Decision No. C20-0207-I

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 19R-0096E

IN THE MATTER OF THE PROPOSED AMENDMENTS TO RULES REGULATING ELECTRIC UTILITIES, 4 CODE OF COLORADO REGULATIONS 723-3, RELATING TO ELECTRIC RESOURCE PLANNING, THE RENEWABLE ENERGY STANDARD, NET METERING, COMMUNITY SOLAR GARDENS, QUALIFYING FACILITIES, AND INTERCONNECTION PROCEDURES AND STANDARDS.

INTERIM DECISION SCHEDULING HEARING, PROPOSING ADDITIONAL RULE REVISIONS, AND SOLICITING FURTHER COMMENTS

Mailed Date: April 2, 2020
Adopted Date: February 27, 2020

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I. BY THE COMMISSION

A. Statement

1. On February 27, 2019, the Colorado Public Utilities Commission (Commission) issued a Notice of Proposed Rulemaking (NOPR) to amend the Commission's Rules Regulating Electric Utilities, 4 *Code of Colorado Regulations* (CCR) 723-3 (Electric Rules).[1] The proposed amendments revise the Electric Rules in six areas: (1) the rules governing Electric Resource Planning (ERP Rules) at 4 CCR 723-3-3600, *et seq.*; (2) the Renewable Energy Standard Rules (RES Rules) at 4 CCR 723-3-3650, *et seq.*; (3) the Net Metering Rules presently in 4 CCR 723-3-3664; (4) the rules governing Community Solar Gardens (CSG Rules) presently in 4 CCR 723-3-3665; (5) the provisions for utility purchases from Qualifying Facilities (QF Rules) presently at 4 CCR 723-3-3900, *et seq.*; and (6) the Interconnections Standards and Procedures presently in 4 CCR 723-3-3667. The NOPR solicited comment, in addition to scheduling a public comment hearing, which was held April 29, through May 3, 2019.

2. After subsequent written comments and in response to legislative changes enacted by the 2019 General Assembly, through Decision No. C19-0822-I, issued October 7, 2019 (October 2019 Decision), the Commission proposed further rule revisions and scheduled a public comment hearing on October 29, 2019. In addition, the Commission later severed both the CSG Rules and Interconnection Standards and Procedures from this Proceeding.[2]

[1] *See* Decision No. C19-0197.

[2] As indicated in Decision No. C19-0822-I, the Commission opened rulemaking proceedings through subsequent Decisions No. C19-0900, issued November 5, 2019, Proceeding No. 19R-0608E (Community Solar Garden Rules), and Decision No. C19-0951, issued November 25, 2019, Proceeding No. 19R-0654E (Interconnection Standards and Procedures).

3. Through this Decision, we solicit further written comments from interested participants and schedule an additional day of public comment hearing on April 23, 2020.[3] As discussed below, in response to stakeholder comments and changes in legislation, we propose further revision to the ERP Rules and QF Rules. Considering comments and public discussion following the October 2019 Decision, we include in the attached proposed rules additional revisions as well to proposed Electric Rules pertaining to the cost of carbon dioxide emissions and workforce transition plans. Procedures for the April 23, 2020 hearing will be established by a separate decision.

4. The proposed rules in legislative (*i.e.*, strikeout/underline) format (Attachment A) and final format (Attachment B) are available through the Commission's Electronic Filings (E-Filings) System at:

https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=19R-0096E

5. At this time, we do not address or make further proposed revisions to the RES Rules or Net Metering Rules. The RES Rules and Net Metering Rules will be addressed through a separate Commission decision, including without limitation, proposing additional changes to those sections of the Electric Rules, providing an opportunity for further comment, and determining whether those rules should be severed from the instant rulemaking proceeding.

[3] On March 10, 2020, Colorado Governor Jared Polis declared a state of emergency over the novel coronavirus pandemic (COVID-19). Since then, Colorado State government and the Commission have been working diligently to address how to safely and effectively manage the challenges presented by COVID-19. These efforts have focused on limiting the disruption to the services delivered by the Commission (and other State agencies), while minimizing the risks to State employees and the public. For example, the Commission has added to its website a link entitled "PUC Notifications Regarding COVID-19." See:

https://puc.colorado.gov and https://puc.colorado.gov/puc_covid19.

Beginning March 18, 2020, the Commission's Weekly Meetings will be conducted remotely, and the Commission has asked members of the public not to attend meetings in person, but to view them by webcast. Continuances of, or other actions regarding, administrative hearings and prehearing conferences will be addressed on a case-by-case basis. The responses of State and local governments in Colorado for dealing with the impacts of the expanding COVID-19 crisis on our jobs, our lives, and our society have been changing and updated every day.

B. Discussion

1. Background

6. As explained in the NOPR, the Commission found it necessary to open this rulemaking to examine potential changes to the Electric Rules for several reasons. The Commission had issued multiple decisions in preceding years indicating that certain sections of the Electric Rules warranted examination. The need for rule changes was further confirmed through the stakeholder outreach conducted by Staff of the Colorado Public Utilities Commission (Staff) in Proceeding No. 17M-0694E (Stakeholder Outreach Proceeding). We agreed with the participants in the Stakeholder Outreach Proceeding that a comprehensive rulemaking is appropriate due to significant changes in the Colorado market for electricity services, the available cost-effective technologies, and various economic and environmental interests.

7. The NOPR schedule a five-day rulemaking hearing beginning on April 29, 2019 and concluding on May 3, 2019. Prior to the scheduled hearings, written comments were submitted by: Public Service Company of Colorado (Public Service); Black Hills Colorado Electric, LLC (Black Hills); Tri-State Generation and Transmission Association, Inc. (Tri-State); the Colorado Rural Electric Association (CREA); Holy Cross Electric Association, Inc. (Holy Cross); Colorado Energy Consumers; Energy Outreach Colorado; the Colorado Energy Office (CEO); the Colorado Independent Energy Association (CIEA); Interwest Energy Alliance (Interwest); Western Resource Advocates (WRA); Sierra Club; the Southwest Energy Efficiency Project (SWEEP); Vote Solar; Colorado Solar and Storage Association (COSSA) and the Solar Energy Industries Association (SEIA); GRID Alternatives Colorado, Inc. (GRID); Southwest Generation Operating Company, LLC (SWGen); Colorado Renewable Energy Society (CRES);

Rocky Mountain Environmental Labor Coalition (RMELC) and the Colorado Building and Construction Trades Council, AFL-CIO (CBCTC); the City of Boulder; San Juan County; The Western Way; the Institute for Policy Integrity at New York University School of Law; and various individuals.

8. Through the NOPR, the Commission foresaw the possibility of significant statutory changes that would require additional changes to the Electric Rules.[4] During the weeklong hearing, the Commission instructed the participants to address additional rule changes that were necessary as a result of new legislation.[5] The Commission also made statements at the hearing that additional hearings could be scheduled in this Proceeding by a decision other than a supplemental NOPR published in *The Colorado Register*.[6]

9. Written post-hearing comments were filed by: Public Service; Black Hills; Tri-State; CREA; the Colorado Office of Consumer Counsel (OCC); CEO; CIEA; Interwest; SWEEP; Vote Solar; COSSA and SEIA; GRID; SunShare LLC; SWGen; CRES; RMELC and CBCTC; the City of Golden; Leslie Glustrom; and Walter Sharp. Among their comments, participants respond to matters discussed at the week-long hearing, and respond to statutory changes enacted in the 2019 legislative session.

10. In response to the comments filed and considering the recently enacted statutes, the Commission issued Decision No. C19-0822-I, on October 7, 2019 (October 2019 Decision). The Commission noted that three bills enacted by the 2019 General Assembly affect the modifications to the Electric Rules to be accomplished in this rulemaking: (1) Senate Bill (SB)

[4] The Commission adopted the decision opening this Proceeding and issuing the NOPR in special Commissioners' deliberations meetings on December 6 and 10, 2018 following the November 6, 2018 general election.

[5] Proceeding No. 19R-0096E, Hearing Transcript, April 29, 2019, pp 6-7.

[6] Proceeding No. 19R-0096E, Hearing Transcript, May 30, 2019, p. 90.

19-236, the Commission's "Sunset Bill" that makes numerous changes and additions to the statutes in Title 40 of the C.R.S., including revised language with respect to electric utilities; (2) House Bill (HB) 19-1261 that requires the Air Quality Control Commission (AQCC) to promulgate implementing rules and regulations to cause, at a minimum, a 26 percent reduction in statewide greenhouse gas pollution by 2025, a 50 percent reduction by 2030, and a 90 percent reduction by 2050, relative to 2005 statewide levels, which significant emission reductions will, in turn, have a substantial impact on the electric utilities in Colorado; and (3) HB 19-1003 that modifies § 40-2-127, C.R.S.,[7] regarding CSGs.

11. The Commission therefore stated that, while it held its intention to release a second version of redlined rules, it requested additional comment on rule language in specific areas responsive to the changes in legislation. The October 2019 Decision therefore addressed a number of focused issues, including: (1) proposed rules regarding the cost of carbon dioxide emissions in response to changes in SB 19-236;[8] (2) soliciting comment regarding HB 19-1261 relating to statewide greenhouse gas pollution reduction goals, and requesting input from AQCC on our shared objectives, coordination, and ongoing consultation;[9] (3) encouraging CEO to take the lead on developing and presenting a consensus view on proposals or alternative rule changes that address Governor Polis' Roadmap and policy goal for 100 percent renewable energy by 2040;[10] and (4) proposing rules to implement § 40-2-133, C.R.S., enacted by SB 19-236, that

[7] Colorado Revised Statute (C.R.S.) citations include 2018 and 2019 versions of the C.R.S. Commenters should use the 2019 C.R.S. with the most recent updates from the General Assembly.

[8] Decision No. C19-0822-I, issued October 7, 2019, at ¶¶ 22-28.

[9] *Id*, at ¶¶ 29-38.

[10] *Id.*, at ¶¶ 39-47.

requires a workforce transition plan as a part of an application filing with the Commission for approval of either an ERP or a proposed early requirement of an electric generating facility.[11]

12. The Commission further determined in its October 2019 Decision that both the CSG Rules and Interconnection Procedures and Standards are severable from the larger rulemaking effort.[12] Through separate decisions, the Commission subsequently initiated independent proceedings through issuance of notices of proposed rulemaking to revise the CSG Rules and Interconnection Procedures and Standards.[13] Each matter was referred to an Administrative Law Judge (ALJ) for recommended rules and a decision.[14]

13. Numerous participants provided written comments in response to the October 2019 Decision and participated in the public comment hearing held on October 29, 2019. Considering comments to date and statutory changes made during the 2019 legislative session, additional proposed revisions to the Electric Rules are appropriate.

2. Additional Rule Revisions and Request for Comments

14. Through this interim decision, we focus exclusively on four sections of the Electric Rules: carbon dioxide emission costs pursuant to SB 19-236; the ERP Rules generally; workforce transition plans required under SB 19-236; and the QF Rules.

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[11] *Id*, at ¶¶ 48-50.

[12] *Id.*, at ¶¶ 51-64.

[13] *See,* Decisions No. C19-0900, issued November 5, 2019, Proceeding No. 19R-0608E (Community Solar Garden Rules), and Decision No. C19-0951, issued November 25, 2019, Proceeding No. 19R-0654E (Interconnection Standards and Procedures).

[14] As of the date of deliberations on these rules, both matters remain ongoing. ALJ Robert Garvey conducted a public comment hearing on the proposed CSG Rules on January 13, 2020, in Proceeding No. 19R-0608E. ALJ Steven Denman conducted a public comment hearing on proposed Interconnection Procedures and Standards on February 3, 2020, in Proceeding No. 19R-0654E.

15. As discussed below, for each rule section we discuss proposals in comments to date, and propose additional revisions for participant comment and consideration. An additional public comment hearing is scheduled for April 23, 2020.[15]

16. Written comments may be provided at any time; however, we request that participants provide written comments no later than April 10, 2020, such that they may be responded to through subsequent written comments.

17. In addition to the sections of the Electric Rules discussed in this Decision, at this time the RES Rules and Net Metering Rules remain within the sections of Electric Rules considered in this Rulemaking. However, the RES Rules and Net Metering Rules are not discussed within this Decision. Instead, we aim to pursue a sequential discussion in which those remaining rule sections will be addressed by a separate order.

C. Rules Addressing the Cost of Carbon Dioxide Emissions

18. As discussed in the October 2019 Decision, SB 19-236 enacts new statutory provisions in § 40-3.2-106, C.R.S., that require the utilities to consider the cost of carbon dioxide emissions when determining the cost, benefit, or net present value of any plan or proposal submitted in certain proceedings before the Commission.[16]

19. Through the October 2019 Decision, the Commission proposed a new section of the Electric Rules to implement the statutory provisions set forth in §§ 40-3.2-106(1), 40-3.2-106(4), and 40-3.2-106(6)(a), C.R.S.

20. Participants provided responses and proposed language revisions to the Commission's proposed rules both in writing and at the October 29, 2019, public comment

[15] The Commission will establish procedures for the April TK, 2020 hearing by separate decision.
[16] Decision No. C19-0822, issued October 7, 2019, at ¶¶ 22-28.

hearing. As discussed below, we consider comments provided in response to the revised statutes and proposed rules provided in the October 2019 Decision.

1. Definition of "Beneficial Electrification"

21. From our Sunset Bill, SB 19-236, § 40-3.2-106(6), C.R.S., defines the term "beneficial electrification" to mean:

> [A] utility's change in the energy source powering an end use from a nonelectric source to an electric source, including transportation, water heating, space heating, or industrial processes, if the change:
>
> (I) Reduces system costs for the utility's customers;
>
> (II) Reduces net carbon dioxide emissions; or
>
> (III) Provides for a more efficient utilization of grid resources.

22. In Decision No C19-0822-I, the Commission proposed a definition for "beneficial electrification" as an addition to the definitions applicable to the entire set of Electric Rules in proposed Rule 3001.[17]

23. In response, SWEEP argues that the Electric Rules should not limit technologies that would qualify as beneficial electrification, and that end uses provide significant opportunities for beneficial electrification. WRA, similarly states that a commercial building that uses natural gas for cooling, cooking, or operating commercial dryers and converts to fueling these operations with electricity could be beneficial electrification.

24. For participant comment, we propose the rule language based on the suggestions of both SWEEP and WRA regarding the definition of "beneficial electrification." For further participant comment, these revisions aim to better ensure that the definition does not limit the

[17] "Proposed Rule" number corresponds to the Electric Rules proposed for adoption as shown in the attachments to this Decision.

types of beneficial electrification, but makes clear that the definition provides examples for purposes of the rule.

2. Proceeding to Set the Cost of Carbon Emissions

25. Section 40-3.2-106(1), C.R.S., lists the specific proceedings in which the cost of carbon dioxide must be applied. Section 40-3.2-106(4), C.R.S., sets forth specific requirements for the Commission's calculation of the cost of carbon dioxide emissions within those proceedings. In its October 2019 Decision, the Commission included proposed rules to implement these two sections of the statute. The Commission also anticipated comment or proposed revisions regarding related sections of the statute.[18]

26. In response, Sierra Club suggests that the Commission add a sentence to Proposed Rule 3550 to specify that the carbon cost rule applies to Tri-State. We propose adding this revision to Rule 3550 in the attached rules for participant comment.

3. Consideration of Air Pollutants and Greenhouse Gasses

27. WRA recommends the Commission clarify that the social cost of carbon applies to all pollutants defined as greenhouse gases, not just carbon dioxide, including those air pollutants identified as greenhouse gasses by § 25-7-103, C.R.S. Along these lines, WRA further recommends that the global warming potential of non-carbon dioxide greenhouse gasses, defined as "CO2-equivalent," be determined based on the most recent values adopted by the AQCC.

28. The Institute for Public Integrity at New York University School of Law (IPI) likewise argues that the social cost of carbon by itself may not be sufficient to allow a fully rational and transparent comparison of the alternative climate consequences of various action

[18] Decision No. C19-0822, issued October 7, 2019, at ¶ 28.

options. IPI concludes that the Commission should require use of the social cost of methane when relevant and should more broadly refer in its rules to "the social cost of greenhouse gases" generally, instead of just the social cost of carbon.

29. Section 40-3.2-106, C.R.S., addresses only carbon dioxide emissions and the implementing rules should conform to this highly prescriptive statute. The proposed rule is intended to ensure that carbon costs are calculated in a specific way for consideration in specific types of proceedings, as required by §§ 40-3.2-106(1) and (4), C.R.S.

30. While we do not include the proposed revisions from WRA and IPI in the rules attached to this Decision, we remind participants that parties may raise arguments to consider greenhouse gases more broadly in case-specific adjudications. By way of example, prior to statutory changes regarding the social cost of carbon, the Commission's Phase I decision in Public Service's most recent ERP considered the social cost of carbon and other greenhouse gasses under statutory requirements that remain in effect, including without limitation § 40-2-123, C.R.S.[19] That the proposed rule does not include WRA and IPI's suggestions is in no way a discouragement of these or other arguments regarding greenhouse gas emission considerations if warranted in an adjudication. The proposed rules here, however, focus more narrowly on implementing § 40-3.2-106, C.R.S., which addresses carbon dioxide emissions. For purposes of these rules, the intent of the proposed rule changes is to conform with requirements of the prescriptive statute and to ensure that carbon dioxide costs are calculated in a specific way for utility and Commission consideration.

[19] Decision No. C17-0316, issued April 28, 2017, Proceeding No. 16A-0396E, at ¶¶ 73-89.

4. Listed Proceedings for Considering Carbon Dioxide Costs per Statute

31. CEO claims that some of the proceedings for which the social cost of carbon dioxide emissions must be determined do not relate to the acquisition of new electric generating resources, but instead involve the purchase of electric energy or capacity. CEO thus prompts a reexamination of which proceedings should be listed in the Commission's rules in which the utility shall consider the cost of carbon dioxide emissions per statute. CEO and WRA also recommend that the proceedings that require consideration of carbon dioxide costs include transmission plans.

32. Section 40-3.2-106(1)(a), C.R.S., adds to ERPs the applications that consider or propose the "acquisition of new electric generating resources or the retirement of existing utility generation" to the list of proceedings in which carbon dioxide costs are considered. Consistent with CEO's conclusion that some of the proceedings listed in Proposed Rule 3551(b)(II) do not relate to the acquisition of new electric generating resources but instead involve the purchase of electric energy or capacity outside of an ERP proceeding, the revised proposed rule suggests removing the provisions involving energy or capacity purchases from CSGs, net metering, other distributed energy resource (DER) installations, and QFs. In addition, we agree that an application for approval of a transmission plan considers "new electrical generation resources" and can consider "the retirement of existing utility generation," and we therefore include transmission plans on the list of proceedings by the proposed rule.

5. Basis and Calculation of Carbon Cost

33. CEO claims that Rule 3552(a) fails to require the cost of carbon to be based on the "most recent assessment" of the social cost of carbon. WRA likewise recommends that the Commission modify the proposed rule so that the Commission may update the values it uses for

the cost of carbon based on “equally robust science and economics, so long as those values are not less than the central value and escalation rates in the 2016 technical support document.”[20] Similarly, IPI notes that the federal Interagency Working Group (Working Group) did not provide a single set of estimates but provides four sets of estimates. IPI thus suggests that the Commission should require consideration not just of the central estimates, but also the high-impact estimates, the 2.5 percent discount rate estimates, or both, as sensitivity analyses.

34. IPI further notes that the 2016 estimates from the Working Group may not technically be the most recent estimates produced by the federal government. IPI argues that the estimates “produced in recent years by federal agencies during the Trump administration would not be appropriate for Colorado to use, as they are not consistent with best science and economics.”[21] IPI argues that the Commission “should be free to follow the best science and economics, rather than remaining forever tethered to … past estimates from the federal government.”[22]

35. Section 40-3.2-106(4), C.R.S., is clear: “The commission shall base the cost of carbon dioxide emissions on the most recent assessment of the social cost of carbon dioxide developed by the federal government.” This basis, however, does not prohibit additional analysis for Commission consideration. For purposes of promulgating a rule that effectuates the statutory directive for carbon dioxide emissions, we do not include the suggested revisions from participants. We instead clarify the rule language for better consistency with the statutory language and explain our reasoning that adjudications could include additional considerations.

[20] WRA Supplemental Comments at p. 5.

[21] IPI Comments at p. 3.

[22] *Id.*

36. In addition, WRA concedes that, despite the statutory requirement that the utility must "present a calculation of the net present value of revenue requirement for the resources in each optimized portfolio" in an ERP proceeding, using the statutorily mandated carbon dioxide costs for planning purposes does not in itself impact the utility's revenue requirement. WRA states, however, that utilities may face actual compliance costs for greenhouse gas emissions – the costs associated with complying with a state or federal regulatory program, such as a carbon tax, a cap and trade, or a program such as the Clean Power Plan or Affordable Clean Energy Plan. WRA suggests that, in any proceeding where the utility is evaluating actual compliance costs of carbon dioxide emissions, the Commission require the utility to calculate the difference between the statutorily required cost of carbon and the actual compliance cost on a per ton basis.

37. IPI questions the basis of the $46 per short ton specified in § 40-3.2-201(4), C.R.S. IPI states that the Commission must specify the dollar-year for the minimum value for year 2020 emissions to prevent the value of the minimum estimate from eroding over time due to inflation. IPI adds that the Commission must further specify that estimates of the cost carbon must be updated to be presented in the same dollar-year as any other estimates of costs and benefits presented in an application or other submission from a utility.

38. Considering these comments, we propose revisions to Rule 3552(a)(I) such that the $46 per short ton specified in § 40-3.2-201(4), C.R.S., is based on 2020 dollar amounts.

39. IPI further recommends that when calculating the cost of carbon emissions, Commission Staff should follow the Working Group's methodology of relying on three p eer-reviewed integrated assessment models to directly estimate the cost for each year. IPI states that the language of § 40-3.2-106(4). C.R.S., is "awkward," noting that the 2016 Technical Support Document also does not specify a single "escalation rate" to apply to the central

estimates. IPI warns that choosing a single "escalation rate" to apply over a 40-year period to the initial base calculation for year 2020 emissions could lead to significant departures from the actual year-by-year estimates reported by the Working Group. IPI suggests that it would be simpler, and more consistent with the practices of the Interagency Working Group, to simply adopt the entire table of social cost figures as minimum values rather than requiring the Commission to recalculate a "modified" value for each year. Considering these comments, we propose revisions to Rule 3552(a)(II), and invite participant comment.

6. Annual Staff Calculation

40. Sierra Club recommends that the Commission clarify what these rules direct Commission Staff to do each year by August 1 regarding calculating the cost of carbon dioxide pursuant to Rule 3552(b). Sierra Club further questions whether the Commission needs to calculate the cost of carbon dioxide 40 years into the future. Sierra Club notes that while it would be possible to calculate the cost of carbon beyond 2050, the Commission would need to make several decisions related to the assumed growth rate in damages caused by carbon emissions contributing to climate change. Sierra Club suggests that it may make more sense for the Commission to provide values for the social cost of carbon that match the timeframe used by the Working Group which extend only through 2050.

41. IPI suggests that the Commission adopt minimum estimates based on the Working Group's 2016 Technical Support Document and Addendum, converted to short tons, adjusted to 2018 dollars, and extended from the year 2050 to the year 2060 using reasonable growth rate assumptions based on the Working Group's summary statistics.

42. WRA argues that opening a proceeding each year to update the social cost of carbon values may be administratively onerous and instead recommends that in each year,

Commission Staff should first determine whether an update is necessary. If Commission Staff determines that an update is not necessary, it should submit a recommendation that no change is needed to the existing calculation and the Commission could issue a decision finding that the Commission will continue to use the existing calculation for the following calendar year.

43. IPI likewise observes that, in many years, there will be no substantive changes in the best available estimates of the social cost of carbon. IPI states that "[s]o long as the Commission recognizes that a substantive update may not be necessary every year, an annual process to revisit the numbers may be appropriate to adjust for inflation and to allow the public to weigh in on any recent developments in the best available estimates."[23]

44. We are not convinced that updates to Rule 3552(b) are needed based on these comments. The 40-year horizon is often necessary to calculate the revenue requirements associated with ERP portfolios. We anticipate that the initial carbon cost proceeding, and a proceeding following a change in the social cost of carbon established by the federal government, could result in a hearing, settlement, or some sort of process beyond an uncontested presentation of Staff's calculations of carbon dioxide costs based on the social cost of carbon, which is why a comment process in the rule is provided. However, there is little annual burden on the Commission and Commission Staff based on the proposed rule, and we agree with WRA and IPI that it is likely that most years there will be little to no substantive changes in the best available estimates of the social cost of carbon.

D. Electric Resource Planning Rules

45. In the NOPR, the Commission proposed to retain the provisions in the ERP Rules that promote competitive bidding as the cornerstone of the utilities' resource acquisition plans.

[23] IPI Comments at p. 7.

Among its proposed rule changes, the NOPR organizes the ERP Rules around Phase I and II requirements and clarifies its objectives in each phase.[24] The modified ERP Rules build not only on significant stakeholder processes before the initiation of the NOPR, but are based on the experiences in the most recent ERP proceedings for each utility since the rules were last updated in 2007.[25]

46. Through the NOPR, the Commission anticipated legislative changes in 2019[26] and prepared for subsequent proposed rule revisions necessary to reflect any revised statutes. While legislation provided prescriptive calculations and processes, including with regard to the social cost of carbon dioxide emissions and workforce transition plans as addressed here, the overall ERP practices were not significantly altered by statute. However, considering the changed statutes and subsequent stakeholder comments, we offer further rule revisions for participant comment within this rulemaking as discussed below and included in the attachments to this Decision.

1. Carbon Emissions, Clean Energy Plan, and ERP Filing Dates

47. Among its new statutory requirements, the Sunset Bill requires and allows certain utilities to file a "Clean Energy Plan" as an ERP to achieve substantial reductions in carbon dioxide emissions. The Sunset Bill further sets forth various requirements for the utilities and the Commission to consider the cost of carbon dioxide emissions in an ERP context.

48. The Sunset Bill specifically requires that Public Service's next ERP must include a Clean Energy Plan. Public Service has stated that it will be prepared to file its Clean Energy

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[24] Decision No. C19-0197, issued February 27, 2019, ¶¶ 31-103.

[25] The Commission amended its Integrated Resource Planning Rules in Proceeding No. 02R-137E, resulting in the Least-Cost Resource Planning (LCP) Rules. In 2007, the LCP Rules were again revised into the ERP Rules in Proceeding Nos. 07M-256E, 07R-368E, and 07R-419E.

[26] *See,* Decision No. C19-0197, issued February 27, 2019, at ¶ 52.

Plan on March 31, 2021. For utilities other than Public Service, such as Black Hills, a Clean Energy Plan filing may be an option in its next ERP filing.[27]

49. Public Service suggests that, in general, it is unnecessary to develop a standalone set of ERP Rules that will specifically govern its Clean Energy Plan filing. However, § 40-2-125.5(4), C.R.S., requires a resource acquisition period for a Clean Energy Plan to extend through 2030. In addition, the Colorado Department of Public Health and Environment (CDPHE) argues that the Colorado Legislature contemplated that the Commission might move forward with consideration of Clean Energy Plans prior to adoption of rules by AQCC addressing greenhouse gas reduction strategies from the electric utilities.

50. Considering participant comments, we conclude that certain revisions to the ERP Rules should move forward in this Proceeding and that such rule changes can foster consideration of Clean Energy Plan filings even prior to adoption of related rules by AQCC. Also, given the changes in statutes and participant comments, we revise a number of general provisions for ERP proceedings related to carbon emission requirements and Clean Energy Plan filings that were codified through 2019 legislation.

51. Proposed Rule 3601(c) that describes the purpose of the ERP process is updated for participant comment to include that carbon emission reductions are among the primary goals of ERP. The rule proposal includes, with minor revision, proposals made by CEO in its comments.

52. Proposed Rules 3602(o) and 3604(a) addressing the utility's resource acquisition period (RAP) are revised to propose a RAP ending in 2030 for the first ERP filings made

[27] The Commission has not yet provided Public Service or Black Hills a date certain to file their next ERPs and has instead determined it would decide the timing of their next ERP filings in this rulemaking.

pursuant to the modified ERP Rules, consistent with the timeframe provided in revised statutes. For subsequent ERP filings, the proposed rules would permit the utility to propose the RAP, and that the Commission establish the RAP in its Phase I decision.

53. Proposed Rule 3603(a) concerns the ERP filing date is revised to require that Public Service file its Clean Energy Plan ERP no later than March 31, 2021. Black Hills would file its ERP one year later on March 31, 2022. This proposal staggers the dates consistent with participant comments, allows for spreading of Commission resource needs for these time-intensive proceedings, and coincides with dates the utilities have indicated will allow them to provide full ERP applications.

54. Proposed Rule 3604 is revised to include four new provisions regarding contents of the utility's ERP application filing. First, the revised rules require the utility to provide the costs of the projected carbon dioxide emissions using the cost of carbon calculated by the Commission pursuant to Proposed Rule 3552 (Rule 3604(h) in the attachments to this Decision). Second, the revisions require the utility to propose in its initial ERP filing a base case portfolio of resources and at least one proposed alternative portfolio of resources as now statutorily required in an ERP proceeding for applying the social cost of carbon dioxide emissions (Rule 3604(m) in the attachments to this Decision). Third, the proposed rule as revised directs the utility to provide a progress report on the implementation of a Commission-approved Clean Energy Plan in accordance with § 40-2-125.5(7), C.R.S. (Rule 3604(q) in the attachments to this Decision). Fourth, the rule is revised to require the utility present an assessment of the costs and benefits of early retirements of utility-owned resources and acquisition of new utility resources required to reduce the carbon dioxide emissions associated with the utility's sales by 80 percent from 2005 levels by 2030 (Rule 3604(k) in the attachments to this Decision). We propose these

revisions to cause the utility to present the essence of a Clean Energy Plan in its next ERP filing, consistent with the comments put forward by CDPHE and others.

55. Proposed Rule 3610 regarding "Assessment of Need for Resources" is further modified to include that the utility is required to address statewide goals set by AQCC to reduce greenhouse gas emissions pursuant to HB 19-1261.

56. Proposed Rule 3614(f)(III) regarding contents of a Phase I decision is further modified to: (1) set forth the specific carbon costs to be used in the 120-day report; (2) define the "base case portfolio" the utility must present in its 120-day report as required for the use of the social cost of carbon; (3) address additional alternative portfolios, as the Commission may want, to address the social cost of carbon and other values of carbon dioxide costs; and (4) to set forth the other factors the Commission intends to consider in approving a resource plan in addition to considering the cost of carbon dioxide.

57. Similarly, Proposed Rule 3615(d)(I) regarding contents of the utility's 120-day report presented in Phase II is modified: (1) to require the utility to apply the cost of carbon dioxide emissions to the existing and new resources; (2) to require the presentation of net present value of revenue requirements that include the cost of carbon dioxide; and (3) to require the calculation of the net present value of the total cost of the carbon emissions. These provisions flow from §§ 40- 3.2-106(2)(a) and (b), C.R.S.

58. Finally, Proposed Rule 3615(e)(I) is modified to expand the contents of a Phase II decision, which states that the Commission shall consider the net present value of the cost of carbon dioxide emissions and other factors as required by § 40-3.2-106(3), C.R.S.

2. Review of Existing Generation and "Benchmarking"

59. As identified in proposed Rule 3607(c) attached to the NOPR, the Commission introduced a benchmarking requirement. The Commission explained that the benchmarking proposal was intended to address the operating characteristics and costs of existing utility resources for multiple purposes. For example, it could identify the existing resources whose cost or performance deviates from expectations, which can impact ratepayers in the future. It was also intended to inform the analysis for potential early plant retirements pursuant to Proposed Rule 3604(k).[28] Notably, however, this purpose was prior to legislative changes regarding carbon emission reduction requirements.

60. Public Service accepts, to some degree, the proposed benchmarking of existing generation to generic resources in an ERP context. The Company proposes certain language changes to several of the related rules, primarily to narrow the benchmarking to generation resources. Public Service also proposes a new rule that requires the utility to provide a description of the processes, procedures, or protocols that the utility employs in dispatching its power supply fleet and that Public Service's proposed rule revisions would further require discussion on the following topics: (a) unit commitment and dispatch; (b) operation of storage resources; (c) curtailment of variable energy resources; (d) maintaining operating reserves; (e) economic purchases and sales of capacity and energy from the market; and (f) real time transmission limitations.

61. SWEEP opposes Public Service's proposal to narrow benchmarking to supply side resources. In addition, WRA objects to benchmarking "qualitative information," which WRA claims is being suggested by Public Service. WRA argues that consideration of such

[28] Decision No. C19-0197, issued February 27, 2019, ¶ 68.

information is best in Phase II. WRA also objects to benchmarking as comparisons between similar technologies; WRA instead advocates for heterogeneous benchmarking. And, with respect to the ERP regulatory process, WRA suggests that the Commission clarify that changes to the operation of existing resources may be brought forward by any party or *sua sponte* by the Commission.

62. CEO and WRA each suggest that the Commission specify certain data points for existing resources and generic alternatives, such as capital costs, variable operating costs, minimum operating requirements, flexibility, ramping capability, capacity cost, and levelized cost of energy. WRA also suggests that the Commission provide examples of how this information is to be presented by the utility, and that the Commission consider requiring generic model runs, with each excluding one utility-owned fossil fuel resource.

63. With respect to the useful lives of existing resources, CIEA seeks to narrow the consideration to only utility-owned generation.

64. Vote Solar urges the Commission to ensure that the utilities do not oversimplify benchmarks. Vote Solar also recommends that if benchmarking relies on computer modeling, stakeholders should have access to all modeling inputs and outputs and to information about the model's structure and capabilities.

65. Sierra Club proposes rules that would effectively require a mandatory assessment of the need for each existing generation resource in the utility's fleet. Sierra Club also proposes specific modeling provisions related to the benchmarking.

66. CEC seeks an iterative least-cost planning process with annual reported updates to the ERP. CEC urges benchmarks based on solicitation results rather than utility assumptions.

CEC further proposes to add "any resulting necessary reliability and transmission investments" to the utility's early retirement bid.[29]

67. Reviewing the comments, we agree with Public Service in that the focus should be on generation facilities larger than 20 MW, and that the definition of "generic resource" should be modified to provide clearer direction and to narrow the definition to supply side resources. However, we disagree with Public Service that an additional rule is necessary to ensure the utility describes "the processes, procedures, or protocols" for its generation dispatch. Although this is critical information that we anticipate could be discussed in an ERP proceeding, such processes, procedures, or protocols necessitate reliance on modeling in ERP proceedings. We are not convinced a rule requirement for a corresponding narrative in the benchmarking rule is necessary.

68. Benchmarking is a new proposal, which was introduced into the proposed rules prior to statutory changes regarding Clean Energy Plans. Conducting a comprehensive assessment of existing generation resources in an ERP is required to develop and support a Clean Energy Plan. We invite further participant comment given these observations and concerns, but remind stakeholders not to complicate the practical purpose of benchmarking in adjudication through overly prescriptive rules.

3. Early Plant Retirements

69. If adopted by the Commission, Proposed Rule 3604(k) as set forth in the NOPR would require the utility's initial ERP filing to include an assessment of potential cost-effective early retirements of utility-owned resources with retirement dates during the planning period.

[29] CEC Initial Comments at p. 10. (Emphasis Omitted)

70. In comments filed before the end of the 2019 legislative session, the utilities express concern about forced retirements of utility owned resources with associated cost disallowances. The independent power producer (IPP) community also stated concern about canceled contracts caused by the potential scope of early retirement considerations.

71. SB 19-236 and HB 19-1261 have greatly altered the potential role for this new rule. Public Service is required to file a Clean Energy Plan that will undoubtedly entail early plant retirements. Black Hills may file a Clean Energy Plan, but it also has no coal facilities serving its native load.

72. Consistent with its general position on the benchmarking of a utility's existing generation assets, Public Service does not object to certain new provisions in the ERP Rules intended to accommodate the Commission's consideration of early plant retirements. But Public Service expands the consideration of early retirements to include "retirement" of contracted resources (*i.e.*, purchased power agreements with IPPs). Public Service also provides additional language that modifies the approach to be used for considerations. Notwithstanding its statements regarding the absence of any strong opposition to the consideration of early plant retirements, Public Service argues that early plant retirements must be proposed by a utility, and that the ERP process should not be used to force retirements or contract cancellation.

73. Sierra Club strongly supports the provisions regarding early plant retirements in the NOPR and provides support for their adoption. Sierra Club also offers two options for contracted resources: (1) require utilities to evaluate existing contracted resources in the same manner as utility owned resources, but make clear that the Commission is not encouraging utilities to breach contracts; or (2) adopt an ERP rule stating that utilities are not required to evaluate contracted resources unless ordered to do so in a specific ERP proceeding.

74. CEO also supports these aspects of the NOPR, but provides a series of suggestions for further modifications to the rules.

75. WRA recommends considering the location of replacement resources associated with an early plant retirement, particularly for locating replacement resources in the same city or county as the retiring fossil fuel facility.

76. SW Gen urges the Commission to clarify that, while it agrees the Commission has the authority to evaluate existing resources, it argues that such authority does not extend to forcing the premature termination of any project contracts. CEC argues that the utility should not be allowed to seek approval to retire a power purchase agreement (PPA) without substantiated data on comparative costs.

77. In its latest set of comments filed in January of 2020, Public Service states: "While Public Service does not oppose performing an assessment of potential cost-effective early retirements of existing resources as part of its ERP filing, it strongly believes such assessment must consider the entire system of both utility-owned and contracted resources."[30] CIEA filed in opposition to Public Service's supplemental comments, claiming that including contracted resources would have a "chilling effect" by allowing the utility to break PPA contracts through ERP processes.

78. The Commission does not generally approve IPP contracts, stemming from long standing practice since the enactment of the LCP Rules.[31] The Commission has also been clear that ERP proceedings are not rate cases and that its interest in ensuring cost-effective operation of existing resources is not for the purpose of second-guessing past ERP decisions through cost

[30] Public Service Supplemental Response Comments at p. 7.

[31] Proceeding No. 02R-137E.

disallowances. Further, a well-understood benefit of contracted generation is that the utility's cost commitment ceases when the term of the contract is reached. Contracts in the form of PPAs typically have terms less than the useful life of a utility-owned generation facility.

79. Utilities should not view an ERP proceeding as an opportunity to seek Commission approval to break its contractual commitments with IPPs, just as the Commission cannot abrogate its responsibilities regarding the financial health of Colorado utilities under the regulatory compact. Nevertheless, the ERP Rules do not prohibit the utilities from negotiating contract modifications or proposing contract buy-outs for the benefit of customers. The Commission's application process is available to the utilities in circumstances where explicit approval of a contract change is necessary. Further, as previously noted, HB 19-1261 and SB 19-236 require a refocusing of an ERP proceeding, beyond only addressing new resources and toward review of all resources, in order to achieve decarbonization requirements.

80. Before adopting final provisions in Rule 3604 addressing early retirements and potential buy-outs of PPAs, we require additional information and comment from the participants on: (1) whether an additional assessment regarding resource retirements should be required in Rule 3604 if a Clean Energy Plan is also required to be filed in the utility's next ERP either by statute or by another Commission rule; (2) whether this separate and additional assessment of resource retirements should include both utility-owned generation and contracted resources; and (3) whether additional rule provisions or Commission determinations are necessary to address stakeholder concerns about stranded utility costs and breached contracts. We encourage the interested rulemaking participants to propose rule changes consistent with their positions on these three questions.

4. Best Value Employment Metrics

81. In the NOPR, the Commission consolidated the provisions in the ERP Rules defining the best value employment metrics (BVEM) into Proposed Rule 3613. The Commission further enhanced the BVEM–related provisions in the ERP rules based on comments by Public Service, developed in consultation with the RMELC/CBCTC.

82. The Sunset Bill requires the Commission to modify certain ERP Rules related to BVEM issues due to revisions to § 40-2-129(1)(a), C.R.S., the "best value metrics statute." First, the enacted bill requires the Commission, "in all decisions involved in electric resource acquisition processes," to consider best value regarding employment of Colorado labor. Second, the bill requires the Commission to require the electric utilities to "obtain and provide to the commission" the BVEM. Third, as the most substantive of the statutory changes, the bill states that the Commission shall not approve an ERP that fails to either: (1) provide the BVEM required by a request for proposals (RFP); or (2) certify compliance with objective BVEM standards; however, the Commission may approve an ERP if the utility agrees to use a project labor agreement for construction of expansion of a generating facility.

83. The Sunset Bill also exempts from statutory BVEM requirements all projects involving "retail distributed generation," *i.e.*, renewable resources located at a customer's site, interconnected on the customer's side of the meter, and sized to be eligible for net metering.

84. Public Service argues that the new provisions in § 40-2-129, C.R.S., do not require new rules as compared to the proposed changes in the NOPR.

85. RMELC/CBCTC argues that all ERP resource acquisitions are subject to mandatory BVEM requirements. RMELC/CBCTC further suggests that, as an alternative to providing the required BVEM, the utility or IPP can either: (1) certify a particular standard; or

(2) submit a request for waiver. With respect to the various types of BVEM factors in Rule 3613, for example, RMELC/CBCTC proposes certain alternative certifications such as: registered apprenticeships or college credits for training programs; a commitment of 80 percent of construction workers being Colorado residents; and industry wage standards.

86. For Phase I, RMELC/CBCTC proposes a BVEM-related requirement in the Commission's Phase I decision. For Phase II, RMELC/CBCTC proposes: (1) access to BVEM documentation by the Independent Evaluator (IE) and a requirement for the IE to assess the BVEM information; (2) a summary of the BVEM approach for each bid (certification, information, or waiver); (3) an initial BVEM review upon the receipt of bids; and (4) a requirement that the utility present a scoring regime and weights for BVEM information.

87. In response, CIEA argues that the BVEM information requested should not be overly prescriptive and should allow for IPP bidders to respond with flexibility.

88. CIEA and Interwest further argue that the changes advocated by RMELC/CBCTC go beyond and are inconsistent with the requirements of § 40-2-129, C.R.S. CIEA argues that the submission of BVEM documentation in response to an RFP is not an area where IPPs may be subject to "enforcement" or "mandatory" submissions, and the initial review of bids is not the correct time for the Commission's review of bid data. CIEA also argues that the Commission should allow for flexibility in BVEM considerations for IPP projects and should not require labor-related commitments by bidders at an early stage of project development. CIEA states that IPPs are bound to their bid price, which could limit their ability to negotiate a project labor agreement, for example.

89. We are not convinced by Public Service's comments that no changes are needed to the BVEM rules. We instead propose to strike a balance between the flexibility needs raised

by CIEA and Interwest, while taking into consideration some of the concerns REMLC/CBCTC's comments raise.

90. First, we propose including in Proposed Rule 3615(d)(I) that the 120-day report shall provide the Commission with the BVEM information provided by bidders.

91. Second, we update Proposed Rule 3615(e)(I) to better allow the Commission proceeding flexibility with respect to the PPA-related provisions in § 40-2-129, C.R.S. Considering these changes, we remind participants that ERP proceedings do not typically include Commission approval of specific PPAs. While ERP proceedings can culminate in approvals of resource portfolios that include bids for PPAs with specific bidders (*e.g.*, the Colorado Energy Plan Portfolio in Proceeding No. 16A-0396E), the projects are assessed as bids, as opposed to final contracts. Considering that context, we agree with CIEA that it is unlikely that a PPA bidder would be in a position to offer certification or a project labor agreement during an ERP proceeding because PPA bids are submitted prior to the completion of project specifications, financing, and other contractual necessities.

92. We also agree with commenters that the utility or another party could provide supporting documentation of the certification or project labor agreement, if any is reached, so that the PPA bidder could avail itself to the related provisions in § 40-2-129, C.R.S., including requested rule waivers, if any are necessary as commenters suggest.

93. Our proposed changes to Proposed Rule 3615 also recognize that the utility may be in a position to certify compliance or enter into a project labor agreement during the course of the ERP proceeding. This may be the situation, for example, where utility-owned resources are at issue and are sometimes directly addressed in an ERP Proceeding. The ERP Rules therefore

require the utility to provide BVEM information to the Commission for its statutorily-required considerations in the case of proposed utility ownership.[32]

94. We do not agree with the commenters who suggest requiring the IE to assess the BVEM information. The Commission can satisfy its statutory obligations regarding BVEM in Phase II without assistance from the IE. We further agree with CIEA that the ERP Rules should not be overly prescriptive with respect to the Commission's assessment of BVEM information in Phase II.

5. Utility Ownership of Renewable Energy Resources

95. In the NOPR, the Commission moved the rules implementing § 40-2-124(1)(f)(I), C.R.S., from the RES Rules to the ERP Rules. However, SB 19-236 eliminates § 40-2-124(1)(f)(I), C.R.S., that had allowed a utility to develop and own as rate-based property certain amounts of renewable energy resources without being subject to the competitive bidding requirements of the Commission's ERP and RES Rules.

96. Due to the repeal of § 40-2-124(1)(f)(I), C.R.S., we propose deletion of corresponding Proposed Rule 3614(c)(II) and modify Proposed Rule 3614(c)(III).

6. Utility Demand-Side Management, Energy Efficiency, and Demand Response

97. SWEEP, WRA, and CEO suggest the introduction of a more prominent role of demand-side management (DSM), energy efficiency, and demand responses in the ERP process.

[32] Existing Rule 3611(f) and Proposed Rule 3614(c)(V) require an application for a certificate of public convenience and necessity to be filed with an ERP when the utility proposes acquisition of a new resource that the utility shall own. Existing Rule 3611(h) and Proposed Rule 3614(c)(VI) further require that the utility provide BVEM information.

98. SWEEP and CEO offer suggestions for more coordination between a utility's electric DSM plan, which is based on its energy savings and demand reduction goals, and the various components of its ERP filing. They also propose consideration of forward cost curves for DSM and demand response: (1) in determining resource needs to be addressed by an ERP; and (2) in the required portfolio modeling.

99. WRA and SWEEP propose that demand-side resources compete in competitive solicitations.

100. CEO further proposes that DSM be considered the first source of contingency resources in Rule 3609(c).

101. We are not persuaded that it is necessary for the Commission to modify its ERP Rules in order to cause an expanded role for DSM in ERP proceedings. No rule changes are required to allow for consideration of additional utility-administered DSM programs in the context of a Clean Energy Plan or other ERP filing. All-source bidding also will continue to offer an opportunity for DSM to compete. From the perspective of case administration, the consideration of resource portfolios necessary to achieve the emission reductions required in a Clean Energy Plan or otherwise required by HB 19-1261 will fully engage the utilities, the Commission, and the parties. We prefer the use of "DSM strategic issues" proceeding for consideration of such things as forward cost curves for DSM and demand response. CEO's proposal for DSM to be used as a first source of contingency resources is undeveloped and unsupported, and we do not include it in the revised proposed rules.

7. Pre-Application Filing Process

102. CEO proposes a new rule to implement a process for a miscellaneous proceeding with Staff-led workshops.

103. SWEEP supports an informal pre-filing stakeholder process, and Sierra Club supports requiring the utility, prior to the filing of its ERP, to conduct a workshop on its modeling software. Sierra Club offers two options: (1) a complaint process if model runs are not conducted; or (2) a detailed timeline for pre-filing activities related to the model.

104. We are not convinced that a rule requirement for pre-application filing processes should be required for pre-filing workshops or other stakeholder outreach.

105. We remind participants that part of the necessary streamlining of the integrated resource planning process that led to the LCP Rules had been the elimination of the requirement for "a public participation process prior to the filing of a proposed plan with the Commission." The Commission determined that, prior to the adoption of the LCP Rules in 2002, the then-existing public participation process added up to nine months to the overall resource planning regulatory process. The Commission adopted a "more streamlined and flexible resource acquisition process" based on a competitive resource acquisition to preserve "Commission review of the most important elements of the resource acquisition process" and to "turn over many of the resource acquisition details to the utility."[33]

106. In addition, we agree with CDPHE that the purpose of the Clean Energy Plan provisions in SB 19-236 is "to provide an incentive for utilities to develop flexible, creative approaches that meet their needs and the State's GHG reduction targets."[34] Section 40-2-125.5, C.R.S., is very prescriptive with respect to utility compliance options and Commission obligations. The General Assembly required no pre-filing conferrals with stakeholders with respect to Clean Energy Plan filings. The General Assembly further expects the Clean Energy

[33] Decision No C02-793, issued July 22, 2002, Proceeding No. 02R-137E pp. 3 and 11.
[34] CDPHE's Comments at p. 5.

Plan to be subject to the Commission's ERP process that presently includes no pre-filing stakeholder process.

107. Notwithstanding that we decline to revise the proposed ERP Rules to include pre-filing process requirements, we encourage utilities to take steps prior to filing their ERPs to minimize contested issues and to foster efficiencies in the adjudicated proceedings.

8. Portfolios and Scenarios

108. The NOPR proposed two significant changes to the "scenario rule" in the existing ERP Rules and posed a series of scenario-related questions to the rulemaking participants. First, the NOPR proposed to replace the "alternate plans" requirements in Rule 3604(k) with new provisions to address the potential early retirement of utility-owned resources during the planning period. The Commission explained that it intends to examine potential plant retirements and replacement capacity based on the experience gained in recent ERPs and other resource acquisition proceedings. Second, the NOPR also proposed to remove the Phase I alternate plans from Rule 3604(k) because the plant retirement scenario would serve as the primary area of interest in the next rounds of ERP filings.

109. In addition to the specific proposed changes to Rule 3604(k), the Commission asked stakeholders whether the Commission should: (1) promulgate new rules to incorporate a form of scenario planning to be applied within an ERP proceeding; and (2) develop different sets of assumptions about the future for exploring possible risks that may arise from those assumptions in an ERP context.

110. After the 2019 General Assembly session, in its October 2019 Decision, the Commission addressed the Polis Administration's Roadmap to 100 percent Renewable Energy by 2040 and Bold Climate Action. With respect to Rule 3604(k), the Commission

asked stakeholders if the utilities should provide information in their initial ERP submissions, specific information regarding future possible resource portfolios that track with the Polis Administration's goal to achieve 100 percent renewable energy by 2040. The Commission also asked if Rule 3604(k) portfolios should be retained and modified to define "an alternative plan" that includes 100 percent renewable energy resources by 2040. The Commission further encouraged CEO to "take the lead on developing and presenting a consensus view on rule changes that address the policy goal for 100 percent renewable energy by 2040."[35]

111. On December 20, 2019, CEO submitted a joint filing with SWEEP, CEC, Vote Solar, Southwest Generation, the OCC, Ms. Leslie Glustrom, Sierra Club, WRA, CIEA, Boulder, Interwest, COSSA, and SEIA stating their agreement that the only elements of the Roadmap that should be added to rules are those that are also contained in statute.

112. The joint filing appears to support the changes in Proposed Rule 3604(k) as set forth in the NOPR, which requires an assessment of potential cost-effective early retirements of utility-owned resources. Joint filers also propose additional redlines to Proposed Rule 3604 that point to the greenhouse gas reduction goals set forth in § 25-7-102(2), C.R.S., per HB 19-1261 or required in a Clean Energy Plan pursuant to § 40-2-125.5, C.R.S., per SB 19-236.

113. Separately, Public Service proposes new language that calls out sensitivities and scenarios. As explained above concerning early plant retirements, Public Service argues that any scenario to be evaluated as part of Phase II that contains the early retirement of utility owned or contracted resources must be proposed by the utility or the owner of the contracted resource.

114. Prior to joining in the comments filed in response to the October 2019 Decision, WRA argued in favor of retaining the three alternative plans set forth in existing Rule 3604(k).

[35] Decision No. C19-0822-I, issued October 7, 2019, ¶ 47.

WRA suggested, at a minimum, that the Commission retain the foundational requirement that multiple plans be presented. CEC also sought presentation of "a least-cost portfolio" as well as: (1) annual portfolio costs for each year; (2) the costs of individual resources within the NPVRR; and (3) measures of rate impacts.

115. In its supplemental comments following the issuance of the October 2019 Decision, Sierra Club suggests two primary modifications to the Commission's NOPR proposal. First, for all electric utilities other than Public Service, the Commission should require information on a scenario for an "80 percent reduction in carbon emissions by 2030 relative to 2005 levels"[36] According to Sierra Club, this would have the effect of requiring the utilities not required by HB 19-1261 to submit a Clean Energy Plan to at least provide the Commission and stakeholders with information on the costs to meet the Clean Energy Plan target of reducing carbon emissions 80 percent by 2030. For Public Service, Sierra Club suggests that the Commission require a scenario that represents either a 90 percent or 95 percent reduction in carbon emissions by 2030 relative to 2005 levels instead of a scenario corresponding to "100 percent renewable energy resources by 2040."[37]

116. Considering the comments, we are not convinced that further revision of Proposed Rule 3604 is necessary beyond the changes included in the revised rules attached to this Decision and discussed above. Those modifications include proposed additions for a Clean Energy Plan scenario (*i.e.*, the assessment of the costs and benefits of early retirements of utility-owned resources and the acquisition of new utility resources required to reduce the carbon dioxide emissions associated with the utility's sales by 80 percent from 2005 levels by 2030), and "early

[36] Sierra Club Comments at p. 10.
[37] *Id.*

plant retirement" scenarios. These focused revisions to the scenario requirements address the statutory mandates and retain essential flexibility. We aim to avoid overly prescriptive requirements that risk overburdening the Phase I ERP proceeding that must meet the state's carbon and other greenhouse gas reduction goals.

117. We are confident that the scenarios required by the proposed rules attached to this Decision will spur the development of the evidentiary records necessary to support the Commission's Phase I decision that will "set forth the information the utility shall provide in its 120-day report regarding potential resources, proposed utility-owned resources, and the modeling of portfolio combinations of resources to support the development of cost-effective resource plans."[38]

9. Ancillary Services

118. The NOPR sought comment on whether a more detailed assessment of the ancillary services available from the utility's existing resources is warranted. The Commission set forth Proposed Rule 3607(d) to help identify the existing resources that play critical roles beyond the simple economic dispatch of generation resources. The Commission explained that analysis of ancillary services could inform the Commission about the scope of ancillary services procurement that could occur if the utility begins to participate in an integrated organized wholesale electricity market during the planning period.

119. Public Service raises no objections to addressing ancillary services, but proposes language changes to Rule 3607(d), primarily adding to the list of example ancillary services.

[38] Proposed Rule 3614(f)(III).

120. WRA suggests that the Commission require the utility to define: (1) the set of ancillary services provided by existing resources; (2) the set of needed ancillary services, given the utility's system and expected load; and (3) a description of how the utility will define the characteristics and value of ancillary services in its Phase II solicitation.

121. SWEEP argues that disclosure of the ancillary services procured from the utility's generation fleet will allow potential bidders to include the value of ancillary services in bids.

122. We agree with adopting certain suggested revisions proposed by Public Service and WRA to better clarify the listed ancillary services. While WRA's suggestion that the set of ancillary services needed in the future could be considered in an ERP proceeding, it has not been demonstrated that the utilities are presently in a position to forecast this type of need. We anticipate that any forecasting of the need for ancillary services will be complicated due to the possibility that existing fossil-fueled generation could be proposed to fulfill new roles, including the provision of ancillary services due to necessary modifications to dispatch and "emission-averaging" to meet carbon reduction goals.

123. One purpose of the "ancillary services rule" proposed in the NOPR is to help the Commission gain greater familiarity with such services and how they are used by Colorado electric utilities. We recognize that such services can be procured in organized wholesale markets and the development of such markets can lead refined definitions and business cases for these services. We therefore retain the singular rule to assess ancillary services provided by existing resources and intend to defer the promulgation of further rules to future potential rulemakings.

10. Section 123 Resources

124. The NOPR proposes to eliminate provisions that cause specific treatment of what were defined as "Section 123 resources."[39] In responsive comments, WRA, SWEEP, and CEO oppose the elimination of the provisions related to the Commission's consideration of Section 123 resources as a specific category of resources. SWEEP also opposes removal of definition and role for Section 123 resources as premature. SWEEP argues that the current practice is necessary for fullest possible consideration.

125. We are unpersuaded by participant comments that prescribed rules on Section 123 resources are necessary. The elimination of "Section 123 resources" as a defined resource category and the elimination of the rules that had relied on that definition do not diminish the role of new clean energy and energy efficient technologies in an ERP. Utilities and the Commission must consider new clean energy and energy efficient technologies to achieve the significant carbon reduction goals established by the 2019 General Assembly. The generally applicable rule established in 2007 however, has proven to be unnecessary. Deleting certain provisions in the ERP Rules related to Section 123 resources accomplishes streamlining and does not – nor could it – diminish the effect of the namesake statute.

11. ERP Exemptions and Exclusions

126. The NOPR made only a single change to the provisions in Rule 3611 Exemptions and Exclusions: the size cap on certain projects to be exempt from an ERP was reduced from 30 MW to 20 MW.

[39] *See,* Decision No. C19-0197, issued February 27, 2019, at ¶ 50.

127. Vote Solar supports reducing the ERP threshold to 20 MW but also recommends that the Commission set new standards detailing when the utility can acquire certain large utility-owned resources outside of an ERP. For example, the new resource must be: (1) carbon-free; (2) at least 10 percent below the best bid in the most recent ERP; and (3) occur in a narrow timeframe between ERPs.

128. As a general matter, WRA argues that if the Commission wishes to move to a system in which all generation resources, no matter how small, may only be acquired through an ERP competitive solicitation, it must create a framework by which the locational benefits of small generation facilities and other DER can be presented and evaluated.

129. With respect to a specific rule change, WRA argues for the elimination of the exemption of emission control equipment from an approved ERP. WRA argues that prior to the utility installing new emission control equipment, the Commission should have an opportunity to evaluate, in the context of an ERP, whether it would be more cost effective and environmentally beneficial to retire the existing generation resource and replace it with lower emitting alternatives. Sierra Club agrees with WRA.

130. Public Service does not oppose the reduction in the exemption threshold in Proposed Rule 3611(a)(IV) from 30 MW to 20 MW, but suggests that the Commission apply that measure to a generation "unit" instead of a "generation facility site."

131. We expect that achieving the significant carbon reduction goals established by the 2019 General Assembly will mitigate the concerns raised by WRA, Sierra Club, and Vote Solar. At the same time, we decline to include Public Service's proposed revisions as well, which could serve to increase the exemption threshold. We maintain the proposed rule for further comment, particularly in light of the revised carbon reduction goals.

12. Modeling

132. Participants addressed various modeling considerations throughout their comments filed or provided orally at the public comment hearing.

133. Regarding Proposed Rule 3602 and discount rates, CRES proposes to require that future fuel costs not be discounted at a rate exceeding 3 percent. WRA proposes a new definition for the net present value of revenue requirements: the current worth of the total expected future revenue requirements associated with a particular resource portfolio, expressed in dollars in the year the electric resource plan is filed, as discounted over the planning period by the appropriate discount rates.

134. Regarding Proposed Rule 3604 and the provision for fuel forecasts, CEO proposes a new rule that requires fuel price forecasts, including base, low, and high price forecasts including the methodology to derive the forecasts.

135. CEO also proposes a new rule that would require the utility to provide in its initial ERP filing, a description of the modelling assumptions, inputs, and software the utility proposes to use to evaluate bids and existing resources. Vote Solar suggests that the Commission require utilities to provide access to the full set of input and output data used in resource modeling, as well as the underlying assumptions. WRA argues that it would be overly restrictive to require, by rule, the use of a particular model.

136. WRA argues that it would benefit the Phase II process if the utility is required to provide modeling output in spread-sheet form. WRA further suggests that the Commission, in its Phase I decision, set forth "any modeling inputs, assumptions, and sensitivities that will be used

to evaluate bids in Phase II."[40] Vote Solar suggests that the Commission require utilities to provide access to the full set of input and output data used in resource modeling, as well as the underlying assumptions.[41]

137. CIEA proposes the Commission render findings in its Phase II decision on the utility's modeling software with direction for future ERPs.

138. The existing rule that becomes Proposed Rule 3614(d)(II), requires a utility's proposed RFP to set forth its "general planning assumptions," and has long served to ensure that the utility provides in its initial ERP filing, the data that CEO suggests be provided by a new rule. Similarly, the existing rule defining a Phase I decision revised as Proposed Rule 3614(f)(II) has successfully fostered Commission decisions that address the long list of planning assumptions. We therefore decline to adopt in the attached proposed rules, the specific revisions advocated regarding resource portfolio modeling.

139. However, we agree with WRA that the Commission should, in its Phase I decision, set forth "any modeling inputs, assumptions, and sensitivities that will be used to evaluate bids in Phase II." We clarify that is the purpose of the provision in Proposed Rule 3614(f)(II) where the Commission addresses the contents of the utility's filed plan including the RFP that sets forth the general planning assumptions used in modeling and "any other information necessary to implement a fair and reasonable bidding program." As general guidance, parties to the ERP proceeding should set forth the "modeling inputs, assumptions, and sensitivities that will be used to evaluate bids in Phase II" in their post-hearing statements of position filed in the Phase I application proceeding.

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[40] WRA Initial Comments at p. 22. (Emphasis Omitted)

[41] *See* Proposed Rules 3604(n) and 3614(f)(II) regarding modeling inputs and outputs.

140. Discovery in the application proceeding provides parties input and output data. We recognize that the provision of this data has been limited historically due to orders granting protections to information claimed to be highly confidential. But those decisions strike a necessary balance between protections for sensitive information and access for purposes of adjudication. As part of the discovery provisions established in Phase I, parties can also advocate for modeling output in particular format, including spreadsheet or other executable format.

141. Based on these comments to date, we are not persuaded changing the definition of net present revenue requirements, particularly if we assume that the 2019 General Assembly relied on the existing definition in its development of various provisions in SB 19-236.

142. Finally, we do not agree that a rule is needed to address CIEA's concern about the occasional need to provide direction for future ERPs in a Phase II decision. These determinations are case-specific and this type of direction may not always be necessary.

13. Access to Highly Confidential Information

143. In comments, WRA argues that Rule 3615(b)(IV) should clearly specify that all parties that have signed and filed the Non-Disclosure Agreements (NDAs) have access to all bid information as of release of the "30-Day Report" that initially summarizes information on the bids received to an ERP competitive solicitation. In addition, WRA suggests that the Commission provide access to privileged IE information if the party field the required NDA.

144. We do not agree with WRA that the Commission should take on the responsibilities and burdens of providing information claimed to be highly confidential. Appropriate avenues are available to parties for allegations that a party is noncompliant with Commission confidentiality rules and release requirements. Comments do not convince us that more generally applicable rules, or clarifying language, is needed.

14. Qualifying Facilities

145. CIEA proposes new rule language that explicitly links the utility's 120-Day Report, the Commission's Phase II decision, and QF bidding opportunities under the modified QF rules. For context, the proposed QF Rules proposed in the NOPR in the series beginning with Rule 3900 place the burden on the utilities to demonstrate that their ERP competitive bidding is reasonably accessible to QFs, and if the Commission instead finds that the ERP bidding is not reasonably accessible to QFs, the proposed rules require alternative tariff-based processes for establishing utility obligations to purchase and for determining avoided cost payment rates.

146. CIEA suggests that the Commission add a requirement in ERP Rule 3615(d)(I) that the utility's 120-day report "detail the utility's evidence regarding" whether the ERP is sufficiently available for QF bidding. As CIEA proposes, this information from the 120-day report would then inform the Phase II decision.

147. We welcome CIEA's suggestion to help clarify processes between the QF Rules and information provided in the ERP, and offer an alternative for participant comment in Proposed Rule 3614(f). Rather than requiring information in the 120-day report, we propose that the Commission's determination be made in the Phase I decision regarding whether the ERP is sufficiently available to QFs.

148. In making this proposed change, we anticipate that, based on the advocacy of the utilities in this rulemaking and previous proceedings, the utilities will address QF participation in their proposed RFP solicitations in their initial ERP filings – well prior to the filing of the 120-day report. By including a rule that makes clear that the Commission will address this matter in its Phase I decision, the adjudicated application process will cause the advocacy of

parties to address the issues surrounding QF bidding in the litigated Phase I proceeding rather than requiring those issues to be addressed solely through the 120-day report review process and the Phase II decision.

15. Forecasts of Peak Demand and Energy Sales

149. In the October 2019 Decision, the Commission observed that the Polis Administration's Roadmap speaks to at least four policy objectives that could have an impact on an electric utility's electric energy and demand forecasts. The NOPR, however, proposed only limited changes to Rule 3606, Electric Energy and Demand Forecasts. The Commission thus stated that: "The Roadmap and the participant comments regarding energy efficiency, demand response, retail renewable distributed generation, and other factors that have impacts on energy sales and demand forecasts suggest further examination of potential changes to Rule 3606 may be in order."[42] The Commission encouraged CEO to take the lead on developing and presenting a consensus view or rule changes regarding Rule 3606.

150. In the joint filing that CEO submitted on December 20, 2019, the participating parties proposed two additions to Proposed Rule 3606(b). In response to the joint comments, Public Service states that it was an active participant in the discussions led by CEO and supports the additions to Rule 3606 in full.

151. We appreciate participant efforts in reaching consensus and include the additions in Proposed Rule 3606 for additional stakeholder comment.

[42] Decision No. C19-0822-I at ¶ 43.

16. Other ERP Issues and Proposed Revisions

152. There were several requests or suggestions for additional rule modifications raised by participants in this rulemaking proceeding.

153. CEO proposes a new rule describing an ERP: "Electric resource planning integrates modeling, forecasting, planning and changes in utility load related to or derived from the implementation of utility planning, including Renewable Energy Standard Compliance Plans, demand side management plans, Distribution System Plans, electric vehicle infrastructure plan and other plans for beneficial electrification to comprise a comprehensive integrated resource planning process." The Commission's orders have historically set the context for the determinations made by the Commissioners. The adoption of this type of rule language would be unique in the Commission's Electric Rules, and we conclude that this type of descriptive language is unnecessary.

154. Regarding Proposed Rule 3604 addressing the utility's initial ERP filing, CEO proposes a new provision that would require the utility to provide: "A description of the methodology it intends to use for evaluation of bid contracts for Renewable Energy Credits (RECs) without associated energy." We do not agree that this rule is necessary and are concerned that the adoption of this rule language would elevate REC-only bidding. Overemphasizing REC bidding may be an outdated option for Colorado utilities and also may be inconsistent with current policy emphasizing reductions in greenhouse gas emissions.

155. WRA recommends the Commission require that all utility studies be updated as part of each ERP cycle in Proposed Rule 3604(m). We are not persuaded this requirement is necessary. We cannot anticipate the types of studies necessary in each future ERP, and depending on the circumstances, "updated" studies alone may be insufficient. The Commission has

historically required through order updated studies or information depending on the specific facts at issue in a proceeding, which allows flexibility and avoids a generally applicable rule that could lead to costly and unneeded studies.

156. CIEA seeks an explanation in a utility's 120-Day report of any proposed changes from the utility's previous 120-Day report as an addition in Proposed Rule 3604(n). We conclude that this proposed rule provision could prove to be unnecessary and needlessly burdensome.

157. Public Service proposes to add the following to Proposed Rule 3606: "The utility may elect to limit the amount of growth in the energy and demand forecasts it applies within its modeling of years beyond the resource acquisition period for the purpose of reducing the number of generic resources in the outer years of the planning period. The utility shall explain and justify any such limitations." Although circumstances may warrant this type of modeling adjustment, we are not persuaded to include it as an ERP Rule. Utilities are not prohibited from including such information and reasoning, and they may request modeling adjustments as needed and circumstances require without a generally applicable rule.

158. CEO proposes language on "transmission benefits" and treatment of "system costs." "Transmission benefits" would include, for example, the ability to interconnect greater amounts of renewable resources. In this definitional rule, CEO also proposes another reference to § 40-2-126, C.R.S., which addresses "energy resource zones" per 2007-vintage legislation. We do not agree that further elaboration on transmission benefits is needed through the rule language

based on the comments, or that a second reference to § 40-2-126, C.R.S., is necessary in Proposed Rule 3608.[43]

159. In the context of the Commission's consideration of planning reserve margins under Proposed Rule 3609(a), Holy Cross recommends a separate proceeding to develop uniform resource rating criteria to apply in Colorado. We do not agree that developing a separate proceeding and criteria is beneficial at this time.

160. Public Service objects to the term "cost cap" and proposes alternative language. To encourage additional participant comment, we propose language modifications in Proposed Rule 3614(b)(III).

161. With respect to the model contracts addressed in Proposed Rule 3614(d), WRA argues in favor of keeping requirements for different model contracts for different resource types, questioning whether model contracts will develop "naturally" in the absence of the current rule requirements. We disagree with the rule addition proposed by WRA. Because the utility is required pursuant to Rule 3614(d) to file in Phase I the model contracts for the RFP(s) to be used in an all-source competitive solicitation, any deficiency can be addressed in the course of the Phase I proceeding.

162. In Phase I, and in relation to Rule 3614(e)(I) regarding the IE, CEC seeks limited discovery on the IE's credentials and objectives. We remind participants that the NOPR revises the manner in which an IE is identified in the Phase I portion of the ERP proceeding. The provisions in Rule 3614(e)(I) provide parties to the ERP proceeding opportunities to query the proponents of the IE before and during the Phase I hearing. This process, in lieu of discovery, balances the need to vet the IE given that the IE is not a party in the proceeding.

[43] Section 40-2-126, C.R.S., is referenced directly in Proposed Rule 3608(b).

163. In Phase II, and in relation to Rule 3615(a) (III) regarding the IE, CEC further seeks an opportunity to pose questions or serve discovery to test the IE's conclusions and findings to ensure the IE is not "an agent of the utility." Similarly, CEC seeks discovery on the 120-day report as a predicate to filing comments through additions in Proposed Rule 3615(d)(III). As emphasized by the Commission before regarding the Phase II comment process, the ERP Rules for Phase II provide sufficient procedures to parties to raise questions for the Commission to consider regarding the IE's conclusions and findings. The Phase II process lacks discovery and an evidentiary hearing in order to preserve the viability of bids to the competitive bid process. Nevertheless, the comment process provides an opportunity to concerned parties to persuade the Commission to adopt different procedures for good cause shown.

164. Regarding Proposed Rule 3615(d)(I) concerning the requirements for the utility's 120-Day report submitted in Phase II, CIEA proposes separate consideration of certain transmission network upgrades developed in concept through the bid evaluation and selection process. We do not include CIEA's proposal, which is unnecessary, duplicative, and could unfairly disadvantage or prejudice certain bidders over others. The biennial transmission plan filings pursuant to the Commission's Transmission Planning Rules as referenced in Proposed Rule 3608(b) are intended to address such opportunities for transmission project development before a Phase II ERP process. CIEA's proposal risks upsetting this process, and potentially causing certain bidders and projects to gain advantage because of the utility's previously undisclosed intentions to develop network upgrades.

165. CIEA also proposes an explicit directive to the utility that the 120-day report must comport with the Commission's Phase I decision within the context of Proposed Rule 3615(d)(I).

We do not include this revision. It is well understood that the 120-day report should comply with the directives in the Commission's Phase I decision.

E. Rules Addressing Workforce Transition Planning

166. The October 2019 Decision explains that SB 19-236 requires investor-owned electric utilities to include a workforce transition plan as part of an application filing with the Commission for approval of either an ERP or a proposed early retirement of an electric generating facility. The statute primarily sets forth the information that must be included in the filing and does not require the Commission to enter any specific findings or take other actions with respect to the information set forth in the "plan."

167. The Commission proposed a new section of the Electric Rules to implement the new statutory provisions set forth in § 40-2-133, C.R.S. The Commission also asks addition questions about whether it was necessary to promulgate additional rules regarding the Commission's use of the information provided in a workforce transition plan.[44]

168. In response to the Commission's proposal and questions, CEO suggests that the Commission consider including a preference for workforce transition plans wherein most of the workers are able to retire as planned or be retained within the utility. CEO further suggests that the Commission consider requiring justification from the utility if these preferred paths are not taken. CEO adds that although the rules proposed in the October 2019 Decision address only § 40-2-133, C.R.S., they could be expanded to also address § 40-2-125.5(4)(a)(VII), C.R.S., which discusses community assistance plans with respect to Clean Energy Plans. According to CEO, the provisions can readily be combined into a single set of rules, even though the requirements for Clean Energy Plans and other types of plans are slightly different.

[44] Decision No. C19-0822-I, issued October 7, 2019, at ¶¶ 48-50.

169. The OCC faults the October 2019 Decision for restating in rules what is already contained in the enabling statute. In contrast to the OCC's perspective, Public Service supports the rules for Workforce Transition Plans provided by the Commission and proposes a few minimal changes to "ensure the rule language mirrors that of statute." Also, contrary to the OCC and CEO, Public Service opposes the Commission promulgating additional rules regarding workforce transition planning, arguing that while the contents of any required workforce transition plan are fairly prescriptive under the statute.

170. We agree to include certain clarifying changes proposed by Public Service. We also agree with Public Service that no additional rules should be promulgated at this time. We anticipate that the Commission will gain valuable experience in Public Service's upcoming ERP proceeding regarding workforce transition plans in relation to the required Clean Energy Plan. Based on that experience and any other plant retirement proceedings brought to the Commission in the next few years, the Commission can consider rule refinements along the lines suggested by CEO and OCC in a future rulemaking.

F. Qualifying Facilities Rules

171. Prior to issuing the NOPR in this proceeding, the Commission held a number of workshops in the "Stakeholder Outreach Proceeding", including a July 11, 2018 workshop focused on QF Rules.[45] At the workshop, participants discussed contradictory provisions within the QF Rules, including concerns regarding the second sentence of prior Rule 3902(c), which included that the "only" means by which a QF could obtain a legally enforceable obligation is through competitive bidding. The Commission subsequently completed a focused rulemaking

[45] See Decision No. C19-0197, issued February 27, 2019, ¶¶ 4-13 (discussing QF concerns raised through ERP proceedings, subsequent workshop proceedings on interrelated issues, and related considerations).

that struck the word "only" to recognize this inconsistency.[46] Several participants in that rulemaking, including CEO, agreed with the proposition that the second sentence of that rule was in direct conflict with existing practices and other provisions in the Electric Rules. However, a common theme in the comments submitted by the participants was support of the Commission's planned review of the QF Rules within this more comprehensive rulemaking. The Commission further stated that, while it adopted the single rule revision to strike contradictory language in the second sentence of Rule 3902(c), it was committed to revising the interrelated and complex rules in this subsequent, and more comprehensive, rulemaking.

172. In addition, during the course of the Stakeholder Outreach Proceeding and Proceeding No. 18R-0492E, sPower Development Company, LLC (sPower) filed a series of applications seeking enforcement of alleged legally enforceable obligations on the part of Public Service and Black Hills to purchase energy and capacity from QFs owned by sPower.[47] The combined nameplate capacity of the sPower facilities seeking utility purchases total approximately 1,400 MW, which is larger than the resource need addressed in Public Service's most recent ERP.[48]

173. As proposed in the NOPR, the QF Rules preserve the ERP competitive bidding process as the primary means for a QF to secure a contract in Colorado. The rules are modified to ensure clearer coordination with the ERP Rules while also safeguarding ongoing compliance with the Federal Public Utility Regulatory Policies Act of 1978 (PURPA). Specifically, the

[46] Decision No. C18-1045, issued November 27, 2018, Proceeding No. 18R-0492E

[47] Proceeding Nos. 18A-0505E, 18A-0506E, 18A-0507E, 18A-0508E, 18A-0509E, 18A-0510E, 18A-0511E, 18A-0512E, 18A-0513E, 18A-0514E, 18A-0515E, 18A-0516E, 18A-0517E, 18A-0518E, 18A-0519E, 18A-0520E, and 18A-0521E address QFs owned by sPower with alleged purchase obligations on the part of Public Service. Proceeding No. 18A-0524E addresses a QF owned by sPower with an alleged purchase obligation on the part of Black Hills.

[48] Proceeding No. 16A-0396E.

Commission determines in the Phase I ERP process whether the utility's competitive solicitation will be reasonably open to QF bids. The proposed rules addressed inconsistencies and also provided for a new tariff-based QF program that would arise when ERP competitive bidding becomes irregular, infrequent, or too expensive for owners and developers of small QFs.

174. The proposed QF Rules also more explicitly address avoided costs for QF purchases, whether determined through competitive bidding or by tariff, including recognition that the ERP competitive bidding process takes into account integration costs. In addition to these substantive changes, the NOPR proposes the complete elimination of most of the existing QF Rules because they are outdated or have been largely replaced by other processes or documents, some of which are no longer directly governed by the Commission's Electric Rules.

175. Rulemaking participants remain sharply divided regarding the Commission's modified QF Rules. Utilities seek to reinsert the recently removed "only" into the competitive procurement provisions governing legally enforceable obligations of the Commission's use of competitive bidding alone for QFs to procure contracts. In contrast, some QF proponents argue against competitive bidding as the primary means for QFs to secure a contract.

176. As described in greater detail below, we propose certain changes to the rules provisions initially proposed in the NOPR for further participant comment.

1. Applicability.

177. In the NOPR, the Commission modified Proposed Rule 3900 by renaming it "Applicability" for consistency with the other sections of the Electric Rules, and included revisions to avoid inconsistencies with provisions for interconnections for QFs with nameplate ratings of 10 MW or less.

178. Through subsequent comments, CREA recommends that Rule 3900 be revised to expressly exempt co-ops that exempt themselves from the Public Utilities Law. Vote Solar opposes CREA's proposal stating that PURPA governs co-ops. Vote Solar states that an exemption is "not appropriate" but does not give a further explanation.

179. Although we agree the QF Rules would not apply to co-ops that exempt themselves from Public Utilities Law, an express exemption in this rule is not necessary and could cause confusion. Under § 40-9.5-103, C.R.S., articles 1 to 7 of Title 40, including without limitation any resulting Commission rules, "shall not apply" to cooperative electric associations that have exempted themselves under the statutory process. However, co-ops, particularly those that exempt themselves from Colorado's Public Utilities Law, must still follow relevant state and federal laws. This includes applicable federal requirements in PURPA. For purposes of the generally applicable rules, however, we do not include express exclusion language.

2. Competitive Bidding and Tariff Options

180. Proposed Rule 3903(a) maintains the Commission's current practice of tying the establishment of a legally enforceable obligation to a contract awarded to the QF based on a winning bid in a Phase II ERP competitive solicitation. The proposed rule applies to all QFs with nameplate capacity greater than 20 MW.

181. In addition, under Proposed Rule 3903(a), the Commission may determine that the means to secure a legally enforceable obligation for facilities smaller than 20 MW (but greater than 100 kW) also is a contract awarded to the QF based on a winning bid in Phase II of an ERP. The NOPR highlights that the significant modification in the Commission's QF practices would be the rendering of a specific finding in each ERP Phase I Decision establishing the minimum project size eligible to bid into the RFP solicitation. The Commission's proposed

rules place the burden on establishing that the ERP is open to QF facilities smaller than 20 MW on the utility.

182. Upon consideration of the continuing opportunity for smaller QFs to compete in the Phase II bid solicitation process, the Commission may either: (1) maintain its existing practice of implementing PURPA requirements through ERP competitive bidding upon finding that the RFP bidding is accessible to facilities as small as 100 kW or some other level below 20 MW; or (2) supplement the competitive bidding with tariff-based provisions, as necessary.

183. Therefore, Proposed Rule 3903(b) allows for an alternative tariff-defined process if the Commission finds there is a gap in the accessibility of the ERP competitive bidding.

184. Proposed Rule 3904(d) would govern the utility tariff requirements for QF purchases, as needed to fill "the gap." In the NOPR, the Commission suggested two options for the determination of avoided costs in the tariff for the purpose of soliciting comments–one with computer-based modeling and alternative using market-based mechanisms.

185. Rulemaking participants are sharply divided on this issue. The utilities seek QF rules that ensure legally enforceable obligations to purchase from a QF arise *only* from ERP competitive solicitations. Public Service proposes to reintroduce the word "only" to ensure purchase obligations are exclusive to winning bids from ERP competitive solicitations. Public Service places the burden on the Commission to ensure that competitive bidding is accessible to small QFs[49] and advocates for a tariff only for QFs no greater than 100 kW.

[49] The elimination of the word "only" from the phrase "the utility is obligated to purchase capacity or energy from the qualifying facility *only* if the qualifying facility is awarded a contract pursuant to the competitive bidding provisions in the Commission's Electric Resource Planning Rules" was the sole issue addressed by the Commission in Proceeding No. 18R-0492E. The Commission eliminated "only" by Decision No. C18-1045, issued November 27, 2018, Proceeding No. 18R-0492E.

186. Public Service and Black Hills further oppose the alternative targeted solicitations or bid evaluations for relatively small QFs proposed by CIEA and CEO. Critics of all of those approaches—primarily solar advocates and QF developers—seek an alternative "administrative" means to secure the legally enforceable obligation, particularly for QFs between 100kW and 1 MW. Certain QF proponents continue to argue that competitive bidding requirements are contrary to PURPA.

187. Notwithstanding the divisive comments, we resolve to examine rule changes that claim middle ground by striking a reasonable balance: regular competitive bidding is encouraged as the primary means for resource acquisition, consistent with longstanding Commission policy, while alternative opportunities for QFs are ensured, particularly when regular competitive bidding is unavailable to them. Utility positions fail to recognize the need that they ensure competitive bidding is open to QFs, and especially if it is not, that alternative means should be considered. However, we agree with utilities that the alternative targeted solicitations and bid evaluations proposed by CIEA, CEO, and some small developers are not fully developed and could disrupt successful ERP bidding processes overall.

188. The QF tariff framework in the rules attached to this Decision, including the adjudicated tariff option, along with the proposed revisions to Rule 3614(f), provides a more clear and incorporated process between the ERP and QF Rules that establishes the ERP as the primary backbone of creating legally enforceable obligations, but with alternatives.

189. We further recognize that the establishment of a method for administratively determining avoided costs is a complex regulatory exercise.[50] However, we do not agree with the utilities that any alternative to competitive bidding should be struck altogether. Striking the option in the rule ignores the practical reality that proceedings outside of an ERP could establish avoided costs, even if proceedings to date have been unable to do so. The additional alternative through rule-required tariffs provides a structured and measured avenue for utility and QF filings before this Commission.

190. Therefore, if the alternative tariff is needed to set avoided costs, Proposed Rule 3609(d) provides that the adjudicated tariff proceeding shall determine the methodology for determining the avoided cost. This variation of the rules initially proposed in the NOPR will allow for the utility to propose the method for calculating avoided costs, and the Commission can review the proposed method and the rates resulting from the method in an advice letter tariff proceeding administered pursuant to the Commission's Rules of Practice and Procedure.

191. In combination, the rules aim to encourage regular, competitive bidding, with appropriate flexibility and backstops for QFs as the circumstances may require. With this further explanation and reasoning, we invite participant comment for consideration.

3. Avoided Costs.

192. In the NOPR, the Commission added a clarifying sentence to the rule requiring payments to QFs based on the utility's avoided costs in Rule 3904(a) to include integration costs.

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[50] Proceeding No. 13AL-0958E, "In the Matter of the Advice Letter No. 1649 - Electric Filed by Public Service Company of Colorado to Implement a New Methodology to Derive Payment Rates Applicable to Qualifying Facilities ("QFs") with a Design Capacity between 10 and 100 KW," commenced with an advice letter tariff filing on August 27, 2013 and concluded with a final decision, Decision No. C16-0136, addressing an application for rehearing, reargument, or reconsideration on February 22, 2016.

193. Vote Solar objects to the lowering of avoided costs to account for integration costs. Vote Solar proposes additional payments for avoided facilities and environmental costs.

194. The NOPR further clarified that avoided costs for payments to QFs greater than 20 MW would be established through ERP competitive bidding, but that the processes – including a tariff backstop if bidding becomes irregular or prohibitive for QFs – also applies.

195. Public Service proposes to strike Rule 3904(c), and seeks to adopt practices that this Commission struck through a prior rulemaking that rejected the ERP as the "only" means to obtain avoided costs.

196. Consistent with our statements above, we do not agree that Proposed Rule 3904(c) should be eliminated as argued by Public Service. The rule is necessary, because the two concepts of the "Obligation to Purchase" and "Avoided Costs" that once were intertwined in existing Rule 3902(c)[51] are now separated in the revised structure of the QF Rules.

197. At the same time, we also disagree with Vote Solar that avoided costs should not be adjusted to account for integration costs. Integration costs are included in competitive bidding processes that determine avoided costs, and should similarly be accounted for – regardless of the method of avoided cost determination used.

198. Therefore the rules attached to this Decision show no changes to Proposed Rules 3904(a) and (c).

[51] Existing Rule 3902(c) states: A utility shall use a bid or an auction or a combination procedure to establish its avoided costs for facilities with a design capacity of greater than 100 KW." The utility is obligated to purchase capacity or energy from a QF if the QF is awarded a contract under the bid or auction or combination process.

4. Same Site Capacity Aggregation

199. Public Service warns of potential gaming of the RFP process by developers disaggregating larger projects into multiple smaller projects. Public Service's proposal places the burden of proof to establish that the applicable threshold has not been met on the utility. Vote Solar opposes Public Service's approach and rejects codifying an "aggregation test." Vote Solar argues that Public Service's rule goes beyond the existing Federal Energy Regulatory Commission aggregation test.

200. We understand the concerns raised by Public Service regarding potential disaggregation of larger projects. Particularly in light of recent adjudications that sought utility purchases totaling approximately 1,400 MW between 18 applications, we are acutely aware that smaller projects combined could create significant concerns in the aggregate. We therefore propose rule language to invite further participant comment and alternative proposals.

5. Small QF Tariff

201. In the NOPR, the Commission generally left unchanged the rule language regarding tariffs for QF purchases from facilities with less than 100 kW. The rule requires the utility to determine the avoided cost rate in a "transparent fashion."

202. Public Service proposes alternative language for the phrase "in a transparent fashion." Vote Solar proposes a "modernizing" of the avoided cost calculation to reflect the actual distribution, transmission, and environmental costs avoided. With respect to transparency, Vote Solar recommends that the Commission require a complete set of modeling inputs, outputs, and assumptions to stakeholders, subject to appropriate protections.

203. CEO proposes that the small tariff option extend to QFs between 100 kW and 5 MW.

204. We agree with commenters that the language regarding "transparent fashion" should be revised and propose alternate language for comment. We disagree, however, with CEO that the small tariff option should apply to facilities as large as 5 MW. Particularly as the newly proposed processes include the utility's burden to show that competitive bidding is open to QFs between 100kW and 20 MW, this subset of QFs will have tariffing options under the new rules in the appropriate circumstances.

6. Interconnection

205. The NOPR explains that most of the provisions in Existing Rules 3910 through 3953 can be eliminated because the provisions are outdated and unnecessary. Many of the provisions once set forth in those rules are instead addressed elsewhere in the Electric Rules, such as the Interconnection Procedures and Standards or the ERP Rules.

206. The NOPR posits that interconnections of QFs to the utilities' transmission systems can be addressed by the utility's Open Access Transmission Tariff (OATT) in conjunction with the "Level 3" process in the revised Interconnection Procedures and Standards.

207. Public Service proposes language changes such that the OATT provisions are applicable only when the QF does not seek to sell all of its output to the utility. Public Service also proposes a provision to accommodate alternative arrangements for the payment of QF interconnections. This alternative ties to Public Service's position on the applicability of Rule 3905(c) to only winning bids in an ERP solicitation. Vote Solar objects to requiring QFs to pay facility upgrade costs.

208. Due to the ongoing Interconnection rulemaking in Proceeding No. 19R-0654E, and due to present availability of the utility's OATTs that were not available when these

QF Rules were initially adopted, we do not include rule revisions in the revised proposed rules on QF interconnection.

7. Model Contract

209. Vote Solar objects to the use of the ERP model contract as the basis for contracts for resources of 1 MW or less. Vote Solar also objects to contracts of less than 20 years.

210. The review of the model contracts in an ERP proceeding will be modified given the new considerations by the Commission regarding the accessibility of the ERP competitive solicitations to small QFs. We also do not agree that setting minimum terms for model contracts is appropriate through a rule at this time.

8. Other Requests

211. Public Service proposes a simpler formulation of Proposed Rule 3904(f), stating that nothing in the Commission's QF Rules requires a utility to pay more than its avoided costs of energy and capacity for purchases from QFs. Proposed Rule 3904(f) reflects longstanding language in the QF Rules. Public Service's comments to date do not convince us that it should be modified as requested.

212. Regarding a new provision under Rule 3904, Mr. Walter Sharp proposes an adder to avoided costs applicable to small QF projects based on: general location; distance to load; brownfield siting; and system configurations. Mr. Sharp's suggestions are important considerations, but are best left to ERP Proceedings or QF tariff proceedings. Comments to date do not support adopting rule language either requiring or establishing adders.

G. Additional Day of Hearing and the Filing of Written Comments

213. The Commission will conduct an additional day of hearing on April 23, 2020. Procedures for the April 23, 2020 hearing will be established by a separate decision.[52]

214. Comments on all areas of interest relevant to the rulemaking, including those that are outside of the topics addressed by this Decision are permitted.

215. The Commission encourages interested persons to submit written comments before the April 23, 2020 hearing. Written comments are requested to be filed by April 10, 2020.

216. The Commission prefers that comments be filed using its E-Filings System at https://www.dora.state.co.us/pls/efi/EFI.homepage in this proceeding. The Commission will consider all submissions, whether oral or written.

II. ORDER

A. The Commission Orders That:

1. A hearing in this matter shall be held as follows:

DATES: April 23, 2020

TIME: 9:00 a.m. until not later than 5:00 p.m.

PLACE: Determined through future decision

2. Procedures for the April 23, 2020 hearing will be established by a separate decision.

3. Consistent with the discussion above, the Commission encourages interested persons to submit written comments on the topics raised in this Decision. The Commission

[52] On March 24, 2020, Commission offices, including hearing rooms, were closed to the public. "[F]or good cause shown," the Commission can "regulate the course of the hearing, set the time and place for continued hearings, and fix the time for the filing of appropriate documents." § 24-4-103(13), C.R.S. Through a separate decision, the Commission will establish procedures, including remote location and access, to accommodate public comment, as necessary.

requests that comments be filed no later than April 10, 2020 and that any changes are proposed in legislative redline format.

4. The Commission prefers and encourages interested persons to pre-file comments in this proceeding (19R-0096E) through its E-Filings System at:

https://www.dora.state.co.us/pls/efi/EFI.homepage.

5. This Decision is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING February 27, 2020.

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<td>(S E A L)

ATTEST: A TRUE COPY

Doug Dean

Doug Dean,
Director</td>
<td>THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

JEFFREY P. ACKERMANN
____

JOHN GAVAN
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Commissioners

COMMISSSIONER FRANCES A. KONCILJA
VOTED TO ADOPT THIS DECISION BUT
RESIGNED EFFECTIVE MARCH 13, 2020.</td>
</tr>
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