Decision No. C19-0957

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 19M-0670E

IN THE MATTER OF THE COMMISSION'S IMPLEMENTATION OF § 40-2-132, C.R.S., RELATING TO DISTRIBUTION SYSTEM PLANNING.

DECISION OPENING PROCEEDING, DESIGNATING CHAIRMAN ACKERMANN AS HEARING COMMISSIONER, AND SOLICITING INFORMATION AND COMMENTS

Mailed Date: December 3, 2019
Adopted Date: November 6, 2019

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I. BY THE COMMISSION

A. Statement

1. By this Decision, the Colorado Public Utilities Commission opens this proceeding to collect comments and other information given statutory changes in Senate Bill (SB) 19-236 that, among other revisions, creates § 40-2-132, C.R.S., directing the Commission to promulgate rules regarding the filing of Distribution System Plans (DSPs) by Colorado electric utilities.

2. The Commission designates Chairman Jeffrey Ackermann as Hearing Commissioner,[1] pursuant to § 40-6-101(2)(a), C.R.S., to work with the Staff of the Colorado Public Utilities Commission (Staff), stakeholders, and other interested participants to collect and organize information, conduct public comment hearings, and make recommendations to the full Commission as to possible next steps in promulgating rules required by § 40-2-132, C.R.S.

3. Through separate decision, after the conclusion of this stakeholder outreach proceeding, the Commission will consider a Notice of Proposed Rulemaking (NOPR) to implement the requirements in SB 19-236 requiring this Commission to promulgate rules

[1] At the Commissioners' Weekly Meeting on June 26, 2019, the Commissioners agreed to divide responsibilities as individual hearing officers for the first stages of implementation of the new obligations in the PUC Sunset Bill, Senate Bill 19-236 with Chairman Ackermann having responsibility for Distribution System Planning, Commissioner Gavan for Performance Based Ratemaking, and Commissioner Koncilja for Colorado Transmission Coordination Act. Final decisions, including reports and rule revisions, if any are needed, in areas implementing the PUC Sunset Bill will be considered for adoption from the full Commission, consistent with Commission rules and practice.

regarding the filing of DSPs. Stakeholder comments, proposed rule revisions, and discussion in this outreach proceeding will be instrumental in a future NOPR issued pursuant to the requirements in § 40-2-132, C.R.S.

B. Consideration of Distribution System Planning Prior to SB 19-236

4. The Commission has heard from parties in previous proceedings on the need for exploring an Integrated Distribution System Planning process. As set forth in Rule 3207, 4 *Code of Colorado Regulations* (CCR) 723-3, the Commission currently considers all distribution system investments to be in the "ordinary course of business" and therefore exempt from CPCN requirements under § 40-5-101(1)(a)(III), C.R.S. As several stakeholders have noted in filings, the utilities currently engage in developing an internal, five-year distribution plans. Accordingly, neither stakeholders nor the Commission have an opportunity to provide input on that plan.

5. In Public Service's 2015-2016 DSM Plan Application proceeding (Proceeding No. 14A-1057EG), Western Resources Advocates (WRA) recommended in its exceptions to Decision No. R15-0496, that the Commission consider a future rulemaking proceeding to establish a public distribution planning process that would require a utility to consider stakeholder input in its distribution system planning, similar to the existing transmission planning process identified in Rules 3625- 3627, 4 CCR 723-3.

6. The concept of distribution planning also came up during the miscellaneous proceeding on Net Metering (Proceeding No. 14M-0235E). Several parties provided the Commission information on the benefits of distribution planning, including WRA, SolarCity (now Tesla), and National Renewable Energy Laboratory (NREL). Additionally, we note that the approval of AGIS (Advanced Grid Intelligence and Security), requires the Commission to examine how such systems should be used in an effort to develop an integrated distribution

system to ensure numerous potential consumer and system benefits of grid modernization investment. AGIS (16A-0588E) included the integration of new utility systems such as Advanced Distribution Management Systems (ADMS), Advanced Metering Infrastructure (AMI), and Integrated VoltVAr Optimization (IVVO).

7. More recently, in Proceeding No. 17M-0694E, initiated through Decision No. C17-0878, issued October 26, 2017, the Commission examined the implementation of an Integrated Distribution System Planning process. In that Decision, the Commission invited comment on the concept of distribution grid planning and "initial regulatory steps that the Commission should take to ensure that investor-owned electric distribution systems have the capability to handle increased penetration of distributed generation, storage, and certain load-building technologies such as electric vehicles."

8. Through a stakeholder and outreach effort that began in the spring of 2018, the Commission solicited input and explored many topic areas regarding distribution system planning. A DSP work group was formed and the ongoing effort and recent utility filings revealed the benefits of more thorough and transparent distribution system planning processes.

9. WRA submitted proposed model Distribution System Planning rules in the pre-rulemaking Proceeding No. 17M-0694E. WRA noted in its initial comments that the proposed rules were discussed with a number of stakeholders, including Clean Coalition, COSEIA, Vote Solar, the CEO, EOC, CIEA, and others. WRA the purpose of DSP should meet several goals: 1) it provides an opportunity for additional oversight and cost control for large investments in the distribution grid; 2) it provides an opportunity for more holistic planning and preparation surrounding the proliferation of DER, including an examination of how DER can impact grid reliability and resilience; 3) it provides an opportunity for utilities to provide pilots in order to

gain experience and comfort with new technologies; 4) and it should review, in detail, the reliability and resilience of the distribution grid, by city and neighborhood, and identify areas where the reliability needs improvement should be identified and targeted for investment.

10. CEO stated in its comments that it believes DSP is in the best interest of Colorado ratepayers and that the time is ripe for the Commission to adopt rules governing a DSP. CEO's proposed draft DSP rules established a process to review utility management of the distribution grid to ensure cost effective investments that support grid reliability and resilience and diversification of energy supply; support utilization of distributed energy resources that reduce the need for conventional distribution grid investment; encourage local ownership or renewable generating facilities; provide transparency of grid investments and capabilities; and facilitate the modernization of grid monitoring and control technologies and processes.

11. The Joint Solar Parties[2] filed comments in support of the new DSP proposals WRA has submitted, and stated it would submit additional comments in reply on any specific areas where they can identify improvements.

12. Energy Freedom Colorado filed comments and attachments in support of the development of rules regarding Hosting Capacity Analysis.

13. Through this stakeholder outreach and workshop process that ended in late 2018, the Commission and stakeholders developed an understanding that the increasing adoption of distributed energy is accelerating due to changes in customer choices, technological development, cost reductions, and public policy. DSP may help the Commission ensure grid

[2] The Joint Solar Parties generally included CoSEIA, SEIA, Vote Solar, and Sunrun, Inc.

modernization allows for continued safe, reliable, and cost-effective utility operations. An integrated planning approach across discrete aspects of utility operations may help the utilities, the Commission, and stakeholders meet distribution needs and expand customer choice through: (1) integrating DER into grid planning; (2) streamlining the interconnection process; (3) utilizing new resources to increase demand flexibility; and (4) avoiding unneeded investment in transmission and bulk power generation.

14. As a result of the stakeholder process, many stakeholders concluded that an Integrated DSP process is an important step for the Commission to take. As more DER are added to utility systems because of technological development, cost reductions, public policy, and customers interested in having more choices, stakeholders include that DSP may be an integral part of a systematic approach to meeting this growth in adoption. Comments further discuss that increasing DER is not the only reason for requiring integrated distribution planning. Many states across the country see such DSP as a way to better engage customers, cut costs and improve reliability and resiliency. Other state the driver for such a process is a means to achieve cost-effective grid modernization or a way to replace aging infrastructure.

C. Initial Stakeholder Comments Regarding § 40-2-132, C.R.S.

15. Following the stakeholder outreach in Proceeding No. 17M-0694E, the Commission opened a rulemaking in Proceeding No. 19R-0096E, by Decision No. C19-0197, with proposed amendments to 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 Interconnection Standards and Procedures presently in 4 CCR 723-3-3667.

16. Rules relating to Distribution System Planning were not proposed in the comprehensive rulemaking in Proceeding No. 19R-0096E. Nevertheless, SB 19-236, effective May 30, 2019, includes § 40-2-132, C.R.S., that directs the Commission to promulgate rules establishing the filing of Distribution System Plans and the evaluation of Non-Wires Alternatives (NWA). Section 40-2-132, C.R.S., specifies that the Commission shall promulgate rules establishing the filing of a distribution system plan that includes: 1) a methodology for evaluating the costs and net benefits of using DER as NWA; 2) a determination of the threshold for the size of new distribution projects requiring NWA analysis for any new neighborhood or housing development; 3) a determination of what should be included in a DSP filing including, the consideration of NWA regarding new development (greater than 10,000 residences), the consideration of increases in load forecasts resulting from beneficial electrification programs, a forecast of DER growth, a summary of planning process for cyber and physical security risks, a proposed cost-recovery method, anticipated new distribution system expansion investments, a process to evaluate DSP feasibility and economic impacts of NWA, and an estimate of peak demand growth or DER growth that merits analysis of new NWA projects; 4) a determination of the public interest in approval of NWA; and, 5) a determination of ratepayer benefits from NWA and establish benchmarks or accountability mechanisms.

17. During the ongoing rulemaking, the 2019 General Assembly passed several Commission related bills, including SB 19-236. Decision No. C19-0197 foresaw the possibility

of significant statutory changes that would require additional changes to Electric Rules.[3] During the weeklong hearing, the Commission instructed the participants to address additional rule changes that were necessary as a result of new legislation.[4] 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*.[5] In addition, during the hearing from April 29, 2019 through May 3, 2019, the Commission invited post-hearing comments regarding the impacts of recently passed legislative changes on the Electric Rules including § 40-2-132, C.R.S.

18. Several comments were filed in Proceeding No. 19R-0096E regarding the development of DSP rules.

19. Public Service states that SB 19-236 creates a requirement, but not a deadline, for the Commission to promulgate DSP rules. The Company argues that DSP, unlike the other areas addressed in the comprehensive NOPR, which tend to be modifications to rules that have had years of practical application, is a wholly new topic for the Commission to develop rules around. Public Service includes in its comments that careful Commission consideration of this new area will take time, and should be the focus of a dedicated proceeding to evaluate.

20. Public Service also states that as the Company works to integrate more DER to accommodate customer choice, a grid more integrated with distributed energy resources is needed and increased visibility of these generating resources becomes more important, both for

[3] 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.

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

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

real-time operations as well as generation and distribution system planning. The AMI system (approved in Proceeding No. 16A-0588E) is planned to read solar production meter data every four hours. The data will include readings on a 15-minute basis. Accordingly, the Company states the data enabled by AMI and production meters will improve over time. Public Service also has the capability to read additional points, including five-minute average voltage for each phase, and five/fifteen minute interval kWh and KVAR (reactive power). The Company believes this additional data will be useful to investigate or study a particular area of a feeder, inform the distribution planning processes, or conduct a NWA analysis.

21. Public Service furthers argues that from a distribution planning perspective, PV production data (from Production Meters) improves the accuracy of such a hosting capacity process. Public Service states that solar production meter data flows into its distribution planning model, Synergi. This information helps identify how much solar generation is on a given feeder, as well as specific locations along the feeder. If the solar production data is not available in the future, it will reduce the precision of the Company's PV hosting capacity analysis. Public Service states that solar data becomes particularly important to investigate NWA analyses as part of a distribution planning processes. They believe NWA will evolve to a more sophisticated and streamlined analysis, and detailed solar production data is useful to analyze how solar is behaving on the system, so that it can be considered as a reliable technology available to support a particular solution.

22. CEO recommends in its comments that the development of DSP rules take place following a re-noticing of this proceeding to include DSP rules. CEO states this will ensure the Commission addresses DSP in a timely manner and that all of the Commission's Rules that are

interrelated with this topic, such as the ERP and RES rules are updated accordingly. Following this re-noticing, CEO states that it plans to work with stakeholders to provide an updated DSP rule proposal that incorporates the requirements of the new legislation.

23. CEO further states that it does not have a position currently on how these proceedings should be aligned or what issues should be presented in conjunction with one another, suggesting that the Commission might consider whether to integrate a DSP filing with a RES compliance plan filing. Both DSP plans and RES compliance plans will consider the acquisition of DERs and will determine whether and how a utility acquires resources below 20 MW in size and resources behind the customer meter.

24. As previously noted, WRA submitted proposed model Distribution System Planning rules in the pre-rulemaking Proceeding No. 17M-0694E. WRA states in its filed comments that it is working to update those model rules in light of Senate Bill 19-236 and would share them with the Commission and other stakeholders in a workshop or any other forum the Commission deems appropriate.

25. COSSA and SEIA states in its comments that DSP rules can be geared towards achieving cost reductions on the distribution system and potentially allowing for more innovative and competitively bid grid modernization solutions to increase hosting capacities of DERs. COSSA and SEIA state the Commission will have the opportunity to carefully consider how distributed generation and other DERs, which are installed and funded by customer decisions, can reduce the costs associated with de-carbonization and electrification and can provide grid solutions that will contribute to the reliability, resiliency and demand reductions necessary to transform the electric sector. They note that the DSP process could result in a longer term needs to modify and update the RES rules.

26. COSSA and SEIA recognize that new DSP processes may influence the need for interconnection rule amendments in the future. They support taking additional time to work through these complicated and varied policy and technical issues.

27. Vote Solar urges the Commission to consider the Production Meter issue as part of a future distribution system planning rulemaking, rather than finalizing the mandatory production meter proposal in the current rulemaking. If the utilities conclude mandatory production meters are needed for distribution system planning, the upcoming rulemaking on that topic would be the more appropriate forum to consider this issue.

D. Discussion

28. Although the stakeholder input to date regarding DSP issues has been robust and beneficial, we find that continued discussion of the potential issues surrounding § 40-2-132, C.R.S., as well as the collection of additional information is necessary prior to the development of a NOPR to initiate a future rulemaking proceeding as required by the statute. There are several technical issues, particularly surrounding the statute's directives on NWAs, which the Commission should address with stakeholders through further outreach.

29. The purpose of this proceeding is to invite interested stakeholders to submit comments and potentially file rule change proposals prior to the Commission's issuance of a NOPR for DSP filings as required by § 40-2-132, C.R.S. Responses to questions set forth in this Decision can help inform the Commission of the costs and benefits, impacts to ratepayers, regulatory and policy implications, and impact on DER integration and growth due to the filing of DSPs and the evaluation of NWAs.

1. Guidance or Policy Statements

30. Distribution System Planning is occurring in various states, and has been initiated for various purposes. The experiences in these other states has demonstrated that the stated purpose for initiating DSP (e.g., the policy and regulatory objectives) influences how DSP is designed and ultimately implemented. However, § 40-2-132, C.R.S., does not explicitly state a purpose for implementing DSP.

31. We seek examples of other states' efforts in DSP initiatives to explore:

- What is the purpose of implementing a DSP?
- What types of guidance should the Commission ultimately provide to utilities?
- What principles should the Commission consider in setting criteria to govern the review and approval of a DSP?

32. In addition to recent statutory changes, the administration of Governor Jared Polis "has set a goal of 100 percent renewable electricity by 2040."[6] We invite comments on Governor's policy statements and other public policy goals in this examination of DSP.

2. Non-Wires Alternatives (NWAs)

33. NWAs generally comprise energy efficiency, demand response, solar PV, storage and other DERs solutions to remedy constraints on the distribution grid. They may be employed individually (*e.g.*, energy storage at a substation) or in combination (*e.g.*, energy efficiency, demand response, and energy storage at customer sites), depending upon the system's needs.

34. Possible benefits from NWAs include deferred capital requirements, integration of non-carbon-emitting resources, additional flexibility, increased reliability in targeted areas, and

[6] See:
https://www.colorado.gov/governor/environment-and-renewables and
https://www.colorado.gov/governor/2019-executive-orders

decreased energy and capacity costs for the distribution utility, along with potential ratepayer benefits.

35. Some states, such as New York and California, have spent several years trying to develop a market for NWAs. Several other states are attempting to develop a process for utilities to evaluate and implement NWAs. Progress in this area has been slow and difficult for several reasons, including the complexity of trying to match identified distribution upgrade needs to the capabilities and services that DERs could provide.

36. NWAs are typically sought to defer capital investment, which may reduce the utility's opportunity to earn a rate of return and potentially may lead to lost revenue. Contractual and performance assurance issues between utilities and third-party providers also contribute to the complexity and perceived risk of implementing NWAs.

37. New incentives, regulations, and changes in traditional utility business models may be needed to expand NWAs.

38. We seek information on the following related to NWAs:

- Should the Commission establish thresholds with respect to project type (e.g., load relief or reliability), project cost (to set a minimum size given transaction costs for utilities and DER providers), timing (sufficiently in advance of distribution system need) to govern consideration of NWAs?
- How can DSP integrate NWAs in a way that allows utility customers and DER providers to provide incremental value to the utility system?
- Is it necessary to define deferred investment in the distribution grid as distinct from avoided investment? How should each be considered and compensated?
- How should the Commission's evaluation of NWAs be conducted (e.g., a "pilot project" model, an application for a certificate of public convenience and necessity (CPCN), per tariff provisions, or some other type of regulatory framework)?
- What information and data need to be provided for utility customers and third-parties to respond to potential NWA project requests?

- What contractual and compensation issues between utilities and potential NWA providers need to be addressed upfront?
- How should NWA opportunities take into account the potential of beneficial electrification of buildings and transportation and associated load growth in the future?

3. Modeling Load Growth, DER Forecasts and Scenario Analysis

39. Distribution planners assess current and future system needs based on internal modelling. The load forecasts that feed into such models are thus foundational for DSP. Colorado electric utilities currently take into account some forecasted DER in their load forecasts (*e.g.*, energy efficiency and expected amounts of distributed generation from renewable energy programs), but there may be a need for them to more fully account for the impacts of state policies and goals in that forecasting (*e.g.*, increasing electrification of heating and transportation due to the Polis administration's policies).

40. We invite comment on the following:

- How are utilities currently conducting load forecasting? What tools are they using and at what level of granularity?
- How are utilities currently forecasting different types of DER?
- What are the options and the corresponding costs and benefits of increasing granularity of load forecasts and using alternative methods, including customer adoption methods, for projecting DER adoption scenarios?
- Should stakeholders have the opportunity to review and provide input into forecasting assumptions and methodology?
- With respect to scenarios, how should utilities incorporate load growth patterns and drivers outside of their historical experience? How should they properly treat the associated uncertainty with investment?

4. Plan Requirements

41. Section 40-2-132, C.R.S., specifies certain components of an electric utility's DSP filing. We seek information on whether the Commission should clarify any statutory

requirements for DSP filings and whether the DSP filing should include information in addition to the statutorily-required components.

42. For example, a DSP filing might address: NWAs for new developments (greater than 10,000 residences); increases in load forecasts resulting from beneficial electrification programs; forecasts of DER growth; summary of planning process for cyber and physical security risks; and proposed cost-recovery methods and anticipated new distribution system expansion investments.

43. We seek comment on the basic requirements for the submission of a DSP filing. For example, how often should DSP filings be made? Should plans address both short-term capital investments (1-3 years) and long-term capital plans (7-10 years)?

44. We also seek responses to the following questions:

- What specific concerns around safety and reliability should be addressed in the DSP filing?
- Should the Commission require proposed benchmarks and accountability mechanisms for each DSP filing?
- How should NWA procurements (or other procurements) be structured into a DSP? For example, should a Request for Proposals (RFPs) be required in a DSP filing?
- What functions and capabilities of modern distribution grids should the Commission consider to guide and evaluate the utility's development of DSPs? How should these be identified in a DSP filing?[7]

5. Data, Data Privacy, and Data Security

45. Distribution planning is data intensive, raising privacy and security concerns. The main question is what data should be shared to foster NWAs in a DSP in a way that ensures that

[7] For more information of functions and capabilities of Modern Distribution Grid Projects, see the Next Generation Distribution System Platform (DSPx) Guidance Project at Pacific Northwest National Laboratory. https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

sensitive system information, company trade secrets, and individual customer personal identifiable information are protected:

- What can be learned from other states regarding data, data privacy, and data security (e.g., New York, National Grid has developed a publicly accessible System Data Portal, which allows third parties to access key information, such as peak/load forecasts, capital plans, distribution system planning process descriptions, and hosting capacity maps)?
- How can DSP provide transparency in utility planning and decision-making while protecting data privacy and security? Who might use DSP data (system and customer) and for what purposes?
- What types of data and level of data access should be considered as part of the DSP? What data formats need to be established or required?
- Should the Commission establish guidelines for data access, sharing procedures, data requests, dispute settlement, and privacy/security protections?
- Should customers have the right to access their own usage and billing data in an easily organized and standard format?
- Should customers be able to authorize third party access to their data?

6. Costs and Benefits

46. Other states are exploring whether a standard cost-benefit methodology should be established for evaluation of DSP. The federal Department of Energy (DOE) is also developing a cost-benefit framework for its Modern Distribution System initiative.[8]

47. With respect to costs and benefits, we seek comments on the framework expected from the DOE, experiences in other states, and on the following:

- What types of costs and benefits should be considered when quantifying the value of NWAs in distribution planning and operations?
- How should the Commission evaluate the value of DER to the grid versus the value to the ratepayer?

[8] The DOE is expected to publish a paper framework, "core" (or platform) components that are foundational investments necessary for providing the services required of modern grids are evaluated using a least-cost, best fit approach; "applications" (or modules) that are additional, single-purpose components that can be layered on top of core components to provide additional functionality are evaluated using traditional economic methods for benefit-cost analysis.

- Should the Commission take initial steps to develop a method to quantify locational and temporal costs and benefits of DERs, avoided costs of traditional utility distribution investments, and the appropriate rates and incentive policies?

7. Hosting Capacity Analysis and Interconnection

48. In general terms, hosting capacity analysis (HCA) determines the maximum amount of DER that can be interconnected at a specific point in the distribution system without adversely impacting power quality or reliability under existing control and protection systems and without additional upgrades. HCA reveals areas where DER is less costly to interconnect. Hosting capacity maps can help streamline interconnection processes and create an environment that encourages the addition of DER to the grid. Accordingly, we seek responses to the following questions

- What are the uses and objectives of HCA? What are the granularity, frequency, and accuracy requirements for each use of HCA?
- How often should hosting capacity maps be updated now and in the future?
- How should the Commission ensure than any HCA requirements meet cybersecurity and privacy standards?

49. With respect to interconnection, we solicit comments on the following:

- What improvements to the utility's interconnection process are required to implement a DSP?
- How can the Commission best develop smart inverter policies?

8. Coordination of Filings and Other Issues

50. Several states are attempting to align DSP with other planning processes. For example, California is aiming for consistent DER forecasts across multiple planning processes. Minnesota is seeking greater linkage with its integrated resource planning and grid modernization efforts. Similarly, Rhode Island intends to synchronize two planning processes

that previously operated under separate schedules and making the processes more open to stakeholders.

51. Along these lines, we seek information on the following:

- How should DSP filings be coordinated with other filings with the Commission, specifically Electric Resource Plans (ERPs), Renewable Energy Standard (RES), annual generation and transmission facilities filings, CPCN filings, and transportation electrification applications?
- Is there a preferred sequencing of planning and reporting, whereby certain proceedings yield decisions that inform other proceedings? Can or should the proceedings occur in parallel?

52. Finally, we invite suggestions on other issues that Commission should explore in this proceeding.

E. Procedures

53. We open this proceeding as administrative proceeding under 4 *Code of Colorado Regulations* 723-1-1004(b).

54. We request that persons interested in participating in this proceeding, file a notice of participation. These notice filings should be made no later than January 10, 2020.

55. We intend to use this pre-rulemaking proceeding as a means to collect information on the initial regulatory steps that the Commission should take to meet the requirements of Senate Bill 19-236, as well as addressing the issues and questions discussed above. We request that stakeholders and interested participants suggest rules that would allow the Commission to engage in distributed resource planning Comments submitted in prior related proceedings as discussed above may be submitted into this Proceeding.

56. We invite stakeholders and other interested participants to submit initial comments in response to this Decision no later than February 3, 2020.

57. Responsive comments and draft redline rules shall be filed by March 13, 2020

58. We designate Chairman Jeffrey P. Ackermann as the Hearing Commissioner.

59. We further welcome suggestions as to topics the Commission should explore through workshops, as part of this proceeding. The scheduling of the workshops will be by separate decision issued by the Hearing Commissioner.

60. This Proceeding shall be a precursor to the rulemaking required by § 40-2-132, C.R.S. A future NOPR will issue in the future in a separate proceeding based on the comments and information gathered in this Proceeding.

61. This proceeding will be governed by Rule 4 Code *of Colorado Regulations* 723-1-1111, the "Permit, but Disclose" process. Interested persons may schedule *ex parte* presentations to a Commissioner that shall include Commission Staff provided that the contacts relate solely to the DSP issues and the implementation of § 40-2-132, C.R.S, and do not concern any matter pending before the Commission in another proceeding. Within two business days following a permitted presentation, the person requesting the meeting is required to file in this Proceeding a letter disclosing the contact with a copy of materials provided to the Commissioner during the meeting.

62. The Commission will attempt to accommodate all reasonable requests for *ex parte* meetings, subject to the schedule and availability of each Commissioner. To schedule an *ex parte* presentation with a Commissioner, an interested person should contact the Executive Assistants to the Commissioners and should clarify that the presentation is associated with this Proceeding.

II. ORDER

A. The Commission Orders That:

1. The Commission opens this Miscellaneous Proceeding to collect comments and other information given statutory changes in Senate Bill (SB) 19-236 that, among other revisions, creates § 40-2-132, C.R.S., directing the Commission to promulgate rules regarding the filing of Distribution System Plans (DSPs) by Colorado electric utilities.

2. This Proceeding is designated as an administrative proceeding under 4 *Code of Colorado Regulations* 723-1-1004(b).

3. This Proceeding will follow the "Permit, but Disclose" process pursuant to Rule 1111 of the Commission's Rules of Practice and Procedure 4 *Code of Colorado Regulations* 723-1.

4. The Commission designates Chairman Jeffrey P. Ackermann as the Hearing Commissioner.

5. Persons interested in participating in this proceeding shall file a notice of participation by January 10, 2020.

6. Interested stakeholders shall submit initial comments in response to this Decision no later than February 3, 2020.

7. Responsive comments and draft redline rules shall be filed by March 13, 2020.

8. This Decision is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING November 6, 2019.

(S E A L)

ATTEST: A TRUE COPY

Doug Dean

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

JEFFREY P. ACKERMANN

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FRANCES A. KONCILJA

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JOHN GAVAN

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Commissioners