Decision No. C21-0183

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 19R-0654E

IN THE MATTER OF THE PROPOSED AMENDMENTS TO RULES REGULATING ELECTRIC UTILITIES, 4 CODE OF COLORADO REGULATIONS 723-3, RELATING TO INTERCONNECTION PROCEDURES AND STANDARDS.

DECISION ADDRESSING EXCEPTIONS TO DECISION NO. R20-0773 AND ADOPTING RULES

Mailed Date: March 30, 2021
Adopted Date: February 24, 2021

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I. BY THE COMMISSION

A. Statement

1. Through this Decision, the Commission grants, in part, and denies, in part the exceptions filed on November 25, 2020 to Decision No. R20-0773, issued November 5, 2020, by Administrative Law Judge (ALJ) Steven H. Denman (Recommended Decision). The Commission adopts revised rules governing Interconnection Rule and Procedures (Interconnection Rules), located within the Commission's Rules Regulating Electric Utilities, 4 *Code of Colorado Regulations* (CCR) 723-3 (Electric Rules) at 4 CCR 723-3-3875 *et seq*. The

adopted Interconnection Rules are attached to this Decision in legislative format (*i.e.*, strikeout/underline) as Attachment A, and in final format as Attachment B.

B. Background

2. On November 25, 2019, the Commission commenced this rulemaking through a Notice of Proposed Rulemaking (NOPR) issued as Decision No. C19-0951 in this proceeding, Proceeding No. 19R-0654E. The NOPR proposed to move the Interconnection Rules to a new standalone section within the Electric Rules of 4 CCR 723-3, comprising new Rules 4 CCR 723-3-3850 *et seq*. The NOPR also proposed substantive changes to the provisions of the Interconnection Rules.

3. Prior to this rulemaking, the Commission first proposed changes to the Interconnection Rules through a NOPR issued as Decision No. C19-0197 in Proceeding No. 19R-0096E.[1] In that first NOPR, the Commission proposed to amend the Electric Rules in six areas including Electric Resource Planning, the Renewable Energy Standard, Net Metering, Qualifying Facilities, and Community Solar Gardens (CSGs) as well as the Interconnection Rules. After considering the amendments to § 40-2-127, C.R.S., enacted by the 2019 Colorado General Assembly, and the participants' comments to date in Proceeding No. 19R-0096E, the Commission decided to sever the Interconnection Rules and open a new, separate rulemaking. By Decision No. C19-0951 the Commission determined it had sufficient information to issue a new set of proposed Interconnection Rules that implement the recent statutory changes and respond to participant comments to date. The Commission concluded a standalone rulemaking would allow for amended Interconnection Rules implementing the statutory changes to be implemented sooner than if they remained part of Proceeding No. 19R-0096E.

[1] Proceeding No. 19R-0096E, Decision No. C19-0197 (issued February 27, 2019).

4. By Decision No. C19-0951, the Commission issued the NOPR initiating this Proceeding. The NOPR adopted a schedule for filing comments and invited interested participants to file initial comments no later than January 7, 2020 and to file reply comments no later than January 21, 2020. A public rulemaking hearing was scheduled for February 3, 2020. The Commission referred this matter to an ALJ to preside over rulemaking hearings and for the issuance of a recommended decision.

5. Joint Consensus Interconnection Rules (Consensus Rules) were filed on March 20, 2020, by Public Service Company of Colorado (Public Service or Company), Black Hills Colorado Electric, LLC (Black Hills), Colorado Solar and Storage Association and the Solar Energy Industries Association (together referred to as COSSA/SEIA), and Western Resource Advocates (WRA). The Consensus Rules included definitions for certain terms in proposed Rule 3852 and language for proposed Rules 3853, 3854, and 3855. By the spring of 2020, the record in this Proceeding contained a large volume of written and oral comments, as well as extensive post-hearing comments and numerous revisions to the proposed rules.

6. In Decision No. R20-0423-I (issued on June 5, 2020), the ALJ found that holding an additional rulemaking hearing was needed to gather additional information from Participants and to help clarify certain issues so that the ALJ could fully evaluate and consider the arguments and revised rules proposed by the Participants. The additional rulemaking hearing was held on July 27, 2020 as scheduled. Oral comments were presented by representatives of COSSA/SEIA, Colorado Energy Office (CEO), WRA, SunShare LLC, Public Service, and Black Hills.

7. On November 5, 2020, ALJ Denman issued Recommended Decision No. R20-0773, which is the subject of this Decision.

8. The Commission, on its own motion, stayed the Recommended Decision on November 18, 2020 to explore the potential introduction of performance incentive mechanisms (PIMs) as applied to the interconnection of Distributed Energy Resources (DERs).

9. On November 25, 2020, the following rulemaking participants filed exceptions to the Recommended Decision: Public Service, Black Hills, Colorado Rural Electric Association (CREA), CEO, and COSSA/SEIA.

10. On December 9, 2020, the following rulemaking participants filed responses to the exceptions: Public Service, Black Hills, WRA, CEO, and COSSA/SEIA.

11. On December 11, 2020, the Commission issued a Supplemental Notice of Proposed Rulemaking, indicating that it would explore performance incentive mechanisms in these Interconnection Rules.[2]

12. An additional public comment hearing on the issue of adding PIMs to these Interconnection Rules was held on January 22, 2021. The Commission now addresses the Exceptions filed to the ALJ's Recommended Decision.

C. Exceptions to Recommended Decision

13. Below, we address the exceptions filed to the Recommended Decision, any responses, and the Commission's findings and conclusions granting or denying the exceptions.

1. <u>Rule 3850 - Applicability</u>

14. This rule adopts current terms for "small generation" as used throughout the Commission's Electric Rules, 4 CCR 723-3, and references certain updates to Federal Regulatory Energy (FERC) policies. It clarifies which DER and interconnection resources will be subject to

[2] *See* Decision No. C20-0880.

the Interconnection Rules and clarifies that the Commission can review utility standards and guidance for consistency when necessary.

a. Exceptions

15. Black Hills argues it is not appropriate to include substantive demands in the applicability section, as such requirements are better placed in the requirements sections of the Interconnection Rules. Black Hills recommends the Commission remove the redundant substantive language from Rule 3850 that addresses utility requirements concerning standards and guidance.

16. Public Service takes exception to the language within Rule 3850 and Rule 3859 that requires a utility to file an Advice Letter and Tariff or application for Commission approval of interconnection standards, technical guidance, and interconnection manuals. This is detailed in the discussion of Rule 3859.

b. Findings and Conclusions

17. We agree with Black Hills that substantive descriptions and requirements do not belong in the Applicability section, as consistent with similar sections throughout the Electric Rules. As discussed below regarding Rule 3859, the language both utilities recommend deleting from this section are no longer relevant to the updated rules. We note that Public Service does not take issue with such descriptions appearing in the Applicability section, however, we address their concerns regarding Rule 3850 further in Rule 3859.

2. Rule 3852 - Definitions

18. The Recommended Decision provides several new definitions to integrate energy storage technologies into the rules, in accordance with Senate Bill (SB) 18-009, and several revised definitions to promote clarity and effectiveness of the rules. Other revisions simplify or

update the definitions. Consensus Rule definitions were adopted for export capacity, highly seasonal circuit, inadvertent export, minor modifications, operating mode, and party or parties.

19. The ALJ adopted a new definition of Interconnection Resource in Rule 3852(l) and added language to clarify which interconnection resources fall within the definition. When appropriate throughout the adopted Interconnection Rules, the term "DER" has been changed to "interconnection resource."

a. Exceptions

20. COSSA/SEIA argues that the Commission should amend the DER definition noting that under current rules in other jurisdictions, this standard will not be fully implemented until January 2022. COSSA cites jurisdictions where this standard will be adopted on that timeframe include Maryland and Hawaii and aligning the timeframe for applying this standard in Colorado with the implementation of this standard in other states will ensure that there are sufficient products certified under the 1547-2018 standard available on the market when implementation begins.

21. COSSA/SEIA also urge the Commission to specify in Rule 3857 that 1547-SA remains the standard for inverters that is applied until sufficient equipment compliant with the new standard, 1547-2018, becomes available.

22. Public Service recommends adding the term "electrical" within the definition in order to clarify how the definition of energy storage is applied to the interconnection rules.

23. Black Hills recommends the Commission delete the proposed definition of "Interconnection Resource," as they argue term is redundant with the definition of a "Distributed energy resource or 'DER'." The revised Interconnection Rules include a new definition of DER

to address an interconnection customer's behind-the-meter facilities. Black Hills supports the DER definition and the use of DER throughout the Interconnection Rules.

b. Responses

24. Public Service agrees with COSSA/SEIA that the advanced inverter functionality should not be activated until such advanced functions are tested and certified as compliant to IEEE 1547-2018. The Company also agrees with COSSA/SEIA that January 2022 would be consistent with IEEE-1547 certified inverters being widely available and is a timeframe sufficient for Public Service to consider evolving research and utility best practices for implementation of utility interactive functions for DER meeting the functional requirements of IEEE 1547-2018.

25. CEO concurs with COSSA/SEIA's rationale that it is important to ensure that there are sufficient products in the market prior to implementation, and recommends that the Commission adopt COSSA/SEIA's Exception on adding the timeline regarding 1547-2018.

26. WRA argues that IEEE 1547-2018 has been in effect since early 2018. Most manufacturers have been using inverters that meet these standards for some time. WRA notes that the rules under consideration here will not be in effect until near the end of 2021 at the earliest. WRA sees no need to add language that delays the applicability of IEEE 1547-2018 until January 2022. WRA suggests that this exception be denied.

27. Public Service agrees with Black Hills that "distributed energy resource" broadly applies to all customer interconnected generation sources of electric power connected to the utility's distribution grid. Public Service states these include bidirectional storage, electric vehicle chargers, vehicle to home, vehicle to building, or a combination of any of these elements.

Public Service states that it already reviews battery systems and has reviewed several vehicle-to-building interconnection requests following current Interconnection Rules.

28. CEO responds to Black Hills and recognizes that certain redundancy exists between these definitions, however, CEO argues they are not equivalent and views both as necessary to retain in rules as determined in the Recommended Decision. CEO supports the updated terminology because it more appropriately includes resources subject to the interconnection procedures and standards, such as energy storage. CEO, COSSA/SEIA, and WRA have noted that while all small generating facilities are DERs, not all DERs are subject to the Interconnection Rules. CEO provides an example that demand response and electric vehicles with one-directional Level 1 charging are DERs but are not subject to these rules.

c. Findings and Conclusions

29. We agree with Public Service that adding the term "electrical" clarifies the definition of energy storage that applies to the Interconnection Rules.

30. We agree with COSSA/SEIA that establishing a timeline for implementation of advanced inverters will allow for widely available technologies, as well as taking advantage of the latest research and utility best practices for implementation of utility interactive functions for DER meeting the functional requirements of IEEE 1547-2018. We note that both CEO and Public Service agree with COSSA/SEIA that the advanced inverter functionality should not be activated until such advanced functions are tested and certified as compliant to IEEE 1547-2018.

31. We agree with CEO's response to Black Hills, as well as previous discussions made by CEO, COSSA/SEIA, and WRA throughout this rulemaking that there are specific instances to differentiate between DER and Interconnection Resource. We agree that the updated terminology appropriately includes resources subject to the interconnection procedures and

standards, such as energy storage. While all small generating facilities are DERs, not all DERs are subject to the interconnection rules. For example, demand response and electric vehicles with one-directional Level 1 charging are DERs but not subject to these rules. We therefore deny Black Hills' request to delete the proposed definition of "Interconnection Resource".

3. Rule 3853(a) - General Interconnection Procedures

32. The Recommended Decision's adopted Rule 3853(a)(IV) includes a new option for customers to request a pre-application report. The intent of the adopted language is to expedite the implementation of the formal interconnection requests by customers.

33. COSSA/SEIA argued in this Proceeding that proposed Rule 3854(a)(IV)(E) should require that the utility provide the limiting conductor's ratings and length from the proposed point of interconnection to the distribution substation. Public Service opposed this suggestion and asserted that it might require setting up and performing circuit traces within the geographical information system, which could add cost and more time to the pre-application process. The ALJ agreed with Public Service that the rule should not add cost and more time to the pre-application process, and the adopted rule will not require conductor length and ratings to be provided.

a. Exceptions

34. COSSA/SEIA recommend adding language to the Rule that requires utilities to provide conductor ratings and lengths in order to facilitate evaluation of project feasibility by developers. COSSA/SEIA argue that providing the rating together with the length of the limiting conductor enables interconnection customers to determine if the existing conductor can accommodate the DER, and if the conductor cannot accommodate the DER, this information

allows the IC to estimate the cost of replacing the wires in order to evaluate whether such replacement would prove cost-effective.

35. Public Service takes exception to a requirement within Rule 3853(a)(IV) to post all pre-application reports to its website due to site confidentiality concerns and the fluid nature of the distribution system which leads to the data lacking validity quickly as the system changes. Public Service points out that the pre-application report is a high-level snapshot of a particular feeder which does not provide any insight as to whether that particular site is in fact valid for interconnection. They also express concern that posting this information publicly could compromise site confidentiality because the feeder activity contained within the pre-application report may provide certain developers a competitive advantage with respect to sought-after sites and queue activity, as well as providing information concerning which feeders are stressed or reaching capacity limits. Public Service recommends striking this requirement from the rule.

b. Responses

36. Black Hills agrees with the ALJ's conclusion and recommends the Commission not grant COSSA/SEIA's exceptions to include the requested addition to the pre-application requirements. Black Hills states that determining conductor lengths and ratings would require a utility to engage in a burdensome and manual process to detail this requested information. Black Hills is concerned about the additional labor requirements and expenses associated with COSSA/SEIA's request and requests the Commission approve the ALJ's decision to exclude the conductor length and ratings information from the pre-application reports.

37. COSSA/SEIA responds to Public Service's recommendation to strike if a recent pre-application report on that feeder were publicly available, a developer contemplating siting a project in that area would be able to quickly see that they should find another site, instead of

wasting time on a feeder that is likely to cause delays and require upgrades. COSSA/SEIA believe that avoiding such applications saves time and expense for all involved and adds that a developer could find a recent pre-application report that shows there is likely lots of capacity on a particular feeder, and could then, at their own risk, file an interconnection application. COSSA/SEIA argue that if the developer's gamble pays off, they have skipped a step in getting a likely duplicative pre-application report of their own, if not, their interconnection application is denied, they have lost their application fee and no negative impacts to the utility, the system, or other customers has occurred.

38. In addition, COSSA/SEIA argue that Public Service's "site confidentiality concerns" are both misguided and inaccurate. COSSA/SEIA state that Public Service claims, without any basis or experience that "there is also concern that posting this information publicly could compromise site confidentiality because the feeder activity contained within the pre-application report may provide certain developers a competitive advantage with respect to sought-after sites and queue activity…" COSSA/SEIA's argue that its members represent the vast majority of the solar and storage industries in Colorado and are not concerned about competitive threats between developers siting projects based on the posting of pre-application reports. Instead, COSSA/SEIA argue that the public posting of these reports is a positive step towards transparency that will reward developers that exercise due diligence in siting projects and will ultimately lead to lower costs, and increased competition in the electricity sector.

c. Findings and Conclusions

39. We agree with the ALJ's decision that COSSA/SEIA have not shown that the benefits of the utilities providing such information on conductor ratings and lengths outweigh the added costs and burdens upon the utility, and ultimately, costs to ratepayers. Black Hills notes in

its response to exceptions that determining conductor lengths and ratings would require a utility to engage in a burdensome and manual process to detail this requested information. Public Service made similar arguments during this proceeding. While such information may benefit solar developers, much more detail on the costs and benefits would need to be provided. The ALJ properly decided that COSSA/SEIA did not provided these details in its comments or at hearing, and we believe that there has not been adequate new information provided in exceptions.

40. We also agree with the ALJ's decision to increase transparency on interconnections by the utilities. Beginning with the initial NOPR, the ALJ found that additional transparency from utilities with regard to information on interconnections, and potential issues with new interconnections is a vital piece of updated interconnection rules. This requirement is one such tool for increased transparency, which will lead to increased accountability for the utilities. COSSA/SEIA explain that if a recent pre-application report on that feeder were publicly available, a developer contemplating siting a project in that area would be able to quickly see that they should find another site, instead of wasting time on a feeder that is likely to cause delays and require upgrades. Similarly, a developer could find a recent pre-application report that shows there is likely lots of capacity on a particular feeder, and could then, at their own risk, file an interconnection application.

41. We also agree with COSSA/SEIA that Public Service's "site confidentiality concerns" are both misguided and inaccurate. Public Service seems to claim, without any basis or experience that "there is also concern that posting this information publicly could compromise site confidentiality because the feeder activity contained within the pre-application report may provide certain developers a competitive advantage with respect to sought-after sites and queue

activity…"[3] We believe that public posting of these reports is an important step towards increased transparency that will reward developers by exercise of due diligence in siting projects and will ultimately lead to lower costs and increased competition.

4. Rule 3853(c) - Energy Storage Interconnections

42. This rule specifies that a CSG's capacity is measured in an AC (alternating current) rating rather than a DC (direct current) rating. In the rulemaking, COSSA/SEIA advocated for this clarification and the Recommended Decision agrees with COSSA/SEIA that DC ratings are not representative of the maximum output capacity of a CSG system. The Recommended Decision concludes that capacity should be measured using the AC rating, as the AC rating is what determines how much electricity can be exported at any one time.

a. Exceptions

43. Public Service notes that the Recommended Decision failed to delete the term "exporting" from both Rule 3853(c)(III) and (V) as agreed to within the consensus. The Company is concerned that not following the consensus language would result in rules that exclude non-exporting systems that operate in parallel with the utility and can have grid impacts. Non-exporting systems will contribute to utility faults and have the potential to cause power quality issues. Non-exporting systems need to be certified to IEEE 1547 and meet the defined grid ride-through interactive capabilities. Public Service recommends that the Commission again review the Joint Consensus Interconnection Rules filed on March 20, 2020.

[3] Public Service's Exceptions to Decision No. R20-0773 at p. 19.

b. Findings and Conclusions

44. We grant Public Service's request to modify the adopted rules to meet the consensus language. We reiterate that the Commission appreciates participants working together to achieve consensus rules and want to make sure we continue to encourage that cooperation.

5. <u>Rule 3853(i) - Interconnection Metering</u>

45. The ALJ agreed with Public Service and Black Hills, who argued that the exemption of energy storage systems from additional metering requirements should be lowered from 500 kW to 25 kW AC. The revision is consistent with revisions of 20 kW to 25 kW in other adopted Interconnection Rules. Public Service recommended that the exemption of energy storage systems from additional metering requirements should be lowered from 500 kW to 20 kW, because 500 kW energy storage systems could cause significant impacts on distribution feeder circuits. Public Service argued that visibility is a critical component in grid modernization initiatives, requiring an understanding of the gross generation and load levels in order to plan and to operate a stable grid effectively and efficiently.

46. Black Hills agreed with Public Service that the additional metering exemption threshold should be lowered to 20 kW from 500 kW. Black Hills argues that the introduction of energy storage systems on its grid is a new and evolving process, necessitating a measured approach to exempting metering requirements. According to Black Hills, as more information is obtained on the impact of these systems on its grid, raising this metering over time could be appropriate.

a. Exceptions

47. COSSA/SEIA state the adopted rules remove specific reference to "load or production metering" and instead generically prohibit all "additional metering" for the purposes

of monitoring energy storage systems below 25 kW. COSSA/SEIA state they do not object to this change as it is consistent with SB 18-009, codified at § 40-2-130, C.R.S. However, COSSA/SEIA cite § 40-2-130, C.R.S., at subpart (3)(d) and argue utilities may not require any customer-sited meters above and beyond "a single net energy meter" if the additional meters are used to monitor energy storage systems, with the exception of large energy storage systems. COSSA/SEIA suggest the Commission should simply clarify for the avoidance of doubt that this includes load meters that are used to monitor energy storage systems, which the Commission should further clarify are disallowed for both small- and medium-sized systems.

48. COSSA/SEIA also argue that in the initial NOPR, the Commission proposed a 500 kW size threshold for when a utility could use additional metering to monitor an energy storage system. This 500 kW threshold is consistent with the Colorado Legislature's direction that "the commission may authorize the requirement of metering for certain large energy storage systems." However, COSSA/SEIA note the Recommended Decision adopts a 25 kW threshold based, at least in part, on Public Service's argument that most residential and small commercial system designs will fall below the 20 kW threshold.

49. COSSA/SEIA argue that Public Service's own Solar*Rewards program defines small systems as those of up to 20 kW, medium systems as those sized from 20 kW to 500 kW, and large systems as those above 500 kW. Consistent with these prevailing size demarcations, COSSA/SEIA argue that the Commission should adopt a 500 kW exception to the prohibition against metering of energy storage systems, as the Commission originally proposed in the draft rules attached to the Commission's NOPR in this proceeding and consistent with SB 18-009.

b. Responses

50. WRA believes that the adopted rules as currently written are clear, and comply with SB 18-009. It recommends that the Commission retain the ALJ's recommended rule language.

51. Black Hills argues the Recommended Decision did not err in Rule 3853(i) by exempting storage systems below 25 kW AC from additional metering requirements. Black Hills believes the ALJ reasonably concluded that 25 kW is an appropriate threshold at this time because energy storage systems can cause adverse reliability impacts without visibility into their operation. The ALJ also cited statements from Black Hills that over time the threshold could be raised as the impact of energy storage systems is further understood. In addition, the ALJ found that a 25 kW threshold is consistent with the 25 kW threshold adopted for the Level 1 process addressed in Rule 3853(e)(I).

52. Black Hills further argues that it does not understand what relevance one utility's (*i.e.*, Public Service) solar rewards program has on establishing a first of its kind metering threshold for storage systems in interconnection rules that are applicable to other utilities in Colorado. Black Hills argues that COSSA/SEIA's singular focus on Public Service's solar programs do not justify departing from the ALJ's establishment of a 25 kW threshold for determining additional metering requirements for storage systems.

53. Public Service believes that the requirement that meters are not required for energy storage systems of 500 kW and below is arbitrary. Public Service explains that only 3 percent of the Company's commercial and industrial customers draw more than 500 kW for their energy requirements, which provides insight into how significant the 500 kW load is on the system. Public Service believes that such a lack of visibility is not practical and anything above

25 kW should be considered “large” in order to provide the utility with the needed visibility to adequately plan and operate the system both reliably and safely. Public Service argues this strikes a reasonable balance between most small residential and commercial systems that are less than 10 kW AC and those systems that can have a much greater impact on the distributions system if there is no adequate visibility.

c. Findings and Conclusions

54. We deny COSSA/SEIA’s revision to Rule 3853(i), as well as their request that the Commission clarify issues surrounding additional metering. The ALJ was correct that energy storage systems may cause adverse reliability impacts without visibility into their operation. As Black Hills points out, as more experience with storage systems are developed, the threshold can be raised as the impact of energy storage systems is further understood. Public Service also makes the point that the proposed language strikes a reasonable balance between residential and commercial systems that are less than 10 kW AC and those systems that can have a much greater impact on the distributions system if there is inadequate visibility.

55. We do not agree with COSSA/SEIA that additional language by the Commission is needed to clarify that the Rules prohibit all “additional metering” for the purposes of monitoring energy storage systems below 25 kW AC. WRA notes that the Recommended Decision and the adopted rules as currently written are clear, and comply with SB 18-009.

6. Rule 3853(o) - Insurance

56. Adopted Rule 3853(o) derives from existing Rule 3667(e)(XI), but deletes the requirements that interconnection customers must carry liability insurance for bodily injury and that the utility be named as an additional insured, but only implies that interconnection customers pay for the insurance and that insurance coverage be for each occurrence. Under the adopted

rule, a utility could only require an applicant to purchase insurance covering "Utility Damages" and with coverage limits of less than the existing rule. Adopted Rule 3853(o) also clarifies that interconnection customers shall pay for the required insurance coverage and that the required coverages be for each occurrence.

a. Exceptions

57. Public Service takes exception to certain aspects of this rule, noting that it forces the utilities to assume risk for systems under 1 MW in capacity. Public Service argues that without sufficient insurance from the generator, the Company could be liable for these damages and losses due to the shared nature of the interconnection contract for the facility that failed to abide by the operating requirements. Despite contract provisions for programs and interconnections that limit Company liability, Public Service argues that utilities are often targeted for claims. Public Service emphasizes that a lack of insurance increases the potential for the Company's self-funded insurance to be called upon to cover these costs, which then places that risk onto its customers.

58. Public Service highlights that while it is common among states and utilities to exclude Level/tier 1 systems from insurance requirements beyond a typical homeowner's policy (often $100,000 or higher), larger systems and commercial systems tend to require larger policy coverage, and all insurance is required to include a mutual indemnification provision except as prohibited by law.

b. Responses

59. WRA responds that there are tens of thousands of distributed generation systems operating in Public Service territory in Colorado, and Public Service has not provided any in-state examples of a problem requiring insurance. WRA argues the example Public Service gives

is for a very large system in another region, and that the utility provides scant details, concluding that the Company does not provide compelling evidence justifying its exceptions.

60. CEO states that in this Proceeding, it has raised concerns with the Commission's current requirements for liability insurance in multiple proceedings, specifically with regard to Level 1 systems. Prior to the NOPR in the instant proceeding, CEO conducted a 50-state analysis of liability insurance requirements for Level 1 systems and noted that Colorado had one of the strictest requirements nationally. At the time, Colorado was one of five states with the highest liability insurance requirements for systems of less than 10 kW nationally. CEO also provided observations on the practical implications for the state's Weatherization Assistance Program.

61. CEO also argues that no entity has introduced evidence of instances in Colorado or nationally that justify retaining the current liability insurance requirements for Level 1 systems, as opposed to those adopted in the Recommended Decision. Given the substantial discussion in the record, CEO recommends that the Commission reject Public Service's proposal for Rule 3853(o) that modifies the Recommended Decision.

62. COSSA/SEIA point out that neither utility acknowledges that the FERC Small Generation Interconnection Procedures (SGIP) do not require specific amounts of insurance on any sized systems. COSSA/SEIA adds that neither utility provided evidence in the record regarding any damages that have ever been caused by an onsite solar system in Colorado.

c. Findings and Conclusions

63. We deny Public Service's exceptions. The ALJ was correct that the updated insurance requirements are necessary and important to protect interconnection customers, the utilities, utility consumers, and the public interest. The ALJ notes that the adopted rules will also

clarify that interconnection customers shall pay for the required insurance coverage and that the required coverages be for each occurrence.

64. CEO, WRA, and COSSA/SEIA have provided evidence throughout this proceeding on the negative impacts of such stringent insurance requirements on residential customers. The utilities have not provided any relevant data or evidence on the negative impacts of these updated requirements. As many participants pointed out, Colorado's historically high and burdensome insurance requirements have practical implications that harm the development of DERs.

65. We note that COSSA/SEIA point out that neither utility acknowledges that even the FERC SGIP, which is relied upon by the utilities throughout this proceeding, does not require specific amounts of insurance on any sized systems.

7. Rule 3853(p) - Implementation by Tariff

66. Rule 3853(p) will establish requirements for tariff filings from the utilities that set forth certain interconnection fees and deadlines. Tariff filings will accommodate utility-specific costs and procedures, which were particular concerns for the rural cooperatives in Proceeding No. 19R-0096E, while allowing for appropriate statewide standardization in the provisions set forth in the Interconnection Rules. Specifically, the rule proposed that a tariff be required to address fees, timelines, material modifications, maximum rated capacity, and insurance.

67. The ALJ explains that in the past, the Commission has adopted rules setting forth general criteria and requirements to be included in tariffs and requiring that utilities file tariffs in compliance with the rules. For example, the Commission's rules for filing line extension tariffs and gas transportation tariffs followed this process. After the general (and less complex) line extension rules became effective, each electric and natural gas utility was required to file line

extension tariffs to comply with the rules. After the first gas transportation rules became effective, each natural gas utility filed gas transportation tariffs to comply with the rules. Thus, the ALJ stated that adopted Rule 3853(p) is not unusual or unreasonable because it sets forth the general criteria and requirements to be addressed in interconnection tariffs and requires that utilities file tariffs complying with the Interconnection Rules

a. Exceptions

68. CEO recommends that cost-based justification of interconnection fees be required. CEO argues that IOUs are familiar with this approach and cost-based justification should also be required of Co-ops as a result of such a revision. CEO's cost-based justification proposal specifically permits utilities to recover legitimate expenses associated with the interconnection process but does not risk unduly burdening customers with excessive fees. Therefore, CEO requests that the Commission require utility tariff sheets to include justification for the reasonableness of various interconnection fees as cost-based.

69. CEO argues its recommended change would maintain the flexibility for utility-specific costs and procedures, as requested by utilities and utility representatives in this proceeding. CEO believes this cost-based justification would be consistent with the current traditional model of Cost of Service regulation and also supports greater transparency for customers and third-party interconnection resource providers.

70. COSSA/SEIA recommends that the wording in 3853(p) be more general, *i.e.,* not every fee listed. COSSA/SEIA argues that this change is necessary because it is conceivable that not all potential fees can be anticipated.

71. COSSA/SEIA also identified an inconsistency between the consensus rules and Adopted Rule 3853(p)(III)(D), concerning implementation by tariff. This rule appears to allow a

utility to establish "maximum rated capacity" under Rules 3853(a), (b), and (c) within a utility's Interconnection Tariff filing. If codified, COSSA/SEIA believes this could essentially allow utilities to circumvent adherence to Rule 3853(c) and would provide them the ability to calculate maximum rated capacity in a way that departs form the consensus rules.

72. COSSA/SEIA argue that Rule 3853(p)(III)(D), a similar version of which was included in the Notice of Proposed Rulemaking, was inadvertently left in the Adopted Rules and should be removed. Further, Adopted Rule 3853(p)(III)(D)'s reference to Rule 3853(a) is not appropriate. COSSA/SEIA notes that adopted Rule 3853(a) concerns pre-application reports which are available to all sizes of DERs and does not contain any reference to "maximum rated capacity." Most importantly, allowing utilities to propose "maximum rated capacity" by tariff would defeat the purpose of statewide interconnection rules and would fail to fulfill the intent of SB 18-009.

73. CREA asserts that Co-ops should have interconnection deadlines different from those for IOUs; specifically, it proposes deadlines of up to three times longer than those for IOUs. CREA notes that Co-op resources, being less than those of IOUs, make current deadlines infeasible for Co-ops. CREA argues that these short turnarounds would pose significant challenges for cooperative electric associations, which do not have the same level of staffing for interconnection requests as Colorado's larger utilities. As a result, CREA requests that the Commission allow exempt cooperative electric associations to vary from the deadlines in the rules by up to a factor of three.

b. Responses

74. CEO argues that CREA's proposal would exempt cooperative electric associations from Rule 3853(p) entirely with no additional parameters, resulting in substantial variations in

interconnection timelines across utilities. CEO recommends the Commission adopt clear timelines, cost parameters, and requirements across all utilities subject to the Commission's interconnection procedures and standards. In recognition that smaller cooperative electric associations operate under a different environment than the state's largest utility, CEO believes it is reasonable if the Commission chooses to adopt alternative timelines for different-sized utilities. However, CEO believes any flexibility in costs or timelines must be explicitly stated in the Commission's rules through maximum or minimum requirements, ensuring that ICs in different utility jurisdictions would have equity with other customers of similarly-situated utilities.

75. COSSA/SEIA recommend the Commission reject CREA's proposal to allow cooperatives to vary from the deadlines in the Adopted Interconnection Rules because doing so would defeat the core purpose of having statewide interconnection rules and, as discussed above, would violate § 40-9.5-118(2)(d), C.R.S., which requires cooperatives to comply with the Commission's interconnection standards. CREA's proposal to allow cooperatives to include deadlines that are up to three times as long as those contained in the Commission's rules will lead to a patchwork of interconnection processes across the state with potentially different timelines in each cooperative's service territory.

c. Findings and Conclusions

76. We grant CEO's exception on Rule 3853(p)(III)(B) enabling more transparency for the Commission and stakeholders. We agree with CEO that in addition to increased transparency, the cost-based justification proposal specifically permits utilities to recover legitimate expenses associated with the interconnection process but does not risk unduly burdening customers with excessive fees. We also agree that the addition of cost-based

justification of interconnection fees in its interconnection tariffs supports greater transparency for customers and third-party interconnection resource providers.

77. We agree that COSSA/SEIA's additional language provides needed transparency that **all** potential fees (including new fees) must be listed in the tariff. Because these specific rule references ultimately may not encompass every fee that a utility may propose to charge for interconnection services, including but not limited to optional study services, all proposed fees must be included in utility tariffs. COSSA/SEIA note that such a change is consistent with § 40-3-103(1), C.R.S., which requires utilities to have tariffs for "all rates, tolls, rentals, charges, and classifications collected or enforced, or to be collected." Therefore, we grant COSSA/SEIA's exception on Rule 3853(p)(III)(B) clarifying that all potential fees will be listed.

78. We also grant in part COSSA/SEIA's language clarification surrounding 3853(p)(III)(D). We believe the adopted Rules regarding maximum rated capacity are appropriate based on the record in the rulemaking, as well as the consensus rules and deny COSSA/SEIA additional recommended changes. However, we agree with COSSA/SEIA that (III)(D) incorrectly references 3853(a).

79. We deny CREA's exception and are not convinced that these rules need to be adjusted (and in some case waived) for Co-ops. While the Commission acknowledges that Co-ops have a lower level of staffing, for potential interconnection requests, these Co-ops also have fewer IC requests from potential customers. The goals of these adopted rules to increase transparency and allow for a better process for potential customers should apply to all applicable customers, not just customers of the state's regulated utilities. We note that not only does an exception unfairly punish Co-op member owners, it creates a lead to a patchwork of

interconnection processes across the state with potentially different timelines in each cooperative's service territory, causing difficulties for solar developers and DER customers.

8. Rule 3853(q) - Reporting

80. In the Proceeding, CEO recommended that the Commission adopt, as proposed Rule 3853(q), the reporting framework provided in the Interstate Renewable Energy Council's (IREC) Model Interconnection Procedures with several modifications. The ALJ concluded that reporting of this interconnection data two times per year will further increase transparency and will provide beneficial background information to the Commission and Staff when they address interconnection issues. Adopted Rule 3853(q) includes most of CEO's proposed reporting requirements with certain modifications intended to promote fairness. If a utility needs more time to update systems to be able to fulfill the reporting requirements in Rule 3853(q), the ALJ explained that the utility can always file an appropriate pleading showing good cause for an extension of time.

a. Exceptions

81. COSSA/SEIA provides two recommendations for this rule. First, reporting should be required for missed deadlines for all stages of the interconnection process, and that not just summary statistics, *e.g.,* mean, median, be provided. Second, COSSA/SEIA recommend that both customers and the Commission be informed of such reporting semi-annually.

82. Public Service opposes these reporting requirements, arguing that they will be very expensive ($3 million) and difficult to tie with other utility systems, *e.g.,* billing. Public Service states that in order to comply with new reporting requirements and other interconnection rule changes, the Company will have to rebuild its DER application system to create automation and workflows, as well as adding many time-stamped milestones to its system tracking to enable

to process and milestone management and reporting. The upgrades would necessarily interchange data with several systems, including the Company's billing systems and data reporting systems, which require adequate vetting so that process, data, and reporting errors do not occur.

83. Public Service also proposes reporting only summary statistics, *e.g.,* mean, median, rather than more complete statistics as recommended by COSSA/SEIA. Public Service recommends the standard offer be based on rates informed by competitive solicitations. Public Service contends this will balance the incentive with the most recent market price, rather than set an artificial incentive rate.

84. Black Hills states that it already files monthly reports in Proceeding No. 16A-0436E on interconnection matters. These reports contain information on the number of interconnection applications received, number of interconnection applications completed, the average turnaround time to complete the applications, installed capacity, number of Renewable Energy Credits, and total expenditures. Black Hills argues that Rule 3853(q) will require Black Hills to engage in duplicative reporting requirements.

85. Black Hills requests the Commission revise the reporting requirement to require one report per year, not two. They argue Rule 3853(q)'s reporting requirements will take considerable effort and labor to aggregate and report. Black Hills will need to compile the information requested by Rule 3853(q) by hand, as the Company does not have existing software to compile the requested information.

86. CREA takes exception to the interconnection reporting requirement because Co-ops are exempt utilities in Colorado. CREA also contends that Co-op resources are less than

those of IOUs and, therefore, the reporting requirement represents an unnecessary burden to Co-ops. Tracking and reporting systems would be cost-prohibitive for coops.

b. Responses

87. Black Hills opposes COSSA/SEIA's proposal to add more reporting requirements to Rule 3853(q). In particular, Black Hills does not believe that additional benefits would derive from the requirement for the utilities to compile and file in their reports all copies of notices of delays or missed deadlines to interconnection customers. Black Hills believes a utility's communications with its customers should not require filings with the Commission and argues that if an interconnection customer has concerns with notices of delays or missed deadlines, they have options available to them to resolve their concerns, including the dispute process in Rule 3853(h). Black Hills believes the reporting requirements in Rule 3853(q) will already require considerable effort and labor to complete. Adding to these requirements with additional items that have no established need fails to serve the public interest and infringe on the utility's communication channels with its customers.

88. Public Service states that while additional reporting functionality would still be required to be built to enable this yearly reporting, the key metrics they list will enable better tracking for the Company's objective of meeting interconnection timelines as well as establish a foundation for any PIMs that could be incorporated through separate applications made by utilities.

89. WRA believes the reporting requirements proposed by CEO and incorporated into the proposed rules are consistent with those in other states, and should be maintained.

90. CEO replies that in the instant proceeding and in Proceeding No. 19R-0096E, parties have raised concerns regarding compliance with interconnection timelines. CEO notes

that the Commission has also recently encountered proceedings related to interconnection disputes through Proceeding Nos. 20D-0148E and 20D-0262E. CEO is not certain of whether the Commission may encounter similar disputes in the future, however, the current process affords the Commission minimal transparency unless a matter appears as a formal complaint. CEO argues that the Commission and stakeholders do not know if DER interconnections occur in a timely manner or not. Both COSSA/SEIA and CEO have suggested that routine reporting would permit the Commission to understand whether interconnection timeliness and timeline compliance are concerns for one or more utilities in the state.

91. CEO states that it understands that Black Hills reports certain sets of interconnection data already to the Commission on a monthly basis and that Public Service reports interconnection data monthly in its Minnesota service territory. CEO argues the Recommended Decision builds on current requirements from Rule 3667(e)(VII), which specify utility record retention practices for interconnections. While Rule 3853(q) requires utilities to complete new analyses, utilities should already be maintaining the core data for these reporting requirements pursuant to the current rules or their own internal procedures.

92. COSSA/SEIA respond that the only recourse that developers currently have to resolve a delay is to file a complaint at the Commission. COSSA/SEIA argues that most developers can only work with the utility to resolve their issues because they are fearful of retribution if they elevate matters to regulators, particularly when utilities control competitive processes for programs such as community solar that have significant subjective components to their request for proposals scoring criteria. COSSA/SEIA argue that more importantly, complaints are also costly and often take more time than the delay itself and do not result in the award of damages to cover the legal and expert expenses or the cost of the delay. Instead,

COSSA/SEIA explain that developers simply cancel projects or try to relocate them thus driving up costs and leading to deferred or cancelled investment in distributed generation in Colorado. By creating a regular reporting process, COSSA/SEIA believes the Commission can get a better sense of issues that can be addressed through policy changes or through the establishment of PIMs.

93. COSSA/SEIA also argue the Commission should also not be persuaded that upgrades to utility data storage and software systems are a reason to dispose of the Adopted Rule's reporting requirements. They believe there is no evidence in the record of this proceeding that utilities are unable to report on interconnection metrics, using less automated techniques. In addition, as CEO also noted, Public Service has recently completed a very similar system upgrade in Minnesota.

c. Findings and Conclusions

94. We grant in part and deny in part COSSA/SEIA's exceptions. We agree with COSSA/SEIA's addition requiring utilities to report on missed deadlines in order to better understand when and where the utilities may not be meeting the needs of customers trying to install certain DERs. We do not agree with COSSA/SEIA's additional requirements regarding the Level III process.

95. We disagree with Black Hills that the dispute process should be the only mechanism for the Commission to learn about potential delays and missed deadlines throughout the Interconnection Process. As CEO notes in its response, the current process affords the Commission minimal transparency unless a matter appears as a formal complaint. CEO argues that the Commission and stakeholders do not know if DER interconnections occur in a timely manner or not.

96. We deny Public Service and Black Hills' exceptions. We believe the adopted reporting rules are a vital step in dealing with potential issues surrounding interconnections that have been brought to the Commission, as well as the first step in evaluating potential PIMs. We agree with WRA that the reporting requirements proposed by CEO and incorporated into the proposed rules are consistent with those in other states, and should be maintained. As the ALJ noted, if a utility needs more time to update systems to be able to fulfill the reporting requirements in Rule 3853(q), it can always file an appropriate pleading showing good cause for an extension of time.

97. We deny CREA'S exceptions and require Co-ops to file semi-annual reporting. Again, we reiterate that staffing levels of Co-ops should be acknowledged by the Commission, but that does not mean that customers in Co-op territories should have the reduced ability to interconnect DERs, or that the Co-ops should not face increased transparency in their IC processes. The Commission has the capability to reevaluate the impact to Co-ops who are required to meet these reporting guidelines.

9. Rule 3854 – Level 1 Process

98. Provisions governing "Level 1" interconnections are dispersed throughout existing Rule 3667. In the NOPR, these rules were consolidated under proposed Rule 3854. Proposed Rule 3854(a)(IV) replaced the components of the initial Level 1 review with the screens applied in the Level 2 process. This change allows for existing Rules 3667(f)(IV)(A) through (D) to be eliminated. Proposed Rule 3854(b) contains the same outline for a Level 1 interconnection application as found in existing Rule 3667(g) with additional information required for energy storage systems.

a. Exceptions

99. COSSA/SEIA recommends that Level 1 and Level 2 projects be treated identically in the event that screen(s) are failed; that is, they are not automatically relegated to detailed studies, but rather can be salvaged via other mechanisms. COSSA/SEIA argue there is no reasonable basis to limit the utility's discretion in the Level 1 review process if it is not limited in the Level 2 process, therefore the two rules should be parallel. If the utility determines that there will be no harm to safety, reliability, and power quality standards, Level 1 interconnections should also be allowed to move forward.

100. COSSA/SEIA also recommends the Commission substitute the term "export capacity" for "output limits setting" in Rule 3854(b)(III)(G). The reason for this substitution is that the term export capacity is a defined term under Rule 3852(e), whereas "output limits setting" is not defined. For purposes of clarity and consistency, the Commission should use the defined term.

101. CEO and COSSA/SEIA both note that there are several instances where "10 kW" AC remains, although the new Level 1 criterion is "25 kW" AC.

102. Public Service takes exception to power quality screens being excluded and are concerned that the increase in solar + storage projects may cause power quality issues, such as flicker and voltage fluctuations. Public Service recommends not excluding power quality screens and instead allow the industry to develop appropriate testing. Public Service recommends mitigating inadvertent exports, where non-exporting systems send energy back to the grid due to unanticipated mismatches between customer load and battery discharging, creating power quality disturbances or operational concerns for line workers during emergencies that cause local or larger area outages.

b. Findings and Conclusions

103. We grant COSSA/SEIA's clarification to (a)(IV), and (b)(III)(G) as well as changing all references from "10 kW" to 25 kW AC. We agree that there is no reasonable basis to limit the utility's discretion in the Level 1 review process if it is not limited in the Level 2 process, therefore the two rules should be parallel. The original NOPR, as well as the ALJ's recommended rules attempted to remove these types of inefficiencies in the rules. The utility still has the ability to determine that there will be no harm to safety, reliability, and power quality standards, therefore, the Level 1 interconnections should also be allowed to move forward.

104. We deny Public Services' exception on (a)(IV). We are concerned that Public Service's request allowing the industry to develop appropriate testing does not provide any timelines or accountability mechanisms. While we understand solar + storage is a newer technology that utilities and developers continue to gain experience with, we note that throughout this proceeding participants have provided evidence that utilities are being overly cautious when it comes to solar + storage and have been unable to cite actual issues faced by other utilities who have taken a more proactive approach with the adoption of solar + storage on their systems. We agree that following IEEE 1547-2018 and its requirement for advanced inverters should be the focus of the utilities, rather than allowing the utilities their own timeline for implementation.

10. <u>Rule 3855 – Level 2 Process</u>

105. This rule adds a provision that requires the Level 2 "supplemental review" for highly seasonal circuits. Adopted Rule 3855(b)(V) has been updated to reference the most current IEEE standards.

a. Exceptions

106. COSSA/SEIA state that in (b)(II), the so-called 15 percent screen, *i.e.,* 15 percent of maximal load, is recommended to be replaced by the minimum daytime (or daily) load screen as in other states. In addition, COSSA/SEIA recommends that maximal transformer capacity, not the arbitrary 20 kW criterion, be used for aggregate generation capacity as is the case in other states.

107. COSSA/SEIA also recommend that (b)(XII) be eliminated to ensure consistency with IEEE 1547-2018 and its effective requirement for advanced inverters, which will make advanced inverter solutions possible.

108. Public Service states that the plain language of Rule 3855(a)(V) appears to allow both initial and supplemental review screens, however, Rule 3855(d) only references the supplemental review process. In order to better clarify the inclusion of both the initial and supplemental screens, the Company recommends a minor modification.

b. Responses

109. Public Service disagrees with COSSA/SEIA and recommends that the Commission maintain the language in adopted Rule 3855(b)(II). Public Service notes that the initial screen in Rule 3855(b)(II) reviews the aggregate levels of DER on a distribution circuit where the 15 percent aggregate criteria can be exceeded by a combination of large and small DER, only large DER, or only small DER. As an initial screen, it is intended to be simplistic utilizing a much less refined approach and information.

110. Public Service also disagrees with COSSA/SEIA that Rule 3855(b)(VII) should be amended to permit a maximum aggregate generation capacity of 100 percent on a shared secondary line or transformer capacity ratings rather than a specific capacity such as 20 kW or

another specific numerical capacity level. The Company argues the shared secondary has both capacity and voltage considerations, with a voltage dependency based on the customer distance from the transformer, DER size, and impacts of other DER on the shared facilities. An aggregate limit of up to 20 kW provides for a reasonable screening limit based on secondary designs and consideration of extensive legacy secondary systems. The Company emphasizes that 20 kW is not a hard limit; it is simply an initial screen prior to moving to supplemental screening if necessary.

111. WRA generally agrees that any changes to the screening of applications should be detailed in tariffs or interconnection manuals, which must be approved by the Commission. It recommends that the Commission adopt COSSA and SEIA's proposed modifications in (a)(V).

112. In contrast, WRA disagrees with COSSA and SEIA's proposal in their part (b), which suggests changing the 15 percent screening threshold to the minimum load criteria that is used in supplemental screens. The 15 percent of maximum load screen is still in wide use, with 100 percent of minimum daytime load used as the supplemental screen. WRA argues that maintaining this screen is especially important for smaller utilities, like Black Hills, that may not have minimum load data for all feeders. WRA believes that NREL has not modified their recommendation to go beyond the 15 percent threshold for initial screens.

113. WRA notes that part (c) of COSSA/SEIA's exceptions addresses secondary transformer capacity and includes a recommendation that interconnection of up to 100 percent of capacity be allowed. WRA advocated that the interconnection rules take a percentage of the transformer capacity approach. Under this approach, WRA states it picked 75 percent as a reasonable number, giving some "headroom" for older transformers that may not have the thermal capacity of newer units. While 100 percent of transformer capacity would no doubt be

safe in most situations, WRA asks why the Commission should risk potential problems. WRA also notes that there is little data on high voltage and flicker problems that may be associated with too much distributed generation on a shared secondary transformer capacity. WRA continues to advocate for 75 percent of transformer capacity to be adopted in the rules.

114. WRA also notes that part (d) of COSSA/SEIA's exceptions suggests eliminating a safety provision that WRA feels is prudent. WRA states that customers should not install generation systems that exceed the capacity of their service and while some systems may be able to limit overall export that is less than the capacity of their electrical service, some will not, and the ones that can limit capacity may not be set correctly to do so. WRA states it is concerned that systems which exceed service limits may trip customer circuit breakers, causing customer complaints that the utility will eventually need to address, even though it would not be the utility's problem. WRA recommends that the limiting screen be retained.

115. COSSA/SEIA urges the Commission to reject Adopted Rule 3855(a)(V), which follows Public Service's proposed additions, in that it would allow utilities to deviate from the Level 2 screens. COSSA/SEIA adds that if the Commission nevertheless decides to let this grant of discretion to utilities persist, COSSA/SEIA recommends it should at least require that any proposed deviations of methodologies to perform screens is properly vetted in an interconnection advice letter filing, as noted in COSSA/SEIA's Exceptions.

116. COSSA/SEIA also believe that to the extent the Commission makes any changes to Adopted Rule 3855, it should adopt the proposed modernizations to technical screens found at Adopted Rules 3855(b)(II) and (VII) proposed by COSSA/SEIA and adopted in other jurisdictions with aggressive clean energy goals.

c. Findings and Conclusions

117. We grant Public Service's minor modification to the reference of 3855(d). We agree with Public Service that the plain language of Rule 3855(a)(V) appears to allow both initial and supplemental review screens, however, Rule 3855(d) only references the supplemental review process. Public Service's recommended edit clarifies the inclusion of both the initial and supplemental screens.

118. We grant in part and deny in part COSSA/SEIA's requested changes. We agree with COSSA/SEIA and WRA that any changes to the screening of applications should be detailed in tariffs or interconnection manuals, which must be approved by the Commission. Therefore, we recommend that the Commission adopt COSSA/SEIA's proposed modifications in (a)(V).

119. We believe the ALJ was correct in focusing on safety and reliability and concluded that CSSA/SEIA did not provide enough evidence to show that their proposed rules would not impact the safety and reliability. Both utilities and WRA argued in favor of the 15 percent of maximum load screen, arguing it is still in wide use, with 100 percent of minimum daytime load used as the supplemental screen. WRA argues that maintaining this screen is especially important for smaller utilities, like Black Hills, that may not have minimum load data for all feeders.

120. We believe that COSSA/SEIA did not demonstrate how the elimination of (b)(XII) ensures consistency with IEEE 1547-2018 and its effective requirement for advanced inverters.

121. We also agree with WRA and the utilities that while some systems may be able to limit overall export that is less than the capacity of their electrical service, some will not, and the

ones that can limit capacity may not be set correctly to do so. WRA states it is concerned that systems which exceed service limits may trip customer circuit breakers, causing customer complaints that the utility will eventually need to address, even though it would not be the utility's problem.

122. Therefore, we recommend denying COSSA/SEIA's recommended changes to (b)(II), (b)(VII), and (b)(VIII).

11. <u>Rule 3856 - Level 3 Process</u>

123. This rule tracks existing Rule 3667(d) with certain changes discussed in the NOPR. The introduction to the rule is based on existing Rule 3667(d)(I), and proposes to increase the maximum size for the interconnection resource eligible for the Level 3 process from 10 MW to 20 MW. Adopted Rule 3856(a)(IV) adds a provision to existing Rule 3667(d)(II)(D), setting a deadline for the utility to provide an executable interconnection agreement if the utility and the customer were to reach a mutual agreement on the lack of need for studies related to "simpler projects." Adopted Rule 3855(b)(I) adds a provision that requires the Level 2 "supplemental review" for highly seasonal circuits. Adopted Rule 3855(b)(V) has been updated to reference the most current IEEE standards.

a. Exceptions

124. COSSA/SEIA's recommendation concerns timelines regarding the Level 3 Study Process. They believe the Adopted Rules adequately recognize the need for deadlines in Level 3 studies, but fail to include any specific deadline for a feasibility study. COSSA and SEIA recommend 15 business days (approximately three weeks) as a reasonable timeframe for completion of the initial feasibility study.

125. Public Service takes exception with Rule 3856(a)(II) which now allows the decision to move forward with a Level 3 feasibility study solely on the interconnection customer. This rule historically required that the decision to move forward was mutually agreed upon by both the utility and the interconnection customer, and the Company notes that the FERC SGIP indicates that both parties must agree to proceed to waive a feasibility study.

126. Black Hills points out Rules 3856(a)(II) and (III) deviates from FERC's SGIP. Common to both these rules are a deviation from FERC's SGIP that Black Hills opposes. Specifically, these rules vest the interconnection customer with the sole decision-making authority of whether it is appropriate to move forward with a feasibility study. Similar to other parties, it recommends a mutual, *i.e.,* interconnection customer - utility, decision on moving to either a feasibility study or a system impacts study during a scoping meeting(s).

b. Responses

127. Black Hills argues that should the Commission establish a new deadline for the completion of feasibility studies, they recommend the Commission adopt rules consistent with the FERC guidance. A minimum deadline for the completion of feasibility studies (if any) should be set at 45 business days. A shorter time period than 45 business days would be unreasonable and would establish unworkable processes for utilities, exacerbating potential disagreements with interconnection customers.

128. WRA supports the rule as written that interconnectors be allowed to participate, under the facilities study agreement, in the design and construction of some interconnection facilities.

129. CEO recommends the Commission deny Black Hills' and Public Service's proposed modifications and retain the rule as adopted by the Recommended Decision. CEO

argues that requiring mutual agreement permits the utility to functionally be the sole decision maker. For example, if a utility opposes proceeding with a study that a customer wishes to pursue, there will not be mutual agreement. Contrary to Black Hills' assertion, CEO does not believe that the alternative would occur, where a utility would advocate for a customer to pursue a study that the customer is uninterested in. CEO believes the rule adopted by the Recommended Decision permits an IC to undergo Level 3 studies at a cost that the IC is responsible for paying.

130. COSSA/SEIA state that the Commission should reject these exceptions and affirm the Recommended Decision's finding that "utilities should not be allowed to refuse to study the costs of upgrades to facilitate interconnection, so long as the interconnection customer is willing to pay for the necessary studies."[4] COSSA/SEIA argue interconnection procedures are intended to ensure that utilities can only use legitimate safety and reliability concerns to delay established timelines or increase interconnection costs and they are not intended to allow utilities to block construction of projects or even to outright deny an interconnection request if an IC is willing to pay its own way.

c. Findings and Conclusions

131. We disagree that 15 days is an appropriate turnaround for the initial feasibility study, and therefore deny COSSA/SEIA's exception

132. We deny Public Service's and Black Hills' exceptions. We believe the ALJ properly balanced the need for timeliness and cooperation. The ALJ specified that utilities should not be allowed to refuse to study the costs of upgrades to facilitate interconnection, so long as the interconnection customer is willing to pay for the necessary studies. WRA, CEO, and COSSA/SEIA have argued throughout this proceeding that interconnection procedures are

[4] Recommended Decision at ¶ 51.

intended to ensure that utilities can only use legitimate safety and reliability concerns to delay established timelines or increase interconnection costs. They are not intended to allow utilities to block construction of projects or even to outright deny an interconnection request if an IC is willing to pay its own way. While the Company notes that the FERC SGIP indicates that both parties must agree to proceed to waive a feasibility study, we are concerned that this is a mechanism for utilities to simply block a potential interconnection of DERs.

12. Rule 3856(a)(V) – Level 3 Combined Study

133. The Recommended Decision adopted COSSA/SEIA's proposal to permit a single Level 3 study to be combined to include feasibility studies, scoping studies, and facilities studies.

a. Exceptions

134. Public Service recommends against combining feasibility, system impact, and facility studies into an aggregate 60-day timeframe. Public Service notes that results from the system impact study often determine whether the facility study is conducted, *i.e.,* if the former shows several impacts, the interconnection customer may not proceed with the latter. Public Service therefore argues for flexibility.

135. Black Hills also contends that there should be mutual agreement to move forward with a facility study, which would be consistent with FERC's SGIP. In addition to pointing out that lack of a requirement for mutual agreement to move forward deviates from the SGIP, Black Hills contends that a 60-day deadline is infeasible for it to meet. It recommends a 90-day deadline.

b. Findings and Conclusions

136. We grant these exceptions by Public Service and Black Hills. We note that FERC's SGIP does not include timelines in its main section, SGIP includes model agreements

for each of the Level 3 studies and each of these model agreements explicitly contain required timelines for a utility to complete each study. We are concerned that the aggregate 60-day timeframe for combined studies is too restrictive for the utilities and therefore require a 90-day timeline.

13. Rule 3856(c) – System Impact Study

137. This rule includes the requirement that, within 30 business days of executing a system impact study agreement, the utility shall perform a system impact study using the screens set forth in Rule 3856(c). Otherwise, the ALJ has adopted Rule 3856(c) as proposed in the NOPR with minor revisions for clarity. The ALJ states that ensuring certainty for both interconnection customers and the utilities is important in the Level 3 feasibility study process, and establishing reasonable timeframes will assist to accomplish this objective.

a. Exceptions

138. Black Hills expresses concerns with the deadline for completing a system impact study and the application of screens in this process, as required by Rule 3856(c)(I). This rule provides that the utility has 30 business days to perform a system impact study, and that this study should "apply screens set forth below." Black Hills submits that the Commission should change the 30-business day deadline to that of one of 90 business days.

b. Responses

139. COSSA/SEIA argue the Commission should deny Black Hills' Exceptions to triple the timeline for a system impacts Study from Adopted Rule 3856(c)(I)'s 30-day deadline to 90 days. Black Hills ignores the fact that a 30-day timeline for a system impact study is entirely consistent with SGIP. The SGIP "feasibility study must be completed and the feasibility study report transmitted within 30 Business Days of the Interconnection Customer's agreement to

conduct a feasibility study." COSSA/SEIA notes that Black Hills also proposes a 90-day timeline for a combined study. COSSA/SEIA points out that this proposal is internally inconsistent in that it would provide the utility 90 days whether it is performing only a system impact study, or whether it combines all three studies. It should not take a utility the same amount of time to complete one study as it would to complete all three.

c. Findings and Conclusions

140. We deny the exceptions of Black Hills, as we believe the ALJ was correct in utilizing the recommended timeframes from FERC's SGIP for Level III System Impact Studies.

14. <u>Rule 3856(d)(III): Cost Caps in Facilities Studies</u>

141. In this proceeding, CEO recommended that Rule 3856(d) establish a time limit for a facilities study to be completed and proposed that the facilities study be completed within 45 business days of the interconnection customer's delivery of the executed facilities study agreement. According to CEO, this is consistent with the IREC Model Interconnection Procedures and industry best practices.

142. CEO also argued that Rule 3856(d)(III) should set a parameter around the accuracy of a utility when estimating the cost of equipment, engineering, procurement, and construction work (including overhead) needed to implement the conclusions of the system impact studies. CEO recommended that Rule 3856(d)(III) be modified to implement binding cost envelopes or to require careful tracking of costs that exceed a specified margin.

143. Adopted Rule 3856(d)(III) sets forth the items to be included in the facilities study and includes CEO's recommendation that costs for completing actual upgrades may not be exceeded by 125 percent of the cost estimate, which should afford utilities with greater

flexibility. Otherwise, the ALJ adopted Rule 3856(d) as proposed in the NOPR with minor revisions for clarity.

a. Exceptions

144. Public Service opposes the imposition of a cost envelope, *i.e.,* 25 percent below or above the utility's initial estimate, arguing that delays due to field inspections and additional estimation time will result. Public Service notes that in order to guarantee that the Company's costs would remain within the cap, a substantial increase in field inspections and other additional estimation outside of the Company's normal process would be needed in order to warrant that the cap would not be exceeded. Public Service argues this in turn would cause delays in the interconnection process. Additionally, similar to construction projects outside the interconnection process, Public Service emphasizes that these costs currently are not subject to true up and adding this process would cause accounting issues and likely lead to an increase in sunk costs for the Company and its customers.

145. Similar to Public Service, Black Hills takes exception to a cost envelope. It provides three reasons why this envelope is inappropriate, including: 1) no consequence for not meeting the requirement is provided; 2) it is inappropriate in circumstances beyond the utility's control; and 3) it may create perverse incentives, *e.g.,* inadequate maintenance of the grid.

b. Responses

146. CEO believes that Public Service's and Black Hills' Exceptions raise reasonable concerns and may even result in utilities inflating costs to avoid exceeding estimates, which could be an unintended barrier to DER adoption. Therefore, CEO recommends the Commission adopt Public Service's Exceptions with a modification. CEO recommends that the Commission add language requiring utilities to indicate which itemized cost estimates are uncertain and could

be exceeded by 125 percent if actual upgrades are undertaken. This proposal will remove the binding nature of the estimate but also provide ICs with an understanding of the variability of specific costs.

147. COSSA/SEIA support Public Service's reporting requirement as a necessary first step to identifying issues.

c. Findings and Conclusions

148. We grant in part Public Service's and Black Hills' exceptions, using CEO's recommended language. We agree with CEO that the utilities' exceptions raise reasonable concerns and may even result in utilities inflating costs to avoid exceeding estimates, which could be an unintended barrier to DER adoption. CEO's modified language requires utilities to indicate which itemized cost estimates are uncertain and could be exceeded by 125 percent if actual upgrades are undertaken. We agree that this proposal will remove the binding nature of the estimate but also provide ICs with an understanding of the variability of specific costs and results in a suitable compromise.

15. Rule 3856(d)(IV): Non-Utility Builds Rule

149. In this proceeding, CEO recommended that Rule 3856(d) establish a time limit for a facilities study to be completed and proposed that the facilities study be completed within 45 business days of the interconnection customer's delivery of the executed facilities study agreement. According to CEO, this is consistent with the IREC Model Interconnection Procedures and industry best practices. The adopted rule adopts CEO's recommendation.

a. Exceptions

150. Public Service recommends that customer design and upgrading of interconnection facilities not be allowed. Public Service argues that this practice will lead to

inefficiencies. For example, it will have to perform additional oversight to ensure compliance with Public Service's standard practices, and potential safety consequences may also result.

151. Public Service emphasizes that it is not safe, practical, or economical to arrange for the additional oversight now needed for this rule modification, which now includes a review to ensure consistency with approved materials, reviewing construction to ensure it meets utility standards, costs to replicate design in GIS, and costs for utility resources needed to support non-utility construction. This dynamic is particularly true for the relatively small scope of these projects.

152. Black Hills also objects to customer design and upgrading of interconnection facilities. It points out that certain words/phrases are vague, *e.g.,* "some facilities", and asserts that such an arrangement could compromise grid reliability/safety. Black Hills argues the rule does not provide any guidance. Without guidance, the rule will lead to unnecessary disputes of what "some" means between the utilities and interconnection customers. The future disputes are easily avoided by the Commission either being specific as to what types of interconnection facilities are available for this process or deletion of this new interconnection customer option.

153. Similar to Public Service's and Black Hills' positions, CREA takes exception to the option of a customer designing and upgrading an interconnection facility. Safety considerations are also raised by CREA, and it recommends deletion of this option from the rule.

154. CREA argues Rule 3856(d)(IV) would allow an interconnection customer to choose to "separately arrange" for the design and upgrade of utility interconnection facilities. CREA requests that the Commission reject this language because it believes that utilities must maintain exclusive control over the design of their own facilities. Utilities—not interconnection customers—are ultimately responsible for the safety and reliability of their systems. Allowing

interconnection customers to take significant control over the design and upgrade process for interconnection facilities potentially would compromise these important responsibilities and should be rejected.

b. Responses

155. Public Service reiterates that providing the interconnection customer with the level of control of design and construction that is now memorialized within the rule would jeopardize the safety and reliability of the distribution system. The Company again emphasizes that the rule does not require that the interconnection customer or its contractor follow the utility's standard work practices or its vendor risk assessment processes, nor is it safe, practical, or economical for the utility to arrange for the additional oversight now needed for this rule modification.

c. Findings and Conclusions

156. We grant the utilities' exceptions and delete the proposed language in (d)(IV). As no participants responded to this proposed deletion, we see no reason to deny the exceptions requested by both utilities and the organization representing cooperatives.

16. Rule 3859: Filing of Interconnection Manual

157. Rule 3859 requires that within 90 days after the effective date of the Interconnection Rules, each utility subject to these rules shall file with the Commission, information about its Interconnection Manual in an advice letter and tariff filing pursuant to Rule 1210 of the Rules of Practice and Procedure, 4 CCR 723-1. This information should include an electronic link to the utility's filing, along with the date on which it was last updated. Rule 3859 also requires each utility to update the filed information about its Interconnection Manual within 30 days after changes have been made to its manual. Requiring utilities to file

their Interconnection Manuals and updates to their manuals is intended to ensure increased transparency for developers, interconnection customers, and the Commission and its Staff and should thereby provide benefits to the interconnection process in Colorado.

158. The ALJ states that the Interconnection Manual and update filings required by Rule 3859 are only informational filings. Rule 3859 does not require that the Commission approve the filed Interconnection Manuals and updates to Interconnection Manuals.

a. Exceptions

159. COSSA/SEIA recommend that a utility's Interconnection Manual be redlined during revision to ensure transparency for developers.

160. Public Service's exception covers language within both Rule 3850 and Rule 3859 that require a utility to file an Advice Letter and Tariff or application for Commission approval of interconnection standards, technical guidance, and interconnection manuals. Public Service points out that it has traditionally posted this information onto its website where it is readily available to the industry and stakeholders and is therefore subject to their input. In addition to being inefficient, it argues that such a process exposes Public Service to a litigation risk.

161. Public Service proposes an alternative where utilities would be required to file with the Commission a notice in the event of a material change to its manuals or standards, as well as establish an internal process for acquiring timely feedback from stakeholders on the material changes incorporated within the notice. This reasonable alternative would serve to increase transparency while affording utilities the flexibility to adequately maintain its distribution system without causing regulatory lag and inefficiencies.

162. Black Hills also takes exception to this rule, contending that an Advice Letter and Tariff are litigation-prone, and that it would be challenging to transfer contents of an

Interconnection Manual into a tariff sheet. Black Hills alternatively recommends using a Miscellaneous Proceeding, which would promote transparency. Black Hills adds that filings should be made when material changes to an Interconnection Manual are made; otherwise, annual filings should suffice.

163. Black Hills further argues that tariff sheets are not appropriate to address the information filing of lengthy interconnection manuals. The appropriate process to accomplish the Recommended Decision's informational filing intent is to require the filing of the interconnection manual in a miscellaneous proceeding. Black Hills believes the filing of the manual in such a proceeding will accomplish the transparency needs articulated in the Recommended Decision, and it will avoid the cumbersome and litigation prone advice letter with tariff sheet requirements currently adopted in Rule 3859.

164. Black Hills argues the Commission should also revise Rule 3859 to change the frequency of filing of the interconnection manual to either an annual update or, alternatively, when material revisions are undertaken. Black Hills notes that Rule 3859 currently requires the filing of the interconnection manual based on "any change." The term "any change" would appear to cover non-substantive and non-material changes to the interconnection manual.

165. CREA similarly takes exception to the requirement for filing Advice Letters to the Commission for Interconnection Manual changes. CREA asserts that, as exempt utilities, electric cooperatives should not be subject to this requirement. CREA also asserts that its customer-owners have access to Interconnection Manuals.

b. Responses

166. Public Service reiterates that if utilities are now required to file an Advice Letter and Tariff for Commission approval within 30 days after any change has been made to its

manual, frequent litigation may be the result demonstrating regulatory inefficiencies in implementing any critical updates that may impact the safety and reliability of the Company's distribution system. The Company believes that its proposed informational notice process provides both stakeholder inclusion and transparency.

167. Public Service agrees with Black Hills that the redlined rules are inconsistent with the intent of the Recommended Decision that the interconnection manual filings be informational. In its Exceptions, Black Hills points out that Rule 3859 will not accomplish this intent through "voluminous" Advice Letter filings.

168. Public Service reminds the Commission of its reasonable alternative proposal within its Exceptions where utilities would be required to file with the Commission an informational Notice in the event of a material change to its manuals or standards, as well as establish a process which will be vetted during stakeholder meetings for acquiring timely feedback on the material changes incorporated within the Notice. This reasonable alternative is consistent with the informational intent of the Recommended Decision, provides the transparency that the Commission and the industry is seeking, while affording utilities the flexibility to maintain its distribution system without causing inefficiencies.

169. WRA responds that this requirement is consistent with rules adopted in Arizona that went through five years of discussion and multiple revisions. WRA believes the requirement is necessary due to many technical details that the utilities will need to put in their interconnection standards and manuals that may be disputed by other parties. WRA provides an example regarding the requirement for certain initial settings on advanced (smart) inverters that comply with IEEE 1547-2018. This IEEE standard has options for how the inverters act and react to various situations on the grid. Some of the settings will reduce the output from

distributed solar generating units as one way to mediate voltage and other power quality issues on the grid. The requirements that Colorado utilities make for these settings should be discussed and decided among interested parties, and then approved by the Commission.

170. WRA does not believe that requiring Commission approval for interconnection manuals is a process that will cause any risk to the grid, adding that this requirement will improve safety and reliability on the grid, and also include additional voices in how standards are best set.

171. CEO believes COSSA/SEIA's recommendation to be practical, consistent with the intent of the Recommended Decision, and aligned with CEO's interest in increasing transparency. Therefore, CEO recommends that the Commission adopt COSSA/SEIA's Exception.

172. COSSA/SEIA argue that the utilities fail to acknowledge that Rule 3859 is entirely consistent with state law, which requires any utility specific rules or regulations to be contained in an approved tariff and that such a practice would align with current utility practices for non-interconnection related rules, regulations, and other policies. COSSA/SEIA further argues that allowing utilities to exercise unilateral discretion in the setting of interconnection rules and policies through their own interconnection manuals would circumvent the Commission's clear and explicit duty to regulate utility interconnection procedures and would defeat the very purpose of interconnection rules — to ensure proper oversight of utility interconnection practices. COSSA/SEIA believes it would also inject uncertainty, which translates to higher costs, on the part of interconnection customers who could be subject to different rules, and potentially ever-changing rules and restrictions created by utilities.

173. COSSA/SEIA state that Adopted Rule 3853(p)(I) will now require that utilities "have on file with the Commission an interconnection tariff that sets forth certain fees, deadlines, and interconnection procedures."[5] In other words, all interconnection costs must now be filed in a tariff, and thus according to § 40-3-103(1), C.R.S., and Commission Rules relating to tariffs generally, all utility specific "rules, regulations, forms of contracts, terms, conditions, and service offerings" must also be included in tariffs. Adopted Rule 3853(p)(II) notes that "tariffs filed by cooperative electric associations shall be informational only. Tariffs filed by investor-owned electric utilities may be set for hearing and suspended in accordance with the Commission's Rules of Practice and Procedure and applicable statutes."

174. COSSA/SEIA argue that this is the very practice employed by the utilities for almost all other policies and procedures for utility programs and services, other than interconnection. COSSA/SEIA also recommend the Commission clarify that filing interconnection manuals via interconnection tariff filings will not be "for informational purposes only" in the case of a regulated utility. COSSA/SEIA agrees with Black Hills that the Recommend Decision is confusing on this point because Rule 3859 requires that interconnection manuals be filed "in an advice letter and tariff filing pursuant to rule 3108." According to Colorado Law and Commission Rules, "[a]ny person affected by a tariff change … may submit a written protest to the proposed change" pursuant to Rule 1210(a)(VII) and the Commission may suspend and set for hearing any tariff of a regulated utility under Rule 1210(a)(VIII). The filing of interconnection manuals should be no different.

175. COSSA/SEIA recommend the Commission should also continue to require cooperatives to file interconnection tariffs as part of their informational only Interconnection

[5] COSSA/SEIA Responses to Exceptions at p. 9.

Tariffs, required under Adopted Rule 3853(p)(II). COSSA/SEIA argue this will allow the Commission to review cooperative-specific interconnection policies and to identify any deviations from the statewide interconnection rules. COSSA/SEIA add that requiring cooperatives to file interconnection manuals is consistent with § 40-9.5-118(2)(d), C.R.S., which requires cooperatives to comply with the Commission's interconnection standards.

c. Findings and Conclusions

176. We grant in part Public Service's and Black Hills' requests for clarification of how the IC manuals should be filed with the Commission and modify the language on the Commission's own motion. We believe a compromise is acceptable that allows for added transparency regarding changes to Interconnection Manuals. We agree with the utilities that Advice Letters and Tariffs are litigation-prone, and that it would be challenging to transfer contents of an Interconnection Manual into a tariff sheet. The utilities also point out that frequent litigation may be the result demonstrating regulatory inefficiencies in implementing any critical updates that may impact the safety and reliability of the Company's distribution system.

177. We note that Public Service provides a reasonable alternative proposal within its Exceptions where utilities would be required to file with the Commission an informational Notice in the event of a material change to its manuals or standards, as well as establish a process which will be vetted during stakeholder meetings for acquiring timely feedback on the material changes incorporated within the Notice. We believe records of the feedback could be collected periodically by Staff through an audit which would be a helpful step in making sure the terms of the IC Manual remain fair and reasonable.

178. We also modify the language in 3859 on the Commission's own motion that enables the Commission to ensure the terms and conditions contained in the Interconnection Manual are just, reasonable, and not unduly discriminatory.

179. We grant COSSA's exception requiring redline changes to the Interconnection Manual. We agree with COSSA/SEIA that any changes to a utility's Interconnection Manual must be redlined during revision to ensure transparency for developers and the Commission.

180. We grant in part CREA's request for exemption. We agree with CREA that Co-ops are exempt from filing its Interconnection Manual in a miscellaneous proceeding, however, we do require each utility, including cooperative electric associations, to provide on its website, interconnection standards or other technical guidance not included in, but that are consistent with, these procedures.

17. Miscellaneous Edits and Clarifications

181. Many of the Participants' Exceptions suggested various grammatical changes and non-substantive edits to improve readability or accuracy of the Interconnection Rules. The Commission appreciates these suggestions, and the Interconnection Rules that we adopt today reflect nearly all of those changes and edits.

II. ORDER

A. The Commission Orders That:

1. The exceptions to Recommended Decision No. R20-0773, filed by Public Service Company of Colorado on November 25, 2020, are granted in part, and denied in part, consistent with the discussion above.

2. The exceptions to Recommended Decision No. R20-0773, filed by Black Hills on November 25, 2020, are granted in part, and denied in part, consistent with the discussion above.

3. The exceptions to Recommended Decision No. R20-00773, filed by the Colorado Energy Office on November 25, 2020, are denied, consistent with the discussion above.

4. The exceptions to Recommended Decision No. R20-0773, filed by Colorado Rural Electric Association on November 25, 2020, are granted in part, and denied in part, consistent with the discussion above.

5. The exceptions to Recommended Decision No. R20-0773, filed by the Colorado Solar and Storage Association and the Solar Energy Industries Association on November 25, 2020, are granted in part, and denied in part, consistent with the discussion above.

6. The Rules Implementing the Interconnection Procedures within the Commission's Rules Regulating Electric Utilities, 4 *Code of Colorado Regulations* 723-3, contained in legislative (*i.e.*, strikeout/underline) format (Attachment A), and final format (Attachment B) are adopted, and are available through the Commission's Electronic Filings system at:

https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=19R-0654E

7. Subject to a filing of an application for rehearing, reargument, or reconsideration, the opinion of the Attorney General of the State of Colorado shall be obtained regarding constitutionality and legality of the rules as finally adopted. A copy of the final, adopted rules shall be filed with the Office of the Secretary of State. The rules shall be effective 20 days after publication in *The Colorado Register* by the Office of the Secretary of State.

8. The 20-day time period provided by § 40-6-114, C.R.S., to file an application for rehearing, reargument, or reconsideration shall begin on the first day after the effective date of this Decision.

9. This Decision is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING February 24, 2021.

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

JOHN GAVAN

MEGAN M. GILMAN

Commissioners

ATTEST: A TRUE COPY

Doug Dean

Doug Dean,
Director