - 506 Miscellaneous steam power expenses.
 - 507 Rents.
 - 509 Allowances.
 - 510 Maintenance supervision and engineering.
 - 511 Maintenance of structures.
 - 512 Maintenance of boiler plant.
 - 513 Maintenance of electric plant.
 - 514 Maintenance of miscellaneous steam plant.
- Hydraulic Power Generation – O&M
 - 535 Operation supervision and engineering.
 - 536 Water for power.
 - 537 Hydraulic expenses.
 - 538 Electric expenses.
 - 539 Miscellaneous hydraulic power generation expenses.
 - 540 Rents.
 - 541 Maintenance supervision and engineering.
 - 542 Maintenance of structures.
 - 543 Maintenance of reservoirs, dams, and waterways.
 - 544 Maintenance of electric plant.
 - 545 Maintenance of miscellaneous hydraulic plant.
- Other Power Generation – O&M
 - 546 Operation supervision and engineering.
 - 548 Generation expenses.
 - 549 Miscellaneous other power generation expenses.
 - 550 Rents.
 - 551 Maintenance supervision and engineering.
 - 552 Maintenance of structures.
 - 553 Maintenance of generating and electric plant.
 - 554 Maintenance of miscellaneous other power generation plant.

The above O&M expenditures are reported for individual power plants. Administrative and general (A&G) expenses in FERC accounts 920 through 935 are reported for the entire utility company. A&G expenses in these accounts were not included in this evaluation because of the significant differences in company sizes, mix of resources, and methods of allocating costs to individual power plants. In a similar manner, corporate-level A&G costs were also excluded from Sargent & Lundy's internal data.

The above FERC accounts 500 to 554 correspond to the following fixed and variable O&M components:

- Fixed O&M
 - Labor
 - Maintenance materials
 - Supplies and miscellaneous expenses
- Variable O&M
 - Consumables (chemicals, water, waste disposal, etc.)
 - Other costs proportional to generating output

The FERC accounts do not explicitly break out labor costs, as most of the accounts include both labor and non-labor expenditures. Likewise, the FERC accounts are not categorized according to fixed and variable cost components. The O&M costs in a given account are combined fixed and variable costs at the reported generating output.

2.2.2 Sargent & Lundy Internal Data

In addition, Sargent & Lundy compared publicly available, non-fuel-related financial and cost data with a characterization of proprietary information with which we are familiar, to the extent permissible by applicable confidentiality agreements (information about plant location, equipment type, or plant configuration was never disclosed from the proprietary data). We utilized our knowledge of actual projects to assemble a characterization of life extension/repowering costs from our in-house data.

A large portion of the in-house data used in this report was developed from business plan forecasts that capture actual budgeted costs for scheduled projects as well as longer-term projections. Historical spending data for standalone projects was not usable for this analysis, unless Sargent & Lundy had access to the complete O&M or CAPEX spending totals at a given plant for a given year. For consistent comparisons with other plants over time, each O&M or CAPEX data point needed to represent a comprehensive total of all spending projects.

2.2.3 Other Data Sources

Other publicly available data sources were searched, including regulated utility filings with public utility commissions, routine financial reports for publicly traded companies, utility integrated resource plans, data reported by various municipalities and electric cooperatives, and requests for proposals (RFPs) for plant improvements at public power entities. Cost data from each of these sources was found to be unsuitable for this study for one or more of the following reasons:

- Cost data was for initial capital investment costs only, with no O&M or ongoing CAPEX spending reported;
- Annual O&M or annual CAPEX amounts were for limited purposes and not representative of a complete year; and/or
- Annual O&M and annual CAPEX amounts were aggregated across business units and not assigned to specific plants.

Several publications or studies of power plant aging and life extension costs were used, which are cited herein.

2.3 DATA VALIDATION

Sargent & Lundy's approach to validating the FERC Form 1 data involved the following steps (note that capitalized words are proper FERC Form 1 terms):

1. For each Plant/Prime Mover combination (e.g., steam turbine, CC, simple-cycle CT), determine the difference between the prior and current year TCP reported in the FERC data. Note that a plant can have multiple prime movers on site (e.g., CT units and steam turbine units). Fortunately, that data is reported separately.
2. Flag and invalidate any years where the difference is negative (i.e., a decreasing value of the TCP).
3. Identify if the TCP difference is significantly due to asset retirement costs. If so, flag this plant reporting year consider it invalid, as capital would have been spent on non-aging items.
4. Identify if there has been any year-to-year change in nameplate capacity. If so, flag this plant reporting year and consider it invalid, because the TCP would be assumed to be spent on an expansion or addition.
5. Identify if any sulfur dioxide (SO₂), nitrogen oxide (NO_x), particulate matter (PM), or mercury (Hg) control equipment was installed for the plant reporting year. If so, flag that plant reporting year and consider it invalid, because capital would have been spent on non-aging items. The year

- prior to or after the actual emissions control installation date is sometimes flagged as well, because of when the spending occurred (this is usually a judgement call).
6. Identify if any unit at the plant has been retired in a plant reporting year. If so, flag that plant reporting year and consider invalid, because capital would have been spent on non-aging items. Also, if the plant's TCP dropped significantly the last few years before retirement, flag those plant reporting years and consider them invalid.
 7. Cross-check if any additional units at the plant site (using the same technology) show too great of time duration between installed dates of the units. If the first unit and the last unit installed is greater than 10 years apart, then flag the data and consider it invalid, because the TCP difference would not reflect the actual age of the plant (considered to be the age of the first unit). This was flagged as "Removed due to non-equal units at site."
 8. If any TCP is reported to be zero for most of all of the reporting years of the plant, consider the data invalid.
 9. If the TCP difference is highly volatile, flag and invalidate at discretion. For example, if one year TCP drops from \$2,000/kW-year to \$1,000/kW-year and then back to \$2,000/kW-year in the year after, this would be considered highly volatile for those two reporting years.
 10. If a reporting plant has only one or two years of reported TCP data, flag the plant and do not use its data.
 11. If any plant reports negative Total O&M Costs, flag that year and do not use it.
 12. Use only data that is valid for both CAPEX spending and O&M spending in the analysis of combined CAPEX and O&M spending. Otherwise, analyze CAPEX spending and O&M spending separately. Sargent & Lundy found that a large portion of the data points determined to be valid for CAPEX spending were also valid for O&M spending.

The resulting data points from this validation process are summarized in Table 2-1.

For each year of plant data, we also compiled the associated nameplate capacity (MW) and annual generation (MWh). EIA Form 860 was used to confirm the plant technology, environmental equipment, year in service, and other attributes.

Table 2-1 — Summary of Valid Data Points

Technology / (Dataset Identifier)	Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
				O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
Coal (10)	All MW	All	3,713	3,098	3,109	655	615
	< 500 MW	All	1,592	1,274	1,284	318	318
	500 MW – 1,000 MW	All	986	689	689	337	297
	1000 MW – 2,000 MW	All	813	813	814	0	0
	> 2,000 MW	All	322	322	322	0	0
	All MW	< 50%	965	889	896	76	76
	All MW	> 50%	2,748	2,209	2,213	579	539
Gas/Oil Steam (20)	All MW	All	2,220	2,204	2,226	20	16
	< 500 MW	All	1,377	1,361	1,366	20	16
	500 MW – 1,000 MW	All	488	488	489	0	0
	> 1,000 MW	All	355	355	355	0	0
Gas/Oil Combined Cycle (30)	All MW	All	1,367	980	981	408	387
	< 500 MW	All	764	462	463	304	302
	500 MW – 1,000 MW	All	547	462	463	104	85
	> 1,000 MW	All	177	177	177	0	0
	All MW	< 50%	843	661	662	203	182
	All MW	> 50%	524	319	319	205	205
Gas/Oil Combustion Turbine (40)	All MW	All	5,041	4,905	4,949	437	136
	< 100 MW	All	2,873	2,873	2,911	189	0
	100 MW – 300 MW	All	1,341	1,239	1,248	177	102
	> 300 MW	All	901	867	875	71	34
Conventional Hydroelectric (50)	All MW	All	2,179	2,179	2,180	0	0
	< 100 MW	All	1,272	1,272	1,272	0	0
	100 MW – 500 MW	All	924	924	925	0	0
	> 500 MW	All	41	41	41	0	0

Technology / (Dataset Identifier)	Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
				O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
Pumped Storage Hydroelectric (55)	All MW	All	226	226	227	0	0
	< 100 MW	All	12	12	12	0	0
	100 MW – 500 MW	All	88	88	88	0	0
	> 500 MW	All	126	126	126	0	0
Solar Thermal (60)			0				
Solar Photovoltaic (65)	All MW	All	57	410	57	0	0
Geothermal (70)							
Wind Turbine (80)	All MW	All	310	310	310	270	0
	< 100 MW	All	174	174	174	165	0
	100 MW – 200 MW	All	91	91	91	56	0
	> 200 MW	All	51	51	51	73	0

Note: A data point is one reported value for one year by one plant, i.e., a plant that reports values for 25 years will have 25 data points.

2.4 DATA NORMALIZATION

Sargent & Lundy developed a Microsoft Excel model template for compiling and normalizing all of the CAPEX and O&M data, subsequent to the initial review and validation steps outlined in the previous sections. The data normalization consisted of the following steps:

Step 1: Assign data “identifiers” for each plant:

Technology ID:

- 10 = Coal Steam Plants
- 20 = Gas/Oil Steam Plants
- 30 = Gas/Oil CC Plants
- 40 = Gas/Oil CTs
- 50 = Conventional Hydropower; Pumped Storage – Hydraulic Turbine Reversible
- 60 = Solar Thermal – Central Tower;
- 65 = Solar PV – Single-Axis Tracking
- 70 = Geothermal
- 80 = Wind

Data source:

- 1 = FERC Form 1
- 2 = Sargent & Lundy Internal Data
- 3 = Other Public Source

Step 2: Enter basic information for each plant:

- Year of commercial operation date (COD)
- End year of project life or forecast period
- Nameplate capacity (MW)
- Summer net capacity (MW)

Step 3: Adjust pricing basis for raw data:

- If provided in current dollars, adjust to 2017 dollars
- If provided in 2017 dollars, do not adjust
- If provided in constant dollars of another reference year, adjust to 2017 dollars

Step 4: Enter annual data for each plant (any available data from 1980 to 2060, historical or forecasted by plant owner):

- Plant MW (summer)
- Annual MWh
- Annual O&M (from FERC Form 1)
- Annual O&M (from other sources)
- Annual CAPEX (from FERC Form 1)
- Annual CAPEX (from other sources)
- Annual environmental compliance costs

Using the inputs from Steps 1-4 above, the “Normalizer” worksheet derives the following for each plant:

- Annual O&M in 2017 \$/kW-year versus age (years from COD)
- Annual CAPEX in 2017 \$/kW-year versus age (years from COD)
- Annual O&M + CAPEX in 2017 \$/kW-year versus age (years from COD)

The output worksheets (“O&M,” “CAPEX,” and “O&M + CAPEX”) each have the following user-selected filters:

- Technology ID (10, 20, 30, etc.)

- Data source (1,2, or 3)
- MW range (low, high)
- Outlier maximum \$/kW
- Annual O&M + CAPEX in 2017 \$/kW-year versus age (years from COD)

Each output worksheet (“O&M,” “CAPEX,” and “O&M + CAPEX”) calculates the following for a given user-defined set of filters:

- \$/kW-year (2017 dollars) versus age
- Statistical tests of linear curve fit: annual spending in 2017 \$/kW-year = \$/kW-year (y-intercept) + [constant × age (years from COD)]
- Average \$/kW-year (2017 dollars) for age bands (10-year bands, 30-year bands, and all-years band)

In all cases, the yearly values are expressed in constant 2017 price levels and increase annually with the inflation rate.

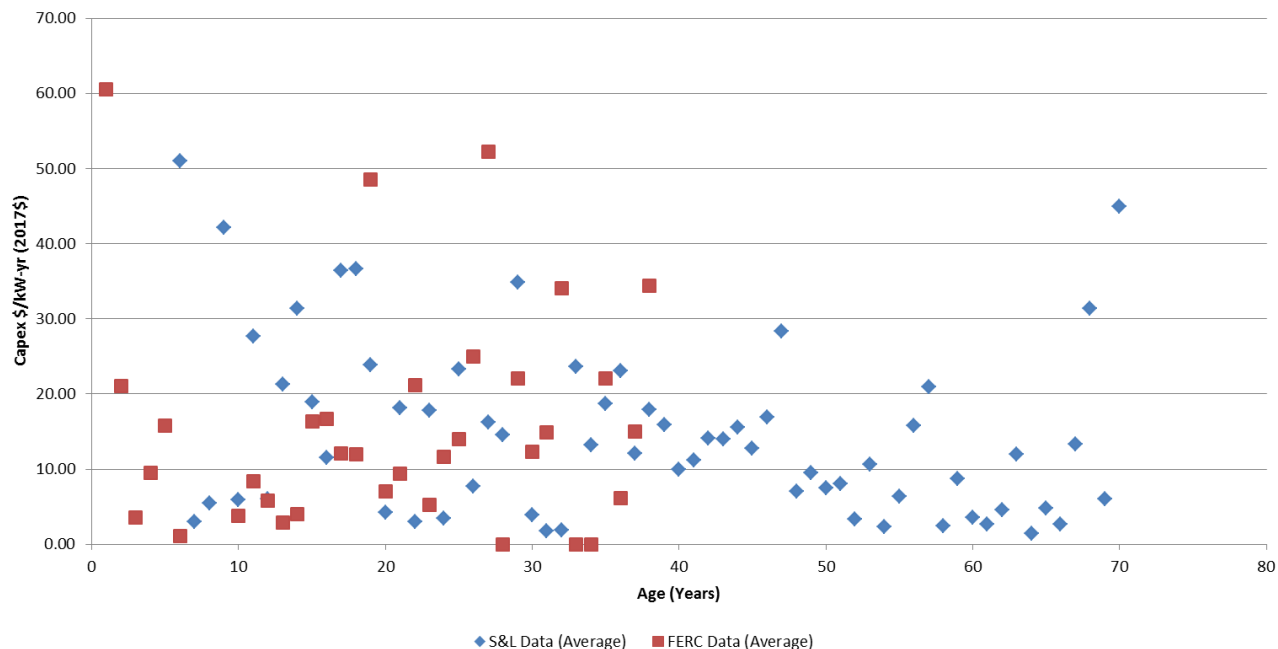
2.5 STATISTICAL TESTS

2.5.1 Consistency of FERC Form 1 and Sargent & Lundy Internal Data

FERC Form 1 data only covers historical data for utilities that are required to file and does not include the owners’ projected expenditures or any data for merchant plants and independent power plants. Most of Sargent & Lundy’s proprietary data, on the other hand, covers the owners’ projected expenditures for utility plants and includes both historical and projected expenditures for merchant plants and independent power plants. The data points from both data sources were judged to be complementary and combined as a single dataset.

The compatibility of the FERC data and Sargent & Lundy internal data is illustrated by the CAPEX spending for a sample of 500-MW coal plants (Figure 2-1). This example is based on a sample of 11 plants from the Sargent & Lundy data and 12 plants from the FERC data, each sample having an average plant capacity of approximately 500 MW and an average age of approximately 30 years. Each data point in the figure is the average value for all the plants that have a valid data point at the given plant age. There are a total of 175 valid data points for the FERC plants and 200 valid data points for the Sargent & Lundy plants. In this particular sample, all of the FERC data is historical and all of the Sargent & Lundy data is owners’ projected expenditures.

Figure 2-1 — CAPEX vs. Age for 500-MW Coal Plants – FERC and Sargent & Lundy Data



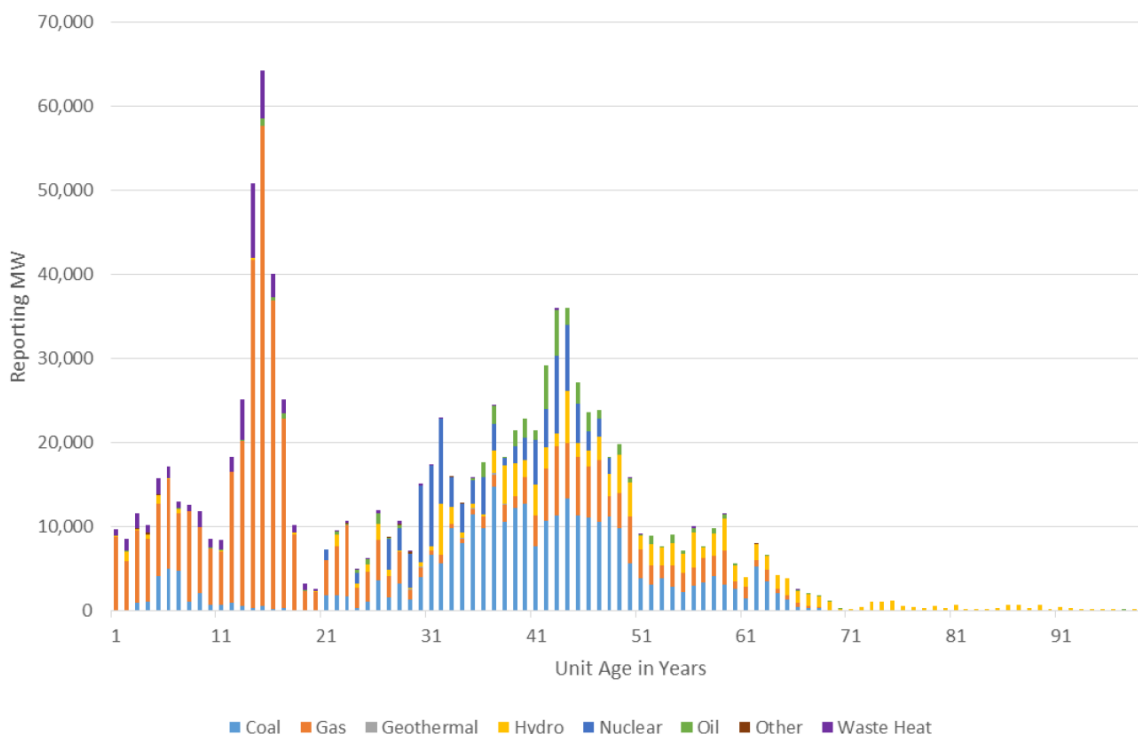
As discussed in Section 0, CAPEX spending for coal plants does not follow a uniform pattern for all plants. For example, different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

For some utility plants, data was available from both FERC Form 1 and proprietary data. The historical O&M and CAPEX spending for these plants were examined in each year to verify their consistency.

The distribution of valid data points for each technology versus age (years from COD in which the spending occurs) was examined to verify consistency with typical plant ages nationwide. Figure 2-2 shows a recent distribution of the U.S. power plant fleet by unit age and fuel type as reported by FERC⁸. This distribution indicates a large portion of coal-fired capacity with ages of 30-50 years, and a large portion of gas-fired capacity (mostly CT or CC) with ages under 20 years. The valid data points assembled in this report were found to be representative of these major age and technology cohorts.

⁸ North American Electric Reliability Corporation, *State of Reliability 2017*, June 2017 (p.116)

Figure 2-2 — U.S. Power Plant Fleet Capacity by Age and Fuel Type



A recent study found that the average age of the U.S. generator fleet has increased significantly over time, due in part to regulatory uncertainty in a deregulated market environment. At the same time, the average expected physical life of the fleet has been decreasing as a result of new investments in smaller, shorter-lived capacity. This has been a means of mitigating the regulatory risk of more limited stranded cost recovery mechanisms.⁹ In another recent study, this one on the causes of power plant retirements, the strongest predictors of retirements were found to be SO₂ emission rates, planning reserve margins, variations in load growth or contraction, the age of older thermal plants, the ratio of coal to gas prices, and delivered natural gas prices. The impacts of annual CAPEX and O&M spending on retirement decisions were not specifically identified.¹⁰

2.5.2 Significance of Plant Age on Annual Capital and O&M Expenditures

For each technology group, Sargent & Lundy performed a regression analysis on the O&M spending, CAPEX spending, and combined O&M plus CAPEX spending using the following linear equation:

- Annual spending in 2017 \$/kW-year = \$/kW-year (y-intercept) + (constant × age)

⁹ Rode, D., Fischbeck, P., and Paez, A., “Power Plant Lives and their Policy Implications,” *Energy Policy*, 106 (2017) 222-232, April 1, 2017.

¹⁰ Mills, A., Wiser, R., and Seel, J., “Power Plant Retirements: Trends and Possible Drivers,” Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory, November 2017.

The purpose of the regression analysis was to determine whether plant age is a statistically significant predictor of annual spending. The regression coefficient for age measures the change (+ or -) in annual spending as a function of plant age, measured as the number of years from the COD. Its statistical significance is measured by the p-value, which tests the null hypothesis that the coefficient is equal to zero (i.e., has no effect on spending).

The R-squared (R^2) statistic (“coefficient of determination”) is an indication of the goodness of fit of the regression equation to the real data points. A low R^2 indicates that the regression equation explains a relatively small amount of the variability of the data around its mean. A low p-value (< 0.05) indicates that the age coefficient is statistically significant, regardless of the R^2 statistic. A low p-value corresponds approximately to a t-value that is greater than 2 or less than -2. For higher p-values, the simple average \$/kW-year per year may be a more appropriate estimation for a given age band (e.g., 20-year bands and all-years band). Depending on the characteristics of the dataset, especially the number of data points, Sargent & Lundy applied engineering judgement (as further described in each section that follows) in our recommendations.

2.5.3 Autocorrelation of Time Series Data

In addition to the correlation between annual spending and plant age, an autocorrelation may also exist between spending in a given year and spending in previous years. Autocorrelation commonly occurs with time series data. If statistical tests verify the presence of autocorrelation, a lagged (autoregressive) variable may be added to improve the goodness of fit (R^2) of the regression model. Models with this functional form are referred to as “autoregressive integrated moving average” (ARIMA) models.

ARIMA models are typically constructed for the purpose of predicting the future from a given point in time, based on correlations with historical values and other exogenous variables. The functional form of an ARIMA model may better capture curvilinear or cyclical data trends and therefore improve the goodness of fit. For the purposes of this study, an ARIMA model was not necessary or appropriate. The datasets in this analysis already capture plant O&M and CAPEX spending patterns throughout a typical plant lifespan. The purpose of this study was to represent costs for generators as they age, and not to predict future spending from a given point in time.

3. COAL STEAM

3.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for coal steam plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M expenditures:
 - 456 plants in FERC data and 32 plants from Sargent & Lundy internal data
 - 3,098 valid data points in FERC data, 655 valid data points in Sargent & Lundy internal data
- CAPEX:
 - 457 plants in FERC data and 29 plants from Sargent & Lundy internal data
 - 3,109 valid data points in FERC data, 615 valid data points in Sargent & Lundy internal data

The coal steam data was broken down by plant MW capacity and average capacity factor—as summarized in Table 3-1—for the regression analysis shown in Appendix A.

Table 3-1 — Coal Steam Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	3,713	3,098	3,109	655	615
< 500 MW	All	1,592	1,274	1,284	318	318
500 MW – 1,000 MW	All	986	689	689	337	297
1,000 MW – 2,000 MW	All	813	813	814	0	0
> 2,000 MW	All	322	322	322	0	0
All MW	< 50%	965	889	896	76	76
All MW	> 50%	2,748	2,209	2,213	579	539

Table 3-2 below identifies the relative effects in the data validation process of the top three data filters on the number of valid data points. These filters are described as follows:

- Change in Capacity: A change in nameplate capacity of 20% or more during the reported time of the unit. Data points prior to the change in capacity are no longer comparable to the data points after the change in capacity, so the entire unit was filtered out.
- Negative Change in Total Cost: Any year with a decrease in the cumulative historical capital cost reported in the FERC data was not included.
- Environmental Retrofit: Data points in years where SO₂, NO_x, PM, or Hg removal equipment was installed were filtered out.

Table 3-2 — Effect of Data Validation Filters on Coal Data Points

Coal Steam – FERC Dataset	Data Points
Total Data Points, Unfiltered	6,699
Total Data Points, Filtered Out	3,774
Top Three Filters	
Change in Capacity	1,659
Negative Change in Total Cost	889
Environmental Retrofit	599
Total Data Points, Valid (FERC Only)	2,925

3.2 SUMMARY OF RESULTS

3.2.1 Recommended CAPEX Values

The analysis of the coal steam dataset (Appendix A) identified two significant variables affecting annual changes in real CAPEX spending (on a constant \$/kW-year basis): age and flue gas desulfurization (FGD). Variables not having a significant effect on annual changes in real CAPEX spending (on a constant \$/kW-year basis) were: plant capacity (kW), fuel type, and regulatory environment. When CAPEX spending was expressed on a constant \$/MWh basis, it was significantly related to age, primarily as a result of declining MWh generation with age.

Table 3-3 below compares the new CAPEX values derived from the coal steam dataset with the CAPEX values currently used in the EMM. The new CAPEX values are similar in magnitude with the current EMM values over the long term, except the new values follow a continuous pattern rather than a step pattern. As discussed below, the new values include life extension projects that occur throughout the plant life, including the first 30 years of operation.

Table 3-3 — Coal Steam CAPEX Results – All MW, All Capacity Factors

Net Total CAPEX (2017 \$/kW-year)	\$/kW-yr (Years 1-10)	\$/kW-yr (Years 10-20)	\$/kW-yr (Years 20-30)	\$/kW-yr (Years 30-40)	\$/kW-yr (Years 40-50)	\$/kW-yr (Years 50-60)	\$/kW-yr (Years 60-70)	\$/kW-yr (Years 70-80)
New Value – No FGD*	17.16	18.42	19.68	20.94	22.20	23.46	24.72	25.98
New Value – with FGD*	22.84	24.10	25.36	26.62	27.88	29.14	30.40	31.66
Existing EMM Value	17.55	17.55	17.55	24.62	24.62	24.62	24.62	24.62

*Calculated from the following regression equation to the midpoint of the given age band:

$$\text{Annual CAPEX spending in 2017 } \$/\text{kW-year} = 16.53 + (0.126 \times \text{age}) + (5.68 \times \text{FGD})$$

Where FGD = 1 if a plant has FGD; zero otherwise

“Life extension costs” in the existing CAPEX values are covered by the step increase after year 30. Life extension costs in the new CAPEX values are distributed throughout the plant life. This is a result of discretionary spending, which is a common practice for most coal steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

Typical industry-standard frequencies for repairs and replacement of major equipment within a coal plant are not absolute, but rather indicative of when a coal plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair.

The new values also account for CAPEX relating to FGD. An FGD system tends to be capital-intensive to own and operate. The corrosive environment of chemicals and reagents significantly reduces the life of equipment such as pumps, mills, nozzles, valves, etc. These components must be replaced more frequently compared with plants without FGD.

Table 3-4 below provides indicative typical industry-standard frequencies for repairs and replacement of major equipment within a coal plant.

Table 3-4 — Coal Plant Indicative Typical CAPEX Projects and Intervals

Project Description	Typical Frequency of Repairs/Replacement from COD (Years)
Boiler	
Coal mills and exhausters, burner tips and ignitors	5
Lower nose tube, burner panels, economizer banks, air heater tubes, and baskets	15
Lower and upper waterwalls, superheater and reheater horizontal sections and pendants, economizer header, coal feeders, mill motors	20
Superheater and reheater header, feedwater supply piping	25
Mud and steam drums	30
Turbine and Generator	
Control valves, nozzle block	12
Electro-hydraulic control system (EHC), governor, turbine controls, generator rotor, turbine lubrication pumps	15
Stop valves, low-pressure (LP) turbine and blades, LP casing/diaphragms,	20
Steam chest, high-pressure/intermediate-pressure (HP/IP) turbine with blades, HP/IP casing/diaphragm, generator stator, exciter	25
HP/IP rotor, LP rotor, isophase	30
Balance of Plant	
Condensate pumps, cooling tower fill, cooling tower fan drives and blades, conveyor belts, conveyer idlers/pulleys/motors, coal crushing equipment	10
Slag conveyors and tanks	12
Induced draft (ID) fans, electrostatic precipitator (ESP) casing, ESP plates/wires, deaerator, circulating water pumps, boiler feed pumps, distributed control system (DCS)/unit controls, boiler master/combustion controls, coal handling dust control system	15
Forced draft (FD) fans, primary air (PA) fans, fan motors, windbox and ductwork, ESP transformer/rectifier (TR) sets and rappers, condenser valves and cleaner system, LP feedwater heaters, HP feedwater heaters, gland coolers, conveyor structures, coal unloading equipment, fuel oil heaters, and delivery pumps	20
Condenser retube, deaerator storage tank, vacuum pumps/steam air ejectors, pump motors	25
Main power transformer, auxiliary transformer	30

3.2.2 Recommended O&M Values

The analysis required an understanding of the cost breakdowns in the reported data between 1) capitalized (CAPEX) and expensed (O&M) cost components and 2) fixed O&M and variable O&M cost components. From a system modeling perspective, CAPEX and fixed O&M costs are typically expressed in \$/kW-year, while

variable O&M is typically expressed in \$/MWh. Normalized cost breakdowns in these units are necessary for compatibility with the EMM.

O&M costs for the coal steam plants include a significant variable component. By definition, variable O&M costs are proportional to plant generation and are typically expressed in \$/MWh. As previously mentioned, the variable O&M component cannot be clearly delineated from the total reported O&M in the FERC Form 1 data. For this assessment, the variable component was combined with the fixed component and expressed in \$/kW-year. The combined total O&M in the coal steam plant dataset for this analysis was found to be nearly equivalent to the existing combined total O&M representation in the EMM, which already includes the necessary \$/MWh variable O&M breakout (Table 3-5).

Table 3-5 — Coal Steam O&M Comparison with Existing EMM

	Fixed O&M (2017 \$/kW-yr)	Variable O&M (2017 \$/MWh)*	Variable O&M (2017 \$/kW-yr)**	Total O&M (2017 \$/kW-yr)**
Coal Steam Dataset Results – All Plants	36.81	1.78	9.20	46.01
< 500 MW	44.21	1.78	9.20	53.41
500 MW – 1,000 MW	34.02	1.78	9.20	43.22
1,000 MW – 2,000 MW	28.52	1.78	9.20	37.72
> 2,000 MW	33.27	1.78	9.20	42.47
Existing EMM Value***	40.63	1.78	9.20	49.83

*Fixed and variable split is estimated using the existing EMM variable O&M cost of \$1.78/MWh.

**Calculated at the coal steam dataset average capacity factor of 59%.

***Source: Internal communication with EIA, February 2018.

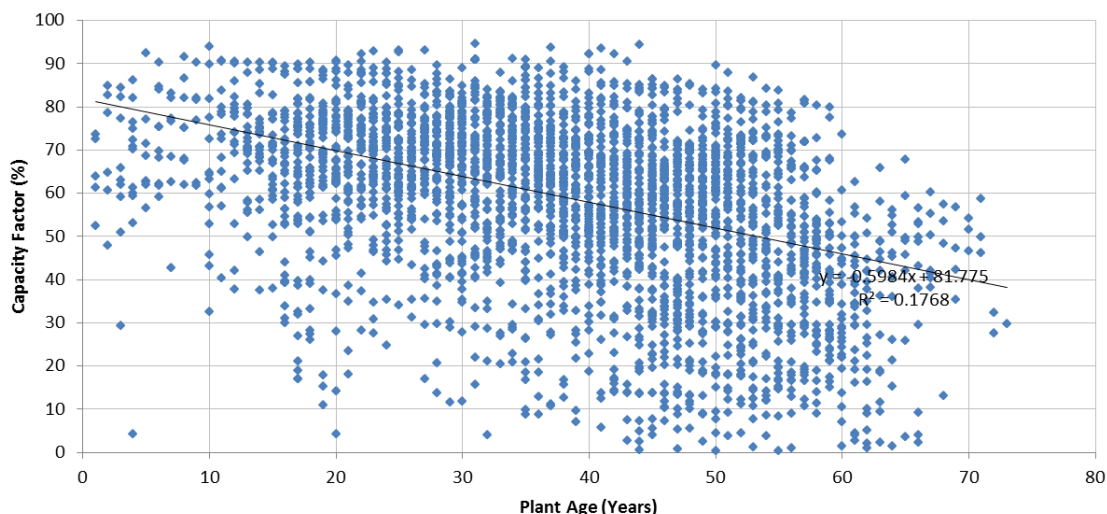
CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

3.2.3 Effect of Plant Capacity Factor

CAPEX and O&M spending for the coal steam plants increased significantly with age when expressed on a \$/MWh basis. This was primarily a result of significant declines in plant capacity factors over time, as shown in Figure 3-1.

Figure 3-1 — Capacity Factor vs. Age for All Coal Plants



3.2.4 Effect of External Market Conditions

The declining capacity factors with age may have been a result of external market conditions and/or declining plant performance. These are areas for further exploration.

External market conditions over the same time period that may have contributed to lower capacity factors for coal steam plants include:

- Competition with lower gas prices and more efficient gas turbines
- Competition with renewable energy having lower dispatch costs
- Lower load growth due to increased amounts of energy efficiency and distributed resources

For some coal steam plants, the decline in capacity factor was also a result of less efficient heat rates, increased component failures, and increased outage rates over time. A major contributor to this decline in performance is often a result of increased cycling operation. Increased cycling leads to higher O&M and CAPEX spending over time.¹¹

External market conditions may have also reduced the number of data points with higher age-related spending, due to plant retirements. The least efficient coal steam plants would likely retire under the following circumstances:

¹¹ Kumar, N., Besuner, P., Lefton, S., and Agan, D., *Power Plant Cycling Costs*, National Renewable Energy Laboratory, April 2012.

- Lower efficiency may contribute to less frequent dispatch and more cycling, leading to more component failures and higher spending
- Less frequent dispatch reduces hours of operation and power sales
- Lower power sales income may not adequately cover plant fixed costs

Some of the older coal steam plants (23 in this data sample) maintained consistently high capacity factors throughout their lives, with no real increase in spending. These high capacity factor plants had an installed capacity ranging from 70 MW to 2,400 MW, with an average of 850 MW and an average COD of 1961. These plants are slightly larger and older, on average, than the entire dataset of coal steam plants, which have an average installed capacity of 720 MW and an average COD of 1964. Table 3-6 shows the average capacity factors and O&M and CAPEX spending for the entire dataset of coal steam plants compared with the older consistently high capacity factor plants.

Table 3-6 — High Capacity Factor Coal Plants – Spending Comparison

	Average – All Years	Years 1-20	Years 20-40	Years 40-80
Capacity Factor – All Plants	59.1%	66.8%	64.5%	52.9%
Capacity Factor – High CF Plants	74.0%	-	72.8%	74.4%
O&M – All Plants (2017 \$/kW-yr)	46.01	53.90	40.06	48.77
CAPEX – All Plants (2017 \$/kW-yr)	22.78	17.92	26.20	21.25
Total – All Plants (2017 \$/kW-yr)	68.67	71.86	66.25	69.82
O&M – High CF Plants (2017 \$/kW-yr)	36.65	-	31.07	38.78
CAPEX – High CF Plants (2017 \$/kW-yr)	20.26	-	23.13	19.16
Total – High CF Plants (2017 \$/kW-yr)	57.02	-	54.20	58.10

Market conditions at the older, high capacity factor plants may have led to fewer competing resources, which would support higher levels of dispatch and higher capacity factors. In addition, lower cycling requirements at those plants would have reduced spending requirements.

3.2.5 Effect of Regulatory Environment

Owners of coal steam plants in deregulated states were found to have no aversion to capital spending compared to plant owners in regulated states (see Appendix A). Some of the difference may be due to higher labor costs in many of the deregulated states. This is the opposite of what would be expected, whereby plant owners in a deregulated environment would have a greater incentive to reduce O&M costs that cannot be passed through to ratepayers. The higher O&M spending is likely a result of other factors, such as higher average labor costs in

deregulated states, which tend to have a higher percentage of union labor compared with regulated states. Therefore, the net effect of regulatory status on average O&M spending was not apparent at this level of detail.

3.2.6 Effect of Fuel Characteristics

Sargent & Lundy's regression analysis compared CAPEX spending for coal steam plants with bituminous and subbituminous coal types (Appendix A). The results indicate that average CAPEX spending is not likely affected by coal type at a high-level designation (i.e., bituminous/subbituminous) without more detailed coal specifications.

4. GAS/OIL STEAM

4.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for gas/oil steam plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
 - 283 plants in FERC data and four plants from Sargent & Lundy internal data
 - 2,204 valid data points in FERC data, 20 valid data points in Sargent & Lundy internal data
- CAPEX
 - 283 plants in FERC data and four plants from Sargent & Lundy internal data
 - 2,226 valid data points in FERC data, 16 valid data points in Sargent & Lundy internal data

The gas/oil steam data was broken down by plant MW capacity, as summarized below in Table 4-1, for the regression analysis shown in Appendix B.

Table 4-1 — Gas/Oil Steam Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	2,220	2,204	2,226	20	16
< 500 MW	All	1,377	1,361	1,366	20	16
500 MW – 1,000 MW	All	488	488	489	0	0
> 1,000 MW	All	355	355	355	0	0

4.2 SUMMARY OF RESULTS

4.2.1 Recommended CAPEX Values

Sargent & Lundy's analysis of the gas/oil steam dataset (Appendix B) identified only one significant variable affecting annual changes in real CAPEX spending (on a constant \$/kW-year basis): plant capacity (kW). That is, CAPEX was lower on a \$/kW-year basis for larger plant sizes due to economies of scale. When CAPEX spending was expressed on a constant \$/MWh basis, it was significantly related to age, primarily as a result of declining MWh generation with age.

Table 4-2 compares the new CAPEX values derived from the gas/oil steam dataset with the CAPEX values currently used in the EMM. The new CAPEX values are similar in magnitude with the current EMM values over the long term, except that the new values follow a continuous pattern rather than a step pattern. As discussed below, the new values include life extension projects that occur throughout the plant life, including the first 30 years of operation.

Table 4-2 — Gas/Oil Steam CAPEX Results

Plant Size	Net Total CAPEX (2017 \$/kW-year)	
	Years 1-30	Years 30-80
Gas/Oil Steam Dataset Results – All Plants	15.96	15.96
New Value: < 500 MW	18.86	18.86
New Value: 500 MW – 1,000 MW	11.57	11.57
New Value: > 1,000 MW	10.82	10.82
Existing EMM Value	9.14	16.21

“Life extension costs” in the existing CAPEX values are covered by the step increase after year 30. Life extension costs in the new CAPEX values are distributed throughout the plant life. This is a result of discretionary spending, which is a common practice for most gas/oil steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

Typical industry-standard frequencies for repairs and replacement of major equipment within a gas/oil steam plant are not absolute, but rather indicative of when a gas/oil steam plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair. Typical industry-standard frequencies for repairs and replacement of major equipment are similar to those of coal units, as presented in the previous section.

The use of a constant annual value on the modeling of annual CAPEX would be similar to representing a major maintenance reserve account (MMRA), which is commonly used for non-recourse financing of power projects. MMRA's are usually required by power project lenders over the tenor of debt as protection against maintenance spending uncertainty. An MMRA is typically funded by annual contributions drawn from a project's cash flow, sometimes as a uniform annual amount. Annual contribution levels are based on estimated long-term

maintenance expenditure patterns. Over the long term, annual contributions represent a smoothed version of irregular actual annual values.

The use of a long-term average value also recognizes the inherent variability in long-term spending patterns for any given plant. Since the EMM is a large-scale model, it is conceptually designed to represent plant types as averages rather than as individual plants. When summed across a large number of plants in a utility system, some of the variability in annual expenditure patterns would tend to even out. The level of accuracy between average values and year-specific values for a given plant type is nearly equivalent in large-scale models.

4.2.2 Recommended O&M Values

The analysis required an understanding of the cost breakdowns in the reported data between 1) capitalized (CAPEX) and expensed (O&M) cost components and 2) fixed O&M and variable O&M cost components. From a system modeling perspective, CAPEX and fixed O&M costs are typically expressed in \$/kW-year, while variable O&M is typically expressed in \$/MWh. Normalized cost breakdowns in these units are necessary for compatibility with the EMM.

O&M costs for the gas/oil steam plants include a significant variable component, although typically smaller than coal units. The combined total O&M in the gas/oil steam plant dataset for this analysis was found to be somewhat lower than the existing combined total O&M representation in the EMM, which already includes the necessary \$/MWh variable O&M breakout (see Table 4-3). However, the variable O&M of \$8.23/MWh in the EMM is much higher than values Sargent & Lundy has observed in actual gas/oil steam plants and should not be higher than the variable O&M of \$1.78/MWh in the EMM used for the coal units.

Table 4-3 — Gas/Oil Steam O&M Comparison with Existing EMM

	Fixed O&M (2017 \$/kW-yr)	Variable O&M (2017 \$/MWh)*	Variable O&M (2017 \$/kW-yr)**	Total O&M (2017 \$/kW-yr)**
Gas/Oil Steam Dataset Results – All Plants	24.68	1.00	1.84	26.52
< 500 MW	29.73	1.00	1.84	31.57
500 MW – 1,000 MW	17.98	1.00	1.84	19.82
> 1,000 MW	14.51	1.00	1.84	16.35
Existing EMM Value***	19.68	8.23	15.14	34.82

*Fixed and variable split is estimated using an approximate value for variable O&M of \$1.00/MWh based on confidential projects.

**Calculated at the gas/oil steam dataset average capacity factor of 21%.

***Source: Internal communication with EIA, February 2018.

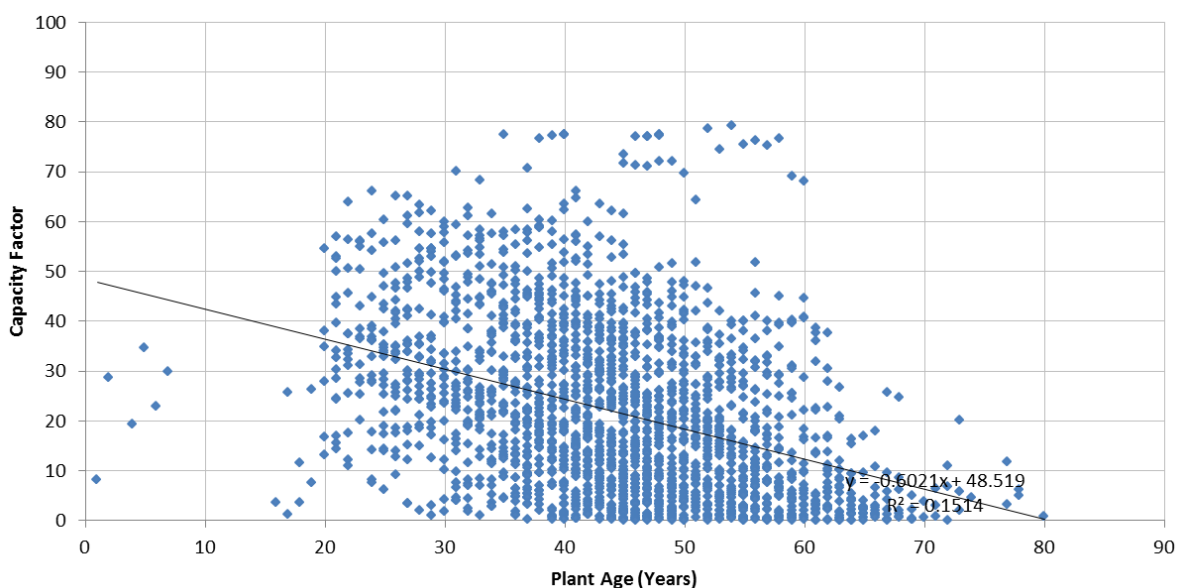
CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

4.2.3 Effect of Plant Capacity Factor

CAPEX and O&M spending for the gas/oil steam plants increased significantly with age when expressed on a \$/MWh basis. This was primarily a result of significant declines in plant capacity factors over time, as shown in Figure 4-1.

Figure 4-1 — Capacity Factor vs. Age for All Gas/Oil Steam Plants



4.2.4 Effect of External Market Conditions

The declining capacity factors with age may have been a result of external market conditions and/or declining plant performance. These are areas for further exploration.

External market conditions over the same time period that may have contributed to lower capacity factors for gas/oil steam plants include:

- Competition with more efficient gas turbines

- Competition with renewable energy having lower dispatch costs
- Lower load growth due to increased amounts of energy efficiency and distributed resources

For some gas/oil steam plants, the decline in capacity factor was also a result of less efficient heat rates, increased component failures, and increased outage rates over time. A major contributor to this decline in performance is often a result of increased cycling operation. Increased cycling leads to higher O&M and CAPEX spending over time.

External market conditions may have also reduced the number of data points with higher age-related spending, due to plant retirements. The least efficient gas/oil steam plants would likely retire under the following circumstances:

- Lower efficiency may contribute to less frequent dispatch and more cycling, leading to more component failures and higher spending
- Less frequent dispatch reduces hours of operation and power sales
- Lower power sales income may not adequately cover plant fixed costs

5. GAS/OIL COMBINED CYCLE

5.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for gas/oil CC plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
 - 144 plants in FERC data and 20 plants from Sargent & Lundy internal data
 - 980 valid data points in FERC data, 408 valid data points in Sargent & Lundy internal data
- CAPEX
 - 142 plants in FERC data and 17 Sargent & Lundy proprietary plants with valid data
 - 981 valid data points in FERC data, 387 valid data points in Sargent & Lundy internal data

The gas/oil CC data was broken down by plant MW capacity and average capacity factor, as summarized below in Table 5-1, for the regression analysis shown in Appendix C.

Table 5-1 — Gas/Oil CC Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	1,367	980	981	408	387
< 500 MW	All	764	462	463	304	302
500 MW – 1,000 MW	All	547	462	463	104	85
> 1,000 MW	All	177	177	177	0	0
All MW	< 50%	843	661	662	203	182
All MW	> 50%	524	319	319	205	205

5.2 SUMMARY OF RESULTS

As with coal steam and gas/oil steam plants, CAPEX spending for gas/oil CC plants represents a series of capital projects throughout the plant life, which includes projects for “life extension.” Most CAPEX spending for gas/oil CC plants is for vendor-specified major maintenance events. Other CAPEX spending, other than for emission control retrofits, is relatively minor.

Vendor-specified major maintenance spending is based on cumulative hours of operation and/or cumulative starts. Implicitly, CAPEX spending for CC plants is age-related and vendor-specified, and may be expressed as an equivalent \$/MWh value, which covers:

- Major maintenance costs for periodic combustion inspections, hot gas path inspections, and major overhauls account for nearly all of the CAPEX expenditures. Many plant owners choose to capitalize major maintenance expenditures. As these expenditures normally follow the equipment vendor’s recommendations, they maintain plant performance and extend the plant life.
- Major one-time costs include rotor replacement, typically at about 150,000 equivalent operating hours, 7,000 equivalent starts, or within the first 30 years of plant operation. These costs are captured within the dataset. As gas turbines age, major maintenance parts often become available from third-party suppliers at a discounted price.

As with MMRAs (described in Section 4.2.1), major maintenance contracts are priced according to smoothed versions of irregular long-term expenditure patterns. Apart from adjustments for operating conditions, major maintenance (and nearly all of the CAPEX) is effectively priced as an equal annual value, expressed in constant \$/MWh with annual escalation.

Table 5-2 compares the new CAPEX and O&M values derived from the gas/oil CC dataset with the values currently used in the EMM. As previously mentioned, the combined CAPEX and O&M in the dataset would be expected to correspond to the combined CAPEX and O&M in the EMM, with most of the CAPEX in the EMM represented as variable O&M. However, some of the EMM values are higher than values Sargent & Lundy has observed in actual CC plants, as detailed below:

- The EMM fixed and variable O&M costs for CC plants are reasonable for smaller CC installations (< 500 MW) but high for larger plants.
- The EMM CAPEX addition of \$7/kW-year after 30 years of operation should not be represented as a fixed cost. As previously mentioned, age-related costs would be built into the \$/MWh variable O&M and would be a function of cumulative operating hours rather than operating years.

Table 5-2 — Gas/Oil CC CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 \$/kW-yr)	Variable O&M (2017 \$/MWh)	Variable O&M (2017 \$/kW-yr)*	Total O&M (2017 \$/kW-yr)*	CAPEX (2017 \$/kW-yr)	Total O&M and CAPEX (2017 \$/kW-yr)*
CC Dataset Results – All Plants	13.08	3.91	(included in CAPEX)	13.08	15.76	28.84
< 500 MW	15.62	4.31	(included in CAPEX)	15.62	17.38	33.00
500 MW – 1,000 MW	9.27	3.42	(included in CAPEX)	9.27	13.78	23.05
> 1,000 MW	11.68	3.37	(included in CAPEX)	11.68	13.57	25.25
Existing EMM Value**	27.52	2.64	10.64	38.16	0.18; 7.25 (after year 30)	38.34; 45.41 (after year 30)

*Calculated at the gas/oil CC dataset average capacity factor of 46%. Fixed and variable O&M split is estimated.

**Source: Internal communication with EIA, February 2018.

CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

6. GAS/OIL COMBUSTION TURBINE

6.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for gas/oil CT plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
 - 625 plants from FERC data and 27 plants from Sargent & Lundy internal data
 - 4,905 valid data points in FERC data, 437 valid data points in Sargent & Lundy internal data
- CAPEX
 - 579 plants from FERC data and five plants from Sargent & Lundy internal data
 - 4,949 valid data points in FERC data, 136 valid data points in Sargent & Lundy internal data

The CT data was broken down by plant MW capacity, as summarized below in Table 6-1, for the regression analysis shown in Appendix D.

Table 6-1 — Gas/Oil Combustion Turbine Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	5,041	4,905	4,949	437	136
< 100 MW	All	2,873	2,873	2,911	189	0
100 MW – 300 MW	All	1,341	1,239	1,248	177	102
> 300 MW	All	901	867	875	71	34

6.2 SUMMARY OF RESULTS

As with coal steam and gas/oil steam plants, CAPEX spending for gas/oil CT plants represents a series of capital projects throughout the plant life, which includes projects for “life extension.” Most CAPEX spending for gas/oil CT plants is for vendor-specified major maintenance events. Other CAPEX spending, other than for emission control retrofits, is relatively minor.

Vendor-specified major maintenance spending is based on cumulative hours of operation and/or cumulative starts. Implicitly, CAPEX spending for CTs is age-related and vendor-specified, and may be expressed as an equivalent \$/MWh value, which covers:

- Major maintenance costs for periodic combustion inspections, hot gas path inspections, and major overhauls account for nearly all of the CAPEX expenditures. Many plant owners choose to capitalize major maintenance expenditures. As these expenditures normally follow the equipment vendor’s recommendations, they maintain plant performance and extend the plant life.
- Major one-time costs include rotor replacement, typically at about 150,000 equivalent operating hours, 7,000 equivalent starts, or within the first 30 years of plant operation. These costs are captured within the dataset. As gas turbines age, major maintenance parts often become available from third-party suppliers at a discounted price.

As with MMRAAs (described in Section 4.2.1), major maintenance contracts are priced according to smoothed versions of irregular long-term expenditure patterns. Apart from adjustments for operating conditions, major maintenance (and nearly all of the CAPEX) is effectively priced as an equal annual value, expressed in constant \$/MWh with annual escalation.

Table 6-2 compares the new CAPEX and O&M values derived from the gas/oil CT datasets with the values currently used in the EMM. As previously mentioned, the combined CAPEX and O&M in the datasets would be expected to correspond to the combined CAPEX and O&M in the EMM, with most of the CAPEX in the EMM represented as variable O&M. However, EMM fixed and variable O&M costs across all plant sizes are higher than values Sargent & Lundy has observed in actual CT plants. Since most CT plants operate as peaking plants with low capacity factors, the variable O&M component is likely to be based on equivalent starts rather than equivalent operating hours.

Table 6-2 — Gas/Oil Combustion Turbine CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 \$/kW-yr)	Variable O&M (2017 \$/MWh)	Variable O&M (2017 \$/kW-yr)*	Total O&M (2017 \$/kW-yr)*	CAPEX (2017 \$/kW-yr)	Total O&M and CAPEX (2017 \$/kW-yr)*
CT Dataset Results – All Plants	5.33	(starts based)	(included in CAPEX)	5.33	6.90	12.23
< 100 MW	5.96	(starts based)	(included in CAPEX)	5.96	9.00	14.96
100 MW – 300 MW	6.43	(starts based)	(included in CAPEX)	6.43	6.18	12.61
> 300 MW	3.99	(starts based)	(included in CAPEX)	3.99	6.95	10.94
Existing EMM Value**	12.60	14.63	5.13	17.73	1.52	19.25

*Calculated at the gas/oil CC dataset average capacity factor of 4%.

**Source: Internal communication with EIA, February 2018.

CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

7. CONVENTIONAL HYDROELECTRIC

7.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for conventional hydroelectric plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
 - 348 plants in FERC data
 - 2,179 valid data points in FERC data
- CAPEX
 - 348 plants in FERC data
 - 2,180 valid data points in FERC data

The conventional hydroelectric data was broken down by plant MW capacity, as summarized below in Table 7-1, for the regression analysis shown in Appendix E.

Table 7-1 — Conventional Hydroelectric Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	2,179	2,179	2,180	0	0
< 100 MW	All	1,272	1,272	1,272	0	0
100 MW – 500 MW	All	924	924	925	0	0
> 500 MW	All	41	41	41	0	0

7.2 SUMMARY OF RESULTS

Sargent & Lundy's linear regression analysis of the dataset for conventional hydroelectric plants (Appendix E) supports age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). CAPEX spending for this dataset may be estimated by the regression equation:

Annual CAPEX spending in 2017 \$/kW-year = 7.269 + (0.296 × age)

The dataset also supports age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

Annual O&M spending in 2017 \$/kW-year = 22.360 + (0.073 × age)

The CAPEX and O&M values derived from the conventional hydroelectric dataset are significantly higher than the existing values used in the EMM (Table 7-2) and outside the range of values published in the AEO¹² and by the International Renewable Energy Agency (IRENA).¹³ The reasons for this discrepancy are not known without having the data sample used for the EMM values. It appears that the EMM does not currently account for CAPEX or life extension expenditures for conventional hydroelectric.

Table 7-2 — Hydroelectric CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 \$/kW-yr)	Variable O&M (2017 \$/MWh)	CAPEX (2017 \$/kW-yr)	Total O&M and CAPEX (2017 \$/kW-yr)
Conventional Hydroelectric Dataset Results – All Plants	22.00	-	22.56	44.56
Existing EMM Value*	14.58	0.00	0.00	14.58

*Source: Internal communication with EIA, February 2018.

¹² Energy Information Administration, *Annual Energy Outlook 2018*, Cost and Performance Characteristics (Table 8.2), February 2018.

¹³ International Renewable Energy Agency, *Renewable Energy Technologies: Cost Analysis Series, Hydropower*, June 2012.

8. PUMPED HYDROELECTRIC STORAGE

8.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for pumped storage plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
 - 37 plants in FERC data
 - 226 valid data points in FERC data
- CAPEX
 - 37 plants in FERC data
 - 227 valid data points in FERC data

The pumped storage data was broken down by plant MW capacity, as summarized below in Table 8-1, for the regression analysis shown in Appendix F.

Table 8-1 — Pumped Storage Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	226	226	227	0	0
< 100 MW	All	12	12	12	0	0
100 MW – 500 MW	All	88	88	88	0	0
> 500 MW	All	126	126	126	0	0

8.2 SUMMARY OF RESULTS

Overall, the pumped storage dataset does not support any age-related CAPEX or O&M spending trend across the full data and on any of the subsets by plant size. The average value over all operating years is \$14.83/kW-year for CAPEX and \$23.63/kW-year for O&M (Table 8-2). The existing values used in the EMM are not available.

Table 8-2 — Pumped Storage CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 \$/kW-yr)	Variable O&M (2017 \$/MWh)	CAPEX (2017 \$/kW-yr)	Total O&M and CAPEX (2017 \$/kW-yr)
Pumped Storage Dataset Results – All Plants	23.63	-	14.83	38.46
Existing EMM Value	N/A	N/A	N/A	N/A

9. SOLAR PHOTOVOLTAIC

9.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for solar PV storage plants were compiled using the assessment methodology described in Section 2. The FERC data includes 105 solar PV installations ranging in capacity from 10 kW to 36 MW.

The solar PV data, summarized below in Table 9-1, was used for the regression analysis shown in Appendix G.

Table 9-1 — Solar Photovoltaic Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	57	410	57	0	0

9.2 SUMMARY OF RESULTS

The solar PV dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size (see Appendix G). Sargent & Lundy determined that a significant portion of the data needed to be filtered out, resulting in a limited dataset of 15 sites. The average annual CAPEX (i.e., change in TCP) for these sites was approximately \$26/kW-year. However, due to the limitations of the solar PV dataset, described in Appendix G, Sargent & Lundy advises that caution be taken when trying to establish any definitive solar PV capital cost trends from the FERC data.

The solar PV dataset appears to support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, based on a closer inspection of the data, a more appropriate predictor of O&M spending for this dataset would be a simple average across all years. This determination is based on the lack of data points for plants over 10 years old and the fact that nearly all data points for plants over 10 years old are reported as having zero O&M expenses. Additionally, many of these plants also reported zero O&M expenses for all years of operation.

Solar PV O&M activities include a variety of work scopes, including administrative work, monitoring, cleaning, preventative maintenance, and corrective maintenance. Some specific examples of O&M activities may include cleaning modules, monitoring system voltage and current, inspecting and cleaning electrical equipment,

inspecting modules for damage, inspecting mounting systems, and checking inverter settings. The cost of O&M is dependent on several factors, including the number of components, the type of system (e.g., roof, tracking, ground mount, fixed, etc.), warranty coverage, and location. Environmental conditions, such as hail, sand/dust, snow, salt in air, high winds, etc., also play a significant role in O&M costs. For these reasons, a higher level of variation is expected when compared to traditional generating technologies.

An average O&M cost of \$75/kW-year was calculated from the FERC data for sites under 5 MW, and \$15/kW-year for sites over 5 MW. Sargent & Lundy notes that, compared to other industry metrics shown in Appendix G, the FERC data averages are similar for the sites over 5 MW but much higher for the sites under 5 MW.

If the results of the regression analysis are used, the average O&M costs are reduced to \$41/kW-year for sites under 5 MW and \$10/kW-year for sites over 5 MW. The regression analysis uses each year of plant data as a unique data point, which captures the years in which zero O&M costs were reported.

By comparison, the EMM uses an average O&M value of \$28.47/kW-year for all solar PV plants and an average CAPEX value of zero.¹⁴ Neither dataset captures the most recent trends in solar PV technology due to rapid changes in cost, size, and efficiency.

¹⁴ Internal communication with EIA, February 2018.

10. SOLAR THERMAL

10.1 DATA DESCRIPTION

There are no solar thermal power plants that report operating data in FERC Form 1. Industry-wide, there are a limited number of solar thermal projects; a majority of which have been constructed within the last 10 years—the exception being small test facilities and the Solar Energy Generating Systems (SEGS) plants built in the 1980s.

10.2 SUMMARY OF RESULTS

The U.S. National Renewable Energy Laboratory (NREL) published an Annual Technology Baseline (ATB) in 2017 that estimates the capital and O&M cost of a 100-MWnet solar power tower plant with 10 hours of thermal storage, based on cost models benchmarked with industry data.¹⁵ The estimate includes future projections based on possible reductions in costs (high, mid, or low). The 2017 ATB includes a 2015 baseline. An update is expected to be made available in 2018.

¹⁵ NREL 2017 Annual Technology Baseline (<https://atb.nrel.gov/electricity/2017/index.html?t=sc>)

11. GEOTHERMAL

11.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for geothermal plants were compiled using the assessment methodology described in Section 2. The FERC data includes five geothermal installations ranging in capacity from 23 MW to 1,224 MW.

The geothermal data summarized in Table 11-1 was used for the regression analysis shown in Appendix I.

Table 11-1 — Geothermal Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	36	38	36	0	0

11.2 SUMMARY OF RESULTS

Overall, the geothermal dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size. Instead, we recommend a simple average be used across the full age range. Sargent & Lundy recommends using the indicated \$/kW-year average in Table 11-2 for O&M and CAPEX spending. As shown in the table, it appears the EMM does not currently account for CAPEX or life extension expenditures for geothermal plants.

Table 11-2 — Geothermal CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 \$/kW-yr)	Variable O&M (2017 \$/MWh)	CAPEX (2017 \$/kW-yr)	Total O&M and CAPEX (2017 \$/kW-yr)
Geothermal Dataset Results – All Plants	157.10	-	40.94	198.04
Existing EMM Value*	91.66	0.00	0.00	91.66

*Source: Internal communication with EIA, February 2018.

12. WIND

12.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for wind plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
 - 73 plants in FERC and 24 from Sargent & Lundy proprietary plants with valid data
 - 310 valid data points in FERC, 270 valid data points in Sargent & Lundy proprietary plants
- CAPEX
 - 97 plants in FERC with valid data
 - 310 valid data points in FERC

Sargent & Lundy's dataset includes both actual historical cost reporting from operating wind projects as well as forecasted budgetary cost projections prepared by project developers and operators with large project portfolios.

Operating costs are assumed to include all expenses related to the maintenance of the wind project, such as planned and unplanned maintenance of the wind turbines and electrical balance of plant (including labor, parts, materials, and consumables) as well as operating expenses (such as facility monitoring and management fees, utilities, land lease and royalty payments, professional service fees, taxes, and insurance).

The wind data was broken down by plant MW capacity, as summarized below in Table 12-1, for the regression analysis shown in Appendix J.

Table 12-1 — Wind Cost Data Distribution

Plant Size	Average Net Capacity Factor (%)	Valid Data Points	FERC Data		Sargent & Lundy Internal Data	
			O&M Data Points	CAPEX Data Points	O&M Data Points	CAPEX Data Points
All MW	All	310	310	310	270	0
< 100 MW	All	174	174	174	165	0
100 MW – 200 MW	All	91	91	91	56	0
> 200 MW	All	51	51	51	73	0

12.2 SUMMARY OF RESULTS

The dataset supports age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equations shown in Table 12-2. Age was not a significant predictor of CAPEX spending, although CAPEX was found to vary significantly as a function of capacity (kW). That is, CAPEX was lower on a \$/kW-year basis for larger plant sizes due to economies of scale.

The CAPEX and O&M values derived from the wind dataset are significantly higher than the existing values used in the EMM. The reasons for this discrepancy are not known without having the data sample used for the EMM values. Neither data sample is stratified by wind technology or turbine size. Neither dataset captures the most recent trends in wind turbine technology due to rapid changes in cost, size, and efficiency.

Table 12-2 — Wind CAPEX and O&M Comparison with Existing EMM

	Fixed O&M (2017 \$/kW-yr)	Variable O&M (2017 \$/MWh)	CAPEX (2017 \$/kW-yr)
Wind Dataset Results – All Plants	$31.66 + (1.22 \times \text{age})$	0.00	18.29
< 100 MW	$39.08 + (1.12 \times \text{age})$	0.00	20.48
100 MW – 200 MW	$23.80 + (1.17 \times \text{age})$	0.00	16.93
> 200 MW	$26.78 + (0.92 \times \text{age})$	0.00	13.48
Existing EMM Value*	29.31	0.00	0.00

*Source: Internal communication with EIA, February 2018.



Appendix A. Regression Analysis – Coal Steam

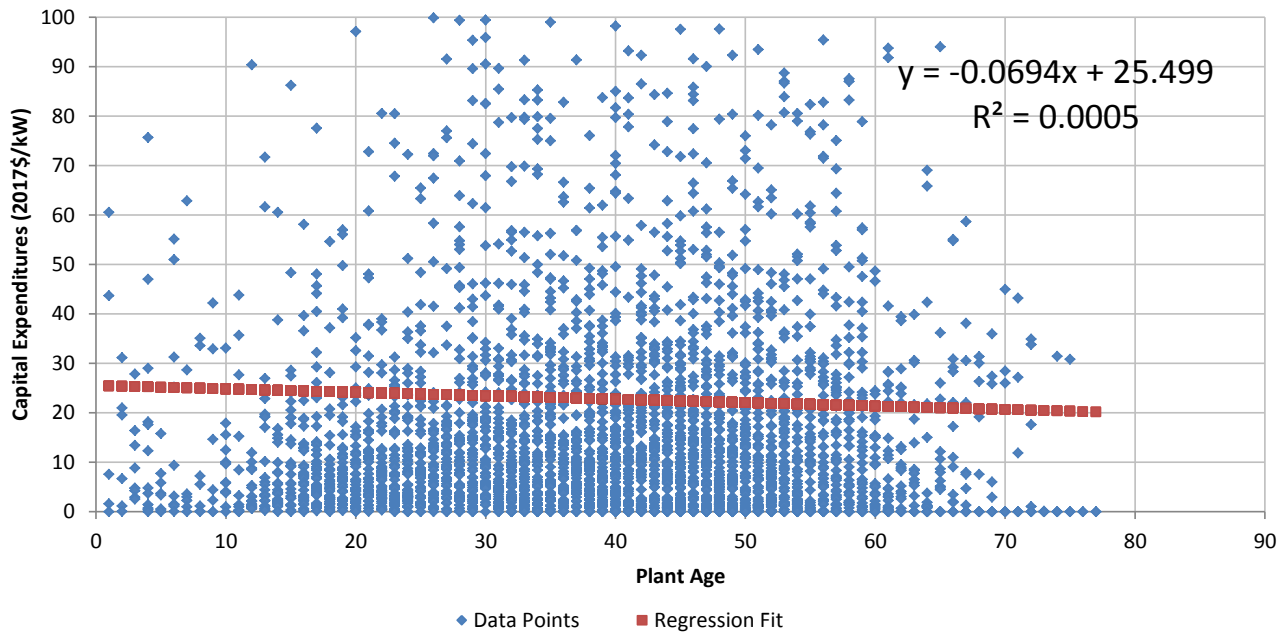
CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.19, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). However, age and FGD are significant variables when an FGD variable is added to the regression equation (see below).

Table A-1 — Regression Statistics – Coal CAPEX for All MW

		<i>t statistic</i>	<i>p-value</i>
Observations	3,724		
Simple Average (\$/kW)	22.782		
Intercept	25.499	11.4859	4.95E-30
Slope	-0.069	-1.3054	1.92E-01
R ²	0.00046		

Figure A-1 — Coal Steam Dataset – CAPEX for All MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

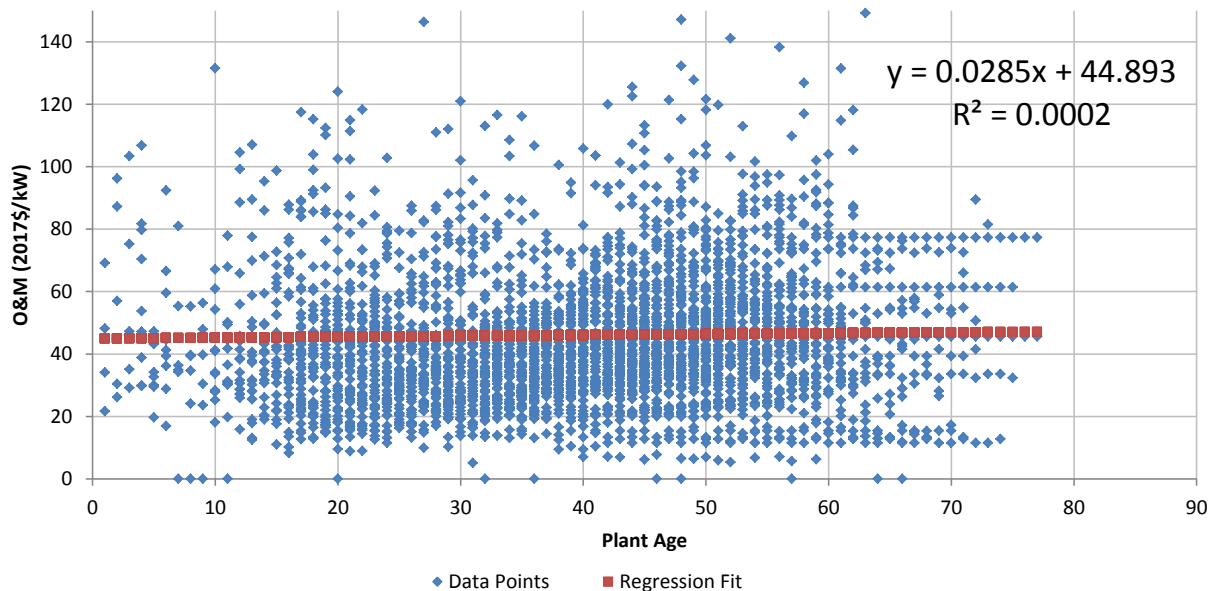
OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of O&M spending for coal steam plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.38, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table A-2 — Regression Statistics – Coal O&M for All MW

		<i>t statistic</i>	<i>p-value</i>
Observations	3,753		
Simple Average (\$/kW)	46.013		
Intercept	44.893	33.2097	3.08E-212
Slope	0.028	0.8843	3.77E-01
R ²	0.00021		

Figure A-2 — Coal Steam Dataset – O&M for All MW Plant Sizes



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

	Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =
All MW, All Capacity Factors								
Net Total O&M- 2017 \$/kW	53.90	40.06	48.77	46.01	440	1,448	1,865	3,753
Net Total Capex - 2017 \$/kW	17.92	26.20	21.25	22.78	441	1,450	1,833	3,724
Net Total O&M and Capex - 2017 \$/kW	71.86	66.25	69.82	68.67	440	1,448	1,825	3,713

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

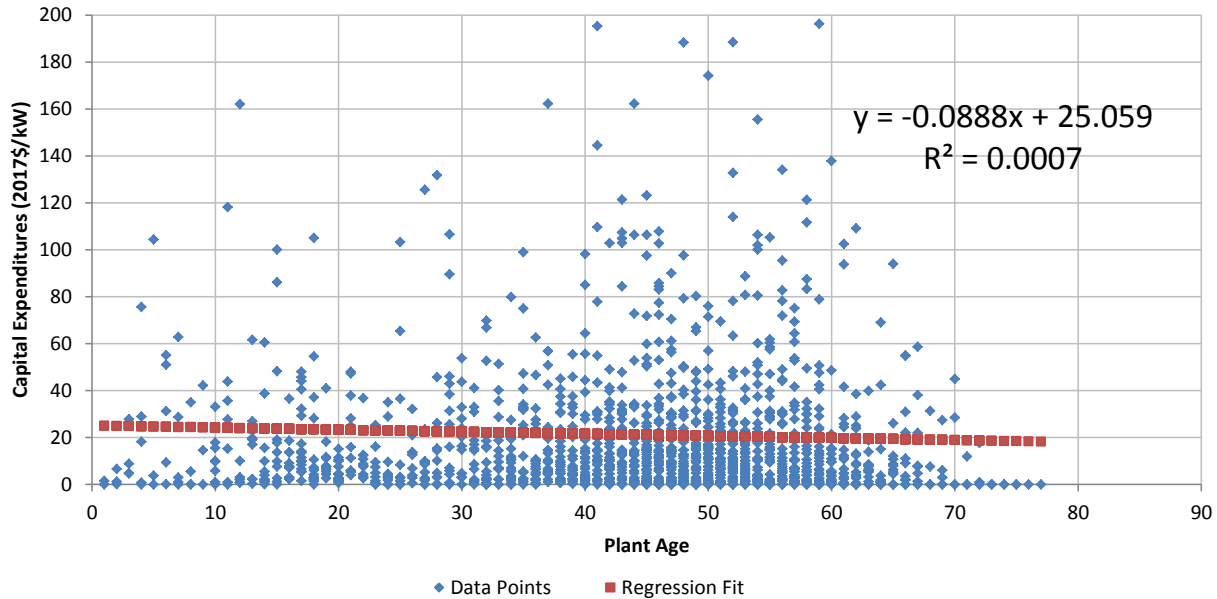
CAPITAL EXPENDITURES – LESS THAN 500 MW

The results of the linear regression analysis of CAPEX spending for coal steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.28, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table A-3 — Regression Statistics – Coal CAPEX < 500 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	1,602		
Simple Average (\$/kW)	21.187		
Intercept	25.059	6.5593	7.28E-11
Slope	-0.089	-1.0685	2.85E-01
R ²	0.00071		

Figure A-3 — Coal Steam Dataset – CAPEX for Less than 500-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 500 MW

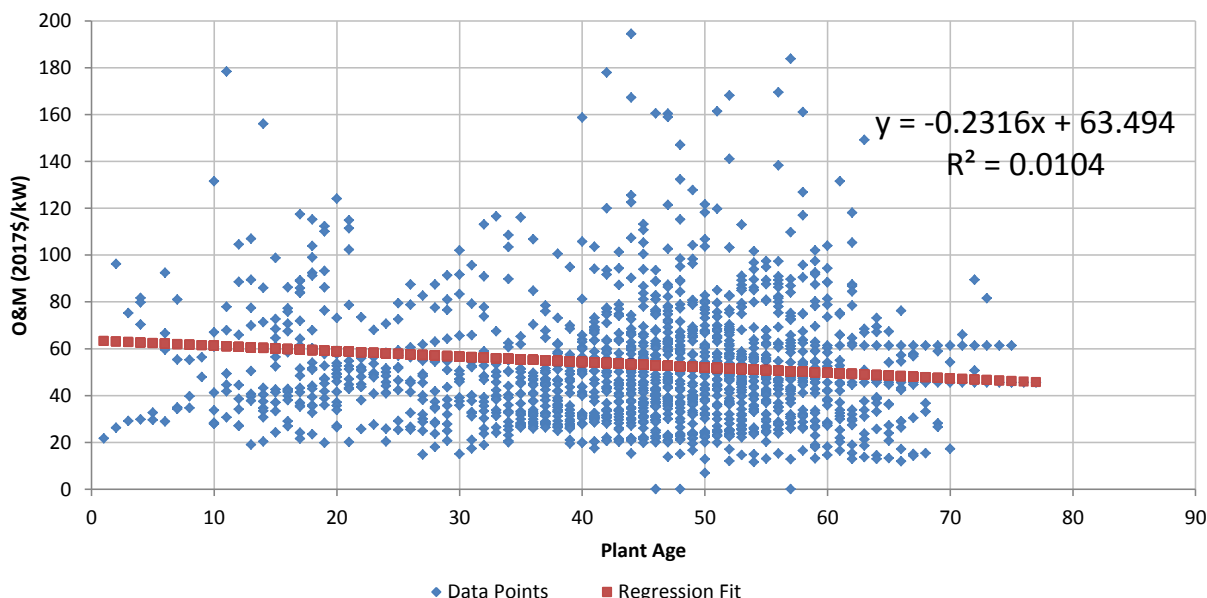
The results of the regression analysis of O&M spending for coal steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the following regression equation:

$$\text{Annual spending in 2017 \$/kW-year} = 63.494 + (-0.232 \times \text{age})$$

Table A-4 — Regression Statistics – Coal O&M < 500 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	1,592		
Simple Average (\$/kW)	53.406		
Intercept	63.494	24.4603	2.03E-112
Slope	-0.232	-4.0977	4.38E-05
R ²	0.01045		

Figure A-4 — Coal Steam Dataset – O&M for Less than 500-MW Plant Size



The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

	Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =
< 500 MW, All Capacity Factors								
Net Total O&M- 2017 \$/kW	68.13	47.13	53.16	53.41	169	355	1,068	1,592
Net Total Capex - 2017 \$/kW	21.01	22.83	20.67	21.19	169	357	1,076	1,602
Net Total O&M and Capex - 2017 \$/kW	89.14	69.91	73.93	74.65	169	355	1,068	1,592

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

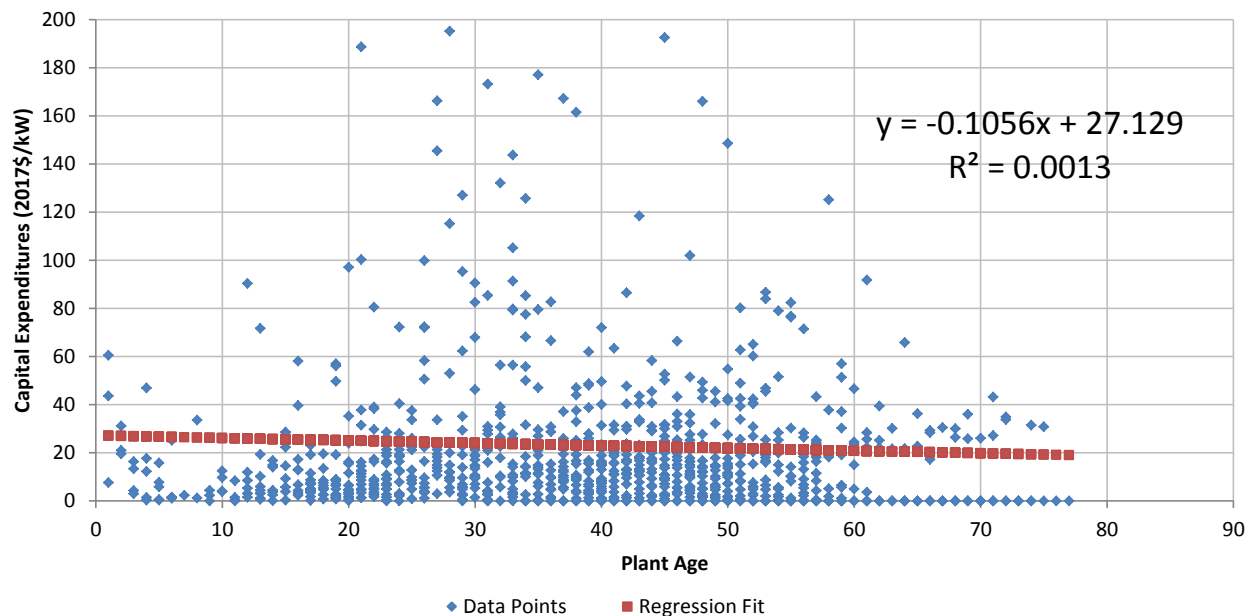
CAPITAL EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the linear regression analysis of CAPEX spending for coal steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.26, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table A-5 — Regression Statistics – Coal CAPEX 500 MW to 1,000 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	986		
Simple Average (\$/kW)	23.021		
Intercept	27.129	6.8576	1.24E-11
Slope	-0.106	-1.1195	2.63E-01
R ²	0.00127		

Figure A-5 — Coal Steam Dataset – CAPEX for 500-MW to 1,000-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

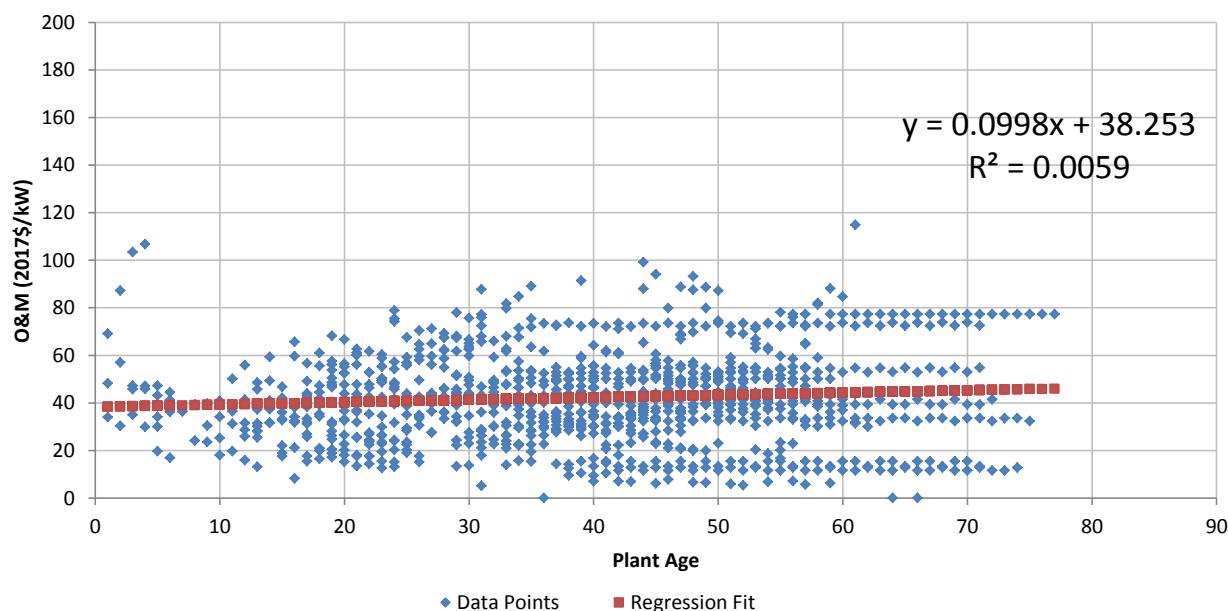
The results of the linear regression analysis of O&M spending for coal steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is less than 0.05, age is a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

Annual spending in 2017 \$/kW-year = 38.253 + (0.100 × age)

Table A-6 — Regression Statistics – Coal O&M 500 MW to 1,000 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	1,026		
Simple Average (\$/kW)	42.223		
Intercept	38.253	22.0915	9.54E-89
Slope	0.100	2.4710	1.36E-02
R ²	0.00593		

Figure A-6 — Coal Steam Dataset – O&M for 500-MW to 1,000-MW Plant Size



Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

	Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =
500 MW - 1000 MW, All Capacity Factors								
Net Total O&M- 2017 \$/kW	38.15	42.09	43.40	42.22	138	369	519	1,026
Net Total Capex - 2017 \$/kW	12.27	32.63	18.71	23.02	138	369	479	986
Net Total O&M and Capex - 2017 \$/kW	50.41	74.72	60.65	64.49	138	369	479	986

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

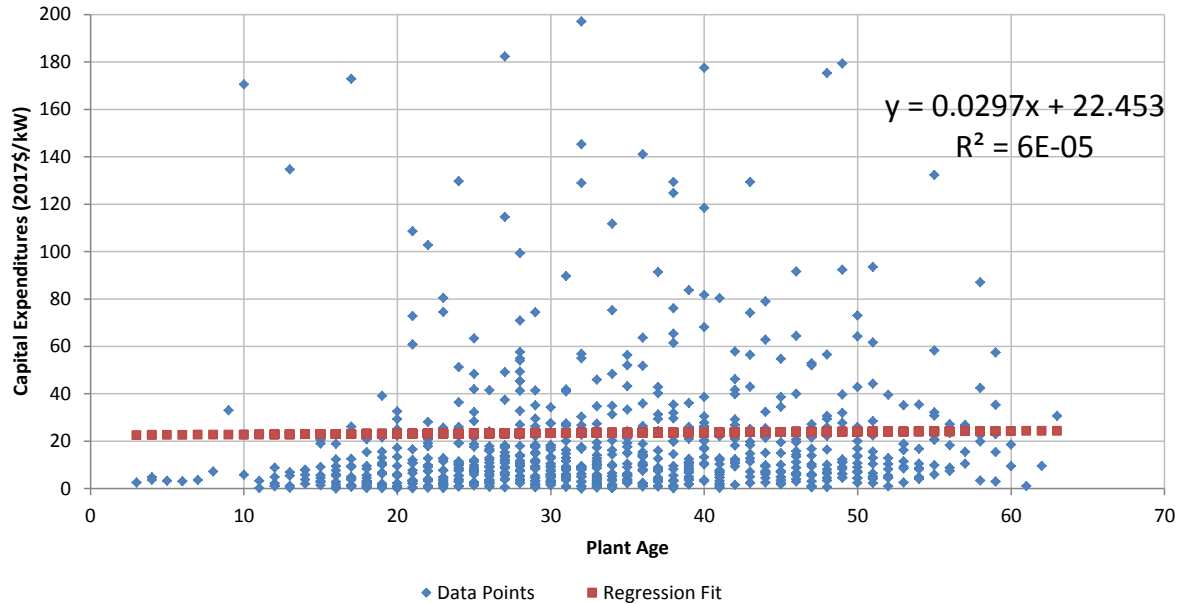
CAPITAL EXPENDITURES – BETWEEN 1,000 MW AND 2,000 MW

The results of the regression analysis of CAPEX spending for coal steam plants between 1,000 MW and 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.83, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table A-7 — Regression Statistics – Coal CAPEX 1,000 MW to 2,000 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	814		
Simple Average (\$/kW)	23.448		
Intercept	22.453	4.6325	4.21E-06
Slope	0.030	0.2174	8.28E-01
R ²	0.00006		

Figure A-7 — Coal Steam Dataset – CAPEX for 1,000-MW to 2,000-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 1,000 MW AND 2,000 MW

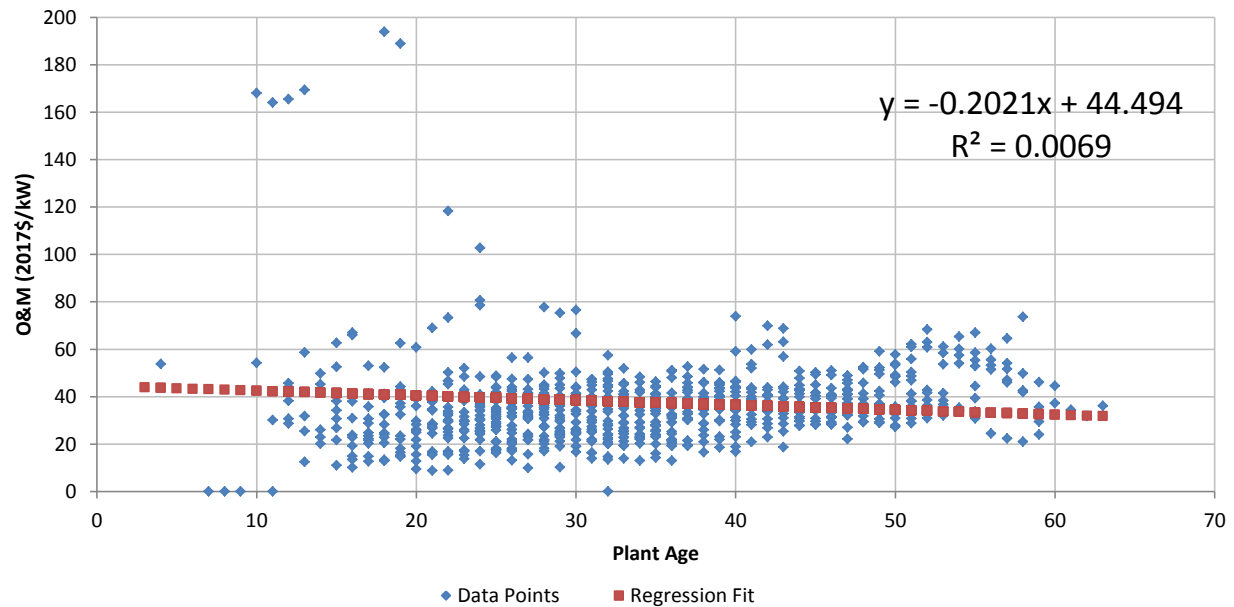
The results of the regression analysis of O&M spending for coal steam plants between 1,000 MW and 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

Annual spending in 2017 \$/kW-year = 44.494 + (-0.202 × age)

Table A-8 — Regression Statistics – Coal O&M 1,000 MW to 2,000 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	813		
Simple Average (\$/kW)	37.722		
Intercept	44.494	14.7620	7.42E-44
Slope	-0.202	-2.3785	1.76E-02
R ²	0.00693		

Figure A-8 — Coal Steam Dataset – O&M for 1,000-MW to 2,000-MW Plant Size



The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

	Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =
1000 MW - 2000 MW, All Capacity Factors								
Net Total O&M- 2017 \$/kW	53.51	32.80	40.62	37.72	107	478	228	813
Net Total Capex - 2017 \$/kW	22.56	23.31	24.16	23.45	108	478	228	814
Net Total O&M and Capex - 2017 \$/kW	76.28	56.11	64.78	61.20	107	478	228	813

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

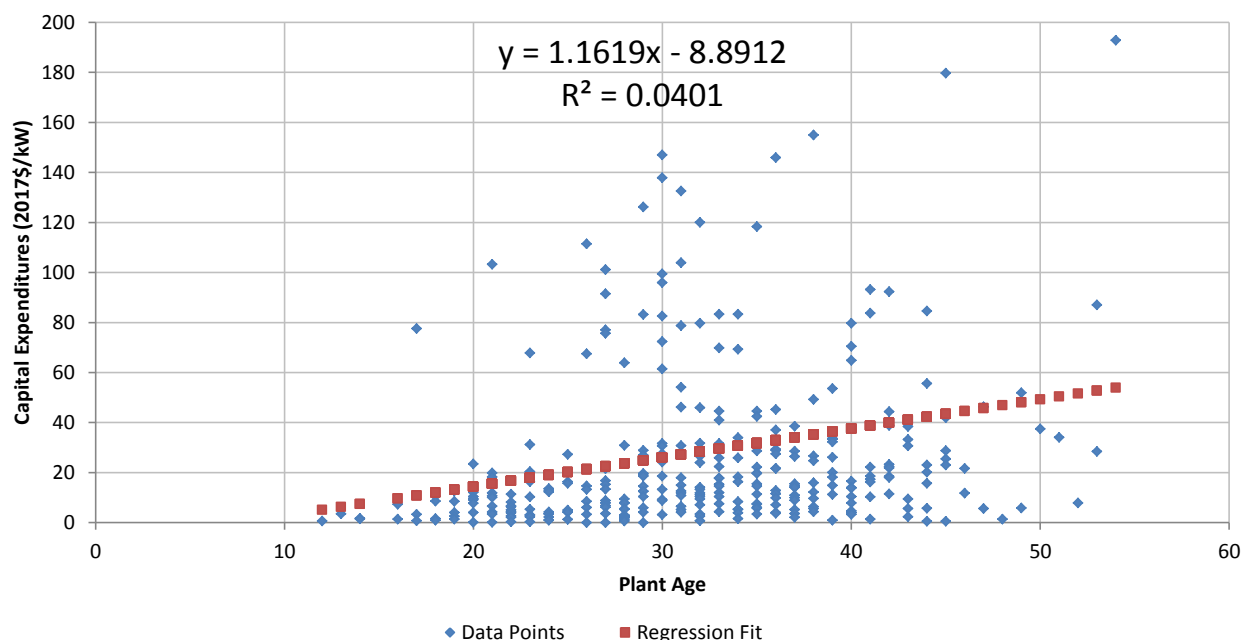
CAPITAL EXPENDITURES – GREATER THAN 2,000 MW

The results of the regression analysis of CAPEX spending for coal steam plants greater than 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is less than 0.05, age is a statistically significant predictor of CAPEX spending. However, the linear regression analysis shows the intercept value (i.e., the CAPEX cost during the first year) to be less than zero. This is because of the lack of data for plant ages up to 20 years—the limited amount of data causes the regression analysis to be distorted and unrealistic.

Table A-9 — Regression Statistics – Coal CAPEX > 2,000 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	322		
Simple Average (\$/kW)	28.303		
Intercept	-8.891	-0.8468	3.98E-01
Slope	1.162	3.6556	3.00E-04
R ²	0.04009		

Figure A-9 — Coal Steam Dataset – CAPEX for Greater than 2,000-MW Plant Size



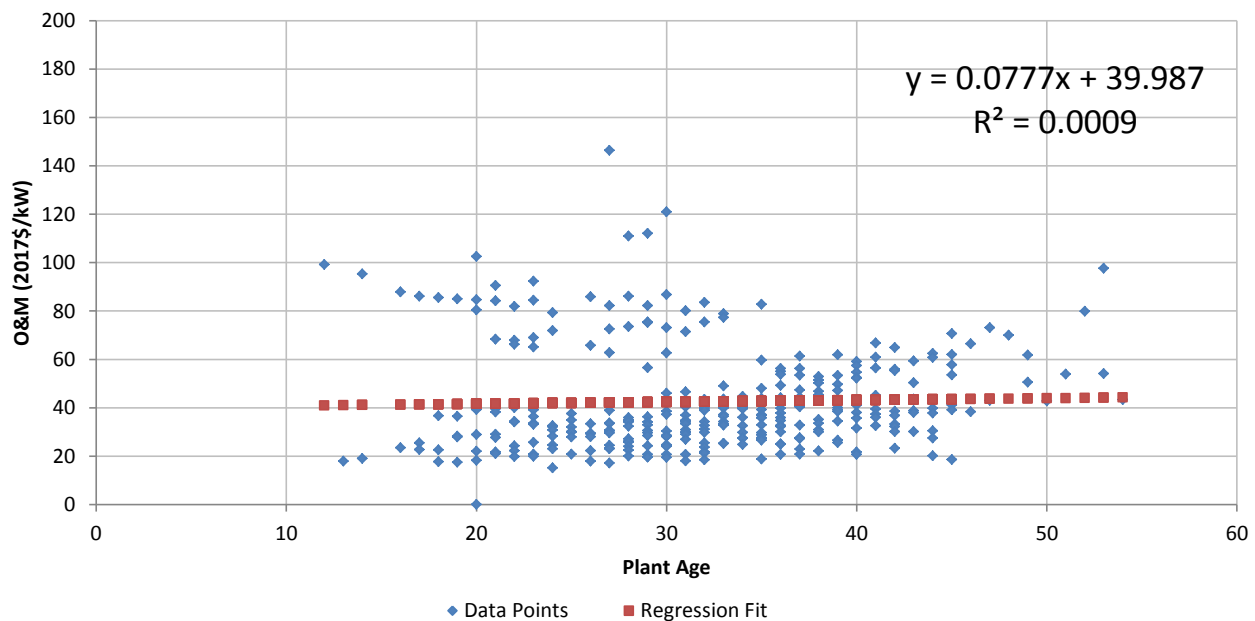
OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 2,000 MW

The results of the regression analysis of O&M spending for coal steam plants greater than 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.59, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table A-10 — Regression Statistics – Coal O&M > 2,000 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	322		
Simple Average (\$/kW)	42.474		
Intercept	39.987	8.3303	2.39E-15
Slope	0.078	0.5348	5.93E-01
R ²	0.00089		

Figure A-10 — Coal Steam Dataset – O&M for Greater than 2,000-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

	Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =
> 2000 MW, All Capacity Factors								
Net Total O&M- 2017 \$/kW	46.55	40.91	48.04	42.47	26	246	50	322
Net Total Capex - 2017 \$/kW	8.65	27.06	44.64	28.30	26	246	50	322
Net Total O&M and Capex - 2017 \$/kW	55.20	67.97	92.67	70.78	26	246	50	322

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

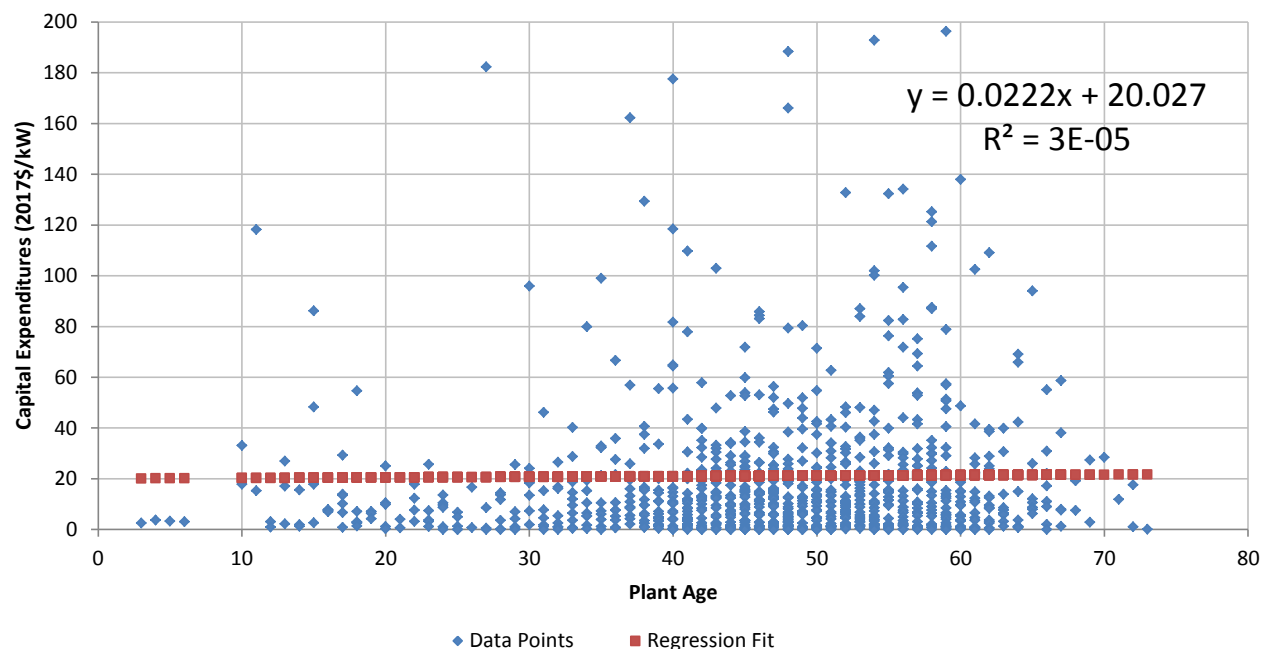
CAPITAL EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes and with capacity factors less than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.87, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table A-11 — Regression Statistics – Coal CAPEX for Capacity Factor < 50%

		<i>t statistic</i>	<i>p-value</i>
Observations	972		
Simple Average (\$/kW)	21.063		
Intercept	20.027	3.1188	1.87E-03
Slope	0.022	0.1663	8.68E-01
R ²	0.00003		

Figure A-11 — Coal Steam Dataset – CAPEX for All Plants with Avg. Net Capacity Factor < 50%



Note: Age coefficient in above regression equation is not statistically significant.

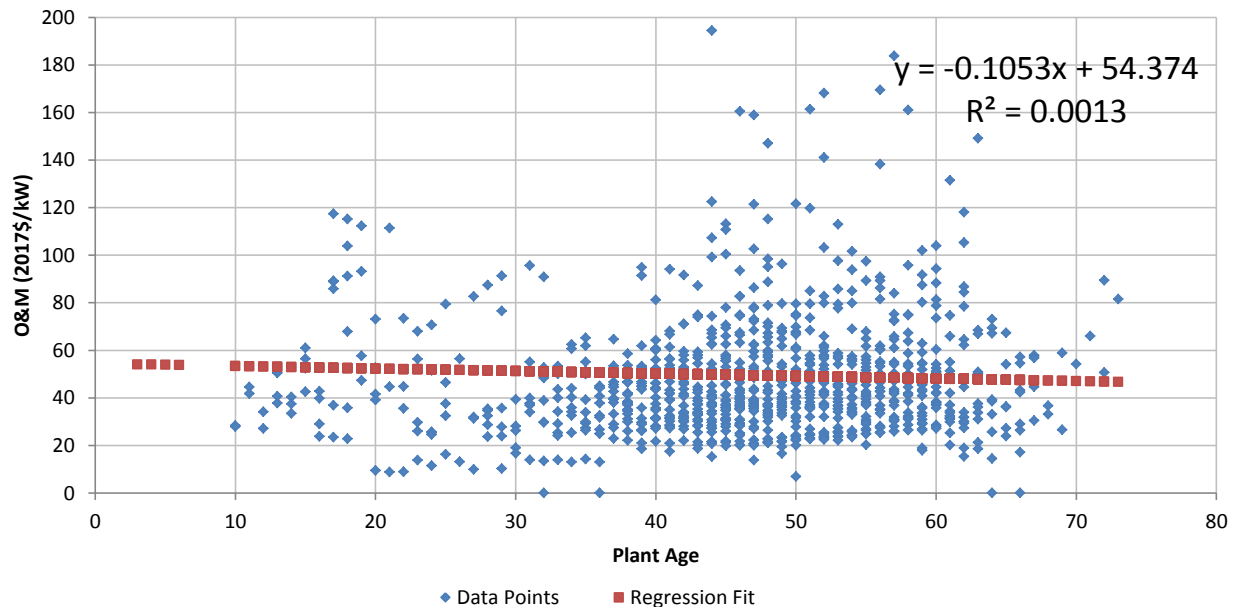
OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

The results of the regression analysis of O&M spending for coal steam plants of all MW sizes and with capacity factors less than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.26, which is greater than 0.05, age is not a statistically significant predictor of O&M spending.

Table A-12 — Regression Statistics – Coal O&M for Capacity Factor < 50%

		<i>t statistic</i>	<i>p-value</i>
Observations	965		
Simple Average (\$/kW)	49.454		
Intercept	54.374	12.0380	3.43E-31
Slope	-0.105	-1.1234	2.62E-01
R ²	0.00131		

Figure A-12 — Coal Steam Dataset – O&M for All Plants with Avg. Net Capacity Factor < 50%



Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

	Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =
All MW, Capacity Factors 0 - 50%								
Net Total O&M- 2017 \$/kW	76.43	40.01	50.07	49.45	45	177	743	965
Net Total Capex - 2017 \$/kW	19.62	23.74	20.51	21.06	45	179	748	972
Net Total O&M and Capex - 2017 \$/kW	96.04	63.66	70.63	70.54	45	177	743	965

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

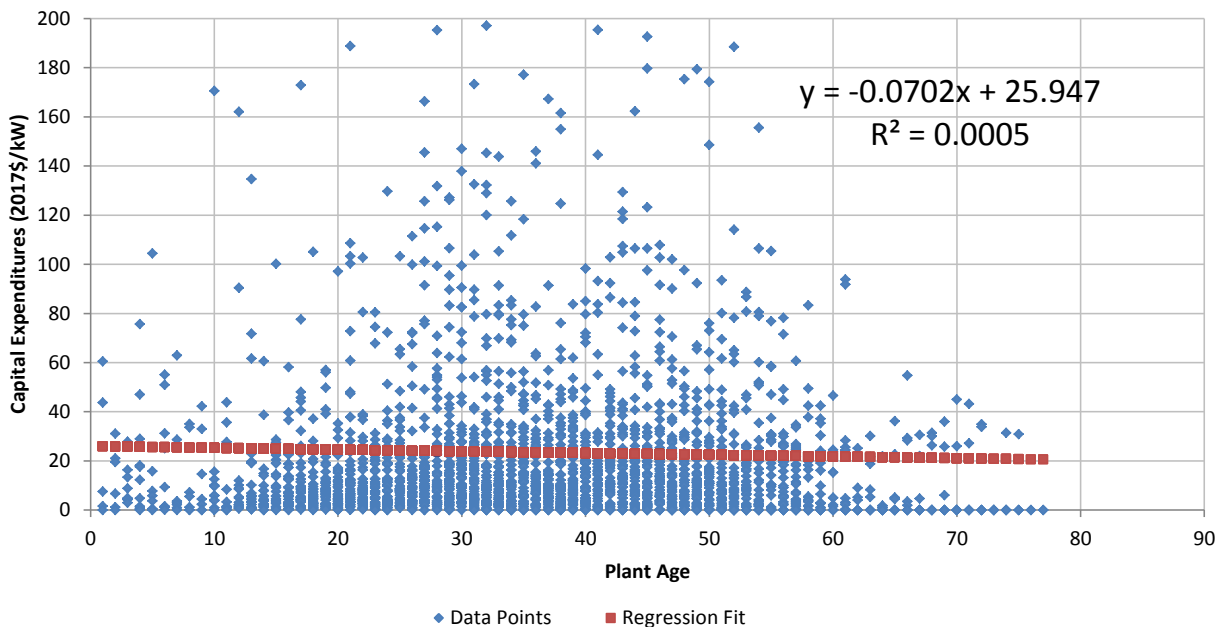
CAPITAL EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes and with capacity factors greater than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.25, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table A-13 — Regression Statistics – Coal CAPEX for Capacity Factor > 50%

		<i>t statistic</i>	<i>p-value</i>
Observations	2752		
Simple Average (\$/kW)	23.389		
Intercept	25.947	10.7905	1.29E-26
Slope	-0.070	-1.1446	2.52E-01
R ²	0.00048		

Figure A-13 — Coal Steam Dataset – CAPEX for All Plants with Avg. Net Capacity Factor > 50%



Note: Age coefficient in above regression equation is not statistically significant.

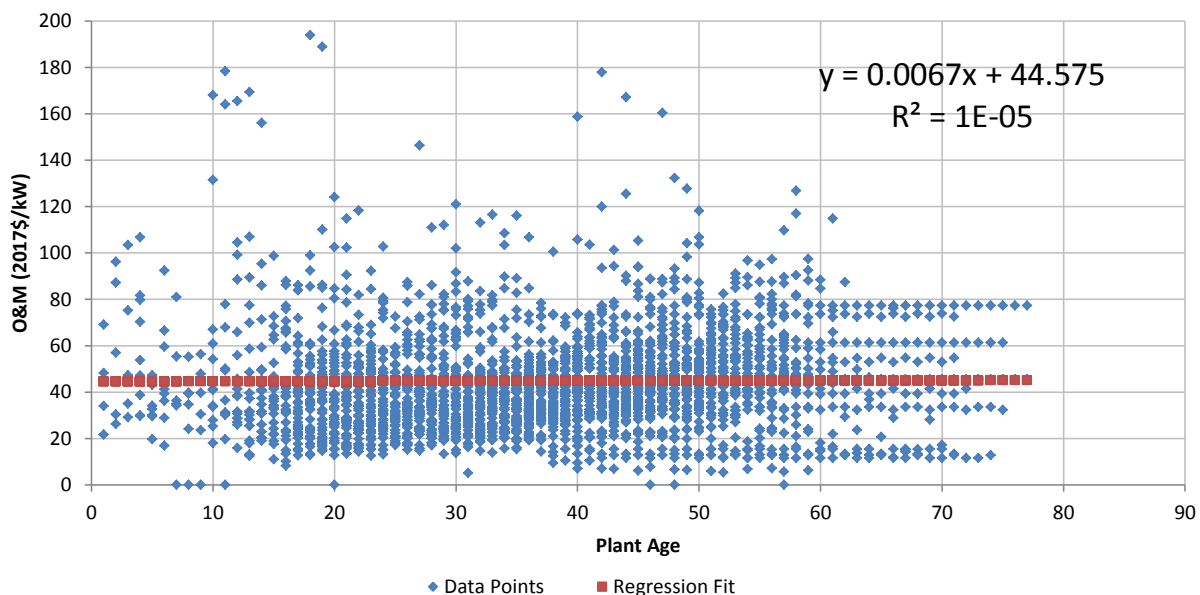
OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

The results of the regression analysis of O&M spending for coal steam plants of all MW sizes and with capacity factors greater than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.85, which is greater than 0.05, age is not a statistically significant predictor of O&M spending.

Table A-14 — Regression Statistics – Coal O&M for Capacity Factor > 50%

		<i>t statistic</i>	<i>p-value</i>
Observations	2788		
Simple Average (\$/kW)	44.822		
Intercept	44.575	32.6995	8.78E-199
Slope	0.007	0.1954	8.45E-01
R ²	0.00001		

Figure A-14 — Coal Steam Dataset – O&M for All Plants with Avg. Net Capacity Factor > 50%



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

	Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =
All MW, Capacity Factors 50% - 100%								
Net Total O&M- 2017 \$/kW	51.33	40.07	47.92	44.82	395	1,271	1,122	2,788
Net Total Capex - 2017 \$/kW	17.73	26.55	21.75	23.39	396	1,271	1,085	2,752
Net Total O&M and Capex - 2017 \$/kW	69.11	66.62	69.25	68.01	395	1,271	1,082	2,748

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

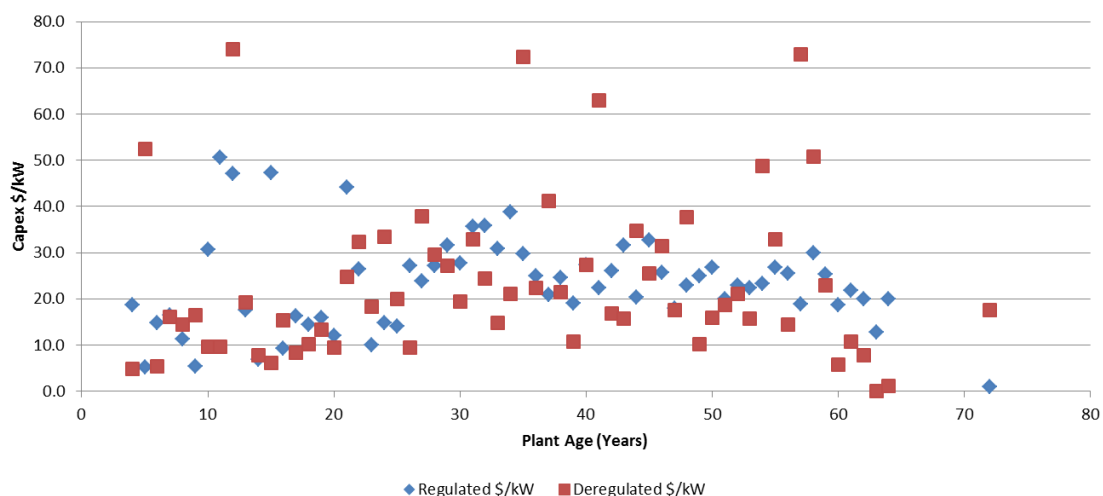
CAPITAL EXPENDITURES – REGULATED VS. DEREGULATED

The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) in regulated versus deregulated locations are summarized in the table below. Since the p-value for the age (“slope”) and regulation/deregulation coefficients are much greater than 0.05, age and regulatory status are not statistically significant predictors of CAPEX spending.

Table A-15 — Regression Statistics – Coal CAPEX for Regulated/Deregulated

	Coefficients	Standard Error	t Stat	P-Value
Intercept	23.22826383	2.9645403	7.835367875	6.36821E-15
Age	0.097334249	0.064355791	1.512439626	0.130523796
Reg./Dereg. (1/0)	-2.479225741	2.148990587	-1.153669893	0.248724297

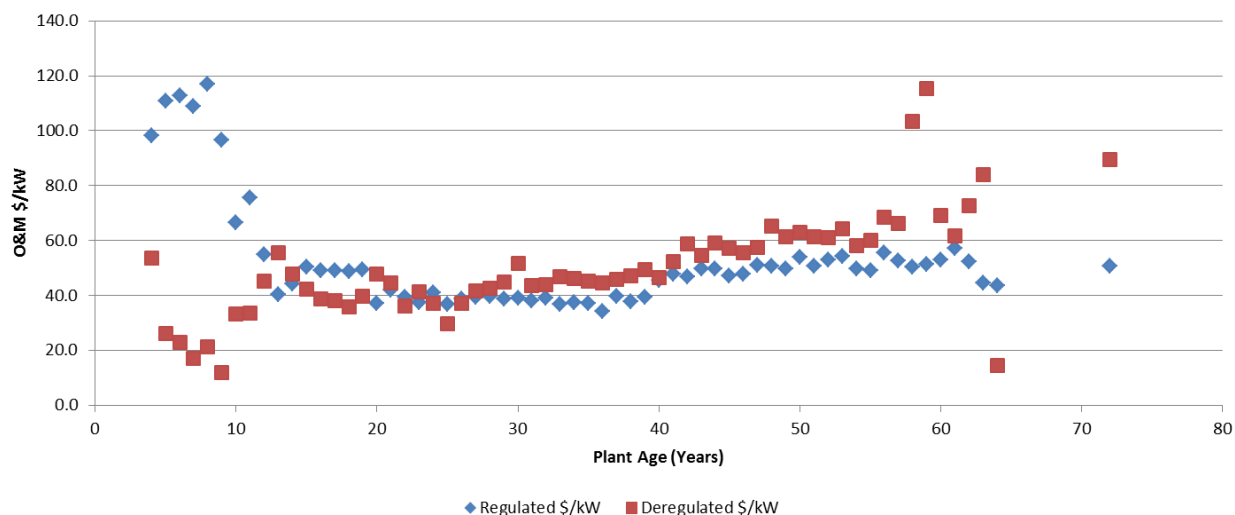
Figure A-15 — Coal Steam Dataset – CAPEX for Regulated/Deregulated



OPERATIONS & MAINTENANCE EXPENDITURES – REGULATED VS. DEREGULATED

The regression analysis of O&M expenditures indicates that the p-value for the age (“slope”) and regulated/deregulated coefficients are much less than 0.05 (i.e., statistically significant). However, the outliers before year 20 may tend to distort the regression analysis. After year 20, a visual inspection of the data points indicates higher O&M spending in deregulated states compared with regulated states (Figure A-16). This is the opposite of what would be expected, whereby plant owners in a deregulated environment would have a greater incentive to reduce O&M costs that cannot be passed through to ratepayers. The higher O&M spending is likely a result of other factors, such as higher average labor costs in deregulated states, which tend to have a higher percentage of union labor compared with regulated states. Therefore, the net effect of regulatory status on average O&M spending is not apparent at this level of detail.

Figure A-16 — Coal Steam Dataset – O&M for Regulated vs. Deregulated



CAPITAL EXPENDITURES – FGD VS. NO FGD

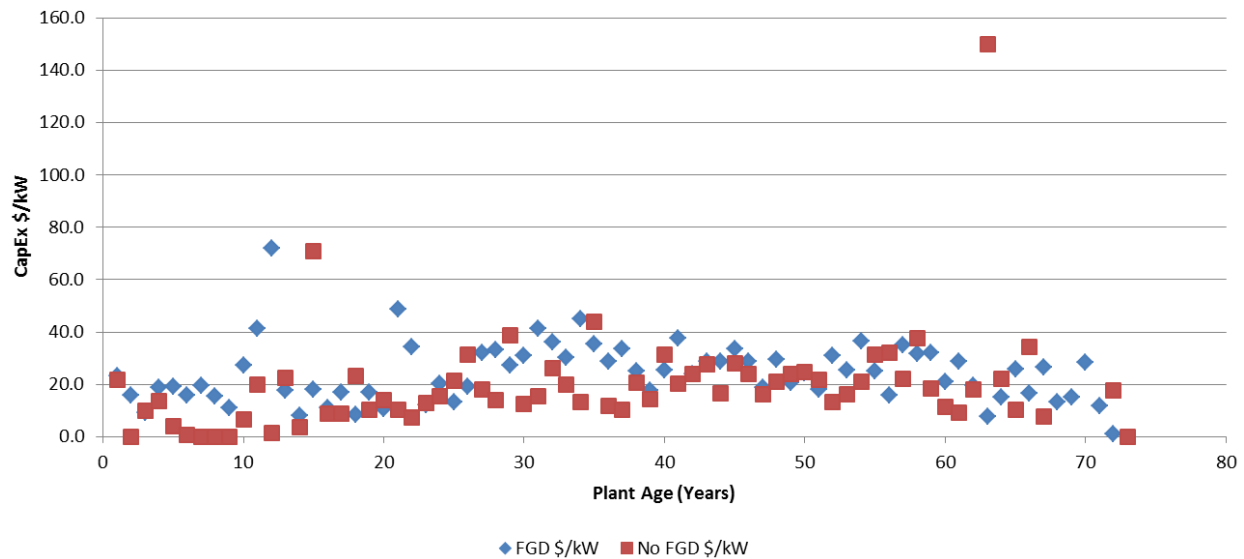
The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) with and without FGD are summarized in the table below. The p-value for the age (“slope”) coefficient is slightly greater than 0.05 (nearly statistically significant) while the p-value for the FGD/no-FGD coefficient is much less than 0.05 (statistically significant). A visual inspection of the difference between the FGD and no-FGD data points in Figure A-17 shows a similarity in CAPEX spending amounts across all ages. Therefore, average CAPEX spending may be represented by the following regression equation:

Annual CAPEX spending in 2017 \$/kW-year = $16.53 + (0.126 \times \text{age}) + (5.68 \times \text{FGD})$ Where FGD = 1 if plant has FGD; zero otherwise

Table A-16 — Regression Statistics – Coal CAPEX for FGD/No FGD

	Coefficients	Standard Error	t Stat	P-Value
Intercept	16.52586075	3.06139723	5.39814323	7.2399E-08
Age	0.126266024	0.065143952	1.93826166	0.05268181
FGD/No FGD (1/0)	5.6788887	1.913609818	2.96763146	0.00302395

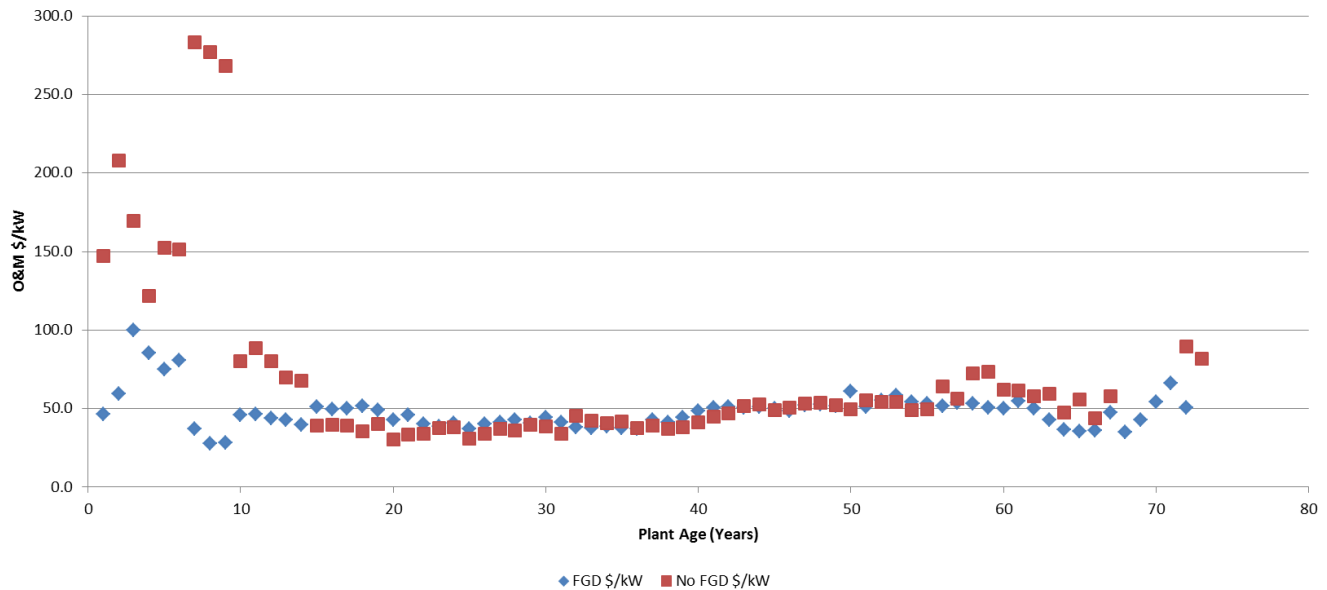
Figure A-17 — Coal Steam Dataset – CAPEX for FGD/No FGD



OPERATIONS & MAINTENANCE EXPENDITURES – FGD VS. NO FGD

The regression analysis of O&M expenditures indicates that the p-value for the age (“slope”) and FGD/no-FGD coefficients are much less than 0.05 (i.e., statistically significant). However, outliers before year 15 may tend to distort the regression analysis. A visual inspection of the difference between the FGD and no-FGD data points in Figure A-18 shows a similarity in O&M spending amounts across all ages after year 15. The differences in annual coal plant spending due to having FGD is more significant in the CAPEX accounts, as shown in the previous subsection, rather than the O&M accounts.

Figure A-18 — Coal Steam Dataset – O&M for FGD vs. No FGD



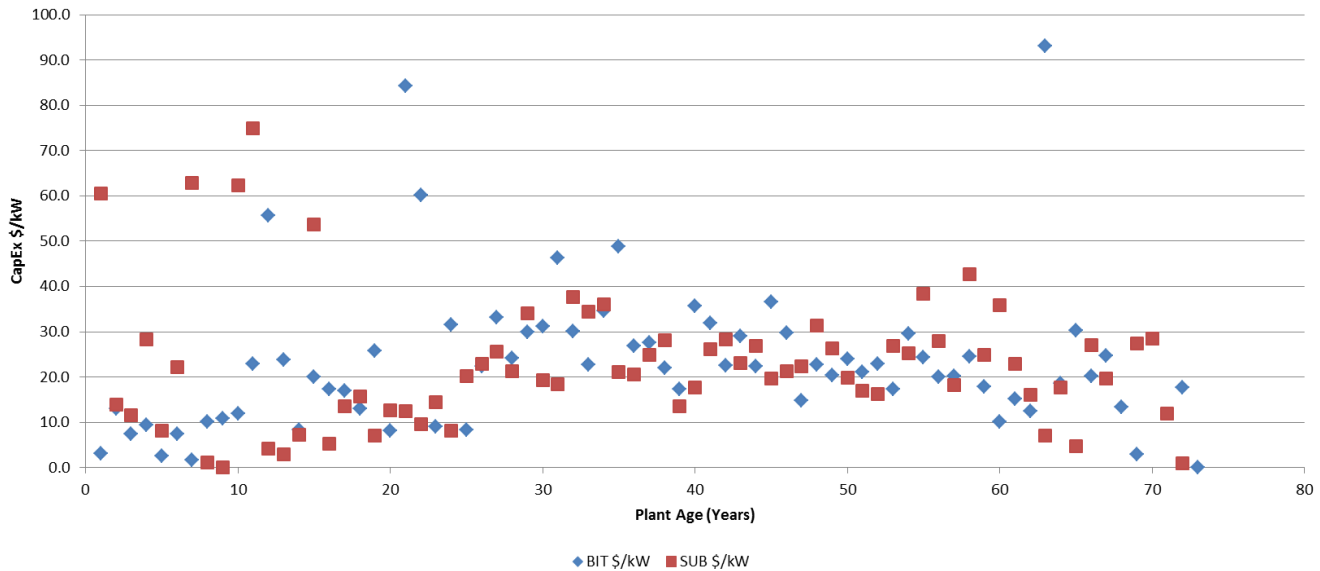
CAPITAL EXPENDITURES – BITUMINOUS VS. SUBBITUMINOUS

The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) in bituminous versus subbituminous coal types are summarized in the table below. The p-value for the age (“slope”) coefficient is much greater than 0.05 (not statistically significant), while the p-value for the bituminous/subbituminous coefficient is much less than 0.05 (statistically significant). However, the outliers before year 20 may tend to distort the regression analysis. Further, a visual inspection of the difference between the bituminous and subbituminous data points in Figure A-19 shows a similarity in CAPEX spending amounts across all ages. Therefore, average CAPEX spending is not likely affected by coal type at a high-level designation (i.e., bituminous/subbituminous) without more detailed coal specifications.

Table A-17 — Regression Statistics – Coal CAPEX for Bituminous/Subbituminous

	Coefficients	Standard Error	t Stat	P-Value
Intercept	15.39252046	2.257695952	6.817800442	1.08205E-11
Age	-0.00350504	0.054578287	-0.064220408	0.948798346
Bit./Sub. (1/0)	10.93481186	1.525466511	7.168175624	9.20398E-13

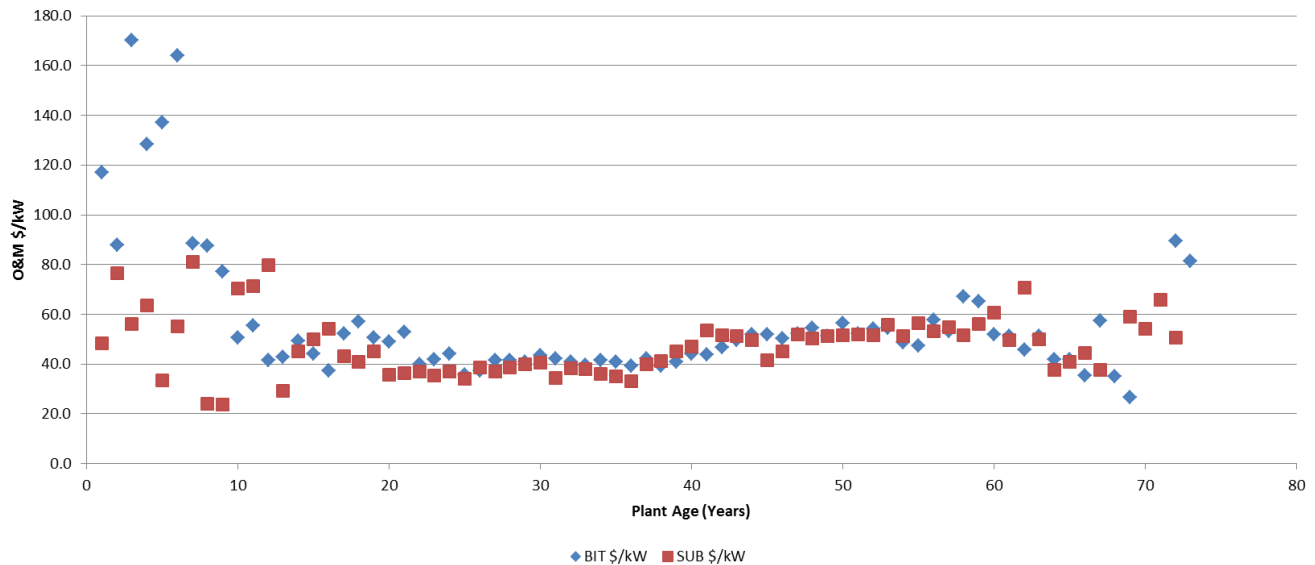
Figure A-19 — Coal Steam Dataset – CAPEX for Bituminous/Subbituminous



OPERATIONS & MAINTENANCE EXPENDITURES – BITUMINOUS VS. SUBBITUMINOUS

The regression analysis of O&M expenditures indicates that the p-value for the age (“slope”) and bituminous/subbituminous coefficients are much less than 0.05 (statistically significant). However, as with CAPEX spending, the outliers before year 20 may tend to distort the regression analysis. Further, a visual inspection of the difference between the bituminous and subbituminous data points in Figure A-20 shows a similarity in O&M spending amounts across all ages. Therefore, average O&M spending is not likely affected by coal type at a high-level designation (i.e., bituminous/subbituminous) without more detailed coal specifications.

Figure A-20 — Coal Steam Dataset – O&M for Bituminous vs. Subbituminous



EFFECT OF PLANT CAPACITY FACTOR

CAPEX and O&M spending for the coal steam plants increased significantly with age when expressed on a \$/MWh basis. This was primarily a result of significant declines in plant capacity factors over time. Figure A-21 and Figure A-22 indicate real annual increases in CAPEX and O&M spending for the coal steam plants in constant 2017 \$/MWh versus plant age, with linear regression results as follows:

- Annual CAPEX in 2017 \$/MWh = $3.27 + (0.0426 \times \text{age})$
- Annual O&M in 2017 \$/MWh = $5.44 + (0.133 \times \text{age})$

Figure A-21 — CAPEX vs. Age for All MW Coal Plants (2017 \$/MWh)

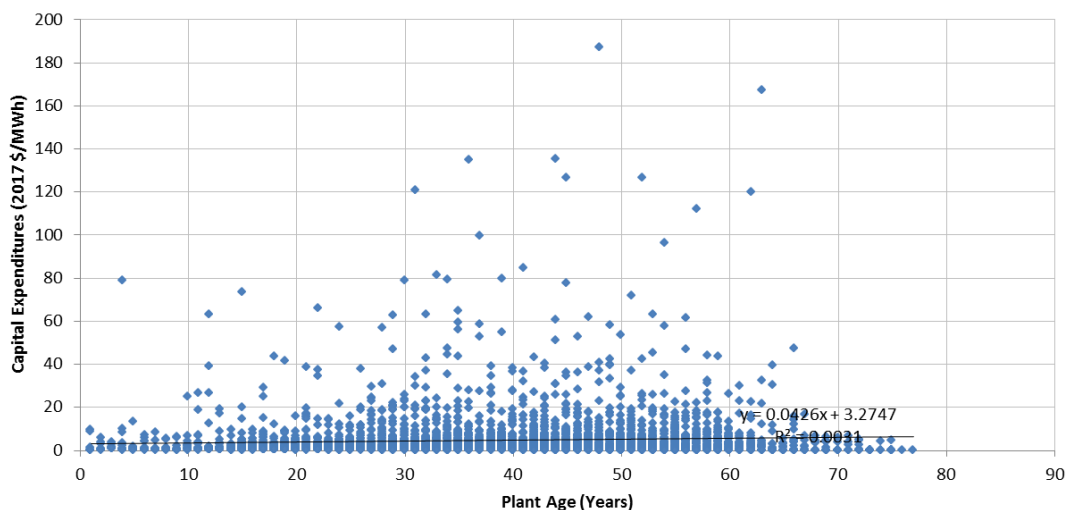
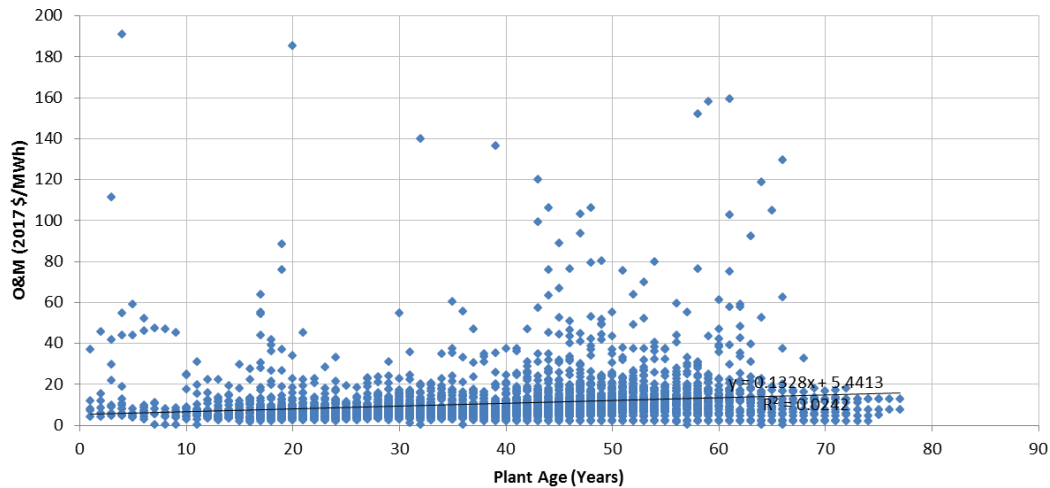


Figure A-22 — O&M vs. Age for All Coal Plants (2017 \$/MWh)



In both of the above regression results, the age coefficient was found to be statistically significant. This was determined to be a result of the average decline in capacity factors for the coal steam plants, as shown in Figure A-23. A similar decline also occurred with the gas/oil steam plants, as shown in Figure A-24.

Figure A-23 — Capacity Factor vs. Age for All Coal Plants

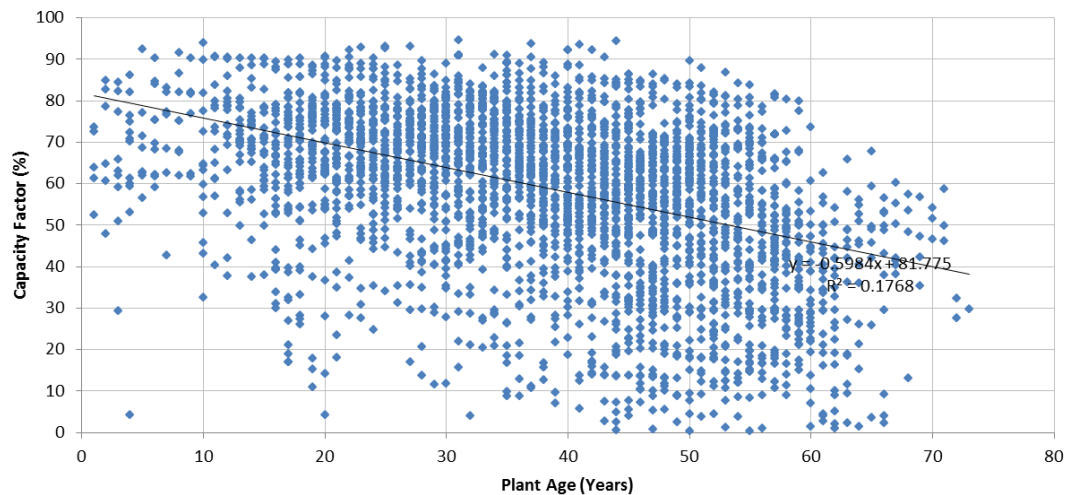
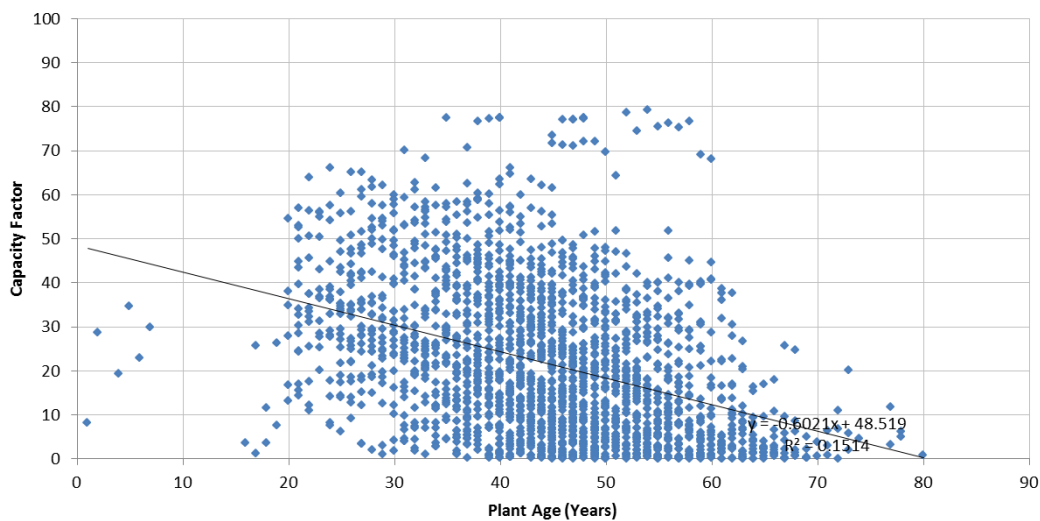


Figure A-24 — Capacity Factor vs. Age for All Gas/Oil Steam Plants





Appendix B. Regression Analysis – Gas/Oil Steam

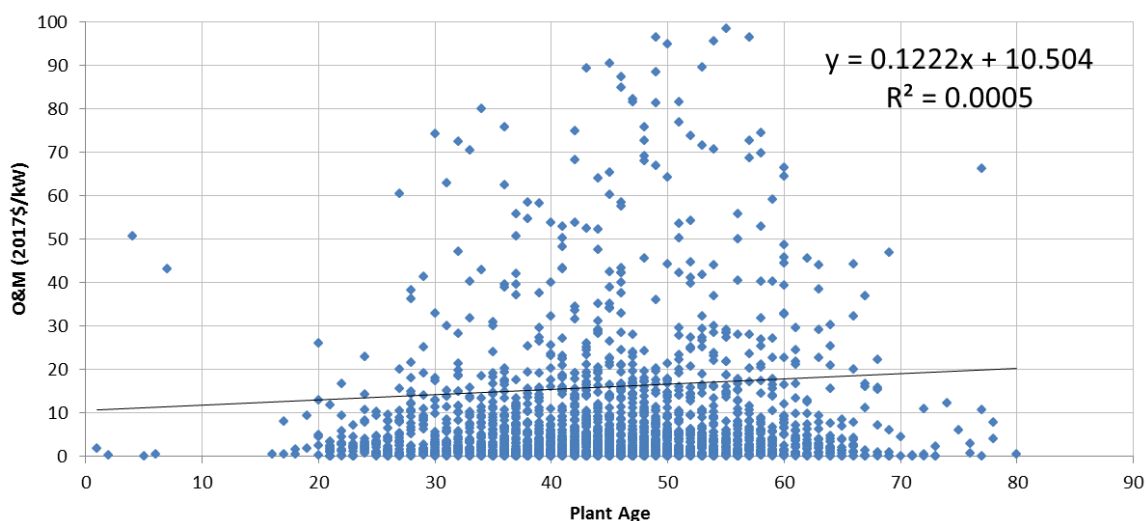
CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the regression analysis of CAPEX spending for gas/oil steam plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.29, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table B-1 — Regression Statistics – Gas/Oil Steam CAPEX for All MW

		<i>t statistic</i>	<i>p-value</i>
Observations	2,226		
Simple Average (\$/kW)	15.955		
Intercept	10.504	1.9741	4.85E-02
Slope	0.122	1.0551	2.91E-01
R ²	0.00050		

Figure B-1 — Gas/Oil Steam Dataset – CAPEX for All Plant MW Sizes



Note: Age coefficient in above regression equation is not statistically significant.

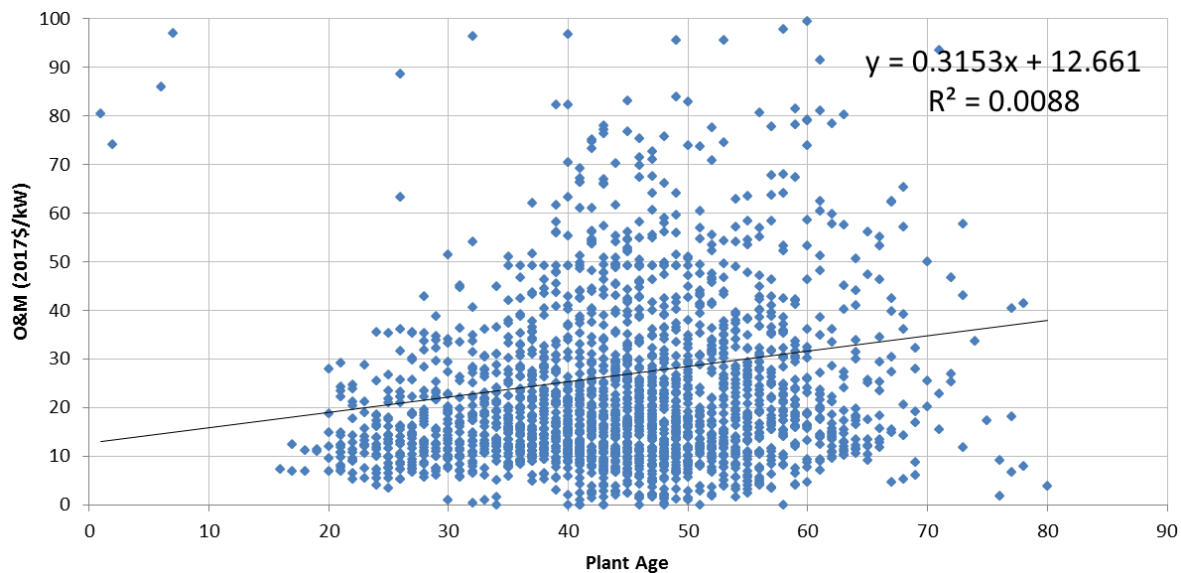
OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of O&M spending for gas/oil steam plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the limited number of data points before year 20 may distort the regression analysis.

Table B-2 — Regression Statistics – Gas/Oil Steam O&M for All MW

		<i>t statistic</i>	<i>p-value</i>
Observations	2,224		
Simple Average (\$/kW)	26.723		
Intercept	12.661	3.8863	1.05E-04
Slope	0.315	4.4455	9.20E-06
R ²	0.00882		

Figure B-2 — Gas/Oil Steam Dataset – O&M for All Plant MW Sizes



Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

	Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =
All MW, All Capacity Factors								
Net Total O&M- 2017 \$/kW	39.39	23.48	28.18	26.72	19	733	1,472	2,224
Net Total Capex - 2017 \$/kW	8.91	14.18	16.93	15.96	19	733	1,474	2,226
Net Total O&M and Capex - 2017 \$/kW	48.30	37.53	45.10	42.63	19	731	1,470	2,220

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil steam plants are described in Section 4.

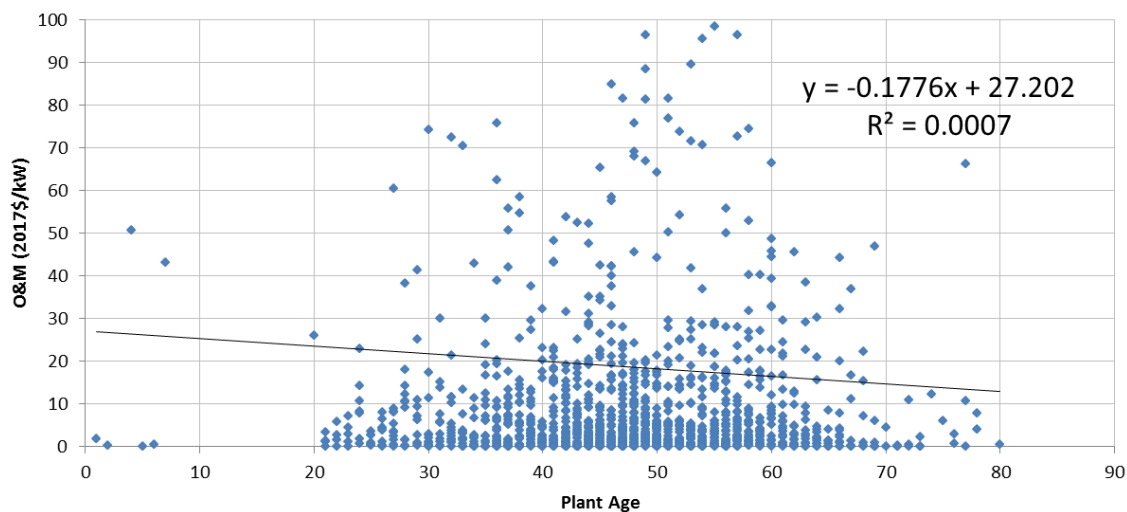
CAPITAL EXPENDITURES – LESS THAN 500 MW

The results of the regression analysis of CAPEX spending for gas/oil steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.32, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table B-3 — Regression Statistics – Gas/Oil Steam CAPEX < 500 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	1382		
Simple Average (\$/kW)	18.392		
Intercept	27.202	3.1265	1.81E-03
Slope	-0.178	-0.9867	3.24E-01
R ²	0.00071		

Figure B-3 — Gas/Oil Steam Dataset – CAPEX for Less than 500-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

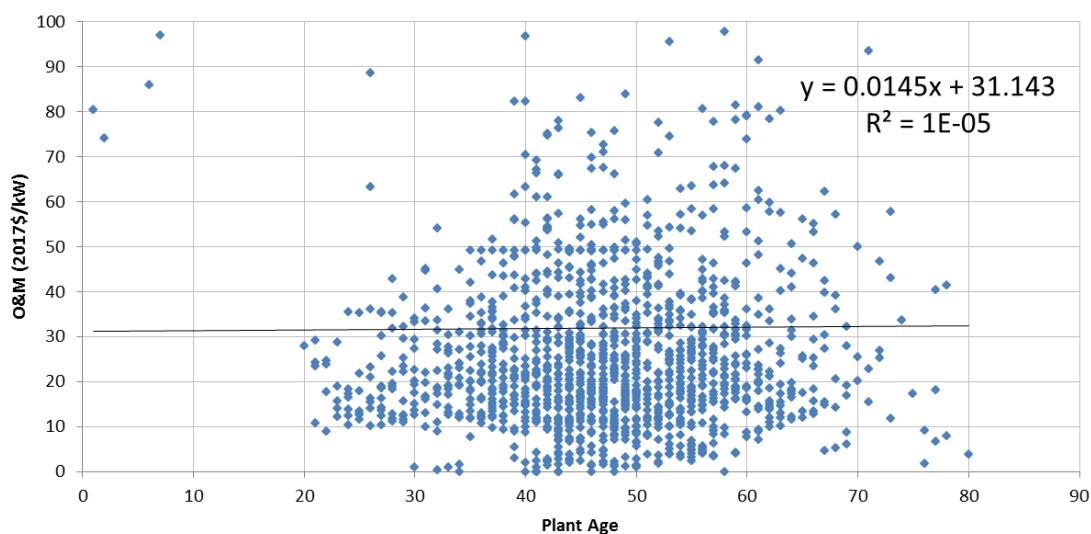
OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 500 MW

The results of the linear regression analysis of O&M spending for gas/oil steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.90, which is greater than 0.05, age is not a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table B-4 — Regression Statistics – Gas/Oil Steam O&M < 500 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	1,381		
Simple Average (\$/kW)	31.827		
Intercept	31.143	5.7925	8.58E-09
Slope	0.015	0.1305	8.96E-01
R ²	0.00001		

Figure B-4 — Gas/Oil Steam Dataset – O&M for Less than 500-MW Plant Size



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

	Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =
< 500 MW, All Capacity Factors								
Net Total O&M- 2017 \$/kW	88.54	33.36	30.98	31.83	7	324	1,050	1,381
Net Total Capex - 2017 \$/kW	17.44	22.13	17.82	18.83	7	324	1,051	1,382
Net Total O&M and Capex - 2017 \$/kW	105.98	55.32	48.78	50.60	7	322	1,048	1,377

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil steam plants are described in Section 4.

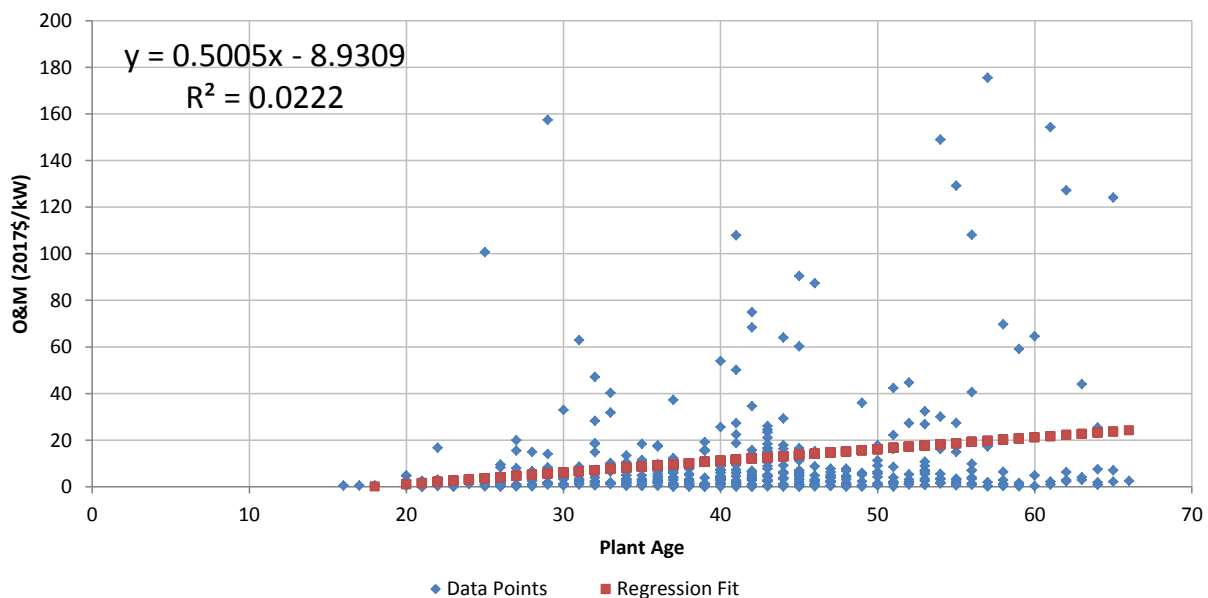
CAPITAL EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the regression analysis of CAPEX spending for gas/oil steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is less than 0.05, age is a statistically significant predictor of CAPEX spending. However, the regression analysis shows the intercept value (i.e., the CAPEX cost during the first year) to be less than zero. This is because of the lack of data for plant ages up to 20 years—the limited amount of data causes the regression analysis to be distorted and unrealistic.

Table B-5 — Regression Statistics – Gas/Oil Steam CAPEX 500 MW to 1,000 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	489		
Simple Average (\$/kW)	11.570		
Intercept	-8.988	-1.4118	1.59E-01
Slope	0.501	3.3322	9.27E-04
R ²	0.02229		

Figure B-5 — Gas/Oil Steam Dataset – CAPEX for 500-MW to 1,000-MW Plant Size



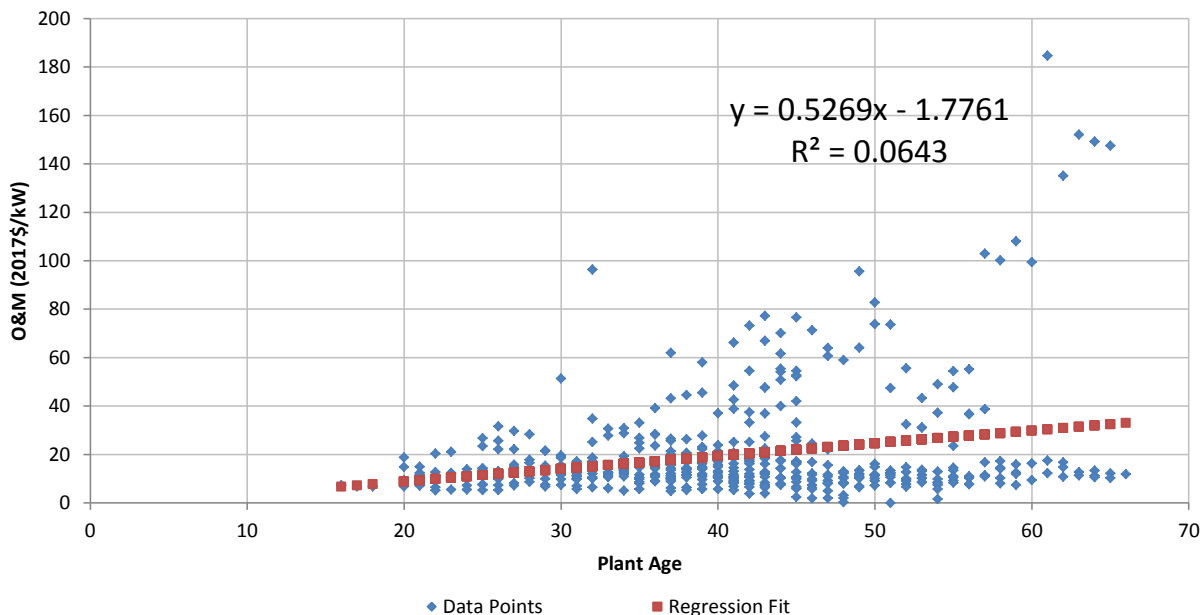
OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the regression analysis of O&M spending for gas/oil steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is less than 0.05, age is a statistically significant predictor of O&M spending. However, the regression analysis shows the intercept value (i.e., the O&M cost during the first year) to be less than zero. This is because of the lack of data for plant ages up to 20 years—the limited data causes the regression analysis to be distorted.

Table B-6 — Regression Statistics – Gas/Oil Steam O&M 500 MW to 1,000 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	488		
Simple Average (\$/kW)	19.823		
Intercept	-1.776	-0.4606	6.45E-01
Slope	0.527	5.7810	1.33E-08
R ²	0.06434		

Figure B-6 — Gas/Oil Steam Dataset – O&M for 500-MW to 1,000-MW Plant Size



The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

	Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =
500 MW - 1000 MW, All Capacity Factors								
Net Total O&M- 2017 \$/kW	10.10	15.82	23.61	19.82	7	225	256	488
Net Total Capex - 2017 \$/kW	1.94	6.32	16.43	11.57	7	225	257	489
Net Total O&M and Capex - 2017 \$/kW	12.04	22.14	40.07	31.40	7	225	256	488

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil steam plants are described in Section 4.

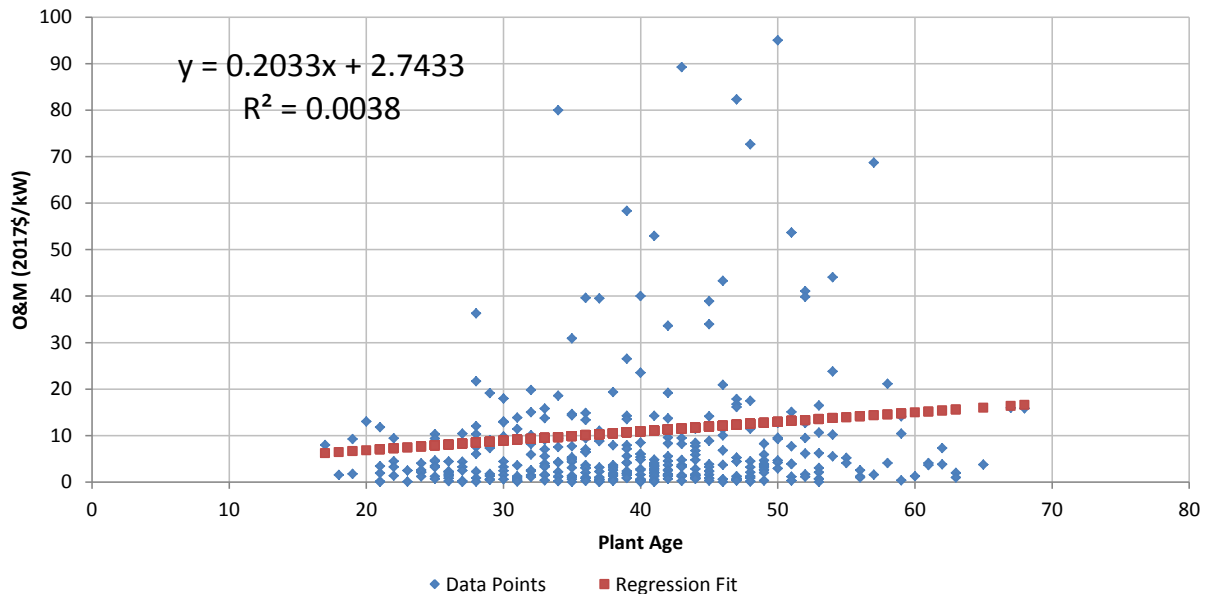
CAPITAL EXPENDITURES – GREATER THAN 1,000 MW

The results of the regression analysis of CAPEX spending for gas/oil steam plants greater than 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.24, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table B-7 — Regression Statistics – Gas/Oil Steam CAPEX > 1,000 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	355		
Simple Average (\$/kW)	10.815		
Intercept	2.743	0.3846	7.01E-01
Slope	0.203	1.1660	2.44E-01
R ²	0.00384		

Figure B-7 — Gas/Oil Steam Dataset – CAPEX for Greater than 1,000-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

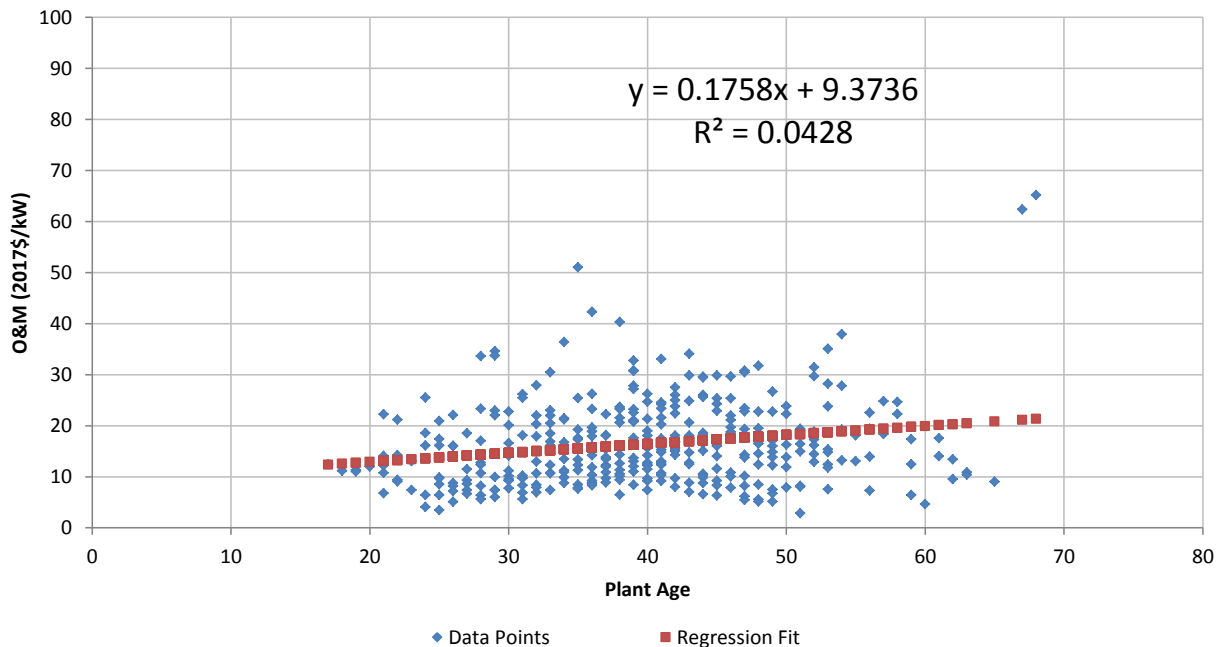
OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 1,000 MW

The results of the regression analysis of O&M spending for gas/oil steam plants greater than 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the limited number of data points before year 20 may distort the regression analysis.

Table B-8 — Regression Statistics – Gas/Oil Steam O&M > 1,000 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	355		
Simple Average (\$/kW)	16.353		
Intercept	9.374	5.1812	3.71E-07
Slope	0.176	3.9752	8.53E-05
R ²	0.04285		

Figure B-8 — Gas/Oil Steam Dataset – O&M for Greater than 1,000-MW Plant Size



The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

	Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =
> 1000 MW, All Capacity Factors								
Net Total O&M- 2017 \$/kW	11.59	15.44	17.50	16.35	5	184	166	355
Net Total Capex - 2017 \$/kW	6.70	9.78	12.09	10.82	5	184	166	355
Net Total O&M and Capex - 2017 \$/kW	18.29	25.22	29.60	27.17	5	184	166	355

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil steam plants are described in Section 4.



Appendix C. Regression Analysis – Gas/Oil Combined Cycle

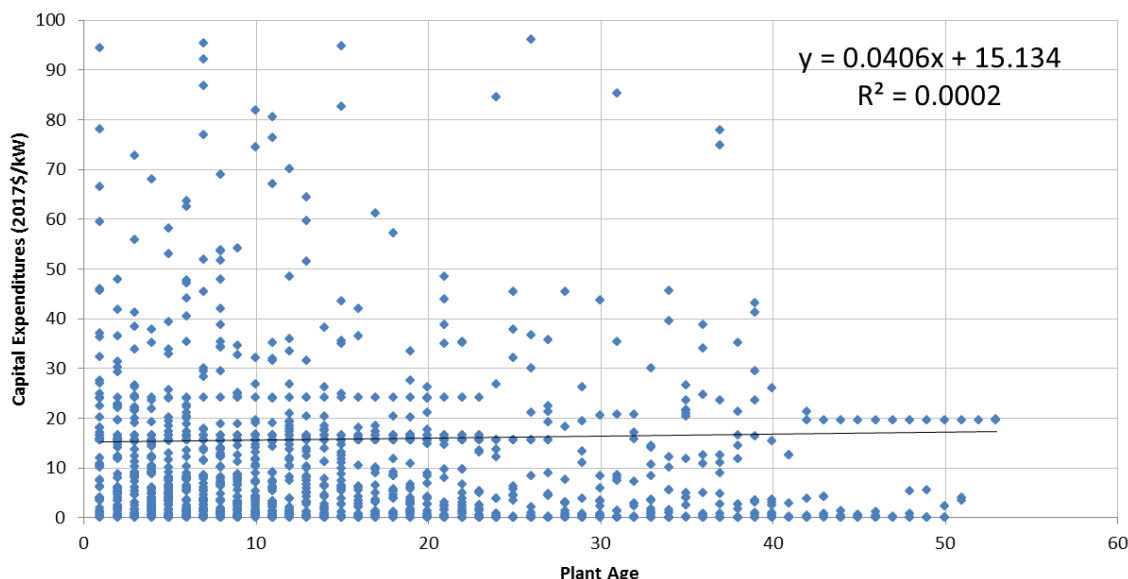
CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the regression analysis of CAPEX spending for gas/oil CC plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.63, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table C-1 — Regression Statistics – CC CAPEX for All MW

		<i>t statistic</i>	<i>p-value</i>
Observations	1,368		
Simple Average (\$/kW)	15.765		
Intercept	15.134	9.2176	1.11E-19
Slope	0.041	0.4853	6.28E-01
R ²	0.00017		

Figure C-1 — Gas/Oil CC Dataset – CAPEX for All Plant MW Sizes



Notes: Age coefficient in above regression equation is not statistically significant.
 Sequential data points with identical values are forecasted values for the same plant.

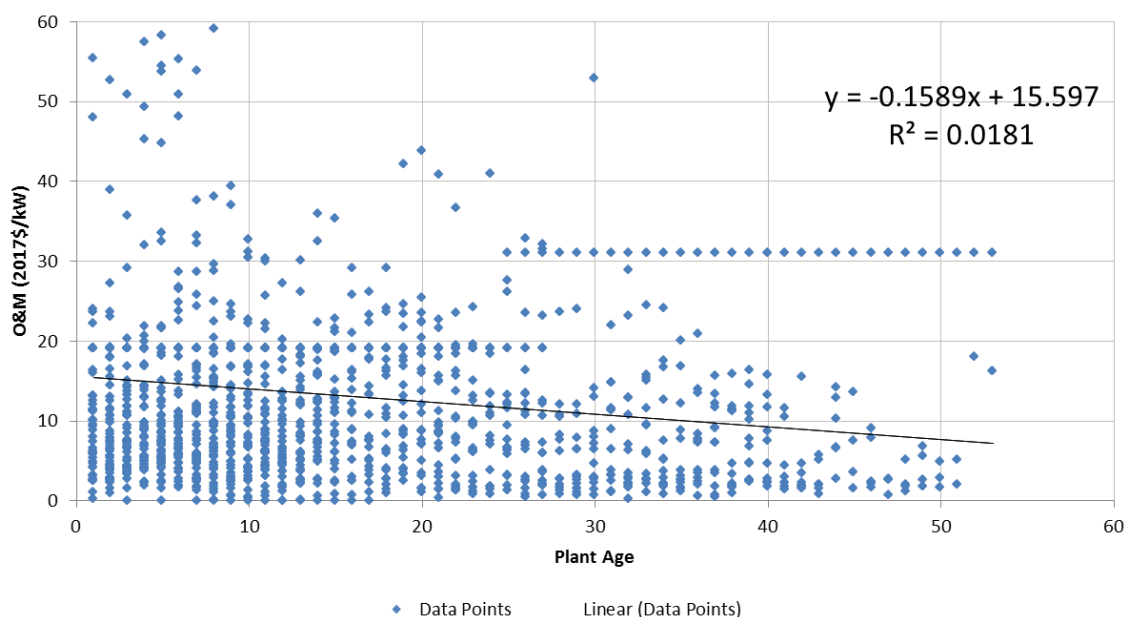
OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of O&M spending for gas/oil CC plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is much lower than 0.05, the dataset appears to support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table C-2 — Regression Statistics – CC O&M for All MW

		<i>t statistic</i>	<i>p-value</i>
Observations	1,388		
Simple Average (\$/kW)	13.080		
Intercept	15.597	24.8961	2.19E-113
Slope	-0.159	-5.0573	4.82E-07
R ²	0.01812		

Figure C-2 — Gas/Oil CC Dataset – O&M for All Plant MW Sizes



Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

	Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =
All MW, All Capacity Factors								
Net Total O&M - 2017 \$/kW	14.16	10.56	10.26	13.08	978	344	66	1,388
Net Total Capex - 2017 \$/kW	15.45	16.37	17.56	15.76	979	326	63	1,368
Net Total O&M and Capex - 2017 \$/kW	29.64	27.24	28.19	29.00	976	326	63	1,365

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

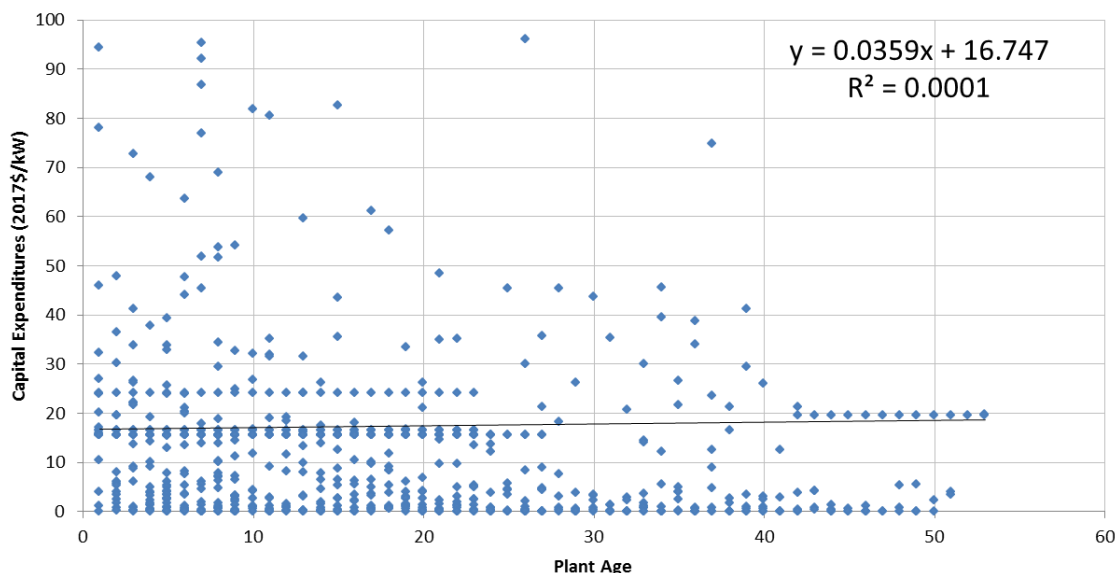
CAPITAL EXPENDITURES – LESS THAN 500 MW

The results of the regression analysis of CAPEX spending for gas/oil CC plants under 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.76, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table C-3 — Regression Statistics – CC CAPEX < 500 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	765		
Simple Average (\$/kW)	17.378		
Intercept	16.747	6.4870	1.57E-10
Slope	0.036	0.3007	7.64E-01
R ²	0.00012		

Figure C-3 — Gas/Oil CC Dataset – CAPEX for Less than 500-MW Plant Size



Notes: Age coefficient in above regression equation is not statistically significant.
 Sequential data points with identical values are forecasted values for the same plant.

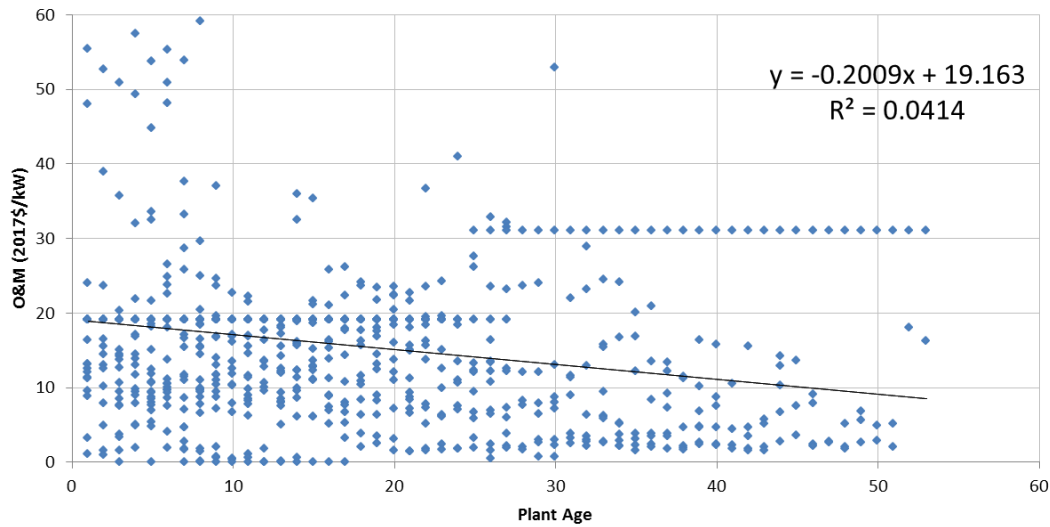
OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 500 MW

The results of the regression analysis of O&M spending for gas/oil CC plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the outliers before year 20 and relatively low number of data points after year 40 may distort the regression analysis.

Table C-4 — Regression Statistics – CC O&M < 500 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	766		
Simple Average (\$/kW)	15.619		
Intercept	19.163	25.2973	4.82E-103
Slope	-0.201	-5.7467	1.31E-08
R ²	0.04143		

Figure C-4 — Gas/Oil CC Dataset – O&M for Less than 500-MW Plant Size



Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

	Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =
< 500 MW, All Capacity Factors								
Net Total O&M- 2017 \$/kW	17.10	13.01	12.27	15.62	498	216	52	766
Net Total Capex - 2017 \$/kW	16.83	17.78	21.01	17.38	499	214	52	765
Net Total O&M and Capex - 2017 \$/kW	34.00	30.72	33.28	33.03	497	214	52	763

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

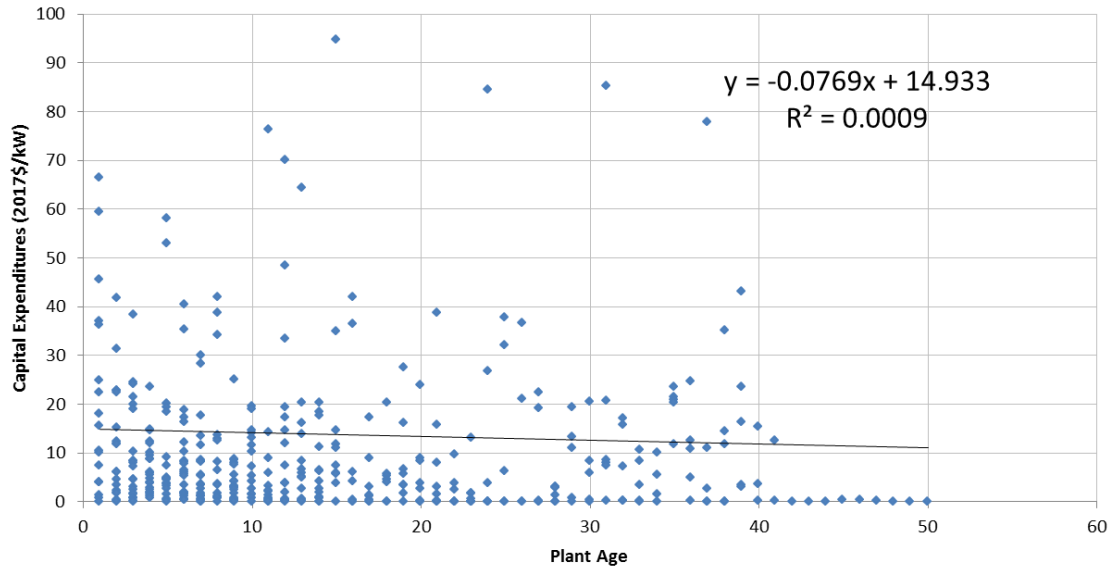
CAPITAL EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the regression analysis of CAPEX spending for gas/oil CC plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.52, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table C-5 — Regression Statistics – CC CAPEX 500 MW to 1,000 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	426		
Simple Average (\$/kW)	13.780		
Intercept	14.933	6.3972	4.19E-10
Slope	-0.077	-0.6252	5.32E-01
R ²	0.00092		

Figure C-5 — Gas/Oil CC Dataset – CAPEX for 500-MW to 1,000-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

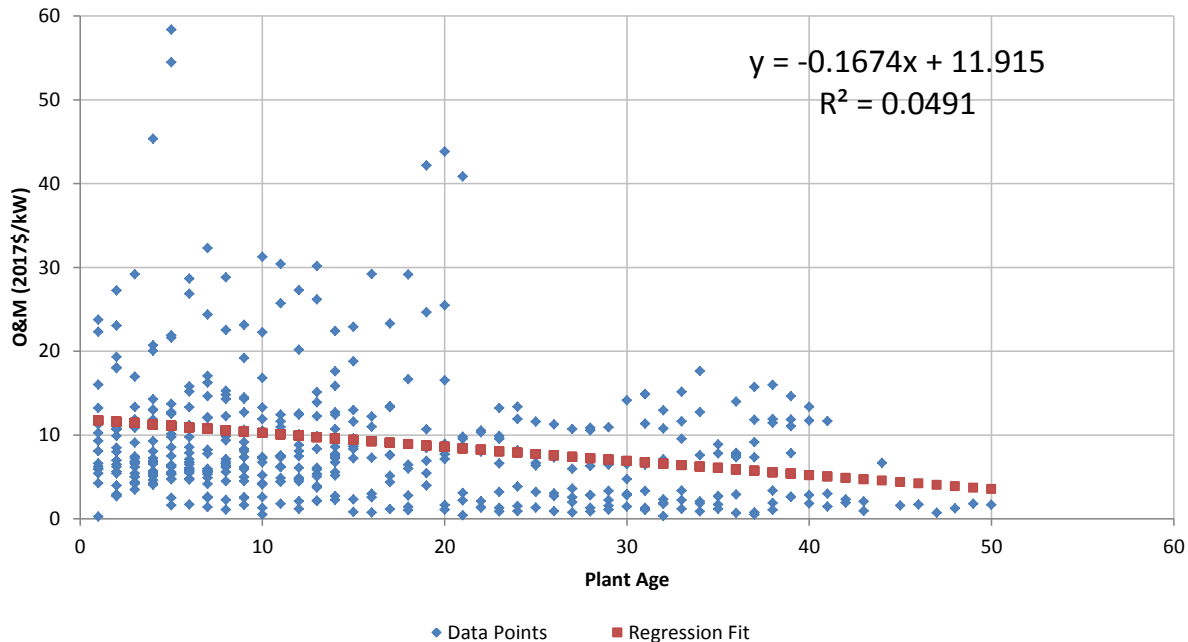
OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the regression analysis of O&M spending for gas/oil CC plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the outliers before year 20 and relatively low number of data points after year 40 may distort the regression analysis.

Table C-6 — Regression Statistics – CC O&M 500 MW to 1,000 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	445		
Simple Average (\$/kW)	9.269		
Intercept	11.915	17.1008	1.04E-50
Slope	-0.167	-4.7810	2.38E-06
R ²	0.04907		

Figure C-6 — Gas/Oil CC Dataset – O&M for 500-MW to 1,000-MW Plant Size



The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =

500 MW - 1000 MW, All Capacity Factors

Net Total O&M- 2017 \$/kW	10.68	6.50	2.78	9.27	307	124	14	445
Net Total Capex - 2017 \$/kW	14.38	13.36	1.28	13.78	307	108	11	426
Net Total O&M and Capex - 2017 \$/kW	25.06	20.38	4.15	23.33	306	108	11	425

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

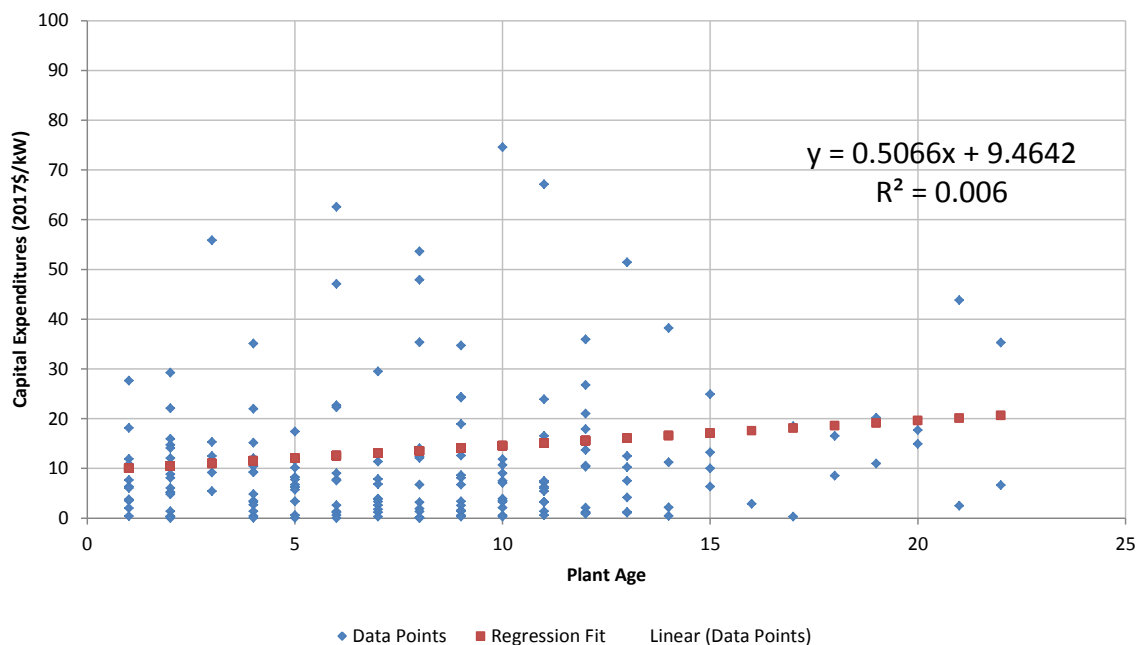
CAPITAL EXPENDITURES – GREATER THAN 1,000 MW

The results of the regression analysis of CAPEX spending for gas/oil CC plants greater than 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.30, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table C-7 — Regression Statistics – CC CAPEX > 1,000 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	177		
Simple Average (\$/kW)	13.566		
Intercept	9.464	2.0308	4.38E-02
Slope	0.507	1.0309	3.04E-01
R ²	0.00604		

Figure C-7 — Gas/Oil CC Dataset – CAPEX for Greater than 1,000-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

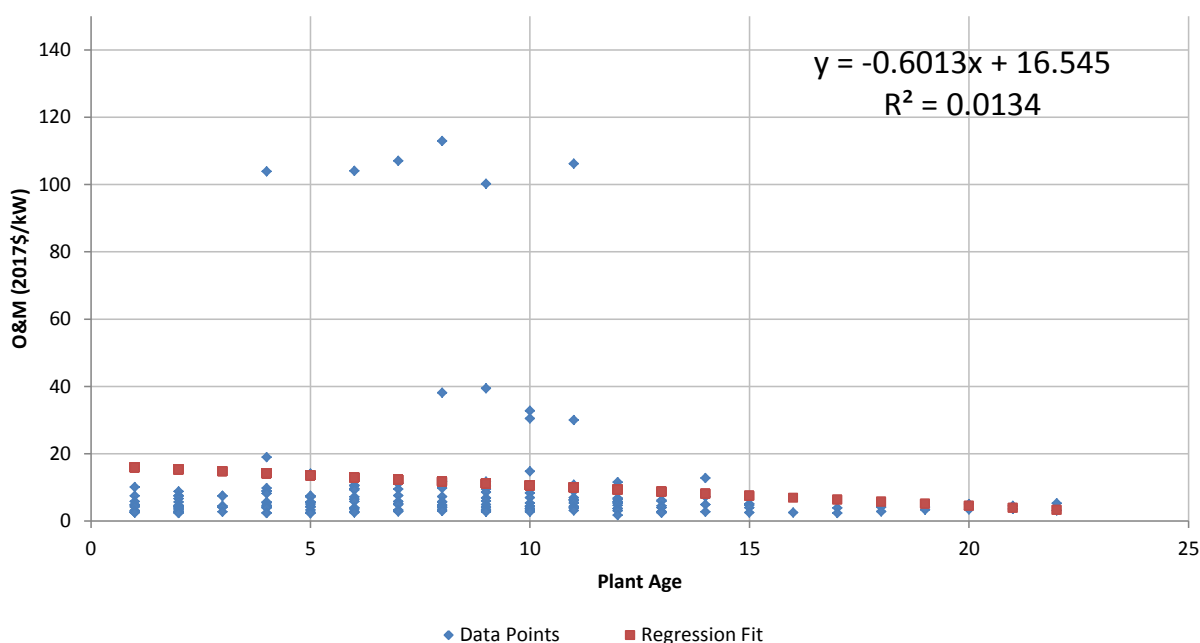
OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 1,000 MW

The results of the regression analysis of O&M spending for gas/oil CC plants greater than 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.13, which is greater than 0.05, age is not a statistically significant predictor of O&M spending.

Table C-8 — Regression Statistics – CC O&M > 1,000 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	177		
Simple Average (\$/kW)	11.676		
Intercept	16.545	4.4651	1.43E-05
Slope	-0.601	-1.5389	1.26E-01
R ²	0.01335		

Figure C-8 — Gas/Oil CC Dataset – O&M for Greater than 1,000 MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

	Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =
> 1000 MW, All Capacity Factors								
Net Total O&M- 2017 \$/kW	11.85	4.14	-	11.68	173	4	0	177
Net Total Capex - 2017 \$/kW	13.37	22.06	-	13.57	173	4	0	177
Net Total O&M and Capex - 2017 \$/kW	25.22	26.20	-	25.24	173	4	0	177

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

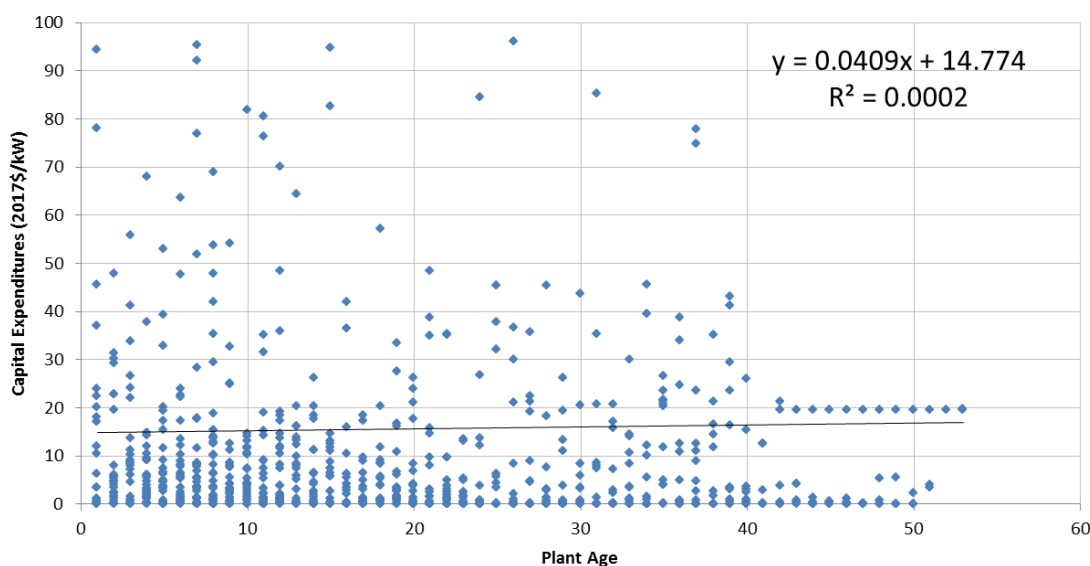
CAPITAL EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

The results of the regression analysis of CAPEX spending for gas/oil CC plants of all MW sizes (full dataset) with capacity factors under 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.71, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table C-9 — Regression Statistics – CC CAPEX for Capacity Factor < 50%

		<i>t statistic</i>	<i>p-value</i>
Observations	844		
Simple Average (\$/kW)	15.554		
Intercept	14.774	5.7075	1.59E-08
Slope	0.041	0.3659	7.15E-01
R ²	0.00016		

Figure C-9 — CC Dataset – CAPEX for All Plant Sizes and Avg. Net Capacity Factor < 50%



Notes: Age coefficient in above regression equation is not statistically significant.
 Sequential data points with identical values are forecasted values for the same plant.

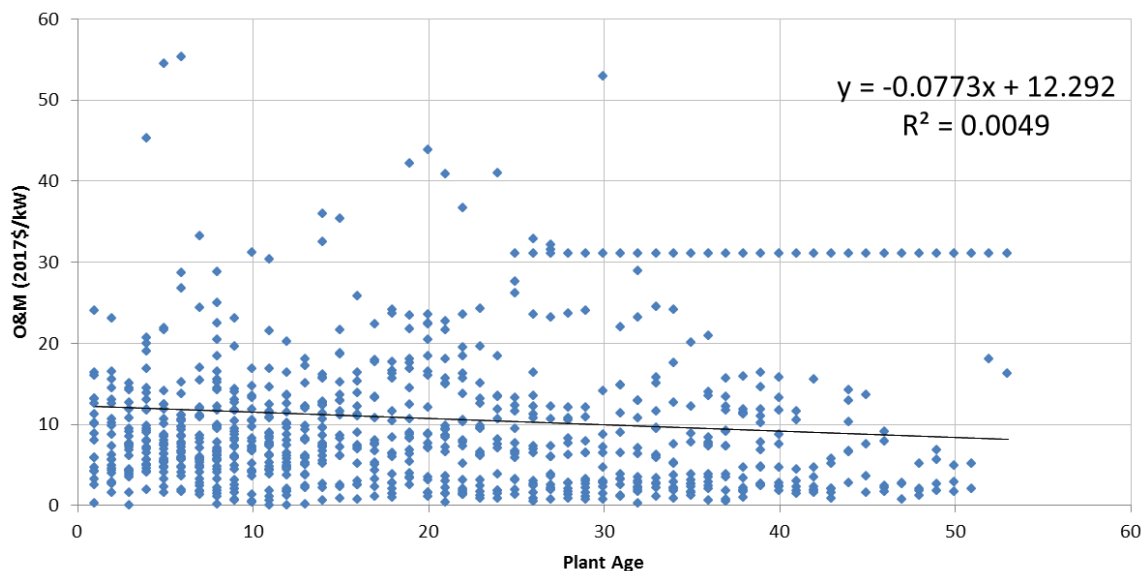
OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

The results of the regression analysis of O&M spending for gas/oil CC plants of all MW sizes (full dataset) with capacity factors under 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the outliers before year 20 and relatively low number of data points after year 40 may distort the regression analysis.

Table C-10 — Regression Statistics – CC O&M for Capacity Factor < 50%

		<i>t statistic</i>	<i>p-value</i>
Observations	864		
Simple Average (\$/kW)	10.791		
Intercept	12.292	13.9850	3.33E-40
Slope	-0.077	-2.0625	3.95E-02
R ²	0.00491		

Figure C-10 — CC Dataset – O&M for All Plant Sizes and Avg. Net Capacity Factor < 50%



Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =

All MW, Capacity Factors 0 - 50%

Net Total O&M- 2017 \$/kW	11.54	9.65	10.26	10.79	500	298	66	864
Net Total Capex - 2017 \$/kW	15.35	15.46	17.56	15.55	501	280	63	844
Net Total O&M and Capex - 2017 \$/kW	26.95	25.41	28.19	26.53	499	280	63	842

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

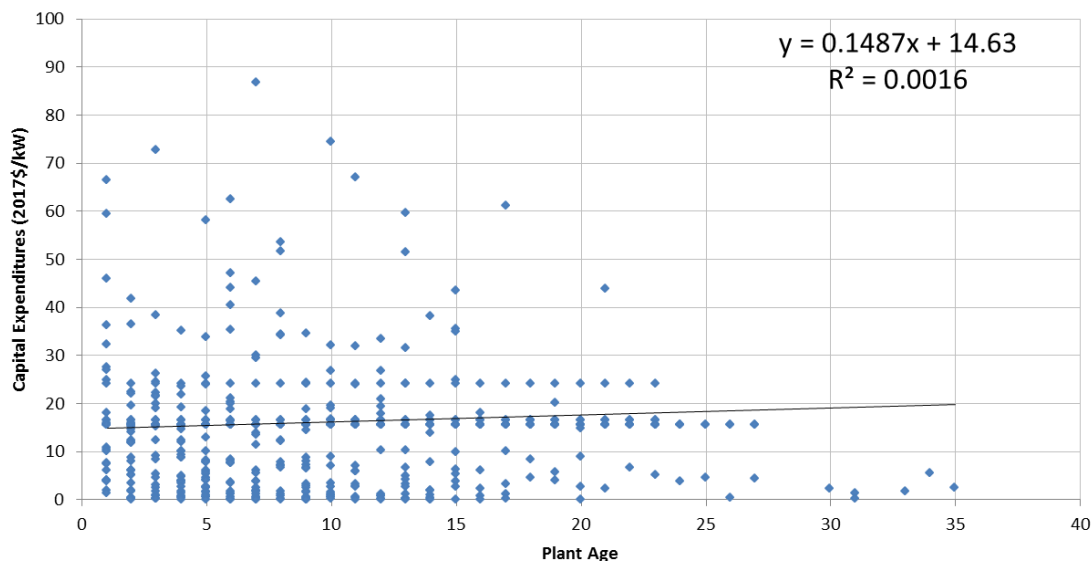
CAPITAL EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

The results of the regression analysis of CAPEX spending for gas/oil CC plants of all MW sizes (full dataset) with capacity factors greater than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.37, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table C-11 — Regression Statistics – CC CAPEX for Capacity Factor > 50%

		<i>t statistic</i>	<i>p-value</i>
Observations	524		
Simple Average (\$/kW)	16.104		
Intercept	14.630	7.3893	5.90E-13
Slope	0.149	0.9054	3.66E-01
R ²	0.00157		

Figure C-11 — CC Dataset – CAPEX for All Plant Sizes and Avg. Net Capacity Factor > 50%



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

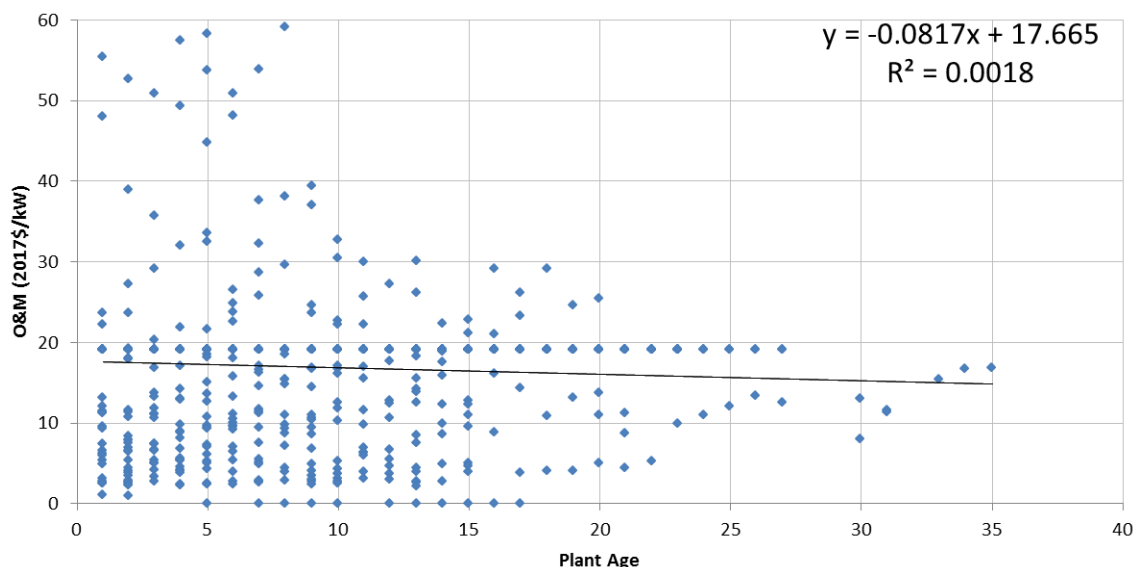
OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

The results of the linear regression analysis of O&M spending for gas/oil CC plants of all MW sizes (full dataset) with capacity factors greater than 50% are summarized in the table below. Since the p-value for the age coefficient (“slope”) is 0.33, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table C-12 — Regression Statistics – CC O&M for Capacity Factor > 50%

		<i>t statistic</i>	<i>p-value</i>
Observations	524		
Simple Average (\$/kW)	16.855		
Intercept	17.665	17.5298	1.93E-54
Slope	-0.082	-0.9777	3.29E-01
R ²	0.00183		

Figure C-12 — CC Dataset – O&M for All Plant Sizes and Avg. Net Capacity Factor > 50%



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =

All MW, Capacity Factors 50% - 100%

Net Total O&M- 2017 \$/kW	16.90	16.44	-	16.85	478	46	0	524
Net Total Capex - 2017 \$/kW	15.55	21.89	-	16.10	478	46	0	524
Net Total O&M and Capex - 2017 \$/kW	32.46	38.32	-	32.98	477	46	0	523

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.



Appendix D. Regression Analysis – Gas/Oil Combustion Turbine

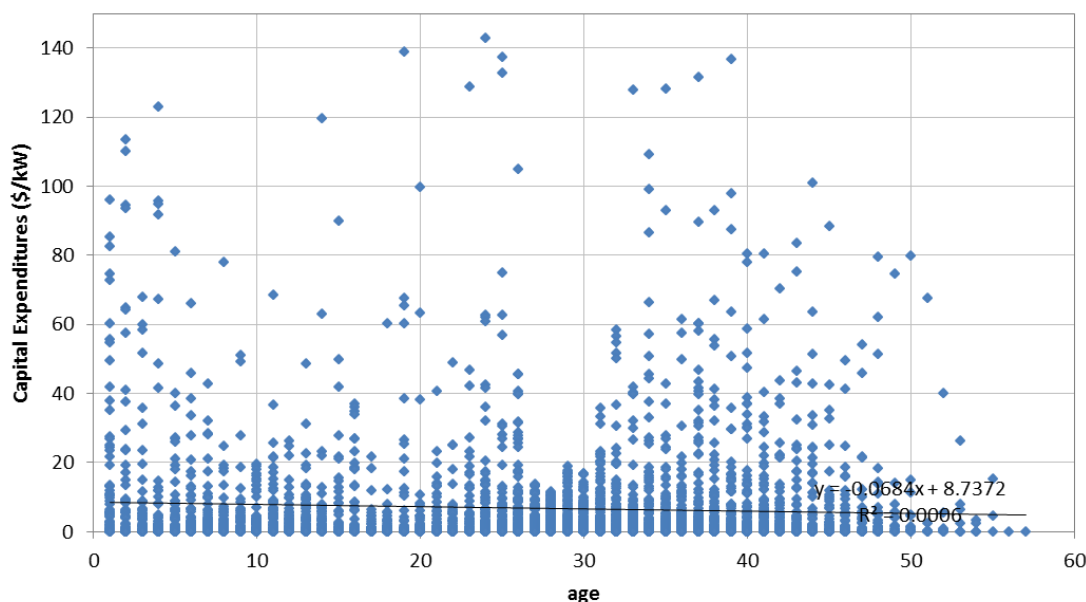
CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the regression analysis of CAPEX spending for gas/oil CT plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.09, which is greater than 0.05, dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table D-1 — Regression Statistics – CT CAPEX for All MW

		<i>t statistic</i>	<i>p-value</i>
Observations	5065		
Simple Average (\$/kW)	6.897		
Intercept	8.737	7.3087	3.12E-13
Slope	-0.068	-1.6948	9.02E-02
R ²	0.00057		

Figure D-1 — Gas/Oil CT Dataset – CAPEX for All Plant MW Sizes



Note: Age coefficient in above regression equation is not statistically significant.

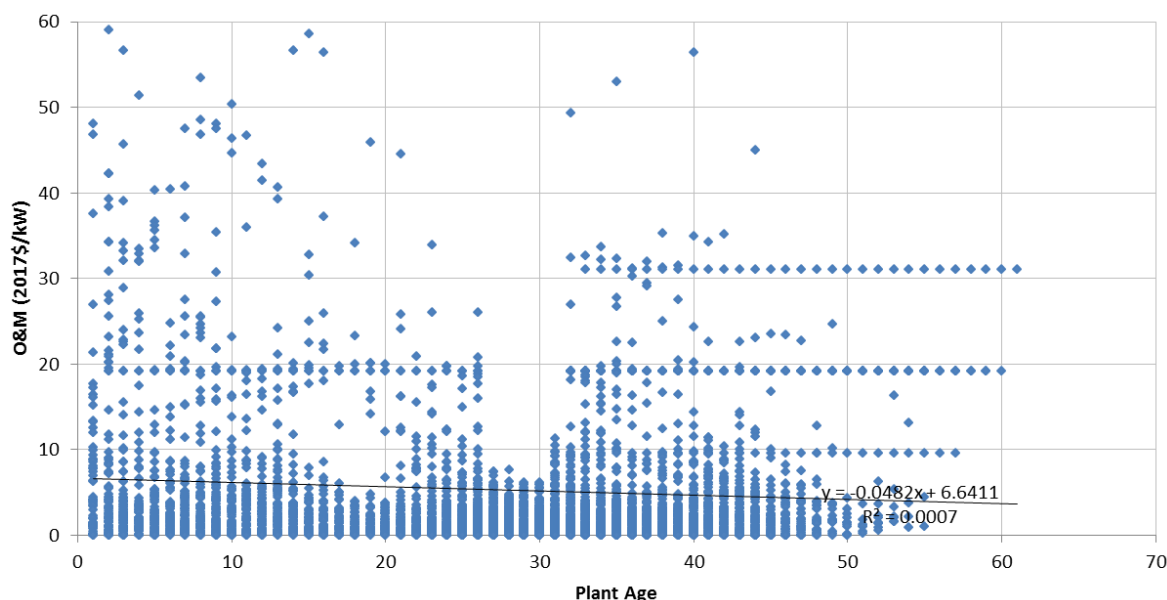
OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the regression analysis of O&M spending for gas/oil CT plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.062, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table D-2 — Regression Statistics – CT O&M for All MW

		<i>t statistic</i>	<i>p-value</i>
Observations	5283		
Simple Average (\$/kW)	5.331		
Intercept	6.641	8.5764	1.27E-17
Slope	-0.048	-1.8683	6.18E-02
R ²	0.00066		

Figure D-2 — Gas/Oil CT Dataset – O&M for All Plant MW Sizes



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

	Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =
All MW, All Capacity Factors								
Net Total O&M- 2017 \$/kW	7.86	3.99	6.11	5.33	1,418	3,118	747	5,283
Net Total Capex - 2017 \$/kW	9.17	5.78	7.40	6.90	1,360	3,054	651	5,065
Net Total O&M and Capex - 2017 \$/kW	16.43	9.43	10.92	11.49	1,341	3,040	640	5,021

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CT plants are described in Section 6.

CAPITAL EXPENDITURES – LESS THAN 100 MW

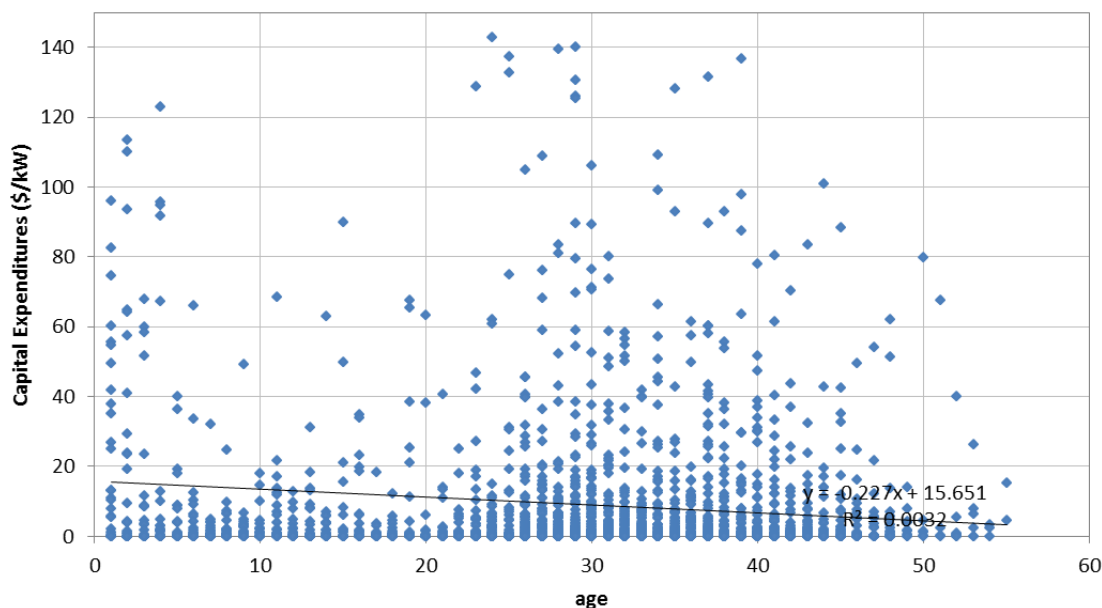
The results of the regression analysis of CAPEX spending for gas/oil CT plants less than 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.002, which is less than 0.05, age is a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, CAPEX spending for this dataset may be estimated by the regression equation:

$$\text{Annual CAPEX spending in 2017 } \$/\text{kW-year} = 15.651 + (-0.227 \times \text{age})$$

Table D-3 — Regression Statistics – CT CAPEX < 100 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	2,911		
Simple Average (\$/kW)	9.003		
Intercept	15.651	6.6753	2.94E-11
Slope	-0.227	-3.0345	2.43E-03
R ²	0.00316		

Figure D-3 — Gas/Oil CT Dataset – CAPEX for Less than 100-MW Plant Size



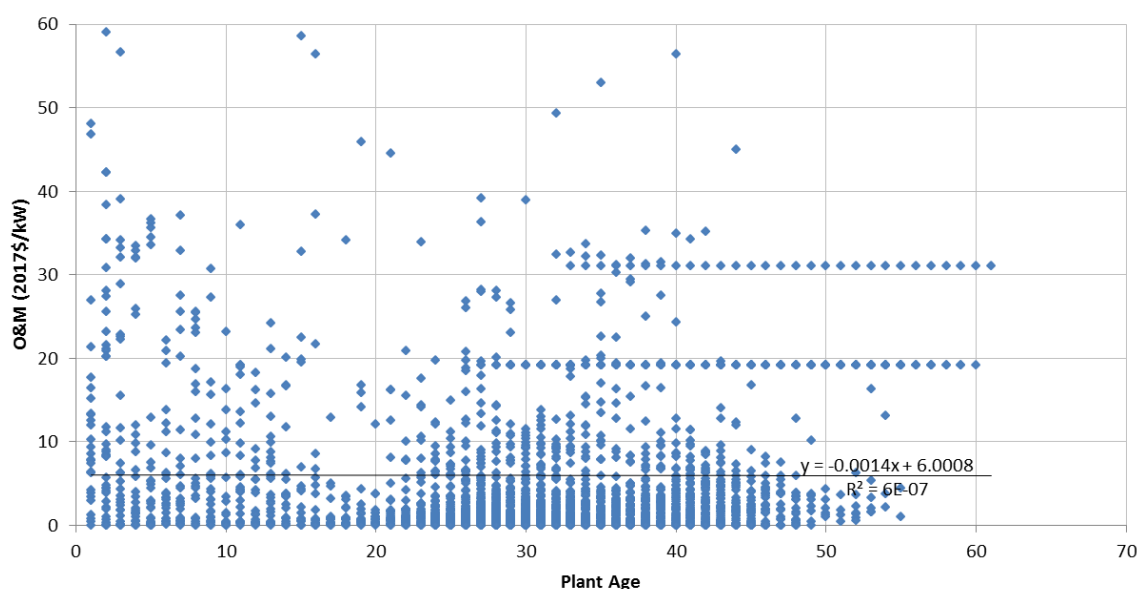
OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 100 MW

The results of the regression analysis of O&M spending for gas/oil CT plants less than 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.966, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table D-4 — Regression Statistics – CT O&M < 100 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	3,062		
Simple Average (\$/kW)	5.958		
Intercept	6.001	5.5008	4.09E-08
Slope	-0.001	-0.0423	9.66E-01
R ²	0.00000		

Figure D-4 — Gas/Oil CT Dataset – O&M for Less than 100-MW Plant Size



Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =

< 100 MW, All Capacity Factors

Net Total O&M - 2017 \$/kW	8.76	4.93	7.40	5.96	489	2,060	513	3,062
Net Total Capex - 2017 \$/kW	15.08	7.98	6.64	9.00	497	1,999	415	2,911
Net Total O&M and Capex - 2017 \$/kW	24.04	12.31	10.26	14.02	489	1,978	406	2,873

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CT plants are described in Section 6.

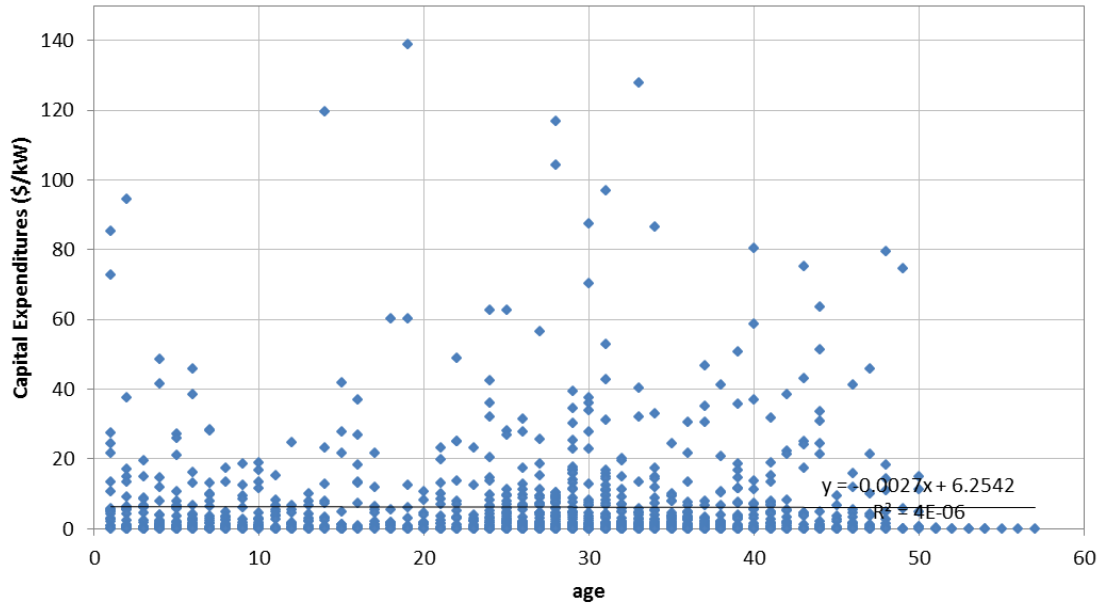
CAPITAL EXPENDITURES – BETWEEN 100 MW AND 300 MW

The results of the regression analysis of CAPEX spending for CT plants between 100 MW and 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.939, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

Table D-5 — Regression Statistics – CT CAPEX 100 MW to 300 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	1,350		
Simple Average (\$/kW)	6.183		
Intercept	6.254	6.0376	2.02E-09
Slope	-0.003	-0.0768	9.39E-01
R ²	0.00000		

Figure D-5 — Gas/Oil CT Dataset – CAPEX for Between 100-MW and 300-MW Plant Size



Note: Age coefficient in above regression equation is not statistically significant.

OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 100 MW AND 300 MW

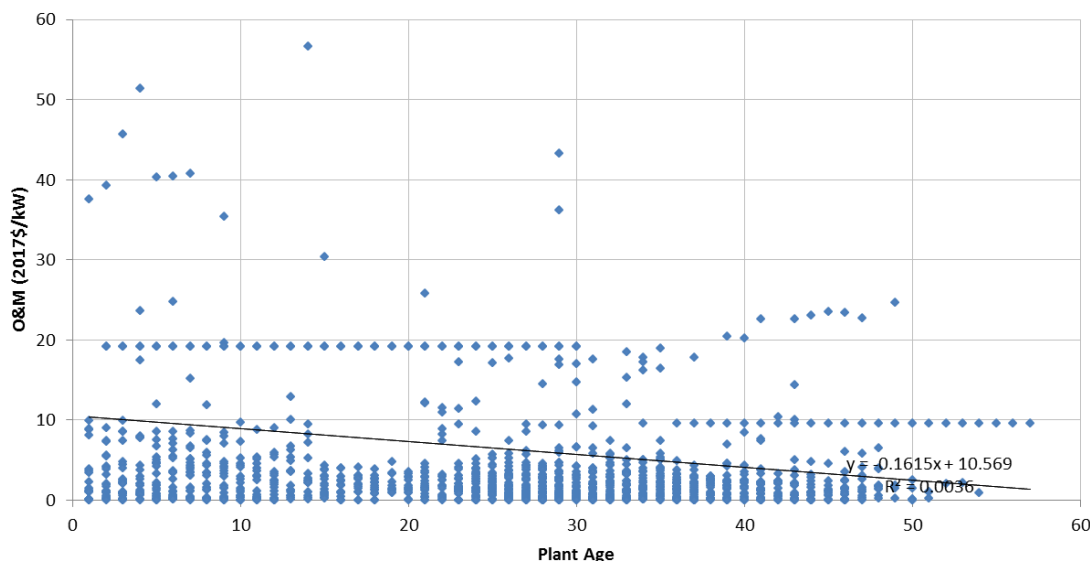
The results of the regression analysis of O&M spending for gas/oil CT plants between 100 MW and 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.023, which is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

$$\text{Annual O\&M spending in 2017 \$/kW-year} = 10.569 + (-0.162 \times \text{age})$$

Table D-6 — Regression Statistics – CT O&M 100 MW to 300 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	1,416		
Simple Average (\$/kW)	6.430		
Intercept	10.569	5.1759	2.59E-07
Slope	-0.162	-2.2723	2.32E-02
R ²	0.00364		

Figure D-6 — Gas/Oil CT Dataset – O&M for Between 100-MW and 300-MW Plant Size



Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =

100 MW - 300 MW, All Capacity Factors

Net Total O&M- 2017 \$/kW	9.97	5.18	3.24	6.43	442	794	180	1,416
Net Total Capex - 2017 \$/kW	6.32	6.07	6.38	6.18	407	762	181	1,350
Net Total O&M and Capex - 2017 \$/kW	15.14	9.09	9.66	10.98	402	759	180	1,341

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CT plants are described in Section 6.

CAPITAL EXPENDITURES – GREATER THAN 300 MW

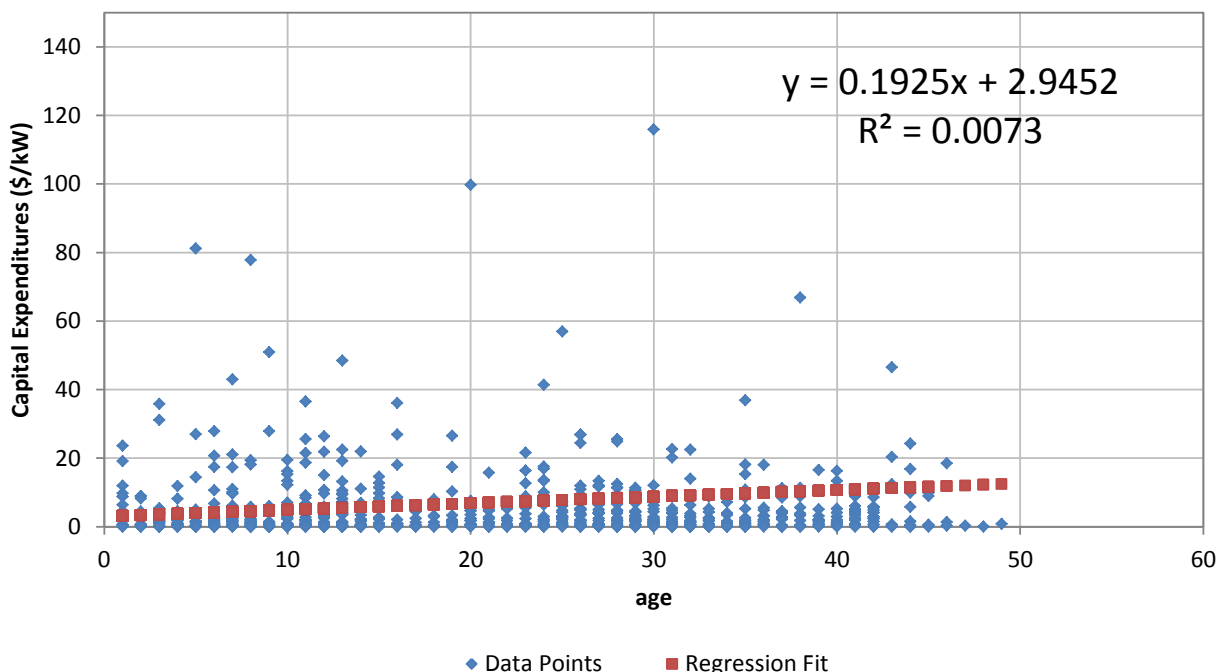
The results of the regression analysis of CAPEX spending for gas/oil CT plants greater than 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.010, which is less than 0.05, age is a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, CAPEX spending for this dataset may be estimated by the regression equation:

$$\text{Annual CAPEX spending in 2017 \$/kW-year} = 2.945 + (0.193 \times \text{age})$$

Table D-7 — Regression Statistics – CT CAPEX > 300 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	909		
Simple Average (\$/kW)	6.952		
Intercept	2.945	1.6382	1.017E-01
Slope	0.193	2.5842	0.010
R ²	0.00731		

Figure D-7 — Gas/Oil CT Dataset – CAPEX for Greater than 300-MW Plant Size



OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 300 MW

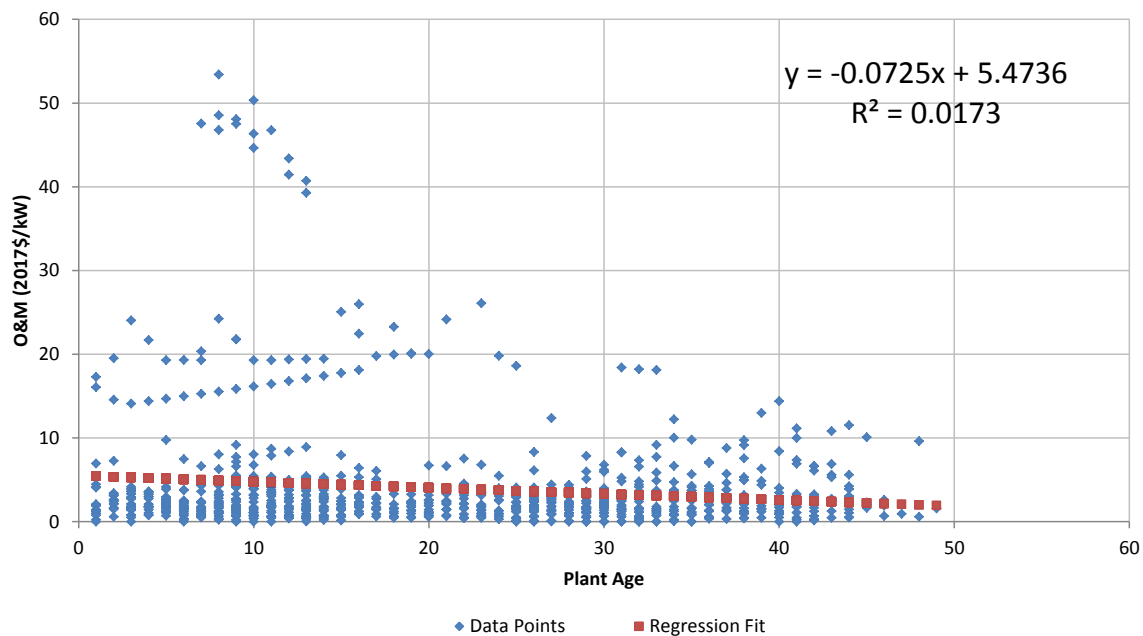
The results of the regression analysis of O&M spending for CT plants greater than 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

Annual O&M spending in 2017 \$/kW-year = $5.474 + (-0.072 \times \text{age})$

Table D-8 — Regression Statistics – CT O&M > 300 MW

		<i>t</i> Statistic	<i>p</i> -value
Observations	938		
Simple Average (\$/kW)	3.994		
Intercept	5.474	12.8980	3.75E-35
Slope	-0.072	-4.0612	5.29E-05
R ²	0.01732		

Figure D-8 — Gas/Oil CT Dataset – O&M for Greater than 300-MW Plant Size



The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

	Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =
> 300 MW, All Capacity Factors								
Net Total O&M- 2017 \$/kW	5.03	2.78	3.46	3.99	488	396	54	938
Net Total Capex - 2017 \$/kW	5.26	7.58	16.50	6.95	457	397	55	909
Net Total O&M and Capex - 2017 \$/kW	9.30	10.38	20.11	10.42	451	396	54	901

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CT plants are described in Section 6.



Appendix E. Regression Analysis – Conventional Hydroelectric

CAPITAL EXPENDITURES – ALL PLANT SIZES

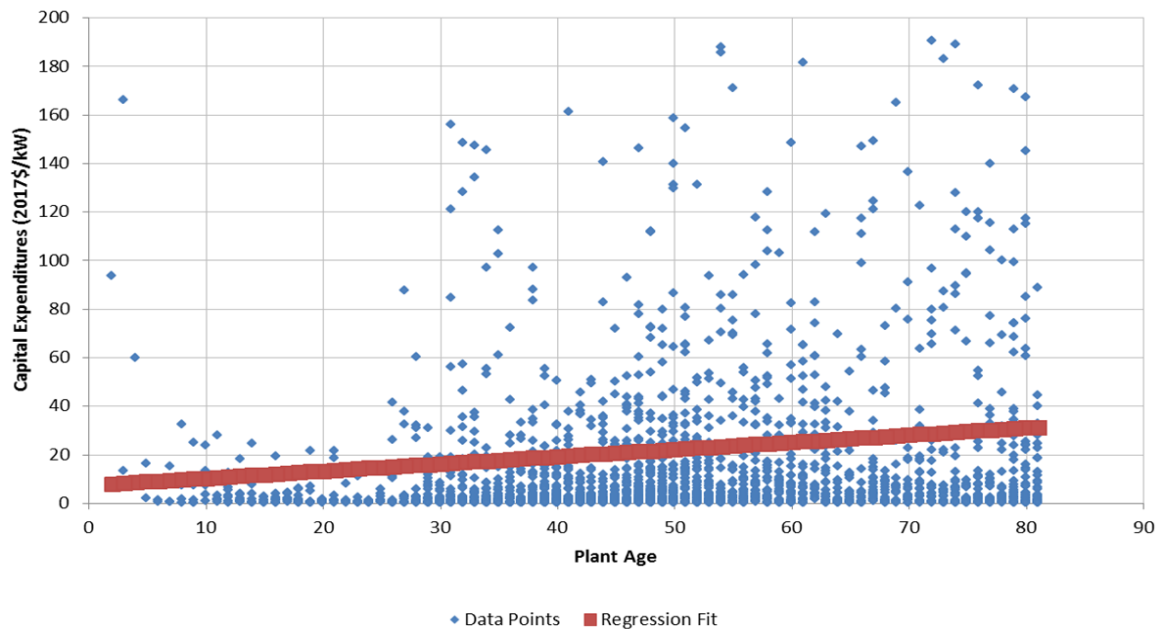
The results of the linear regression analysis of CAPEX spending for conventional hydroelectric plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is significantly less than 0.05, age is a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, CAPEX spending for this dataset may be estimated by the regression equation:

$$\text{Annual CAPEX spending in 2017 \$/kW-year} = 7.269 + (0.296 \times \text{age})$$

Table E-1 — Regression Statistics – Hydroelectric CAPEX for All MW

		<i>t statistic</i>	<i>p-value</i>
Observations	2180		
Simple Average (\$/kW)	21.999		
Intercept	7.269	1.4681	1.42E-01
Slope	0.296	3.1441	1.69E-03
R ²	0.00452		

Figure E-1 — Conventional Hydroelectric Dataset – CAPEX for All MW Plant Sizes



OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

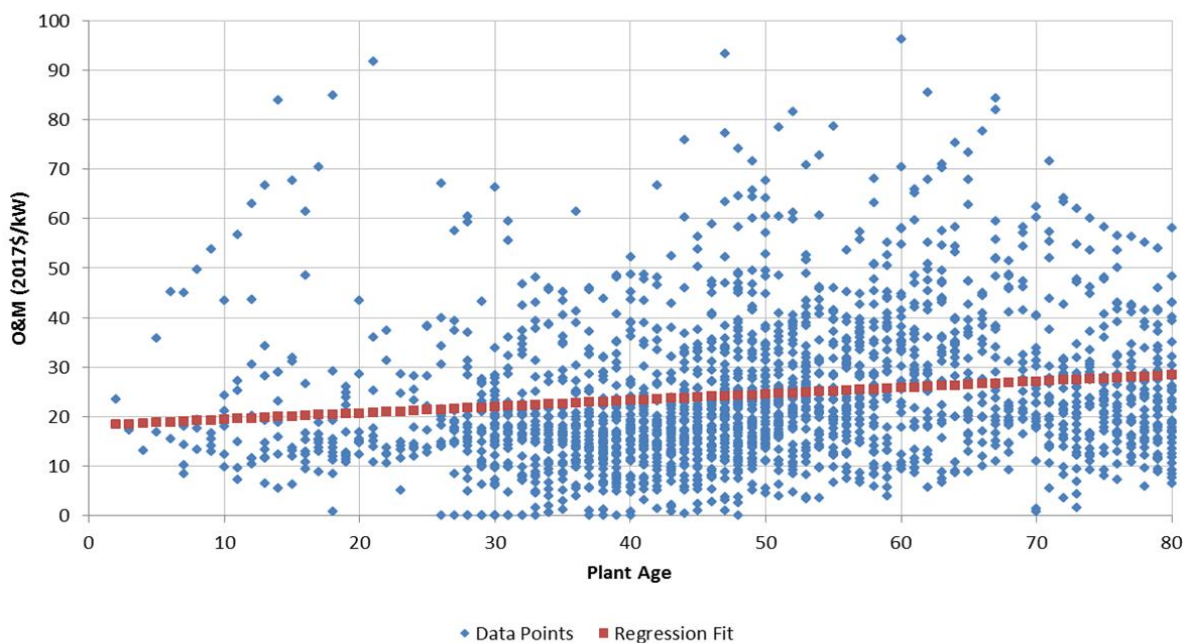
The results of the linear regression analysis of O&M spending for conventional hydroelectric plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

Annual O&M spending in 2017 \$/kW-year = 22.360 + (0.073 × age)

Table E-2 — Regression Statistics – Hydroelectric O&M for All MW

		<i>t statistic</i>	<i>p-value</i>
Observations	1,272		
Simple Average (\$/kW)	24.473		
Intercept	22.360	13.7360	3.92E-40
Slope	0.073	2.5053	1.24E-02
R ²	0.00492		

Figure E-2 — Conventional Hydroelectric – O&M for All MW Plant Sizes





Appendix F. Regression Analysis – Pumped Hydroelectric Storage

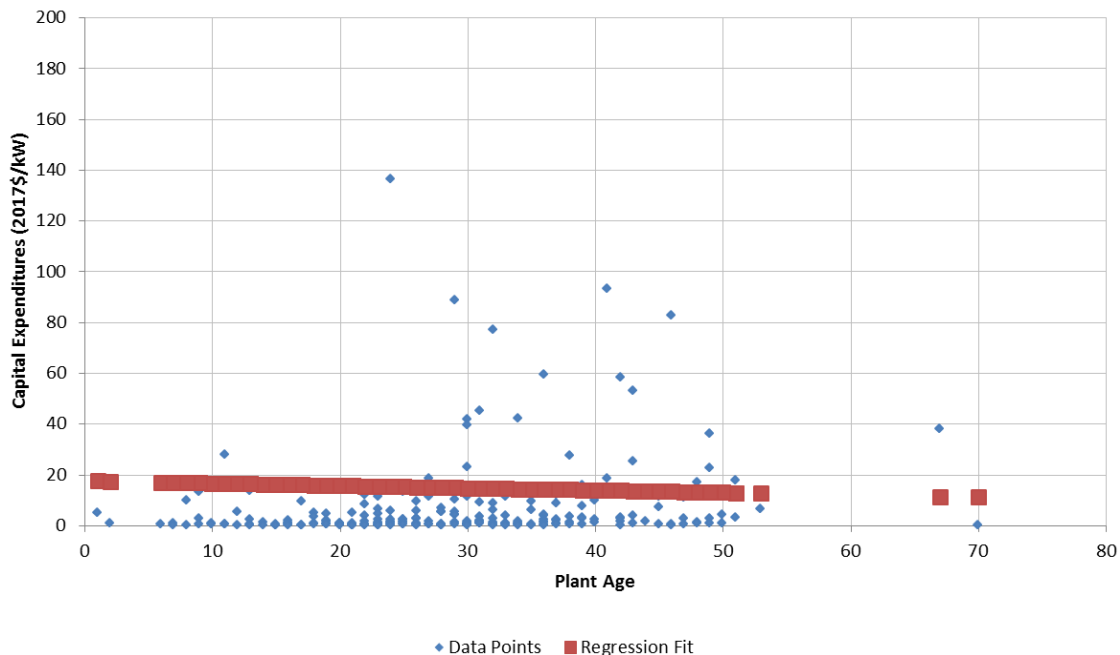
CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of CAPEX spending for pumped hydroelectric storage plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). The dataset was not divided by unit capacity due to the limited number of data points.

Table F-1 — Regression Statistics – Pumped Hydroelectric CAPEX for All MW

		<i>t statistic</i>	<i>p-value</i>
Observations	227		
Simple Average (\$/kW)	11.398		
Intercept	-6.907	-0.4501	6.53E-01
Slope	0.743	1.2723	2.06E-01
R ²	0.01278		

Figure F-1 — Pumped Hydroelectric Dataset – CAPEX for All MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

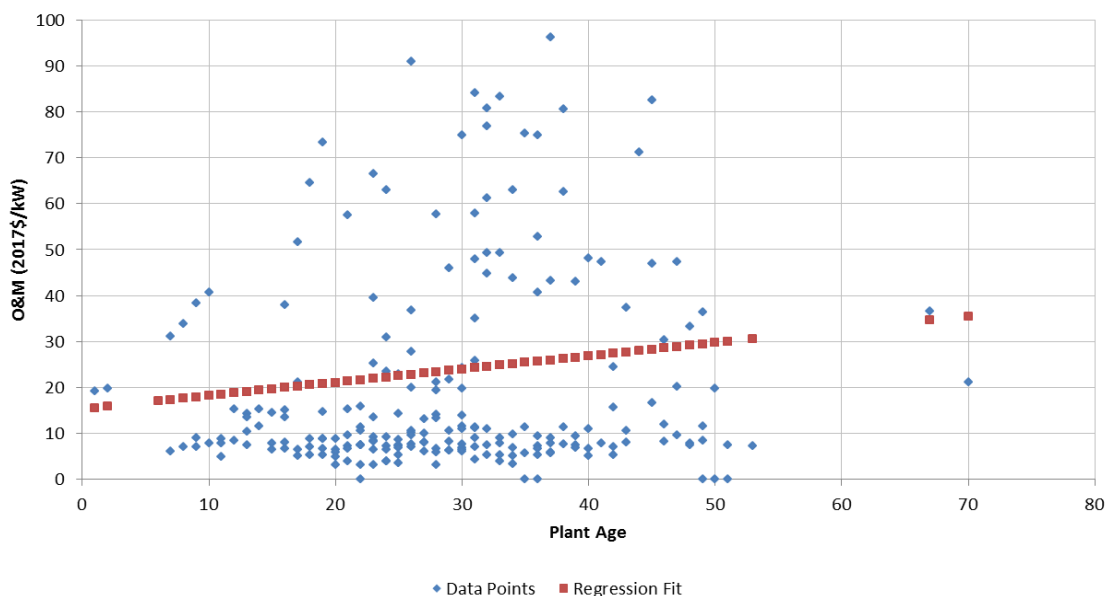
OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of O&M spending for pumped hydroelectric storage plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). The dataset was not divided by unit capacity due to the limited number of data points.

Table F-2 — Regression Statistics – Pumped Hydroelectric O&M for All MW

		<i>t statistic</i>	<i>p-value</i>
Observations	226		
Simple Average (\$/kW)	23.634		
Intercept	15.296	2.9021	4.08E-03
Slope	0.288	1.7010	9.03E-02
R ²	0.01275		

Figure F-2 — Pumped Hydroelectric – O&M for All Plant MW Sizes



Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

	Average \$/kW (years 1 - 20) =	Average \$/kW (years 21 - 40) =	Average \$/kW (years 41 - 80) =	Average \$/kW (all years) =	Data Points (years 1 - 20) =	Data Points (years 21 - 40) =	Data Points (years 41 - 80) =	Data Points (all years) =
All MW, All Capacity Factors								
Net Total O&M- 2017 \$/kW	18.97	23.41	31.00	23.63	50	140	36	226
Net Total Capex - 2017 \$/kW	22.94	11.93	14.92	14.83	50	141	36	227
Net Total O&M and Capex - 2017 \$/kW	41.91	35.34	45.92	38.46	--	--	--	--

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing pumped hydroelectric storage plants are described in Section 8.



Appendix G. Regression Analysis – Solar Photovoltaic

CAPITAL EXPENDITURES

Annual CAPEX, labeled in FERC Form 1 as TCP, are broken down into subcategories, including:

- Land & Land Rights
- Structures & Improvements
- Reservoirs, Dams & Waterways
- Water Wheels
- Turbines & Generators
- Accessory Electric Equipment
- Equipment
- Asset Retirement Costs
- Roads, and Railroads & Bridges

These subcategories are based on traditional power generation technologies and have minimal applicability to solar PV. Expected CAPEX for solar PV, such as inverter replacement and repair or module replacement, are clearly not applicable to any of the categories listed in FERC Form 1.

In the FERC Form 1 data, only 10 of the solar PV sites had a breakdown of TCP into the above subcategories, with even fewer providing such a breakdown for more than one year. As discussed in Section 9, the year-over-year change in TCP is the sole source of annual CAPEX information in FERC Form 1. Of this data, Sargent & Lundy determined that a significant portion of it needed to be filtered out due to the following reasons:

- A negative change in the TCP between two consecutive years
- A change in the capacity of the plant greater than 20%
- A significant increase in TCP without a capacity increase
- Large unexplained fluctuations (e.g., negative to positive) in TCP from year to year
- Large gaps in annual data

After filtering out clearly suspect data, about one-third of the remaining data was for plants having only three years of data or less. In addition, many of the plants reported no changes in TCP, suggesting that most annual expenditures at those sites were being reported as O&M rather than being capitalized.

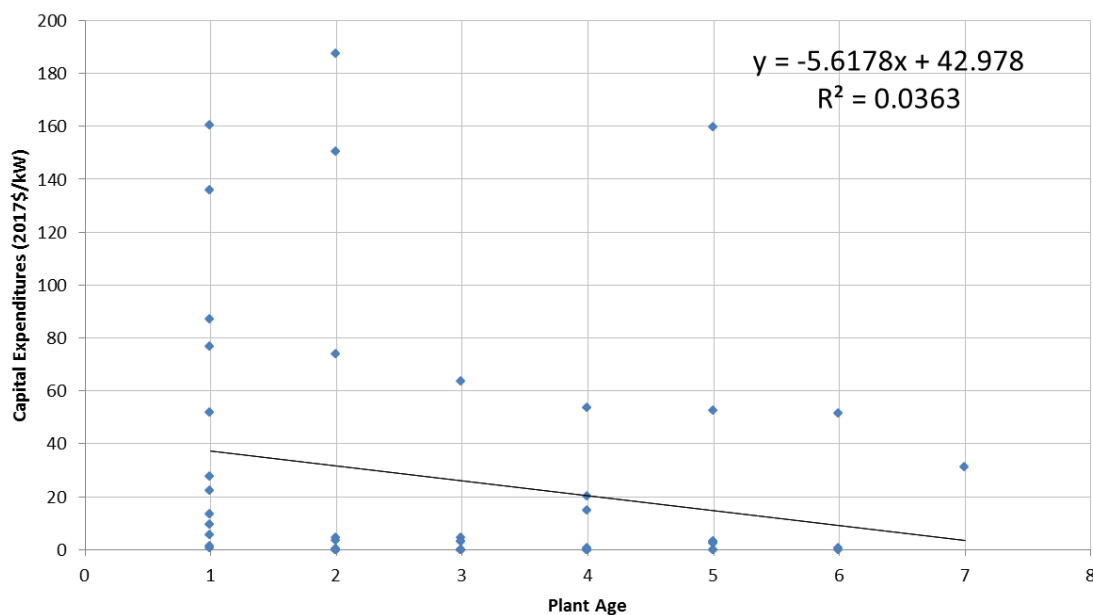
Thus, Sargent & Lundy had to rely on a limited dataset for solar PV consisting of 15 sites. The average change in TCP for these sites was approximately \$26/kW-year. Based on the available FERC Form 1 information, it cannot be determined whether this change in TCP was due to typical CAPEX for solar PV, such as inverter or module replacement, or other factors.

The results of the linear regression analysis of CAPEX spending for solar PV plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.16, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). In addition, as indicated in the table below, there are a relatively small number of data points for CAPEX (less than 60 points). The average CAPEX across all years is approximately \$26/kW-year (2017 dollars).

Table G-1 — Regression Statistics – Solar PV CAPEX for All MW

		<i>t statistic</i>	<i>p-value</i>
Observations	57		
Simple Average (\$/kW)	26.026		
Intercept	42.978	3.2248	2.12E-03
Slope	-5.618	-1.4387	1.56E-01
R ²	0.03627		

Figure G-1 — Solar PV Dataset – CAPEX for All MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

OPERATIONS & MAINTENANCE EXPENDITURES

Solar PV O&M activities include a variety of work scopes, including administrative work, monitoring, cleaning, preventative maintenance, and corrective maintenance. Some specific examples of O&M activities may include cleaning modules, monitoring system voltage and current, inspecting and cleaning electrical equipment, inspecting modules for damage, inspecting mounting systems, and checking inverter settings. The cost of O&M is dependent on several factors, including the number of components, the type of system (e.g., roof, tracking, ground mount, fixed, etc.), warranty coverage, and location. Environmental conditions, such as hail, sand/dust, snow, salt in air, high winds, etc., also play a significant role in O&M costs. For these reasons, a higher level of variation is expected when compared to traditional generating technologies.

The total production cost, which is the sum of the total operating expense and total maintenance expense, was reported for slightly over half of the sites. Of the sites reporting, several sites only reported this data in certain years, leaving gaps in the data. Subcategories for operating costs and maintenance cost were provided in the FERC Form 1 data, but rarely was the reported data broken into subcategories.

Sargent & Lundy organized the FERC Form 1 data into two presentation formats. In the first format, the annual O&M cost was averaged across all years of the reported data to obtain the average annual O&M cost per plant. This resulted in approximately 60 data points. In the second format, the annual O&M cost was averaged across each year of operation. This resulted in approximately 200 data points. The average O&M cost results are not equal between the two presentation formats. Table G-2 provides a simple example of these differing results, using FERC Form 1 O&M data from three plants.

Table G-2 — Example of Calculation Method Differences

Age (Years)	O&M Cost (\$/kW-year)															Plant Average
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	
Example Plant 1	127.8	0.0	0.1	0.0	-	-	-	-	-	-	-	-	-	-	-	32.0
Example Plant 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Example Plant 3	32.2	15.3	24.8	-	-	-	-	-	-	-	-	-	-	-	-	24.1

Example Average (All Data Points)	9.1
Example Average (of Plant Averages)	18.7

In the example above, a single plant with more data points is able to sway the average O&M cost across the three plants. The values calculated below are based on averaged data points (i.e., a data point is the average annual O&M cost across the reported data for a given plant).

Figure G-2 and Figure G-3 show the average site O&M cost, expressed in \$/MWh, for sites with a capacity less than 5 MW and greater than 5 MW, respectively. In general, these figures show a high level of variability across sites, with smaller sites having a higher O&M cost per MWh produced. Several data points were for sites having very low capacity factors (less than 5%), which also results in higher O&M costs per MWh. For the sites greater than 5 MW, the average O&M cost was \$8.5/MWh. When expressed on the basis of cost per kW of capacity (see Figure G-4 and Figure G-5), the average O&M for sites greater than 5 MW was \$15/kW-year.

Figure G-2 — Average Site O&M Cost per MWh Generated vs. Project Nameplate Capacity (< 5 MW)

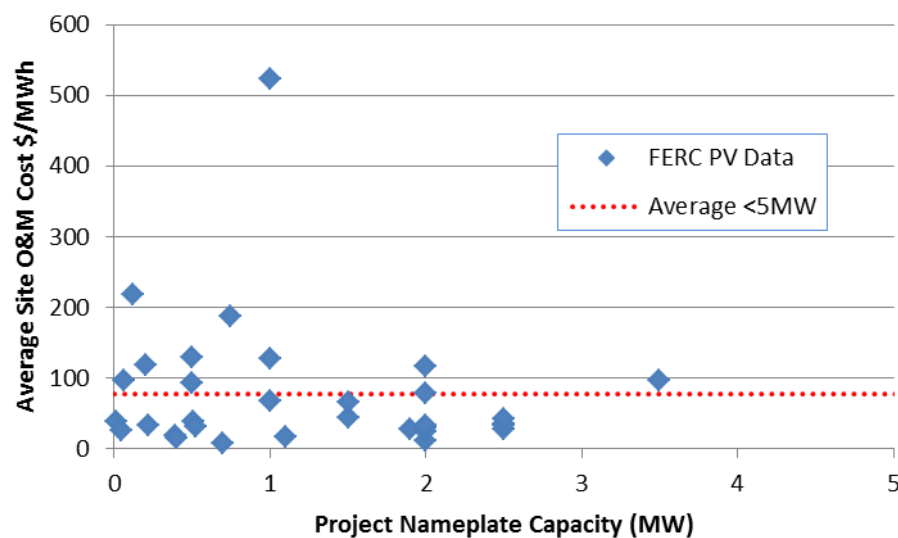


Figure G-3 — Average Site O&M Cost per MWh Generated vs. Project Nameplate Capacity (> 5 MW)

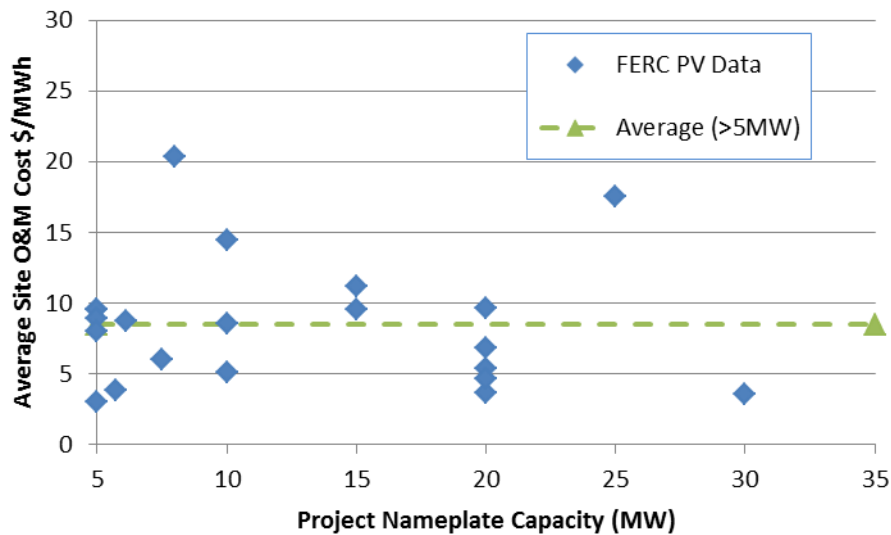


Figure G-4 — Average Site O&M Cost per kW-Year Capacity vs. Project Nameplate Capacity (< 5 MW)

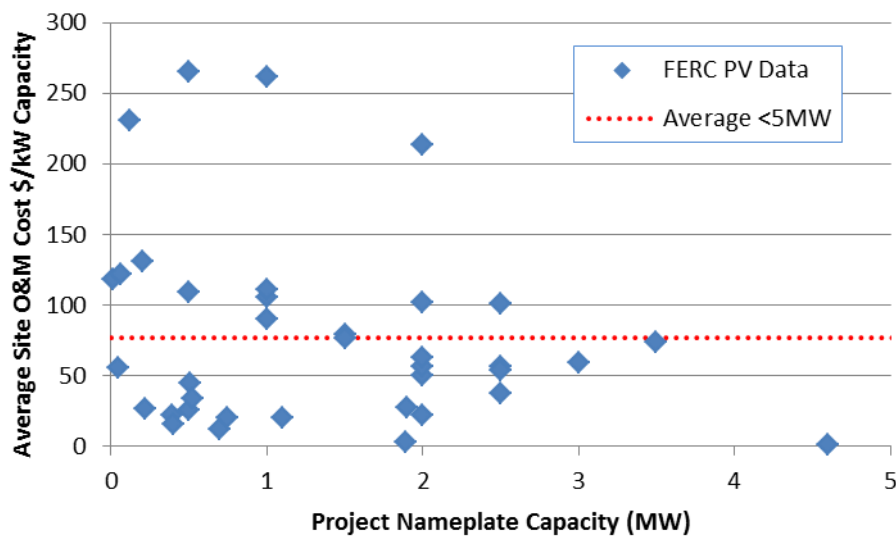
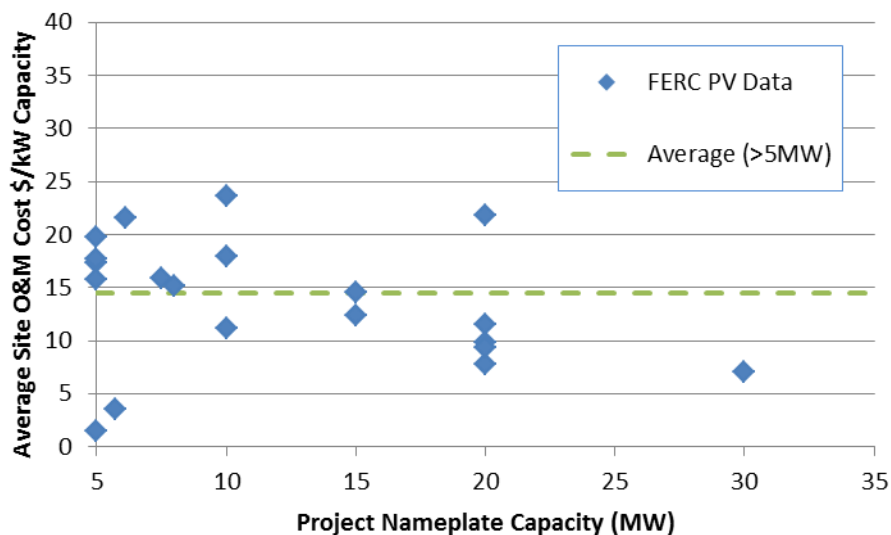


Figure G-5 — Average Site O&M Cost per kW-Year Capacity vs. Project Nameplate Capacity (> 5 MW)



The figures below show the annual site O&M cost (in \$/MWh and \$/kW-year) versus the age of the project. In general, little correlation can be seen between age and O&M cost.

Figure G-6 — Annual Site O&M Cost per MWh vs. Age of Project

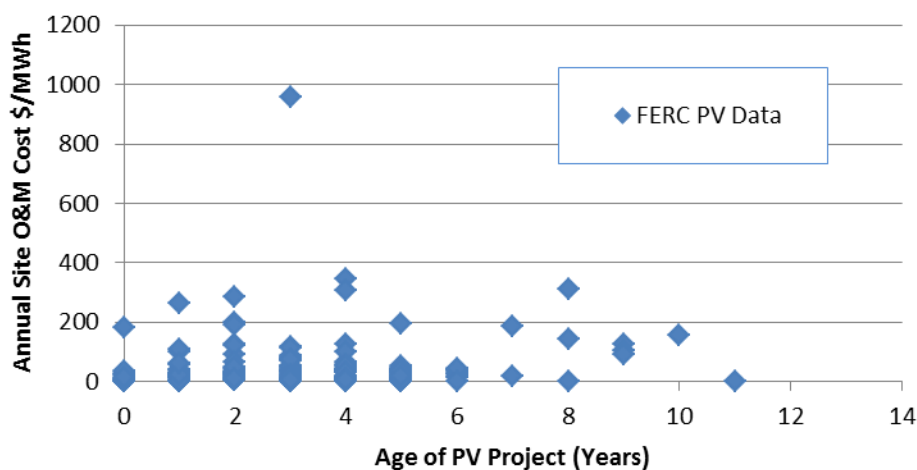
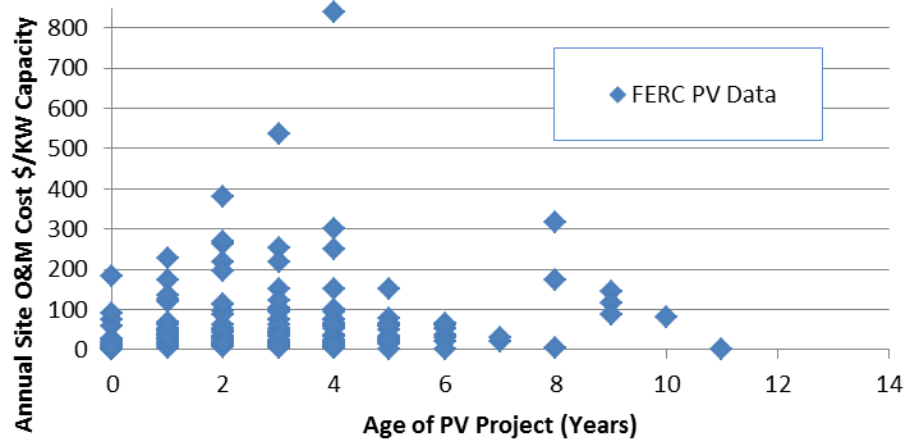


Figure G-7 — Annual Site O&M Cost per kW-Year Capacity vs. Age of Project



Sargent & Lundy compiled O&M data from other sources in Table G-3 below for comparison against the FERC data. In general, the O&M costs in \$/kW-year capacity are in the same range as the FERC data for sites over 5-MW capacity.

Table G-3 — Summary of Industry O&M Cost Data for Solar PV

O&M Cost Sources	O&M Cost \$/kW-yr	Notes	Report Source Data Year
NREL & Sunshot	15	Fixed	2015
NREL & Sunshot	18	Single-Axis Tracking	2015
Sunshot + NREL	20.5	Good O&M	2016
Sunshot + NREL	25.0	Optimal O&M	2016
IRENA Power to Change	10	Minimum	2015
IRENA Power to Change	18	Maximum	2015
Utility Scale Solar	17	Overall	2014
Utility Scale Solar 2016	7	Minimum	2016
Utility Scale Solar 2016	27	Maximum	2016
Utility Scale Solar 2016	18	Mean	2016
NREL U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017	15.4	Fixed LCOE Assumption	2017
NREL U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018	18.5	SAT LCOE Assumption	2017

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing solar PV plants are described in Section 9.



Appendix H. Regression Analysis – Solar Thermal

There are no solar thermal power plants that report operating data in FERC Form 1. Industry-wide, there are a limited number of solar thermal projects; a majority of which have been constructed within the last 10 years—the exception being small test facilities and the Solar Energy Generating Systems (SEGS) plants built in the 1980s.



Appendix I. Regression Analysis – Geothermal

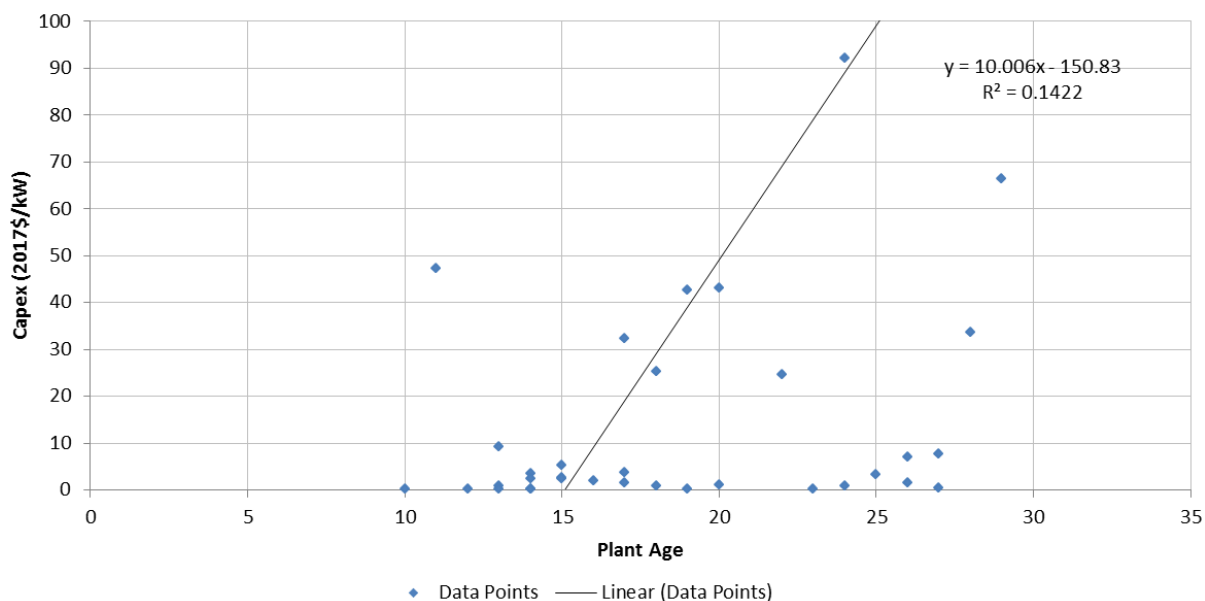
CAPITAL EXPENDITURES

The results of the linear regression analysis of CAPEX spending for geothermal plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Although the p-value is less than 0.05, the dataset is inconclusive because the intercept is negative due to no plants reporting data between ages and 0 and 10.

Table I-1 — Regression Statistics – Geothermal CAPEX for All MW

		<i>t statistic</i>	<i>p-value</i>
Observations	36		
Simple Average (\$/kW)	40.948		
Intercept	-150.830	-1.7907	8.23E-02
Slope	10.006	2.3736	2.34E-02
R ²	0.14215		

Figure I-1 — Geothermal Dataset – CAPEX for All MW Plant Sizes



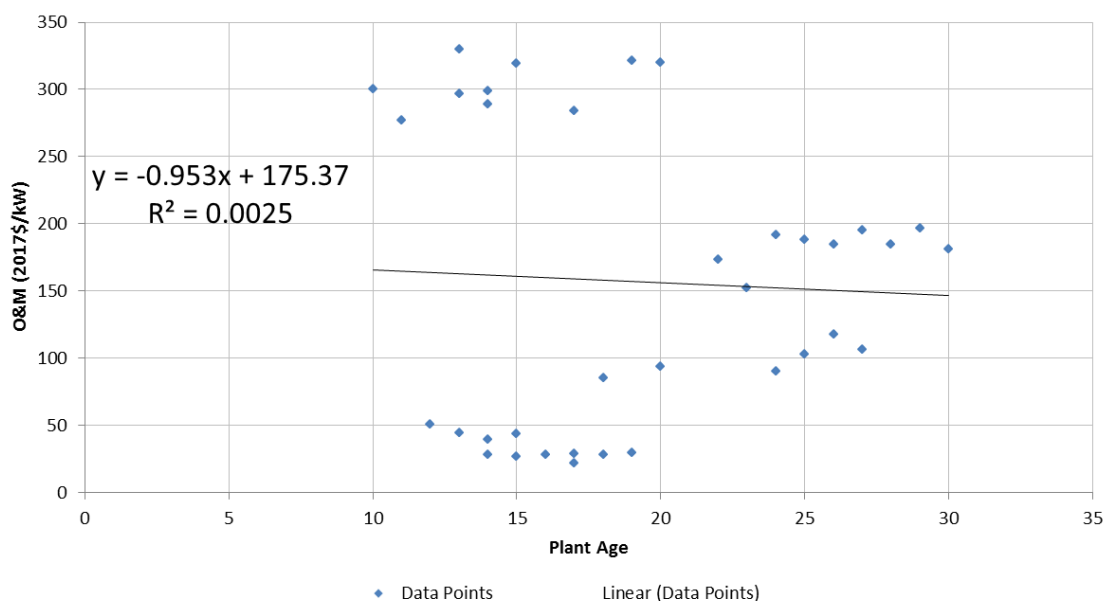
OPERATIONS & MAINTENANCE EXPENDITURES

The results of the linear regression analysis of O&M spending for geothermal plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.071, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

Table I-2 — Regression Statistics – Geothermal O&M for All MW

		<i>t</i> Statistic	<i>p</i> -value
Observations	36		
Simple Average (\$/kW)	157.103		
Intercept	175.369	2.6984	1.08E-02
Slope	-0.953	-0.2930	7.71E-01
R ²	0.00252		

Figure I-2 — Geothermal Dataset – O&M for All MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each five-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

Table I-3 — Geothermal All MW Summary of Results

	Average \$/kW-yr (Years 1-5)	Average \$/kW-yr (Years 6-10)	Average \$/kW-yr (Years 11-15)	Average \$/kW-yr (Years 16-20)	Average \$/kW-yr (Years 21-25)	Average \$/kW-yr (Years 26-30)	Average \$/kW-yr (All Years)	Data Points (Years 1-5)	Data Points (Years 6-10)	Data Points (Years 11-15)	Data Points (Years 16-20)	Data Points (Years 21-25)	Data Points (Years 26-30)	Data Points (All Years)
All MW, All Capacity Factors														
Net Total O&M – 2017 \$/kW-yr	--	300.62	170.44	124.24	149.97	166.77	157.10	--	1	12	10	6	7	36
Net Total CAPEX – 2017 \$/kW-yr	--	--	72.05	30.16	27.64	114.45	40.94	--	1	12	10	6	7	36

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing geothermal plants are described in Section 11.



Appendix J. Regression Analysis – Wind

CAPITAL EXPENDITURES

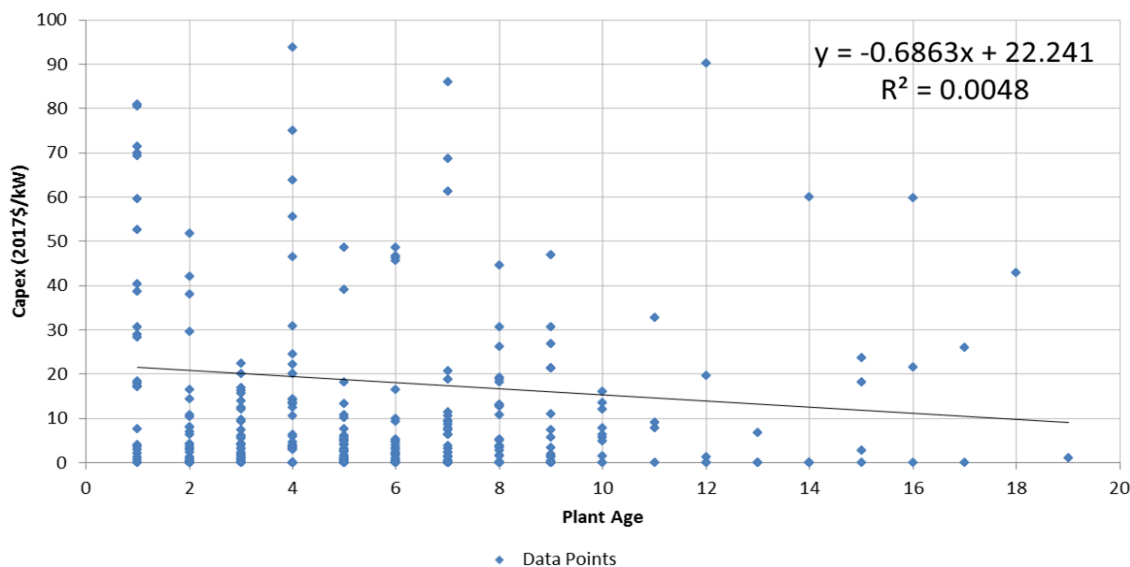
Full Dataset

The results of the linear regression analysis of CAPEX spending for wind plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.224, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table J-1 — Regression Statistics – Wind CAPEX for All MW

		<i>t</i> Statistic	<i>p</i> -value
Observations	310		
Simple Average (\$/kW)	18.285		
Intercept	22.241	5.7807	1.82E-08
Slope	-0.686	-1.2194	2.24E-01
R ²	0.00480		

Figure J-1 — Wind Dataset – CAPEX for All MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each five-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

Table J-2 — Wind All MW Summary of Results

	Average \$/kW-yr (Years 1-5)	Average \$/kW-yr (Years 6-10)	Average \$/kW-yr (Years 11-15)	Average \$/kW-yr (Years 16-20)	Average \$/kW-yr (All Years)	Data Points (Years 1-5)	Data Points (Years 6-10)	Data Points (Years 11-15)	Data Points (Years 16-20)	Data Points (All Years)
All MW, All Capacity Factors										
Net Total CAPEX – 2017 \$/kW-yr	21.06	10.97	32.62	21.60	18.29	168	112	23	7	310

Starting with the initial analysis of CAPEX raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing wind plants are described in Section 12.

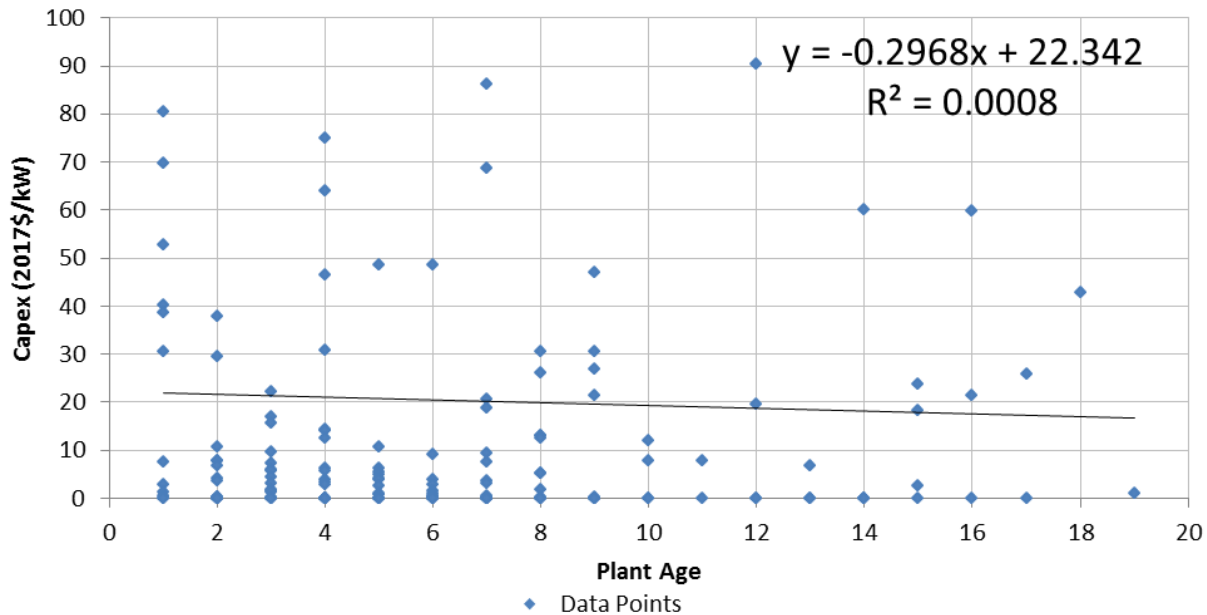
0-100 MW

The results of the linear regression analysis of CAPEX spending for wind plants between 0 MW and 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.706, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, a more appropriate predictor of CAPEX spending for this dataset is a simple average by plant age band, as discussed in Section 12.

Table J-3 — Regression Statistics – Wind CAPEX for 0-100 MW

		<i>t Statistic</i>	<i>p-value</i>
Observations	174		
Simple Average (\$/kW)	20.483		
Intercept	22.342	3.7750	2.20E-04
Slope	-0.297	-0.3779	7.06E-01
R ²	0.00083		

Figure J-2 — Wind Dataset – CAPEX for 0-100-MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

The simple average CAPEX values for each five-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

Table J-4 — Wind < 100-MW Summary of Results

	Average \$/kW-yr (Years 1-5)	Average \$/kW-yr (Years 6-10)	Average \$/kW-yr (Years 11-15)	Average \$/kW-yr (Years 16-20)	Average \$/kW-yr (All Years)	Data Points (Years 1-5)	Data Points (Years 6-10)	Data Points (Years 11-15)	Data Points (Years 16-20)	Data Points (All Years)
< 100 MW, All Capacity Factors										
Net Total CAPEX – 2017 \$/kW-yr	22.83	11.62	35.35	21.60	20.48	89	58	20	7	174

Starting with the initial analysis of CAPEX raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing wind plants are described in Section 12.

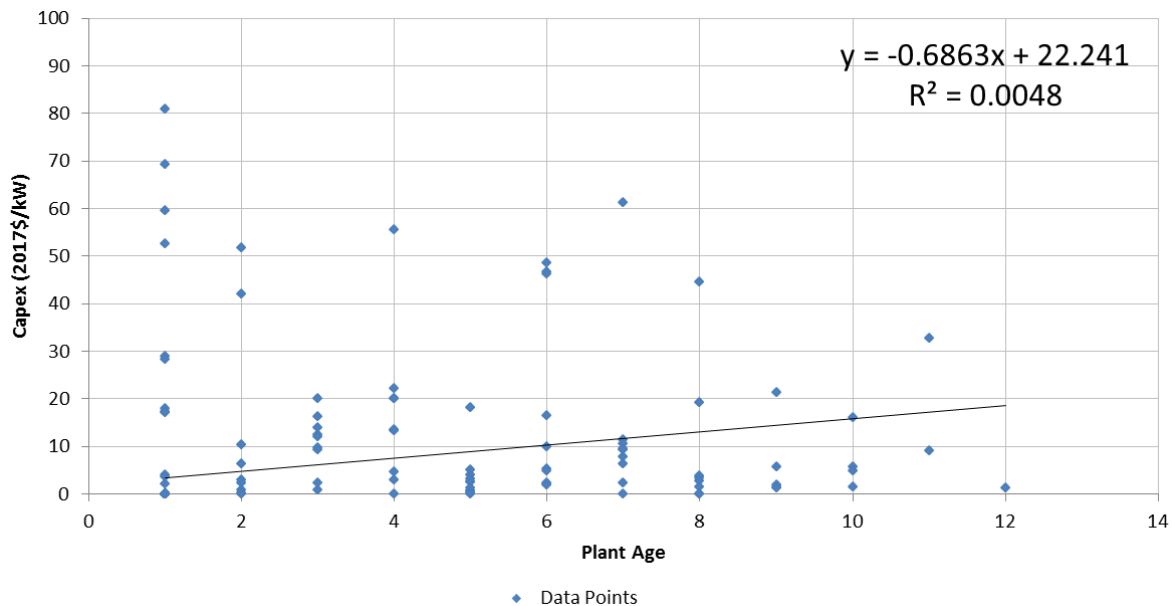
100-200 MW

The results of the linear regression analysis of CAPEX spending for wind plants between 100 MW and 200 MW are summarized in the table below. Since the p-value for the age coefficient is 0.224, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

Table J-5 — Regression Statistics – Wind CAPEX for 100-200 MW

		<i>t</i> Statistic	<i>p</i> -value
Observations	310		
Simple Average (\$/kW)	16.935		
Intercept	22.241	5.7807	1.82E-08
Slope	-0.686	-1.2194	2.24E-01
R ²	0.00480		

Figure J-3 — Wind Dataset – CAPEX for 100-200-MW Plant Sizes



Note: Age coefficient in above regression equation is not statistically significant.

The simple average CAPEX values for each five-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

Table J-6 — Wind 100-200-MW Summary of Results

	Average \$/kW-yr (Years 1-5)	Average \$/kW-yr (Years 6-10)	Average \$/kW-yr (Years 11-15)	Average \$/kW-yr (Years 16-20)	Average \$/kW-yr (All Years)	Data Points (Years 1-5)	Data Points (Years 6-10)	Data Points (Years 11-15)	Data Points (Years 16-20)	Data Points (All Years)
100 - 200 MW, All Capacity Factors										
Net Total CAPEX – 2017 \$/kW-yr	20.36	12.20	14.41	--	16.93	52	36	3	--	91

Starting with the initial analysis of CAPEX raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing wind plants are described in Section 12.

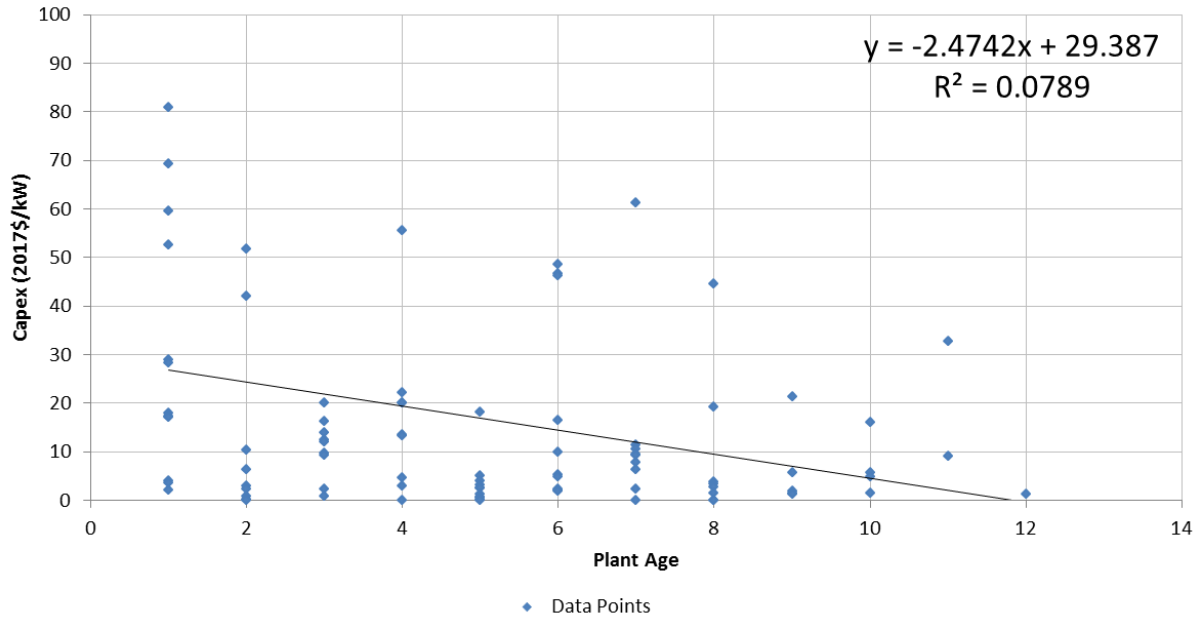
Greater than 200 MW

The results of the linear regression analysis of CAPEX spending for wind plants greater than 200 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.006, which is less than 0.05, the dataset does support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). However, a visual inspection of the data in the graph below shows that there are a limited number of data points over 10 years, which may be skewing the regression.

Table J-7 — Regression Statistics – Wind CAPEX for Greater than 200 MW

		<i>t Statistic</i>	<i>p-value</i>
Observations	91		
Simple Average (\$/kW)	16.935		
Intercept	29.387	5.6538	1.87E-07
Slope	-2.474	-2.7612	6.99E-03
R ²	0.07891		

Figure J-4 — Wind Dataset – CAPEX for Greater than 200-MW Plant Sizes



The simple average CAPEX values for each five-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

Table J-8 — Wind Greater than 200-MW Summary of Results

	Average \$/kW-yr (Years 1-5)	Average \$/kW-yr (Years 6-10)	Average \$/kW-yr (All Years)	Data Points (Years 1-5)	Data Points (Years 6-10)	Data Points (All Years)
> 200 MW, All Capacity Factors						
Net Total CAPEX – 2017 \$/kW-yr	16.61	8.65	13.48	31	20	51

Starting with the initial analysis of CAPEX raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing wind plants are described in Section 12.

OPERATIONS & MAINTENANCE EXPENDITURES

Full Dataset

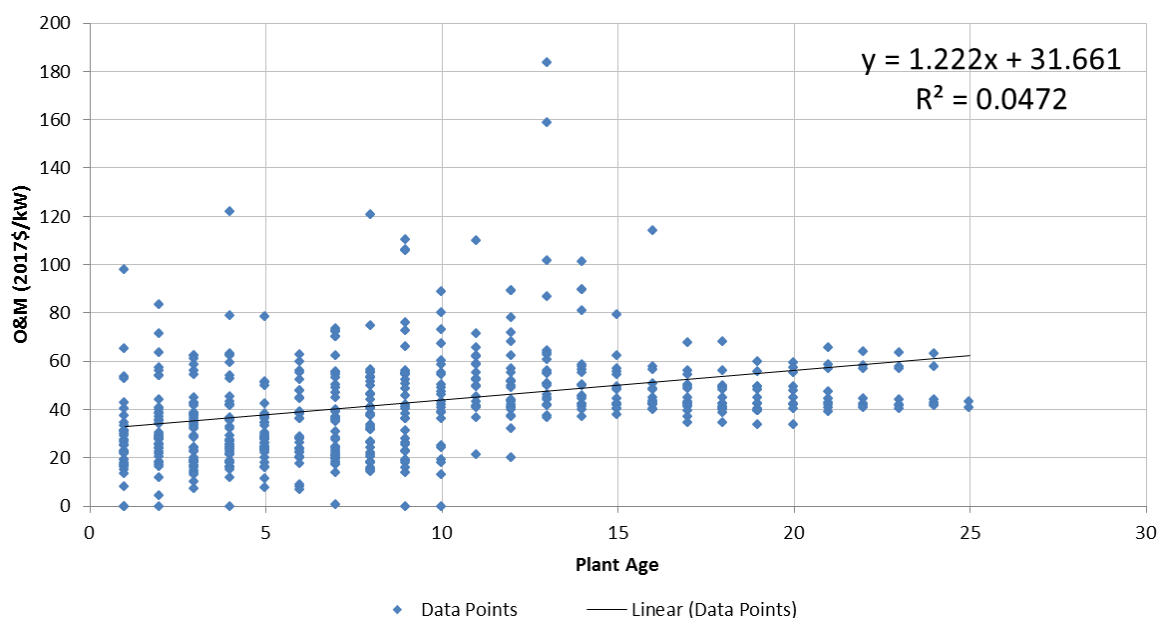
The results of the linear regression analysis of O&M spending for wind plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for the dataset may be estimated by the regression equation:

$$\text{Annual O\&M spending in 2017 \$/kW-year} = 31.661 + (1.222 \times \text{age})$$

Table J-9 — Regression Statistics – Wind O&M for All MW

		<i>t statistic</i>	<i>p-value</i>
Observations	580		
Simple Average (\$/kW)	42.680		
Intercept	31.661	12.7763	4.24E-33
Slope	1.222	5.3515	1.26E-07
R ²	0.04721		

Figure J-5 — Wind Dataset – O&M for All MW Plant Sizes



0-100 MW

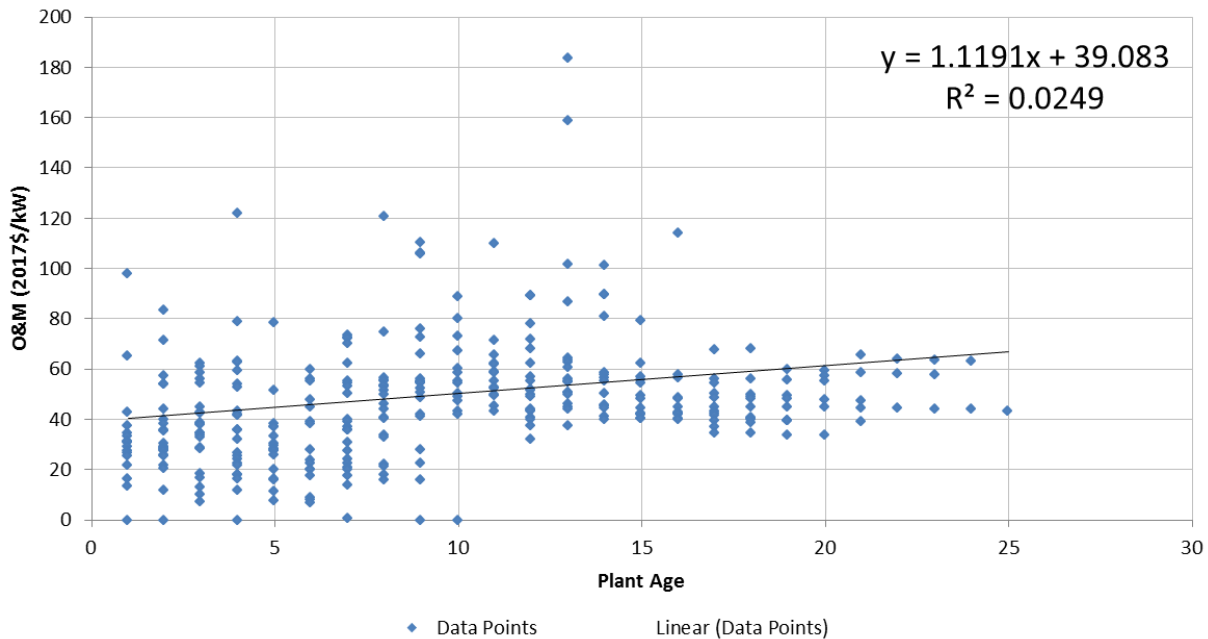
The results of the linear regression analysis of O&M spending for wind plants between 0 MW and 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.003, which is less than 0.05, the dataset age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for the dataset may be estimated by the regression equation:

Annual O&M spending in 2017 \$/kW-year = 39.083 + (1.119 × age)

Table J-10 — Regression Statistics – Wind O&M for 0-100 MW

		<i>t</i> Statistic	<i>p</i> -value
Observations	339		
Simple Average (\$/kW)	49.888		
Intercept	39.083	9.0574	1.10E-17
Slope	1.119	2.9310	3.61E-03
R ²	0.02486		

Figure J-6 — Wind Dataset – O&M for 0-100-MW Plant Sizes



100-200 MW

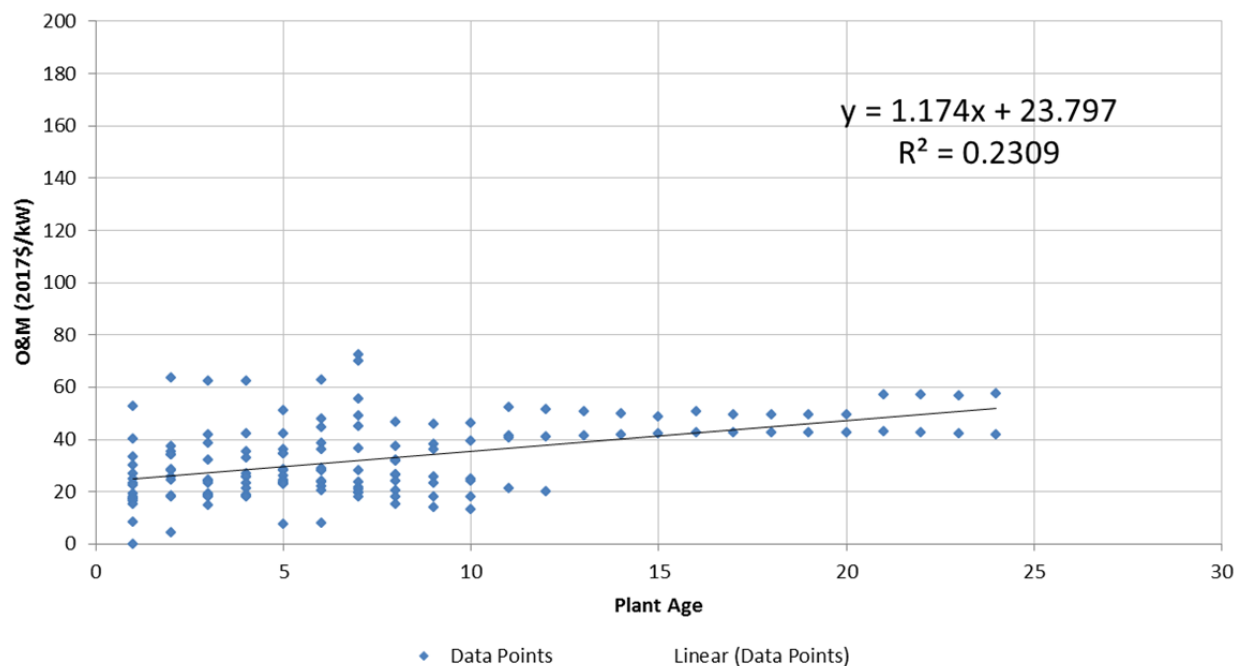
The results of the linear regression analysis of O&M spending for wind plants between 100 MW and 200 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for the dataset may be estimated by the regression equation:

$$\text{Annual O\&M spending in 2017 \$ /kW-year} = 23.797 + (1.174 \times \text{age})$$

Table J-11 — Regression Statistics – Wind O&M for 100-200 MW

		<i>t</i> Statistic	<i>p</i> -value
Observations	147		
Simple Average (\$/kW)	35.645		
Intercept	23.797	14.1919	3.27E-29
Slope	1.174	6.5971	7.33E-10
R ²	0.23086		

Figure J-7 — Wind Dataset – O&M for 100-200-MW Plant Sizes



Greater than 200 MW

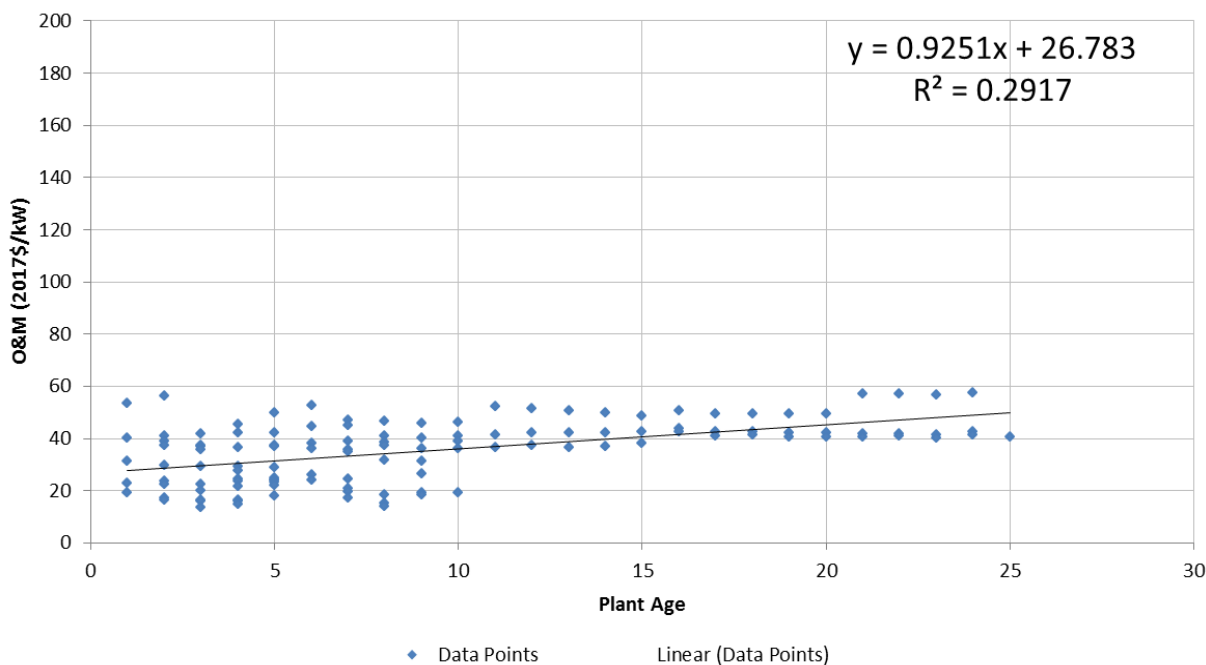
The results of the linear regression analysis of O&M spending for wind plants greater than 200 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for the dataset may be estimated by the regression equation:

$$\text{Annual O\&M spending in 2017 \$ /kW-year} = 26.783 + (0.925 \times \text{age})$$

Table J-12 — Regression Statistics – Wind O&M Greater than 200 MW

		<i>t statistic</i>	<i>p-value</i>
Observations	124		
Simple Average (\$/kW)	35.645		
Intercept	26.783	17.5334	3.90E-35
Slope	0.925	7.0885	9.55E-11
R ²	0.29171		

Figure J-8 — Wind Dataset – O&M for Plant Sizes Greater than 200 MW



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-25-14
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
<u>PacifiCorp, and Xcel Energy</u>	)	

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

Filed January 28, 2026

Exhibit 1-163
Trump Advisor Says Electricity Customers Pay for 202(c) Orders



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— The J.H. Campbell coal-fired power plant in Michigan. Consumers Energy had planned to retire the plant in 2025, but President Trump ordered it to keep operating.
© Jim West / UCG / Getty Images

A Trump administration official said Wednesday that efforts to keep coal-fired power plants running beyond their planned retirement dates will ultimately be paid for by electricity customers.

Federal efforts to block coal plant retirements aim to preserve grid reliability amid a surge in electricity demand driven by data centers and artificial intelligence, said Peter Lake, a member of the White House's National Energy Dominance Council, speaking at the American Enterprise Institute's "Powering Prosperity and the New Electricity Economy" conference in Washington.



13 Retirement Blunders to Avoid

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"All costs end up on ratepayers," Lake said, responding to a question about who pays when utilities are required by the federal government to keep coal plants online after having invested billions of dollars in replacement power generation.

He added that industrial customers typically bear a larger share of those costs, equivalent to about 60%. But it depends on the utility, their generation makeup, and how rate structures allocate expenses based on load size and peak demand.

The Trump administration has so far prevented dozens of coal units from retiring, invoking emergency authorities and directing federal agencies to intervene in power markets. Officials say the U.S. grid cannot afford to lose generation as electricity demand accelerates faster than expected.

The administration has also framed its coal policy as an affordability and reliability measure, aimed at avoiding what Lake said could be \$34 billion to \$40 billion in replacement costs if operating coal plants were allowed to retire before new dispatchable resources are in place.

 **Related video:** Why renewables did not cut bills (Simon Clark)

 Simon Clark

Why renewables did not cut bills



Government estimates call for roughly 100 gigawatts of new power by 2030, a figure Lake compared with adding “California plus two New Yorks” to the grid in less than five years.

“Yes, we need coal. We need gas. We need batteries. Anything with an answer,” Lake said.

Coal is getting a boost from AI power and industrial demand. Several utilities, including Duke Energy and some subsidiaries of Southern Company, revised plans to retire some coal units after forecasting sharp increases in demand from data centers and advanced manufacturing. The changes were approved through state-regulated processes.

But utilities say that being forced to keep some coal plants open is upending years of state-approved planning.

For example, the Michigan-based Campbell coal plant, owned by CMS Energy, was forced by the Trump administration to continue operating into 2026 after being scheduled to retire in 2025, costing about \$615,000 a day, according to company filings. The state utility running the plant, Consumers Energy, had already invested in replacement gas generation, renewable contracts, and grid upgrades.

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Consumers Energy warned that extending Campbell’s operations will add millions of dollars in incremental fuel, maintenance, and staffing costs that weren’t contemplated in approved rates, according to regulatory filings.

Consumers in regulated energy markets may be hit hardest as coal plants stay open longer than planned. A utility that voluntarily plans to delay a plant retirement often gets approval from regulators in a deal that includes freezing rates for consumers and special tariffs that shift costs toward large industrial users like data centers.

That framework can collapse when Washington forces plants to keep operating. When a plant is kept online after replacement assets are already in the rate base, customers effectively pay twice—once for the new plant, and again for the old one.

Some utilities are trying to manage rising AI power needs without passing along costs to households. In Louisiana and parts of the Midwest, for instance, utilities have negotiated special large-load tariffs and contract terms with data-center customers that include higher base rates, upfront infrastructure contributions, and curtailment provisions during grid stress.



43



12





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Still, some energy experts say the administration's plans to delay coal retirements may be counterproductive and obscure the more pressing problem: permitting delays to upgrade the grid.

"Mandating that an old power plant operate isn't consistent with a market-based approach," said Rob Gramlich, president of Grid Strategies LLC, at the AEI conference, noting that tens of gigawatts of approved generation remain stalled in interconnection queues due to permitting and transmission constraints.

A [study by Grid Strategies](#), a consultancy funded partly by environmental groups including the Sierra Club, found that the administration's plan to stop fossil fuel plants from closing could cost ratepayers \$3.1 to \$5.9 billion a year.

Write to Laura Sanicola at laura.sanicola@barrons.com

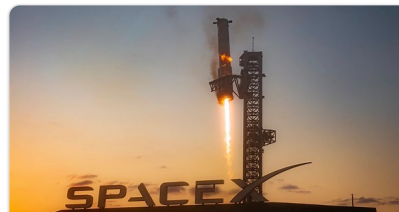
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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Tri-State	)	Order No. 202-25-14
Generation and Transmission	)	
Association, Platte River Power	)	
Authority, Salt River Project,	)	
<u>PacifiCorp, and Xcel Energy</u>	)	

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

Filed January 28, 2026

Exhibit 1-164
Colorado Commission Decision No. C24-0052

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 21A-0141E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN.

PHASE II DECISION: (1) ADDRESSING RESOURCE SELECTION AND THEREBY MODIFYING PUBLIC SERVICE’S CLEAN ENERGY PLAN; (2) ADDRESSING THE ADDITIONAL TRANSMISSION INVESTMENTS IDENTIFIED IN PHASE II; (3) ESTABLISHING PERFORMANCE INCENTIVE MECHANISMS FOR UTILITY-OWNED GENERATION; (4) ADDRESSING THE 2024 JUST TRANSITION SOLICITATION; AND (5) ADDRESSING RELATED MATTERS

Mailed Date: January 23, 2024

Adopted Date: December 6, 13, 20, 2023

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I. BY THE COMMISSION

A. Statement

1. In accordance with § 40-2-125.5(4), C.R.S., the electric resource plan (ERP) filed by Public Service Company of Colorado (Public Service or the Company) on March 31, 2021, includes a Clean Energy Plan (CEP) to reduce the Company's carbon dioxide (CO₂) emissions by a target of 80 percent by 2030 as compared to 2005 levels. As set out in Decision No. C22-0459 (the Phase I Decision)¹ and Decision No. C22-0559 (addressing applications for rehearing, reargument, or reconsideration)² the Commission approved certain elements of the Company's CEP, including the Coal Action Plan that transitions Public Service away from its remaining coal facilities. The Commission also authorized Public Service to use Phase II of this Proceeding to further implement the requirements for approval of a CEP such that the Commission could continue evaluation of, among other things, the additional clean energy plan activities, the actions and investments projected to achieve compliance with the clean energy targets in § 40-2-125.5(3)(a)(I) and (3)(a)(II), and whether the CEP is in the public interest and consistent

¹Issued August 3, 2022.

² Issued September 21, 2022.

with the clean energy target in § 40-2-125.5(3)(a)(I). The Commission's decisions in Phase I and Phase II of this ERP proceeding thus implement a bold clean energy policy that helps avoid the worst impacts of climate change while allowing Coloradoans to enjoy the benefits of reliable clean energy at an affordable cost.

2. Throughout the course of Phase II, Public Service showcased its preferred resource portfolio of new utility resources to be acquired through 2027 and, in response to party and public comments, its updated preferred portfolio of resources. In accordance with the Commission's Phase I directives, the Company also presented numerous alternate portfolios for consideration. Although the Company's preferred resource portfolio³ projects sufficient emission reductions to exceed statutory requirements, comments point out that not only might these projected reductions in emissions be overstated, but that the costs to customers would be significant – pointing to, among other major concerns, billions of dollars in modeled transmission investment changes between Phase I and II, and significant utility ownership in gas resources presented in the Company's updated preferred plan.

3. Building on our determinations in Phase I, we find that modifying the Company's CEP by selecting an alternative resource portfolio (the Alternative Portfolio)⁴ is necessary considering statutory and public interest concerns.

4. The Alternative Portfolio exceeds Colorado's goals in emission reductions and protects reliability of the electrical system, according to the Company's analysis. At the same time,

³ As detailed below, in the 120-Day Report, Public Service presented its Preferred Portfolio, and this Preferred Portfolio is what comments from intervenors address. In its Response Comments, the Company presents an Updated Preferred Portfolio. Apart from a few minor modifications (*e.g.* replacing a wind project with a different wind project) the Updated Preferred Portfolio and the Preferred Portfolio are identical. The benefits of the Alternative Portfolio set forth throughout this Phase II decision apply both to the Preferred Portfolio and the Updated Preferred Portfolio.

⁴ As discussed below, the Alternative Portfolio is the Inverse 1324 (\$0CO₂) Plan that Public Service included in the 120-Day Report. (*See* 120-Day Report (Appendix S) Rev. 1, p. 26).

the Alternative Portfolio—which includes fewer new utility-owned resources than the Company’s preferred resource portfolio and is thus better tailored to the developing capabilities of the Company’s system—will reduce costs to customers, especially considering factors such as the curtailment of generated renewable energy.

5. This case propels Colorado’s transition towards greater reliance on renewable resources, takes massive strides towards emission reductions, and continues on a path towards 100 percent clean energy resources; however, the Company maintains that system reliability currently requires at least some new natural gas-fired generation resources. Like the Company’s updated preferred portfolio, the Alternative Portfolio includes nearly half the amount of gas resources predicted in the Phase I Settlement modeling, which was supported by a majority of parties with diverse interests, including some environmental advocates.⁵ Moreover, and unlike the Company’s updated preferred plan, the Alternative Portfolio better allows for technological advancements and flexibility by deferring certain resource acquisitions, reducing the amount of Company-owned gas resources, and significantly increasing the amount of storage on the electrical system. For similar reasons, the Alternative Portfolio creates the opportunity to better optimize transmission upgrades during resource procurement in future proceedings.

6. Particularly given the billions of dollars in discrepancies of modeled transmission costs, granting authority to Public Service to move forward with acquiring the resources in the Alternative Portfolio with the Phase I authorizations also allows us to better support Colorado customers and communities. Through directed modeling and filing considerations, we include further direction to support transitioning communities through the 2024 Just Transition Solicitation. As we remain dedicated to supporting the economic changes facing our state’s

⁵ Phase I Settlement (Attachment D), p. 2.

transitioning communities, optionality and opportunity through ongoing, robust, competitive bidding is essential to continue selecting optimal resources to support Colorado's needs. In recognition that affordability of energy bills remains a significant focus, we also include direction on performance incentive mechanisms that further incentivize Public Service to reduce the costs of the new Company-owned generation and promotes fairness and transparency within the competitive bidding process.

7. On balance, the Phase I and Phase II Decisions together provide a measured approach to reliability and cost considerations, while taking exponential strides towards a clean energy future that supports Colorado citizens. These decisions propel the Company towards an 86 percent reduction in emissions by 2030 as well as the goal of providing its customers with energy from 100 percent clean energy resources by 2050.

8. Thus, through this Decision we find that modification of the proposed CEP to include the Alternative Portfolio is necessary to ensure the CEP is in the public interest. Consistent with the Phase I Decision and determinations in this Phase II order, we direct Public Service to pursue this modified CEP and its Alternative Portfolio of resources with further due diligence and contract negotiations and to file applications for Certificates of Public Convenience and Necessity (CPCNs) for all Company-owned generation resources arising from the modified CEP. We further direct that all Company-owned generation resources arising from the modified CEP are subject to both the cost to construct performance incentive mechanism (PIM) and the operational PIM set forth below.

9. In addition, we make several directives regarding transmission investments as well as future proceedings, including the 2024 Just Transition Solicitation proceeding and the

application Public Service will file regarding the attribution of costs between the CEP rider (CEPR) and the Renewable Energy Standard Adjustment (RESA).

B. Discussion

1. Electric Resource Planning

10. The Commission's ERP Rules, set forth at 4 *Code of Colorado Regulations* (CCR) 723-3-3600, *et seq.*, serve two primary functions. First, the rules require a regular, periodic examination of an electric utility's energy sales and demand forecasts as compared to an assessment of its existing resources to ensure that sufficient generation will be available to meet customer needs in the future. Second, the Commission's review and approval of an ERP ensures that the utility acquires a cost-effective mix of additional resources consistent with the state's public policy objectives.

11. As established in the ERP Rules, for decades Colorado electric utilities have used competitive bidding to procure additional resources to meet identified future resource needs. An ERP thus describes in detail how the utility will evaluate the bids and proposals submitted in response to Requests for Proposals (RFPs), including the inputs and assumptions to its bid evaluation models (*e.g.*, natural gas prices, the social costs of emissions, discount rates, etc.), and how it will apply resource selection criteria.

12. The ERP process includes two phases. In Phase I, the Commission reviews and may approve, or approve with modifications, the utility's plan to acquire new utility resources.⁶ In Phase II, the Commission issues a final decision regarding the utility's preferred cost-effective plan for pursuing the acquisition of particular resources.

⁶ Rule 4 CCR 723-3-3617(c) describes the contents of the Commission's Phase I decision in more detail.

13. Phase II begins after the Commission issues its Phase I decision. Public Service issues its RFPs, receives competitive bids and utility-owned proposals, and files a report no later than 120 days after the bids are received in accordance with Rule 4 CCR 723-3-3613(d) (120-Day Report). The 120-Day Report presents an evaluation of all proposed resources, based on the criteria established in the Phase I decision (*e.g.*, the base modeling inputs and assumptions to be used in developing optimized resource portfolios and the sensitivities that “re-price” optimized portfolios using alternative values for selected inputs and assumptions).

14. At the end of Phase II, the Commission issues a final decision that approves, conditions, modifies, or rejects the utility’s preferred cost-effective resource plan. Rule 3613(h) describes the contents of a Phase II decision as follows:

Within 90 days after the receipt of the utility’s 120-day report under paragraph 3613(d), the Commission shall issue a written decision approving, conditioning, modifying, or rejecting the utility’s preferred cost-effective resource plan, which decision shall establish the final cost-effective resource plan. The utility shall pursue the final cost-effective resource plan either with a due diligence review and contract negotiations, or with applications for CPCNs (other than those CPCNs provided in paragraph 3611(e)), as necessary. In rendering the decision on the final cost-effective resource plan, the Commission shall weigh the public interest benefits of competitively bid resources provided by other utilities and non-utilities as well as the public interest benefits of resources owned by the utility as rate base investments. In accordance with §§ 40-2-123, 40-2-124, 40-2-129, and 40-3.2-104, C.R.S., the Commission shall also consider renewable energy resources; resources that produce minimal emissions or minimal environmental impact; energy-efficient technologies; and resources that affect employment and the long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado’s energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

15. Upon the conclusion of Phase II, and consistent with Rule 3613(h), upon the issuance of this Phase II Decision, Public Service will continue its due diligence and contract negotiations, as appropriate, and file applications for CPCNs in accordance with § 40-5-101, C.R.S., for each of the Company-owned projects arising from approval of the modified CEP.

These projects will be entitled to a presumption of prudence per Rule 3617(d), supported primarily through the determinations of need in Phase I and Phase II, the use of competitive bidding, and the implementation of bid evaluation and selection pursuant to our Phase I decision. Given the magnitude of this ERP Proceeding and the complexity associated with the CEP considerations set forth below, the Commission waives the 90-day deadline to issue a Phase II decision as contemplated by Rule 3613(h).

2. Clean Energy Plans Pursuant to SB 19-236

16. While longstanding statutes, the Commission's rules, and competitive bidding processes are foundational to the Colorado's utility resource planning process, recent legislative changes, including Senate Bill (SB) 19-236 further overlay CEP considerations on Public Service's current ERP.

17. SB 19-236 enacts § 40-2-125.5(1) that declares the statewide importance of promoting cost-effective clean energy and new technologies and reduction of carbon dioxide emissions from the Colorado electric generating system and includes that "[a] bold clean energy policy will support this progress and allow Coloradans to enjoy the benefits of reliable clean energy at an affordable cost." Specifically, § 40-2-125.5(3) requires that, in addition to the other requirements of the section, Public Service shall meet the following clean energy targets:

- (I) By 2030, the qualifying retail utility shall reduce the carbon dioxide emissions associated with electricity sales to the qualifying retail utility's electricity customers by eighty percent from 2005 levels; and
- (II) For the years 2050 and thereafter, or sooner if practicable, the qualifying retail utility shall seek to achieve the goal of providing its customers with energy generation from one-hundred-percent clean energy resources so long as doing so is technically and economically feasible, in the public interest and consistent with the requirements of this section.

18. The statute further requires that the first ERP following January 1, 2020, must include a CEP that “will achieve the clean energy target set forth in subsection (3)(a)(I)” and will “make progress toward the [100 percent] clean energy goal set forth in subsection (3)(a)(II).”⁷ Subsection 4 further specifies what a CEP must include (*e.g.*, a plan of actions and investments projected to achieve compliance with the clean energy targets set forth in subsection (3)(a)(I) and (3)(a)(II), the projected costs of the CEP’s implementation, and workforce transition and community assistance plans).

19. Subsection 4(d) includes that the Commission “shall approve the [CEP] if the commission finds it to be in the public interest and consistent with the [80 percent target], and the commission may modify the plan if the modification is necessary to ensure the plan is in the public interest.” In evaluating whether a CEP submitted is in the public interest, the Commission is directed to consider the following factors, “among other relevant factors as defined by the commission”:

- (I) Reduction in carbon dioxide and other emissions that will be achieved through the clean energy plan and the environmental and health benefits of those reductions;
- (II) The feasibility of the [CEP’s] impact on the reliability and resilience of the electric system. The commission shall not approve a plan that does not protect system reliability.
- (III) Whether the [CEP] will result in a reasonable cost to customers, as evaluated on a net present value basis.⁸

20. If the Commission approves a CEP that achieves an emission reduction of at least 75 percent from 2005 levels, then the relevant utility is provided with a “safe harbor” from any

⁷ § 40-2-125.5(4)(a).

⁸ § 40-2-125.5(4)(d)(III).

additional emission reduction regulations that the Air Quality Control Commission (AQCC) might develop for the power sector through 2030.⁹

21. As a general matter, the Colorado Department of Public Health and Environment (CDPHE) is tasked with calculating whether a proposed CEP will meet these clean energy targets. In particular, the division of administration in the CDPHE must describe the methods of measuring CO2 emissions and verify the projected CO2 emission reductions of the CEP.¹⁰ The statute goes on to state that the division of administration, in consultation with the AQCC, must determine whether the CEP will meet the 2030 clean energy targets, and will report to the Commission the division's calculation of CO2 emission reductions attributable to any approved CEP.¹¹

22. SB 19-236 also sets forth accounting requirements to track the costs of the CEP. For instance, § 40-2-125.5(4)(a)(III) states the utility must “clearly distinguish” between the set of resources necessary to meet customer demands in the resource acquisition period (RAP) and the additional CEP activities—such as the retirement of existing generating facilities—that may be undertaken to meet the clean energy target of 80 percent emission reduction by 2030. Moreover, the CEP must set forth the projected cost of its implementation and anticipated reductions in carbon dioxide and other emissions.¹² Likewise, the CEP must list the “actions and investments” necessary to meet the clean energy target and describe the effect of such actions and investments on the safety, reliability, renewable energy integration, and resiliency of the electric system.¹³

23. The statute goes on to direct the utility to collect revenues for the additional CEP activities through a CEPR assessed on a percentage basis on all retail customer bills.¹⁴ This CEPR

⁹ § 25-7-105(1)(e)(VIII)(C), C.R.S.

¹⁰ § 40-2-125.5(4)(b).

¹¹ § 40-2-125.5(4)(c)(I).

¹² § 40-2-125.5(4)(a)(VI)

¹³ § 40-2-125.5(4)(a)(IV)—(V).

¹⁴ § 40-2-125.5(5)(a)(II)

is limited to a maximum electric retail rate impact of 1.5 percent of the total annual electric bill for each customer for implementation of the approved additional clean energy plan activities and “may be established as early as the year following approval of a clean energy plan by the commission.”¹⁵

24. SB 19-236 requires that the ERP containing the CEP use a RAP extending through 2030. If the CEP calls for the accelerated retirement of any generating facilities, the CEP must include a workforce transition plan for impacted utility workers. Similarly, the CEP must include a plan to pay community assistance to any local government or school district whose voters previously approved projects, the costs of which are expected to be paid for from property taxes that the accelerated retirement directly impacts.¹⁶

25. While the statute requires the utility to use a competitive bidding process to procure any energy resources to fill the cumulative resource need derived from the ERP and CEP, the Commission shall also allow the utility to own a target of 50 percent of the energy and capacity developed or acquired to meet the resource need “if the commission finds the cost of utility or affiliate ownership of the generation assets comes at a reasonable cost and rate impact.”¹⁷

26. As discussed in our Phase I Decision, several of the statutory findings required for an approved CEP could not be made in the Phase I Decision but must wait until Phase II. For instance, the actions and investments required to fill the additional resource need for the CEP, the projected cost to implement the CEP, and the cost and rate impact of the 50 percent utility ownership target could not be known until after the 120-Day Report. The Phase I Decision permitted Public Service to issue the RFP and proceed to Phase II and established the framework in which bids will be evaluated and selected, setting important Phase II assumptions regarding the

¹⁵ § 40-2-125.5(5)(a)(I).

¹⁶ § 40-2-125.5(4)(a)(VII).

¹⁷ § 40-2-125.5(5)(b).

treatment of the Company's remaining coal-fired power plants, and ensuring that the 120-Day Report contains the information required to make the statutory findings necessary to reach an approved CEP.

27. The Commission did not anticipate, and no party requested, a fully litigated hearing in Phase II.¹⁸ Rather, through its usual Phase II process, the Commission can address the necessary statutory findings in this Phase II Decision (*e.g.*, upon consideration of the 120-Day Report, the parties' comments to the 120-Day Report, and the IE Report). As the parties assert in their Joint Brief Addressing Phase II Topics, (filed on August 2, 2021) SB 19-236 might change the objectives of the ERP process, but it does not direct any changes to the process itself.¹⁹

3. Procedural Background

28. A complete procedural history through Phase I of this Proceeding is provided in the Phase I Decision.

29. The parties in this Proceeding consist of the following: Public Service; Staff of the Colorado Public Utilities Commission (Staff); the Office of Utility Consumer Advocate (UCA); the Colorado Energy Office (CEO); the City of Boulder (Boulder); the Colorado Energy Consumers (CEC); Climax Molybdenum Company (Climax); Colorado Independent Energy Association (CIEA); Interwest Energy Alliance (Interwest); Colorado Solar and Storage Association and Solar Energy Industries Association (jointly COSSA/SEIA); the International Brotherhood of Electrical Workers, Local No. 111 (Local 111); Rocky Mountain Environmental Labor Coalition and Colorado Building and Construction Trades Council, AFL-CIO (jointly,

¹⁸ This is consistent with the position of the parties. (Joint Brief Addressing Phase II Topics, p. 8 (arguing that the statutory findings required to approve a CEP do not necessitate a Phase II hearing)).

¹⁹ Joint Brief Addressing Phase II Topics, p. 13.

RMELC and CBCTC);²⁰ Holy Cross Electric Association, Inc. (Holy Cross); CORE Electric Cooperative (CORE); Western Resource Advocates (WRA); Vote Solar; Walmart Inc. (Walmart); Colorado Renewable Energy Society (CRES); Natural Resources Defense Council and Sierra Club (collectively, the Conservation Coalition); the City and County of Denver (Denver); the Board of County Commissioners of Pueblo County (Pueblo County); the City of Pueblo and Board of Water Works of Pueblo (jointly Pueblo City and Water); Onward Energy Management (Onward); and the Colorado Oil and Gas Association (COGA). The Commission also granted Black Hills Colorado Electric, LLC (Black Hills) leave to participate as an *amicus curiae* in this Proceeding.²¹

30. In addition, in Decision No. C21-0343-I,²² the Commission granted the Unopposed Motion for Limited Participation that CDPHE filed on April 29, 2021. As such, CDPHE is participating in this Proceeding as a neutral verifier.

31. In response to Decision No. C21-0404-I,²³ in which the Commission solicited briefs from the parties regarding Phase II procedures, on August 2, 2021, Public Service, Staff, UCA, CEO, CIEA, COSSA/SEIA, RMELC and CBCTC, Local 111, Conservation Coalition, Interwest, Onward, Pueblo County, Pueblo City and Water, Walmart, and WRA jointly filed a brief arguing that no Phase II hearing is required. Vote Solar was the only party to file a separate Phase II brief, in which it states that it “does not believe Senate Bill 19-236 requires a Phase II hearing” but argues that “additional evidentiary hearing process may nonetheless be necessary in Phase II if Public Service Company of Colorado proposes any portfolios in its 120-Day Report that include gas plants located in, or near, any disproportionately impacted communities.”²⁴

²⁰ Local 111, RMELC, and CBCTC collectively refer to themselves as the Labor Interests.

²¹ The Commission denied the Motions to Intervene filed by Ms. Leslie Glustrom and the Coalition of Ratepayers. (Decision No. C21-0315-I, pp. 16-22.)

²² Issued June 9, 2021.

²³ Issued June 23, 2021.

²⁴ Vote Solar’s Phase II Brief, p. 1.

32. On September 30, 2021, the Office of Just Transition (OJT) filed a motion to intervene out of time, or in the alternative, to participate as *amicus curiae*. On October 25, 2021, the Commission granted OJT's motion to intervene out of time, allowing OJT to participate as a party in this Proceeding.²⁵

33. On August 3, 2022, the Commission issued the Phase I Decision addressing Public Service's ERP and CEP and approving, in part, the Updated Non-unanimous Partial Settlement Agreement (Phase I Settlement) filed on April 26, 2022.²⁶ Among other things, the Phase I Decision directed Public Service to issue RFPs for an all-source, competitive bidding process to meet its resource need.

34. On September 21, 2022, the Commission issued Decision No. C22-0559 addressing applications for rehearing, reargument, or reconsideration of the Phase I Decision.

35. On December 1, 2022, Public Service issued its 2022 All-Source RFPs.

36. On March 31, 2023, Public Service filed its "30-Day Report" describing bids received in response to its competitive bid solicitation.

37. On March 31, 2023, Public Service filed an unopposed motion to, among other things, extend by 50 days the time to file the 120-Day Report. By Decision No. C23-0246-I,²⁷ the Commission granted the Company's motion and extended the deadline for the 120-Day Report as well as all associated deadlines.

²⁵ Decision No. C21-0666-I, issued October 20, 2021.

²⁶ The Phase I Settlement was supported by the following parties: Public Service, Staff, UCA, CEO, RMELC and CBCTC, COSSA/SEIA, Pueblo County, Holy Cross, Pueblo City and Water, Walmart, Boulder, Denver, COGA, Local 111, the OJT, CIEA, Onward, Interwest, Conservation Coalition, and WRA.

²⁷ Issued on April 13, 2023.

38. On July 27, 2023, Public Service filed the Motion for Second Extension requesting an additional 24-day extension of time within which to file the 120-Day Report. By Decision No. C23-0522-I,²⁸ the Commission granted the Motion for Second Extension.

39. On September 5, 2023, Public Service together with the Independent Evaluator (IE) and Staff filed a Motion that requested a third extension of time for the Phase II deadlines. On September 5, 2023, various parties representing the interests of independent power producers (IPPs) filed a Response to the Joint Motion for Third Extension (Joint IPP Interests Response). The Joint IPP Interests Response was specifically filed by COSSA/SEIA, CIEA, and Interwest. These parties argued that the IPP projects will be prejudiced by the additional requested delay, which could postpone final decisions in this matter through March of 2023 to consider requests for rehearing, reargument, and reconsideration. By Decision No. C23-0594-I²⁹ and Decision No. C23-0647-I,³⁰ the Commission granted, in part, and denied, in part, the requested Phase II extensions. While the Commission recognized the significant complexity of this Phase II process relative to past ERPs, it agreed with other parties regarding the urgency of issuing a Phase II decision.

40. Ultimately, the Company filed the 120-Day Report on September 18, 2023, approximately 80 days after the Company was initially scheduled to file the 120-Day Report.³¹ Public Service would subsequently file corrections to the 120-Day Report on October 18, 2023.

²⁸ Issued on August 8, 2023.

²⁹ Issued September 7, 2023.

³⁰ Issued September 27, 2023.

³¹ The original deadline for the 120-Day Report was June 29, 2023. (Decision No. C23-0246-I, ¶ 4).

41. On October 5, 2023, the Commission issued Decision No. C23-0672-I, that required the Company, and invited other parties, to submit comments outlining a potential risk sharing mechanism for Company-owned generation.

42. On October 18, 2023, the Air Pollution Control Division of the CDPHE filed the Phase II Clean Energy Plan Verification Report.

43. On October 20, 2023, in response to Decision No. C23-0672-I, Public Service submitted a proposal for risk-sharing mechanisms regarding Company-owned generation resources. Staff similarly filed a proposal on October 20, 2023, which UCA and CEC joined.

44. On October 21, 2023, the IE filed its report (the IE Report).

45. On November 8, 2023, intervenor comments on the 120-Day Report were filed.

46. On November 20, 2023, Public Service filed its Response Comments to the 120-Day Report.

47. On December 6 and 13, 2023, the Commission commenced deliberations. On December 13, 2023, the Commission also issued Decision No. C23-0841-I, directing Public Service to set forth certain information related to the cost-to-construct performance incentive mechanism (PIM) and the operational PIM. In addition, we instructed the Company to consider and potentially refile the Highly Confidential Exhibit 1 to the Response to Decision No. C23-0672-I.

48. On December 19, 2023, Public Service filed its Response to Decision No. C23-0841-I, providing the specific information requested, and a corresponding narrative on the identified highly confidential document.

49. The Commission resumed deliberations on December 20, 2023, and concluded deliberations that same day.

50. In addition to the public comment hearings and written comments provided in Phase I, throughout Phase II of this Proceeding, the Commission received numerous written public comments that the Commission reviewed and retains in the administrative record.

C. Phase I Decision and Public Service CEP

51. In the Phase I Decision, the Commission set the framework in which Public Service may proceed to issue RFPs for an all-source, competitive bidding process to meet its resource need and advance its CEP toward final consideration and approval. The Commission's rulings on topics such as the Company's coal action plan, workforce transition and community assistance, best value employment metrics (BVEMs), and the CEPR paved the way for the development of a CEP in Phase II that complies with the requirements of SB 19-236 and advances the establishment of a bold clean energy policy for Colorado.

52. The following list summarizes the primary rulings the Commission made in its Phase I Decision that relate to the Company's CEP and the requirements of SB 19-236:

- a) Consistent with the Phase I Settlement, the resource acquisition period (RAP) for the Company's ERP/CEP extends through 2030 per § 40-2-125.5(4)(a)(I).
- b) Subject to certain exceptions, starting in 2024, the Company must retire all RECs in the year generated, per § 40-2-125.5(3)(a)(III).
- c) In the 120-Day Report, the Company will clearly distinguish between the set of resources necessary to meet customer demands in the resource acquisition period and the additional clean energy plan activities that may be undertaken to meet the clean energy target in § 40-2-125.5(3)(a)(I), per § 40-2-125.5(4)(a)(III).
- d) In the 120-Day Report, the Company will set forth the actions and investments required to meet the clean energy target of § 40-2-125.5(3)(a)(I).
- e) The Company will set forth a proposal for the CEPR as part of the 120-Day Report that enables us to consider the appropriate timing for Public Service to initiate the CEPR via an advice letter filing.
- f) The suite of portfolios the Company will present in the 120-Day Report will allow the Commission to evaluate whether the proposed level of utility ownership comes at a reasonable cost and rate impact per § 40-2-125.5(5)(b).

- g) Consistent with the Phase I Settlement, the 120-Day Report will include the information necessary for the Commission to consider BVEM in conjunction with our other Phase II decisions.
- h) The Company will include the projected costs of both workforce transition plans and community assistance plans in the Phase II modeling. The estimated cost of the community assistance aspect will be equal to projected lost property tax revenues for six years following retirement (or conversion) for Hayden 1 and Hayden 2, and Pawnee (the Brush Coal plant), respectively, and ten years for Pueblo Unit 3, and will be offset by any new investment in the respective community.³²
- i) Public Service will file post-Phase II updated Just Transition Plans (JTPs) for the Hayden coal plants, the Brush Coal Plant, and Pueblo Unit 3.³³ Regarding the Pueblo Unit 3 in particular, no later than June 1, 2024, Public Service will file a JTP that includes a standalone competitive solicitation. To the extent not otherwise addressed in the Phase I Settlement, this 2024 Just Transition Solicitation (the 2024 JTS) shall be treated as an interim ERP under Rule 3603(a). While the focus of the 2024 JTS is the replacement of Unit 3 and the Pueblo community, the 2024 JTS is not geographically limited to the Pueblo area nor is the resource need limited to replacing Unit 3.³⁴
- j) The Phase II modeling will allow the Commission to evaluate both the social cost of carbon (SCC) and the social cost of methane (SCM), consistent with the spirit of § 40-3.2-106.

53. In addition, the Phase I Decision ruled on such things as the provisions in the Company's model PPA, the inputs and assumptions to be used in the Phase II modeling, and the portfolios and sensitivities that the Company will present in the 120-Day Report.

D. Phase II Filings

1. 120-Day Report

54. The 120-Day Report summarizes the results of the Public Service's Phase II modeling and puts forth the Company's Preferred Portfolio for Commission approval. Under the Preferred Portfolio, the Company would move forward with developing numerous generation resources and associated transmission infrastructure. While the relevant details of the 120-Day

³² Phase I Settlement, pp. 18-19.

³³ Phase I Settlement, p. 19.

³⁴ Phase I Decision, pp. 40, 42; Phase I Settlement, pp. 27-31.

Report and the subsequent Updated Preferred Plan (UPP) will be discussed below, we highlight here some of the major components.

55. Public Service's Preferred Portfolio contains about half as much gas-fired generation resources as what the Phase I modeling predicted (628 MW versus 1,176 MW).³⁵ Conversely, the Preferred Portfolio adds almost twice as much renewable generation and six times as much storage as was anticipated in Phase I.³⁶ As to the storage specifically, Public Service states that the Preferred Portfolio takes advantage of the IRA tax benefits for storage, and uses storage to "effectively utilize otherwise curtailed renewable energy, provide critical ancillary services, and meet peak demand in the evenings when solar generation declines."³⁷

56. Regarding emissions reductions, Public Service estimates that the Preferred Portfolio will achieve 87.4 percent reduction in CO2 emissions by 2030—far exceeding the 80 percent clean air target.³⁸ Public Service acknowledges, however, that "in addition to all of the normal variance in forecasting, the modeling process itself leads to structural optimism in emissions reduction potential" and that "real time operations will likely have less optimistic results than those predicted by the models."³⁹ The Company states that it "believes we would likely achieve an 80%-85% reduction."⁴⁰

57. The emissions reductions are due largely to the Coal Action Plan and the renewable resources the Preferred Portfolio adds as replacement and new utility resources. Indeed, Public Service states that the Preferred Portfolio is "the largest portfolio ever advanced through the ERP

³⁵ 120-Day Report, p. 36.

³⁶ 120-Day Report, p. 36.

³⁷ 120-Day Report, p. 36.

³⁸ 120-Day Report, p. 38.

³⁹ 120-Day Report, p. 23.

⁴⁰ 120-Day Report, p. 24.

process.”⁴¹ Public Service estimates that through 2055 the Preferred Portfolio has a net present value (NPV) of approximately \$44.2 billion. Included in this total price is an estimated \$2.82 billion in transmission investments. By far the most significant portion of the total transmission investment is an estimated \$2.2 billion needed for Denver Metro Transmission Network Upgrades.⁴²

58. The Preferred Portfolio includes higher levels of Company-owned resources compared to past ERPs. Out of the 7,192 MW of nameplate capacity additions that would be acquired under the Preferred Portfolio, Public Service would own 66.6 percent of the capacity and 69.7 percent of the energy. The Company argues that the higher ownership percentage is a direct result of the more equitable tax credit policy for clean energy resulting from the historic IRA.⁴³

2. CDPHE Verification

59. On October 18, 2023, CDPHE filed the Phase II CEP Verification Report. In its Verification Report, CDPHE opines that the GHG emissions reduction calculations for each portfolio submitted in this Phase II of Proceeding No. 21A-0141E are expected to be 80 percent or more below 2005 baseline levels. CDPHE further states that the portfolios “would be expected to achieve the minimum percent reduction levels required by the statutes for the CEP and Safe Harbor.”⁴⁴

60. In its Phase II CEP Verification Report, CDPHE lists the expected 2030 emissions reductions for each of the submitted portfolios. Of note, the expected emissions reductions for the Preferred Portfolio is 87 percent.⁴⁵

⁴¹ 120-Day Report, p. 22.

⁴² 120-Day Report, p. 130.

⁴³ 120-Day Report, p. 40-41.

⁴⁴ CDPHE Phase II CEP Verification Report, p. 6.

⁴⁵ CDPHE Phase II CEP Verification, pp. 4-6.

3. IE Report

61. On October 21, 2023, the IE filed its Report in this Proceeding. In its Report, the IE attests that the Phase II process was conducted fairly and without bias. The IE states: “The IE can attest to the results of the evaluation and fidelity to the protocols and that the Phase I assumptions were used in evaluation. The IE also was unable to identify any bias towards or against any technology or respondent, including the options presented for the [Public Service] self-owned assets.”⁴⁶

62. That said, the IE also raised several recommendations for future ERP proceedings that the IE asserts will allow the process to better accommodate the large number of bids and increasing reliance on renewable resources. For example, the IE states that “inadequate time was allotted for the transmission analysis” and suggests changes going forward that allow for a better understanding of the transmission requirements associated with the proposed generation projects.⁴⁷

4. Intervenor Comments

63. Numerous intervenors submitted comments on the 120-Day Report, including Staff, CEO, the UCA, CEC, CIEA, COSSA/SEIA, Interwest, WRA, the Conservation Coalition, Boulder, CRES, the OJT, and the Labor Interests.

64. Several parties, such as CEO, WRA, CRES, and Conservation Coalition, cite concerns with the Phase II modeling process and recommend selecting an alternative portfolio with fewer gas resources or simply removing some or all of the gas resources from the Preferred Portfolio.⁴⁸ Conversely, UCA argues that the Phase II modeling shows that eliminating gas-fired

⁴⁶ IE Report, p. 35.

⁴⁷ See IE Report, p. 37.

⁴⁸ CEO’s Comments, pp. 13-14; WRA’s Comments, pp. 15-17; CRES’s Comments, p. 2; Conservation Coalition’s Comments, pp. 12-13.

capacity is extremely expensive.⁴⁹ CEC similarly argues that the Commission should approve a less-costly portfolio that meets but does not greatly exceed the required emissions reductions.⁵⁰

65. Some parties, including Boulder and UCA, suggest that the existing resources in the Preferred Portfolio could be replaced with other resources that they perceive to be lower-priced.⁵¹

66. Other parties representing IPP interests, like CIEA, argue that the Commission should choose an alternative portfolio that better balances how many resources will be owned by Public Service versus IPPs.⁵² Conversely, the Labor Interests argue that there is a positive relationship between portfolios with high BVEM and portfolios with high Company-ownership numbers.⁵³

67. At a high level, the parties have mixed opinions regarding the transmission investments presented in the 120-Day Report—some raise serious concerns while others argue the Commission should approve and expedite the transmission. Likewise, several parties raise cost and emissions concerns about the Hayden Biomass project, while other parties argue that the project should be included in any approved portfolio.

68. Out of the intervenors that filed comments, it appears that the Labor Interests, COSSA/SEIA, the OJT, and Pueblo County, do not oppose adoption of the Preferred Portfolio as presented.⁵⁴

⁴⁹ UCA's Comments, p. 17.

⁵⁰ CEC's Comments, pp. 12-13.

⁵¹ See UCA's Comments, pp. 20-24; Boulder's Comments, pp. 14-15.

⁵² CIEA's Comments, pp. 12-15.

⁵³ Labor Interests' Comments, pp. 2.

⁵⁴ See, e.g., Labor Interests' Comments, pp. 2; COSSA/SEIA's Comments, pp. 1-2.

69. For its part, Staff raises concerns that Public Service's Preferred Portfolio is too aggressive, too costly, and not well supported. Staff states that the Preferred Portfolio contains unexpectedly large generation and transmission investments and high levels of expected curtailments that together could lead to potentially large rate impacts for customers.⁵⁵ Staff encourages the Commission to consider selecting one of five smaller portfolios that would reduce expected curtailments, enable the Commission to defer some of the proposed projects, and to further analyze alternatives for the proposed transmission investments.

5. Comments from the Northern Cheyenne Nation

70. At the CWM on October 25, 2023, William Walksalong presented comments on behalf of the Northern Cheyenne Nation regarding the potential impacts to the Sand Creek Massacre National Historic Site. As described more below, tribal leaders urged the Commission to protect the Sand Creek Massacre National Historic Site as sacred grounds and its view shed from the encroachment of energy development.

6. Public Comments

71. After Public Service filed the 120-Day Report, the Commission received numerous public comments. Many of these public comments argue against the Preferred Portfolio's inclusion of three new-build gas facilities that Public Service would own. At a high level, these comments urge the Commission to reject the new natural gas plants, citing concerns regarding stranded costs, climate change, and air pollution. The Commission also received more substantive public comments from Leslie Glustrom, Advanced Energy United, Sustainable Resilient Longmont, and 350 Colorado that similarly argue for modifications to the Preferred Portfolio, including not approving the proposed gas facilities in the Preferred Portfolio.

⁵⁵ Staff's Comments, pp. 5-7.

72. In addition, the Commission received several comments from organizations and local governments like Upstate Colorado, Alamosa County, the City of Alamosa, Kiowa County, Prowers County, Baca County, and Pueblo County that support the Preferred Portfolio on the basis of emissions reductions and economic development. Of these supportive comments, several public comments specifically support the inclusion of the Hayden Biomass facility in the Preferred Portfolio, arguing that it will provide important economic benefits to Moffat and Routt Counties, which will be impacted by the closure of coal-fired power plants. Northwest Colorado Development Council, Routt County, Colorado State Senator Dylan Roberts, and the Town Council and Mayor of Hayden are some of the entities that submitted these types of comments specifically addressing the Hayden Biomass facility.

73. Since the Commission had its initial Phase II deliberations on December 6, 2023, we have continued to receive and review numerous public comments. At a high level, the majority of these most recent public comments urge the Commission to select a resource portfolio with fewer or no gas resources on the basis of climate change, air pollution, price volatility for natural gas, or concerns that the resources will become stranded. Several of the public commenters argue that the Alternative Portfolio is more expensive on a dollar per MW basis than the Company's UPP.

7. Public Service's Response Comments and the UPP

74. In its Response Comments, Public Service responds to criticisms and concerns raised by intervenors and public commentators and presents an UPP that modifies a few of the proposed generation projects. Aside from the modifications to a few of the generation projects, however, the Company largely maintains its initial position in the 120-Day Report.

75. For example, in response to arguments that the Commission should reduce or eliminate the amount of gas resources included in the portfolio, Public Service asserts that—due to reliability concerns—the Company “cannot become comfortable with any level of reduction in dispatchable resources.”⁵⁶ Public Service argues that adjusting the portfolio by eliminating gas units or using questionable short-term power purchase agreement (PPA) extensions makes the portfolio less reliable and the Company “cannot compromise on reliability.”⁵⁷

76. As for arguments that the UPP has too many utility-owned resources or is too large, the Company argues that all of the selected clean energy projects are either build-own-transfer, PPA, or were purchased from IPPs by the Company earlier in the commercial lifecycle. Public Service agrees that the UPP is large but asserts that the size of the portfolio is ultimately driven by economics and state energy policy goals.⁵⁸

77. Turning to the concerns raised about the approximately \$2.8 billion in transmission investments, Public Service states that the ultimate decision before the Commission is approval of a generation portfolio and that “approval of a resource portfolio does not constitute a final approval of the transmission projects presented in the 120-Day Report.”⁵⁹ Public Service maintains, however, that to achieve the State’s emissions reduction goals, the Company must begin moving forward with the transmission investments needed to support the CEP.⁶⁰

78. As for the proposed resource modifications under the UPP, in response to concerns that Bid 1029 could impact the Sand Creek Massacre National Historic Site due to its proximity, in the UPP, Public Service recommends that the Commission approve a specific backup bid for

⁵⁶ Public Service’s Response Comments, p. 29.

⁵⁷ Public Service’s Response Comments, pp. 27-29.

⁵⁸ Public Service’s Response Comments, pp. 33-34.

⁵⁹ Public Service’s Response Comments, p. 66.

⁶⁰ Public Service’s Response Comments, p. 65.

Bid 1029 while still allowing Bid 1029 to move forward. Similarly, the Company proposes that the Commission conditionally approve the Hayden Biomass project but further analyze the costs, emissions reductions, workforce and community benefits, tax benefits, and viable alternatives in a follow-on CPCN proceeding.⁶¹

79. The Company proposes a few other changes to the resources in the UPP, but the suggested changes result from problems with the original resources as opposed to intervenor concerns.⁶²

80. As compared to the Preferred Portfolio, the UPP adds 329 MW of nameplate capacity. This increase is comprised of an additional 101 MW of solar resources and an additional 228 MW of additional wind resources. The UPP is also \$288 million more expensive on a present value revenue require (PVRR) basis.⁶³ Regarding the price increase, Public Service asserts that the \$288 million increase is caused by unavoidable changes to bids that appear in virtually all portfolios. Thus, the Company asserts that all of the other portfolios would increase by the same amount, meaning there is little to no impact on the differences between plans.⁶⁴ The percentage of resources that the Company would own decreases slightly in the UPP from 66.6 percent of capacity to 62.7 percent.⁶⁵

E. Modification of the CEP's Resource Portfolio

81. As described above, the statute prescribes when the Commission must approve a CEP and when the Commission may modify the CEP. Specifically, the Commission may modify the plan if the modification is necessary to ensure the plan is in the public interest. In evaluating

⁶¹ Public Service's Response Comments, pp. 19-20.

⁶² Public Service's Response Comments, pp. 18-24.

⁶³ Public Service's Response Comments, p. 9.

⁶⁴ Public Service's Response Comments, p. 9.

⁶⁵ Public Service's Response Comments, p. 9.

whether a CEP submitted to the Commission is in the public interest, the Commission shall consider (1) emissions reductions, (2) the CEP’s impact on reliability and resilience of the electric system,⁶⁶ and (3) the cost of the CEP on a NPV basis. The statute also permits the Commission to consider “other relevant factors.”

82. A CEP includes “clean energy plan activities that may be undertaken to meet the clean energy target... which may create an additional resource need for the [CEP].”⁶⁷ Public Service’s CEP is thus comprised of several components, including the Coal Action Plan, the workforce transition and community assistance plans,⁶⁸ and the “investments required to fill the additional resource need,”⁶⁹ (*i.e.*, the portfolio of resources procured through the competitive solicitation). In this Proceeding, significant clean energy plan activities involve the conversion of the Brush plant from coal to gas and the lower capacity values of Pueblo Unit 3.⁷⁰ The UPP represents a portion of Public Service’s CEP as proposed by the Company.

83. Given that the Company’s preferred resource portfolio comprises a portion of the total CEP, the selection of an alternative resource portfolio does not replace the overall CEP. Because the Commission maintains the other important elements of the CEP—like the Coal Action Plan—the selection of an alternative portfolio is a modification to the overall CEP.

84. While the Commission recognizes that Company proposals in Phase I and II in this Proceeding have made progress towards Colorado’s energy transition, there are significant

⁶⁶ The statute makes clear that the Commission “shall not approve a plan that does not protect system reliability.” (§ 40-2-125.5(4)(d)(III), C.R.S.)

⁶⁷ § 40-2-125.5(4)(a)(III), C.R.S.

⁶⁸ § 40-2-125.5(4)(a)(VII), C.R.S.

⁶⁹ § 40-2-125.5(4)(a)(IV), C.R.S.

⁷⁰ Although the Coal Action Plan includes the early retirement of the Hayden and Craig coal plants, the coal actions are not technically part of the CEP because they are also included in the reference ERP portfolio.

concerns raised by parties and public commenters regarding the UPP.⁷¹ For instance, Staff argues that given the large price tag of the Preferred Portfolio as well as the concerns Staff has about the Phase II modeling process, the Commission should reduce the size of the resource portfolio or delay decisions until further analysis and support can be provided.⁷² Regarding its modeling concerns, Staff notes that Public Service's decision to increase the generic price of most renewables for years 2029 and 2030 might be causing the model to over-value acquisitions in the near-term.⁷³ Similarly, the reliability rubric the Company implemented in Phase II arguably prohibited the model from "backsliding" or removing resources after dispatchable resources were added. Staff states that the reliability rubric "introduced constraints into the capacity expansion step that fundamentally render the process suboptimal as it is no longer able to truly optimize the portfolio."⁷⁴ Staff goes on to suggest that the reliability rubric's constraints made the Commission-ordered demand response sensitivity ineffective.⁷⁵

85. In addition, Staff notes that the Preferred Portfolio likely fails to account for high levels of curtailment and the resulting increase in costs and emissions. Staff argues that the model likely fails to capture significant levels of curtailments for several reasons, including the model's limitations regarding simplified commitment logic and the inability to capture curtailments from perturbations in the system as well as the timing mismatch between when generation will come online and when the transmission will be ready to serve the new generation. Staff ultimately concludes that the "the level and costs of curtailments portrayed by the model cannot be trusted"

⁷¹ Because Public Service presented the UPP after intervenors submitted their Comments on the 120-Day Report, intervenors address the Preferred Portfolio rather than the UPP. The differences between the UPP and the Preferred Portfolio, however, are largely immaterial as to the concerns that the intervenors raise.

⁷² Staff's Comments, p. 6.

⁷³ Staff's Comments, p. 28.

⁷⁴ Staff's Comments, p. 30.

⁷⁵ Staff's Comments, pp. 34-35.

and that the Preferred Plan “may saddle customers with extra costs for renewable energy that does not reduce emissions because it is never delivered.”⁷⁶ In contrast, Staff notes that other portfolios presented in the 120-Day Report achieve comparable levels of emission reductions with much lower levels of curtailments and higher levels of storage.⁷⁷

86. UCA also criticizes the Phase II modeling process and is especially critical of the May Valley Longhorn Extension (MVLE) and the most expensive part of the Denver Metro Area transmission upgrades—the Harvest Mile Chambers-Sandown-Cherokee (HCSC) project. UCA recommends that the Commission reject the HCSC, the MVLE, and the wind projects that UCA argues necessitate the transmission projects.⁷⁸

87. Other parties, such as Conservation Coalition and CRES argue that the Commission should not approve any of the gas resources in the Preferred Portfolio.⁷⁹ CEO similarly recommends the Commission not approve 200 MW of the 628 MW of gas included in the Preferred Portfolio. CEO argues that it is unclear whether an additional 200 MW of new gas generation will actually be necessary and recommends that the Commission address this proposed new gas in future ERPs, including the 2024 JTS and the 2026 ERP.⁸⁰ WRA suggests that the Commission select the lower dispatchable portfolio, which has 504 MW of new gas generation—124 MW less than the Preferred Portfolio.⁸¹ WRA also suggests modifying the Preferred Portfolio by reducing reliance on new construction and instead utilizing available existing generation.⁸²

⁷⁶ Staff’s Comments, pp. 31-32, 34.

⁷⁷ Staff’s Comments, p. 32.

⁷⁸ See UCA’s Comments, pp. 29-30.

⁷⁹ Conservation Coalition’s Comments, p. 10; CRES’s Comments, p. 2. Relatedly, the Commission has received numerous public comments urging the Commission to select a resource portfolio with fewer or no gas resources on the basis of climate change, air pollution, price volatility, or concerns that the resources will become stranded.

⁸⁰ CEO’s Comments, p. 14.

⁸¹ WRA’s Comments, pp. 15-16.

⁸² WRA’s Comments, pp. 16-17.

88. CIEA raises several concerns with the Phase II modeling, arguing that the Company used a heavy-handed approach to manipulate the model.⁸³ Many of CIEA's recommendations are aimed at the goal of achieving a higher proportion of PPA resources in the Company's resource mix—both in this Proceeding and in future ERPs. CIEA asserts there have been “huge project cost overruns at the [Company-owned] Cabin Creek, Comanche, and Pawnee stations” and that customers are seeing less value than anticipated from two Company-owned wind projects.⁸⁴ CIEA argues that given the high percentage of Company-owned projects in the Preferred Portfolio, Public Service might be biting off more than it can chew.⁸⁵ CIEA reasons that PPA resources can help insulate ratepayers from both capital cost overruns and performance issues with generators. Noting that all of the gas resources in the Preferred Portfolio would be owned by Public Service, CIEA recommends that the Commission select an alternative resource portfolio that replaces some of the Company-owned gas-fired projects with existing PPA gas resources.⁸⁶ CIEA argues that PPA resources “should be at least 50% of Public Service's resource mix to balance ratepayer and shareholder risks.”⁸⁷

89. CEC argues that there are too many red flags and unknowns for this Commission to approve the Preferred Portfolio as presented. CEC notes that Preferred Portfolio will far exceed the clean air targets established by SB 19-236 and argues that the Commission should not approve a plan that goes “above and beyond” statutory requirements to the detriment of customers, particularly given the current affordability concerns.⁸⁸ For instance, CEC notes that the Preferred

⁸³ CIEA's Comments, pp. 26-28.

⁸⁴ CIEA's Comments, p. 13.

⁸⁵ CIEA's Comments, pp. 9-10.

⁸⁶ CIEA's Comments, pp. 16-18.

⁸⁷ CIEA's Comments, pp. 13-15.

⁸⁸ CEC's Comments, pp. 12-13.

Portfolio is approximately \$600 million more expensive than the \$0CO₂ Least Cost Plan, and the \$0CO₂ Least Cost Plan still exceeds SB19-236 bold emission reduction targets.⁸⁹

90. Given these concerns, and considering the record as a whole, we find that modification of the CEP in the selection of an alternative portfolio is necessary to ensure the plan is in public interest based on the three enumerated statutory factors as well as “other relevant factors” that the Commission defines.

91. As noted above, Staff recommends for several reasons that the Commission focus its consideration on five “portfolios of interest.”⁹⁰ We agree with Staff and, consistent with the discussion below, determine that the Inverse 1324 (\$0CO₂) Plan best represents an “Alternative Portfolio” that incorporates the necessary modifications to Public Service’s CEP to support the public interest findings required by SB 19-236.

92. Compared to the Preferred Portfolio set forth in the 120-Day Report, the Alternative Portfolio has 1,338 MW lower nameplate additions (7,192 MW – 5,854 MW). More specifically, the Alternative Portfolio has 19 MW fewer biomass, 41 MW more gas resources, 350 MW fewer solar resources, and 1,706 MW fewer wind resources. However, the Alternative Portfolio has 678 MW more storage resources.⁹¹ The Alternative Portfolio also requires fewer transmission investments and is \$194 million less expensive on a NPV basis. Regarding curtailments, the Phase II report suggests that in 2028 the Alternative Portfolio will result in 1,629 GWh of modelled curtailments, compared to 5,433 GWh of modelled curtailments in the Preferred Portfolio.⁹² Moreover, the Company states in its Phase II Report that the modelled curtailment is the “best

⁸⁹ CEC’s Comments, pp. 12-13.

⁹⁰ Staff’s Comments, p. 11.

⁹¹ See Staff’s Comments, p. 49.

⁹² See Staff’s Comments, p. 49.

possible case scenario [rather] than a realistic expectation of [the curtailment level that]...would occur in real-time operations.”⁹³ This uncertainty over actual curtailment levels further supports the more cautious approach taken with the Alternative Portfolio.

93. In addition, unlike three of the five portfolios of interest, the Alternative Portfolio was included in the 120-Day Report and thus was reviewed by the IE and CDPHE. As noted by Staff and confirmed by CDPHE, the emissions reductions resulting from the Alternative Portfolio exceed the 2030 greenhouse gas reduction targets. While the Alternative Portfolio has somewhat lower interim emissions reductions compared to the Preferred Portfolio, consistent with the Company’s statements that the modeling does not capture curtailments resulting from transmission congestion and other perturbations in the system, Staff argues that it is unclear that the higher emissions reductions in the Preferred Portfolio “would bare out in reality” given the concerns regarding curtailments and the deliverability of the renewable energy.⁹⁴

94. Moreover, the smaller size of the Alternative Portfolio addresses concerns raised by Staff and others that the Preferred Portfolio is too large due to factors such as the repricing of generic resources in the Phase II modeling and the no “backsliding” component of the Reliability Rubric modeling. Likewise, the smaller size ameliorates Staff’s concerns about new generation coming online before the 2029/2030 in service date (ISD) for major transmission projects that Public Service indicates are necessary to take full advantage of the renewable resources.⁹⁵ Finally, the Alternative Portfolio reduces the Company’s ownership percentage so that it is expected to be

⁹³ See 120-Day Report, at p. 95.

⁹⁴ Staff’s Comments, p. 63.

⁹⁵ Staff’s Comments, p. 61.

closer to the 50 percent IPP and 50 percent PPA statutory expectations.⁹⁶ Given the Company's significant upcoming investments in transmission through the Colorado Power Pathway and issues identified by intervenors of the Company's struggles to adhere to project budgets and timelines in different instances, a better balance between Company and IPP ownership presents an opportunity to decrease the risk of performance issues by a single entity impacting overall performance of the CEP.

95. Considering the statutory factors and additional public interest considerations raised in comments by parties and the public, based on this record and supported by party filings, we find that the Alternative Portfolio better aligns with Colorado's multi-faceted goals to achieve significant emission reductions and progress towards 100 percent emission reductions in the future, all while ensuring reliability and protecting affordability for ratepayers. Addressing specific factors below—and as supported by policy direction throughout our Phase II Decision that also includes PIMs and directives for the 2024 JTS—we find that modification of the CEP to include the Alternative Portfolio is necessary to ensure the CEP is in the public interest.

1. Emission Reductions

96. The statute requires the Commission to consider the emissions reductions associated with the CEP. Because the Alternative Portfolio is included in the 120-Day Report, CDPHE evaluated it along with all of the other Phase II portfolios in the Phase II Clean Energy Plan Verification Report. CDPHE opines that the emissions reduction calculations for each of the Phase II portfolios are expected to be 80 percent or more below 2005 baseline levels.

⁹⁶ To be clear, the Commission does not find that SB 19-236 in any way sets a floor or a ceiling for Company-ownership. The Commission does, however, find persuasive arguments from CIEA and others that more balanced levels of PPA and Company-owned resources help insulate ratepayers from potential cost overruns and performance issues.

Regarding the Alternative Portfolio in particular, CDPHE estimates that the expected 2030 emissions reductions will be 86 percent by 2030.⁹⁷ Thus, the Alternative Portfolio is expected to exceed the 80 percent emissions reductions set forth in the statute and makes progress towards achieving the goal of 100 percent clean energy resources by 2050.

97. As presented in the Phase II modeling, the UPP arguably achieves slightly greater emissions reductions, especially in the interim years prior to 2030. However, Public Service admits that these emissions reductions estimates are optimistic and that the model does not include curtailments caused by transmission congestion or perturbations in the system.⁹⁸ Thus, it is questionable how accurate these emissions reductions predictions are, especially in the interim years before Public Service has finished building the transmission upgrades the Company states are necessary to reliably deliver power.⁹⁹ In other words, these modeled interim emissions reductions are unlikely to materialize if Public Service cannot construct the majority of the associated transmission investments until 2030.¹⁰⁰ Moreover, it is these same transmission upgrades that resulted in the \$2.2 billion “surprise” in Phase II, as discussed more below. We find it unsettling to rely on predictions that are speculative, at best, on transmission availability in the UPP that result in the seemingly higher emissions reductions. Given that the transmission modeling results changed dramatically between Phase I and II with costs escalating billions of dollars beyond the Company’s initial estimates, we cannot depend on emission reduction predictions tied explicitly to those same transmission needs.

98. Throughout this Proceeding and in selecting the Alternative Portfolio, the Commission has considered the PVRR of both the social cost of carbon (SCC) and the social cost

⁹⁷ CDPHE Phase II CEP Verification, pp. 4-6.

⁹⁸ 120-Day Report, p. 95.

⁹⁹ 120-Day Report, pp. 130-133.

¹⁰⁰ See Staff’s Comments, pp. 43-44 (citing Appendix Q to the 120-Day Report).

of methane (SCM), which also helps in our considerations on emission reductions. The Alternative Portfolio significantly reduces the SCC and SCM compared to Public Service's ERP or business-as-usual portfolio.¹⁰¹ For the capacity expansion phase of the modeling, the Alternative Portfolio does not include the social cost of emissions.¹⁰² Post-modeling, however, in the 120-Day Report the SCC and SCM associated with the Alternative Portfolio are both presented.¹⁰³ Moreover, the Coal Action Plan, which is critical to emissions reductions, is hardwired into the Alternative Portfolio. While there are other portfolios that have still greater reductions in SCC and SCM, notwithstanding the uncertainties around curtailment impacts to those figures, the Alternative Portfolio exceeds the 80 percent emissions reductions set forth in the statute while balancing other factors such as costs, reliability, and future optionality.

99. While the Alternative Portfolio—like other portfolios the Company claims protect reliability¹⁰⁴—includes over 600 MW of gas resources, these gas resources do not impede Colorado's emissions reductions goals. Rather, the new gas resources are all equipped with both fast start and fast shutdown capability, which allows the units to sit idle most of the time while providing essential operating reserves and ancillary services.¹⁰⁵ The Commission reluctantly recognizes that there does not appear to be a path forward that excludes or significantly reduces the need for new gas resources, given the Company's repeated assertions that it cannot support any reduction in gas resources based on the Company's reliability analysis¹⁰⁶ and the lack of modeling demonstrating the contrary within the record.

¹⁰¹ 120-Day Report (Appendix S) Rev. 1, pp. 1, 26.

¹⁰² 120-Day Report, p. 97.

¹⁰³ 120-Day Report (Appendix S) Rev. 1, p. 26.

¹⁰⁴ Public Service argues that the No New Gas and No Gas Portfolios are not reliable. The Lower Dispatchable portfolio includes somewhat fewer gas resources (504 MW), but the Company has raised reliability concerns with this portfolio as well. (Public Service's Response Comments, pp. 29-30).

¹⁰⁵ 120-Day Report, pp. 80-81, 126.

¹⁰⁶ Public Service Response Comments, p.29

100. Moreover, as discussed more below, rather than simply eliminating 200 MW of gas-fired resources as argued by some parties and sacrificing reliability, the Alternative Portfolio reduces the amount of Company-owned gas resources, increasing the Company's ability to fully transition away from carbon emitting resources as we approach 2050 and reducing risk of stranded assets to ratepayers. This reduction in Company ownership provides continued opportunities to further accelerate towards 100 percent renewable resources by not tying the Company – and Colorado – to the full amount of utility-owned gas-fired resources presented in the UPP.

101. Under SB 19-236, the CEP must achieve 80 percent emissions reductions by 2030 while working towards 100 percent clean energy by 2050, and the Commission must consider reliability and affordability when determining whether the CEP is in the public interest. The Alternative Portfolio with its 669 MW of gas resources provides this balanced, transitional plan that SB 19-236 contemplates. Even though the gas resources will be run infrequently with the vast majority of the energy coming from wind and solar resources, the units provide an important insurance policy during sustained periods of hot or cold weather – including in extreme circumstances given the realities of climate change.¹⁰⁷ Providing this backup option and permitting the integration of substantial additions of new clean energy resources allows Public Service to retire its remaining coal plants and several of its older gas units.¹⁰⁸

102. In sum, when considering emission reductions, the Alternative Portfolio exceeds Colorado's ambitious emission reduction goals, sets the state towards a path for 100 percent renewable resources, all while continuing to avoid extreme costs and outages.

¹⁰⁷ 120-Day Report, pp. 22-23, 80-81.

¹⁰⁸ 120-Day Report, pp. 22-23, 80-81.

2. Reasonable Cost to Customers

103. The statute requires the Commission consider if the CEP will result in a reasonable cost to customers on an NPV basis. The NPV of the UPP is \$44,479 million while the NPV of the Alternative Portfolio as presented is \$43,997 million.¹⁰⁹ However, in its Response Comments, Public Service states that the \$288 million NPV increase from the Preferred Portfolio to the UPP is a result of unavoidable changes that would appear in virtually all portfolios.¹¹⁰ Assuming that the same incremental change appears in the Alternative Portfolio, the updated NPV of the Alternative Portfolio is \$44,285 million ($\$43,997 + \$288 = \$44,285$). Even using this updated NPV, the Alternative Portfolio is \$194 million less expensive than the UPP ($\$44,479 - \$44,285 = \$194$).

104. While the Alternative Portfolio is preferable to customers on an NPV basis as contemplated in SB 19-236, another relevant factor the Commission must consider is the cost to customers as experienced through increased rates. Intervenor such as Staff, UCA, and CEC have raised alarms regarding the Preferred Portfolio's impact on rates. For instance, Staff states that the rate increase attributable to the Preferred Portfolio for the single year from 2026 to 2027 is just over 10 percent.¹¹¹ As discussed more below, the rate analysis the Company provides in the 120-Day Report only includes the impact of the CEP and fails to include other planned investments such as \$4.5 billion in projected distribution investments through 2028, an additional \$800 million in generation projects outside of the CEP, as well as investments in wildfire mitigation, transportation electrification, distributed solar, and others.¹¹² Staff asserts that the impact of real time operations, construction schedules, system curtailments, and other factors will likely result in

¹⁰⁹ Public Service's Response Comments, p. 9; 120-Day Report (Appendix S) Rev. 1, p. 26.

¹¹⁰ Public Service's Response Comments, p. 9.

¹¹¹ Staff's Comments, p. 19.

¹¹² See Staff's Comments, p. 19.

higher rate impacts than the Company's calculations suggest.¹¹³ Given the importance of maintaining affordability, the Commission must consider these costs to customers more generally and not limit our consideration to the NPV comparison of the various resource portfolios.

105. An example of a cost to customers that does not explicitly appear in the NPV considerations is the likely cost of curtailments that the modeling fails to capture. Although the NPV estimates do include the costs of curtailments included in the modeling, the Company admits as discussed above that the model's curtailment forecasting is "more a 'best possible case scenario' than a realistic expectation of what would occur in real time operations."¹¹⁴ Public Service notes that "a large percentage of curtailment" is caused by perturbations in the system from transmission issues or reliability events and that these curtailments "are not captured in the model."¹¹⁵ The curtailments resulting from transmission issues are especially concerning given that under the UPP the Company will be connecting vast amounts of new renewable generation years before most of the associated transmission upgrades can be constructed.¹¹⁶ The Company indicates that while the transmission investments are being built, Public Service will maintain reliable service using tools such as curtailments and redispatch.¹¹⁷ Thus, the NPV calculations do not reflect significant amounts of curtailments that the modeling fails to capture, but these missing curtailments will result in additional costs that customers must pay.

106. The Alternative Portfolio cuts modeled curtailments from 15 percent in the UPP to 5 percent,¹¹⁸ and curtailments that the model does not capture will likely also be reduced due to a decreased reliance on yet-to-be-built transmission and an increased investment in storage. By way

¹¹³ Staff's Comments, p. 19.

¹¹⁴ 120-Day Report, p. 95.

¹¹⁵ 120-Day Report, p. 95.

¹¹⁶ See Staff's Comments, pp. 43-44.

¹¹⁷ 120-Day Report, p. 134.

¹¹⁸ See Staff's Comments, p. 49.

of analogy, Public Service predicts that the UPP will have 6,043 GWh of curtailments in 2028,¹¹⁹ but the Alternative Portfolio is only predicted to have 1,629 GWh of curtailments in 2028.¹²⁰ It is reasonable to assume that curtailments that the model fails to capture will follow similar trajectories resulting in significant additional costs savings in the Alternative Portfolio.

107. Put simply, the Alternative Portfolio will achieve the state's ambitious clean energy targets while mitigating the risk that ratepayers will be required to pay for resources that have less incremental value because they are significantly curtailed.

108. Another category of costs that does not appear in the NPV calculations are the potential costs associated with Company-owned gas generation assets, including construction and operational cost overruns, decommissioning costs, and the potential that the gas resources will become stranded. On this last point, several parties including UCA, WRA, Conservation Coalition, and Boulder, as well as numerous public comments, raised concerns that the new gas resources will become stranded assets. The Alternative Portfolio is again preferable to the UPP in this regard because it contains a substantial decrease in Company-ownership of new gas capacity. Specifically, the UPP contains 628 MW of new build gas resources, all of which are Company-owned.¹²¹ The Alternative Portfolio contains 669 MW of new build gas resources, but of this 669 MW, 219 MW is a PPA resource with a 20-year term.¹²² By diversifying the ownership of the gas resources, the Alternative Portfolio reduces the risks that customers will be saddled with future costs associated with Company-owned gas resources.

¹¹⁹ Public Service's Response Comments, Attachment 2, p. 1.

¹²⁰ 120 Day Report (Appendix T), p. 23.

¹²¹ Public Service's Response Comment, p. 9.

¹²² 120-Day Report (Appendix S) Rev. 1, p. 26.

109. Finally, yet another cost that is not included in the NPV estimates is the risk that a larger, more sprawling resource portfolio like the UPP will eliminate opportunities to take advantage of future technology developments or reductions in price in some of the newer technologies. As discussed more below, acquiring a smaller portfolio of resources in this Proceeding creates more optionality in future proceedings for efficiencies and cost savings, including through a more robust use of demand side resources. In other words, the Alternative Portfolio reduces the risk that customers will pay for generation and transmission resources that could have been avoided through better use of developing technologies.

110. As we consider costs, we believe that least-cost options presented in the Phase II report may be unworkable for Colorado. We find unpersuasive arguments raised during Phase II that the Commission should select the Least Cost Portfolio. While the Least Cost Portfolio is slightly less expensive on a NPV basis than the Alternative Portfolio,¹²³ the Company has raised reliability concerns with the portfolio because it does not include the strategically located gas resources the Company asserts are necessary for transmission support.¹²⁴

111. Similarly, we reject arguments that selecting a larger portfolio to reduce emissions at any cost is appropriate. It is critical that we examine costs and emissions together, and in conjunction with reliability as required by statute. Not only is the diverse technical makeup of the Alternative Portfolio needed for the reliability needs raised by the Company and discussed more below, but because of the increase in storage in the Alternative Portfolio, modifying the CEP to move forward with this portfolio also allows further development with not only load but storage capacity that could help increase efficiencies and reduce costs in the future. In addition,

¹²³ The Least Cost Portfolio has a PVRR of \$43,984 million, which is \$13 million less than the Alternative Portfolio's PVRR or 43,9997. (120-Day Report, p. 38; 120-Day Report (Appendix S) Rev. 1, p. 26).

¹²⁴ 120-Day Report, pp. 39-40; Public Service's Response Comments, p. 29.

overinvesting in the system could price electricity out of competition with other fuels, jeopardizing beneficial electrification efforts.¹²⁵ To help ensure that Colorado can continue to decarbonize all sectors of the economy—many parts of which will rely on the electrical system as the backbone of the transition—it is essential to provide electrical service at a reasonable cost and rate impact.

112. Finally, CRES and certain public commentors note that Public Service’s NPV cost numbers were calculated using the Company’s weighted average cost of capital (WACC) as the discount rate, and they urge the Commission to use a lower discount rate. CRES argues that using the WACC as the discount rate will have the effect of discounting future fuel and other costs sharply. Moreover, CRES states that in enacting SB 23-291, the legislature has directed the Commission in C.R.S. § 40-2-139 to use a discount rate for future fuel costs that does not exceed the long-term rate of inflation. CRES recommends that the Commission direct the Company to resubmit the NPV values in accordance with what is now Colorado law.¹²⁶

113. We note that the appropriate use of discount rates was litigated in Phase I. The Phase I Decision put forward a compromise to help mitigate the substantive concerns raised by CRES, requiring Public Service to provide in Phase II the annual nominal cash flows associated with each portfolio so that the parties and the Commission could calculate the NPV calculation using various discount rates.¹²⁷ As such, this Commission believes it is important to understand the potential cost and other resource choice impacts that might occur at lower discount rates, but

¹²⁵ Numerous public commenters argue that the Alternative Portfolio is more expensive than the UPP on a dollars per MW basis. This argument only looks at the nameplate capacity of the respective portfolios and does not account for important distinctions in how different resources contribute to the electrical system. For example, a 300 MW solar facility will be of no value to the electrical system after the sun sets. A 300 MW solar plus storage facility, however, is able to help serve load after the sun sets and, in this way, can be more useful to the electrical system, even though it has the same nameplate capacity as the solar facility. Thus, the addition of storage resources to a portfolio can contribute value in ways that are not reflected in the amount of nameplate capacity.

¹²⁶ CRES’s Comments, pp. 2-3.

¹²⁷ Phase I Decision, ¶ 211.

declines to upset the compromise position we adopted in the Phase I decision particularly since the Company did provide the requested Excel worksheet as Appendix W to the 120-Day Report.

114. Likewise, we reject CRES's argument that the Commission is required in this Phase II process to use an alternative discount rate per SB 23-291's amendment to C.R.S. § 40-2-139, which would further extend the Phase II process with additional modeling and process by relitigating issues resolved in Phase I. CRES is correct that, going forward, the requirement imposed by the amended § 40-2-139, C.R.S. imposes a duty on the Commission that, if it relies on the use of a discount rate when calculating NPV of future carbon-based fuel costs, the rate must not exceed the long-term rate of inflation. However, the law does not consider or include the necessary Phase I and II process or other clarifications.

115. A law is presumed prospective unless the legislature "clearly and unequivocally expressed" ¹²⁸ intent for the statute to apply retrospectively. Generally, when the cause of action "accrues prior to the effective date of an amending statute," the prior statute controls. ¹²⁹

116. Here, Public Service filed its application in this Proceeding in March 2021. At that time, and at the time of the Phase I order, the statute did not include the updated language, which went into effect in August 2023. The party evidence and record overall, including the expectation of the Company when it filed the application, were set well before the 2023 legislative session. The issue was fully concluded through the Phase I Decision issued in 2022. To change the required scope of the considerations at this late phase is not required and counters long-standing precedent. ¹³⁰

¹²⁸ *Edelstein v. Carlile*, 33 Colo. 54, 57, 78 P. 680, 681 (1904)

¹²⁹ *United Bank of Denver Nat. Ass'n v. Wright*, 660 P.2d 510, 511 (Colo. App. 1983); *Diversified Veterans Corp. Ctr. v. Hewuse*, 942 P.2d 1312, 1314 (Colo. App. 1997) (holding that the imposition of penalties involves substantive rights and liabilities and is therefore governed by the law in effect on the date of the party's injury).

¹³⁰ *See, e.g., United Bank of Denver Nat. Ass'n v. Wright*, 660 P.2d at 511.

117. Phase I is complete and has always been the appropriate phase for determination of the applicable discount rate. In enacting its statute in 2023, the Legislature is presumed to understand this process, and the Commission certainly will be required to apply the statute in future ERP Phase I decisions that direct the necessary considerations of discount rate determinations. The Commission is not, however, required to alter its Phase II process and extend already tight timelines for further modeling, analysis, and to expand the record. Indeed, if it did, these actions would potentially put at risk the time-sensitive bidding process.

118. Nevertheless, as the Commission did in its Phase I order in considering updates to statute subsequent to the 2021 ERP application filing by directing the Company to include the social cost of methane in its Phase II information, the Commission is in no way precluded from recognizing the statutory considerations and discussing the spirit and application based on the record. The Commission generally has a broad delegation of power to regulate utilities from the Colorado legislature.¹³¹ Where the legislature has not directly prohibited the Commission from considering certain factors, the Commission generally can exercise its power over rates and utilities as it sees fits.¹³² Specifically, when approving resource plans, the Commission can consider “other relevant factors, as determined by the commission.”¹³³ The legislature grants the Commission broad power here to determine what factors are appropriate to use to compare bids in a resource plan.¹³⁴ Recognizing these statutory provisions, the record here indicates that the Alternative Portfolio would still be the most appropriate selection.

119. No parties to this Proceeding submitted analysis during Phase II showing the PVRR of various portfolios using a lower discount rate, although certain public commentators submitted

¹³¹ See *City of Montrose v. Pub. Utils. Comm’n*, 629 P.2d 619, 622 (Colo. 1981).

¹³² See § 40-3-102, C.R.S.

¹³³ § 40-3.2-106(3)(c), C.R.S.

¹³⁴ § 40-3.2-106(3)(c), C.R.S.

analysis regarding the impact of different discount rates on the NPV of fuel costs. Regardless, even assuming that certain that a lower discount rate makes the Alternative Portfolio more expensive on a NPV basis compared to the lower dispatchable portfolio, the no new gas portfolio, and the no gas portfolio, this does not justify the selection of a different portfolio. First, the Commission is still prohibited from selecting a portfolio that fails to protect reliability. Public Service states in its Response Comments: “neither the No New Gas Portfolio nor the No Gas Portfolio protect system reliability and therefore cannot be approved by law.”¹³⁵ Public Service has also raised concerns with the reliability of the lower dispatchable portfolio. Moreover, while one of the enumerated statutory factors is the cost on a NPV basis, the statute permits the Commission to also consider other relevant factors. One such unenumerated factor the Commission is considering is the cost to customers more generally. Through this lens, the lower dispatchable portfolio, the no new gas portfolio, and the no gas portfolio all require significantly more resource acquisitions in the short term that will have significant consequences for the affordability of electric service. This factor weighs in favor of granting authority to Public Service to move forward with acquiring the resources in the Alternative Portfolio.

3. Reliability and resilience of the electric system

120. The statute also requires the Commission to consider the impact of the CEP on the reliability and resilience of the electric system and prohibits the Commission from approving a plan that does not protect system reliability. Based on modeling in this record, the Alternative Portfolio is just as reliable, if not more so, than the UPP.

121. As presented by the Company, gas-fired generation resources are a key factor in ensuring reliability. In response to arguments that the Commission should reduce the amount of

¹³⁵ 120-Day Report, p. 60.

gas resources, Public Service asserts that it “cannot become comfortable with any level of reduction in dispatchable resources.”¹³⁶ In addition to the total amount of gas resources included in the portfolio, Public Service asserts that two gas resources within the UPP are strategically located and necessary to provide transmission support: Bid 989 in the Denver Metro area and a new gas resource in the Alamosa area. Regarding Bid 989, the Company states that it “is the only bid submitted that includes firm dispatchable generation providing supportive benefit to the transmission constraint” in the Denver Metro area.¹³⁷ Similarly, the Company notes that, after a 2026 retirement of an existing gas resource, there will be no firm dispatchable resources located in the San Luis Valley. The Company asserts that it is essential from a reliability perspective to continue to have firm dispatchable generation in the region.¹³⁸

122. The Alternative Portfolio slightly increases the amount of gas resources included in the UPP and retains the two gas resources that Public Service argues are strategically located and necessary to provide transmission support.¹³⁹ The only modification the Alternative Portfolio makes to the gas resources in the UPP is to Bid 1000, which the Company does not flag as being necessary for transmission support.¹⁴⁰ Bid 1000 is a Company-owned project with two 200 MW combustion turbines (CTs). The Alternative Portfolio would eliminate one of the 200 MW CTs in Bid 1000 and replace it with a 219 MW CT (Bid 235) that is owned by an IPP. As set forth above, this change provides valuable diversification benefits that, among other things, reduces the risk of stranded assets that customers face from Company-owned gas resources. In addition, Public Service has raised no reliability concerns with Bid 235. Indeed, Bid 235 is included in the backup

¹³⁶ Public Service’s Response Comments, p. 29.

¹³⁷ 120-Day Report, p. 39.

¹³⁸ 120-Day Report, p. 39.

¹³⁹ 120-Day Report (Appendix S) Rev. 1, p. 26. While the Alternative Portfolio replaces the UPP’s Alamosa gas resource with a slightly larger gas resource that is also located in the Alamosa area.

¹⁴⁰ 120-Day Report, p. 29.

portfolio and is the only gas bid that the Company includes in its Prospective New Load portfolio.¹⁴¹ Thus, the Alternative Portfolio maintains or increases the reliability of the UPP in that it retains the two strategically located gas resources, slightly increases the total amount of gas resources, and replaces a Company-owned gas resource with a PPA resource that the Company has found to be reliable.¹⁴²

123. Furthermore, the Company ran both the Alternative Portfolio and the Preferred Portfolio (which closely resembles the UPP) through an “extreme summer” scenario that—according to the Company—“provides useful information on the reliability of the portfolios under extreme events.”¹⁴³ Under this extreme summer scenario, the Alternative Portfolio performed better than the Preferred Portfolio.¹⁴⁴ Thus, we are left to conclude that the Alternative Portfolio is not only reliable based on Public Service’s own metrics, it appears to be more reliable than the UPP.

124. Although the UPP and the Alternative Portfolio have comparable levels of gas-fired generation, we acknowledge the arguments from several parties and numerous members of the public that the Commission should only approve a resource portfolio with fewer or no new gas resources. We share their disappointment that the Phase II competitive resource solicitation failed to result in any viable portfolio with fewer gas resources and again urge the Company to come

¹⁴¹ 120-Day Report, p. 55; Public Service’s Response Comments, p. 27.

¹⁴² Pursuant to the Phase I Settlement and the Phase I Decision, the model PPA for dispatchable resources was amended to, among other things, require that gas resources have backup fuel on site necessary to allow the facility to run continuously for a minimum of five days at maximum load on the alternative fuel. Firm gas transportation contracts could serve as a substitute for the requirement to have a backup alternative fuel on site. (Phase I Decision, pp. 106-06; 120-Day Report, pp. 122-23). In the 120-Day Report, Public Service confirms that “[a]ll bids that were advanced to EnCompass modeling are compliant with the requirement for either onsite backup fuel storage or firm gas transportation contracts” but that the model did not select the fuel oil storage bids due to economics. (120-Day Report, p. 125). The Commission reiterates its interest in having five days of backup fuel onsite for the new gas resources.

¹⁴³ 120-Day Report, p. 77.

¹⁴⁴ Corrected Table 19 of 120-Day Report, p. 1.

forward in future proceedings, including the 2024 JTS, with more developed demand side resources and other reliability solutions that do not involve new gas resources. As described above, the requirement to include at or near the amount of gas resources in the Alternative Portfolio stemmed from the Company's reliability determinations and their direct modifications to the modeling in Phase II, as a result. The Commission is disappointed that specific, locational reliability concerns were not clearly communicated in Phase I, which could have been informative to potential bidders and provided additional options.

125. We therefore find that granting authority to Public Service to move forward with acquiring the resources in the Alternative Portfolio, including its gas resources, is in the public interest. First, SB 19-236 prohibits the Commission from approving a plan that does not protect system reliability. Thus, we cannot simply carve out from a modeled resource portfolio some or all of the firm dispatchable resources that Public Service maintains are necessary for reliability.

126. Other modeled resource portfolios with fewer gas resources than the Alternative Portfolio were presented by Public Service—including the Lower Dispatchable portfolio, the No New Gas portfolio, and the No Gas portfolio. None of these portfolios, however, represent a better option than the Alternative Portfolio. Public Service states in its Response Comments that “neither the No New Gas Portfolio nor the No Gas Portfolio protect system reliability and therefore cannot be approved by law.”¹⁴⁵ In addition, we note the No New Gas portfolio and the No Gas portfolio are significantly larger and more costly than the Alternative Portfolio.

127. As for the Lower Dispatchable portfolio, it is much larger than the Alternative Portfolio (7,163 MW instead of 5,835 MW) and more expensive on a NPV basis (\$45,315

¹⁴⁵ 120-Day Report, p. 60.

compared to 43,997).¹⁴⁶ Moreover, as compared to the Alternative Portfolio, the Lower Dispatchable portfolio simply reduces the amount of PPA gas resources by selecting a smaller CT (Bid 1061). The Company-owned gas resources are essentially unchanged.¹⁴⁷ In addition, the Company argues in its Response Comments that it has reliability concerns with Bid 1061.¹⁴⁸ Thus, on this record we find that the Alternative Portfolio is superior to the Lower Dispatchable portfolio, the No New Gas portfolio, and the No Gas portfolio.¹⁴⁹

128. Even though we would have preferred selecting a portfolio with fewer or no gas resources, we find it useful to consider the total amount of gas resources in the context of what was originally anticipated in Phase I of this Proceeding. Based on the inputs and assumptions established in the Phase I Settlement, the modeling predicted that the competitive solicitation could lead the Company to acquire 1,372 MW of gas additions.¹⁵⁰ The vast majority of the parties in this Proceeding joined the Phase I Settlement, including CEO, WRA, and Conservation Coalition. Thus, we conclude that the 669 MW of gas resources in the Alternative Portfolio are well within the guardrails established in Phase I.

129. While we find on this record that the Alternative Portfolio and its gas resources are in the public interest, we acknowledge the numerous concerns that parties raised regarding how Public Service tested for reliability in the Phase II modeling and the manual adjustments the Company made regarding gas resources. In particular, we share the concerns raised by parties

¹⁴⁶ 120-Day Report (Appendix S) Rev. 1, pp. 26, 28.

¹⁴⁷ 120-Day Report (Appendix S) Rev. 1, pp. 26, 28.

¹⁴⁸ Public Service's Response Comments, p. 30.

¹⁴⁹ For similar reasons, we reject CIEA's arguments that the Commission select a portfolio that use the annuity tail instead of the replacement chain modeling. As between the Alternative Plan and the Alternative Plan with the annuity tail, the new 219 MW PPA CT (Bid 235) is replaced with three short-term extensions of existing PPA CTs, but the Company-owned gas resources remain essentially the same. The record before us better supports the reliability of Bid 235 as compared to the extensions of the existing PPA CTs. Moreover, because the annuity tail version is just a sensitivity, its projected emissions have not been reviewed by CDPHE.

¹⁵⁰ Public Service's Response Comments, p. 28 (citing Phase I Settlement (Attachment D), at Table 3 and noting that the 1,372 MW of gas additions is over a longer RAP).

such as Staff, COSSA/SEIA, and Conservation Coalition regarding the Company's reliability rubric.¹⁵¹ We also question whether the Company adequately communicated to bidders the importance of strategically located gas resources. It is our expectation that the Company will strive to resolve these issues prior to the 2024 JTS. Nevertheless, while these concerns further support our decision to select a tailored resource portfolio, we are unconvinced that these concerns warrant additional Phase II modeling or the manual removal of gas resources from the modeled portfolios.

4. Future Technology Development

130. Another related factor that the Commission considers when evaluating the CEP is the impact of future technology developments. For instance, the Alternative Portfolio includes a much higher percentage of storage resources than the UPP. This significantly expanded level of storage may be critical to future efforts to incorporate still greater amounts of renewables without unreasonable levels of curtailments while reducing the need for gas resources.

131. Colorado's bold clean energy targets necessitate a rapid shift in the electrical system, which in turn requires us to think about our electrical system in a different way. We cannot attempt to build Colorado's future, low-emission electrical system by continuing to build the system as we have in the past. Simply building increasing amounts of generation resources as the UPP would do results in high curtailments and high costs. In contrast, modifying the CEP to include the Alternative Portfolio helps the Commission start building a different type of electrical system that takes advantage of developing technologies in several ways. Efficient and cost-effective planning of such a system will rely on a variety of components: flexible supply, flexible demand, participation in larger geographic markets, energy efficiency and acquisition of

¹⁵¹ See, e.g., Staff's Comments, pp. 29-30; COSSA/SEIA's Comments, pp. 14-15; Conservation Coalition's Comments, pp. 10-13.

clean resources. While other dockets are addressing regional markets, demand flexibility and energy efficiency, in this CEP we address clean resources and flexible supply, placing a greater emphasis on supply management through increased storage capacity. As an example, energy storage resources in the Alternative Portfolio represent 32 percent of new capacity,¹⁵² compared to just 16 percent in the UPP.¹⁵³ In this way, the Alternative Portfolio marks the first step in a new approach to resource planning for a modern, efficient, and cost-effective grid.

132. In addition, the modification of the CEP to include the Alternative Portfolio results in a smaller, less aggressive resource acquisition. Although it is likely that our selection of a smaller resource portfolio in this Proceeding will result in a larger acquisition in the 2024 JTS, deferral of some of the new generation resources will also provide additional time for the Commission to better understand and take advantage of developing technologies that might reduce the cost of, or eliminate the need for, new generation and transmission resources. In this vein, the Alternative Portfolio's acquisition of a PPA gas resource reduces the amount of gas resources that Public Service would otherwise own.¹⁵⁴ This gives Public Service more flexibility if future technology improvements render gas resources unnecessary. Moreover, advancements in various types of distribution system management are particularly promising for ensuring that the distribution system is more capable of the dynamic load management that will be more important as beneficial electrification advances. The Commission also expects that more robust and innovative demand response programs will be a critical part of the future electrical system. As more items like electric vehicles, heat pumps, and heat pump water heaters come onto the grid, the management of these loads will become increasingly important, but also increasingly possible.

¹⁵² Staff's Comments, p. 11.

¹⁵³ Public Service's Response Comments (Attachment 1), p. 1.

¹⁵⁴ See 120-Day Report (Appendix S) Rev. 1, p. 26.

To ensure that the Commission is being good stewards of ratepayer funds, we need the Company and their planning processes to evolve away from overbuilding resources and instead look for ways to enable more dynamic management of both supply resources and demand resources.

133. Several parties similarly argue that the Commission should continue examining how new technological developments could be used to meet system needs instead of traditional generation and transmission investments. For instance, WRA suggests that the need for some of the Denver Metro transmission upgrades could instead be addressed by load management programs. WRA states that investment in transmission system upgrades to alleviate the Denver Metro constraint may be needed but recommends that the Company develop without delay load management programs in the metro area. WRA also recommends that the Company improve distributed energy resource (DER) programs and interconnection rules, with financial incentives to ensure the growing DER capacity provides benefits to the grid.¹⁵⁵

134. Similarly, noting that the Company's proposal for metro Denver transmission upgrades was "significantly influenced by the lack of cost-effective bids [for generation] in the Denver metro area," COSSA/SEIA asserts that the Company should consider alternatives to conventional transmission upgrades, including non-wires alternatives such as virtual power plants (VPPs).¹⁵⁶ CEO likewise encourages the exploration of non-wires alternatives associated with the proposed upgrades in its new Distribution System Plan as well as additional details in the 2024 JTS.¹⁵⁷ CRES argues that with the new storage contained in the Preferred Portfolio, together with the fact that long-term storage technologies are evolving quickly, the Commission should not

¹⁵⁵ WRA's Comments, p. 22.

¹⁵⁶ COSSA/SEIA's Comments, pp. 22.

¹⁵⁷ CEO's Comments, pp. 29-30.

approve the proposed gas resources until Public Service has gained significant experience operating its system with the large amount of storage that will be added in the coming years.¹⁵⁸

135. Staff asserts that Public Service never mentioned the possibility of demand side or other generation solutions to alleviate the \$2.1 billion in transmission in the Denver Metro area. Staff notes that demand response solutions, aggregation of customer-sited generation and storage, and the use of electric vehicles to deliver grid benefits are being discussed in the Commission's Distribution System Plan proceedings and VPP Miscellaneous Proceeding. Staff argues that it is unclear whether solutions such as Time-of-Use rates, critical peak pricing, additional demand response, VPPs focused on this period, managed charging, Vehicle-to-Grid programs, strategically located storage at Community Solar Gardens, etc. could prove to be more cost-effective solutions than what the Company proposes.¹⁵⁹

136. Future development also implicates changing needs for workforce labor and development. Despite the many positive attributes of the Alternative Portfolio, we have not lost sight of best value regarding employment of Colorado labor and the impacts the Alternative Portfolio will have on the long-term economic viability of Colorado communities.¹⁶⁰ As set forth more below, the 120-Day Report assigns a BVEM score to each portfolio and the Alternative Portfolio's BVEM score is slightly lower than the UPP's BVEM score. Although it is disappointing that the Alternative Portfolio has a lower BVEM score, just as deferral of some of the new generation resources will provide additional time for the Commission to take advantage of developing technologies, the Alternative Portfolio allows time for better evaluation of BVEM for those resources that will be acquired in future solicitations. Notably, the BVEM scores appear

¹⁵⁸ CRES's Comments, p. 2.

¹⁵⁹ Staff's Comments, p. 41.

¹⁶⁰ See generally § 40-2-129(1)(a), C.R.S.

to track to some degree with the percentage of utility ownership, so as IPPs prepare for future solicitations, they should take special care to improve BVEM performance to ensure that in future solicitations the Commission does not see lower BVEM scores as a reason to disturb the ownership balance between the utility and IPPs. Ultimately, we believe that the positive attributes of the Alternative Portfolio, including cost, emissions reductions, reliability, and the ability to better address future technology developments and transmission concerns, outweigh the lower BVEM score.

137. In sum, the prospect of future technology developments weighs in favor of modifying the CEP to include the resources in the Alternative Portfolio. The composition of the Alternative Portfolio itself with the large amounts of storage will likely be key for the future low emissions electrical system. Likewise, the more tailored acquisition of resources provides the Commission with more opportunities to evaluate quickly advancing technologies such as distribution management and new demand response programs and balances the risk that some of these new technologies could reduce the need for future generation and transmission investments.

5. Transmission Concerns

138. The transmission concerns that have arisen in Phase II are another factor that contributes to the finding that granting Public Service authority to move forward with acquiring the resources in the Alternative Portfolio is necessary for the public interest. The Company presents several categories of transmission costs, but all are overshadowed by the \$2.2 billion in investments for transmission network upgrades to the Denver Metro area.¹⁶¹ In Phase I of this Proceeding, the Company identified a need in the Denver Metro area, but only estimated the need

¹⁶¹ 120-Day Report, p. 130.

at a capital cost of “approximately \$250 million”.¹⁶² Therefore, the Phase II modeling did not consider the new and significantly larger cost or how to minimize or avoid it as part of the resource selection process. Moreover, as noted above, the majority of the transmission investments are not scheduled to be completed until 2030, years after many of the resources in UPP would otherwise come online,¹⁶³ exacerbating concerns regarding both the modelled and actual levels of curtailments that will occur in the UPP.

139. As discussed in more detail elsewhere in this Decision, several parties raise concerns about the \$2.2 billion investment in transmission upgrades that Public Service states is necessary for the Denver Metro area and question whether the selection of resources could be better optimized to reduce the transmission upgrades. For example, Staff states that there “seems to be a fundamental problem that the modeling process does not integrate transmission planning in a meaningful way” and notes that Public Service “has not provided any analysis of the amount and type of metro area generation that would be needed to reduce this transmission network upgrade cost or the amount by which it could be reduced.”¹⁶⁴ Staff argues that the \$2.2 billion surprise raises several questions including whether the transmission costs would be substantially different under any other generation portfolio, whether there are cost effective Denver Metro bids, and whether demand side or other generation resources could reduce the overall cost and need for the transmission network upgrades.¹⁶⁵

140. Among the other parties that raise transmission concerns, CEC argues that the estimated \$2.2 billion in transmission upgrades for the Denver Metro area is “shocking” and notes that this current estimate is almost nine times larger than the estimate provided in Phase I. CEC

¹⁶² HE 107 p. 50-51

¹⁶³ Staff’s Comments, pp. 43-44 (citing Appendix Q to the 120-Day Report).

¹⁶⁴ Staff’s Comments, p. 40.

¹⁶⁵ Staff’s Comments, pp. 39-41.

asserts that this change fundamentally alters the facts the Commission and stakeholders relied on in Phase I.¹⁶⁶ UCA similarly argues that in the Preferred Portfolio Public Service intertwines generation and transmission projects to provide a circular basis for one another, which significantly expands Company ownership, costs, and capacity beyond what was contemplated in the Phase I Settlement.¹⁶⁷

141. In the 120-Day Report, the Company cites several factors driving the need for large investments in the Denver Metro area, including population growth, the scale and location of new generation that the Company is acquiring in the Preferred Portfolio, and the lack of cost-effective bids in the Denver Metro area.¹⁶⁸ In its Response Comments, Public Service recognizes that “additional work remains to better integrate transmission and generation planning” but argues against the idea that material cost savings could be obtained with further analysis of the transmission costs or tweaks to the resource portfolio.¹⁶⁹ As support, the Company notes that a 30 percent reduction in the size of the resource portfolio only results in a 20 percent reduction in modeled transmission costs.¹⁷⁰

142. The large and unexpected costs of the transmission investments, the timing of the investments compared to the associated generation, and the analysis that resulted in the proposed transmission investments all support the selection of the Alternative Portfolio. The costs associated with curtailments is discussed above, but the UPP creates a timing mismatch in which the majority of the transmission resources will be put into service years after the generation resources. In addition, we share Staff’s questions as to whether alternatives exist that could reduce

¹⁶⁶ CEC’s Comments, pp. 5-7.

¹⁶⁷ UCA’s Comments, pp. 11-15.

¹⁶⁸ 120-Day Report, pp. 131-32.

¹⁶⁹ Public Service’s Response Comments, pp. 68-69.

¹⁷⁰ Public Service’s Response Comments, p. 69.

the overall costs and need for the network upgrades. While we cannot determine on this record whether the transmission network upgrades in the Denver Metro area will be necessary in the future,¹⁷¹ the Alternative Portfolio defers certain resource acquisitions. At the very least, the deferrals provide more opportunities to further evaluate the proposed transmission network upgrades and enable the Commission – and Colorado as a whole – to have greater confidence that the acquisition of new resources minimizes transmission investments and is in the public interest.

6. Conclusion

143. Granting authority to Public Service to move forward with acquiring the resources in the Alternative Portfolio instead of the UPP will likely reduce costs to customers, especially when the Commission considers costs more generally. Such costs include those that are likely to result from the curtailments that the model fails to capture and the potential future costs associated with Company-owned gas resources in the UPP (*e.g.*, decommissioning). At the same time, the Alternative Portfolio is just as reliable as the UPP, and perhaps more so. While the modeling shows that the UPP achieves greater emissions reductions than the Alternative Portfolio, the Alternative Portfolio still exceeds the state’s ambitious clean energy targets, while leaving open the possibility for more cost effective emission reductions in the future. Furthermore, the emissions reductions in the UPP, and especially the interim emissions reductions, appear to be optimistic given the likely impact of curtailments that the modeling presented in the 120-Day Report does not fully incorporate. Finally, pursuing a smaller, more tailored portfolio of resources is necessary for the public interest because it creates an opportunity to investigate how to better optimize transmission upgrades during resource selection and provides more opportunities to take advantage of

¹⁷¹ While the estimated cost of the transmission investments is still quite large in Alternative Plan, it is approximately \$397 million less than the associated transmission investments in the UPP (\$2,353 - \$1,956 = \$397). (*Compare* Public Service’s Response Comments, p. 9, *with* 120-Day Report (Appendix S) Rev. 1, p. 26.)

developing technologies that might reduce or eliminate investments in traditional generation and transmission assets. Given the point in this Proceeding in which the significantly higher transmission costs were disclosed and the opportunity to take advantage of other technologies to limit ratepayer expenses, including the UPP in the approved CEP cannot be found to be in the public interest, as the UPP leaves too many unanswered questions and opportunities for optimization still on the table. As discussed throughout this decision, modifying the CEP by including the Alternative Portfolio is necessary to ensure the plan is in the public interest.

144. To reach an approved CEP that meets Colorado’s needs, we find that modification of the presented CEP to include the Alternative Portfolio is necessary to ensure the approved CEP is in the public interest. With its CEP activities—including the Coal Action Plan that is critical for reducing emissions—and the plans for workforce transition and community assistance, the modified CEP moves Colorado significantly forward in its clean energy transition.

F. Transmission

1. Phase II Changes in Transmission Investments

145. In Phase I of this Proceeding, Public Service explained that it would need to make transmission investments in four areas to accommodate the new generating resources to be procured: 1) Denver Metro network upgrades, 2) grid strength reinforcement, 3) reactive power/voltage support, and 4) generator interconnections. At that time, Public Service provided a “preliminary and illustrative” cost estimate of \$250 million for the Denver Metro upgrades, and a “rough” estimate of the combined costs for voltage support and grid strength of \$150 to \$250 million.¹⁷²

¹⁷² Hearing Exhibit 107, Direct Testimony and Attachments of Hari Singh, pp. 50-59.

146. In the 120-Day Report, the Company states that the transmission analysis it conducted to support the CEP is its most thorough transmission analysis for an ERP ever, involving numerous power flow studies, scenario modeling and “tabletop exercises” to develop project scoping and cost estimates. The Company states that 1) the scale and (largely remote) location of the new generation the Company will procure via this ERP, 2) the planned generation retirements the ERP entails, and 3) the lack of bids for new or existing generation located within the Denver Metro area transmission constraint all combine to require significant evolution of, and investment in, the transmission system to maintain reliable delivery of power to load centers.¹⁷³

147. More specifically, the Company states that its existing substations lack the space for expansions necessary to eliminate overloads and expand the system’s capacity, and that it has identified significant needs for new substations and new transmission lines. Moreover, it states that siting, permitting, and the need for extensive undergrounding in the Denver Metro area add cost and complexity to many of the network upgrade projects it has identified. Given these siting challenges, the Company states that its planning approach has been to create long-term ratepayer value by considering not only what upgrades are needed for its Preferred Portfolio, but also designing to accommodate future renewable development and growth in electricity demand.¹⁷⁴

148. The Phase II cost estimates for grid strength/voltage support and the MVLE are consistent with the estimates for those costs in Phase I of this Proceeding. However, the Company adds a new, previously unreported category of transmission investments in Phase II—the San Luis Valley (SLV) network upgrades with an estimated cost of \$176 million. In addition, in Phase II the estimated costs of the Denver Metro upgrades increase from \$250 million to \$2,146 million.

¹⁷³ 120-Day Report, pp. 128-134.

¹⁷⁴ 120-Day Report, pp. 128-134.

While Public Service asserts that its Phase II costs are not CPCN-level estimates, the Company states that its “process improvements” give it a higher confidence in these estimates than in those provided in previous ERPs.¹⁷⁵

149. The Company claims that the need for Metro Denver upgrades have greatly expanded in Phase II and that the Phase II analysis identified substantial network upgrades needed within the SLV as well. The Company states that “[w]hile the smaller portfolio of transmission projects contemplated in Phase I may have alleviated transmission overloads within a short time window, the customer value of a smaller transmission portfolio would be quickly overwhelmed by additional load growth and resource acquisitions, requiring costly and difficult upgrades to new transmission facilities.”¹⁷⁶ The Company stated reasons for the higher costs of the transmission investments include the following: siting and permitting challenges and the need for undergrounding many facilities in the Denver Metro area, the scale and location of new generation that will be acquired in this Proceeding, and the lack of cost-effective generation bids in the Denver Metro area.¹⁷⁷

2. Party Comments

150. Staff reiterates that Public Service’s transmission power flow analysis—conducted at the tail end of the Phase II modeling—estimates that almost \$3 billion in transmission investment is needed to support the Preferred Portfolio (in addition to the approximately \$1.7 billion investment recently approved in the CPP). Staff states that this estimated \$4.5 billion in transmission investments is perhaps “Staff’s largest concern with the Company’s Preferred

¹⁷⁵ 120-Day Report (Appendix Q), p. 3.

¹⁷⁶ 120-Day Report (Appendix Q), p. 11.

¹⁷⁷ 120-Day Report (Appendix Q), p. 12.

Plan.”¹⁷⁸ Staff reviews the Company’s explanation of the necessary transmission upgrades but states that it is left with more questions than answers. Staff recommends that 1) the Commission make clear that “the Commission is in no way approving the transmission projects presented and described in the Report;” 2) the Commission add consideration of improved integration between transmission and resource planning and modeling to the recently-opened transmission pre-rulemaking docket 23M-0472E; 3) the Commission consider directing the Company to file a standalone transmission planning application; and 4) that the Commission consider options for implementing an independent transmission monitor.¹⁷⁹

151. Staff acknowledges the concern that some of its recommendations could further delay transmission investments needed to deliver renewable energy. Given that many of the ISDs for the transmission investments are in 2029 and 2030, however, Staff argues that such delays might be avoidable.¹⁸⁰

152. CEO, UCA, and CEC similarly criticize the transmission network upgrade proposals the Company presents in the 120-Day Report. For example, CEO recommends the Commission clarify that it is not providing a presumption of prudence on the proposed Denver Metro transmission network upgrades until additional information is provided. Specifically, CEO recommends the Company provide more information on the degree to which upgrades are necessary for reliability, as compared to planning for future growth.¹⁸¹ UCA complains that the Company did not inform the Commission in the CPP proceeding that additional billions of dollars would be needed to deliver power from the CEP and states that had it

¹⁷⁸ Staff’s Comments, p. 8.

¹⁷⁹ Staff’s Comments, pp. 44-45.

¹⁸⁰ Staff’s Comments, p. 45.

¹⁸¹ CEO’s Comments, pp. 29-30.

been aware of the magnitude of the transmission upgrade needs the Company now claims, it would have approached the proceeding differently.¹⁸²

153. In contrast, other parties such as CIEA and COSSA/SEIA generally support the Company's proposed transmission investments.¹⁸³ In fact, COSSA/SEIA suggests that the transmission investments should be designed to accommodate continued growth in renewable energy development.¹⁸⁴

154. In its Response Comments, Public Service maintains that transmission projects will be necessary for any generation portfolio to achieve the aggressive emission reductions the State requires.¹⁸⁵ In response to party comments recommending that the Commission not provide final approval of the network upgrade projects, the Company notes that it has not sought such approval, and reiterates its recommendation that the Commission schedule a Commissioners' Information Meeting (CIM) on CEP-related transmission in the first quarter of 2024 where the Company can further detail its broader transmission plans and analysis, and answer Commissioner questions. Following this, the Commission and parties can vet transmission projects through CPCN filings.¹⁸⁶

155. The Company urges the Commission to deny the Staff recommendations to require a transmission planning proceeding and an independent transmission monitor. Public Service claims that "[t]hese recommendations are vague and would unnecessarily slow down the energy transition by requiring parties to expend valuable time and resources on processes with little, if any, incremental benefit."¹⁸⁷

¹⁸² UCA's Comments, pp. 14-15.

¹⁸³ *See, e.g.*, CIEA's Comments, pp. 19-20.

¹⁸⁴ COSSA/SEIA's Comments, pp. 20-21.

¹⁸⁵ Public Service's Response Comments, pp. 65-66.

¹⁸⁶ Public Service's Response Comments, pp. 66-67.

¹⁸⁷ Public Service's Response Comments, pp. 67-68.

156. The Company expresses strong disagreement with Staff's suggestion that generating resources should be delayed to future ERPs in recognition of the time it will take to put the new transmission assets into service (and the likely curtailment this will cause). The Company argues that the State's policy objectives do not allow for this delay, and it encourages the Commission to approve the UPP now. It claims that delaying approval of generation assets will only result in increased bid prices for generation and increase both the cost and siting difficulties for transmission.¹⁸⁸ Public Service further argues that using tools such as curtailment and redispatch in the short term as transmission buildout is completed is superior to delaying the acquisition of resources.¹⁸⁹

157. Responding to party arguments that some of the transmission upgrades are unnecessary, the Company notes that none of these parties conducted detailed transmission planning analyses and refers to their contentions as conjecture. The Company asserts that the transmission portfolio is a reasonable set of solutions and states that it sought to upgrade existing transmission facilities wherever possible instead of constructing new greenfield transmission lines.¹⁹⁰

3. Findings and Conclusions regarding Transmission

158. We share the serious concerns expressed by parties regarding the large, unexpected cost increases in transmission investments. After nearly three years of process, it was incredibly frustrating to see such a major failure of planning and estimating come to light so late in this Proceeding, upending the understandings of this Commission and many of the parties about the cost to integrate resources associated with this solicitation. Public Service will need to improve

¹⁸⁸ Public Service's Response Comments, pp. 72-73.

¹⁸⁹ Public Service's Response Comments, pp. 73-74.

¹⁹⁰ Public Service's Response Comments, pp. 70-72.

its transmission modelling and cost estimation processes in in future ERP proceedings to allow the Commission and relevant stakeholders a better ability to assess the critical links between generation and transmission resources. As noted above, the concern around transmission that arose in Phase II of this Proceeding was one of the factors that compelled us to select a smaller, more tailored resource portfolio.

159. In addition, the Commission emphasizes that the proposed transmission network upgrades, grid strength reinforcements, and reactive power/voltage support investments presented in the 120-Day Report are not part of the approved CEP. We are neither approving (or denying) these transmission actions here nor entitling the investments to any sort of presumption of prudence (or prejudice). Substantially more process will be required to fully assess the need for, alternatives to, and cost of remedial actions on the transmission grid in light of significant transition that this Proceeding initiates. Not only does the Company note that it is not seeking approval of those actions here, but the Commission has made clear it is modifying the CEP such that these actions are still to-be-determined with possible alternative solutions.

160. Moreover, as presented, the transmission network upgrades appear designed to accommodate future renewable development and growth in electricity demand, not *just* the CEP and its emissions reduction goals. Likewise, the alleged need for some of the proposed transmission upgrades may simply be the result of an aging system and changing dynamics. Though prudence only attaches to the “approved CEP,” Company filings continue to emphasize that the transmission network upgrades presented here are not part of its CEP.

161. In the context of the shocking cost increases associated with the new transmission and concerns regarding the analysis and vetting of the proposed alternatives to the transmission investments, the Commission agrees with Staff that we simply do not have enough information or

reliable modeling to authorize the spending on another \$2.8 billion in transmission investments at the current time.¹⁹¹ While the Commission recognizes that a prudency determination was not sought by the Company in this Proceeding, we are wary to approve a suite of resources that all but lock in the future need for significant additional future system expenses without first vetting alternatives to mitigate those costs. The Commission needs to see a more holistic picture of the various transmission projects arising from this Proceeding, including what investments are necessary and how the various transmission investments work together with other system requirements and constraints. This additional review of the proposed transmission projects is necessary even if Rule 3206 technically would not require a CPCN for some of the individual transmission projects in other circumstances. Accordingly, we waive Rule 3206 as to the transmission projects arising from this Proceeding; we emphasize that it is incumbent upon Public Service to provide a fulsome and comprehensive description of all transmission projects necessary to accommodate power delivery and maintain reliable service from the approved CEP. Thus, the Company is requested to bring forward one or more CPCN or other filings regarding transmission projects raised in this Proceeding. However, and particularly given our emphasis that selecting the Alternative Portfolio presents the opportunity that not every transmission project raised will ultimately be pursued, we leave it to the Company's discretion on how best to present this type of analysis to the Commission; *i.e.*, both in timing and type of filings made, but also with regard to the number or combination of filings.

162. The Commission does not oppose the Company's offer in its Response Comments to make a presentation on expected transmission requirements in a CIM. As a general matter, we are particularly interested in additional information regarding the differences in transmission plans

¹⁹¹ Staff's Comments, p. 45.

between the UPP and the Alternative Portfolio as well as any explanation the Company can provide regarding the failure to better anticipate the significant transmission needs in the Denver Metro area. Likewise, the Commission is interested in learning from Public Service how the Company's planning processes will improve and any innovative ways to approach future ERP proceedings so that the optimization of costs includes transmission investments, and to avoid similar major discrepancies between Phase I and Phase II expectations presented in modeling. Nevertheless, we recognize that when the Company proposed the transmission CIM, it did so in the context of the UPP rather than the Alternative Portfolio. Given the significant changes associated with the Alternative Portfolio and timing concerns with the upcoming filing of the 2024 JTS, we refrain from directing a transmission CIM at this time but invite the Company to determine the appropriate time and forum to address our concerns.

163. In addition, we find merit in Staff's proposal that the scope of Proceeding No. 23M-0472E (*i.e.*, regarding review of the provisions addressing transmission CPCN and planning in the Commission's Rules Regulating Electric Utilities, 4 CCR 723-3, in anticipation of future rulemaking) should be specifically defined to include consideration of improved processes for integrating transmission planning into generation resource plan proceedings and modeling. It is reasonable to expect that a previously unknown \$2 billion in additional expenses is an important variable to optimize around by reevaluating what different resource acquisition decisions would or could have been made to bring the entire portfolio of resource and transmission needs to a reasonable and optimized cost for ratepayers. As appropriate we will address these considerations in the context of Proceeding No. 23M-0472E, including through future order in that proceeding.¹⁹²

¹⁹² Staff and interested stakeholders are encouraged to bring forward proposals in the context of that proceeding. The Commission will address any necessary direction directly in the context of the pre-rulemaking proceeding.

164. We similarly find merit in Staff's recommendation to consider options for implementing an independent transmission analyst. The Commission sees value in having some independent transmission and power flow modeling expertise among Staff, CEO, and UCA with which the Company could collaborate. The presence of such outside expertise could help accelerate approvals and lessen the overwhelmingly negative reactions of "surprises," such as the \$2.2 billion in transmission network upgrades for the Denver Metro area. We see the primary role of this independent transmission analyst as building up the analytical capabilities of parties, particularly Staff, UCA, and CEO, regarding power flow modeling and other transmission issues.

165. Accordingly, we direct Staff to initiate a stakeholder process with UCA and CEO and in conferral with Public Service. The objective of the stakeholder process would be for Staff to bring forward a scope of work for hiring an independent transmission analyst. While we will leave it to the stakeholders to work through the details, this scope of work could be based on the IE contracting approach the Commission uses in ERP proceedings in which the Company contracts with the outside expert. Our expectation is that the analyst would work integrally with Staff. Ultimately, however, the independent transmission analyst must maintain independence from the Company.

166. Regarding timing, Staff should bring forward the proposed scope of work as soon as reasonably feasible but no later than through initial filings at the commencement of the 2024 JTS proceeding. Ideally, the independent transmission analyst could assist with the modeling in Phase I of the 2024 JTS. It would be ideal in Phase I of the process to have the help of an expert third-party to identify approximate quantities of certain resource types in targeted geographic areas to test assumptions about total costs for different portfolios, inclusive of both generation and transmission costs. We acknowledge the short timeframe this creates but find that time is of the

essence to ensure that the relevant state agencies have this type of expertise available during Phase I of the 2024 JTS to inform the parameters of the Phase II portfolios, given the shortcomings of this Proceeding.

167. As should be evident from our decisions on items such as the selection of the Alternative Portfolio and the directive for Staff to produce a scope of work for an independent transmission analyst, it is our expectation that the Company will look for better ways to model and analyze transmission costs in Phase I of the 2024 JTS. Part of these efforts should focus on mechanisms to provide reliable electrical service through dynamically managing both supply resource and demand resources—as opposed to simply building more generation and transmission resources.

168. We aspire for the independent transmission analyst discussed above to be engaged during Phase I of the 2024 JTS to bolster the analytical capabilities of Staff, CEO, and UCA regarding the integration of transmission and generation resources. However, given the possibility that the independent transmission analyst cannot be engaged in time for Phase I, as a backstop we direct Public Service to include certain portfolios in its direct case. Specifically, Public Service must present—at a bare minimum—one or more portfolios that examine minimizing transmission costs by increasing resources interconnecting in the Denver Metro area or using capacity on existing transmission lines, including capacity that will become available as thermal generating units retire. Broadly communicating the geographic areas for resource development anticipated to minimize transmission costs could also increase the likelihood of bidders to provide additional options in these target areas.

G. Performance Incentive Mechanisms

1. Background and Party Comments

169. After the filing of the 120-Day Report, in Decision No. C23-0672-I¹⁹³ the Commission directed the Company to submit comments outlining a potential symmetric risk sharing mechanism that would apply to Company-owned projects. The goal of this project-specific mechanism would be to better align customer and utility incentives, treat Company-owned generation projects in ways that are at least somewhat closer to the risks that are routinely imposed on IPP projects, and to ensure reasonable costs for customers.¹⁹⁴ While the Commission required a response from Public Service, it also invited comments from the intervenors.¹⁹⁵

170. On October 20, 2023, Public Service filed its Response to Decision No. C23-0672-I. Staff similarly filed a proposal on October 20, 2023, which UCA and CEC joined.

171. Public Service proposes two complimentary risk-sharing proposals or PIMs, with possible variations for both PIMs. The first is a cost to construct PIM intended to incentivize the Company to complete projects within its estimated capital expenditures that formed the basis of its Phase II bids. The Company proposes either (1) a dead band with sharing approach, or (2) a fixed capital cost approach. For either of these two approaches, the Company recognizes that the Commission could implement the PIM on either a project specific basis or on a portfolio basis.¹⁹⁶

172. The second PIM is an “operational performance” PIM modeled after the Commission’s suggested Levelized Energy Cost (LEC) metric identified in Appendix P to the 120-Day Report. Noting that the committed energy and weather adjustment provisions of PPA

¹⁹³ Issued October 6, 2023.

¹⁹⁴ Decision No. C23-0672-I, p. 3.

¹⁹⁵ Decision No. C23-0672-I, p. 4.

¹⁹⁶ Response to Decision No. C23-0672-I, pp. 6-7.

allow IPPs some flexibility in how much energy their projects produce, the Company argues that a 15 percent dead band around the Appendix P LEC is appropriate.¹⁹⁷ The Company further argues that the operational PIM should not seek to manage curtailments but that this is better addressed in the emissions reduction PIM.¹⁹⁸ In fact, the Company argues that any operational PIM should include curtailed volumes in the calculation of the LEC in part because this avoids creating a perverse incentive to favor Company-owned generation when determining which units to curtail.¹⁹⁹

173. The Company asserts that the combination of these two PIMs should meet the Commission's expectation regarding cost discipline regarding both capital investment and operational performance.²⁰⁰

174. Under Staff's proposed PIM for utility-owned generation, Public Service would be required to recover the costs of Company-owned renewable generation assets entirely through the electric commodity adjustment (ECA) as opposed to base rates.²⁰¹

175. Other intervenors suggest various other types of PIMs in their comments to the 120-Day Report. For example, Boulder's suggestions include a PIM for Company-owned projects that would use as a baseline the cost of seemingly lower priced bids as well as a PIM to address the capacity factors for gas resources.²⁰² COSSA/SEIA suggests that the Commission consider deploying a PIM that would incentivize the on-time construction and deployment of new

¹⁹⁷ Response to Decision No. C23-0672-I, p. 11.

¹⁹⁸ Response to Decision No. C23-0672-I, pp. 12-13.

¹⁹⁹ Response to Decision No. C23-0672-I, p. 13.

²⁰⁰ Response to Decision No. C23-0672-I, pp. 1-2.

²⁰¹ Staff Response to Risk Sharing Mechanism, p. 14.

²⁰² Boulder's Comments, pp. 14-15.

transmission assets.²⁰³ Conservation Coalition in turn proposes a mechanism in which the Company would bear any incremental costs for hydrogen conversion of its gas plants.²⁰⁴

176. In its Response Comments, the Company appears to argue that the cost to construct PIM should only be a fixed capital cost approach based on the total portfolio. Without much explanation, Public Service states that to facilitate approval of a PIM framework in this Proceeding, there should be no dead band for the construction capital cost PIM. Instead, the baseline should be set at the approved portfolio capital budget/point cost estimate.²⁰⁵

177. For the operational PIM, the Company argues in its Response Comments that the baseline should be adjusted to exclude the effect of construction capital expenditures in order to avoid such capital expenditures being subject to both PIMs. Public Service states that this is necessary to avoid double penalty or double reward.²⁰⁶ In addition, the Company states that the evaluation period for projects subject to the operational PIM should occur on three-year intervals beginning with the first through third full calendar years of project operation. As an example, for a project with a commercial operation date of September 30, 2026, the evaluation period for the operational performance PIM would begin January 1, 2027, and extend through December 31, 2029. Public Service argues that this promotes administrative efficiency and better addresses annual variation in weather, maintenance patterns and other performance drivers.²⁰⁷

178. In contrast, Public Service vehemently opposes Staff's proposal, stating that "[t]he magnitude and ramifications of this proposed sea change are difficult to overstate."²⁰⁸ Public Service asserts that Staff's PIM would "essentially deregulate generation in the state" in

²⁰³ COSSA/SEIA's Comments, pp. 20-21.

²⁰⁴ Conservation Coalition's Comments, pp. 16-17.

²⁰⁵ Public Service's Response Comments, pp. 81-82.

²⁰⁶ Public Service's Response Comments, p. 82.

²⁰⁷ Public Service's Response Comments, p. 82.

²⁰⁸ Public Service's Response Comments, p. 83.

that it would reconstitute the Company as an IPP in all but name.²⁰⁹ The Company argues that Staff's proposal would increase the risks conferred to the Company with little incremental benefit and no opportunity to price that risk into its bids. Public Service asserts that, if implemented, Staff's proposal "would require the Company to reassess its project commitments, increasing the cost and delaying the delivery of this plan, or whatever is left of it."²¹⁰

179. On December 19, 2023, Public Service filed its Response to Decision No. C23-0841-I, providing additional point costs and capacity factors data in connection with the Alternative Portfolio and setting forth the Company's proposed sharing percentages for the operational PIM in a non-confidential format.

2. Findings and Conclusions

180. The Commission appreciates that the Company has "sharpened its pencil" and is willing to "stand behind its pricing and performance metrics as bid."²¹¹ Given the significant amount of Company-owned generation projects in the portfolio of resources Public Service will acquire,²¹² this confidence and willingness to share risks is an important component of our decision to move forward with the Alternative Portfolio. In other contexts, costs, performance, or scheduling issues have increased costs for customers relative to the initial estimates the Company provided, and material changes to the cost and performance metrics of a project could impact the justification of the need determinations made in the ERP process.²¹³ More generally, competitive solicitation is the lynchpin of Colorado's ERP process, and a successful competitive solicitation

²⁰⁹ Public Service's Response Comments, p. 83.

²¹⁰ Public Service's Response Comments, p. 86.

²¹¹ Response to Decision No. C23-0672-I, p. 4.

²¹² Of the 5,835 MW that the Alternative Portfolio contemplates acquiring, Public Service would own 53.7 percent of the capacity resources and 67.3 percent of the energy resources. (120-Day Report (Appendix S), Rev. 1, p. 26.)

²¹³ See Decision No. C23-0672-I, pp. 2-3.

relies upon some degree of certainty that, after winning at a lower price, bidders will not be able to materially increase the price of their bids without consequences. To date, the Commission has not had a mechanism in place to hold the Company to their bids and performance, in a similar way to the IPP contracts, which has increasingly become a point of concern. In Phase I of this Proceeding, the Company put forth a plan to convert the Brush Coal Plant to burn natural gas at a capital cost of \$44 million. The Commission and parties relied upon the information provided by the Company to make decisions in Phase I of this Proceeding, broadly considered the Company's Coal Action Plan, which was agreed to be carried forward into the Phase II modeling. Several months later, the Company put forth a CPCN application to complete the conversion at the significantly increased cost of \$85 million. The Commission finds a compelling need to ensure that the pricing relied upon during this Proceeding will not be significantly altered after the fact without a meaningful sharing of risk with the Company. The Company-ownership PIMs that Public Service proposes help ensure that the Commission is making informed resource acquisition decisions, promoting fairness amongst the bidders and the Company, and providing necessary protections to ratepayers.²¹⁴

181. Accordingly, as part of the Commission's approval of the planned acquisition of Company-owned generations projects consistent with the Alternative Portfolio, we adopt a cost to construct PIM and an operational PIM for all Company-owned generation projects arising from this Proceeding.²¹⁵ These cost to construct and operational PIM are based on the Company's proposals, subject to the modifications detailed below.

²¹⁴ See Decision No. C23-0672-I, pp. 2-3.

²¹⁵ The cost to construct PIM applies to all Company-owned generation projects from this Proceeding, including Bid 1029. As set forth below, however, the operational PIM only applies to Company-owned LEC projects.

a. Cost to Construct PIM

182. Starting with the cost to construct PIM, we reject the Company's arguments that the cost to construct PIM should be applied on a portfolio basis. Rather, the cost to construct PIM shall be a project-specific PIM for each Company-owned project in the Alternative Portfolio. Applying this PIM on a portfolio level would be inconsistent with how IPP bids are treated and contrary to the underlying principles of the competitive solicitation that each project must stand on its own.

183. The baseline for each cost to construct PIM will be the point cost for capital costs to construct the particular generation project that was used in the Company's Phase II bid. In its Response to Decision No. C23-0672-I, Public Service states that "each Company-owned bid has a point cost for capital cost to construct that can serve as a baseline for PIM evaluation purposes."²¹⁶ During the course of Phase II, the Company provided the point costs for all relevant Company-owned projects.

184. Under the cost to construct PIM, there would be a five percent dead band around the baseline in which Public Service earns no incentive or disincentive. Outside of the five percent dead band, however, the Company and ratepayers would share any cost overruns or savings based on three symmetrical tiers. Specifically, for a total variance of more than 5.0 percent through 10.0 percent above or below the baseline, 40 percent of the cost overruns or savings would be allocated to Public Service. For a variance of more than 10.0 percent through 15.0 percent above or below the baseline, 50 percent of the cost overruns or savings would be allocated to Public Service. For any variance above or below 15.0 percent of the baseline, 60 percent of the cost overruns or savings would be allocated to Public Service.

²¹⁶ Response to Decision No. C23-0672-I, p. 6.

185. The sharing percentage will be applied to the overage and not on the total project amount. Also, there will be no deduction due to the 5 percent dead band or any other previous tiers. For example, if a project with a \$100 million point cost is actually constructed for \$114 million, Public Service would incur a \$7 million disincentive; *i.e.*, the 14 percent overage means that 50 percent of additional costs are allocated to Public Service (50 percent of \$14 million is \$7 million). The same calculation would be used if Public Service was able to construct the project for only \$86 million. In that scenario, the Company would earn a \$7 million incentive. Resolution of the appropriate PIM assessment (*i.e.* the calculation of any incentive or disincentive) will occur in the first rate case following the ISD of the relevant generation project.

b. Operational PIM

186. Turning to the operational PIM, the baseline will be the LEC for the relevant project set forth in the corrected Appendix P. The operational PIM will be applied on a project-specific basis. Except for LCC-based projects like standalone storage and gas, the operational PIM will apply to all Company-owned generation arising from this Proceeding. Regarding the exclusion of LCC-based projects, we find persuasive the Company's argument that including such project could have an unintended consequence of incentivizing the overuse of dispatchable resources in order to avoid penalties or to accrue incentives.²¹⁷

187. The Commission rejects the 15 percent dead band that Public Service proposes for the operational PIM and will replace it with a 5 percent dead band around the LEC baseline. This narrower dead band is supported by—among other things—CIEA's Comments. CIEA asserts that the Company either exaggerates or obscures the true costs and risks of its proposal when compared to PPA arrangements. CIEA points out that IPPs have no dead band around their bid

²¹⁷ Response to Decision No. C23-0672-I, p. 12.

price and suggests that the Company should not have the benefit of a dead band either.²¹⁸ While we do not agree that removing the dead band altogether is appropriate, we agree with CIEA that the intent of the PIM is to set the Company's bidding risk on par with IPPs more readily. Establishing the mechanism here with a narrower dead band than proposed by the Company better aligns these goals.

188. Aside from the narrower dead band, the basic calculation structure for assessing the incentive or disincentive under the operational PIM would generally match the Company's proposal. Specifically, for variances of more than 5 percent through 10 percent above or below the baseline, 20 percent of the costs or savings would be allocated to Public Service. For variances of more than 10 percent through 15 percent above or below the baseline, 30 percent of the costs or savings would be allocated to Public Service. For variances of more than 15 percent through 20 percent above or below the baseline, 40 percent of the costs or savings would be allocated to Public Service. For variances of more than 20 percent through 25 percent above or below the baseline, 50 percent of the costs or savings would be allocated to Public Service. And finally, for any variance more than 25 percent above or below the baseline, 60 percent of the costs or savings would be allocated to Public Service.²¹⁹

189. Regarding the timing of performance evaluations, the Commission agrees with the Company that performance evaluation for projects should be conducted on a three-year rolling average after the third full operational year is complete and on a similar cadence thereafter.²²⁰

²¹⁸ CIEA's Comments (Attachment A), p. 5-6.

²¹⁹ See Public Service's Response to Decision No. C23-0841, pp. 2-3.

²²⁰ In its Response Comments, Public Service provides the following example of this timing: "As an example, for a project with a commercial operation date of September 30, 2026, the evaluation period for the operational performance PIM would begin January 1, 2027 and extend through December 31, 2029." (Public Service's Response Comments, p. 82).

This approach will stagger the performance reviews so that a subset of projects (*e.g.*, all those with 2026 ISDs) is evaluated each year.

190. We similarly agree with Public Service's arguments that the baseline of the operational PIM should be adjusted to exclude the effect of construction capital expenditures in order to avoid such capital expenditures being subject to both PIMs.²²¹ Excluding the effect of construction capital expenditures is necessary to avoid double penalty or double reward.

191. In connection with the establishment of the operational PIM, all projects subject to the operational PIM in this Proceeding will receive cost recovery through the appropriate rider (RESA or ECA) from the ISD of the project until the project is rolled into base rates.

192. While we direct that the operational PIM as described above apply to all Company-owned LEC projects arising from this Proceeding, we recognize that certain considerations warrant further exploration in future proceedings. For instance, we invite interested stakeholders and the Company to explore whether an operational PIM could be crafted in which the baseline is derived from the project's estimated capacity factor as opposed to the estimated LEC. This would essentially exclude factors such as the capital construction costs and the Company's estimated WACC. We welcome a more robust consideration of this approach in the upcoming 2024 JTS.

193. Similarly, we reiterate the importance of timing as a performance metric,²²² and have a strong interest in evaluating in the follow-on CPCN proceedings a mechanism to incentivize timely completion of Company-owned projects, in accordance with the timing anticipated in the modeling and bidding processes. For example, one possibility would be to commence the LEC

²²¹ Public Service's Response Comments, p. 82.

²²² See Decision No. C23-0672-I, ¶ 6.

calculations on the as-bid ISD of the Company-owned project. Thus, if the as-bid ISD of a project was May of 2026 but the project experienced delays and did not commence operations until October 2026, this six-month delay would decrease the project's achieved LEC as compared to the as-bid baseline LEC. While we do not adopt this structure as part of this Decision, we intend to evaluate in the follow on CPCN proceedings how best to align the Company's incentives regarding the completion of generation projects.

194. Regarding curtailments, we likewise intend to continue evaluating in the follow on CPCN proceedings how exactly the operational PIM should account for curtailments. To be clear, we do not intend for the operational PIM to somehow shift the risk of curtailments on to the Company. The issue of appropriately disincentivizing curtailments across the entire electrical system is better addressed elsewhere, including possibly through the emissions reduction PIM that the Phase I Decision contemplates. In this way, we largely agree with the Company's position that the operational PIM should not seek to manage curtailments.²²³ Nevertheless, there are unresolved details regarding how to make the operational PIM appropriately indifferent to curtailments, and we intend to address these details in the follow on CPCN proceedings.

c. Extraordinary Circumstances

195. Finally, as to both the cost to construct PIM and the operational PIM, the Commission finds merit in Public Service's argument that the Company should be able to petition the Commission for relief in the event of extraordinary circumstances. In other words, Public Service can seek relief from the Commission for any amounts assessed to the Company under either the cost to construct PIM or the operational PIM, with the Company bearing the burden of establishing the existence of extraordinary circumstances and the impact of any such

²²³ Response to Decision No. C23-0672-I, pp. 12-13.

circumstances on unit construction.²²⁴ We clarify that the starting point for the definition of “extraordinary circumstances” could be similar to the definition of “force majeure” in the Model PPA for Wind and Solar.²²⁵ That said, in the proceeding in which the Company attempts to establish the existence of extraordinary circumstances, the parties—including the Company—may advocate for modifications to the definition of “extraordinary circumstances” as appropriate, recognizing that Company-owned projects may not have identical extraordinary issues to the Model PPA.

d. Other proposed PIMs

196. We decline to implement Staff’s proposed PIM in this Proceeding given our adoption of a cost to construct PIM and operational PIM. Nevertheless, we are intrigued about the possibilities offered by Staff’s PIM. As Staff notes, under its PIM, cost recovery increases in direct proportion to the amount of renewable energy the assets produce while also tying cost recovery to Public Service’s Phase II bids. Likewise, the PIM would account for both capital construction costs and performance of the assets.²²⁶ The Commission sees Staff’s PIM as a potential avenue to engage in performance based regulation (PBR) on a more fundamental level as opposed to simply overlaying PIMs on top of the standard cost of service ratemaking, providing a potential opportunity to realign utility incentives to benefit ratepayers.

197. Many of Public Service’s arguments against Staff’s PIM are focused on why it should not be applied to the Company-owned projects arising from this Proceeding. Arguments that Staff’s PIM “moves the goalposts” after submission of Phase II bids and that Staff’s PIM has many unresolved details might be legitimate as to this Proceeding but are far less

²²⁴ Response to Decision No. C23-0672-I, p. 15.

²²⁵ Hearing Exhibit 101, Attachment AKJ-3 (Volume 3.2), pp. 142-43.

²²⁶ Staff’s Response to Decision No. C23-0672-I, pp. 14-15.

persuasive regarding future implementation of Staff's PIM. Given the Commission's longstanding interest in PBR and the fact that the Commission has already approved a similar approach for one of Black Hills' wind projects,²²⁷ the Company's claims that Staff's PIM would essentially deregulate generation in Colorado seem exaggerated.

198. The Commission intends to evaluate in the 2024 JTS whether Staff's PIM can be applied to the Company-owned projects arising from that proceeding. As such, we request that Public Service confer with Staff on its proposed PIM²²⁸ prior to the 2024 JTS in an attempt to reach consensus. Regardless of the outcome of the conferral, we invite the parties in the 2024 JTS to raise this issue for our continued consideration.

199. As for the remaining proposed PIMs, including those that Boulder, COSSA/SEIA, and Conservation Coalition put forth in their comments, we decline to adopt these concepts in this Proceeding. Although the expedited nature of this Phase II process did not allow for the development of a robust record for these proposals, we invite the parties to consider bringing these proposals forward in the PIM stakeholder process that the Phase I Decision contemplates and through future proceedings.

H. The Sand Creek Massacre National Historic Site and Bid 1029

200. Bid 1029 is included in the Preferred Portfolio, the UPP, and the Alternative Portfolio and is a 500 MW Company-owned wind project with an in-service date of 2026. Although the Commission does not know the precise location of Bid 1029, it appears to be close to and possibly adversely impacts, the Sand Creek Massacre National Historic Site view shed.

²²⁷ Staff recounts that Black Hills recovers the cost of the Peak View wind farm exclusively through the ECA and RESA for the first ten years of commercial operation. (Staff's Response to Decision No. C23-0672-I, p. 9).

²²⁸ This conferral should include further evaluation of whether Staff's PIM could be modified to apply to LCC-based projects instead of only LEC-based projects.

201. On October 25, 2023, elder and tribal administrator Mr. William Walksalong of the Northern Cheyenne Nation spoke at the Commissioner's weekly business meeting. Through comments, tribal representatives requested that the Commission protect from energy development the viewshed of the Sand Creek Massacre National Historic Site given its sacred importance to several tribal nations. In addition, Mr. Walksalong asked that the Commission ensure that energy development not disturb any human remains or cultural artifacts from the area around the Sand Creek Massacre National Historic Site. Mr. Walksalong noted that the massacre spilled well-beyond the boundaries of the Sand Creek Massacre National Historic Site that Congress has designated. Consequently, he urged the Commission to require utilities and developers to consult tribal representatives as to how to proceed should remains or artifacts be discovered in the course of construction.

202. In its comments, Staff recommends the Commission not approve Bid 1029 as part of this Proceeding. Staff asserts that a preliminary viewshed analysis indicates that wind turbines from Bid 1029 might impact the Sand Creek Massacre National Historic Site's viewshed. Staff also ran its own modeling runs that forced the model to exclude Bid 1029 and suggests that the Commission could approve a 200 MW solar plant (Bid 375) or a 603 MW wind plant (Bid 1024) in place of Bid 1029.²²⁹

203. CEO also recognizes concerns regarding Bid 1029 but does not suggest that the Commission exclude it from the approved CEP. Rather, CEO recommends the Commission direct the Company to include additional information in subsequent CPCNs, including discussions between the Company and Tribal governments regarding the proposed projects, the status of those

²²⁹ Staff's Comments, p. 58-59.

discussions, and any outcomes or results of such discussions.²³⁰ CEO argues that approach will allow the Commission to take action in the instant proceeding consistent with the presentation by the Northern Cheyenne Nation and also rely on the existing CPCN process to consider alternatives and proposed impacts when making a determination on specific resource proposals.²³¹

204. In its Response Comments, Public Service argues that Bid 1029 has “strong economics” and was included in almost all portfolios. Thus, the Company maintains that it would be premature to set this bid aside. Public Service does, however, acknowledge Staff’s concerns and states that the identified impacts are important to work through and address. Indeed, the Company states that it is already engaged with these issues. Ultimately, Public Service asks that the Commission allow Bid 1029 to move forward and states that the Company would then provide an update on efforts to mitigate the impacts of concern in the follow on CPCN proceeding.²³²

205. The Commission agrees with the positions of Public Service and CEO and rejects Staff’s proposal to exclude Bid 1029 from the approved CEP. We emphasize, however, that allowing the Company to include Bid 1029 in the Alternative Portfolio is in no way an approval of the project, which must necessarily be vetted through continued stakeholder and community considerations. In this vein, we adopt Public Service’s suggestion to approve a backup bid for Bid 1029 so that the Company can pivot to a different project if stakeholder processes, including the Company’s further discussions with the Northern Cheyenne Nation, do not resolve concerns. In addition, we adopt CEO’s recommendation and direct Public Service to include additional information in subsequent CPCN proceedings, including discussions between the Company and Tribal governments.

²³⁰ CEO’s Comments, pp. 26.

²³¹ CEO’s Comments, pp. 26.

²³² Public Service’s Response Comments, pp. 23-24.

206. Resolution of this issue will require collaboration of the interested stakeholders, and we are encouraged by indications that Public Service is already engaging with the Northern Cheyenne Nation regarding Bid 1029. In this instance, Public Service needs to take the lead and work with interested stakeholders, including the Northern Cheyenne Nation, to address potential impacts to the Sand Creek Massacre National Historic Site.

207. As to the precise backup for Bid 1029, in its Response Comments Public Service recommends that the Commission approve Bid 1018. However, Bid 1018 is unavailable as a backup because it is located on the MVLE, which the Alternative Portfolio does not include. Ultimately, we permit the Company discretion to select an appropriate backup for Bid 1029 pursuant to the approved backup selection process set forth in this Decision. We note, however, that Bid 1016 (a 554 MW Company-owned wind bid) appears to be a good candidate.

I. Hayden Biomass

208. Bid 1031 is a 19 MW Company-owned biomass project that Public Service proposes as a Section 123 resource.²³³ The proposed project is located near Hayden, Colorado to support workforce transition as part of the planned retirement of the Hayden coal units.²³⁴

209. Public Service states that it would employ 26 full-time employees, thus reducing workforce transition costs associated with the early retirement of the Hayden coal plants. Public Service further asserts that the project, which is anticipated to use primarily forest waste from fire prevention activities and debris from pine beetle outbreaks, is carbon neutral and would reduce air emissions, including particulate matter, carbon monoxide, volatile organics, and

²³³ Public Service also states that it “complies with the spirit of” the portfolio development framework for HB 21-1324. (120-Day Report, p. 52).

²³⁴ In its Response Comments, Public Service intentionally presents the bid name with the bid ID as public information.

nitrogen oxides.²³⁵ In comparing the Preferred Portfolio with the Hayden biomass project to a reoptimized portfolio without the project, the portfolio excluding biomass adds 19 MW gas and 200 MW solar and is \$257 million less in PVRR.²³⁶

1. Party Comments

210. The Labor Interests argue that the Hayden biomass project should belong in any Commission-approved portfolio, listing its benefits as including 26 well-paid jobs and a high total BVEM rating for its construction phase. The Labor Interests add that the Hayden biomass unit represents an innovative technology under both Section 123 and HB 21-1324, noting that wind and solar projects have often dominated discussions about innovation despite patterns of low-paying jobs post-construction.²³⁷

211. CEO supports the inclusion of the Hayden biomass plant in the Commission-approved CEP primarily because of its just transition benefits. CEO acknowledges, however, that Public Service “does not provide information on the salaries or the estimated tax benefits” and requests that the Company provide more details about the public benefits of the project “so the Commission has a full record on which to make its Phase II decision.”²³⁸ CEO also notes the relatively high cost of the biomass plant, concluding that the Hayden biomass project increases the PVRR of the Preferred Portfolio by \$257 million.²³⁹ CEO recommends that if the Commission does not approve the Hayden Biomass project here, the Commission direct the Company to evaluate the project in future ERPs for additional consideration.²⁴⁰

²³⁵ 120-Day Report, p. 40.

²³⁶ 120-Day Report, p. 138.

²³⁷ Labor Interests’ Comments, pp. 11-14.

²³⁸ CEO’s Comments, p. 23.

²³⁹ CEO’s Comments, p. 22.

²⁴⁰ CEO’s Comments, pp. 17.

212. OJT endorses CEO's Comments as to the just transition issues, including the evaluation of the Hayden biomass project.²⁴¹ OJT opines that the biomass project would employ a third of the coal plant's current workforce, generate a "significant, though yet-unspecified, amount of property tax revenues," and create long-term supply chain jobs in the region for timber harvesting and processing.²⁴² However, OJT also requests that Public Service provide more specific information on the expected local economic and employment benefits, including information about jobs retained or created and property and other tax revenues generated.²⁴³

213. Public comments from entities such as the Moffat County Board of County Commissioners, the Routt County Board of County Commissioners, the City of Craig, Northwest Colorado Development Council, Colorado State Senator Dylan Roberts, and the Town Council and Mayor of Hayden also expressed support for the Hayden biomass project, citing the risk that not replacing the coal plant will lead to cascading effects in the form of losing high-paying jobs and reducing funding for important government services.

214. In contrast, certain other parties recommend the Commission reject the Hayden biomass project and potentially reconsider it in an alternative proceeding, mostly pointing to the upcoming 2024 JTS. For example, CEC asserts that the Company has not established that the project is the best solution for the Hayden community, nor that it is worth the additional expense or necessary for emissions reductions.²⁴⁴

215. Staff argues that the Hayden biomass project is very high cost and is overall uneconomic, with unclear information about jobs benefits and tax revenue replacement.

²⁴¹ OJT's Comments, p. 3.

²⁴² OJT's Comments, p. 6.

²⁴³ See OJT's Comments, pp. 3, 6.

²⁴⁴ CEC's Comments, pp. 13-14.

Staff asserts that the Hayden biomass plant is not designed as a closed-loop facility and thus will not enjoy access to a full production tax credit, meaning that the cost of the biomass unit presented in the 120-Day Report is artificially low. Staff states that it conferred with the Company, which agreed with this critique.²⁴⁵ Staff also raises concerns that the Hayden biomass project is not sufficiently novel or scalable to be a Section 123 project.²⁴⁶ Staff suggests that the Commission consider alternatives to the biomass facility in future proceedings.²⁴⁷

216. Similar to Staff, WRA raises concerns not only about cost, but also about environmental claims made about the Hayden biomass project. Referencing recent studies, WRA asserts that emissions from the harvesting stage strongly erode any potential emissions benefit, and inefficiencies mean electricity generation with woody biomass can be more carbon-intensive per MWh than coal-generated electricity.²⁴⁸ WRA argues that Public Service's assertions about the Hayden biomass project being greenhouse gas neutral are incorrect as a matter of practice—biomass electricity generation produces carbon dioxide—and also that the Company has failed to provide information demonstrating that emissions released from combustion are less than would have been emitted without being converted to electrification, pursuant to § 40-2-124(1)(a)(IV).²⁴⁹ Moreover, WRA states that the 120-Day Report provides insufficient information about planned forest management practices and leaves open the idea that other fuel would be used besides that from fire prevention and pine beetle kill.²⁵⁰

217. Like Staff and WRA, Conservation Coalition raises concerns that greenhouse gas emissions from the biomass project will exceed the Company's estimates. Conservation Coalition

²⁴⁵ Staff's Comments, p. 53.

²⁴⁶ Staff's Comments, pp. 51-52.

²⁴⁷ Staff's Comments, p. 51.

²⁴⁸ WRA's Comments, pp. 9-10.

²⁴⁹ WRA's Comments, p. 11.

²⁵⁰ WRA's Comments, p. 12.

argues that the Commission can consider additional measures for the Hayden community in the 2024 JTS, noting that the last unit at Hayden is not scheduled to retire until 2028.²⁵¹ Additionally, public comments from entities like 350 Colorado similarly urge the Commission to find other ways to meet just transition needs due to environmental risks associated with the proposed biomass project, including air pollutant emissions and the potential that salvage logging and deforestation activities may be required to meet fuel needs.

218. In its Response Comments, Public Service reiterates that the Hayden biomass project contributes to three policy objectives: developing clean firm dispatchable capacity with wildfire mitigation benefits, making progress towards emissions reduction goals, and providing just transition benefits. The Company states that not providing new workforce opportunities for communities affected by energy transition is “not a viable path.”²⁵² However, Public Service also recognizes that questions about cost and tax credit eligibility are legitimate, and therefore proposes alternative procedural pathways, including conditional approval of the project with additional analysis in a follow-on CPCN filing or consideration within the Hayden JTP filing.²⁵³

2. Findings and Conclusions

219. In its Phase I Decision, the Commission approved provisions of the Phase I Settlement specifying that Public Service will make follow-on JTP filings for each area with an affected coal plant after the Phase II final decision.²⁵⁴ For purposes of Phase II modeling, JTP costs will include costs associated with workforce transition and community assistance.

²⁵¹ Conservation Coalition’s Comments, pp. 15-16.

²⁵² Public Service’s Response Comments, p. 19.

²⁵³ Public Service’s Response Comments, pp. 19-20.

²⁵⁴ Phase I Settlement, ¶ 109.

220. Regarding the Hayden 1 and Hayden 2 coal plants, the estimated costs of the community assistance is the projected lost property tax revenues for six years following retirement of the respective plant, but these costs may be offset by other investments in the community.²⁵⁵

221. The Commission takes seriously its role in supporting a just transition for workers and communities that are impacted by the closure of coal units as part of creating a cleaner energy system. The labors and skills of these communities helped propel Colorado's economy and the reliable electricity we have enjoyed for generations. We have a commitment to do what we can to ensure these communities are not left behind in the energy transition, and this might go beyond even the six-year commitment that was contemplated in the Phase I Settlement. Regarding the closures of Hayden 1 and Hayden 2, we recognize the transmission resources that will be made available in the near future as well as the potential expansion of these transmission resources into the western market. In short, the Commission is hopeful that there will be opportunities for resource development that benefit both local communities and ratepayers in general.

222. Nevertheless, we decline to approve the Hayden biomass project in this Proceeding. We do not have in front of us a complete proposal that allows us to determine whether the project is in the public interest. For example, we are concerned by Staff's assertion that the Company will not qualify for closed-loop biomass tax credits, which leaves the actual cost of the project uncertain, and we are troubled by the potential environmental impacts of the plant that WRA and others raise. Moreover, even CEO and OJT seem to acknowledge that the current proposal lacks important information regarding workforce transition and community benefits. The Hayden biomass project would cost ratepayers approximately \$257 million in PVRR before upward

²⁵⁵ Phase I Settlement, p. 19.

adjustments due to tax credit miscalculations, and this is for a relatively small 19 MW project that would replace what has been hundreds of MW of capacity from the Hayden coal plants.²⁵⁶

223. While we decline to approve the Hayden biomass project here, in the event Public Service develops clearer answers to the questions raised by parties about the environmental, financial, workforce, and community benefits of the plant, we encourage the Company to bring this or another just transition proposal forward for further consideration as part of the 2024 JTS. The 2024 JTS proceeding²⁵⁷—as opposed to the Hayden JTP or a standalone CPCN—will allow the Commission and stakeholder to evaluate the costs and benefits of the biomass project, if rebid, more holistically with other alternatives, including potentially other bids from IPPs that could provide similar tax, employment, and other benefits to the local community. We conclude that reconsidering this or other similar projects in a full competitive solicitation will be the best way to maximize benefits to both the Hayden community and to ratepayers more generally.

224. To effectuate this, Public Service shall confer with relevant stakeholders and determine whether it makes sense to bring forward the Hayden JTP within 120 days of the Phase II decision, consistent with approved provisions of the Phase I Settlement, or to postpone that filing. In conferral with settling parties, and particularly those affected by the potential Hayden JTP filing, since the Hayden Biomass project or other beneficial projects could potentially be reevaluated in the 2024 JTS, we permit flexibility on whether the Hayden JTP should be filed 120 days following the Phase II decision or at a later date.

²⁵⁶ See CEO's Comments, p. 22 (comparing Preferred Portfolio with Hayden biomass to the Preferred Portfolio without Hayden biomass).

²⁵⁷ The Commission emphasizes that the primary focus of the 2024 JTS is the replacement of Unit 3 and the corresponding impacts to the Pueblo community. Nevertheless, as an interim ERP the 2024 JTS also provides an opportunity to evaluate more holistically the various resource opportunities in the Hayden community.

J. Backup Bids

225. In the 120-Day Report, the Company proposes three tools to mitigate the risks associated with potential project failure: extensive due diligence, right of first offer (ROFO), and backup bids. Public Service further notes that the 2024 JTS allows for a more rapid opportunity to course correct than the standard four-year ERP cycle typically provides.²⁵⁸ Regarding the backup bids, Public Service states that these bids are intended to be pre-approved by the Commission as a set of projects to be “next in line” to replace a project in the approved portfolio if it fails.

1. Party Comments

226. Staff is generally supportive of the establishment of a pool of back-up resources. However, Staff is concerned that approving a backup pool of bids that includes both Company-owned and PPA bids may create perverse incentives for the Company in negotiating projects. For instance, Staff questions whether the Company’s PPA negotiations with an IPP would be impacted if the IPP project would be replaced with a Company-owned project.²⁵⁹

227. Staff recommends that the Commission consider a back-up bid replacement process in which additional process is required for Company-owned backup bids. If a failed project is being replaced by a PPA project, the Company should notify the Commission of such a failure and the steps it intends to take to address the failure, but the Company need not seek Commission approval prior to commencing negotiations. If a failed project is being replaced by a Company-owned project, however, the Company would be required to do the following: (a) notify the Commission and provide additional evidence and detail regarding the steps taken to attempt to

²⁵⁸ 120-Day Report, pp. 44-46.

²⁵⁹ Staff’s Comments, p. 66.

remediate the failed project; (b) retain the burden to prove that the Company-owned project was the prudent replacement; and (c) provide robust alternatives analysis as part of the follow-on CPCN proceeding. Regarding the available pool of backup bids, Staff recommends that any project included in the Company's inverse Preferred Portfolio that is not ultimately approved in this Proceeding should be eligible for inclusion in the back-up pool.²⁶⁰

228. Similar to Staff, CIEA approves of the backup bid concept and recommends that the Commission approve the backup bid projects as contingency projects. However, CIEA asserts that it will be important for the Commission to clarify the back-up bid process and list clear criteria to avoid controversy in the implementation of Phase II.²⁶¹

229. COSSA/SEIA also raises concerns with perverse incentives that could arise when an IPP project fails but focuses its concern on the Company's ROFO. The ROFO is a provision in the model PPA that allows the Company to step into a failed IPP project and take over development. COSSA/SEIA recommends that the Commission require the Company to first use its identified list of backup bids before deploying the ROFO, as the latter guarantees that the Company's ownership share will grow after a project fails. COSSA/SEIA argues that allowing for ROFO to be used prior to backup bids could incentivize the Company to slow-walk PPA negotiations, placing IPP projects in peril, with the knowledge that the Company can simply offer to buy the developer out if or when the project goes south.²⁶²

230. In its Response Comments, the Company agrees that some of the intervenor recommendations have merit but argues for the importance of maintaining price integrity and

²⁶⁰ Staff's Comments, p. 66.

²⁶¹ CIEA's Comments, pp. 24-25.

²⁶² COSSA/SEIA's Comments, pp. 18-20.

allowing for flexibility to move to a backup bid for timely replacement.²⁶³ The Company argues that, to the extent practicable, the Company will try to select “like for like” backup bids both in terms of technology and ownership. More specifically, Public Service argues that it should be able to move forward with an IPP backup bid after a simple notice provided to the Commission and when the backup bid is Company-owned, the Company should only be subject to a “limited-scope” CPCN process similar to any other Company-owned project in an approved resource plan.²⁶⁴

231. Public Service argues against adopting an approach set forth by Staff and others in which the Company would be required to undergo more process when it replaces an IPP project with a Company-owned project. The Company acknowledges the “academic” concerns about perverse incentives but argues that its commitment to strive for “like for like” replacements and the Company’s conduct in this Proceeding should comfort the Commission.²⁶⁵ Public Service further argues that a limited scope CPCN is appropriate because Company-owned replacement projects would need to move quickly in order to meet resource needs.

232. Public Service also argues the presumption of prudence under Rule 3617(d) should apply to all backup bids as they move forward, providing regulatory certainty for these projects.

233. Finally, in its Response Comments, Public Service notes two resource modifications in the UPP: (1) replacing a Company-owned solar plus storage project (Bid 0476) with an IPP solar plus storage project (Bid 0303), and (2) replacing a Company-owned wind project (Bid 0045) with a different Company-owned wind project (Bid 1024). The Company also requests that the Commission approve a specific backup for Bid 0044. Bid 0044 is an IPP wind

²⁶³ Public Service’s Response Comments, pp. 39-40.

²⁶⁴ Public Service’s Response Comments, p. 42.

²⁶⁵ As an example of the Company’s conduct, Public Service notes that in the UPP the Company proposes to replace a Company-owned bid (Bid 0467) with an IPP bid (Bid 0303). (Public Service’s Response Comments, p. 42).

bid that might not be able to move forward at its as-bid price. The Company requests that the Commission approve Bid 0254 as its backup. Bid 0254 is also an IPP wind project.²⁶⁶

234. Because the resource modifications in the UPP impact the backup bid portfolio, Public Service provides an updated portfolio of backup bids set forth in Table 3 of its Response Comments.²⁶⁷

2. Findings and Conclusions

235. At the outset, the Commission expressly approves the updated list of backup bids set forth in Table 3 of the Company's Response Comments. Recognizing that the backup bids in Table 3 were compiled in anticipation of the UPP and not the Alternative Portfolio, however, we clarify that the Company may use its discretion to adjust the portfolio of backup bids as necessary given the authorizations we have attached to the Alternative Portfolio. For instance, consistent with Staff's recommendation to include projects from the inverse Preferred Portfolio, it would be reasonable to include as a backup bid any bid within the UPP that is not in the Alternative Portfolio.

236. In addition, we agree with the Company's position and confirm that the presumption of prudence set forth in Rule 3617(d) applies to any backup bid that moves forward in accordance with the Commission's approved process for selecting backup bids.

237. Regarding the selection of backup bids, the Commission finds merit in the concerns raised by Staff, CIEA, and COSSA/SEIA that there should be more process in place for when Public Service selects a Company-owned backup bid or when the Company uses its ROFO to buy-out a failing IPP bid. We find persuasive the arguments regarding perverse incentives and worry that without additional process, the selection of a Company-owned backup bid or the

²⁶⁶ See Public Service's Response Comments, p. 6.

²⁶⁷ Public Service's Response Comments, p. 27.

exercise of the Company's ROFO could give rise to the appearance of bias. While the Commission acknowledges the benefits of allowing the Company discretion to quickly pivot to a backup bid, these benefits must be balanced with guardrails that protect customers, enhance fairness amongst bidders, and increase transparency. Conversely, the Commission disagrees with suggestions from CIEA that the Commission should establish clear criteria for the selection of backup bids or mandate like-for-like replacements. Apart from concerns regarding the selection of a Company-owned bid instead of an IPP project, we believe that Public Service should have the flexibility to use its discretion to select the most appropriate backup bid.

238. Accordingly, we generally adopt Staff's suggested approach in which—among other things—Public Service retains the burden of proving that any Company-owned backup project was the prudent replacement and would need to provide a robust alternatives analysis as part of the follow-on CPCN proceeding.²⁶⁸ The additional protections set forth in Staff's approach also apply when the Company exercises its ROFO and when the Company replaces a Company-owned project with a Company-owned backup. That said, we emphasize that the additional process set forth in Staff's proposal must move quickly, especially in instances in which the replacement is like for like.

239. Finally, we clarify that the backup bid selection process set forth above does not apply to the two replacement projects the Company proposed as part of the UPP. Specifically, the Company may replace Bid 0476 with Bid 0303 and may replace Bid 0045 with Bid 1024. The Company already explains the need for replacement and the economics of alternative backup bids in its Response Comments. Moreover, the concerns that the Company would have perverse incentives during PPA negotiations do not apply at this point in the process. For the same reasons,

²⁶⁸ See Staff's Comments, p. 66.

we approve Bid 0254 as the backup bid for Bid 0044 if Bid 0044 cannot move forward. Acknowledging that the Company's Response Comments presumed the selection of the UPP, as opposed to the Alternative Portfolio, we clarify that the Company has the flexibility to make the necessary resource modifications consistent with the Company's Response Comments.

K. Section 123 Resources

240. In the 120-Day Report, Public Service states five bids qualified as Section 123 Resources pursuant to the criteria established in the Phase I Decision.²⁶⁹ In addition to the Hayden biomass project, Bids 0011, 0106, 0269, and 0552 were considered as Section 123 Resources. Other than the Hayden biomass, only Bid 0011 was sometimes selected in the Phase II portfolios.²⁷⁰ While Public Service included the Hayden biomass project in its Preferred Portfolio, the Company rejected the other Section 123 resources for various reasons, including cost, project risk, and location. Regarding Bid 0106 (a hydrogen fuel cell project) and Bid 0269 (a long-duration storage project), the Company states that there could be long term benefits if these projects are successful. Public Service states that the Company would be interested in moving forward with these projects if the Commission were to approve them *in addition to* the other projects in the Preferred Portfolio.²⁷¹

241. CEO supports the Commission approving Bid 0106 (the hydrogen fuel cell project). CEO argues that pursuing this project as a firm resource would help the state continue its development of hydrogen as a pathway to decarbonization. While CEO acknowledges the project involves certain risks, CEO argues that the potential benefits outweigh these risks, noting that the

²⁶⁹ Public Service notes that one additional project claimed Section 123 but did not meet the Phase I Decision's criteria.

²⁷⁰ 120-Day Report, p. 139.

²⁷¹ 120-Day Report, pp. 150-51.

State intends to continue pursuing the development of hydrogen. Alternatively, if the Commission does not believe it is the right time to approve the project, CEO recommends that the Commission “direct Public Service to pursue a similar project in either the Just Transition Plan or through its next ERP in 2026.”²⁷²

242. In its Response Comments, Public Service maintains that it does not recommend approval of the project as part of this Phase II ERP. However, the Company states that it appreciates and shares CEO’s interest in pursuing the hydrogen fuel cell project and that Public Service is interested in exploring the viability of the project. Public Service goes on to state that it sees opportunities to pursue Bid 0106 or other hydrogen projects as part of proceedings conducted pursuant to HB 23-1281, the upcoming 2024 JTS, or through a separate filing.²⁷³

243. Pursuant to § 40-2-123(1)(a), C.R.S., the Commission shall:

give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities, bearing in mind the beneficial contributions such technologies make to Colorado’s energy security, economic prosperity, insulation from fuel price increases, and environmental protection, including risk mitigation in areas of high wildfire risk as designated by the state forest service.

244. As required, the Commission has fully considered Section 123 Resources. This consideration began in Phase I when the Commission approved a modeling approach for Section 123 Resources and adopted guidelines proposed by Public Service to define these resources, emphasizing that they must be new, innovative, not commercialized, and could not include standalone wind, solar, or lithium-ion storage.²⁷⁴ This framework enabled the efficient presentation of Section 123 Resources in the 120-Day Report, which in turn allowed the

²⁷² CEO’s Comments, pp. 18-20.

²⁷³ Public Service’s Response Comments, pp. 110-11.

²⁷⁴ Phase I Decision, ¶ 501.

Commission and stakeholders to evaluate the various risks and potential benefits of the Section 123 Resources.

245. We have considered the beneficial attributes of all of the Section 123 Resources, including Bid 0106 which CEO supports. We further note that the Alternative Portfolio includes Bid 0011 which, while proposed as a Section 123 Resource, was included based on economic modeling. As to the question of whether additional Section 123 Resources should be pursued at this time, however, we agree with Public Service's position set forth above in its Response Comments. Given uncertainty ranging from tax credits to the implementation of HB 23-1281, it would be premature to approve additional projects here, including Bid 0106. Should hydrogen projects be included as bids within the 2024 JTS, they can be more appropriately considered there. Accordingly, no further Section 123 Resources are approved here, and we look forward to consideration of innovative technologies in the 2024 JTS.

L. Prospective New Load

246. In its 120-Day Report, Public Service states that large loads, such as the demand and energy requirements of new data centers, are developing at a faster pace than historic trends. The Company thus requests that the Commission approve a "Prospective New Load Preferred Plan" (PNL) portfolio to accommodate potential new load of 300 MW beginning in January 2026. Public Service states that at least some of this 300 MW new load would be better described as "more likely" than "possible." The Company recommends the Commission allow it to use the backup bid pool to serve this load if needed. Public Service specifically puts forth four additional bids that would be included in the PNL portfolio: two storage projects, as solar project, and a 219 MW gas project.²⁷⁵

²⁷⁵ 120-Day Report, pp. 55-57.

247. Several parties, including CEO, Conservation Coalition, Interwest, Staff, and WRA raise concerns about the PNL portfolio, particularly its inclusion of 219 MW of new gas generation. CEO and Staff suggest that the new load is speculative and could fail to materialize, and with Conservation Coalition and WRA, recommend that new load be addressed as part of the load forecast in the 2024 JTS.²⁷⁶ Staff asserts that two large wholesale loads have announced the intention to leave the Company's system but remain in the Company's load forecast, which cuts against the arguments that additional generation resources will be necessary. Likewise, Staff critiques the Company's demand response sensitivity analysis, arguing that aggressive demand side solutions would mitigate concerns regarding new load.²⁷⁷ CEO adds that if the Commission does approve the PNL portfolio, it should ensure ratepayer protections if the new load fails to emerge. For example, CEO suggests that if new load does not emerge, shareholders should be responsible for the cost of additional new gas generation instead of ratepayers.²⁷⁸

248. In its Response Comments, the Company maintains that that the PNL portfolio has value in this Proceeding and as a general resource planning matter in the current environment. Public Service acknowledges intervenors' comments that new load is speculative but states that it has more information than intervenors and reiterates the challenge associated with new, large loads developing at a faster pace than before. Public Service agrees, however, that should additional resources not be approved for procurement here, it is reasonable to revisit the issue in the 2024 JTS.²⁷⁹

²⁷⁶ Staff's Comments, pp. 53-54; CEO's Comments, pp. 15-16; WRA's Comments, pp. 19-20; Conservation Coalition's Comments, p. 14.

²⁷⁷ Staff's Comments, pp. 53-54.

²⁷⁸ CEO's Comments, p. 16.

²⁷⁹ Public Service's Response Comments, p. 106.

249. We take the risk that new load is increasing seriously,²⁸⁰ but we decline to approve the PNL portfolio. We agree with Staff's assertion that based on what is currently publicly known, these load additions are speculative and could be offset by future load departures and more effective efforts around demand response. Moreover, given that the new load is speculative but would directly result in adding a new gas resource, it deserves both the full vetting of a Phase I process, through which such questions of appropriate load forecasts and sensitivities are traditionally considered, and consideration as to the impact of new large loads that might seek economic development rates on state emissions targets.

M. Clean Energy Plan Rider (CEPR)

250. Section 40-2-125.5(5), C.R.S. authorizes Public Service to initiate a CEPR, capped at a maximum rate of 1.5 percent of customers' total electric bill, to collect new revenues to fund the approved, additional clean energy plan activities that are undertaken to meet the clean energy target applicable to the Company. However, the statute also prescribes limitations on what the CEPR can fund.

251. In Phase I, the Commission rejected the complex, counterfactual modeling proposal put forward by Public Service in support of the approval and prospective implementation of its CEPR. The Commission further declined to move forward with Public Service's presumption that the Company could apply RESA funding to offset CEP costs, even as the Commission approved certain related provisions of the Phase I Settlement that relate to reporting and treatment of over- and under-collections. Instead, the Commission directed Public Service to file significantly more detail on anticipated cost recovery mechanisms in the 120-Day Report and to file an

²⁸⁰ To address this risk, we encourage Public Service to work to ensure that it has additional firm dispatchable resources as close to construction ready as reasonably possible.

application in a separate future proceeding presenting its methodology for defining and assigning costs related to additional clean energy activities as between the CEPR and the RESA, no later than one year in advance of beginning to recover costs attributable to the CEPR.

1. Public Service's New CEPR Proposals and Party Comments

252. In its 120-Day Report, Public Service completely revises its cost recovery methodology as compared to the proposals the Company presented in Phase I of this Proceeding. For instance, the Company compared its Preferred Portfolio to the reference case and identified the following incremental actions and investments: acquisition of clean energy resources, the Brush Coal Plant gas conversion, reduction of Pueblo Unit 3 operations, gas storage, transmission, and community assistance and workforce transition plans. Out of these, Public Service states that clean energy resources, Brush Coal Plant conversion costs from 2025-2030,²⁸¹ and community assistance and workforce transition plans should be considered clean energy plan activities that are eligible for CEPR recovery (noting that community assistance and workforce transition costs are statutorily also eligible to be recovered through other riders). Public Service explains that, pursuant to § 40-2-125.5(5)(b)(III), the Company will exclude transmission, fuel costs for Pueblo unit 3 operations, and gas storage, and proposes they be collected from other cost recovery mechanisms, such as the ECA, the Transmission Cost Adjustment, and base rates.²⁸²

253. To attribute the costs of clean energy plan activities to the CEPR, Public Services proposes to sort resources into energy or capacity and then to stack them from lowest to highest based on accredited capacity and levelized cost of energy or capacity calculated using Encompass, the model used for bid evaluation and selection.²⁸³ This approach results in three solar and storage

²⁸¹ The Brush Coal Plant conversion costs are also being considered within Proceeding No. 22A-0563E.

²⁸² 120-Day Report, pp. 168-69.

²⁸³ 120-Day Report, p. 169.

resources being identified as attributable to the CEP in the “energy resource stack” and no resources being identified as attributable to the CEP in the “capacity resource stack.” Public Service suggests refining this methodology and extending it to CEPR/RESA interactions through the post-Phase II application. Public Service also adds that the exact costs for community assistance and workforce transition will be evaluated in future JTP filings.²⁸⁴

254. Public Service requests that the Commission authorize it to file an advice letter to initiate the CEPR for collections purposes beginning either January 1, 2024, or January 1, 2025, depending on when the Phase II Decision is issued. Public Service forecasts that by starting collections at 1.4 percent in 2024, it would be over-collected by \$6.3 million in 2030, and it would be under-collected by \$19.3 million in 2030 if it began collections at 1.5 percent in 2025.²⁸⁵

255. UCA raises concerns about the Company’s approach, including that the presentation of levelized energy costs for resource stacking does not match costs presented in appendices, and therefore the bids may be incorrectly sorted as to cost recovery mechanism. UCA further argues that the costs associated with the early retirement of Hayden 1, Hayden 2, Craig 2, and the entire costs of the Brush Coal Plant conversion should be considered CEP costs, and therefore the under-collections for the CEPR will be higher than Public Service anticipates.²⁸⁶

256. Public Service argues that UCA has not correctly applied updated modeling values and explains that only the conversion of the Brush Coal Plant from coal to gas would be considered an additional clean energy plan activity. With regard to the RESA, Public Service states that the methodology it used to distinguish between the ERP and the CEP will also be used to distinguish between clean energy resources and eligible energy resources. The Company reiterates that it

²⁸⁴ 120-Day Report, pp. 170-72.

²⁸⁵ 120-Day Report, pp. 172-73.

²⁸⁶ UCA’s Comments, pp. 27-28.

intends to file the application presenting its methodology for defining and assigning costs between the RESA and CEPR promptly after the final Phase II decision, consistent with the Phase I decision. Accordingly, Public Service reiterates its request that the Commission approve the establishment of the CEPR at the full 1.5 percent in its Phase II decision, with collections to begin as soon as possible upon filing of an advice letter.²⁸⁷

2. Findings and Conclusions

257. We conclude that further process is still required to determine whether the CEPR should be initiated at the full 1.5 percent as proposed by Public Service in its 120-Day Report. Nevertheless, we generally agree with, and approve, its categorization of actions and investments which should be considered additional clean energy plan activities, including those that may be recoverable through the CEPR,²⁸⁸ as the Company's new proposals are clearer and will avoid the inappropriate levels of complexity that were present in the counterfactual Phase I proposal.²⁸⁹ That said, given its late introduction, the balance of the Company's latest CEPR proposals has not been fully vetted by stakeholders and questions remain as to variations between data tables and appendices. Moreover, the application of this methodology for RESA/CEPR cost recovery is less clear than its applicability for ERP/CEP questions. Finally, the Commission has selected the Alternative Portfolio instead of the UPP, necessitating greater clarity on cost recovery (*e.g.*, whether the resource stack changes and results in different allocations between cost recovery mechanisms).

²⁸⁷ Public Service's Response Comments, pp. 98-100.

²⁸⁸ To clarify, consistent with the discussion above, transmission investments as presented in the 120-Day Report are not considered additional clean energy plan activities.

²⁸⁹ We note that while the Commission deferred the specifics of cost recovery for early retirement for Craig 2, Hayden 1, and Hayden 2, it approved the provisions of the Phase I Settlement that affirmed that they should be excluded from CEPR recovery (*i.e.*, they would be included within the reference case for modeling purposes), (Phase I Decision, ¶ 63; Phase I Settlement, ¶¶ 27-28). *See also* Proceeding No. 22A-0515E.

258. Given the timing of this Phase II Decision, pursuant to § 40-2-125.5(b)(II), C.R.S., the earliest the CEPR would be able to be placed into effect is January 1, 2025. Accordingly, we direct the Company, as part of its application regarding attribution of costs between the CEPR and RESA as still required by the Phase I Decision, to address the recovery of specific activities within the categories set forth above, based on the approved resource portfolio. The application should also address the appropriate level for the CEPR to be initiated on January 1, 2025.

N. Best Value Employment Metrics

259. The Phase I Settlement established a multistep process in the Phase II bid evaluation to ensure consideration of BVEM in accordance with § 40-2-129(1)(a), C.R.S. First, the RFP directed bidders to include quantitative information with bid packages that addressed the BVEM statutory requirements, including access to apprenticeships and industry-standard wages and benefits. Second, a bid incorporating a Project Labor Agreement (PLA) was deemed to meet threshold BVEM standards. Third, the Company agreed to screen bids based on BVEM and disqualify those that did not provide sufficient BVEM. Fourth, the Company would retain a labor economist to score the bids for advancement to computer modeling. The Phase I Settlement goes on to specify that the Company will provide a cumulative BVEM score for each portfolio in the 120-Day Report.²⁹⁰ Finally, one of the required Phase II portfolios was a “high PLA portfolio.”

260. In the 120-Day Report, Public Service confirms that it implemented this multi-step BVEM process during Phase II. The Leeds School of Business at the University of Colorado-Boulder was hired as a labor economist and provided scoring of 166 bids. The Company states that it disqualified bids with insufficient BVEM information. In addition, the

²⁹⁰ Phase I Settlement, ¶ 69.

Company notes that Appendix K to the 120-Day Report contains the BVEM documentation that the bidders provided.²⁹¹

261. The Labor Interests describe the challenging history of Colorado's efforts to account for the employment impacts of resource planning through the Phase II solicitation and modeling process. The Labor Interests describe the quantitative scoring provided by the labor economist as a positive evolution in the consideration of BVEM but remain concerned that BVEM was less emphasized after bids were advanced to modeling. Ultimately, however, the Labor Interests support the Preferred Portfolio including the Hayden biomass unit as having a strong BVEM score that matches or exceeds other modelled portfolios and offers an imperfect, but positive, middle ground. The Labor Interests note the positive relationship between utility ownership and BVEM due to Public Service's involvement in collective bargaining.²⁹² They further add that SB 23-292 is a recent and strong statement in support of robust and protective labor policies which will have a significant impact on all phases of energy generation in the future.²⁹³

262. Staff argues that the RFP informed the bidders of the categories and subcategories of information that would be used to develop the BVEM score, however, it did not specify the weighting of these categories and subcategories to the bidders. Staff is concerned that the approach incentivizes detail over quality. Staff suggests that the BVEM scoring methodology could use improved documentation as verifying the methodology is challenging due to lack of sufficient information. That said, Staff notes that it checked for consistency of BVEM scoring across

²⁹¹ 120-Day Report, pp. 159-60.

²⁹² Labor Interests' Comments, pp. 7-8.

²⁹³ Labor Interests' Comments, pp. 8.

different bids and found it to be consistent and objective.²⁹⁴ WRA likewise supports utilization of a BVEM scoring methodology in future ERPs.²⁹⁵

263. In its Response Comments, Public Service agrees with the Labor Interests that the BVEM scoring methodology in this ERP is an improvement and should be continued, with iterations. Public Service specifically supports using a similar BVEM scoring methodology in future ERPs, including the 2024 JTS.²⁹⁶

264. As noted earlier, the Commission has considered the employment of Colorado labor and its positive impacts on the long-term economic viability of Colorado communities throughout this ERP proceeding pursuant to § 40-2-129, C.R.S. These considerations began in Phase I of this Proceeding when the Commission approved the multistep process in the Phase II bid evaluation regarding BVEM and continued in Phase II in our review of the 120-Day Report, the relevant party comments, and the cumulative BVEM score for all portfolios. In addition to BVEM, the Commission must consider and balance many factors in its decision regarding the optimal resource portfolio, including emissions reductions, costs, and reliability. The consideration of these combined factors culminates in a Phase II decision.

265. The Alternative Portfolio has a slightly lower BVEM score (48 percent) than the UPP's BVEM score (52.7 percent). Nevertheless, we find that the positive attributes of the Alternative Portfolio, including cost, emissions reductions, reliability, and the ability to better address future technology developments and transmission concerns as detailed above, outweigh the lower BVEM score.

²⁹⁴ Staff's Comments, p. 68.

²⁹⁵ WRA's Comments, pp. 25-29.

²⁹⁶ Public Service's Response Comments, pp. 106-07.

266. As Labor Interests set forth, the process of evolving a qualitative concept like BVEM into a meaningful component of bid evaluation has been a long and thoughtful process, with a significant amount of evolution demonstrated through the Phase I Settlement and Phase II. In such a sweeping and significant process as an ERP, even though moving incrementally can be frustrating, nuanced iterations are often the best course of action.

267. Moreover, the Alternative Portfolio includes slightly fewer resources and therefore will provide time for the application of BVEM to continue to evolve. This also means that resources that are deferred now could be brought into the future ERPs through an even more robust process, which is necessary to comply with additional statutory requirements in § 40-2-129, C.R.S.²⁹⁷

268. We also agree with Labor Interests that the thoughtful work performed by the labor economist in this Proceeding represents an enhancement of how BVEM can be incorporated into decision-making. However, Staff also raises valid points in that the methodology could be more clearly articulated for bidders. In this vein, we would be interested in seeing proposed changes to the model PPAs in the 2024 JTS aimed at clarifying standards for BVEM to ensure that IPPs and the Company are competing on a level playing field regarding BVEM. We encourage the collaboration of Labor Interests in this effort, such that work on the model PPAs will account for the role that the IRA can play in producing projects with high BVEM scores by incorporating factors such as the IRA's prevailing wage requirements. We also note that high BVEM scores generally track high utility ownership percentages and express our desire that IPPs that are interested in building projects in Colorado should improve their BVEM to ensure they stay competitive with Company-owned bids in this regard.

²⁹⁷ These new requirements in § 40-2-129, C.R.S., are effective January 1, 2024.

O. In Service Date Extensions

269. In connection with the delays in this Proceeding associated with Public Service's filing of the 120-Day Report, CIEA argues that the Commission should allow IPPs to have a corresponding extension of the ISDs of their projects. CIEA specifically proposes that all projects in the selected portfolio as well as backup bids with ISDs in 2026 and 2027 (spilling into 2028 by up to 75 days if necessary) should have a one-time election to extend the ISDs up to 75 days. CIEA argues that this will address the acute issues in the market and Public Service's delays in the Phase II process in a straightforward and transparent manner.²⁹⁸ In addition, CIEA requests that backup bids should be granted an ISD extension equal to the number of days after the Phase II Decision when the backup bid gets approved to move to the selected portfolio.²⁹⁹

270. In its Response Comments, the Company supports CIEA's recommendations and agrees that all project developers should have the opportunity to extend the ISD of their approved projects and backup bids commensurate with the extended Phase II timeline. The Company further recommends the Commission acknowledge that delays in generation resource ISDs due to transmission-related delays, such as delays associated with interconnection, backfeed, and substation construction, shall be considered reasonable.³⁰⁰

271. Likewise, Public Service asserts that backup bids should be allowed an extension of their commercial operation date (COD) by the number of days after the Phase II Decision that the backup bid is approved to move to the selected portfolio. The Company supports this COD extension because selected backup bids will see a delay in their selection given their backup bid

²⁹⁸ CIEA's Comments, pp. 41-42

²⁹⁹ CIEA's Comments, pp. 41-42.

³⁰⁰ Public Service's Response Comments, pp. 103-04.

status, and the COD extension increases the likelihood that the backup projects will come to fruition.³⁰¹

272. In accordance with CIEA's recommendations, we authorize Public Service to extend ISDs upon application by IPPs by up to 75 days as well as any delays in transmission assets to which individual projects interconnect. No support should be required of the IPP for ISD delays of 75 days or fewer. Before granting an ISD extension greater than 75 days, the Company should be directed to obtain a thorough and credible explanation from the IPP detailing how delays related to completion of Public Service transmission projects prevented it from achieving its proposed ISD. We likewise adopt the ISD extension for backup bids that Public Service sets forth in its Response Comments.

P. Repricing

273. CIEA also requests that the Commission clarify that Public Service can allow IPPs to reprice their projects if delays in transmission project completion cause cost increases through no fault of the IPP. CIEA asserts that IPPs "cannot be expected to maintain as-bid pricing through material delays in transmission upgrade and interconnection processes."³⁰² CIEA similarly argues that backup bids are likely to be stale by the time Public Service calls upon such bids to move forward. Accordingly, CIEA argues that the Commission should allow an opportunity for limited repricing of backup bids to keep up with inflation.³⁰³

274. Public Service argues against the suggestion that backup bids should be provided a repricing opportunity, arguing that doing so could impugn the integrity of the process. However, the Company does support allowing price increases in the limited circumstance where a

³⁰¹ Public Service's Response Comments, pp. 40-41.

³⁰² CIEA's Comments, p. 22.

³⁰³ CIEA's Comments, p. 25.

transmission cost estimate is different than the estimate provided as part of the RFP. Public Service states that this should be the only basis for repricing and should be equally applicable to any bid with which the Company moves forward.³⁰⁴

275. The Commission agrees with Public Service's position and denies CIEA's request to allow backup bids to reprice. The one exception is that repricing is allowed for backup bids in the case where the transmission costs provided in the RFP have changed, consistent with Public Service's proposal in its Response Comments.

Q. 2024 Just Transition Solicitation

276. Given the various issues that have arisen in Phase II of this Proceeding, several intervenors argue that the Commission should issue various directives to Public Service to improve the ERP process. As discussed below, these proposed improvements cover topics including modeling, the ability of IPPs to negotiate the terms of Model PPAs during Phase II, and the appropriate amount of Company ownership.

1. Modeling Improvements

277. Staff, CIEA, Interwest, Conservation Coalition, and WRA all put forth various proposals aimed at improving the modeling process of bids in the 2024 JTS. Relatedly, CEO suggests process improvements for the 2026 ERP. For example, CIEA's proposals include asking the Commission to reject the use of the things like the best-in-class modeling and the reliability rubric for use in the 2024 JTS.³⁰⁵ CIEA also argues that the annuity method of modeling portfolios should be used going forward and that Public Service should be required to analyze the failure of

³⁰⁴ Public Service's Response Comments, p. 41.

³⁰⁵ CIEA's Comments, pp. 6-7, 29-31.

the model and possible solutions, including a process for returning to the Commission in the event of model failures.³⁰⁶

278. Interwest requests that the Commission require a full analysis of both the computer system used in this ERP as well as an estimate of what computer system would have been able to run the modeling software in the timeframe required under the ERP rules.³⁰⁷ For future ERPs, Interwest argues that the curtailment projections must be more flexible and consider the likelihood that curtailments will be reduced over the long term.³⁰⁸

279. Conservation Coalition proposes numerous directives for the Commission to issue regarding the 2024 JTS. As an example of some of these proposals, Conservation Coalition argues that the Company should be required to provide the modeling input and output files to all parties and provide written explanation for all manual adjustments made to the modeling. Conservation Coalition also recommends that the Commission require the use of round-trip modeling, building all portfolios to the same minimum level of reliability, and running a scenario in which, the model replaces all 2-hour storage with 4-hour storage. Similarly, Conservation Coalition argues that Public Service should be required to conduct capacity accreditation studies and planning reserve studies in the same software tool and database to ensure consistency.³⁰⁹

280. WRA's proposals include things such as how generic prices should be used, requirements for the IE, and—more broadly—a different approach to ERP solicitations that uses sequential, rolling solicitations. WRA also proposes that Public Service develop and propose a

³⁰⁶ CIEA's Comments, pp. 30-31.

³⁰⁷ Interwest's Comments, p. 11.

³⁰⁸ Interwest's Comments, p. 12.

³⁰⁹ Conservation Coalition's Comments, pp. 18-20.

transparent scoring system for non-price factors, such as environmental compliance and community support.³¹⁰

281. Arguing for higher-level changes to the ERP process, CEO raises concerns that the ERP process fails to develop a set of portfolios that are significantly different in terms of the resources considered or even the relative cost. Citing its proposals in Proceeding No. 19R-0096E for requiring electric utilities to submit various types of plans with their ERPs, CEO recommends that the Commission direct the Company to include scenario-type analysis as part of the 2026 ERP. CEO also encourages the Commission to re-open its ERP rules and adopt new rules that are more relevant to today's utility environment and that will help Colorado achieve its climate goals.³¹¹

282. Staff proposes that the Company explain in the 2024 JTS how it will update the effective load carrying capability (ELCC) and planning reserve margin (PRM) studies with the goal of accurately modeling portfolio level ELCC interactions to create reliable portfolios in EnCompass. Staff also recommends that Public Service work with Staff prior to the 2024 JTS to develop more robust modeling processes regarding things like best-in-class modeling, the reliability rubric, meaningful demand side resources options, and inconsistent or unexplained modeling results.³¹²

283. In its Response Comments, the Company does not oppose Staff's recommendation to include an explanation in the Pueblo JTP filing as to how it plans to improve the accuracy of modeling portfolio level ELCC interactions.³¹³ However, Public Service appears to disagree with

³¹⁰ WRA's Comments, pp. 25-29.

³¹¹ CEO's Comments, p. 30.

³¹² Staff's Comments, p. 74.

³¹³ Public Service's Response Comments, p. 104.

Staff's recommendation that the Company be required to work with Staff in the interim to develop more robust modeling processes.³¹⁴

284. Regarding Conservation Coalition's recommendation that the Company conduct capacity accreditation studies and planning reserve studies in the same software tool, Public Service states that, as part of the Phase I Settlement, the Company has already committed to utilize the same modeling software and inputs for ELCC and PRM studies in future resource planning cycles and will also survey best practices in other jurisdictions when developing its methodology for these studies. The Company thus argues that the Phase II Decision does not need to reiterate this requirement.³¹⁵

285. As for the arguments about increased information sharing, process improvements, and transparency, the Company asserts that no directives addressing these issues should be issued in this Proceeding. While Public Service acknowledges that there is always room for improvement in the resource planning and intervenor participation process, the Company argues that such issues are more appropriately resolved a part of a robust Phase I process in the 2024 JTS and the 2026 ERP.³¹⁶

286. The Commission hereby adopts Staff's recommendations and will require Public Service to explain how the Company plans on accurately modelling portfolio level ELCC interactions in connection with its updated ELCC and PRM studies. We further direct the Company to confer with Staff and other interested parties prior to the 2024 JTS to develop more robust modeling processes regarding things like best-in-class modeling, the reliability rubric, meaningful demand side resources options, and inconsistent or unexplained modeling results.

³¹⁴ Public Service's Response Comments, p. 112.

³¹⁵ Public Service's Response Comments, pp. 104-05.

³¹⁶ Public Service's Response Comments, pp. 111-12.

287. In contrast, we decline to adopt in this Phase II Decision the numerous other modeling and process proposals, including those proposed by party commenters that are expressly discussed above. Some of these proposals closely resemble topics that were adjudicated in Phase I (*e.g.*, making the modeling files available for other parties).³¹⁷ More generally, the Commission finds that it would be premature on this Phase II record to specify how the next ERP process will resolve these modelling and process issues. Nevertheless, as referenced above, we take seriously the numerous concerns that parties raised regarding how Public Service conducted the Phase II modeling, including the manual adjustments the Company made in Phase II and how difficult it was for the parties to analyze the impact of these adjustments. Likewise, we share many of the parties' concerns regarding the model's shortcomings as to issues such as curtailments and the interaction between new generation and transmission. While resolution of these issues for purposes of future ERP proceedings will benefit from a more robust record than is available to us during this Phase II, many of these concerns contribute to our decision to modify the CEP to include the Alternative Portfolio.

2. Non-Negotiable PPA Terms

288. Interwest asserts that the negotiating process on the model PPAs was not explained in advance and put some bidders at a significant and unexpected disadvantage. Interwest states that Public Service found several redlines to model PPAs unacceptable during the due diligence process, prior to actual PPA negotiations, but necessary to advance in the bid selection process. Interwest recommends that the Commission consider language in the Phase II decision specifying that only after a bid is selected should the PPA negotiations start, and Public Service should be

³¹⁷ Phase I Decision, ¶ 513.

prohibited from using the threat of bid elimination to force bidders to accept terms that this Commission has specifically intended to be negotiable.³¹⁸

289. COSSA/SEIA similarly recommends that the Commission mandate that the Company identify which model PPA terms it considers non-negotiable, and that this be litigated in Phase I of future ERP proceedings so that all parties would enter Phase II on the same page about which terms are open to negotiation.³¹⁹

290. CIEA claims that many IPPs felt bullied to identify model PPA-changes they would accept or forego the opportunity to raise such issues later in contract negotiation and were pressured to adopt Public Service's position just to remain in the evaluation process. CIEA recommends that the Commission direct a new approach that limits Public Service's ability to negotiate PPA terms with bidders during the bid evaluation process.³²⁰

291. In Public Service's Response Comments, the Company argues that the Commission should reject recommendations that would restrict the Company's ability to negotiate PPA terms with bidders during the bid evaluation process. The Company argues that to the extent bidders do not submit compliant bids, the Company must retain the ability to work with bidders to bring bids into compliance and ensure a viable and comparable bid pool. The Company does, however, support recommendations from CIEA and COSSA/SEIA that non-negotiable model PPA provisions be clearly set forth in its Phase I 2024 JTS filing and be formalized in the Commission's Phase I decision. Public Service states that doing so will provide additional clarity to bidders and

³¹⁸ Interwest's Comments, pp. 9-10.

³¹⁹ COSSA/SEIA's Comments, pp. 15-18.

³²⁰ CIEA's Comments, pp. 32-35 ().

would help mitigate the need for extensive PPA contract discussions during the bid evaluation process.³²¹

292. The Commission agrees with the IPP intervenors and the Company that there should be more clarity for bidders regarding what terms of the model PPA contracts are negotiable. We accordingly adopt Public Service's position and require the Company to clearly set forth the non-negotiable PPA terms in its Phase I 2024 JTS filing with the expectation that such terms will be formalized in the Commission's Phase I decision approving model PPAs.

293. As noted by Interwest and Public Service, "Colorado does not have a 'conforming bid' policy whereby bidders have to bid to the model agreements 'as-is.'"³²² However, having the Company and IE attempt to determine on an *ad hoc* basis during the bid evaluation process which terms of the PPAs are negotiable is a challenging situation. We acknowledge that it may be time for Colorado to move towards a conforming bid policy, especially considering that the Commission already addresses many core issues of the model PPAs in Phase I and the fact that in Phase II the Company and IE are called upon to equitably evaluate numerous bids. To be clear, the Commission is not in this Decision adopting any type of conforming bid policy, but we invite party feedback regarding adopting this type of approach in the future.

3. Company Ownership

294. Interwest takes issue with the high percentage of Company ownership in the portfolios presented in the 120-Day Report, arguing that it is outside of what was expected by virtually all parties. Interwest suggests that this calls into question the validity of the agreements in the Phase I Settlement regarding the amount of replacement capacity from the 2024 JTS that

³²¹ Public Service's Response Comments, p. 105.

³²² See 120-Day Report, p. 86; Interwest's Comments, p. 9.

Public Service would own. Interwest requests that the Commission consider whether Public Service achieved the letter and spirit of the law, whether the Phase I Settlement provisions regarding the ownership of Unit 3's replacement capacity are still valid, and whether action is necessary now to ensure compliance in future ERPs.³²³

295. CIEA similarly recommends that the Commission use the 2024 JTS to course correct and rebalance the resource ownership of IPPs and the Company in the total capacity mix of the system.³²⁴

296. Public Service urges the Commission to reject suggestions that the ownership percentage allowed in the 2024 JTS be adjusted to account for the high ownership the Company proposes in this Proceeding. Public Service argues that this recommendation could lock the Commission into higher-cost and uneconomic outcomes.³²⁵

297. The 2024 JTS is an interim ERP that will largely be governed by the Commission's ERP rules. We find that it would be inappropriate in this Phase II to attempt to set bounds around the Company ownership levels of the approved portfolio coming from the 2024 JTS. Moreover, we note that the selection of the Alternative Portfolio significantly reduces the amount of Company-owned capacity resources approved as part of this Proceeding as compared to the UPP.

4. Just Transition Bids

298. UCA expresses disappointment that there were no bids for wind, solar, storage or solar plus storage at Craig or Hayden. UCA claims that such bids would have contributed to the just transition plan. UCA argues that these type of JTP bids should be encouraged at Craig and

³²³ Interwest's Comments, p. 9.

³²⁴ CIEA's Comments, p. 18.

³²⁵ Public Service's Response Comments, pp. 33-34.

Hayden and other west slope locations as well as in the Pueblo area. UCA goes on to suggest that such bids could even be required from Public Service.³²⁶

299. Although we refrain from creating any sort of requirement for certain bids, we agree with UCA's sentiments about the benefits of bids at Craig, Hayden, and Pueblo and encourage such bids in the upcoming 2024 JTS. We further encourage bids within the Denver Metro area to the extent such bids can mitigate the need for additional transmission investments.

300. The 2024 JTS offers the state an important opportunity to continue acquiring renewable resources to achieve even greater emissions reductions while addressing some of the issues that arose in this Proceeding. Consistent with the Phase I Settlement Agreement, however, we reiterate that the 2024 JTS is the proceeding that will acquire a suitable replacement for the capacity that will be lost when Unit 3 retires and that all parties should work to ensure that the Pueblo community and benefits to the community are the focus of this replacement.³²⁷ In this vein, we note that nothing in this Phase II Decision impacts the Company's commitment in the Phase I Settlement to "make payments to Pueblo County annually from 2031 through 2040 ... in the amount of the projected lost property tax revenues for those years, unless offset by property tax revenues from generation or transmission infrastructure sited at Comanche Station or within Pueblo County."³²⁸

³²⁶ UCA's Comments, p. 20.

³²⁷ See Phase I Decision, p. 43; Phase I Settlement, ¶ 43.

³²⁸ Phase I Settlement, ¶ 42.

5. Discount Rates

301. Conservation Coalition suggests that the Commission direct the Company to confer with stakeholders to reach a consensus approach to discounting the social cost of emissions for the June 2024 JTS.³²⁹

302. While consideration of lower discount rates does not warrant the selection of a different resource portfolio in this Proceeding (as set forth above), we find merit in the Conservation Coalition's request that Public Service attempt to reach consensus with stakeholders on the related issue of discounting the social cost of emissions. Accordingly, we grant Conservation Coalition's request and direct the Company to confer with stakeholders to reach a consensus approach to discounting the social cost of emissions for the 2024 JTS. This conferral should include the impacts of SB 23-291 regarding the appropriate discount rate to use for fuel costs.

6. Comprehensive Rate Analysis

303. In the 120-Day Report, Public Service states that "the average bill impact for the Preferred Plan is expected to grow less than the historical rate of inflation."³³⁰ Staff, UCA, and CEC argue, however, that the costs presented in the 120-Day Report are likely to be artificially low.³³¹ Staff in particular states that there is additional anticipated investment that is not included in the Company's rate impact analysis. Staff asserts that the Company's statement regarding the cumulative average growth rates was carefully worded to include only the incremental rate impact of the CEP, not the rate impact of the entirety of the Company's planned investments including

³²⁹ Conservation Coalition's Comments, pp. 21-22.

³³⁰ 120-Day Report, p. 34.

³³¹ Staff's Comments, p. 19; UCA's Comments, pp. 5-7; CEC's Comments, pp. 15-16.

distribution system investment, other transmission system investment, and additional electric generation not included in this Proceeding.³³²

304. Given the importance of affordability, the Commission and interested stakeholders should have access to a consistent view of Public Service's capital expansion plan for the Colorado electrical system and what this plan means for ratepayers. Accordingly, the Commission directs Public Service to provide in the 2024 JTS a comprehensive long-term rate analysis that fully includes all of the projected investments the Company is communicating to the financial community, including for new distribution investment, wildfire mitigation, transmission upgrade, transportation electrification, distributed solar, and other electricity business investments.³³³ This comprehensive rate analysis should also include an analysis that better quantifies the actual levels of resource curtailment above the modelled levels and, in format, should be similar to the rate forecast models the Company has recently presented in rate cases.

305. We emphasize that this comprehensive rate analysis shall not be limited to projects that have received official regulatory approval or projects that have final cost estimates. Rather, this comprehensive rate analysis shall include all projected investments in the Colorado electric system that Public Service is communicating to the financial community and any that are reasonably expected.

R. Miscellaneous Issues for Future Proceedings

1. Equity Directives

306. In its Comments on the 120-Day Report, Staff notes the importance of evaluating ERP proceedings through an equity lens. Staff further notes that as part of the solicitation that the

³³² Staff's Comments, p. 19.

³³³ Consistent with prior filing expectations, documents are expected to be as robust as possible and in executable format.

Company performed in this Proceeding, all bidders were required to provide information on the assessment of, and plan for continuing to monitor local community, disproportionately impacted (DI) community, and state reaction to the bidder's proposed project, and a plan to work with the local community and DI communities on project issues. In addition, as part of the 120-Day Report, the Company provided maps that identify which projects are located in DI communities.³³⁴

307. After assessing the information that was received in this Proceeding, Staff makes a series of recommendations that the Commission could take in future proceedings to continue to improve the Commission's consideration of equity issues. For example, Staff argues that in the future, the 120-Day Report should include a more detailed analysis of community/state reaction, which goes beyond identifying the DI communities. Staff also suggests that the Commission consider developing rules that (1) identify key metrics that should be reported by bids in DI communities to help understand impacts and benefits of bids on DI communities, and (2) define a process for tracking stakeholder engagement in bids approved in the resource plan in DI communities. Finally, Staff recommends that the Commission consider specifying how it will consider equity metrics in decision making and document the consideration of energy equity issues in written decisions prior to approvals for Resource Plans, Plan amendments, and CPCNs.³³⁵

308. In a similar vein, CEO notes with approval how the Company mapped the bids in this Proceeding relative to DI Communities. CEO encourages a similar presentation of mapping in the Company's next ERP and notes the expectation that the Commission will continue to consider how it will use such mapping in its decision making going forward.³³⁶

³³⁴ Staff's Comments, pp. 69-70.

³³⁵ Staff's Comments, pp. 71-72.

³³⁶ CEO's Comments, pp. 24-25.

309. In its Response Comments, the Company expresses appreciation for Staff's recommendations as the consideration of equity issues in resource planning continues to evolve. The Company notes that it has expanded the scope and reach of its community engagement efforts and expects to continue this expansion. Public Service further expects that the presentation and evaluation of equity issues will continue to improve, similar to how the BVEM bid information and evaluation process has improved. Public Service states that it welcomes and encourages continued discussion in the next ERP Phase I process and in future Just Transition Plan proceedings to ensure meaningful consideration of equity issues but that the Company does not believe specific requirements need be prescribed in rules.³³⁷

310. We acknowledge and appreciate the considerations from Staff and CEO regarding how to continue improving the Commission's consideration of equity issues in future ERP proceedings and rulemakings. At this juncture, however, we will leave it to the relevant stakeholders to work out the appropriate specifics on when and how best to further advance the consideration of equity issues in resource planning. We note that in Proceeding No. 22M-0171ALL the Commission has an ongoing and far-reaching pre-rulemaking underway aimed at improving equity outcomes in the State through reforms to practices, outreach, and rules. The Commission encourages stakeholders to provide comments within that pre-rulemaking proceeding where we are diligently collecting concepts on what rules should be considered and addressed in order to promote equity.

2. CPCN Prioritization

311. CIEA and Conservation Coalition both encourage the Commission to proactively manage the applications for CPCNs that the Company will eventually file for each utility-owned

³³⁷ Public Service's Response Comments, pp. 107-08.

generation asset included in the approved resource portfolio. For instance, noting the large amount of expected CPCN filings, CIEA recommends that there be a priority established for 2024 CPCNs based on the value to ratepayers of the various projects. Denver metro transmission projects with 2030 ISDs could be delayed to later but generation projects that are critical to system or local reliability should be prioritized.³³⁸

312. Similarly, the Conservation Coalition suggests that the Commission consider how it can reduce the litigation burden to parties (and the burden on the Commission) of the CPCNs arising from this Proceeding. The Conservation Coalition specifically recommends one of two solutions for consolidating the various CPCNs. The first proposal is to require the Company to confer with all parties and file a reporting containing the proposals for how best to consolidate and minimize the number of CPCN applications. The Commission would then issue an order in this Proceeding addressing consolidation. The second proposal is to simply order the Company to consolidate its CPCN applications based on some criterion or criteria (*e.g.*, technology type or ISD).³³⁹

313. In its Response Comments, Public Service argues that it has the responsibility to timely file CPCNs and that the Company will need some flexibility to do so. However, the Company proposes providing updates to interested parties and the Commission on the status of CPCN filings in its Annual ERP Reports that it files every year on March 31 as well as in its annual Rule 3205 and Rule 3206 reports. Public Service argues that these existing reporting venues provide the appropriate opportunity for the Company to update stakeholders on CPCN filing

³³⁸ CIEA's Comments, pp. 8, 35-36.

³³⁹ Conservation Coalition's Comments, pp. 22-23.

readiness as well as the anticipated filing dates, sequencing, and grouping of generation and transmission CPCNs moving forward post-Phase II.³⁴⁰

314. We adopt Public Service’s position set forth in its Response Comments and direct the Company to provide additional updates to interested stakeholders regarding the Company’s CPCN prioritization via the existing reporting venues. At this juncture, the Commission will not attempt to dictate the form or timing of Public Service’s CPCN and other applications.

3. Voluntary Additional Emissions Reduction Program

315. Boulder recommends the Commission direct Public Service and interested communities and customers to explore acquiring additional resources to support development of a voluntary customer product that generates additional emissions reductions. Boulder asserts that “communities comprising at least 35 percent of Public Service retail sales seek ‘100% renewable energy’ or zero emissions electricity by 2030.”³⁴¹ Given the importance of decarbonizing the electricity sector as soon as possible to support decarbonization in other sectors like buildings and transportation, Boulder argues that “the time is now to develop next-generation voluntary customer products that quantify incremental emissions reductions.”³⁴²

316. Boulder acknowledges that the Phase I Settlement contains a commitment for Boulder and Public Service to work together to develop such a voluntary program. Boulder indicates that, based on preliminary modeling, it appears that acquiring additional renewable resources could generate incremental emissions reduction but at the significant risk of curtailments. In addition, according to Boulder, the preliminary modeling showed that incremental

³⁴⁰ Public Service’s Response Comments, pp. 100-02.

³⁴¹ Boulder’s Comments, p. 17.

³⁴² Boulder’s Comments, p. 17.

costs of such additional resources “suggests that new voluntary emissions reduction products must be available to all Public Service customers and not limited to one community or customer.”³⁴³

317. Boulder asserts that the bids received in Public Service’s solicitation provide options for the development of a new voluntary emissions reduction product that would enable communities and customers to progress towards their 100 percent renewable energy goals. Boulder suggests that bids included in the Preferred Portfolio could be expanded to add generation or storage, and this expansion could be funded by communities and customers participating in the voluntary emissions reduction program. Boulder also asserts that there are bids that were not included in the Preferred Portfolio, including Section 123 Resources, the acquisition of which could be supported by customers interested in a voluntary emissions reduction program.

318. The Commission understands that certain communities and organizations would prefer to exceed the environmental attributes of Public Service’s general resource mix via a more robust, voluntary offering and believe such a program is feasible. We are interested in better understanding what steps the Commission could put in place to provide such a voluntary program for customers and communities and how the tracking would work to ensure that the program would not dilute the environmental attributes of the general resource mix or unfairly allocate costs.

319. Accordingly, we direct Public Service and Staff of the Commission³⁴⁴ to work together with interested parties to discuss this topic at a CIM. The discussion could include information regarding what stakeholders are interested in, what attributes are desired, the potential structure of such a program, the status of Public Service’s efforts on this topic, and what the next steps are. We are hopeful that this CIM could be convened in late February or early March.

³⁴³ Boulder’s Comments, p. 18.

³⁴⁴ This could be either Trial Staff or staff of the Commission’s Research and Emerging Issues group.

S. Requests not Explicitly Addressed

320. The Commission has weighed the information and filings from all parties and public commentors in balancing its policy and reaching the various decisions set out in this Phase II Decision. To the extent this Phase II Decision does not expressly address requests made by Public Service or an intervening party, such requests are denied. However, these requests were considered in balancing our considerations and reaching our ultimate conclusions in this Proceeding.

II. ORDER**A. The Commission Orders That:**

1. After consideration of the statutory factors and other relevant factors, modifications to the Clean Energy Plan (CEP) presented by Public Service Company of Colorado (Public Service) are necessary to ensure that the Commission's approval of the CEP is in the public interest.

2. In accordance with the discussion above, we authorize Public Service to pursue the modified CEP and the acquisition of the resources included in the Alternative Portfolio with further due diligence and contract negotiations. Public Service shall further file applications for Certificates of Public Convenience and Necessity for all Company-owned generation resources arising from the modified CEP. Public Service's actions, consistent with this Decision, shall be presumed to be prudent at the time of cost recovery consistent with 4 *Code of Colorado Regulations* (CCR) 723-3-33617(d) of the Commission's Rules Regulating Electric Utilities.

3. All Company-owned generation resources arising from the modified CEP are subject to both the cost to construct performance incentive mechanism (PIM) and the operational PIM, in accordance with the discussion above.

4. The proposed transmission network upgrades, grid strength reinforcements, reactive power investments, and voltage support investments presented in the 120-Day Report are not part of the approved CEP. Additional review of the proposed transmission projects is necessary and, accordingly, 4 CCR 723-3-3206 is waived as to the transmission projects arising from this Proceeding, in accordance with the discussion above.

5. In accordance with the discussion above, Staff of the Colorado Public Utilities Commission (Staff) shall also initiate a stakeholder process with the Colorado Office of Utility Consumer Advocate and the Colorado Energy Office and in conferral with Public Service to bring forward a scope of work for hiring an independent transmission analyst as soon as reasonably feasible but no later than the commencement of the 2024 Just Transition Solicitation (JTS) proceeding. If this independent transmission analyst cannot be engaged in time for Phase I of the 2024 JTS, we direct the Company to include certain transmission-related portfolios in its direct case, in accordance with the discussion above.

6. As part of its application regarding attribution of costs between the CEP rider (CEPR) and the Renewable Energy Standard Adjustment, the Company shall address the recovery of specific activities based on the approved resource portfolio and the appropriate level for the CEPR to be initiated on January 1, 2025, in accordance with the discussion above.

7. With respect to the 2024 JTS, Public Service shall confer with Staff prior to the 2024 JTS to develop more robust modeling processes, clearly set forth the Company's proposed non-negotiable PPA terms in its Phase I 2024 JTS filing and provide in the 2024 JTS a comprehensive long-term rate analysis in addition to our other directives in accordance with the discussion above.

8. Public Service and Staff of the Commission shall work together to present at an upcoming Commissioners Information Meeting the interest in, potential structure of, and current efforts to develop a voluntary emissions reduction program, in accordance with the discussion above.

9. The 90-day deadline for a written Phase II Decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan set forth in 4 CCR 723-3-3613(h) is waived.

10. To the extent requests are not addressed in this Decision, they are denied.

11. The 20-day period provided for in § 40-6-114, C.R.S., within which to file applications for rehearing, reargument, or reconsideration, begins on the first day following the effective date of this Decision.

12. This Decision is effective upon its Mailed Date.

**B. ADOPTED IN COMMISSIONERS' WEEKLY MEETINGS
December 6, 13, and 20, 2023.**

(S E A L)



ATTEST: A TRUE COPY

Rebecca E. White

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c))
Emergency Order: Tri-State)
Generation and Transmission)
Association, Platte River Power)
Authority, Salt River Project,)
PacifiCorp, and Xcel Energy)

Order No. 202-25-14

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

Filed January 28, 2026

Exhibit 1-165
Colorado Commission Decision No. C25-0024

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 21A-0141E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF
COLORADO FOR APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN
ENERGY PLAN.

**COMMISSION DECISION GRANTING, IN PART, AND
DENYING, IN PART, THE MOTION TO APPROVE THE
CLEAN ENERGY PLAN DELIVERY PLAN**

Issued Date: January 14, 2025

Adopted Date: December 16, 2024 and December 20, 2024

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I. BY THE COMMISSION**A. Statement**

1. On September 6, 2024, Public Service Company of Colorado (“Public Service” or the “Company”) filed a Motion to Approve Clean Energy Plan (“CEP”) Delivery Plan and for Variances from Certain Commission Rules and Decisions (“CEP Delivery Motion”).

2. Through this Decision, the Commission grants, in part, and denies, in part the CEP Delivery Motion. Our Decision allows the generation and storage projects included within the CEP to continue advancing despite changing market dynamics and geopolitical uncertainties, including importantly potential future changes in federal law. Advancing these generation and storage projects as part of the overall determinations made through the course of this Proceeding moves Colorado forward towards achieving aggressive state emission reduction targets. At the same time, while some amount of price flexibility is necessary, particularly given reliability and emission reduction considerations, our Decision also balances this price flexibility with several protections to ensure the CEP comes at a reasonable cost to customers. These protections include a two-stage process for clean energy projects that caps the amount of price relief and permits intervenor and Commission review as well as using existing regulatory processes for additional investigation and review of price increases associated with utility-owned projects. Similarly, this Decision finds that the record and abbreviated process associated with the CEP Delivery Motion are insufficient to make certain requested findings regarding additional thermal capacity and proposals to modify a demand responses (“DR”) program. As set forth below, the Company is in no way prohibited from making appropriate filings to move these or other endeavors forward, particularly as it ensures reliability.

3. These determinations provide a process in consideration of the CEP Delivery Motion enabling timely review should federal changes in law arise that impact bid pricing, concurrent with guidance towards longstanding Commission processes. This careful balance and necessary flexibility to move towards significant emission reduction targets, while protecting Colorado ratepayers, including by allowing ongoing scrutiny, particularly of utility-owned projects not yet demonstrated as warranting a presumption of prudence.

B. Procedural History

4. Public Service initiated this Proceeding by filing its Verified Application for Approval of its 2021 Electric Resource Plan (“ERP”) and CEP on March 31, 2021.

5. On August 3, 2022, the Commission issued Decision No. C22-0459 (“Phase I Decision”). Among other things, the Phase I Decision authorized Public Service to implement a competitive bidding process for acquiring cost-effective resources to meet its projected resource need from 2022 through 2028. The Commission also approved the process for evaluating bids to the competitive solicitation and established the modeling parameters, including inputs and assumptions, for the presentation and consideration of potential resource portfolios in Phase II of the Commission’s ERP process. Pursuant to the terms of the Updated Non-unanimous Partial Settlement Agreement approved, in part, by the Phase I Decision, the Commission further authorized Public Service to initiate an interim ERP called the Just Transition Solicitation (“JTS”) focused on meeting the projected resource need for the years 2029, 2030, and 2031.¹

6. On January 23, 2024, the Commission issued Decision No. C24-0052 (“Phase II Decision”), approving the Company’s CEP with modifications. Among other things, the Phase II

¹ Public Service filed an Application for Approval of its Just Transition Solicitation on October 15, 2024 in Proceeding No. 24A-0442E (“JTS Proceeding”). The JTS Proceeding is ongoing.

Decision authorized Public Service to pursue the acquisition of more than 5,800 MW of new storage and generation projects that were included in the approved resource portfolio with further due diligence and contract negotiations.² The approved resource portfolio includes 669 MW of thermal resources, consisting of four separate projects: Bid 0989 (a 200 MW Company-owned unit), Bid 0997 (a 200 MW Company-owned unit), Bid 0011 (a 50 MW unit that would be developed and constructed by a third-party but ultimately owned by the Company), and Bid 0235 (a 219 MW power purchase agreement (“PPA”) unit). The Commission found that the inclusion of the PPA thermal resource (Bid 0235) was attractive in that it reduces the risk that customers will bear future costs associated with utility-owned gas resources, including the risks that utility-owned gas resources will become stranded.³

7. The Phase II Decision also established a cost-to-construct (“CtC”) performance incentive mechanism (“PIM”) for each utility owned generation and storage project in the approved resource portfolio. In the Phase II Decision, the Commission recounted how in other contexts, costs, performance, or scheduling issues have increased the costs of utility-owned projects relative to the initial estimates the Company provided.⁴ The Commission opined that material changes to the cost and performance metrics of a project could impact the justification of the ERP need determinations. In addition, with competitive solicitation being the lynchpin of Colorado’s ERP process, we opined that winning bidders should not be able to materially increase the price of bids without consequences.⁵ To incentivize Public Service to build utility-owned projects at or below budget, the Commission established the CtC PIM that used the as-bid capital

² Phase II Decision, ¶ 92.

³ Phase II Decision, ¶¶ 101-108.

⁴ The Commission gave the specific example of the Company’s representations in Phase I of the proceeding that the conversion of the Brush Coal Plant to burn gas would cost approximately \$44 million. In the subsequent CPCN application, however, the Company’s estimated costs had increased to \$85 million. (Phase II Decision, ¶ 180).

⁵ Phase II Decision, p. 125.

construction cost for each project as the baseline, set a five percent deadband around the baseline, and then set three symmetric tiers of costs sharing if the actual construction costs for a project were above or below the deadband.⁶

8. In the Phase II Decision, the Commission directed Public Service to file applications for Certificates of Public Convenience and Necessity (“CPCN”) for all utility-owned resources within the approved resource portfolio. The Commission noted that, consistent with 4 *Code of Colorado Regulations* (“CCR”) 723-3-3617(d) of the Commission’s Rules Regulating Electric Utilities, Public Service’s actions that are consistent with the Phase II Decision have a presumption of prudence.⁷

9. On March 13, 2024, the Commission issued Decision No. C23-0672 Addressing Applications for Rehearing, Reargument, or Reconsideration (“RRR”) of the Phase II Decision (“First RRR Decision”). The First RRR Decision addressed several issues, including challenges to the approved resource portfolio, proposed modifications to the established CtC PIM, and the appropriate process for selecting backup projects. In addition, the First RRR Decision addressed the replacement of Bid 0235, which became unavailable after the Phase II Decision. The Commission specifically rejected the Company’s request to replace Bid 0235 (a PPA project) with Bid 1000 (a utility-owned project). The Commission reiterated that diversifying the ownership of the gas resources can help reduce risks to ratepayers and expressed a strong interest in evaluating whether there were other PPA gas resources that could replace Bid 0235, such as Bid 0510, Bid 0514, and Bid 1061.⁸

⁶ Phase II Decision, ¶¶ 183-185.

⁷ Phase II Decision, p. 125.

⁸ First RRR Decision, pp. 34-35.

10. On September 6, 2024, Public Service filed the CEP Delivery Motion, along with the testimony of Jack Ihle and several attachments. Among other things, the CEP Delivery Motion puts forth a proposed procedural schedule and limited discovery rights to facilitate the Commission's review of the Motion.

11. On September 10, 2024, Climax Molybdenum Company ("Climax") filed a Response to Public Service's proposed procedural schedule, which the Office of Utility Consumer Advocate ("UCA") and the Colorado Energy Consumers ("CEC") join. In the Response, Climax acknowledges the urgency of the CEP Delivery Plan but argues for extending the deadline for intervenor responses and increasing the amount of discovery that parties can propound. In its Response, Climax further states it prefers to proceed with an evidentiary hearing.

12. On September 19, 2024, the Commission issued Decision No. C24-0678-I. Among other things, Decision No. C24-0678-I set a procedural schedule that required the Company to file supplemental information, followed by intervenor responses, and a reply from Public Service to those responses ("Reply Comments"). Decision No. C24-0678-I also established limited discovery rights and scheduled a two-day *en banc* evidentiary hearing. The procedural schedule and discovery limits were a compromise approach that balanced the need for expediency and the concerns that certain intervenors raised regarding the deadline for intervenor responses and the amount of discovery rights afforded.⁹

13. By Decision No. C24-0699-I,¹⁰ the Commission addressed both UCA's request to shorten the timeline for Public Service to respond to discovery and certain recommendations regarding Plains End (an existing PPA thermal resource). In addition, we invited the parties to

⁹ Specifically, the concerns set forth in Climax's Response to Public Service's proposed procedural schedule. As set forth above, Climax argued for extending the deadline for intervenor responses and increasing the amount of discovery. UCA and CEC joined Climax's Response.

¹⁰ Issued September 26, 2024.

comment on a proposed approach to maintain competitive tension and directed Public Service to provide additional information regarding certain wind and thermal bids.

14. On October 4, 2024, Public Service filed supplemental comments and information, pursuant to Decision No. C24-0678-I. Included in this supplemental filing was Hearing Exhibit 166, Attachment JW1-17. This Attachment is a detailed report on the status of all bids and includes information from the bidders regarding whether they are able to move forward with their as-bid pricing and the scope of price relief many bidders assert they need to move forward with their projects. Public Service submitted a revised version of this Attachment on November 1, 2024.

15. On October 11, 2024, the following intervenors filed Answer Testimony to the CEP Delivery Motion: Staff, the Colorado Energy Office (“CEO”), UCA, and the Colorado Solar and Storage Association and the Solar Energy Industries Association (“COSSA/SEIA”). In addition, the following parties filed Comments on the CEP Delivery Motion: the Colorado Independent Energy Association (“CIEA”), Interwest Energy Alliance (“Interwest”), Western Resource Advocates (“WRA”), and CEC.¹¹

16. On October 3, 2024, Mainspring Energy, Inc. (“Mainspring”), filed an unopposed motion to intervene out of time in this Proceeding (“Late Intervention”). Mainspring is the developer of Bid 0011, which is a 50 MW new-build thermal resource in the San Luis Valley. Mainspring has been negotiating a build-transfer agreement with Public Service in which the Company will ultimately own and operate Bid 0011. In its Late Intervention, Mainspring argues the CEP Delivery Motion could directly and substantially impact Mainspring.

¹¹ Climax as well as UCA support and join in CEC’s comments.

17. By Decision No. C24-0736-I,¹² the Commission granted Mainspring's Late Intervention. The Commission found that Mainspring sufficiently demonstrated its interests in this Proceeding and noted that no party opposes the Late Intervention.

18. On October 11, 2024, Mainspring filed Answer Testimony from two witnesses.

19. In Decision No. C24-0746-I,¹³ the Commission directed Public Service to provide additional information in its Reply Comments. The Commission required the Company's Reply Comments to include the relevant PPA and build transfer agreement provisions that would implement a change-in-law price relief mechanism as well as examples of the PPA provisions that allegedly pose an unacceptable level of risk to the Company.

20. On October 25, 2024, Public Service submitted its Reply Comments.

21. On November 1, 2024, Mainspring filed an unopposed motion requesting access to certain confidential and highly confidential information pertaining to Bid 0011 ("Unopposed Motion to Access Information").

22. By Decision No. C24-0805-I,¹⁴ the Commission granted Mainspring's Unopposed Motion to Access Information.

23. On November 7, 2024, the Commission held a remote evidentiary hearing at which the following exhibits and associated attachments were admitted: Hearing Exhibits 166, 509, 1205, 2202, 2204, 2709, 2710, 2711, 2712, 2713, 2714, 2715, 2716, 2717, 2718, 2719, 2720, 2721, 2722, 2723, 2725, 2904, 3000, and 3001.

24. On November 18, 2024, the following parties filed statements of position ("SOPs"): Public Service, Staff, UCA, CEC,¹⁵ CIEA, COSSA/SEIA, Interwest, Mainspring, and WRA.

¹² Issued October 11, 2024.

¹³ Issued October 16, 2024.

¹⁴ Issued November 6, 2024.

¹⁵ Climax supports and joins CEC's SOP.

25. The Commission deliberated on the CEP Delivery Motion at the December 16, 2024 Commissioner’s Deliberations Meeting (“CDM”) and the December 20, 2024 CDM.¹⁶

C. Background of the CEP Delivery Motion

26. In the CEP Delivery Motion, Public Service argues that global and national geopolitical and market forces require some adjustments to the CEP to ensure the generation and storage projects contemplated in the approved resource portfolio can move forward.¹⁷ Public Service categorizes its requests into three components. Component 1 consists of a two-stage process in which renewable energy and storage projects could request price relief.¹⁸ Under this process as initially proposed, developers (including the Company) could individually submit requests to a newly appointed Independent Auditor (“IA”) to increase the price of their projects based on things such as unexpected supply chain difficulties, recent changes in tariff policy, or future changes in federal law. The IA would then verify whether the requested price increase is justified and submit its verification decision to the Commission for review.¹⁹

27. Under Stage 1 of this first component, developers could base price increase requests on a broad set of circumstances such as known and pending tariffs or duties, supply chain issues, or any other impacts of current market conditions such as changes in costs of materials or labor.²⁰ As proposed in the CEP Delivery Motion, developers could receive Stage 1 price relief of up to six percent increase of the as-bid pricing. Under Stage 2 of Component 1, developers could submit price increase requests to the IA based on a specified changes in federal law such as new tariffs or

¹⁶ The procedural history and background of this case are more fully set forth in the Phase II Decision and the First RRR Decision. Here, we provide only that background and procedural history necessary for this Decision.

¹⁷ CEP Delivery Motion, p. 2.

¹⁸ Hr. Ex. 166 (Ihle), p. 35.

¹⁹ Hr. Ex. 166 (Ihle), pp. 40-41.

²⁰ Hr. Ex. 166 (Ihle), pp. 35-36.

the reduction or repeal of the currently available production tax credits (“PTCs”) or investment tax credits (“ITCs”).²¹ Developers could receive additional price relief in Stage 2 up to a total of 15 percent, inclusive of any Stage 1 relief. Thus, if a project received a six percent price relief in Stage 1, it would only be eligible for up to an additional nine percent increase in Stage 2.²²

28. Component 2 addresses the thermal resources contemplated in the approved resource portfolio. Similar to the renewable energy and storage projects in Component 1, Public Service argues that the thermal resources need price increases to address disruptions to supply chains, strong demand for thermal unit components and labor, and the length of time that has elapsed since the bids were initially submitted on March 1, 2023.²³ Public Service seeks the ERP presumption of prudence per Rule 3617(d) that moving forward with the thermal units at the new revised cost levels is prudent. In addition, Public Service asks that the CtC baseline for the utility-owned gas facilities be adjusted upward to match the new cost estimates.²⁴

29. Component 2 includes the Company’s request for Commission approval to replace Bid 0235 with Bid 1000. Bid 0235 (a 219 MW new-build PPA gas resource) was included in the approved resource portfolio but is no longer available. The Company also seeks authorization to not include the selective catalytic reduction (“SCR”) system that it originally planned for Bid 0989 (a 200 MW, utility-owned gas unit).²⁵

30. As an alternative to Components 1 and 2, Public Service suggests the Commission treat utility-owned projects as “a distinct portfolio.” Under this alternative, the projects in the utility-owned portfolio would keep the same construction costs that the Phase II Decision

²¹ Hr. Ex. 166 (Ihle), p. 52.

²² Hr. Ex. 166 (Ihle), p. 51.

²³ Hr. Ex. 166 (Ihle), p. 57.

²⁴ Hr. Ex. 166 (Ihle), pp. 57-58.

²⁵ Hr. Ex. 166 (Ihle), pp. 88-89.

contemplates, but instead of several project-specific PIMs, there would be one portfolio-wide PIM with a five percent deadband.²⁶ PPA projects could continue to seek price relief under the proposed Component 1 process.²⁷

31. In Component 3, the Company requests approval to take certain actions to address near-term resource adequacy concerns by increasing capacity. Specifically, the Company requests a PPA extension for Plains End (a 219 MW unit with a PPA that expires at the end of 2027)²⁸ and increasing the incentives in the interruptible service option credit (“ISOC”) program in an attempt to boost DR capacity.²⁹ Initially, Public Service also requested as part of Component 3 an extension of Bid 1061 (a 76 MW PPA thermal resource).³⁰ However, Bid 1061 subsequently became unavailable.³¹

D. Component 1, Stage 1

1. Party Positions

32. As initially presented, in Stage 1 of Component 1, both utility-owned and PPA clean energy resources could obtain price increases of up to six percent due to current market conditions. To receive such pricing relief, developers would submit requests and supporting information to the IA, and the IA would make a project-specific determination of whether the price increase is legitimate reasonable or whether it was due to an unreasonably low bid estimate. In their SOPs, however, several parties, including Public Service, Staff, CIEA, and COSSA/SEIA argue the Commission should fundamentally modify the proposed Component 1, Stage 1 process by eliminating the IA review process.

²⁶ CEP Delivery Motion, pp. 2-3.

²⁷ Hr. Ex. 166 (Ihle), p. 90.

²⁸ Hr. Ex. 166 (Ihle), p. 114.

²⁹ Hr. Ex. 166 (Ihle), p. 101.

³⁰ Hr. Ex. 166 (Ihle), pp. 112-13.

³¹ Hr. Ex. 166 (Attachment JWI-16), p. 20.

33. Public Service specifically recommends that the Commission apply a uniform one to three percent price increase, without further IA reviews. Public Service “suggests 2 percent but defers to the independent power producer (“IPP”) trade associations on the specific level of relief.”³² For wind projects, Public Service recommends the Commission apply a six percent price increase.³³ PPA projects would receive the approved price increase if the bidder can provide an affidavit of a corporate officer for the IPP bidder supporting the causes of the price increase. Any project that takes a Stage 1 increase would remain eligible for a Stage 2 change-of-law adjustment, and no increase could exceed 15 percent in aggregate, as initially proposed in the CEP Delivery Plan.³⁴

34. For utility-owned clean energy projects, Public Service “would provide sworn testimony in support of the increase to the CtC value in the CPCN proceeding...”³⁵ The individual PIMs would be built around this updated CtC value and the CtC baseline would be entitled to a presumption of prudence in the follow-on CPCN proceeding.³⁶ For the three utility-owned wind projects in particular, Public Service makes clear in its SOP that the Company’s sworn testimony in the CPCN proceeding would support an increase in the CtC value, “which may not exceed 6 percent.”³⁷ Consistent with its initial proposal, Public Service argues that the price increases should be based on the \$/MWh or \$/kW-month PPA rates for IPP projects and should be based on the construction costs for utility-owned projects.³⁸

³² Public Service’s SOP, p. 2.

³³ Public Service’s SOP, p. 2.

³⁴ Public Service’s SOP, p. 8.

³⁵ Public Service’s SOP, p. 8.

³⁶ Public Service’s SOP, pp. 8, 13.

³⁷ Public Service’s SOP, p. 8.

³⁸ Hr. Ex. 166 (Attachment JWI-16), p. 13.

35. CIEA also recommends eliminating the use of the IA and instead requiring IPPs to submit affidavits signed by corporate officers supporting each CEP Project's repricing request. IPPs would provide the affidavits to Public Service, who could report the information to the Commission. Under this "fast-track" approach, CIEA would support a technology-specific reduced pricing flexibility of an up to three percent increase for solar, storage, or hybrid projects and up to six percent pricing flexibility for wind projects.³⁹

36. As support for this position, CIEA argues that "[d]elay is the enemy" and that each month of delay causes cost increases.⁴⁰ CIEA argues that under Public Service's initially proposed IA process, the IA might not realistically complete its review of repricing submittal until approximately April 2025.⁴¹ CIEA asserts that "the benefits of rigorous project pricing flexibility oversight via an IA and more regulatory process are outweighed by the risks of further increased project costs and decreased generation for resource adequacy in 2027 and 2028 due to project withdrawals or inability to meet as-bid [commercial operation dates]."⁴²

37. COSSA/SEIA similarly argues against the IA approach in Stage 1. COSSA/SEIA acknowledges the IA may offer checks and balances and provide additional information but argues the IA process will introduce at least four additional months of delay.⁴³ Instead, COSSA/SEIA recommends the Commission authorize a three percent across-the-board price increase for solar, solar plus storage, and storage projects now based on the record associated with the CEP Delivery Motion filings. COSSA/SEIA argues this will avoid additional delays and price increases that could occur between now and March 2025. COSSA/SEIA states that it "is confident that increasing

³⁹ CIEA's SOP, p. 3.

⁴⁰ CIEA's SOP, p. 7.

⁴¹ CIEA's SOP, p. 8.

⁴² CIEA's SOP, p. 11.

⁴³ COSSA/SEIA's SOP, p. 3.

bid pricing by this amount will allow projects to get across the finish line toward contract execution.”⁴⁴

38. COSSA/SEIA questions the accuracy of the developer survey answers reflected in Hr. Ex. 166, Attachment JW1-17, Rev. 1, which reports the status of all of the projects and the scope of the requested price increases. COSSA/SEIA asks the Commission to refrain from exclusively relying on the information within this attachment, suggesting that the information is inaccurate and outdated.⁴⁵

39. In its SOP, Interwest supports any plan that meets certain attributes that would help provide a quick path to project finalization. For Stage 1, Interwest’s desired attributes include eliminating or minimizing the timeline and complexity of any IA process or additional regulatory review and incentivizing projects to sign agreements as soon as possible.⁴⁶

40. In its SOP, Staff recommends adopting CIEA’s initial proposal in which clean energy resources could request a price increase of between two to six percent by submitting affidavits of corporate officers to the Company, and the Company would then confirm this repricing in a compliance filing to the Commission.⁴⁷ Projects that do not require Stage 1 price relief should be expedited, remain eligible for Stage 2 relief (change of law), and could receive a one percent price increase without verification. Staff argues this option represents the best overall

⁴⁴ COSSA/SEIA’s SOP, p. 11.

⁴⁵ COSSA/SEIA’s SOP, pp. 6-7.

⁴⁶ Interwest’s SOP, p. 1.

⁴⁷ While CIEA modified its position somewhat in its SOP, it initially proposed allowing IPPs to receive a price increase up to six percent in Component 1, Stage 1 without any IA review, with the understanding that such Stage 1 price increases could later be clawed back in Stage 2. Developers who are willing to execute PPAs right away could qualify for a one percent price increase without bidirectional Stage 2 exposure. (CIEA’s CEP Delivery Response Comments, pp. 17-18).

approach to achieving price relief and that eliminating the IA will accelerate the development of all renewable projects.⁴⁸

41. If the Commission moves forward with this approach, Staff argues two clarifications are necessary. First, the approach applies both to PPAs and utility-owned projects. For utility-owned projects, the Company would submit a filing with the Commission attesting to the need for the price increase. Second, Staff recommends the Commission specify that this price relief approach applies to projects in the approved portfolio. Only after an approved project has failed and the Company has gone through the established process for advancing backup bids could a backup bid also be eligible for Stage 1 price relief.⁴⁹

42. In connection with its recommendation to approve pricing relief in Stage 1, Staff argues that the Commission should treat utility-owned generation and PPAs the same by applying a six percent price relief limit to the project's net present value ("NPV") for both ownership types as opposed to a six percent NPV for PPA projects and a six percent CtC baseline increase for utility projects. Staff argues the Commission should ignore the Company's protests and fashion the price relief for both PPAs and utility projects such that it is based on the NPV of the projects.⁵⁰

43. In contrast to the parties arguing for the elimination of the IA, UCA recommends the Commission approve Public Service's initial Stage 1 proposal, including that the potential six percent cost increase would be confirmed by an IA.⁵¹

44. CEC asserts that the Commission must find a path forward that emphasizes transparency and scrutiny of any further cost increases. CEC does not oppose Public Service's initial proposal for an IA process so long as the IA process "is transparent and the results and IA

⁴⁸ Staff's SOP, pp. 3-4.

⁴⁹ Staff's SOP, pp. 4-5.

⁵⁰ Staff's SOP, pp. 6-7.

⁵¹ UCA's SOP, p. 1.

decisions are subject to stakeholder investigation and challenge....”⁵² In contrast, CEC “strongly opposes any proposal that would result in unnecessary and unverified automatic price increases not subject to scrutiny or verification through the IA or a similar process.”⁵³ CEC specifically includes in this opposition proposals to provide uniform cost increases to encourage projects to move forward, especially for those projects that have indicated that no price increase is necessary.⁵⁴

45. CEC reasons that, while the Company’s initial proposal is not perfect, the third-party verification provided by the IA provides necessary customer protections and eliminate frivolous or unnecessary price increases.⁵⁵ CEC asserts that it is clear from the record that many solar and solar plus storage projects report the ability to execute PPAs at the as-bid PPA rate, assuming they could potentially obtain price relief from future changes of law.⁵⁶ CEC acknowledges the timing constraints but maintains the Company and Commission still have a responsibility to protect customers by providing cost increases only for actual and verifiable purposes and not provide unnecessary price increases.⁵⁷

46. More specifically, CEC argues the Commission and Staff should have a role in selecting the IA to ensure that the IA is truly independent from the Company and bidders. In addition, CEC recommends expanding the process for Commission approval of an IA decision. CEC suggests that the 21-day review period be expanded and include an opportunity for intervenor

⁵² CEC’s SOP, pp. 1-2.

⁵³ CEC’s SOP, p. 2.

⁵⁴ CEC’s SOP, p. 2.

⁵⁵ CEC’s SOP, p. 4.

⁵⁶ CEC’s SOP, p. 4.

⁵⁷ CEC’s SOP, p. 5.

comment before the Commission must issue a decision to ensure that interested stakeholders have an opportunity to review, audit, and weigh in on any proposed price increase.⁵⁸

2. Findings and Conclusions

a. PPA Projects

47. The record contains considerable evidence that the current market dynamics and geopolitical environment have evolved since bids were submitted in March 2023 and factors such as supply chain constraints, policy uncertainty, and increased demand for clean energy projects have contributed to upward cost pressures.⁵⁹ Moreover, we agree with assertions from parties such as CIEA that further delay may cause additional price increases. We ultimately conclude that some amount of price flexibility is necessary to appropriately balance considerations of reliability, emissions reductions, and ensuring reasonable costs to customers.

48. The Commission agrees with Public Service, Staff, CIEA, COSSA/SEIA, and Interwest that the proposed IA-review process should be rejected for purposes of Component 1, Stage 1. The IA process will almost certainly result in several months of additional delays,⁶⁰ and additional delays will likely result in further price increases. Moreover, it is unclear how beneficial an IA would be in balancing the limited increases sought in Component 1, Stage 1 given the complexities of evaluating a variety of projects on an abbreviated basis. The risks that such a process would ultimately result in higher costs and the loss of important clean energy projects outweighs the benefits of a more robust project-by-project review of requested price increases. This is especially true for PPA projects, which do not require a subsequent CPCN proceeding.

⁵⁸ CEC's Comments on CEP Delivery, pp. 5-6.

⁵⁹ *See, e.g.*, Hr. Ex. 166 (Ihle), pp. 10-24.

⁶⁰ COSSA/SEIA's SOP, p. 3.

49. Thus, PPA solar, solar plus storage, and storage projects may receive a maximum price increase of one percent in Stage 1. The PPA wind project may receive up to a six percent price increase. This Stage 1 price relief flexibility for the PPAs is supported by the record evidence including the Company's testimony during the evidentiary hearing and especially the highly confidential updated pricing information contained in Hearing Exhibit 166, Attachment JW1-17, Rev. 1.

50. To receive the Stage 1 price increase, PPA developers must present to Public Service affidavits signed by corporate officers providing narrative descriptions supporting the requested increase and agreeing to the bidirectional nature of Stage 2 and the fact that Stage 1 and Stage 2 relief is considered in the aggregate. In other words, projects that receive a Stage 1 price increase could be subject to a price decrease in Stage 2.⁶¹ Additionally, any Stage 1 price increase counts against the 15 percent cap on price increases possible in Stage 2. Thus, if a project obtains a six percent price increase in Stage 1, it would only be eligible for an additional nine percent price increase based on change of law in Stage 2. Projects that move forward without Stage 1 price relief would still be eligible for Stage 2 price increases but would not be subject to any Stage 2 price decreases. This strikes the balance of allowing bidders to move forward with contracts immediately if they currently have no price increase needs but allows for them to return if there is a change of law that significantly impacts their ability to deliver the project at the bid price. For clarity, and consistent with Staff's position, backup projects may also utilize the Stage 1 price relief mechanism but only after full efforts have been made to move forward with the approved projects and after the approved backup bid selection process is employed.

⁶¹ This is directionally consistent with CIEA's initial proposal in which developers would "agree to the terms of a 'bidirectional' claw back of Stage 1 increases in its PPA, as well as liability for fraudulent statements." (CIEA's Comments, p. 17).

51. We recognize the arguments from CEC, UCA, and Climax that across-the-board price increases risk unnecessarily increasing costs to ratepayers and might constitute an unreasonable windfall for developers at ratepayer expense. However, a lengthy project-specific review might also unnecessarily increase costs through additional delay and threaten the viability of multiple clean energy projects, which could raise additional resource adequacy concerns. The cap on Stage 1 price increases together with the bidirectional nature of Stage 2 and the aggregate 15 percent cap for Stage 1 and Stage 2 price increases help weigh these concerns and reduce the risk that projects will obtain an unnecessary price increase in Stage 1. Further, our decision to defer consideration of the requested price increases for utility-owned projects until the CPCN proceedings as discussed below is consistent with arguments that there must be a project-specific review of each price increase.

b. Utility-Owned Projects

52. Given the differences between utility-owned projects and PPA projects, the Commission finds it appropriate to adopt a different Stage 1 approach for utility-owned clean energy projects. Contrary to Public Service's request, we defer granting a presumption of prudence for the proposed price increases or modifying the CtC PIM baselines until the appropriate CPCN proceedings. The Commission and interested stakeholders will be able to evaluate the validity of the requested price increases during the CPCN proceedings in much the same way that Public Service initially anticipated the IA would evaluate price increases. Because Public Service must still obtain CPCNs for the clean energy projects for which it now seeks price relief, withholding approval of the price increases until the CPCN proceedings will not result in any meaningful delay nor the associated concerns about additional price increases and resource adequacy related to further delay, making this distinct from the procedural path for PPA projects.

Moreover, it appears that Public Service is prepared to file CPCN filings for its wind projects in the near future. During the hearing, the Company represented that CPCNs for Bid 1015 and Bid 1024 should be filed about a week after hearing, while the CPCN for Bid 1029 would be filed in early December.⁶²

53. Our decision to defer consideration of the requested price increases for utility-owned clean energy projects is similar to the requests of Staff and CEO for the Commission to defer consideration of price increases for the Company's thermal units,⁶³ and is directionally consistent with Public Service's alternative proposal for those thermal projects.⁶⁴ As determined in the respective CPCN proceedings, costs in excess of as-bid amounts may be added into the baseline for purposes of determining the CtC and operational PIM baselines. For purposes of any future CtC PIM calculation, the market dynamics described in the CEP Delivery Plan filing may potentially constitute extraordinary circumstances within the terms of the CtC PIM (*i.e.*, unforeseen costs that could not have been known at the time the bid was made), subject to future adjudication by the Commission following development of the relevant project. Similarly, although potentially less applicable, the same would be true for the operational PIM. Moreover, prudently incurred costs associated with each of the projects will be eligible for recovery; provided, however, that this in no way impacts the application of the PIMs. For instance, the Company may earn a disincentive under the CtC PIM regardless of whether the underlying costs are imprudent.

54. In addition to the above findings, we clarify that utility-owned clean energy projects are subject to the same price cap as the respective PPA projects. Thus, the Company-owned wind

⁶² Hr. Tr. November 7, 2024, pp. 138-39.

⁶³ Staff's SOP, p. 9; Hr. Ex. 1204 (CEO Response Testimony), pp. 20-21.

⁶⁴ Hr. Ex. 166, Attachment JW1-19HC (Reply Comments), p. 19.

projects are only eligible for up to a six percent Stage 1 price increase in the CPCN proceedings, consistent with the Company's SOP,⁶⁵ and the utility-owned storage project would only be eligible for up to a one percent Stage 1 price increase in the CPCN proceeding. Importantly, this maximum six percent increase and maximum one percent increase shall be applied to the NPV of the respective projects, consistent with the price increases permitted for PPAs, and not on the CtC as the Company requests.

55. On this last point, we find Staff's arguments persuasive. Public Service's proposal to apply the percentage price increase to the project's construction costs for utility-owned clean energy projects but only to the NPV for PPA projects puts utility projects and PPA projects on an unlevel playing field. This unequal treatment could result in utility-owned projects receiving a larger price increase than an otherwise equivalent PPA project.⁶⁶ Public Service's own filings demonstrate the issue. A six percent increase on the construction cost of a wind project "translates to a higher percentage increase when compared to the smaller PTC-adjusted cost."⁶⁷ More precisely: "the 'six percent of baseline' cost increase divided by a smaller denominator (the PTC cuts approximately half of the cost of the project) ends up at about 12 percent on the PTC-adjusted costs."⁶⁸

56. Public Services raises several arguments against Staff's proposal to limit the percentage price increases to an NPV basis, none of which are persuasive. For instance, the Company argues there are material distinctions between utility-owned and PPA projects and that converting an NPV adjustment to a new CtC baseline is complex.⁶⁹ While we agree that material

⁶⁵ Public Service's SOP, p. 8.

⁶⁶ Hr. Ex. 2709 (Staff Response), p. 20.

⁶⁷ Hr. Ex. 166, Attachment JW1-16 (Supplemental Comments), p. 13.

⁶⁸ Hr. Ex. 166, Attachment JW1-16 (Supplemental Comments), p. 13.

⁶⁹ Hr. Ex. 166, Attachment JW1-19 (Reply Comments), pp. 9-10; Public Service's SOP, p. 7.

differences exist between utility-owned and PPA projects, the Company has not established how any of these differences justify additional price flexibility for utility-owned projects. Public Service knew of these differences and presumable accounted for them when the Company formulated its Phase II bids that now serve as the baseline for the Company's projects. As for the complexity of converting an NPV adjustment to a new CtC baseline, Staff asserts that the Company "grudgingly admits" that it could calculate the NPV for utility projects. According to Staff, all of the necessary information to perform this calculation is contained in the project-by-project updated revenue requirements that Staff obtained in discovery.⁷⁰ Moreover, interested parties and the Commission will be able to work through these details in the follow on CPCN proceedings.

57. In its Reply Comments, Public Service makes two alternative requests if the Commission adopts Staff's NPV approach. First, the Company states the NPV approach results in reduced CtC baselines and thus asserts the Commission should modify the methodology used to calculate the incentives and disincentives under the CtC PIM. Specifically, the Company requests the Commission adopt the progressive method as opposed to the landing spot method.⁷¹ Second, the Company argues the Commission should "convert the maximum NPV increase (such as 6%) to a revised CtC for each project, thus setting a new baseline CtC now and avoiding the need for recalculating NPV in the future."⁷²

58. We decline to adopt the Company's two alternative requests at this time. Regarding the first request, in the First RRR Decision we rejected the Company's request to switch to the progressive method on the basis that doing so would significantly reduce the level of potential incentives and disincentives under the CtC PIM.⁷³ In its CEP Delivery Motion filings, the

⁷⁰ Staff's SOP, pp. 6-7.

⁷¹ Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 11.

⁷² Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 10.

⁷³ First RRR Decision, ¶¶ 122-23.

Company does not address this shortcoming with the progressive method. Consistent with our earlier

First RRR Decision, in the CPCN proceedings Public Service may request to implement the progressive method in such a way that is supported and roughly maintains the respective amounts of incentives and disincentives.

59. Similarly, we defer the Company's second request to convert the NPV increase to a revised CtC baseline to the respective CPCN proceedings. In the CPCN proceedings, the Commission and parties can evaluate the actual reasons behind the Company's price increases and the appropriate amount of price relief. The Company's suggestion may be reasonable, but it is unnecessary and premature to rule on the proposal at this time.

E. Component 1, Stage 2

1. Party Positions

60. As proposed, Stage 2 of Component 1 would allow developers to seek additional price relief based on changes of federal law. The Stage 2 process would be initiated by a motion filed by the Company, Staff, or by the Commission on its own motion, describing the change in law and explaining why Stage 2 relief is appropriate. After considering responses to the motion, the Commission would determine whether to initiate a Stage 2 relief process. After Stage 2 is initiated, any requests for relief must be completed through submittal to the IA no later than December 31, 2025, or 18 months prior to the project's commercial operation date ("COD"), whichever is later.⁷⁴ In addition, bidders would be required to submit requests and documentation to the IA within 30 days of any Commission decision approving Stage 2 relief. After the IA makes its verification, it would then submit all materials to the Commission. The Commission would

⁷⁴ Hr. Ex. 166 (Ihle), p. 52.

have 21 days to review the IA's verification and, at the Commission's discretion, suspend the requested relief. If the Commission suspended the requested price relief, then there would be a 10-day intervenor comment period, a seven-day Company and bidder response period, and a Commission decision to approve or reject the requested relief within 14 days after the Company response.⁷⁵

61. Stage 2 relief would provide up to a 15 percent total price increase, inclusive of any prior approved increase in Stage 1.⁷⁶ Stage 2 is also bidirectional. For example, if PTC/ITC benefits increase, or if current tariffs are repealed, the Company could file for a reduction to the underlying PPA rates (for IPP bids) and CtC PIM baseline costs (for self-build and build-transfer bids).⁷⁷

62. In the event the Commission or the IA rejects all or a portion of a requested and verified Stage 2 increase, a project with an executed PPA would be able to terminate the PPA and receive a 75 percent refund of its Security Fund under Article 11 of the Model PPA if it so elects within 14 days of the Commission decision. Similarly, a build-transfer project could terminate its contract with the Company by paying 25 percent of the Termination Payment.⁷⁸ Public Service proposes to implement the Stage 2 process by incorporating the proposed PPA language in Hearing Exhibit 166, Attachment JWI-20.

63. Although Public Service proposes to eliminate the IA in Stage 1, in its SOP the Company continues to support the Stage 2 IA process as initially presented. Public Service reasons that the IA concept "continues to have merit in Component 1, Stage 2, where the time pressures may not be as acute as the current ones and where the required assessments would be more discrete

⁷⁵ Hr. Ex. 166 (Ihle), pp. 43, 53.

⁷⁶ Hr. Ex. 166 (Ihle), p. 51.

⁷⁷ Hr. Ex. 166 (Ihle), p. 51.

⁷⁸ Hr. Ex. 166 (Ihle), p. 53-54.

and less subjective.”⁷⁹ Public Service “requests approval of a Stage 2 process for all PPA and [utility-owned] projects with the same timing and triggers as proposed in the CEP Delivery Plan.”⁸⁰

64. In its SOP, Public Service argues the Stage 2 price relief mechanism “would not cover all potential changes in law, such as a full and immediate repeal of the Inflation Reduction Act (“IRA”) or repeal of relevant tax credits made available or extended by the IRA.”⁸¹ The Company states it is committed to working with developers to address such scenarios, including how posted security is treated under these types of circumstances. In addition, Public Service requests guidance from the Commission as to whether it anticipates using an IA for determining price changes in the event Stage 2 is triggered. The Company asserts an IA could assist the Commission in confirming the project-specific impacts of changes of law in an objective, expedient manner that would significantly reduce the burden on the Commission.⁸²

65. In Staff’s SOP, Staff largely agrees with the Stage 2 price relief concept. Staff argues that whether Stage 2 price relief is permitted and the level of that price relief should be at the Commission’s discretion, up to a maximum of 15 percent inclusive of Stage 1 relief. Consistent with CIEA’s initial recommendation, Staff argues that Stage 2 price relief should be bidirectional, except for those projects that agree to go forward with only a one percent increase in Stage 1. For those projects, Stage 2 price relief should only be upward.⁸³ CEO likewise generally supports the Company’s proposed process for Stage 2 pricing relief.⁸⁴

66. In its SOP, CIEA argues for a more generous Stage 2 price relief structure. CIEA reasons the election has changed the calculus regarding the likelihood and scope of potential

⁷⁹ Public Service’s SOP, p. 6.

⁸⁰ Public Service’s SOP, p. 14.

⁸¹ Public Service’s SOP, p. 14.

⁸² Public Service’s SOP, p. 16.

⁸³ Staff’s SOP, p. 16.

⁸⁴ Hr. Ex. 1204 (CEO Response Testimony), p. 17.

changes of law. According to CIEA, projects that move fast may lock-in existing PTCs, but further delays risk changes of law.⁸⁵ While CIEA continues to support the general concept of an IA review of change of law impacts in Stage 2, it argues that several modifications are now necessary. CIEA states it is “imperative” that the Commission allow developers to recover 100 percent of their security payments if projects must withdraw due to a change in law that causes cost increases of over 15 percent for any project. CIEA asserts that if the PTC/ITC is repealed, costs could rise by 100 percent. CIEA similarly argues that even short of a full repeal, partial repeals or changes in tax credit values or tariff amount could all devastate clean energy projects.⁸⁶

67. If the PTC/ITC is repealed or a change in law results in a price increase of more than 15 percent, CIEA also asks that the Commission request full repricing from all CEP projects without the 15 percent Stage 2 limit.⁸⁷ CIEA further asks that the Commission extend by one year the December 31, 2025, deadline for bidders to request Stage 2 price relief. CIEA states that changes in law are likely to pass in 2026, so the deadline should be December 31, 2026.⁸⁸ CIEA does not oppose the bidirectional nature of Stage 2 but argues developers should be allowed to defend against a downward Stage 2 reduction by showing that their projects did not benefit from a price reduction.⁸⁹ Finally, CIEA provides redlined modifications to Public Service’s proposed PPA language in Hearing Exhibit 166, Attachment JWI-20. CIEA makes it clear that it “does not request Commission approval of such modified language but provides the redline as an example to demonstrate IPP concerns about potential large, more structural changes of law that now must be taken into account.”⁹⁰

⁸⁵ CIEA’s SOP, pp. 14-15.

⁸⁶ CIEA’s SOP, p. 16.

⁸⁷ CIEA’s SOP, p. 5.

⁸⁸ CIEA’s SOP, pp. 5, 15.

⁸⁹ CIEA’s SOP, p. 5.

⁹⁰ CIEA’s SOP, p. 5.

68. In its SOP, COSSA/SEIA strongly supports the Stage 2 price relief for changes in law. COSSA/SEIA further supports retaining an IA to review any requests for Stage 2 price relief, reasoning that “there will be more time for successful bidders to request price relief, for the IA to review the request, and for the Commission to approve that price relief.”⁹¹ Nevertheless, COSSA/SEIA does request changes to the Stage 2 process. COSSA/SEIA asks for an appeals process in which a developer could request Commission review of a price increase that is denied by the IA. COSSA/SEIA asserts the appeal should take place in a separate Commission proceeding so that individual developers could seek Commission review of an unfavorable IA decision.⁹² COSSA/SEIA also argues against the PPA language Public Service proposes in Attachment JWI-20. COSSA/SEIA asserts the Company’s current language forces developers to bear all the risk, including losing their security deposit, if the IA or the Commission denies the requested price relief. COSSA/SEIA does not propose specific changes but asks that the Commission “adopt language that directs the Company to renegotiate bid security terms in any situation where Stage 2 price relief is denied by the Commission.”⁹³

69. More generally regarding PPA provisions, COSSA/SEIA argues the Commission “should refrain from making any determinations regarding the reasonableness or acceptability of any particular PPA provision.”⁹⁴ COSSA/SEIA particularly cautions against any Commission finding related to the security provisions in Hearing Exhibit 166, Attachment JWI-21. COSSA/SEIA argues that PPA terms cannot be viewed in isolation but must be seen in the context of the larger give-and-take negotiation.⁹⁵

⁹¹ COSSA/SEIA’s SOP, pp. 3-4.

⁹² COSSA/SEIA’s SOP, p. 4.

⁹³ COSSA/SEIA’s SOP, p. 4.

⁹⁴ COSSA/SEIA’s SOP, p. 6.

⁹⁵ COSSA/SEIA’s SOP, p. 5.

70. Interwest argues that quick decision making and a fair and robust opportunity for project developer level input is critical if there are any future changes in law or tariff.⁹⁶

71. In its SOP, UCA recommends the Commission approve the Company's plan for a potential 15 percent price increase in Stage 2.⁹⁷ UCA opposes, however, the Company's proposal to partially refund security deposits or other walk-away provisions. UCA reasons that security deposits provide a substantial incentive for developers to go forward with their projects or to minimize the requested price increase. UCA argues that developers knew their security deposits were at risk when they submitted their bids, and the security deposits should not be reduced or lost.⁹⁸

2. Findings and Conclusions

72. The general concept of a Stage 2 process to addresses changes in law has widespread party support and appears to be critical for most, if not all, of the clean energy projects.⁹⁹ The Company's proposed Stage 2 process is a useful structure that will encourage developers to move forward with projects even though future tariffs or changes to tax credits might impact the projects' financials. Therefore, the Commission adopts the Company's proposed Stage 2 process for both PPA and utility-owned projects, subject to the below modifications and clarifications.

73. Although a project-specific IA review in Stage 1 is inappropriate for the reasons discussed above, we agree with several of the parties that an IA review in Stage 2 appears useful and efficient. We find persuasive the Company's arguments that an IA review has merit in Stage 2, "where the time pressures may not be as acute as the current ones and where the required

⁹⁶ Interwest's SOP, p. 3.

⁹⁷ UCA's SOP, p. 9.

⁹⁸ Hr. Ex. 509 (UCA Testimony), pp. 26-27.

⁹⁹ Hr. Ex. 166, Attachment JW1-17, Rev. 1.

assessments would be more discrete and less subjective.”¹⁰⁰ Consistent with the Company’s request in its SOP for more guidance regarding the role of the IA, we clarify that the IA will ideally provide independent analysis of the documentation provided by the various developers and will produce initial determinations as to whether price modifications are appropriate. The methodology underlying these determinations should be consistent across all relevant projects, regardless of technology or ownership type.

74. To ensure the IA is ready and available if and when needed, Public Service shall confer with Staff and UCA on the selection of an IA and development of a scope of work. The Company must submit a motion to approve the proposed IA together with an IA scope of work no later than March 31, 2025. Public Service’s proposal to defer costs associated with the IA and recover them through the ECA seems reasonable, but Public Service must set forth the specifics of its proposed cost recovery mechanism in the March 31, 2025 motion. Parties to this Proceeding would have 14 days to file any responses to the Motion. Establishing this process at the outset will hopefully save time if and when Stage 2 is triggered.

75. Consistent with CEC’s arguments for additional transparency, the Commission finds that certain modifications to the proposed IA review process are necessary. First, intervenors should have an opportunity to review and comment on the IA’s Stage 2 determinations prior to a Commission decision. Intervenors shall have 21 days to review the IA’s initial determination. Public Service and any impacted developer would then have seven days to file response comments. The IA’s determination would not go into effect until the Commission decision, which would be issued in due course.

¹⁰⁰ Public Service’s SOP, p. 6.

76. We generally agree with the Company that any requests for Stage 2 relief should be submitted to the IA no later than December 31, 2025, or 18 months prior to the project's COD. We empathize, however, with concerns from CIEA that changes in law might occur in 2026. Thus, while we adopt the Company's proposed deadline at this time, parties may petition for an extension as necessary.

77. Consistent with our discussion above, we emphasize that the Stage 2 process is bidirectional for any projects that received Stage 1 price relief. Projects that did not pursue and receive Stage 1 price relief are still eligible for Stage 2 relief, but only in the upward direction.¹⁰¹ We agree with CIEA that pricing relief obtained in Stage 1 would be "[s]ubject to downward adjustment in Stage 2."¹⁰² We further agree with CIEA, however, that developers are permitted to argue via the established Stage 2 process that their projects should not be subject to a price reduction.

78. We recognize the importance of clarifying the consequences if a developer does not obtain the requested Stage 2 relief or if such relief is insufficient to address the change in law. The Commission adopts the Company's initial approach in which developers could terminate the PPA/build-transfer agreement if their Stage 2 price relief was denied and only pay 25 percent of the security deposit/termination payment, so long as the developer elects to do so within 14 days of the Commission decision. Adopting the contrary approach supported by CIEA and COSSA/SEIA and allowing developers to terminate their contracts with no financial consequences if any portion of their Stage 2 request is denied would incentivize all developers to request the full 15 percent price relief and would put significant pressure on the IA and Commission to approve

¹⁰¹ Public Service's SOP, p. 15.

¹⁰² CIEA's SOP, p. 6; *see also*, CIEA's Comments, p. 17.

the Stage 2 requests without modification. In contrast, requiring developers to pay at least 25 percent of the security deposit/termination payment incentivizes developers to move forward with the projects at or below the 15 percent price cap. PPA provisions that allow bidders to renegotiate bid security terms or walk away with more than 75 percent of the security deposit/termination payment if any portion of a bidder's Stage 2 request is denied would be contrary to this Decision.

79. While the Commission empathizes with UCA's request that developers be required to pay 100 percent of their security deposit if they withdraw, the Company's 25 percent threshold is a more balanced approach. UCA's request ignores the substantial uncertainty that future changes in law pose to CEP projects. Allowing developers to recover 75 percent of their security deposit/termination payment will encourage serious projects to execute PPAs/build-transfer agreements, despite the uncertain future.

80. A related issue is CIEA's argument that developers be allowed to recover 100 percent of their security payments if projects must withdraw due to a change in law that causes cost increases of over 15 percent for any project. In the event there is an established change of law that exceeds the 15 percent cap, we agree that developers should be allowed to terminate their PPAs and recover 100 percent of their security payments. Allowing this type of flexibility in the event of a significant change in federal law will again encourage developers to execute PPAs and attempt to develop their projects. To be clear, this full return of the security payment would not be allowed whenever a developer claims that a change in law increased prices by more than 15 percent. Rather, this option would only be available after a developer establishes to the

Commission's satisfaction that a project experienced a legitimate price increase of more than 15 percent and this price increase is directly caused by a change in law.¹⁰³

81. We decline from approving at this time CIEA's request that the Commission request repricing from all CEP projects without the 15 percent Stage 2 cap if there is a significant change in federal law. At some point, the Commission may be better off allowing impacted CEP projects to fail and relying on the JTS to reestablish the market price for clean energy projects.

82. Finally, we find COSSA/SEIA's request to establish a separate appeals process for bidders to be unnecessary and duplicative of existing avenues. Under the Stage 2 process established above, bidders already have an opportunity to provide input in the seven-day response period.¹⁰⁴ With the established Stage 2 IA process and the Commission's existing provisions for third parties to file a complaint to initiate a new proceeding, we do not see the need to create an additional appeals process per COSSA/SEIA's request.

F. Other Component 1 Issues

1. Selection of Additional Solar and Solar Plus Storage Bids

83. In addition to its other arguments regarding Component 1, UCA argues the Commission should consider selecting additional solar and solar plus storage bids. UCA asserts the large increase in future capacity need shown in the Company's initial JTS filings in Proceeding No. 24A-0442E supports taking additional capacity in this Proceeding.¹⁰⁵ UCA recommends the Company investigate whether the lowest-cost solar and solar plus storage projects are able to go

¹⁰³ For purposes of determining whether a project can recover 100 percent of its security deposit, the 15 percent threshold is based on the project's initial as-bid price, even if a project obtains a price increase in Stage 1. For instance, if a project received a six percent price increase in Stage 1, the developer would still be required to show more than a 15 percent price increase due to a change of law—even though the project would only be eligible for a nine percent price increase in Stage 2.

¹⁰⁴ *Supra* ¶ 75.

¹⁰⁵ UCA's SOP, pp. 4-5.

ahead under the proposed price increases proposed in Component 1. UCA specifically focuses on Bids 0718, 0649 and 0651 (all solar projects) and Bid 0567 (a solar plus storage).¹⁰⁶

84. The Commission denies UCA's requests to investigate whether additional solar and solar plus storage projects can move forward under the Component 1 price relief mechanism. It is far from clear on this record that the additional bids UCA flags could move forward under Component 1 or that there should be a presumption of prudence for their acquisition. For instance, it is uncertain whether the interconnections for these new projects could be timely achieved. While we ultimately deny UCA's recommendation, we note that Public Service could always seek authorization to pursue such additional projects outside of the JTS Proceeding, especially if the Company sees a potential cost-savings or reliability benefit.

2. Presumption of Prudence for Incremental Cost Increases

85. CEC raises the additional argument that any incremental cost increase in Component 1 should not be afforded the presumption of prudence per Rule 3617(d). CEC reasons the proposed Component 1 cost increases "would occur outside of the Commission's competitive solicitation rules" and thus any approved cost increases should be subject to prudence challenges.¹⁰⁷ CEC further argues that escalating CEP costs were foreseeable and predicted by the Independent Evaluator Report.

86. We reject CEC's argument regarding the application of Rule 3617(d). Given the competitive bidding process underlying the initial selection of these bids, the evidence put forth regarding the need for price increases, and the process and protections inherent in the Stage 1-Stage 2 mechanisms, price increases awarded under Component 1 will carry a presumption of prudence

¹⁰⁶ UCA's SOP, p. 6.

¹⁰⁷ CEC's SOP, p. 3.

per Rule 3617(d). This will help provide Public Service the regulatory certainty it needs to quickly pursue these clean energy projects and avoid future delays and cost increases.

G. PPA Execution and Requests for Rule Variances

1. Party Positions

87. In its CEP Delivery Motion, Public Service seeks variances from Rule 3613(i) and Rule 3613(j). Under Rule 3613(i), a utility must execute contracts for resources within 18 months after the utility's receipt of bids to receive the presumption of prudence per Rule 3617(d). This deadline was September 1, 2024. Public Service seeks a six-month extension so that the new regulatory deadline to execute contracts is March 1, 2025.¹⁰⁸ Under Rule 3613(j), a utility must file a proposal within 14 months after the receipt of bids that addresses the public release of all confidential and highly confidential information related to bids. The deadline for this filing was May 1, 2024. Public Service proposes to extend this deadline by at least 11 months to April 1, 2025. Public Service states that the bids are in a very sensitive state and may change based on the relief contemplated in the CEP Delivery Motion.¹⁰⁹

88. CIEA, COSSA/SEIA, and Interwest all argue the Commission should act to prevent further delays in executing PPAs. CIEA asserts Public Service's delay in PPA executions is a contributing factor for the need for price increases and that Public Service appears to be "understaffed and overwhelmed."¹¹⁰ In its Response Comments, Interwest states that "timeliness" is the most critical factor in achieving the goals of the CEP and that the available time to complete

¹⁰⁸ CEP Delivery Motion, p. 14.

¹⁰⁹ CEP Delivery Motion, p. 15.

¹¹⁰ CIEA's CEP Delivery Comments, p. 20.

projects and meet CODs is becoming prohibitively short.¹¹¹ Interwest further asserts there have been significant delays during contract negotiations due to the Company's own action.¹¹²

89. To prioritize PPA execution going forward, CIEA recommends the Commission require Public Service to submit by December 31, 2024, a filing updating the Commission on all PPA negotiations, and every month thereafter. CIEA also suggests the Commission direct the Company to prioritize quicker PPA execution over holding the line on withdrawal "outs" and penalties for IPPs. That said, CIEA expressly asks that the Commission take no action on the specific terms of PPAs presented by Public Service at this time.¹¹³

90. COSSA/SEIA critiques the Company's requested variance of Rule 3613(i) in the context of delayed PPA execution. COSSA/SEIA argues that Rule 3613(i) puts pressure on the Company to execute PPA and build-transfer contracts swiftly. According to COSSA/SEIA, granting the Company's requested variance would reward "the bad behavior and foot-dragging that occurred from the Company not executing contracts in a timely manner."¹¹⁴ COSSA/SEIA recommends the Commission deny the requested variance and reserve its decision to grant or deny the presumption of prudence until after the CEP Delivery bids are finalized.¹¹⁵ In the alternative, COSSA/SEIA argues that if the Commission grants the variance, the revised deadline for compliance should be as short as possible and a firm deadline that is not subject to additional delays. COSSA/SEIA suggests the extended deadline should be December 31, 2024. COSSA/SEIA also asks that the Commission confirm that bid prices will become public on that date.¹¹⁶

¹¹¹ Interwest's Comments, pp. 2-3.

¹¹² Interwest's Comments, p. 6.

¹¹³ CIEA's SOP, p. 7.

¹¹⁴ COSSA/SEIA's SOP, p. 9.

¹¹⁵ COSSA/SEIA's SOP, p. 9.

¹¹⁶ COSSA/SEIA's SOP, pp. 9, 12.

91. In its Reply Comments, Public Service asserts it is negotiating in good faith with all bidders and warns the Commission against relying on the unattributed statements from COSSA/SEIA and CIEA. Public Service asserts several PPA are in near-final draft form and that this demonstrates the Company's ability to reasonably negotiate with IPPs. For other bids, Public Service says there are issues outside of the Company's control, such as a developer's need for price relief or insistence on receiving a Component 1, Stage 2 relief mechanism.¹¹⁷ The Company states that negotiations of long-term, multi-million-dollar contracts are always challenging and that while it agrees on the importance of executing PPAs, the timeframe for these negotiations is not atypical.¹¹⁸ The Company asserts that no IPP developers were able to execute a PPA given the need for either direct pricing relief or assurances of relief in the event of future changes in tariffs or the availability of tax credits.

92. Ultimately, Public Service proposes to submit monthly reports, beginning in January 2025, on the status of negotiations for all PPA and IPP build-transfer projects. The Company states that these reports will be similar in form to Table 1 in the Company's October 4 Supplemental Filing, Hearing Exhibit 166, Attachment JWI-16HC. The Company commits to continue this monthly reporting until all PPAs for the CEP are executed.¹¹⁹

2. Findings and Conclusions

93. The Commission agrees that timeliness is a critical factor for the CEP's success. Indeed, this urgency is one of the main factors supporting our decision to eliminate the IA process in Stage 1 of Component 1 for PPA projects. Our decisions providing bidders and the Company

¹¹⁷ Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 30.

¹¹⁸ Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 28; Public Service's SOP, pp. 16-17.

¹¹⁹ Public Service's SOP, p. 17.

more certainty regarding Component 1 price relief processes and the extent to which bidders can recover their security deposit should also help accelerate the negotiation process.

94. Nevertheless, the Commission denies CIEA's suggestion to direct Public Service to prioritize quicker PPA negotiations over penalties if IPPs walk away from the PPA. Apart from our earlier decisions regarding the recovery of security deposits, we see little value in issuing vague directives to focus on executing PPAs at the expense of other contested terms. As to CIEA's request that the Commission take no action on specific PPA terms, we agree that there is no need for the Commission to approve specific PPA provisions at this time.

95. Regarding CIEA's request for monthly updates from Public Service on all PPA negotiations, it appears that Public Service largely agrees with this concept. Consistent with the proposals from CIEA and Public Service, we direct the Company to submit monthly reports in this Proceeding on the status of negotiations for all PPA and IPP build-transfer projects. These negotiation reports shall be due on the fifth of every month,¹²⁰ and will continue until all PPAs and build-transfer agreements for the CEP are executed. Public Service shall confer with the individual bidders on the negotiation status that the Company intends to provide in the negotiation report. Conferral confirmation must be provided in the report to the Commission.

96. Turning to COSSA/SEIA's opposition to the Company's requested variance of Rule 3613(i), we agree that Rule 3613(i) ideally should incentivize Public Service to execute PPAs swiftly. We disagree, however, with COSSA/SEIA's primary recommendation to deny the variance and defer granting a presumption of prudence until after bids are finalized. Removing regulatory certainty in this way might cause additional delays. COSSA/SEIA's alternative

¹²⁰ The first report requirement shall commence the fifth of each month following issuance of this Decision, with an initial report for January of 2025 provided as soon as practicable following issuance of this Decision.

recommendation of a December 31, 2024 deadline is not feasible. Therefore, we grant the Company's requested variance and adopt the March 1, 2025 deadline the Company proposes in the CEP Delivery Motion. We clarify, however, that any request to extend the March 1 deadline must be accompanied with a detailed description of Public Service's efforts specific to each individual PPA and build-transfer agreement. Similar to the monthly negotiation reports but with more detail, Public Service shall confer with the individual bidders on the information the Company intends to provide regarding efforts to finalize PPAs, and conferral confirmation must be included.

97. We also grant Public Service's variance from Rule 3613(j) regarding the public release of bid information. We agree with the Company that the bids are in a "sensitive state" and it is too soon to publicly release confidential information regarding such as bid prices. The April 1, 2025 deadline is a reasonable amount of time for Public Service to submit a proposal for the public release of such information.

H. JTS Proceeding

1. Party Positions

98. Several parties recommend the Commission take certain actions regarding the ongoing JTS Proceeding in light of the challenges presented in the CEP Delivery Motion. For instance, Staff argues that in the JTS Proceeding, the Commission should consider consequences for bids that have failed in this process from reappearing in the JTS Proceeding. Such consequences could include higher bid fees or stricter walkaway provisions.¹²¹ Staff suggests the Commission consider consequences for bids that have failed in this process that reappear in the JTS Proceeding (*e.g.*, higher bid fees or stricter walkaway provisions). Staff does not

¹²¹ Staff's SOP, p. 17.

recommend setting such consequences here but encourages the Commission to inform bidders that withdrawing an approved bid submitted in this ERP only to re-bid the same project in the JTS Proceeding may result in heightened review or financial scrutiny.¹²² CEO similarly suggests that bids that receive Component 1 price relief only to pull out of this process and bid into the JTS Proceeding could be subject to higher bid security fees, stricter walk-away provisions, or other measures that will increase the surety of future contracts.¹²³

99. UCA opines that the Company and the Commission have been lax in ensuring that IPPs are not advantaging Colorado's ERP system. UCA recommends that any projects that pull out of this Proceeding from this point forward be ineligible to bid in the JTS Proceeding.¹²⁴

100. COSSA/SEIA and CIEA make sweeping suggestions for how to reform the JTS Proceeding. For instance, COSSA/SEIA suggests setting a deadline in the JTS Proceeding for the expiration of bid pricing after which bidders would be allowed to refresh pricing.¹²⁵ One of CIEA's suggestions is for the Commission to consider a "best and final" pricing opportunity in the JTS Proceeding for IPPs to sharpen their pencils and adjust pricing after the levelized cost screening.¹²⁶

101. Interwest states that the extended timelines in the Proceeding are putting investment at risk. Interwest warns that if development risks in Colorado are not reduced in future solicitations by trimming delays "the state may risk losing its appeal as a key focus for renewable project development."¹²⁷ According to Interwest, it is critical for the Commission to be able to fully investigate the Company's management of the CEP resource solicitation such that the problems in this Proceeding are not repeated in the JTS Proceeding and that "[the Company's] rhetoric be

¹²² Hr. Ex. 2709 (Staff Response), p. 26.

¹²³ Hr. Ex. 1204 (CEO Response Testimony), p. 16.

¹²⁴ Hr. Ex. 509 (UCA Testimony), p. 11.

¹²⁵ Hr. Ex. 2202 (COSSA/SEIA Response Testimony), pp. 34-36.

¹²⁶ CIEA's Response Comments, pp. 26-27.

¹²⁷ Interwest's Comments, p. 3.

reviewed through a factual lens.”¹²⁸ Interwest accordingly requests that the Commission make numerous changes to the JTS Proceeding. For instance, Interwest ask that Public Service be required to submit a separate filing in its JTS Proceeding with an analysis of every point in the CEP where any delay could have been avoided and suggestions for preventing similar delays in the JTS Proceeding.¹²⁹ Interwest also recommends the Commission require Public Service to include a bid price expiration deadline and to develop a PIM that would reward Public Service for conducting timely portfolio reviews and executing contracts efficiently.¹³⁰

2. Findings and Conclusions

102. We reject the various suggestions to use this Proceeding to set new requirements for the currently ongoing JTS Proceeding. The intervenors in the JTS Proceeding are welcome to propose modifications in that proceeding, where they can be adjudicated by all parties in the JTS Proceeding.

103. We similarly deny suggestions from Staff, CEO, and UCA that there should be some type of predetermined consequence in the JTS Proceeding if a bidder abandons a project that was proposed in this Proceeding given all the difficulties, delays, and challenges that have occurred. That said, parties in the JTS Proceeding are free to argue that a particular bidder or a bidder’s pricing is unreliable because of past actions. The Commission will consider such arguments as they come before us, but we decline from using this Proceeding to decide how bidders in the JTS Proceeding will be evaluated.

¹²⁸ Interwest’s Comments, pp. 3-4.

¹²⁹ Interwest’s Comments, p. 7.

¹³⁰ Interwest’s Comments, pp. 8-9.

I. Replacement for Bid 0235

1. Party Positions

104. In the CEP Delivery Motion, Public Service seeks authorization to replace Bid 0235 (a 219 MW new-build PPA thermal resource that was included in the approved resource portfolio but is no longer available) with Bid 1000 (a Company-owned thermal resource). The Company separately seeks authorization to extend the PPA for Plains End (an existing 219 MW PPA thermal resource) to add additional capacity to its system.¹³¹ Public Service argues the additional capacity it seeks in the CEP Delivery Motion is reasonable given the already tight summer capacity positions the Company is facing. The Company further reveals it has updated its methodologies for the planning reserve margin (“PRM”) and effective load carrying capability (“ELCC”) values and is developing a new base load forecast in advance of the JTS. Based on these new assumptions, the Company asserts it is facing real and substantial capacity needs in the coming years.¹³²

105. CEO opposes the Company’s proposal and recommends the Commission approve the Plains End PPA extension as the replacement for PPA Bid 0235. CEO notes that in the Phase II Decision, the Commission approved 669 MW of nameplate thermal capacity via Bids 0989, 0997, 0011, and 0235. Public Service now asks that the Commission approve 869 MW of nameplate thermal capacity via Bids 0989, 0011, and 1000, and by extending the Plains End PPA contract.¹³³ CEO argues that the Company does not need to secure an additional 200 MW of capacity at this time.¹³⁴ CEO asserts that the Commission’s decision should be based on the facts that have been litigated in the instant proceeding.¹³⁵

¹³¹ CEP Delivery Motion, p. 9.

¹³² Hr. Ex. 166 (Ihle), pp. 106-10.

¹³³ Hr. Ex. 1204 (CEO Response Testimony), pp. 21-22.

¹³⁴ Hr. Ex. 1204 (CEO Response Testimony), p. 22.

¹³⁵ Hr. Ex. 1204 (CEO Response Testimony), pp. 26-27.

106. WRA similarly recommends that the Commission approve the Plains End PPA extension as a replacement for Bid 0235 instead of Bid 1000.¹³⁶ WRA raises significant concerns about the Company's thermal proposals but notes that due to the nature of this filing and associated procedural schedule, the Commission and parties are unable to effectively investigate the Company's claims regarding resource adequacy issues. According to WRA, there are significant differences in the Company's capacity position if it is viewed through the lens of the currently approved ELCC and PRM conventions, as compared to the Company's new and unvetted methodologies.¹³⁷ WRA characterizes the issues as follows: "should the Commission approve the acquisition of additional thermal capacity to address resource adequacy concerns outside the RAP of this proceeding, that are based on ELCC and PRM methodologies that have not yet been litigated."¹³⁸

107. WRA argues that with the updated ELCC/PRM methodologies, Public Service is attempting to justify its proposal to extend the Plains End PPA and pursue a larger self-build thermal bid. WRA observes that one factor influencing the capacity position shortage under updated methodologies appears to be the updated treatment of DR resources. Under current conventions, where DR is treated as a load reduction, DR contributes between 651 MW to 787 MW of load reduction, depending on the year. Under the Company's new methodologies, however, DR is included in the generation category, with capacities ranging from 335 MW to 372 MW. WRA reiterates its claim that the Commission and parties have extremely limited evidence about the factors driving the Company's resource adequacy claims and how these factors manifest in the loads and resources table.¹³⁹

¹³⁶ WRA Comments on CEP Delivery, pp. 8-9.

¹³⁷ WRA Comments on CEP Delivery, p. 10.

¹³⁸ WRA's SOP, pp. 2-3.

¹³⁹ WRA Comments on CEP Delivery, p. 14.

108. Staff is more deferential to the Company's obligation to evaluate the reliability of its generating portfolio but ultimately notes the same issues that CEO and WRA raise. In its Response Testimony, Staff acknowledges that the Company retains the obligation to evaluate the reliability of its generating portfolio but states that Staff struggles to see the need for additional thermal capacity in 2028. Staff implores the Company to provide a robust discussion of this issue in its responsive comments and asserts that, without such complete explanation, Staff will not support the acquisition of an additional 200 MW of thermal generation.¹⁴⁰ Conversely, Staff states it will support the Company's position if it can fully demonstrate and explain the reliability concern necessitating the acquisition of the additional 200 MW of thermal capacity.

109. In its SOP, Staff references the load and resources ("L&R") table from Volume 2 of the JTS that Public Service provides in its Reply Comments (JTS Table 2.9-1) as illustrating a significant capacity shortfall through 2033 (e.g., 646 MW in 2025 and 534 MW in 2026). Staff moreover asserts that this L&R Table underestimates the capacity shortfall in that some of the assumed CODs have been pushed back and a solar bid has failed.¹⁴¹ Nevertheless, Staff stops short of endorsing the Company's proposal.

110. If the Commission determines that the Company has not provided sufficient support for its reliability concerns, Staff states there are two options. First, the Commission could retain the two thermal projects currently in the approved resource portfolio (Bid Nos. 0989 and 0997) and simply add Plains End. Second, the Commission could replace both Bid 0989 and 0997 with Bid 1000 as well as Plains End. Staff's preference is the second option, given that Bid 1000 appears more economical than Bid 0989.¹⁴²

¹⁴⁰ Hr. Ex. 2709 (Staff Response), p. 35.

¹⁴¹ Staff's SOP, p. 15.

¹⁴² Staff's SOP, p. 15.

111. In its Reply Comments, Public Service asserts that using the Plains End PPA extension as the replacement for Bid 0235 is untenable. Public Service proffers two arguments in support of its position. First, the Company asserts that replacing a new-build thermal asset with the existing Plains End unit does not work from a reliability perspective. Second, the Company argues that forgoing new thermal capacity now is not an option given anticipated resource needs.¹⁴³ More bluntly, Public Service states that “[t]he Company will not sign the [Plains End] extension if doing so is conditioned on removing Bid 1000—the best available option to replace Bid 0235—from the portfolio, as some intervenors suggest.”¹⁴⁴

112. Regarding the need for a new-build combustion turbine (“CT”) from a reliability perspective, Public Service asserts that it undertook the alternatives analysis the Commission required in its First RRR Decision for the replacement of Bid 0235 and that the preferred result is acquiring Bid 1000 as the replacement for Bid 0235. “Public Service strongly believes that a full portfolio of *new* thermal assets, i.e., at or near 669 MW, is required to continue the energy transition in a reliable manner.”¹⁴⁵ The Company asserts an extension of the Plains End unit, which is 20 years old, “is not a substitute for a new CT unit, which the Commission has already approved.”¹⁴⁶ Public Service further alleges that “[t]he approval of the acquisition of three new CTs in the Phase II Decision to meet reliability needs is a closed issue,” noting that “[n]o party challenged this need on [RRR].”¹⁴⁷ The Company references the Phase II Decision in which the Commission stated that it “cannot simply carve out from a modeled resource portfolio some or all of the firm dispatchable resources that Public Service maintains are necessary for reliability.”¹⁴⁸

¹⁴³ Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), pp. 17-18.

¹⁴⁴ Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 26.

¹⁴⁵ Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 18 (emphasis in original).

¹⁴⁶ Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 21.

¹⁴⁷ Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 25.

¹⁴⁸ Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), pp. 24-25 (quoting Phase II Decision, ¶ 125).

Similarly, Public Services references its earlier arguments in its Response Comments to the 120-Day Report when it stated that “eliminating gas units or taking the shortcut of substituting suboptimal and questionable short-term PPA extensions . . . makes the plan less reliable and risks reliability.”¹⁴⁹

113. On the other hand, Public Service emphasizes that it is not arguing against the Plains End PPA extension. The Company states that Plains End is valuable to the Company from capacity, black start, and transmission support perspectives.¹⁵⁰

114. As to its argument that foregoing additional thermal capacity is not an option, Public Service argues that a five-year extension of Plains Ends is temporary and creates a hole that will need to be filled when the PPA expires. The Company asserts that it cannot count on any capacity from Plains End after the five-year extension expires, making the PPA extension “an inferior option from a reliability perspective.”¹⁵¹

115. Referencing its direct case in the JTS Proceeding, Public Service asserts that it has substantial and growing capacity needs due to projected load growth and its revised ELCC and PRM studies.¹⁵² Public Service acknowledges interveners’ concerns that the JTS L&R table has not been litigated. Public Service argues, however, that “the appropriate question is not whether the updated load forecasts and ELCC and PRM studies have been approved, but whether it represents the best information available to the Company when making choices in a challenging environment.”¹⁵³ Referencing the recently-filed JTS Proceeding, the Company states it is “confident of substantial needs for new generation—including both new renewable generation and

¹⁴⁹ Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 26 (quoting Public Service’s Response Comments to the 120-Day Report, pp. 28-29).

¹⁵⁰ Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), pp. 26-27.

¹⁵¹ Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 25.

¹⁵² Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 27.

¹⁵³ Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 27.

new firm dispatchable generation—above and beyond anything we have seen in Colorado.”¹⁵⁴ Based on this new modeling, Public Service argues that it is prudent to approve the Company’s Component 2 portfolio and to extend the Plains End PPA to meet demand in a dynamic environment. Conversely, the Company argues it would be imprudent to simply ignore the best-available information and hope that capacity needs will remain flat.¹⁵⁵

116. In its SOP, Public Service maintains its position, arguing that it has performed an analysis of all available thermal alternatives and “the Commission has approved the need to build a total of three new [CT] units” in addition to a thermal project in the San Luis Valley.¹⁵⁶ Public Service also states that “Plains End is not a substitute for the new thermal capacity the Commission approved in Phase II.”¹⁵⁷

2. Findings and Conclusions

117. As presented through this CEP Delivery Motion process, Public Service has failed to meet its burden of proof that Bid 1000 is the appropriate replacement for Bid 0235. We therefore deny applying the ERP presumption of prudence under Rule 3617(d) to the Company’s proposed replacement for Bid 0235. Instead, the presumption of prudence is limited to the combination of the Plains End PPA extension, Bid 0011, and *either* Bid 1000 or Bid 989 (discussed further below). If the Company insists that the extension of the Plains End PPA, Bid 0011, Bid 0989, *and* Bid 1000 are all necessary for reliability, it can proceed with that option and retain its burden to show in subsequent proceedings the prudence for the incremental thermal capacity (*i.e.*, Bid 1000 or Bid 989) and any associated costs.

¹⁵⁴ Hr. Ex. 166, Attachment JW-19HC (Reply Comments), p. 18.

¹⁵⁵ Hr. Ex. 166, Attachment JW-19HC (Reply Comments), p. 28.

¹⁵⁶ Public Service’s SOP, p. 9.

¹⁵⁷ Public Service’s SOP, p. 11.

118. The arguments Public Service puts forth for why the Plains End PPA extension cannot be used to replace Bid 0235 are unpersuasive. Starting with the Company's assertions regarding reliability of Plains End compared to a new-build thermal resource, we note the Company raises no concerns with the location of the Plains End unit compared to the Bid 0235 nor points to any known reliability issues with Plains End. Indeed, Public Service states that the Plains End PPA extension "is valuable to the Company from capacity, black start, and transmission support perspectives...."¹⁵⁸ Instead of raising specific reliability concerns with Plains End, Public Service seems to argue that anything less than three *new* CTs is per se unreliable. For instance, the Company asserts that "[t]he approval of the acquisition of three new CTs in the Phase II Decision to meet reliability needs is a closed issue,"¹⁵⁹ and that "Plains End is not a substitute for the new thermal capacity the Commission approved in Phase II."¹⁶⁰ These statements imply that the Commission found in the Phase II Decision that approximately 650 MW of *new-build* thermal resources is necessary for reliability.

119. We disagree with the Company's characterization of our findings regarding new-build thermal resources. While the thermal resources within the approved portfolio were admittedly all new builds, for reasons unknown to the Commission, the Company did not identify the potential to extend the Plains End PPA as an option until the CEP Delivery Motion. Public Service cannot now argue that failure to include such PPA extensions in the approved portfolio is a finding that such resources are inappropriate. Indeed, existing PPA units *were* included in the approved backup thermal portfolio, and Public Service never contested that these approved backup resources could not replace a new-build resource. In fact, in the First RRR

¹⁵⁸ Hr. Ex. 166, Attachment JW-19HC (Reply Comments), pp. 26-27.

¹⁵⁹ Hr. Ex. 166, Attachment JW-19HC (Reply Comments), p. 25.

¹⁶⁰ Public Service's SOP, p. 11.

Decision we rejected Public Service’s request to replace Bid 0235 with Bid 1000 because there was no analysis as to whether the existing PPA units such as Bid 1061, Bid 0510, and Bid 0514 could serve as the replacement.¹⁶¹ Public Service never sought RRR on this point.

120. Contrary to the Company’s assertion that the existing Plains End unit cannot be a substitute for the new-build thermal resources initially in the approved portfolio, we see existing PPA units such as Plains End as providing valuable ownership diversity and protection from additional costs. In our Phase II Decision, we noted that Company-owned thermal resources subject ratepayers to the risk of construction and operational cost overruns, decommissioning costs, and the potential that the gas resources will become stranded. We found the approved resource portfolio more desirable than the Company’s preferred portfolio in part because the approved portfolio contained a PPA thermal resources, which “reduces the risks that customers will be saddled with future costs associated with Company-owned gas resources.”¹⁶²

121. The Company’s second argument regarding growing resource adequacy concerns is also unconvincing. We acknowledge the Company’s new L&R Table put forth in the JTS shows significant capacity shortfalls through 2033. Ultimately, however, we agree with CEO and WRA that our decisions regarding resource adequacy should be grounded in the evidence that has been litigated in this Proceeding. The resource need projections on which the Phase II Decision relies have been thoroughly vetted throughout this long Proceeding. We are disinclined from adopting the Company’s eleventh-hour change in its resource adequacy forecasts as a justification to acquire an additional 200 MW of thermal resources.

¹⁶¹ First RRR Decision, ¶¶ 77-78.

¹⁶² Phase II Decision, ¶ 108.

122. To be clear, we are not prohibiting the Company from moving forward with the requested incremental thermal resources. We simply conclude that Public Service has not earned a presumption of prudence in this Proceeding, particularly based on the relatively truncated and late-stage process associated with the CEP Delivery Motion. If the Company is convinced it needs additional thermal resources above those approved in this ERP Proceeding, it has other methods of obtaining regulatory certainty before construction, including through a CPCN proceeding. Public Service is ultimately responsible for ensuring reliability. In this vein, we encourage Public Service to continue moving forward with actions it reasonably believes are necessary to ensure the Company has the resources it needs to ensure reliability. This may include, for example, development and permitting work associated with all of its proposed thermal resources.

123. As for the thermal resources for which the Company does enjoy a presumption of prudence, we ultimately provide the Company discretion to pursue either of the two options put forth by Staff. In Option 1, Public Service would enjoy a presumption of prudence for the following thermal resources: the Plains End PPA extension, Bid 0989, Bid 0997, and Bid 0011. In Option 2, Public Service would enjoy a presumption of prudence for the following thermal resources: the Plains End PPA extension, Bid 1000, and Bid 0011.¹⁶³

124. We agree with Staff that Option 2 appears more attractive given the cost advantages of Bid 1000. Moreover, Option 2 avoids the complexities associated with Bid 0989 as discussed below. Nevertheless, we acknowledge there are additional factors that might impact the appropriateness of the two options, such as the timing of when various resources can come online

¹⁶³ If, for example, the Company decides to move forward with the Plains End PPA extension, Bid 1000, Bid 0011, *and* Bid 0989, then Bid 0989 would be incremental to Option 2 and thus would not enjoy a presumption of prudence. The other thermal resources would enjoy a presumption of prudence.

and the locational differences of the various resources. Based on the record before us, Public Service is in the best position to determine which option is preferable.

J. Thermal Resource Price Increases

1. Party Positions

125. As part of the CEP Delivery Motion, Public Service seeks the ERP presumption of prudence per Rule 3617(d) that pursuit of the thermal units at the new revised cost levels is prudent. In addition, Public Service asks that the CtC PIM baseline for the utility-owned thermal facilities be adjusted upward to match the new cost estimates.¹⁶⁴

126. Several intervenors disagree with the Company's request regarding the proposed price increases of the thermal units. For instance, Staff recommends that the Commission not grant the Company the specific price relief, arguing there is simply not enough time and information to ascertain whether the requested relief is reasonable.¹⁶⁵ Staff's strong preference would be for the Company to present its financial analysis in the CPCN proceedings to appropriately allow parties time to examine the Company's estimates, changed circumstances, financial accounting, *etc.* Such CPCN proceedings could appropriately re-establish the individual CtC baselines after careful consideration of the detailed information.¹⁶⁶

127. In its SOP, Staff argues that the "the Commission must insist upon properly vetting the significantly increased cost projections" and reiterates its recommendation to do so in follow-on CPCN proceedings.¹⁶⁷ Staff argues that Public Service provides little more than the "limited and cursory explanations for the increases in the right-hand column of Hearing

¹⁶⁴ Hr. Ex. 166 (Ihle), pp. 57-58.

¹⁶⁵ Hr. Ex. 2709 (Staff Response), p. 39.

¹⁶⁶ Hr. Ex. 2709 (Staff Response), p. 40.

¹⁶⁷ Staff's SOP, p. 9.

Exhibit 2718HC.”¹⁶⁸ Staff further asserts that neither the Commission nor any of the intervenors have had an adequate opportunity to vet the reasons the Company gives for the surges in projected costs.¹⁶⁹

128. In its Response Testimony, CEO similarly argues that Public Service has not provided detailed information demonstrating which costs have increased, by how much, and why. Without this information, CEO argues, the Commission cannot reasonably determine if the new baseline costs the Company proposes are reasonable. CEO asserts that more detailed cost comparisons and explanations should be provided in future CPCN proceedings, where any prudence requests can be addressed.¹⁷⁰

129. Interwest recommends that the Commission require Public Service to treat all projects equally in the CEP Delivery Plan to ensure fairness, transparency, and system reliability. According to Interwest, utility-owned projects should be treated in the exact same manner as IPP owned generation, and thermal generation should be treated in the exact same manner as renewable generation.¹⁷¹

130. CEC and UCA argue the Commission should retain the project-specific CtC PIMs with no adjustment to the baseline. CEC asserts that modifying the CtC PIM at this juncture would fundamentally disrupt the purpose of the CtC PIM and set a precedent that utilities can simply dodge PIM disincentives if project costs increase. According to CEC, customers should be protected from the cost increases that the IE Report predicted.¹⁷² UCA similarly argues the CtC

¹⁶⁸ Staff’s SOP, p. 8.

¹⁶⁹ Staff’s SOP, pp. 8-9.

¹⁷⁰ Hr. Ex. 1204 (CEO Response Testimony), pp. 20-21.

¹⁷¹ Interwest’s Comments, pp. 6-7.

¹⁷² CEC’s Comments on CEP Delivery, pp. 8-9.

PIM is intended to protect customers against price increases and thus it would be unreasonable to adjust the baseline for a CtC incentive for a price increase.¹⁷³

131. In its Reply Comments, the Company continues to argue that application of Rule 3617(d) and its presumption of prudence to the updated costs for Bid 0989, Bid 1000, and Bid 0011 is appropriate. The Company reasons that it has presented updated pricing with more detail and background than is typically provided in a Phase II process, and this is an ERP where Rule 3617(d) applies to projects receiving approval. Public Service states that a presumption of prudence would provide the Company regulatory certainty to move forward with CPCN filings for these units where the costs can be examined in more detail and a final determination regarding the costs for the project, including the CtC baseline, can be established by the Commission.¹⁷⁴

132. Nevertheless, the Company acknowledges that several intervenors raise concerns with this concept.¹⁷⁵ If the Commission declines to apply Rule 3617(d), the Company proposes an alternative pathway that it states is responsive to the proposals from Staff and CEO to use the CPCN proceedings reestablish the individual CtC baselines. The Company alternative proposal is for the Commission to make the following findings:

Finding 1: Prudently incurred costs associated with each of the projects will be eligible for recovery.

Finding 2: Costs in excess of as-bid amounts may be added into the baseline for purposes of determining the CtC and Operational PIM baselines, as determined in the CPCN proceeding.

Finding 3: For purposes of any future CtC PIM calculation, the market dynamics described in the CEP Delivery Plan filing are—if established by the utility to have cost impacts on the project as delivered compared to the CtC baseline—extraordinary circumstances within the terms of the CtC

¹⁷³ Hr. Ex. 509 (UCA Testimony), pp. 27-28.

¹⁷⁴ Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), pp. 18-19.

¹⁷⁵ Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 18.

PIM, subject to future adjudication by the Commission following development of the project in question. Similarly, although potentially less applicable, the same would be true for the Operational PIM.¹⁷⁶

133. Public Service states that, in the absence of a Rule 3617(d) application to the updated cost estimates, making the above three findings offers an alternative path forward.¹⁷⁷

134. In its SOP, Public Service does not discuss the alternative approach of making certain findings prior to CPCNs. Instead, Public Service argues the Commission should move forward with the Company's primary recommendation to approve CtC baseline adjustments consistent with the Company's presentation in the CEP Delivery Motion. The Company asserts that intervenors "have conducted extensive discovery relating to these projects over the last two months, and will have an opportunity for additional review in future proceedings as the projects are brought online."¹⁷⁸

2. Findings and Conclusions

135. We agree with Staff and CEO that the requested cost increases for the thermal resources should be examined in follow-on CPCN proceedings before deciding whether the incremental costs are entitled to a presumption of prudence or warrant adjustments to the CtC PIM baseline. The Commission finds unpersuasive the Company's arguments that it has presented updated pricing with more detail and background than is typically provided in a Phase II process and thus is entitled to Rule 3617(d)'s presumption of prudence. In a typical Phase II process, there is competitive tension and various resource options. These elements are largely lacking in the context of the CEP Delivery Motion's requested price increases for thermal units. Moreover, it is

¹⁷⁶ Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 19.

¹⁷⁷ Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 20.

¹⁷⁸ Public Service's SOP, p. 9.

far from clear that Public Service has presented detailed information regarding the requested price increases; Staff's assertions support the opposite conclusion.¹⁷⁹

136. On the other hand, we disagree with CEC and UCA's suggestions to decide in this Proceeding that no adjustments to the CtC baselines are warranted. Public Service appears to raise legitimate claims that thermal generating equipment has seen significant increases in demand and cost. If established in follow-on CPCN proceedings, such cost increases may warrant adjusting the CtC PIM baseline. Similarly, we decline from adopting at this juncture Interwest's position that thermal resources should be treated the same as renewables.

137. In connection with our decision to evaluate the proposed cost increases in the follow-on CPCN proceedings, we largely agree with Public Service's alternative proposal to make certain findings regarding how such cost increases will be evaluated going forward. The thermal projects that have earned a presumption of prudence in this Proceeding will advance to the CPCNs with this presumption of prudence intact as to the project's as-bid amounts. In the CPCN proceedings, the Commission could determine the incremental costs above the project's as-bid amounts potentially constitute extraordinary circumstances and accordingly adjust both the CtC baseline and the level of costs that carry a presumption of prudence.

138. For clarity, we adopt the Company's three requested findings, with the below modifications. As determined in the respective CPCN proceedings, costs in excess of as-bid amounts may be added into the baseline for purposes of determining the CtC and operational PIM baselines. For purposes of any future CtC PIM calculation, the market dynamics described in the CEP Delivery Plan filing may potentially constitute extraordinary circumstances within the terms of the CtC PIM (*i.e.*, unforeseen costs that could not have been known at the time the bid was

¹⁷⁹ Staff's SOP, p. 8.

made), subject to future adjudication by the Commission following development of the relevant project. Similarly, although potentially less applicable, the same would be true for the operational PIM. Moreover, prudently incurred costs associated with each of the projects will be eligible for recovery; provided, however, that this in no way impacts the application of the PIMs. For instance, the Company may earn a disincentive under the CtC PIM regardless of whether the underlying costs are imprudent.

K. Bid 0989

1. Party Positions

139. As part of the CEP Delivery Motion, Public Service requests Commission approval to remove the SCR system from Bid 0989.¹⁸⁰ The Company argues the SCR system is not required for environmental permitting and that its removal will result in cost savings and operational advantages.¹⁸¹ The Company explains that it initially assumed the unit would need an SCR to meet environmental permitting requirements. After further examination, based on permitting requirements, projected capacity factor and operating characteristics, Public Service now maintains that the SCR is not necessary and the unit can be permitted and operated without it. Public Service acknowledges that removing the SCR will likely lower the unit's permitted capacity factor, but the Company states that the lowered capacity factor is still above the range it expects to need for this unit.¹⁸²

140. Public Service states it needs certainty from the Commission on this point in order to commence the air permitting process with the Colorado Department of Public Health and the Environment ("CDPHE"). Public Service asserts that if the Commission defers deciding whether

¹⁸⁰ CEP Delivery Motion, p. 9.

¹⁸¹ Hr. Ex. 166 (Ihle), p. 75.

¹⁸² Hr. Ex. 166 (Ihle), pp. 75-76.

to remove the SCR, the Company would need to proceed with the SCR for permitting reasons, which would result in “unnecessary costs to customers.”¹⁸³

141. In its SOP, Public Service clarifies that the Company is not asking the Commission to either approve anything regarding the permitting of Bid 0989 or approve operational characteristics for Bid 0989. Instead, “the Company simply requests the Commission acknowledge that moving forward without the SCR is permissible in light of the fact that this is a difference from the as-bid configuration.”¹⁸⁴

142. Staff argues the Commission should proceed with caution regarding the removal of the SCR device. Staff notes that the Company’s Phase II modeling and bid assumed that an SCR would be installed for this unit. Staff is particularly concerned about the Company’s representations regarding the capacity factor at which the unit can operate without the SCR. Staff argues the Commission should find a way forward in which it can quickly vet the Company’s cost-reduction claims as well as to verify potential operational concerns associated with removing the SCR. To do this, Staff suggests the Commission direct parties to address the removal of the SCR as part of an operational PIM proceeding.¹⁸⁵

2. Findings and Conclusions

143. We share Staff’s concern that removing the SCR from Bid 0989 might change how Public Service can operate the unit as compared to the Phase II modeling. Public Service has testified, however, that the lowered capacity factor the unit would have without the SCR is not expected to change Public Service’s use of the plant and that there is insufficient time to fully

¹⁸³ Hr. Ex. 166 (Ihle), p. 76.

¹⁸⁴ Public Service’s SOP, p. 10.

¹⁸⁵ Staff’s SOP, p. 11; Hr. Ex. 2709 (Staff Response), p. 44.

evaluate the operational changes before Public Service must initiate the permitting process with CDPHE.

144. Based on the Company's representations in testimony, the Commission grants the Company's clarified request in its SOP and acknowledges that moving forward without the SCR is permissible even though doing so is different than the as-bid configuration. Public Service has put forth evidence that removing the SCR will save ratepayers considerable money without interfering in the planned operation of the unit nor the value it is expected to provide ratepayers. CDPHE is tasked with determining the exact impacts that removing the SCR will have on the plant's operations.

145. Nevertheless, if Public Service moves forward with Bid 0989, the issues surrounding the SCR device will need to be more closely examined in the follow-on CPCN proceeding. Public Service's position that the SCR device is unnecessary is based on assumptions regarding how the Company will use the unit. However, there are several uncertainties that might impact the planned use of the unit, including developments with beneficial electrification, large new loads, and the potential entry into a regional market. If such changes alter the calculus for whether the additional operational flexibility granted by use of the SCR device is beneficial, the Commission will scrutinize whether any incremental costs should fall on Public Service's ratepayers.

146. Similarly, we intend to examine in any future CPCN for Bid 0989 whether there should be a mechanism (*e.g.*, a PIM) to ensure the accuracy of the Company's representations regarding the capacity factor of the unit and the role the unit has in the system. One of the primary purposes of thermal units such as Bid 0989 is to help ensure Public Service has the capacity it needs when the system is peaking. If the Company's removal of the SCR device were to impact

the unit's ability to serve its purpose, we would have significant concerns as to whether ratepayers are receiving the intended benefits of the unit and may find the need to guard against this eventuality at the onset of the project.

L. Bid 0011

1. Party Positions

147. Bid 0011 is a 50 MW thermal resource in Alamosa County. The project is being developed and built by Mainspring, but as bid, Public Service would purchase, own, and operate the unit. As with the other thermal units in the approved Alternative Portfolio, Public Service now seeks price flexibility regarding Bid 0011.¹⁸⁶ However, unlike the other thermal units, Bid 0011 claims designation as a "Section 123 resource" as explained in the Phase II Decision.

148. UCA recommends the Commission reject Bid 0011. UCA asserts the life of the Mainspring generators is unknown given that the Mainspring's first commercial units were deployed in 2020. UCA also points to hearing questions that show Mainspring only has about 20 MW of projects in the field.¹⁸⁷ UCA goes on to assert that the price of Bid 0011 is excessive and not competitive with other projects, especially if Bid 0011 fails to qualify for ITC tax benefits. As an alternative, UCA recommends the Commission approve extending the life of the existing Alamosa CTs as a bridge to the JTS.¹⁸⁸ UCA also suggests that some of the Plains End units could be moved to the San Luis Valley to replace the capacity from Bid 011 at a much lower cost.¹⁸⁹

149. Mainspring submitted testimony that Bid 0011 would reduce CO2 emissions compared to the existing plants in Alamosa County by approximately 59 percent and NOx

¹⁸⁶ Hr. Ex. 166 (Ihle), pp. 27-28; CEP Delivery Motion, p. 9.

¹⁸⁷ UCA's SOP, pp. 6-7.

¹⁸⁸ UCA's SOP, pp. 7-8.

¹⁸⁹ Hr. Ex. 509 (UCA Testimony), pp. 20-21.

emissions by approximately 99 percent on a per MWh basis.¹⁹⁰ Mainspring further asserts that its linear generator technology has the ability to switch between various gaseous fuels, including, but not limited to, natural gas, hydrogen, propane, and biogas. The linear generator uses a low-temperature reaction without a spark or flame, which results in near-zero emissions of nitrogen oxides.¹⁹¹ With its project's fuel flexibility and ability to seamlessly change fuels without hardware or software updates, Mainspring argues the project does not have stranded asset risk of traditional thermal units.¹⁹²

150. Mainspring notes that when it developed its bid, it did not expect that Public Service would require a third-party engineering study, and the associated cost and schedule impacts were not reflected in the bid. Mainspring argues there are similar requirements related to Bid 0011's status as a Section 123 resource that have forced Mainspring to reasonably deviate from its bid assumptions and associated pricing.¹⁹³

151. In its SOP, Mainspring reiterates the positive attributes of Bid 0011 and notes that due to the plant's new, clean technology, it is a Section 123 resource, to which the Commission must give the "fullest possible consideration to the cost-effective implementation" of the project.¹⁹⁴ Mainspring additionally argues that Bid 0011 will not unreasonably shift risk to ratepayers. Mainspring asserts it has the necessary experience deploying its linear generators, noting the other projects its development team has done and the fact that the Department of Energy recently awarded Mainspring an \$87 million grant to build a manufacturing facility to produce its linear generators.¹⁹⁵ Mainspring also states the Commission and parties will be able to evaluate

¹⁹⁰ Hr. Ex. 3001 (Igo Testimony), p. 5.

¹⁹¹ Hr. Ex. 3000 (Hennessy Testimony), pp. 4-5.

¹⁹² Hr. Ex. 3000 (Hennessy Testimony), p. 8.

¹⁹³ Hr. Ex. 3001 (Igo Testimony), pp. 8-9.

¹⁹⁴ Mainspring's SOP, p. 7.

¹⁹⁵ Mainspring's SOP, p. 10.

the build-transfer agreement with Public Service in the CPCN proceeding. According to Mainspring, a core component of the negotiations with Public Service has been reducing risk for ratepayers. Mainspring further notes that it has made substantial investments in the project that will not be recoverable if the Commission ultimately does not approve Public Service's acquisition of Bid-0011.¹⁹⁶

152. In addition, Mainspring argues that advancing Bid 0011 is the best available option to meet the needs of the San Luis Valley. If the Commission removes Bid 0011 in place of other options that were not competitively bid, Mainspring argues it would undermine the entire Phase II process and potentially chill future competitive solicitations in Colorado. Such a result would also arguably violate Commission Rule 3605(h)(II)(A), which provides that in an ERP proceeding, a Phase II decision "shall establish the *final* cost-effective resource plan."¹⁹⁷ Mainspring specifically critiques UCA's recommendation to move some of the Plains End units to the San Luis Valley as a replacement for Bid 0011. Mainspring asserts there is no analysis on the feasibility of this option and, because Plains End will emit more emissions than the linear generator, such a move would be contrary to the Commission's statutory obligation to account for and help correct the historical inequities faced by disproportionately impacted communities in Colorado.¹⁹⁸ Mainspring also adds the record does not support extending the life of the existing Alamosa CTs.

153. Although Staff initially recommended eliminating Bid 0011 due to its price increase, Staff changed its position after reviewing Mainspring's testimony. In its SOP, Staff now asserts the Commission "should no longer consider dropping Bid No. 0011."¹⁹⁹ Staff recommends the Commission vet the projected cost increases in the CPCN proceeding, arguing that determining

¹⁹⁶ Mainspring's SOP, p. 10.

¹⁹⁷ Mainspring's SOP, p. 13 (emphasis in original).

¹⁹⁸ Mainspring's SOP, pp. 13-14.

¹⁹⁹ Staff's SOP, p. 9.

whether the price increase drivers truly constitute justifiable projected cost increases is an ideal topic for a CPCN proceeding.²⁰⁰

154. In Public Service's SOP, the Company continues to recommend moving forward with Bid 0011 at the requested price increase. The Company appreciates Staff's recognition of the importance of Bid 0011. Public Service states that the alternative—life extensions of the existing units at Alamosa—is not preferable, given that they leave the same location-specific capacity hole after 2030.²⁰¹

2. Findings and Conclusions

155. The Commission generally agrees with Public Service, Staff, and Mainspring. Consistent with the other approved thermal resources, Public Service may advance Bid 0011 to the CPCN proceeding, and Rule 3617(d)'s presumption of prudence will remain intact as to the project's as-bid amounts. The Commission will evaluate in the CPCN proceeding whether the incremental costs of the project also warrant a presumption of prudence and whether the CtC PIM baseline for the project should be adjusted as set forth above.

156. We reject UCA's recommendation to use the existing CTs as a bridge until new resources can be acquired in the JTS. The existing thermal resources in Alamosa are aging, and Public Service raised reliability concerns with these plants in the 120-Day Report. UCA's recommendation simply delays when a replacement thermal resource is constructed in Alamosa, with no guarantee that future thermal resources would be more cost effective. We likewise reject UCA's suggestion to move some of the Plains End units to the San Luis Valley. There is insufficient record support for this proposal.

²⁰⁰ Staff's SOP, p. 10.

²⁰¹ Public Service SOP, p. 11.

157. Although Public Service may move forward with Bid 0011 consistent with the other approved thermal resources, we are concerned about the price and size of Bid 0011 and the associated risks to ratepayers. At the same time, we continue to acknowledge the potential fuel flexibility associated with this plant and the potential for benefits in that regard. Accordingly, we direct Public Service to present in the CPCN proceeding as a potential alternative an approach in which the size and costs of the project are reduced. As an example of this alternative option, the Company could consider structuring the build-transfer agreement more as a purchase option and pre-construction development asset with Mainspring. Under such an approach, the Company might have a unilateral option to purchase the project at an agreed upon matrix of prices, with flexibility to adjust the final size of the project. In return for this option, and in addition to the purchase price, the Company could compensate Mainspring for all of its verifiable reasonable third-party development costs at the time the option was signed. Public Service may be able to request accelerated cost recovery of these expenses through the electric commodity adjustment. We encourage the Company to explore and negotiate further this and other potential options regarding Mainspring, with the overarching intent of reducing costs and limiting risks to ratepayers.

M. Purchase of Plains End

1. Party Positions

158. In the CEP Delivery Motion, the Company states that its preferred approach is to extend the Plains End PPA. As a secondary approach, the Company suggests it could pursue purchasing the unit.²⁰²

²⁰² Hr. Ex. 166 (Ihle Testimony), p. 115.

159. In their Answer Testimony, Staff and UCA initially both urged the Commission to direct Public Service to purchase Plains End, arguing that purchasing the unit provides substantial cost advantages. UCA in particular characterized the cost-benefit of owning the plant as “massive.”²⁰³

160. In its Reply Comments, however, Public Service argues that requiring the Company to immediately purchase Plains End is not a prudent path. The Company reasons that before purchasing an asset like Plains End, the Company would need to conduct extensive due diligence. Public Service states that it “could not commit to purchasing the unit prior to conducting due diligence without strong and unambiguous assurances that any unforeseen issues ... would not be a basis for intervenor disallowance recommendations.”²⁰⁴ If the Company’s preferred approach is approved, the Company proposes to report annually, beginning in the March 2025 ERP annual report, on the status of a potential acquisition of Plains End.²⁰⁵

161. After reviewing the Company’s Reply Comments, UCA and Staff both change positions regarding the purchase of Plains End. In its SOP, Staff now argues against requiring Public Service to purchase Plains End. Staff instead recommends the Commission adopt the Company’s preferred approach in which it extends the PPA. In connection with this recommendation, Staff argues the Commission should (1) require Public Service to carry out due diligence regarding the potential acquisition of the unit, and (2) direct the Company to seek Commission approval to purchase or decline from purchasing Plains End in an application filing that contains the Company’s due diligence.²⁰⁶

²⁰³ Hr. Ex. 2709 (Staff Response), pp. 29-30; Hr. Ex. 509 (UCA Testimony), pp. 16-17.

²⁰⁴ Hr. Ex. 166, Attachment JWI-19HC (Reply Comments), p. 22.

²⁰⁵ Public Service’s SOP, p. 12.

²⁰⁶ Staff’s SOP, p. 13.

162. UCA similarly recommends that Public Service extend the PPA and perform due diligence on the condition of the plant and the costs for the Company to operate it. Depending on the results of the due diligence, UCA recommends the Company purchase Plains End as soon as possible.²⁰⁷

2. Findings and Conclusions

163. We approve the Company's preferred approach of extending the Plains End PPA and then conducting due diligence into a potential acquisition of the unit. To be clear, as argued here, we find that the Company has met its burden and extending the Plains End PPA is entitled to a presumption of prudence.

164. Consistent with the Company's position, Public Service shall report annually, beginning in the March 2025 ERP annual report, on the status of a potential acquisition of Plains End. We also adopt Staff's additional proposal and require Public Service to carry out the due diligence and direct the Company to seek Commission approval to purchase or decline from purchasing Plains End in an application filing that contains the Company's due diligence.

165. While we ultimately agree with Public Service's preferred approach regarding Plains End, the Company's decision to wait until September 2024 to seek regulatory approval regarding Plains End is incredibly frustrating. If the Company would have brought Plains End to the Commission earlier, there might have been additional options for cost savings for ratepayers. There is insufficient information to address that concern raised by parties here. While the Company's preferred approach appears to be the only prudent presented option moving forward based on this record and at this very late stage, our determination only addresses prudence of extension given the record before us. In a subsequent proceeding stakeholders may argue whether

²⁰⁷ UCA's SOP, p. 2.

Public Service fails to demonstrate the prudence of its decisions to delay seeking regulatory approval regarding Plains End.

N. Alternative Thermal Proposals

1. Party Positions

166. In its Response Testimony, UCA puts forth an alternative thermal proposal that includes Bid 1000 but then adds a another two CTs at an existing gas-fired generator station. UCA argues that adding CTs at this existing site provides important transmission support as an existing gas-fired generator, Cherokee 4, retires. UCA asserts that its thermal proposal provides 1,019 MW of economical thermal capacity.²⁰⁸

167. UCA continues to advance its alternative thermal proposal in its SOP, reiterating the importance of adding additional generation at Cherokee. Relatedly, UCA asks that the Commission direct Public Service to delay the Cherokee 4 retirement date by a year. UCA argues that delaying the retirement will improve the reliability of the Company's system and help address the projected capacity shortfall in 2028.²⁰⁹

168. CEC offers a similar, but broader, recommendation that the Commission consider extending existing thermal generation capacity as necessary to meet load growth and maintain reliability in the face of lost capacity from withdrawing clean energy projects. CEC asserts that Xcel Energy affiliate Southwestern Public Service Company has turned to extending thermal generating units as it transitions its generation fleet to meet New Mexico's emissions reduction goals. CEC argues the Commission should require Public Service to explore similar opportunities here.²¹⁰

²⁰⁸ Hr. Ex. 509 (UCA Testimony), pp. 20-21.

²⁰⁹ UCA's SOP, p. 3.

²¹⁰ CEC's Comments on CEP Delivery, p. 8.

169. Another alternative proposal from UCA is that the San Luis Valley should have enough capacity to allow it to be “islanded” if the two transmission lines connecting the San Luis Valley are lost. UCA asks the Commission to direct Public Service to provide summer and winter load and gas-pipeline capacity data for the San Luis Valley, with the load data also showing how much load could be curtailed in case the transmission lines are lost. UCA recommends Public Service provide a plan for how much capacity, including gas, storage, and demand management, is needed to island the San Luis Valley if the transmission lines are lost.²¹¹

2. Findings and Conclusions

170. The Commission denies UCA’s alternative thermal proposal and recommendation to require Public Service to delay the retirement of Cherokee 4. There is insufficient record support for UCA’s proposals. We likewise decline CEC’s recommendation to require Public Service to explore extending the lives of existing thermal units. Public Service is responsible for reliability and should already be evaluating all potential options to ensure resource adequacy.

171. We also do not support UCA’s recommendation to require Public Service in this Proceeding to submit an analysis of the amount of additional capacity that would be necessary to island the San Luis Valley. UCA can always advocate for such an analysis in the JTS if it wishes to do so.

O. Expansion of ISOC Incentives

1. Party Positions

172. Public Service seeks authorization to increase the incentives under the ISOC program to encourage more DR capacity. Public Service argues that expansion of this program is most likely to produce incremental growth in short term DR. The ISOC program uses direct-load

²¹¹ UCA’s SOP, pp. 8-9

control and provides a minimum of ten minutes notice to customers prior to controlling the customer's load. Legacy or "grandfathered" customers receive a foundational bill credit of \$15.97/kW-mo, but new customers currently receive a bill credit of only \$11.27/kW-mo. At this lower incentive, however, Public Service states that only one customer has enrolled in the program since 2019.²¹² The Company asks that the Commission increase the "new" program incentive to match the "legacy" incentive of \$15.97/kW-mo through 2028.

173. CEO supports increasing the ISOC incentive back to its legacy level on a pilot basis with additional reporting. CEO reasons this will allow the Company to gather information about the willingness of customers to enroll in the ISOC program at the adjusted incentive level. CEO recommend the Commission direct Public Service to provide any learnings and data collected from the pilot both in its 2026 Demand Side Management ("DSM") Strategic Issues proceeding to assess the potential capacity impacts of the ISOC incentive and in its annual DSM Status Report.²¹³

174. In its Response Testimony, UCA recommends the Commission reject the Company's proposal to expand the ISOC program, arguing Public Service has not provided enough information to enable the Commission to perform an adequate evaluation of its proposal. UCA specifically asserts Public Service has not provided the additional capacity that could be expected nor provided the additional cost of increasing program incentives.²¹⁴

175. Staff likewise recommends rejecting Public Service's ISOC proposal. Staff argues the ISOC proposal does not belong in this Proceeding. Staff further asserts that since modifying the ISOC program requires changing the Company's interruptible service tariff, an advice letter filing is the proper vehicle for Public Service to seek approval of its ISOC proposal.²¹⁵

²¹² Hr. Ex. 166 (Ihle), pp. 118-19.

²¹³ Hr. Ex. 1204 (CEO Response Testimony), p. 30.

²¹⁴ Hr. Ex. 509 (UCA Testimony), p. 24.

²¹⁵ Staff's SOP, p. 14 (citing Hr. Tr. November 7, 2024, p. 261).

176. Public Service continues to advocate for its ISOC proposal in its SOP, reiterating that the ISOC proposal would increase incentives for “new” load from participants to match the “legacy” incentive rate of \$15.97/kW-mo through 2028. Public Service anticipates that approximately 10 additional MW of ISOC capacity could become available if the legacy pricing is expanded.²¹⁶

177. The Company argues that Staff’s suggestion to evaluate the ISOC proposal through a separate advice letter filing could take an additional eight months and would not be an efficient use of the Commission’s, the Company’s, or intervenors’ resources. Public Service argues the proposed change is incremental, the legacy pricing rate has already been vetted and approved, and the change would only be in effect through 2028 when all ISOC pricing can be reevaluated. Public Service also notes it has committed to reporting on the results of its proposal in the ISOC annual reports. Instead of a new advice letter proceeding, Public Service argues the Commission should approve the proposal here and implement it through a compliance advice letter filing.²¹⁷

2. Findings and Conclusions

178. Although the potential for additional DR capacity is attractive and aligned with the Commission’s broader intent, we ultimately deny Public Service’s ISOC proposal. In this relatively abbreviated process associated with the CEP Delivery Motion, Public Service has not adequately supported its proposal. For instance, there has been insufficient evidence regarding the projected costs and benefits of the Company’s proposed modifications to the ISOC program. For these reasons, Public Service will need to present a more fleshed out version of its proposal in a standalone advice letter proceeding.

²¹⁶ Public Service’s SOP, pp. 15-16.

²¹⁷ Public Service’s SOP, p. 16.

179. Public Service complains that requiring a separate advice letter proceeding could take an additional eight months. Based on the record in this Proceeding, however, the Company has not established that an eight-month delay in acquiring perhaps an additional 10 MW of capacity warrants deviating from the Commission's standard regulatory process. We direct Public Service to file its ISOC proposal as a separate advice letter as soon as reasonably practicable.

II. ORDER

A. The Commission Orders That:

1. The Motion to Approve Clean Energy Plan ("CEP") Delivery Plan and for Variances from Certain Commission Rules and Decisions filed by Public Service Company of Colorado ("Public Service") on September 6, 2024, is granted, in part, and denied, in part, consistent with the discussion above.

2. The 20-day period provided for in § 40-6-114, C.R.S., within which to file an Application for Rehearing, Reargument, or Reconsideration, begins on the first day following the effective date of this Decision.

3. This Decision is effective immediately upon its Issued Date.

**B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING
December 16, 2024, and December 20, 2024.**

(S E A L)



ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners