



STEP 1: COMANCHE REPORT

Proceeding No. 25V-0480E

March 2, 2026

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1. Introduction

On November 10, 2025, Joint Petitioners¹ filed a Petition seeking a variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761 to modify the planned retirement date of Comanche Unit 2 from December 31, 2025, to December 31, 2026. As discussed in the Petition, a confluence of events including increasing peak demand growth on the Company's electric system; supply chain and geopolitical issues which have delayed the commercial operation of new generation resources; modifications to resource accreditation assumptions; and the outage of existing generation units informs the need for the extension of Comanche Unit 2. By Decision Nos. C25-0892 and C26-0067 (collectively, the "Decision"), the Commission granted the requested variance and approved, with modifications, a two-step process for further reporting and evaluation of near-term, mid-term, and more permanent resource adequacy solutions considering the extended operation of Comanche Unit 2 through 2026 and the outage of Comanche Unit 3 through at least June 2026. The approved process includes this "Step 1 Report" required to be filed by March 1, 2026 followed by a "Step 2 Application" to be filed by June 1, 2026.

Public Service files this Step 1 Report to provide certain information pursuant to the Decision as the first part of the two-step process, including:

- An update on the repair and return to service status of Comanche Unit 3, including forecasted cost of repairs;
- An initial plan to address ongoing resource needs considering all available options, including those identified in collaboration with the Joint Petitioners for potential near-term resource adequacy benefits; and
- A discussion of whether the outage at Unit 3 and the continued operation of Unit 2 impairs the ability of the Arroyo 2 solar facility—or any other resource—from delivering energy as planned.

For Step 2, the Company will submit an application on or before June 1, 2026, for any additional variances and/or resource approvals, building on this Step 1 report and depending on options identified through the collaborative work with the Joint Petitioners. As part of the Step 2 application filing, the Company will include updated loads and resources tables ("L&R") and loss of load calculations that include analysis of new resources projected to come on-line from the Near-Term Procurement ("NTP"), Just Transition Solicitation ("JTS") Phase II resource solicitation (in Proceeding No. 24A-0442E and to the extent known), or other relevant proceedings. Options proposed for approval will focus on options that can benefit the Company's near- or mid-term resource adequacy position on either a temporary (e.g., a few years) or a more permanent basis.

As this report shows, the repair and return to service of the Comanche 3 Unit underway is the prudent and necessary course. A viable alternative to running Comanche 3 through 2030 has not been and is unlikely to be identified. In addition to its operation, the Company's near-term (i.e., 2026 and 2027) resource adequacy position is negative, 2028 is challenged, and these years present significant operational challenges even with Comanche 2 extended through the end of 2026. This report will discuss the limited incremental options for adding capacity resources that are needed. When the June Application is filed, swift action will be needed to shore up power needs for our customers in the near and intermediate terms. Difficult decisions about extending baseload units may be needed and additive transmission needs are likely part of solutioning these issues, as reliability of the system—in

¹ The Joint Petitioners in this proceeding are Staff of the Public Utilities Commission ("Staff"), the Colorado Energy Office ("CEO"), the Office of the Utility Consumer Advocate ("UCA"), and Public Service.

addition to the safety and affordability of such—remain the paramount goals of the Company and should be for Colorado as well.

2. Update on the Repair & Return to Service Status of Comanche Unit 3

In this section, the Company provides an update on the repair and return to service status of Comanche Unit 3, including forecasted cost of repairs based on the current return to service schedule. This information is also provided in the Company’s monthly reports filed pursuant to the reporting requirements set forth in Decision No. C25-0892 in addition to a summary of actual costs incurred for Unit 3 return to service.²

As shown in Table 1 below, the Company anticipates Comanche Unit 3 return to service around August 2026. The Company has contracted with Mitsubishi to perform off-site repairs to the [REDACTED] to replace and repair the failed equipment. Due to supply chain delays with Mitsubishi’s work, return to service has been delayed, relative to prior reporting. The Company is working with Mitsubishi to recover the return to service schedule.³ General Electric has been contracted to perform the onsite repairs and restoration to service once [REDACTED] has been shipped back to site after the repairs have been made. At the time of this report, this work is still underway.

Table 1: Current Return to Service Schedule for Unit 3

Order of Major Equipment			Mobilization	Begin Re-Assembly	Commissioning & Testing	Return to Service
September 2025	Late May 2026	Mid-July 2026	April 2026	April 2026	July/August 2026	August 2026

The Company currently expects the total cost to repair Unit 3 to fall in the range of [REDACTED] with the Company’s share of ownership equivalent to 66.6% of the final total based upon the ownership agreement. This estimate includes the cost of disassembly, reassembly, and parts; however, as discussed in the Company’s monthly report filed in January 2026,⁴ this estimate does not include any proceeds from insurance which are expected to reduce net costs associated with the repair of the unit to approximately [REDACTED], which includes approximately [REDACTED] allocated to Public Service’s ownership share of the unit. It also does not include [REDACTED] of additional operations and maintenance (“O&M”) to cover the estimated cost to repair the boiler, which must also be completed before the Unit can return to service. In sum, therefore, the Company’s total estimated costs to return the unit to service are approximately [REDACTED].

² Decision No. C25-0892, at ¶ 74.

³ The Loads & Resources tables and RECAP analysis provided elsewhere in this report assume a June return-to-service for Comanche Unit 3 as was expected at the time of those analyses.

⁴ See Monthly Comanche Report filed in Proceeding No. 25V-0480E on January 15, 2026.

Table 2 below provides a summary of forecasted O&M and capital expenditures associated with return to service repairs. A detailed breakdown of the actual and forecasted costs with explanations for the costs is provided in Confidential Appendix A.

Table 2: Summary of Forecasted Costs for Unit 3 Return to Service⁵

	Forecasted O&M Costs – Non-Fuel (\$M)	Forecasted Capital Expenditures – Return to Service (\$M)
Comanche 3		

Additionally, the Company continues to work with third-party consultants on the Root Cause Analysis, which is expected in mid-to-late March. Preliminary results of the analysis largely attribute the issue to the fabrication and design (by third parties) of the failed equipment, concluding that Public Service’s operation of the unit was within the relevant thermal parameters. Additional analysis of the [REDACTED] is needed to understand the full causal analysis. Once this analysis is complete, the Company intends to discuss with Joint Petitioners the implications for the operations of Comanche Unit 2 to determine appropriate operational parameters or approaches that may work for the unit while it operates in 2026, with a specific focus on operations after Comanche Unit 3 returns to service as proposed in the Joint Petition.⁶

In summary, the Company has moved forward with the repair and return to service of Unit 3. As detailed in the Company’s January monthly report, a preliminary analysis found that the incremental cost to replacing Comanche Unit 3 would be magnitudes more expensive for customers than the “business as usual” pathway of repairing the unit and returning it to service this summer. Furthermore, as illustrated in the Company’s analysis below, there are no reasonable alternatives to returning Comanche Unit 3 to service. The timelines to develop and in-service new fixed generation are, at best, in 2029 and will cost billions of dollars to address the 415 MW accredited capacity of Comanche Unit 3.

⁵ Forecasted costs reflect Public Service’s share of costs.

⁶ Due to the timing of the root cause analysis results expected in mid-to late March, the outcome of these operations-focused discussions among Joint Petitioners is not available to include in this March 2, 2026 Step 1 Report as originally contemplated in the Joint Petition filed in November 2025.

3. Options for Ongoing Resource Adequacy Needs

In this section, the Company discusses its initial plan to address ongoing resource needs considering available resource options as identified in collaboration with the Joint Petitioners for potential near-term resource adequacy benefits.

A. OVERVIEW

At the time the Joint Petition was filed on November 10, 2025, the Company explained that due to several factors, an extension of Comanche Unit 3 would be required. Those factors included:

- an unplanned outage, Comanche Unit 3, which provides Public Service’s system with 415 MW of accredited capacity;
- increasing demand growth of over 200 MW in the last five years;
- supply chain and geopolitical issues, including inflationary pressures, tariffs, and market demand which have constrained the ability of new generation resources to come online as expected;
- updates to the assumptions used in generation resource planning to more accurately reflect the peak accreditation of new and existing resources to system needs; and
- the denial of the requested third combustion turbine (“CT”) put forth in the Clean Energy Plan Delivery plan filed in Proceeding No. 21A-0141E.

None of these individual events is singularly or primarily responsible for the need to extend Comanche Unit 2; it is the combination of them that has resulted in the need. As shown below, when including the accredited capacity of Comanche Unit 3, the Company still presents significant capacity shortfalls in 2026 and 2027, as well as the winter of 2028, that will need to be solutioned. As the Company has repeatedly stated, the persistent nature of the near-term capacity deficit in 2026 and 2027 reinforces that resource adequacy is a clear and present concern to the safe and reliable operations of the electric grid.⁷ Furthermore, this deficit persists into 2028, after which the Company’s capacity position begins to improve. But that position is highly contingent upon all things occurring in line with the current forecast. Should any factor—load growth, commercial operation, deliverability, or operational reliability—deviate from the assumptions, the Company’s position may quickly shift to a deficit.

Near-term, the most likely capacity solutions are continued extensions of existing units—namely, Comanche Unit 2 and, to a lesser extent, the Hayden units. Other thermal resources offer other limited capacity opportunities. The Company continues to explore these options as short-term solutions and longer-term contingency plans in addition to the potential to activate or other retain clean energy resources identified through the NTP solicitation or to develop independently of that process. Swift action will be needed as part of the forthcoming Step 2 filing on June 1 to enact a contingency plan to ensure the Company’s reliability position remains positive and it can deliver upon the safe, reliable, and affordable service customers expect.

⁷ For example, the Company requested approval of two purchased power project expansions in Proceeding No. 22V-0388E, the extension of purchased power capacity resource extensions in Proceeding No. 23A-0046E, and additional generation capacity in the CEPD.

B. ASSESSMENT OF LOADS & RESOURCES

In this section, the Company provides an updated Loads and Resources (“L&R”) balance that incorporates the Commission’s JTS Phase I load forecasts and approved NTP resources.⁸ The section then discusses how various coal retirement alternatives could support near- and mid-term resource adequacy needs. All tables and figures in this section use as the load forecast assumption the Low Load forecast as orally approved by the Commission’s deliberations on ARRR.⁹

Before presenting the latest L&R tables, the Company notes two critical considerations. First is that the L&R tables are not the only tool it uses in planning its system. The L&R tables provide a snapshot look at the balance of capacity resources relative to forecasted peak load. It does not give an adequate look at other relevant factors such as the emissions forecasts and loss of load probability. These analytical lenses are appropriately evaluated through other tools. To do so, the Company looks to reliability metrics such as the loss-of-load expectation, operational considerations informed by its commercial operations team, and computer-based modeling. Looking to the L&R tables in this report provides a reasonable first approximation of the viability of the overall capacity position under different scenarios and is useful (but imperfect).

Figure 1 below provides an evaluation for 2026 and 2027 of the potential loss of load probability¹⁰ under several scenarios, which include:

- **Scenario (A)** – Tests impact of a 2-month COD delay for (4) 2021 ERP/CEP Resources (1 Wind, 3 BESS)
- **Scenario (B)** – Applies updated Forced Outage Rates (FOR) of thermal units with more recent GADS data (post 2024 RA Study) to Scenario (A) and extends Comanche 2 through 2027
- **Scenario (C)** – Same as (B) but adds 100 MW purchased capacity
- **Scenario (D)** – Applies updated FOR to Scenario C from previous slide

Looking closely at the Company’s loss of load probability analyses, the various sensitivities indicate substantial risk in the next two years. Under all analyzed scenarios, the Company’s loss of load probability exceeds the planning standard of less than 0.1. In some cases, the loss of load probability is over 10 times greater than planning best practices.

⁸ Included in this analysis are Bids 113, 053, 054, 034, 135, 046, 055, 089, 118, and 099 which reflects the Commission’s February 18, 2026 deliberations.

⁹ The Company developed the JTS ARRR Low Load forecast based on the Company’s understanding of the Commission’s January 14, 2026 JTS ARRR oral deliberations (i.e., regarding modifications to managed charging participation, beneficial electrification, and electric vehicle forecast assumptions). The Company also notes this forecast excludes any incremental growth associated with large customer loads. We continue to disagree with this assumption. The Commission issued its JTS ARRR decision (Decision No. C26-0121) on February 4, 2026 after the forecast was developed.

¹⁰ This analysis was completed prior to updated return to service dates for Comanche 3 and assumes a 6/1/2026 date. The Company is studying the impact of the revised dates and will update in future reporting.

Figure 1: Loss of Load Probability Sensitivities

Metric	No Com 2 No Com 3		Com 2 Ext Through (12/31/26) Com 3 Rep (6/1/26) (Baseline)		Com 2 Ext (12/31/26) Com 3 Rep (6/1/26) 2 mo 2027 CODs Delay (A)		Com 2 Ext (12/31/27) Com 3 Rep (6/1/26) 2 mo 2027 CODs Delay Updated FOR (B)		Com 2 Ext (12/31/27) Com 3 Rep (6/1/26) + 100 MW PCAP 2 mo 2027 CODs Delay Updated FOR (C)		Com 2 Ext (12/31/27) Com 3 Rep (6/1/26) + 100 MW PCAP Updated FOR (D)	
	2026	2027	2026	2027	2026	2027	2026	2027	2026	2027	2026	2027
LOLE	3.368	2.091	0.255	0.432	0.255	1.277	0.964	1.432	0.705	1.109	0.705	0.377
EUE (MWh)	3769	3480	212	560	212	1330	916	1828	640	1334	640	510
LOLH	11.1	7.0	0.7	1.3	0.7	5.5	2.9	4.4	2.1	3.3	2.1	1.1

Second, because the L&R is a snapshot in-time and not a dynamic model, results are inherently dependent upon the certainty that the embedded assumptions come to fruition as expected. Assumptions for which the Company remains concerned include the use of the adjusted Low Forecast, which the Company believes understates the potential load growth underway in Colorado from customers with a reasonable expectation for electric service. In addition, the L&R in and of itself assumes all Clean Energy Plan (“CEP”) and NTP projects will execute as approved;¹¹ and that there are not future generation failures¹² which will stress the Company’s operations. In all, the Company remains concerned that while the L&R tables may show a positive position in the years after 2028, the margin for success is razor thin. All things will need to go to plan or the Company will likely tip back into a resource adequacy deficit. This risk drives the Company’s discussion in Section C below to continue evaluating “contingency planning” to mitigate against these risks in the coming years.

The Company shows updated summer and winter L&R tables in Tables 3 and 4 below, each of which shows the capacity contributions of the Commission’s orally approved NTP resources. Additionally, these forecasts assume Comanche Unit 3 returns to service in June 2026 and remains in service through its expected retirement date, that the Company will procure █████ MW of market resources in 2026, and that Unit 2 retires at the end of 2026. Even with these assumptions and updates, the Company still faces generation capacity deficits of nearly 500 MW in the summer of 2027 and in the winter of 2028.

¹¹ For example, the Company has identified significant concerns with the feasibility of Bid 118 approved in the NTP. This project, included in the L&R tables in years 2029 and 2030, accounts for 197 MW of accredited capacity which is unlikely to come online as expected. The Company discusses the risks with Bid 118 further in its March 2, 2026 NTP Report filing in Proceeding No. 21A-0141E.

¹² For example, 9 out of 21 bids in the original portfolio of resources selected by the Commission in the 2021 ERP/CEP failed and needed to be replaced by alternative options.

Table 3: PSCo L&R Table for Summer Peak (MW)

Business as Usual (Existing Resources as of 2/2026 + NTP)	2026	2027	2028	2029	2030
TOTAL ACCREDITED CAPACITY (Existing, Planned Resources)	7,457	7,243	7,926	7,663	7,656
<i>NTP Resources</i>	-	3	94	1,062	1,062
CAPACITY NEED	(7,534)	(7,692)	(7,755)	(7,948)	(8,093)
CAPACITY POSITION: LONG/(SHORT)	(77)	(445)	265	778	626

Table 4: PSCo L&R Table for Winter Peak (MW)

Business as Usual (Existing Resources as of 2/2026 + NTP)	2027	2028	2029	2030
TOTAL ACCREDITED CAPACITY (Existing, Planned Resources)	5,750	5,807	6,260	6,559
<i>NTP Resources</i>	-	49	478	710
CAPACITY NEED	(5,846)	(6,280)	(6,612)	(7,100)
CAPACITY POSITION: LONG/(SHORT)	(96)	(424)	126	170

The repair, return to operation and running of Comanche 3 through 2030 have recently been questioned. Given these significant 2027 and 2028 resource adequacy needs, the continued operation of this unit is necessary and no viable alternatives to such have been identified by the Company as this time. As discussed more in the next Section below, while the Company is evaluating several incremental capacity resource additions, unit extensions are likely to be options that are brought forward in the Step 2 June Application. The Company first considered expanding the scope of NTP or other capacity resources to supplement the “business as usual” approach; however, there are no additional NTP bids with summer 2027 commercial operation dates. The Company has also explored demand response and other resource procurements to supplement this near-term need, however such options present limited opportunities.

C. INCREMENTAL CAPACITY RESOURCE OPTIONS IDENTIFIED FOR FURTHER EVALUATION

Overview

In this section, the Company presents the categories of potential capacity resources for continued evaluation in advance of the June 1, 2026, application. Categories of resources identified include market purchases and transmission reservations, extensions of Company-owned resources, Purchase Power Agreement (“PPA”) extensions, NTP PPAs, and new utility-owned projects. The Company will continue evaluating these options over the coming months and may bring recommendations for Commission approval forward in future filings.

1. Market Purchases & Transmission Reservations

Market purchases remain a tool for the Company to manage near-term operational needs. As a near-term tool, the Company has contracted approximately █ MW of market purchases to help improve the Company’s 2026 capacity position. Market purchases for 2027 and beyond are under review as the Company identifies and contracts for needed capacity resources. However, due to high demand across the west, limited transmission availability, and the impending implementation of SPP’s Western expansion, the availability of forward short-term market purchases is increasingly constrained. While prior market conditions have made it possible for the Company to procure short-term purchases, there have been significant curtailments to these purchases at times which highlight the concern around transmission and certainty of physical delivery sinking to the Public Service system. The Company’s ability to continue procuring significant market capacity resources is unlikely. This

perspective is reinforced by recent capacity Requests for Information conducted by the Company's Commercial Operations teams which provided limited response. For those purchases that are available to the Company, such options are coming at a higher cost, with less operational flexibility, and higher emissions profiles.

In the Company's Second Supplemental Rule 3205 Report¹³, discussed further below, the Company conducted a forward-looking analysis to estimate pricing for market capacity and energy purchases as an alternative to existing unit extensions. That analysis found that to replace up to 172 MW of capacity through 2028, the Company would incur total costs of approximately [REDACTED]. These market purchases would also come in the form of "block purchases" which require the Company to acquire capacity and energy over a set period of time. That structure reduces the flexibility for this capacity and energy purchase to meet the dynamic system conditions inherent on an increasingly renewable-based generation system.

Where market purchases may be available, additional challenges exist including the availability of transmission to facilitate the delivery of purchases. Lack of interregional transmission and regional system congestion are the primary barriers to delivery. Because of the topology of the western United States, existing transmission corridors are limited and increasingly found within wildfire risk areas. This is resulting in increased risk to transmission line derates or disconnections as was exemplified during the summer of 2025 when wildfires in western Colorado put the availability of interregional transmission lines at risk. The latter, transmission congestion, is a well-known issue not only in Colorado or the West, but across the nation. Transmission expansion has not kept pace with demand as generation resources have evolved. This has resulted in system congestion which creates higher costs or limits delivery to load centers where the energy is needed.

This background is meant to highlight the increasing risks of overreliance upon market purchases as a solution to the Company's resource adequacy needs. Solutions to these challenges – wildfire risk, transmission expansion, and generation supply expansion are long-term issues that will take years, if not decades, to fully address.

2. Unit Extensions & Uprates

As part of its ongoing efforts to meet resource adequacy needs, the Company has recently effectuated the extension of several existing gas units. First, the Company received approval in the Just Transition Solicitation to extend the voluntary retirement of Cherokee unit 4 from 2027 to 2028. The Company also received approval to extend several existing natural gas units through the Rule 3205 process. These extensions include Alamosa Units 1 and 2 through 2030 following the withdrawal of a bid (and withdrawal of backup bids) from the approved 2021 ERP & CEP portfolio intended to replace these units.¹⁴ These two CTs, which had been voluntarily scheduled to retire in 2026, serve a critical reliability need, and their extended operation through 2030 provides 27 MW of firm, dispatchable capacity to support local and regional reliability needs on a unique highly constrained part of the system. A second Rule 3205 request also resulted in the approval to extend the existing Fruita, Fort Lupton 1 and 2, and Valmont 6 units from 2026 until 2028.¹⁵ These units were extended to meet near capacity needs in order to maintain reliability. These extensions are included in the L&R tables used in this report. These units provide valuable opportunity to improve the Company's near-term reliability position; however, these are not – in their

¹³ This was originally filed in Proceeding No. 25M-0012E on December 16, 2025, refiled Confidentiality on January 16, 2026, and the relief approved by Commission Decision No. C26-0077 on February 4, 2026.

¹⁴ Decision No. C25-0826 in Proceeding No. 25M-0012E (issued November 19, 2025).

¹⁵ Decision No. C25-0077 in Proceeding No. 25M-0012E (issued February 4, 2026).

current states – long-term, reliable capacity solutions when looking to the later years of the L&R tables presented above.¹⁶

The Company's other, remaining opportunities for existing units are coal assets – extensions of Comanche Unit 2 and Hayden Units 1 & 2 or the purchase of capacity from the joint owners of these facilities or owners of the remaining Craig units. Like the extensions discussed above, potential extensions provide valuable generation capacity that has historically operated safely and reliably. However, there remain challenges with continued extensions of these units. Most notably, continued coal extensions may create challenges with continuing the pace of the Company's clean energy transition. These units are also likely to require additional investment to continue operations beyond the current retirement dates. Extension of Comanche 2 past 2026 and extension of the Hayden Units 1 and 2 retirement dates past 2028 and 2027 respectively also require modifications to the State Implementation Plan for Regional Haze and the supporting state regulation (i.e. Regulation 23). Such a regulatory change would require significant stakeholder engagement and a new rulemaking at the Air Quality Control Commission to allow for a change to the retirement dates. Any reliance on the Craig units, in addition to the above stated complications, would likely require reliance on multiple additive mandates from the federal government to run the unit. Nonetheless, the Company is evaluating the costs and benefits of possible extensions in order to "leave no stone unturned" as it evaluates how to manage reliability in the near-term. Finally, acquiring the capacity share of other unit joint owners is uncertain at this time. It is unclear if other joint owners would agree to continue operating plants which are slated for retirement or will need the capacity for their own resource adequacy needs.

Finally, the Company has explored the opportunity to uprate certain units to provide additional incremental capacity. Two projects were identified – an uprate to Ft. St. Vrain Unit 1 and at Cherokee Units 5 and 6. The uprate at Ft. St. Vrain Unit 1 is expected to add approximately 26 MW of accredited capacity; however, the uprate to Cherokee units was deemed infeasible due to emissions permit limitations.

3. **PPA Extensions**

The Company continuously looks at opportunities to extend PPAs approaching expiration where possible. The Company is in the process of negotiating with NTP RFP approved projects. In addition, the Company has been in active discussions with various other projects where the Company's offtake is scheduled to expire in the next few years. For example, Public Service has been working on extensions of existing hydro PPAs that expire in 2026 and 2027. The total accredited capacity of these PPAs, however, is less than 10 MW. Although these projects are smaller in size, they are examples of existing clean energy resources that can provide benefits to Public Service and its customers.

Public Service has also been in discussions to potentially extend a wind PPA set to expire Summer 2027. This project has the potential to add approximately 16 MW of accredited capacity to the 2028 – 2030 capacity position.

¹⁶ Generally, these units are at end-of-life which results in degraded operations and increasing risk to operational reliability. To improve operational reliability to the levels needed to support long-term system operations, it will require significant investment including potential repowering and/or reconstruction of these units. Additionally, both the Ft. Lupton units and the Cherokee 4 unit have high barriers to continued extension. The Ft. Lupton units must be retired to make room for new generation (i.e. Bid 099 as approved in Decision No. C26-0081). A further extension of Cherokee Unit 4 is challenged by state environmental policy. Moreover, the Company does not believe that extension beyond 2028 is a feasible option due to restrictions and limitations associated with state ozone regulations and operational limitations of the unit's water treatment system. The Company does not anticipate pursuing further extension of Cherokee 4 at this time.

These discussions are early as the owner is considering several options after the contract expires, but Public Service is committed to exploring all available paths.

4. **NTP Resource Activations - PPAs**

The Company has evaluated potential additional PPA acquisitions from the NTP that with CODs of 2029 or earlier. These options present potential strategic locational benefits and/or system operational flexibility. The Company will continue to evaluate these bids and, if appropriate, engage with the developers to better understand the ability to maintain as-bid price and COD.¹⁷

- Bid 131 – is a 400/400 MW solar and storage project identified in the Tier 2 portfolio of backup projects.
- Bid 022 – is a 400 MW BESS project. Because of its strategic location at the point of interconnection with a CEP approved solar project, it potentially offers system operational benefits by allowing for the storage of otherwise curtailed solar generation or the dispatch of generation during twilight and overnight hours.
- Bid 009 – this is a 250 MW BESS project located in the Just Transition community of Morgan County.
- Bid 003s and 047 – a 500 MW solar and 250/250 MW solar + storage project, these two projects are being evaluated due their geographic diversity relative to the general concentration of solar projects in the Pueblo area.
- Bid 134 – the Company is engaging with the developer, consistent with Decision No. C26-0081 to determine if a contractual agreement can be reached on the project to facilitate a “pre-construction development asset” approach. If feasible, this arrangement may provide incremental thermal capacity with a 2029 COD.

5. **Company-owned Resources**

There are several options for the development or acceleration of Company-owned projects that generally fall into two categories, including NTP projects not selected as part of the Commission-approved portfolio, and projects identified by the Company outside of the NTP.¹⁸

a. NTP Projects

- Bid 094 – is a 450 MW solar with 450 MW storage project with an anticipated COD of Q4 2029. The Commission and NTP parties have expressed interest in this project and it will be a subject of the Company’s March 2 NTP report. With its COD of Q4 2029, it provides valuable capacity within the Denver Metro region in advance of the currently planned retirement of Comanche 3. At this time, the Company is evaluating the opportunity to reduce the project cost estimate, relative to the bid. At the time of bidding, there were significant risks that have since been clarified potentially reducing costs associated with the operation and construction of the project.
- Bid 093 – is a 300 MW storage project bid into the NTP with a Q4 2029 COD. The Company is also evaluating options to modify the project to accelerate the COD; though that may require trade-offs in pricing and capacity.
- Bid 095 – is a 300 MW solar with 300 MW storage project with an anticipated COD of Q4 2029. This bid was reviewed as part of the NTP but not selected in the various portfolios presented. However, the

¹⁷ All capacity is provided at nameplate levels.

¹⁸ All capacity is provided at nameplate levels.

Company continues to evaluate the project because of its strategic location within the Denver Metro region and because there may be potential cost savings identified since bid submission.

b. Non-NTP Projects

- Arroyo 2 BESS – is an approximately 160-170 MW storage project identified by the Company outside of the NTP with a potential anticipated COD of Q4 2029. While conceptually attractive, there are two challenges with this project. First, the existing PLGIA process to secure interconnection rights for the Arroyo 2 project is underway. Second, the project would be limited to surplus interconnection capacity only thereby limiting the Company’s ability to charge/discharge the BESS based upon system needs.
- Thermal Generation – the Company is evaluating several options ranging from smaller or mobile generators less than 50 MW to full-sized, 200+ MW units. The benefit of smaller, possibly mobile, units is they may offer quicker procurement, interconnection, permitting, and construction timelines relative to traditional thermal generators. However, there are trade-offs with these accelerated pathways, generally related to air permits: permitting approval timelines can be lengthy (up to 18 months), capacity factors may be severely constrained by permit limits, and installations may be limited to no more than 12 months. Certain locations may encounter local community opposition or may be disallowed for air permit compliance. Further, broad demand for smaller generators by utilities and large load users is causing supply constraints and long lead times from the factories, which can exceed 12 months. For large units, while valuable from an operational perspective, these units have significantly longer lead times – likely 36 months or more which challenges their ability to meet near-term and even long-term capacity needs.
- Singing Grass Wind – is an approximately 600 MW wind project approved as part of the CEP portfolio and granted a CPCN in September 2025. The Company is evaluating opportunities to accelerate the COD from August 2026 to June 2026 to help meet summer resource adequacy needs and provide incremental generation in early summer before Comanche 3 is expected to come back online. However, this option is challenged by delayed permitting approvals, contentious land rights acquisitions for the gen-tie line, feasibility of accelerated commissioning, and other non-state regulatory compliance matters that would need to be resolved. The Company continues to pursue this option as it potentially provides 2026 resource adequacy and cost-savings benefits to customers and will update stakeholders further in the Company’s quarterly construction reporting.

6. Pre-Construction Development Assets (“PCDA”)

Consistent with the Commission’s direction in Decision Nos. C22-0459 and C26-0121, the Company is exploring the potential to employ a PCDA approach to the NTP for resources discussed above. While this tool is generally considered an option for the development of natural gas CTs, it nonetheless can be used for other types of generation as envisioned in the Commission-approved Incremental Need Pool concept. The Company will continue to evaluate structures which may allow for the continued development of valuable resources in the near-term. If a viable pathway is identified and there are interested counterparties, the Company may present those options in its June 1, 2026 application for Commission consideration and approval.

7. Demand Response

The Company’s evaluation identifies limited opportunity to close the near-term (i.e. 2026 and 2027) resource adequacy gaps with its demand response programs (e.g. Interruptible Service Option Credit (“ISOC”), Peak Partner Rewards, Peak Day Partners, Critical Peak Pricing, and Residential Demand Response (i.e. Saver’s Switch and AC rewards)). Near-term avenues to grow program participation in these programs is likely through increased marketing and customer engagement which the Company is undertaking now. Estimations are that such efforts may lead to capacity increases of 5-20 MW by summer 2027. Other opportunities, such as the adjustment of program incentives and/or bill credits will require additional regulatory process and while potentially an option that could be proposed in the June 1 Application the Company believes the Commission has expressed a desire to evaluate through the forthcoming Integrated Customer Program filing to be filed in July 2026. This filing will include a comprehensive evaluation of existing and new programs to meet longer term demand response goals and support resource adequacy and system operations.

Other program opportunities include the Aggregated Virtual Power Plant (“AVPP”) program, Renewable Battery Connect, Dispatchable Distributed Generation (“DDG”), and Integrated Volt Var Optimization (“IVVO”). Of these, IVVO offers the clearest pathway to incremental demand savings and has limited impact on existing customers. The Company anticipates this tool may provide approximately 20 MW of incremental capacity in 2026 with potential to increase to 50 MW in 2027. However, the other identified programs are still nascent in the market and the potential growth opportunities remain unclear. First, the Company’s L&R tables already incorporate the previously approved capacity forecasts limiting the total amount of incremental growth opportunity. Second, there is the possibility that growth in these programs could reduce or cannibalize existing DR portfolio participation, resulting in little to no net gains. Third, capacity volume is contingent on market response and customer enrollment which is currently untested for the AVPP and DDG programs, while the RBC program has limited experience in the market.

D. COAL PLANT RETIREMENT ALTERNATIVES

The Company presents an evaluation of a variety of coal retirement alternatives below.

1. *Alternative 1* assumes Comanche 2, Hayden 1, and Hayden 2 all operate through the end of 2030;
2. *Alternative 2* extends Comanche 2, Hayden 1, and Hayden 2 operations by one year each; and
3. *Alternative 3* assumes Comanche 3 stays offline through 2030 and extends Comanche 2, Hayden 1, and Hayden 2 through the end of 2030.

Table 5 below shows a matrix of assumptions across the scenarios.

Table 5: Coal Retirement Assumptions across Alternatives 1, 2, and 3

Assumptions	Business as Usual	Alternative 1	Alternative 2	Alternative 3
Load Forecast	JTS ARRR Low Load Forecast			
NTP Resources	Commission's orally approved portfolio as of Feb. 18, 2026			
Comanche 2 Retire	12/31/2026	12/31/2030	12/31/2027	12/31/2030
Comanche 3 Retire	12/31/2030	12/31/2030	12/31/2030	12/31/2025
Hayden 1 Retire	12/31/2028	12/31/2030	12/31/2029	12/31/2030
Hayden 2 Retire	12/31/2027	12/31/2030	12/31/2028	12/31/2030
Craig 1 Retire¹⁹	12/31/2025			
Craig 2 Retire	9/30/2028			

Alternative 1 - Comanche 2, Hayden 1, and Hayden 2 operate through 2030

Alternative 1, which assumes Comanche 3 returns to service for summer in 2026 while extending other coal facilities through 2030, improves the Company's 2027-2030 summer and winter capacity position to a level where we anticipate the remaining short positions could be solved through advanced market purchases. Tables 6 and 7 below review L&R impacts of Alternative 1.

Table 6: Alternative 1 L&R Impact, Summer Peak (MW)

Alternative 1: Com 2, Com 3, Hay 1, Hay 2 Through 2030	2026	2027	2028	2029	2030
TOTAL ACCREDITED CAPACITY (Existing Resources + NTP)	7,457	7,247	8,021	8,726	8,719
<i>Comanche 2 extend 12/31/2030</i>		296	296	296	296
<i>Hayden 1 extend 12/31/2030</i>				120	120
<i>Hayden 2 extend 12/31/2030</i>			90	90	90
CAPACITY NEED	(7,534)	(7,692)	(7,755)	(7,948)	(8,093)
CAPACITY POSITION: LONG/(SHORT)	(77)	(150)	652	1,284	1,132

¹⁹ Craig 1 had been scheduled to retire 12/31/2025. It is currently under a 202(c) order that has it only running during a WECC emergency. Due to this nuance, we have not included Craig 1's capacity contribution in any of these L&R scenarios.

Table 7: Alternative 1 L&R Impact, Winter Peak (MW)

Alternative 1: Com 2, Com 3, Hay 1, Hay 2 Through 2030	2027	2028	2029	2030
TOTAL ACCREDITED CAPACITY (Existing Resources + NTP)	5,750	5,856	6,738	7,269
<i>Comanche 2 extend 12/31/2030</i>	287	287	287	287
<i>Hayden 1 extend 12/31/2030</i>			117	117
<i>Hayden 2 extend 12/31/2030</i>		88	88	88
CAPACITY NEED	(5,846)	(6,280)	(6,612)	(7,100)
CAPACITY POSITION: LONG/(SHORT)	191	(49)	618	662

Alternative 2 – One-Year Extensions of Comanche 2 (2027), Hayden 1 (2029), and Hayden 2 (2028)

This scenario assumes Comanche 3 returns to service for summer in 2026, as currently forecasts. Further, it extends Comanche 2, Hayden 1, and Hayden 2 each one year relative to their current planned retirement date, Alternative 2 improves the Company’s summer 2027 capacity position to a level we anticipate could be solved through advanced market purchases. However, Alternative 2 still leaves a sizeable capacity deficit of 336 MW in the winter of 2028. Tables 8 and 9 below review L&R impacts of Alternative 2.

Table 8: Alternative 2 L&R Impact, Summer Peak (MW)

Alternative 2: Extend Com 2, Hay 1&2 Each One Year	2026	2027	2028	2029	2030
TOTAL ACCREDITED CAPACITY (Existing Resources + NTP)	7,457	7,247	8,021	8,726	8,719
<i>Comanche 2 extend 12/31/2027</i>		296			
<i>Hayden 1 extend 12/31/2029</i>				120	
<i>Hayden 2 extend 12/31/2028</i>			90		
CAPACITY NEED	(7,534)	(7,692)	(7,755)	(7,948)	(8,093)
CAPACITY POSITION: LONG/(SHORT)	(77)	(150)	356	897	626

Table 9: Alternative 2 L&R Impact, Winter Peak (MW)

Alternative 2: Extend Com 2, Hay 1&2 Each One Year	2027	2028	2029	2030
TOTAL ACCREDITED CAPACITY (Existing Resources + NTP)	5,750	5,856	6,738	7,269
<i>Comanche 2 extend 12/31/2027</i>	287			
<i>Hayden 1 extend 12/31/2029</i>			117	
<i>Hayden 2 extend 12/31/2028</i>		88		
CAPACITY NEED	(5,846)	(6,280)	(6,612)	(7,100)
CAPACITY POSITION: LONG/(SHORT)	191	(336)	243	170

Alternative 3 – Retire Comanche Unit 3; Extend Comanche 2, Hayden 1, and Hayden 2 to 2030

Alternative 3 is a variation of Alternative 1 that assumes Comanche 3 stays offline and all other coal units are extended through 2030. Tables 10 and 11 below review the L&R impacts of Alternative 3. This alternative is presented as a hypothetical in order to isolate the impact of Comanche 3 not returning to service, given the interest of some stakeholders in that potential future. As discussed above and in the Company’s January monthly report, the Company analyzed the option of retiring Comanche 3 immediately rather than repairing it and found that doing so would not be in the best interests of our customers or the system. Looking at Alternative 3 confirms that view. As the tables below show, even with all other coal units extended, the absence of Comanche Unit 3

creates sizable gap, that the Company is likely unable to solve through market purchases in 2026 and 2027 and creates new resource adequacy gaps in winter 2028, relative to other scenarios that would require additional unit extensions to resolve.

Table 10: Alternative 3 L&R Impact, Summer Peak (MW)

Alternative 3: Retire Com 3, extend Com 2, Hay 1&2 2030	2026	2027	2028	2029	2030
TOTAL ACCREDITED CAPACITY (Existing Resources + NTP)	7,457	7,247	8,021	8,726	8,719
<i>Comanche 3 stays offline</i>	(415)	(414)	(412)	(412)	(412)
<i>Comanche 2 extend 12/31/2030</i>		296	296	296	296
<i>Hayden 1 extend 12/31/2030</i>				120	120
<i>Hayden 2 extend 12/31/2030</i>			90	90	90
CAPACITY NEED	(7,534)	(7,692)	(7,755)	(7,948)	(8,093)
CAPACITY POSITION: LONG/(SHORT)	(493)	(564)	240	872	720

Table 11: Alternative 3 L&R Impact, Winter Peak (MW)

Alternative 3: Retire Com 3, Extend Com 2, Hay 1&2 2030	2027	2028	2029	2030
TOTAL ACCREDITED CAPACITY (Existing Resources + NTP)	5,750	5,856	6,738	7,269
<i>Comanche 3 stays offline</i>	(414)	(413)	(411)	(411)
<i>Comanche 2 extend 12/31/2030</i>	287	287	287	287
<i>Hayden 1 extend 12/31/2030</i>			117	117
<i>Hayden 2 extend 12/31/2030</i>		88	88	88
CAPACITY NEED	(5,846)	(6,280)	(6,612)	(7,100)
CAPACITY POSITION: LONG/(SHORT)	(223)	(461)	208	251

In summary, because of the resource need, timing for return-to-service and relative low cost of returning Comanche Unit 3 to service, the Company does not see keeping Comanche 3 offline as a reasonable alternative. Beyond the clear reliability concerns outlined above, in order to retire the unit, the Company would need to commit, likely now, to extending all other coal-based assets through the end of the decade. This will require unwinding several regulatory decisions, including those made in the 2016 Electric Resource Plan, 2021 ERP & CEP, and the JTS; as well as taking action at the Air Quality Control Commission to address state emissions regulations. Furthermore, accelerated retirement introduces additional just transition costs and workforce transition questions in the Pueblo community and will require currently undefined capital investments into the other coal units to ensure reliable operations through 2030.

4. Impact of Unit 3 Outage & Operation of Unit 2 on Arroyo 2 Solar

In this section, the Company provides a discussion of whether the outage at Unit 3 and the continued operation of Unit 2 impairs the ability of the Arroyo 2 solar facility—or any other resource—from delivering energy as planned.

Arroyo 2 was previously granted a generator replacement interconnection agreement for use of Comanche 2's interconnection service, but the service for Arroyo 2 was contingent upon the retirement of Comanche 2 in December 2025, which did not occur. A new generator replacement interconnection request was submitted to the generator replacement coordinator on December 14, 2025 for Arroyo 2 service to start on the Comanche 2's current approved retirement date of December 2026. When the generator replacement service is updated to December 2026, there will be a 2-month gap for interconnection rights for Arroyo 2 because the intended in-service date for Arroyo 2 is October 2026. This gap is in the process of being mitigated by a provisional interconnect request, which was submitted to the transmission provider on February 3, 2026. Provisional service could bridge the period between October and December 2026. The transmission provider is in the process of reviewing whether interconnection service for Arroyo 2 can be offered provisionally based on existing capacity of the transmission system and existing facilities, until the new generator replacement agreement becomes effective. Public Service Company of Colorado is currently awaiting results of both the new generator replacement and provisional interconnection requests. If the provisional interconnection is not granted, Arroyo 2 will not have interconnection rights until after the planned retirement of Comanche 2 on December 31, 2026.

5. Summary and Conclusion

As shown above, the Company's near-term (i.e., 2026 and 2027) resource adequacy position is negative and presents significant operational challenges even with Comanche 3 online and Comanche 2 extended through the end of 2026. Furthermore, while the capacity position improves beginning in 2028, it still remains at serious risk to backslide into a deficit – and one which is increasingly challenging to solve through market purchases. All must go correctly. First, new generation must come online as expected – further delays in commercial operation will result in downgrades to the Company's position. Second, the Company needs to make investments into its aging generation fleet and receive the appropriate cost recovery to maintain its fleet, otherwise underperformance will continue. Third, either the subdued levels of load growth forecasts approved in the JTS must come to pass despite ample evidence that electric load growth beyond those levels is real, or additional capacity investments will be needed. Finally, swift approval of the supporting transmission infrastructure to facilitate delivery – and the timely in-servicing of that infrastructure – is critical to the efficient operation of the entire electric grid.

As discussed in the Petition, challenges with supply chains and geopolitical issues remain and threaten to continue disrupting the development of approved and new generation resources. Tight market conditions are creating resource scarcity and increasing costs. The Company, the Commission, and stakeholders cannot and should not take for granted the forecast of improving conditions illustrated in the L&R tables above. Action will be needed to secure generation resources in case the reality of the coming years does not reflect the forecasts and underlying inputs and assumptions. Additionally, the Company will need to invest in other facets of its electric system – namely the transmission system – to ensure the reliable deliverability of new generation. The Company has begun analyses of its transmission system to identify the needs driven by new generation and to facilitate long term clean energy generation development. The Company looks forward to collaborating with the Commission and stakeholders in the coming months to ensure that the electric grid remains the safe, reliable system customers have come to expect and which powers the prosperity of Colorado.

