Decision No. R24-0242-I

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 23M-0464EG

IN THE MATTER OF THE COMMISSION'S IMPLEMENTATION OF ASPECTS OF SENATE BILL 23-291 INCLUDING ITS CONSIDERATION OF CUSTOMER CONNECTIONS TO AND DISCONNECTIONS FROM INVESTOR-OWNED ELECTRIC AND GAS UTILITY SYSTEMS AND THE STUDY OF POTENTIAL BARRIERS TO BENEFICIAL ELECTRIFICATION AND DISTRIBUTED ENERGY RESOURCES.

**INTERIM DECISION OF HEARING COMMISSIONER
MEGAN M. GILMAN
ADDRESSING COMMISSION STUDY OF POTENTIAL BARRIERS TO BENEFICIAL ELECTRIFICATION AND THE DEPLOYMENT OF DISTRIBUTED ENERGY RESOURCES AND RESULTING RECOMMENDATIONS FOR SHORT- AND LONG-TERM IMPROVEMENTS TO PUBLIC SERVICE COMPANY OF COLORADO PROCESSES IN ORDER TO REDUCE BARRIERS**

Mailed Date: April 18, 2024

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I. STATEMENT

1. By Decision No. C23-0627, issued September 18, 2023, the Commission opened this Proceeding to implement certain provisions in Senate Bill (SB) 23-291 related to customer connections to and disconnections from investor-owned electric and gas utility systems. The Commission indicated that one purpose of this Proceeding was to facilitate completion of the study required by SB23-291 of potential barriers to beneficial electrification and the deployment of distributed energy resources (DERs).

2. Specifically, through § 40-3.2-104.6, C.R.S., the Colorado legislature directed the Commission to examine existing utility tariffs and interconnection policies and practices to determine if these tariffs, policies, or practices pose a barrier to the beneficial electrification of transportation and buildings and to the use of offsetting energy from DERs, as well the application of cost allocation in grid upgrades. To complete this work, the Commission engaged the assistance of two consulting firms, Lotus Engineering and Sustainability and Group 14 Engineering. In conducting its examination of these issues, the Commission solicited responses to a series of questions posed directly to the subject Colorado public utilities, convened a public comment hearing, held a series of workshops with a focus on Public Service Company of Colorado (Public Service or the Company), and commissioned a report by Lotus Engineering and Sustainability, as discussed below.

3. By this Decision, Hearing Commissioner Megan M. Gilman addresses the Commission's examination of these issues, completed in accordance with SB23-291. The Hearing Commissioner further provides recommended short- and long-term process improvements to Public Service to alleviate certain of the identified barriers.

II. DISCUSSION

A. Procedural History

4. As the first step in this Proceeding, the Hearing Commissioner issued two sets of questions to Colorado's two investor-owned electric utilities, Public Service and Black Hills Colorado Electric, Inc. (Black Hills). *See* Decision No. R23-0636-I, issued September 20, 2023 (issuing initial set of questions) and Decision No. R23-0797-I, issued November 30, 2023 (issuing additional questions). The responses submitted in this Proceeding by Public Service and Black Hills are publicly available through accessing the Commission's E-Filings System, available at: https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=23M-0464EG.

5. In addition, starting in the fall of 2023, the Commission began to hear concerns about Public Service's inability to connect new electric capacity in certain geographic areas of its service territory, primarily in the Metro Denver area. These recurring concerns were raised to the Commission through multiple forums including public comments, workshops, and direct comments or engagement by developers or stakeholders involved in several affordable housing developments. On this issue, affected Public Service customers generally reported to the Commission that, when Public Service communicated that its electric system could not host the customer's new load, Public Service also communicated that projects would need to bear significant costs, long timelines, or both, in order to get energized. In light of these concerns, and this state's policy goals supporting development of affordable housing and decarbonization through electrification measures, the Hearing Commissioner concluded that understanding this pressing capacity issue was inextricable from the broader examination of barriers to beneficial electrification. The Hearing Commissioner determined this issue—the local utility's inability to

add load—warranted further study as part of the examination already underway in this Proceeding of potential barriers to beneficial electrification in this state.

6. In accordance with Decision No. R23-0636-I, issued September 20, 2023, the Hearing Commissioner conducted a public comment hearing on October 4, 2023, to receive accounts from prospective and existing utility customers, builders and housing developers, local government officials, and utility representatives regarding electric utility policies and practices related to requests for new or upgraded electric service, including the costs and timing of system upgrades for necessary system interconnection. This action was prioritized to ensure the Hearing Commissioner could understand the emerging issues being reported around the inability of the Public Service distribution system to serve new load in certain areas.

7. In addition, the Hearing Commissioner scheduled a series of workshops to solicit input from the diverse range of stakeholders including, among others, existing and prospective utility customers, builders and housing developers, local government officials, and utility representatives. These workshops are summarized below.

8. In accordance with Decision No. R23-0874-I, issued December 29, 2023, the Hearing Commissioner conducted two workshops to further examine issues raised at the October 4, 2023 public comment hearing related to requests for new service or service upgrades within Public Service's electric service area. The first workshop, held February 5, 2024, focused on potential ways to improve the service request process and communications used by Public Service throughout its electric service area. The workshop involved interested representatives from developers, builders, municipalities, and others interested in the interconnection process for new loads, as well as representatives from Public Service. The second workshop, held February 12, 2024, focused on the capacity constraints on the utility's electric system that are

presenting issues to customers, builders, and developers seeking new service or service upgrades. The Hearing Commissioner heard directly from Public Service representatives familiar with the system constraints and planning.

9. In accordance with Decision No. R23-0102-I, issued February 15, 2024, the Hearing Commissioner conducted an additional workshop on February 22, 2024, to further examine the related processes and allocation of costs associated with distribution system upgrades. Participants at this workshop had opportunity to discuss their experiences with the system analysis conducted by Public Service when reviewing applications for new or upgraded electrical service or for the connection of new DERs, as well as the methodology, transparency, and issues around cost allocation of grid upgrades. Public Service discussed the internal and external-facing processes involved with the analysis and cost allocation of grid upgrades, as well as some of the history of the processes and limits around what dictates how costs are allocated. In response, participants then had opportunity to discuss any improvements to these processes and allocation practices to promote fairness, efficiency, and achievement of state policy goals, including suggestions for improvement or examples of processes used elsewhere that may provide improvements.

10. On March 14, 2024, the Hearing Commissioner issued a notice that the Commission had posted on its website the report developed for it by Lotus Engineering and Sustainability examining the areas identified in SB23-291. The notice indicated the Commission had contracted with Lotus Engineering and Sustainability to conduct the study and outreach process. The notice stated the study took a comprehensive approach to exploring the tariffs, policies, practices, and cost allocation principles of each utility and comprised four investigative stages. The report prepared by Lotus Engineering and Sustainability, *Impact of Investor Owned*

Utilities' Tariffs, Policies, and Practices on Beneficial Electrification and Distributed Energy Resources, is available on the Commission's 2023 Legislative Implementation page, listed among the SB23-291 updates, available at:

https://puc.colorado.gov/legislative-updates/2023-puc-legislative-implementation.

Members of the public may also access the report through reviewing the filings in this Proceeding through the Commission's E-Filings System, available at:

https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=23M-0464EG.

B. Significant Takeaways from Workshops and Consultant Report

11. Over the course of the three February 2024 workshops, the Hearing Commissioner heard a wide range of concerns from stakeholders about the processes, communications, and cost allocations experienced by customers or prospective customers when attempting to have new or expanded electric loads served by Public Service or to offset that load with DERs. Most significantly, stakeholders raised pressing concerns that many of Public Service's current practices and policies relating to serving new or expanded load have created an inefficient system that renders the Company ill-informed of upcoming customer needs. Based on these comments, the system seems to result in reactive, piecemeal additions to the electric system, instead of a more proactive system plan. The process appears to obfuscate, delay, or disincentivize customer adoption of beneficial electrification measures and may also pose a barrier to additional housing and other developments that would serve the public interest. Areas specifically identified as problematic include inconsistent communication practices, inefficient and confusing application processes, unforeseen distribution system constraints, short-sighted forecasting, inequitable cost allocation protocols, and a lack of enabling rates and programs that, altogether, create a challenging environment for advancing beneficial electrification within Public Service's territory and also pose

a challenge to development more generally. Based on the stakeholder input, these issues appear persistent regardless of customer type, project size, or location within the service territory, although the inability to serve new load is currently somewhat geographically concentrated.

12. Based on the consistent input received directly from stakeholders at these workshops, along with Public Service's engagement on these same issues, the Hearing Commissioner sees opportunity, and a pressing need, for the Company to improve certain areas in order to better serve customers and state policy goals through a more efficient and straightforward process. The Hearing Commissioner recommends that Public Service should immediately prioritize improving its ability to serve new or upgraded loads, primarily through the following means: better forecasting and planning, improved and more transparent communication, and timely execution of distribution system upgrades. As the incumbent electric utility in many locations in the state, Public Service has a critical role in the state's commitment to increase beneficial electrification. Indeed, achievement of the state's energy policy goals—related primarily to greenhouse gas reduction and the ability for customers have economically beneficial opportunities to participate in electrification programs—is grounded in the Company's ability to create and execute upon appropriate, data-based, and proactive distribution system plans. Thus, Public Service has a duty to ensure its distribution system is ready for the certain increases in electric loads stemming from state, local, and federal policies and incentives to induce building, home, and transportation electrification both in Colorado and nationally. Without reforms, it does not appear the system operated by Public Service is poised to rise to this challenge.

13. On the technical side, Public Service has provided general information on the current state of its distribution system. This includes slides presented at the February 12, 2024

workshop, which are publicly available in this Proceeding.[1] The Company indicated that approximately 23 percent of the Public Service system feeders are at utilization rates of 100 percent or more of their capacity based on 2023 values with an additional 29percent at 75-100 percent of their capacity. For Public Service banks, the Company represented that 3 percent of banks had utilization rates of 100 percent or more of their rated capacity, while an additional 18 percent were within 75-100 percent of their capacity. Upon questioning by the Hearing Commissioner, the Company indicated its current capital plans include mitigation of all known capacity constraints represented by these figures within the next several years.

14. Public Service representatives identified that the two biggest challenges the utility faces in ensuring timely upgrades to the distribution system are supply chain issues and permitting. The Hearing Commissioner notes supply chain issues have been ongoing for years and are a broader issue over which the Commission has little control. However, representatives from the City and County of Denver (Denver) and the City of Boulder (Boulder) provided certain helpful insights into the challenges to permitting. In some cases, permitting challenges and delays are based in truly technical problems. In these instances, issues must be addressed by the municipalities to achieve their electrification and greenhouse gas reduction goals. In other cases, however, it appears Public Service may be unnecessarily complicating the permitting process and causing delay by requesting accommodations that the municipality is unlikely to, or even cannot, provide for the project. This circular process, which appears predestined to end the same every time, while burning valuable time and resources, does not serve anyone well.

[1] These slides can be publicly accessed through the Commission's E-Filings System, available at: https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=23M-0464EG.

15. Public Service also raised that reducing regulatory lag in cost recovery could lead to increased investments in the distribution system. Although a relevant consideration, the Hearing Commissioner cautions that a change in cost recovery alone is unlikely to lead to changed outcomes. At a basic level, the apparent systemic issues related to the Company's processes and communications are the most significant barrier. Additional available capital or more favorable financial terms for the Company are thus of secondary importance.

16. During the workshop series, Denver presented a concept for a "Capacity Assurance & Technical Support Pilot Program." The intent of this proposal is to better align utility and project developer timelines and cost expectations around requests for new and upgraded electrical service. In short, the program would include consultation between Denver, Public Service, and a developer in the design process to provide an early opportunity for the developer to reserve capacity by providing a signed agreement and deposit. Given the potential equity concerns associated with larger upfront fees, Denver's proposal further clarifies that exemptions could be provided for affordable housing developments or other projects that would provide benefits or support to disproportionately impacted communities to provide for reduced or eliminated fees. As proposed, this program would be limited to locations within Denver, given some of the specific roles the municipality would play. The proposed five-year pilot is modeled after a proposal that is currently under consideration in Hawaii. Denver indicates it plans to introduce this proposal for consideration in the upcoming proceeding in which the Commission reviews Public Service's next distribution system planning (DSP) application.[2]

[2] By Decision No. C24-0014, issued on January 8, 2024, in Proceeding No. 23V-0609E, the Commission authorized Public Service to file its next DSP application pursuant to the Commission's Distribution Resource Planning Rules, 4 *Code of Colorado Regulations* 723-3-3525, *et seq*., no later than November 15, 2024.

17. There are a range of interventions that can effectively reduce barriers to beneficial electrification—many of which have been surfaced in the study conducted by Lotus Engineering and Sustainability within this Proceeding. Broadly, programs to support electrification coupled with demand response and energy efficiency programs, enabling rate design, and accurate distribution system planning and operation can help steward the transition to an electrified future. By separate decision, the Hearing Commissioner may address other barriers. This Decision focuses on improving the processes around serving new and upgraded load and considerations, specifically in anticipation of Public Service's forthcoming DSP application, which is expected in November 2024. Reducing these barriers is foundational because, without efficient and transparent transfers of information and more accurate distribution system planning and operation, it is unreasonable to expect that interventions like rate or program design can meaningfully improve customer experience, costs, or time to energize new loads.

C. Recommended Process Improvements

18. Based on the examination and workshops conducted in this Proceeding, the Hearing Commissioner provides the following recommended short- and long-term improvements, which the Hearing Commissioner strongly recommends the Company promptly address. The Company can take immediate steps to improve the communications and processes for service requests, distribution system upgrades, and forecasting. Additionally, recommended longer-term improvements should be addressed in the Company's upcoming DSP application to be filed in November 2024.

1. Short-Term Improvements

a. Communications and Processes

19. The Hearing Commissioner recommends that Public Service immediately improve its communications and processes around receiving and processing information for new or upgraded electrical service. It appears existing communications and processes are rife with project-altering inefficiencies, opacities, and uncertainties. Public Service should improve its conceptual capacity checks and its application form and process.

20. Existing conceptual capacity checks—as currently conducted—are unequally applied, opaque, and provide questionable value to both customers and the Company. Conceptual capacity checks can be requested by a customer at no charge; however, they are not advertised or offered through Public Service's website. This renders them effectively unknown and inaccessible to all customers except those made aware of this option through a specialized Company representative, or perhaps by customers who have utilized this service in the past. Further, the conceptual capacity checks only offer a static snapshot of the capacity available at the location at the point in time in which they were conducted, with no forward-looking analysis. In the February workshops, Public Service customers reported frustrating experiences where they received conceptual capacity checks that purported there was available capacity, subsequently spent significant time and money developing project permitting and construction documents, only to find out when they were about to start construction that the capacity was not actually available, or that obtaining service would now require significant time or expense.

21. In addition to providing limited practical value for customers, these checks do not currently appear to provide value to Public Service. As discussed in the workshops, it appears that Public Service does not track the location, size, occurrences, or trajectory of projects for which

these requests are made—with the exception of acknowledging that requests for these checks have recently significantly increased. The ability to track this data appears readily available to the Company and the data could provide valuable information about potential upcoming capacity needs on the distribution system. Tracking and utilizing this data could also reduce communications inefficiencies and cost allocation challenges, especially where multiple new loads may contribute to distribution system needs in the same area.

22. The Hearing Commissioner sees a clear opportunity to enhance the conceptual capacity check so that these checks can provide more concrete value to both the applicant and the Company. The Company should pursue the following short-term improvements to the conceptual capacity check:

i. Make clear to any customers requesting or receiving a conceptual capacity check that the formal service application—not the conceptual capacity check—is what constitutes an actionable request for service or capacity with the utility. Ensure applicants are aware that the utility does not take any action to secure capacity for a customer based solely on a request for a conceptual capacity check.

ii. Post a clear and conspicuous notice on the Company's website, near other information related to new service requests, indicating that customers can request a conceptual capacity check and instructions for how to make this request.

iii. Clearly explain up-front the data this conceptual capacity check provides, the limitations of the data provided, and how the Company uses this data. Clearly indicate when communicating results to the customer that conditions may change that make capacity availability uncertain at the actual time of application, despite the capacity check results.

iv. Improve how customers can use the results of the conceptual capacity check by providing additional clarity on the amount of capacity left, rather than a simple pass/fail to allow the customer to understand, at a high level, the relative likelihood of capacity within the project's construction timeline.

v. Develop a more comprehensive project tracking system by collecting the size and location of capacity checks done for customers and linking those checks to actual applications and actual service connections, once those steps are complete. In doing so, the Company should monitor—and have available for distribution system planning and reporting to the Commission upon request—an understanding of the trends of locations and sizes of these checks, the percentage of requests that turn into actual applications, and the percentage of applications that turn into load connections.[3] While every check will not turn into real load on the system, there is a significant amount of data available through trending and locational information, which should improve the Company's intelligence into upcoming capacity needs on the system in a way that is proactive and data-driven.

vi. Public Service should work alongside municipalities to improve the permitting process for distribution system upgrades. This area of mutual interest should be a reasonable place for collaboration among the utilities and the communities it serves. An open flow of communications regarding methods and strategies to streamline or improve the timelines on permitting processes is likely a win-win situation. The Company should avoid duplicative processes around permitting requests that have not proved successful in the past and focus on real process improvements to save time and effort for all parties.

23. As currently executed, the application form submission and subsequent application processing is a major project milestone—yet appears inefficient and outdated for the purpose it serves. The Company has reported that a formal service application is the first official request that triggers the Company's obligation to serve electric to a customer. Many customers seem unclear about this distinction and may think that completing a conceptual capacity check or having informal conversations with Company representatives "count" as a project action. However, the Company's perspective is that it does not plan for or reserve any capacity for a customer until the customer has submitted a complete application for service. There may be some rare exceptions for very large loads, in which the Company may try to make earlier evaluations, but specific

[3] In future iterations of the DSP planning and forecasting, the Company should be able to utilize this information to improve its intelligence and insight into areas of planned or upcoming load growth.

examples were not given and there does not appear to be a formal policy around this, so its parameters and application remain unknown.

24. The application form for service is housed on the Company's website.[4] It is a static PDF form, which is readily available to builders, developers, customers, and other project planners; but the application form is limited in scope and must be physically mailed to the Company upon completion. Based on information from the Company and stakeholders, it is not uncommon for there to be significant additional information that must be collected after completion of this initial application. The Company reports it can often take months and several iterations of asking the applicants for additional information, based on project type, to complete this process. Additionally, the Company only really appears to act on the request for service after the application—and subsequent iterations—are fully complete, which creates additional delay.

25. There is also a portal on the Company's website that can be used as an alternative to the PDF application, but it is only available to those who create a login and agree to the terms and conditions.[5] Based on the Company's statements during the workshops, the portal may collect more information than the static PDF form available for download the website. While it may be helpful to have two options available to cater to a broader range of applicants, the fact that the two forms are not identical, and both processes may regularly require case-by-case iteration with Public Service, creates a confusing application experience.

26. In light of the shortcomings of the existing service application process, the Hearing Commissioner recommends Public Service pursue the following short-term improvements to this process:

[4] https://co.my.xcelenergy.com/s/partner-resources/build-remodel/docs-forms
[5] https://my.xcelenergy.com/BuildingRemodeling/XE_Login

i. Endeavor to limit the iterative and inefficient additional requests made to applicants to complete their applications. Certainly, at this point in time, the Company must be well aware of the data points that are needed for a variety of different new load types. The Company should conform the static PDF form to the application on the customer portal so that both methods collect the same level of detail. The forms should collect—for all project types—the information that is regularly needed to process an application without having to go back to the customer for additional information in all but the rarest cases. Additionally, the Company should track when additional information regularly needs to be sought from the customer after the initial application, note the follow-up questions, and determine periodically if additional information fields should be added to the application outright to further streamline this process. This should occur on a regular basis and without prompting from the Commission, as a way for the Company to better serve its customers.

ii. The Company should track and maintain aggregated data showing the typical timeline, for each type of service request, recording the elapsed time between the different points in the process. These points include, at minimum, when the Company received an initial application, when it deemed the application complete, when it began processing the application for connection, and when the customer's new load was ultimately energized.

b. Distribution System Upgrades Triggered by New Capacity

27. The Hearing Commissioner recommends that Public Service immediately improve its processes around customer communications and transparency related to distribution system upgrades that the Company determines are needed to serve the new load. Customers reported a general lack of transparency around the cost allocation and alternatives available when the Company determines that a new load will require grid upgrades upstream of the customer's meter. The method of incremental grid upgrades assessed largely to individual customers can be a deterrent for new projects, especially projects with electrified loads like space heating, water heating, and electric vehicle charging, which might make new projects more likely to trigger upgrades due to larger capacity needs. This practice and surrounding policies should be revisited to ensure it is the best fit to serve state policy goals and promote fairness. However, this Proceeding

is not the proper venue for a full review of line extension policy and cost allocation principles, especially in its non-adjudicated format. Presently, it is most reasonable to address individual parts of this process that could be improved to aid in transparency, fairness, and accountability as part of the recommendations included within this Proceeding.

28. Off-site grid upgrades are governed by the Company's Line Extension Policy.[6] Off-site upgrades are rare, but can cost millions of dollars, if needed. Under the policy, for off-site grid upgrades, the Company assesses the individual customer with the load request 65 percent of the cost of the upgrade and socializes the remaining 35 percent of the cost across the rest of its ratepayers.[7]

29. Stakeholders generally reported it is unclear to the customer whether all upgrades are right-sized for the individual project, or if upgrades are oversized to accommodate additional load growth beyond the project scope. Public Service indicated in the workshops that its standard is to utilize the appropriate size equipment to serve the new load, although that may sometimes leave additional available capacity, since the sizing of the electrical infrastructure is only available in certain increments. Broadly speaking, this general overage in sizing is understood to be the basis for the 35 percent cost sharing of the upgrades, essentially presuming that one or more later customers may benefit from the upgraded infrastructure. However, those future customers, whose capacity fits between the old capacity and new capacity will not have any direct cost responsibility for the use of the upgraded infrastructure.

[6] It is worth noting the Company's Line Extension Policy also covers policies around costs for on-site infrastructure.

[7] The 35 percent Off-Site Distribution Line Extension Credit is described at Sheets R208 and R226 of Public Service's electric tariff.

30. According to the Company, while not the normal circumstance, at times it might oversize a grid upgrade in order to accommodate other growth. It is not immediately clear upon what this determination is made, but it appears to be case-by-case. In this situation, the Company indicated the customer causing the upgrade is not assessed the additional cost of the incremental capacity added on top of what they required. However, there does not appear to be a transparent calculation or report generated for the applicant to prove that they are only paying for the applicant's incremental costs. The Company did not clearly explain how costs were allocated, specifically, whether the customer triggering the upgrade had its allocation for common work reassessed based on a proportion of the project now being covered by the Company or if simply the incremental cost of equipment sizing was covered, and the rest was not reassessed.

31. Stakeholders shared that affordable housing and other public serving projects may be particularly disadvantaged by the costs for grid upgrades because projects that are publicly-or grant-funded may have smaller margins to shoulder unexpected large costs, especially those that arise late in the design process. In the current system, notification of upgrades always appears to happen late in the process, because only an application for service, which is done after substantial completion of construction documents, triggers the official notification to the utility. Therefore, it is even later in the design process when a project team is notified of any substantial charges or delays that might be required for grid upgrades in order to accommodate the new capacity. In the Denver Metro area, several affordable housing developers have communicated that their projects may be unviable if they need to pay large, unexpected costs for grid upgrades.

32. More generally, applicants who have been informed by the Company about the need for grid upgrades to serve their projects indicate a need for increased transparency and optionality. Some stakeholder reported that communication is sparse between the Company and the applicant

in this critical and potentially costly phase. Further, there is the appearance that upgrade costs provided by the Company are inflated, and some applicants reported the initial quote dropped significantly after the applicant questioned the Company's assumptions. Applicants also reported that the Company does not provide the alternative pathways—through interventions like DERs, demand response, or other controls—to mitigate or reduce the need for these grid upgrades. The Company also does not appear to factor in situations when these interventions may already exist in project design, as information about these features does not appear to be collected during the application process. The Hearing Commissioner highlights these issues because this level of uncertainty can lead—at best—to delays, distrust and frustration and—at worst—to failed projects.

33. The Hearing Commissioner recommends the Company pursue the following short-term improvements to the process and notification surrounding off-site distribution system upgrades triggered by the addition of new capacity by a customer:

i. Within applications for service, the Company should ask for data on any planned controls, demand-limiting equipment, or other DERs like batteries that the project team is planning to utilize within the project that could reduce, defer, or eliminate the need for an upgrade related to the new capacity. The Company should also provide a menu of options that a project team could choose to integrate to potentially reduce, defer, or eliminate the need for an upgrade.

ii. The Company should itemize cost projections for grid upgrades and clearly communicate any changes in process or scope, and the associated cost change for grid upgrades, based on the introduction of interventions by project teams like controls, demand-limiting equipment, or other DERs, if the project team has communicated plans or a willingness to deploy such technologies. Likewise, if a reduction in capacity from the building would cause a material change in the scope and cost of grid upgrades, such an option should be provided to the applicant. If the Company elects to upgrade beyond what is needed just to serve the applicant's load, the Company should itemize the incremental costs allocated to the customer and to the additional upgrades to be transparent about what the customer is responsible for financing.

iii. The Company should provide additional details in its next DSP application filing regarding how costs are shared when the Company elects to upgrade beyond what is needed just to serve the applicant's load, including how any common costs are allocated between an applicant and the Company.

iv. Additionally, in the DSP application filing, the Company should elaborate on what, if any, future growth projections should be factored into grid upgrades, when needed, to avoid costly piecemeal additions to the system.

c. Forecasting

34. The Hearing Commissioner recommends that Public Service immediately improve its forecasting. It appears, based on a Company representative's remarks, that the Company may not be using the forecast from the most recently approved DSP[8] to make actual grid planning decisions.

35. The workshop hosted February 12, 2024, helped surface causes contributing to the current challenges on Public Service's electric distribution system, including how the DSP did not foresee and mitigate grid capacity issues. Company representatives indicated that, although the Commission's forecast requirements rule, Rule 3530(a) of the Commission's Rules Regulating Electric Utilities, 4 *Code of Colorado Regulations* 723-3, states the minimum forecasting criteria should comply with state policy goals—including beneficial electrification—the Company did not use the DSP-approved forecasts to make grid planning decisions and capital budgets. Instead, it seems Public Service used a different, lower load growth forecast to make grid planning decisions. According to Company representatives, this decision was purportedly made to avoid overinvesting in upgrades to the distribution grid.[9] The forecasting the Company used has yet to be provided to the Commission. To the extent the Company used a lower load growth forecast, it is somewhat

[8] *See* Proceeding No. 22A-0189E.
[9] Company representatives provided this insight during the February 12, 2024 workshop.

unsurprising to now see issues with the distribution grid's capacity to support electrification loads or additional new loads to meet state policy goals.

36. Another pressing issue is that the Company does not appear to meaningfully consult municipalities on their energy plans, so it is missing opportunities to more accurately model load growth. This is especially important in the coming years, as we might see a divergence in load growth trends on the electric and gas systems, based on policies and incentives targeted around electrification, so insights into local trends and policies could heavily influence the future need for investment as it relates to each system, independently. For example, both Denver and Boulder have local initiatives, building codes, and/or incentives which are meant to influence adoption of electrification measures within the Company's service territory. These local governments also have specific insights into areas of upcoming development and potential density, based on their zoning. The municipalities have expressed a willingness and interest in working with the Company to provide information and ensure that their constituents are able to comply with local regulations and to receive prompt service.

37. Finally, it appears to the Hearing Commissioner that Public Service adds upstream capacity proactively on its gas system by including a presumed ten years of additional growth when sizing capacity expansion projects. In contrast, however, it appears the Company simply upgrades its system only to the size that is the best fit to serve immediately added capacity on the electric system. Often, there is some capacity left over between the new load and the equipment sizing threshold, but there appears a very different strategy in terms of the proactive nature of building for upcoming load between the Company's gas and electric operations. This inherently leads to a more piecemeal, and potentially more expensive, process for incrementally adding electrical capacity.

38. Given these considerations, the Hearing Commissioner recommends Public Service pursue the following short-term improvements to its forecasting:

i. The Company should clearly report in its upcoming DSP application filing if it has ever, or plans to, use a different forecast than what it has provided to date, and upon which its DSP filing is based. If the Company previously utilized a different forecast than the DSP forecasting, the Company should clearly explain its rationale for doing so and provide a clear comparison between the DSP forecast and that which was utilized for actual project planning and capital budgeting. Likewise, if the Company plans to utilize a forecast for internal distribution forecasting or budgeting which varies from the forecast utilized in the DSP proceeding, that intent should be made clear in the DSP filing, including the rationale for the decision and a clear comparison between the DSP forecast and that which the Company plans to utilize for actual project planning and capital budgeting.

ii. The Company should immediately begin meaningful outreach to municipalities in its service territory to gather information about upcoming projects or local policy drivers that could influence forecasting of capacity needs for both the electric and gas system in those territories. The Company should immediately reach out to Denver and Boulder, plus any municipality with building codes or incentives likely to influence the pace of electrification, to initiate this outreach. This will provide the Company much-needed insights about the location, extent, and timing of expected additional capacity needs to include in forecasting in its next the relevant proceeding—Distribution System Planning for electric in November 2024 and Gas Infrastructure Planning for gas in 2025.

2. Additional Long-Term Improvements

39. The Hearing Commissioner recommends that Public Service include the following considerations in its November 2024 DSP application.

a. Capacity Availability Maps

40. In its inaugural DSP in Proceeding No. 22A-0189E, the Company began implementation of hosting capacity mapping to aid renewable developers and interested customers in understanding the ability of the grid to host additional renewables in certain geographic areas. Given the issues faced by customers, who often take years to develop a new construction project

and face different conditions on the distribution grid than their conceptual capacity may have indicated, many of the frustrations experienced may be eased and problems avoided with additional transparency around the current ability, locationally, for new capacity additions to the distribution system. Therefore, in its November 2024 DSP application filing, the Company should consider providing a proposal for hosting a map on its website, similar to the hosting capacity mapping used for DERs, which indicates locational availability of capacity. The proposal should include appropriate considerations for treatment of the data, display considerations to ensure project teams can glean useful information, and an update frequency that allows for transparency as grid conditions change.

41. These maps would have multiple benefits. First, they would enable developers or potential applicants to dynamically track capacity and better understand when the window for available capacity is closing and the relative differences between capacities available in different locations. Second, it is likely these maps could save Company time and resources. Instead of responding to an unprecedented volume of conceptual capacity checks, these maps would allow many customers to bypass conceptual capacity checks and allow the Company to focus its efforts elsewhere.

b. Capacity Reservation

42. Within this Proceeding, Denver proposed a pilot, referred to as the "Capacity Assurance & Technical Support Pilot Program," which was described above. Based on the emerging and concerning issue of the Company's inability to serve some new capacity in certain areas, the Company should strongly consider presenting a capacity reservation pilot or similar offering to be included in the November 2024 DSP application filing. The pilot should be aimed at providing additional transparency and predictability for applicants or soon-to-be applicants for

new capacity to the electric grid, while also providing the Company with earlier, actionable information about likely capacity additions. The pilot design should consider the specific challenges faced by affordable housing and other public-serving projects, which may not have the ability to front large deposits yet should be able to also benefit from any proposed method to more transparently and predictably allow new capacity to plan to join the electric system, perhaps through lower or eliminated fees.

c. Cluster Study Approach

43. As an alternative to the piecemeal additions caused by individual customers triggering upgrades, the Company should study and consider developing a more thoughtful approach that is based on forecasting. As a starting point, this could include a cluster study of projects that all intend to seek new or upgraded service within a similar timeframe. In situations where significant load growth is expected, including in areas where local building codes or standards might result in a significant number of electrification projects within a defined geographic area on a rather predictable timetable, coordination amongst these loads—facilitated either by an engaged municipality or representatives of Public Service—could lead to a more efficient and proactive process. In its November 2024 DSP application filing, the Company should consider if a pilot or other program may serve the purpose of streamlining and coordinating amongst significant upcoming loads with the goal of improving the efficiency of planning and execution of work and resulting in a fairer cost allocation approach where one grid upgrade may serve multiple interested customers.

d. Forecasts

44. In preparation for the November 2024 DSP application filing, Public Service should solicit input from municipalities whose energy plans would influence forecasts based on local

policies, building performance standards, approved upcoming development areas, and incentives. Public Service should then strongly consider using this up-to-date information in preparing its forecasts for the 2024 DSP. For context, so that the Commission and intervenors can better understand the Company's approach to forecasting, the Company's November 2024 DSP application filing should describe these outreach efforts, the information gained from this outreach, and how the Company incorporated this information into developing its forecasts.

III. ORDER

A. It Is Ordered That:

1. This Proceeding to implement certain provisions in Senate Bill 23-291 related to customer connections to and disconnections from investor-owned electric and gas utility systems remains open. The Hearing Commissioner expects to continue examining the issues set forth in Senate Bill 23-291 and may, by separate order, issue further decisions.

2. This Decision is effective upon its Mailed Date.

(S E A L)

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

MEGAN M. GILMAN

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Hearing Commissioner