COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

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PART 3
RULES REGULATING ELECTRIC UTILITIES

3506. – ~~3549~~3524. **[Reserved].**

DISTRIBUTION SYSTEM PLANNING

3525. Applicability

This rule shall apply to all electric utilities in the state of Colorado that own distribution facilities except municipally owned electric utilities and cooperative electric associations that have voted to exempt themselves from the Public Utilities Law pursuant to § 40-9.5-104, C.R.S.

3526. Overview and Purpose.

The purpose of these rules, as directed by § 40-2-132, C.R.S., is to require electric utilities to file a Distribution System Plan (DSP) that enables the Commission to review and evaluate the utility's investments in the distribution grid to ensure that they cost-effectively support grid adequacy, reliability and resilience and prepare for new expectations upon the distribution system, while simultaneously ensuring progress toward priorities highlighted by state legislation, including but not limited to supporting diversification of energy supply through distributed energy resources, expanding the utilization of non-wire alternatives that may reduce the need for conventional distribution grid investment, reducing greenhouse gas emissions, advancing building and transportation electrification, maintaining affordable customer rates, and promoting equity with regard to disproportionately impacted communities. These rules should also establish a proactive and transparent process for enhancing understanding of key distribution system characteristics.

3527. Definitions.

The following definitions apply to rules 3525 through 3542. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Ancillary services" means the functions that maintain the proper flow and direction of electricity, address imbalances between supply and demand, and help the system recover after a power system event. Ancillary services include but are not limited to synchronized regulation, contingency reserves, flexibility reserves, voltage and frequency response, power factor corrections, and spinning reserves.

(b) “Capacity need” means a distribution grid capacity constraint or shortfall projected within a ten-year period.

(c) “Demand flexibility” means the ability to help utilities manage or balance load by shifting electricity use across hours of the day to reshape customer load profiles or dynamically respond to system conditions while delivering end-use services (e.g., air conditioning, domestic hot water, electric vehicle charging) at the same or better quality and delivering net benefits to the system, customers, or society. Demand flexibility often uses distributed energy resources, communication and/or control technologies.

(d) “Demand response measures” or “demand response” or “DR” means any modulation in customer electric usage at targeted times, including reduction of usage or shifting of usage from one time to another, or interruption or curtailment of electric usage, either with load control equipment or in response to incentives, a signal, or changes in the price of electricity designed to induce changes in electricity use at specific times.

(e) “Direct current fast charger” means a high-power fast charging method of at least 50 kW capacity used to resupply an electric vehicle using direct current electricity, typically 208/480V three-phase.

(f) “Distributed energy resources” or “DER” may include, but are not limited to, distributed generation, energy storage systems, electric vehicles, microgrids, fuel cells, and demand side management measures including energy efficiency, demand response, and demand flexibility that are deployed at the distribution grid level, on either the customer or utility side of the meter. DER can be used to optimize energy use and generation to satisfy the energy, capacity, or ancillary service needs of the distribution grid.

(g) “Distribution system plan” or “DSP” means the compliance plan filed in accordance with rule 3528.

(h) “Energy efficiency measures” are measures that target consumer behavior, equipment, or devices that result in the decrease in electricity usage of customers without detriment to end-use services.

(i) “Grid availability” means the hours per year when the utility makes the grid or a portion of the grid available for use not only by load but also by distributed generation and demand response.

(j) “Grid need” means the need for energy, capacity, ancillary services, reliability, or resiliency services to address a forecasted deficiency on the electric distribution system.

(k) “Hosting capacity” means the amount of distributed generation, including distributed generation paired with non-exporting battery storage (and additional technologies including exporting battery storage to the extent reasonably feasible to model), that can be interconnected to the distribution system at a given time and at a given location under existing grid conditions and operations, without adversely impacting safety, power quality, reliability or other operational criteria, and without requiring electric infrastructure upgrades.

(l) “Locational value” means an analysis of distributed energy resources that incorporates location-specific incremental net benefits to the electric grid.

(m) “Major distribution grid project” means planned, proposed, or potential construction, reconfiguring, or upgrade of any electric distribution line, substation, or ancillary structure that meets the following criteria: (1) is a project estimated to require an investment of more than $2 million on the distribution grid or more than $3 million on both the transmission and distribution grids; and (2) will be made at or near an existing or planned substation, or feeders or transformers associated with a substation.

(n) “Microgrid” means a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that can act as a single controllable entity with respect to the grid. A microgrid is capable of connecting and disconnecting from the centralized grid to enable the microgrid to operate in both grid-connected or island-mode.

(o) “N-1 event” means an outage event of one distribution or transmission element such as a transformer, feeder, or transmission line that may cause load to shift to other elements as backup. An N-1 event indicates a need for additional reliability capacity if it is determined to cause a potential overload on elements carrying energy to accommodate the event.

(p) “Non-Wires Alternative” or “NWA” means the strategic deployment of distributed energy resources by a utility or a third party and associated control or aggregation of systems and technologies intended to cost-effectively defer or avoid the need for Major Distribution Grid Projects. An NWA is intended to reliably reduce load, congestion or other constraints at times of peak demand in targeted locations on the grid. NWAs can include one or multiple DER, including but not limited to demand response measures, energy efficiency, energy storage, and distributed generation. NWA projects can include these and other investments individually or in combination to meet the specified need.

(q) “Pilot” means a utility offering to test a new use or deployment of DER for a set period of time with a specified end date and number of customers, wherein the utility seeks to gain experience or expertise, and to inform the Commission.

(r) “Program” means an ongoing, long-term offering by the utility with no specified end date that utilizes or deploys DER on the distribution grid in a manner that provides system benefits or cost savings.

(s) “Ratable procurement” means the procurement of incremental DER capacity to defer or avoid long-term traditional utility infrastructure or grid needs driven by steady load growth.

(t) “Reliability need” means a risk of failure requiring mitigation due to inadequate capacity or voltage support, or an N-1 event on the distribution grid.

(u) “Resilience” is the ability of the distribution grid to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.

3528. Distribution System Plan Filing Requirements.

A utility with over 500,000 customers shall file a DSP as an application, every two years, with the first DSP to be submitted on or before January 31, 2022. A utility with 500,000 or fewer customers shall file a DSP as an application, every two years, with the first DSP to be submitted on or before January 31, 2023.

(a) Each DSP application filing shall conform to the application requirements contained in rules 3002 and rule 1303 of the Commission's Rules of Practice and Procedure.

(b) Within 30 days of the filing of the application, the Commission shall issue a decision addressing whether the contents of the DSP meet Commission standards based on the information provided by the utility set forth in paragraph 3528(d).

(c) If the DSP identifies major distribution grid projects that meet the NWA suitability screening criteria put forth in paragraph 3534(a), then the DSP proceeding shall consist of two phases.

(I) Within the same proceeding and subject to paragraph 3528(b), the utility shall file a Phase II DSP within 120 days of the filing of the Commission's order establishing the final Phase I DSP.

(A) Within 30 days after the filing of the Phase II DSP, parties may submit comments pertaining to the Phase II DSP.

(B) Within 15 days after the deadline for initial comments on the Phase II DSP, parties may submit reply comments.

(d) If the utility claims that any of the requirements set forth in rules 3529 through 3541 are not yet practicable to provide or are currently cost-prohibitive to provide, the utility shall indicate for each requirement:

(I) why the information is not yet practicable or is currently cost-prohibitive, what information could be provided in the alternative and how that alternative information would achieve planning and policy objectives;

(II) how the information could be obtained in future filings, and if so, at what estimated cost, and on what timeframe;

(III) what the benefits or limitations of filing the data in future reports would be as related to achieving the planning and policy objectives; and

(IV) if the information cannot be provided in future reports, what information could be provided in the alternative and how it would achieve planning and policy objectives.

(e) The utility shall file a final DSP action plan in accordance with rule 3536, including all required modifications, within 60 days of the Commission's final decision.

(f) The utility may file, at any time, an application to amend the contents of a DSP approved pursuant to paragraph 3536(c). Such an application shall meet the requirements of paragraphs 3002(b) and 3002(c), shall identify each proposed amendment, shall state the reason for each proposed amendment, and shall be administered pursuant to the Commission's Rules Regulating Practice and Procedure.

(g) Utilities are encouraged to convene regular, informal stakeholder meetings to discuss DSP-related issues and to inform the contents of DSP applications. The utility shall convene at least one stakeholder meeting at least 90 days prior to the filing of the DSP. As part of these stakeholder meetings, the utility shall solicit input on future programs and/or pilots and solicit feedback on both the hosting capacity analysis and the web portal. The utility shall make all reasonable efforts to engage local governments and community organizations representing disproportionately impacted communities. The Commission may, at its discretion, require utilities to host stakeholder discussions regarding specific DSP topics.

3529. Contents of the Distribution System Plan.

(a) The utility shall file a Phase I DSP with the Commission that contains the information specified below. When required by the Commission, the utility shall provide any relevant studies, additional data, and work-papers to support the information contained in the plan. The DSP shall include the following:

(I) a description of the objectives of the DSP, including the utility's ten-year vision for distribution grid capabilities and services that meet customer needs and state policy goals;

(II) a description of how the distribution grid may evolve over the next five and ten years due to various factors, such as increasing DER penetration, the expansion of beneficial electrification programs and other electrification, advanced metering infrastructure, increasing demand flexibility, energy efficiency and other emerging technologies. The utility should discuss the challenges and opportunities presented by the emergence of new technology as well as plans they have to adapt to or utilize these changes to the grid;

(III) a description of the utility's vision of how existing utility demand-side management measures and programs, as well as other existing distributed energy resource offerings, shall or could be utilized or modified to meet distribution system planning needs;

(IV) distribution system forecasts, as described in rule 3530;

(V) an assessment of the existing distribution system, as described in rule 3531;

(VI) an assessment of grid needs, as described in rule 3532;

(VII) a description of grid innovations and any proposed pilots and programs, as described in rule 3533;

(VIII) NWA suitability screening results, as described in rule 3534;

(IX) a proposed NWA cost benefit analysis methodology, as described in rule 3535;

(X) any proposed documents and model contracts that the utility intends to use for NWA solicitation or procurement;

(XI) a Phase I action plan, as described in rule 3536;

(XII) a proposal for cost recovery, which may include an incentive, as described in rule 3538;

(XIII) a security assessment, as described in rule 3539.

(XIV) a proposal for implementation of a web portal as described in paragraph 3541(d);

(XV) a description of the stakeholder engagement process, as described in paragraph 3528(g); and

(XVI) a description of how the utility has engaged, and plans to engage, on DSP with communities, particularly disproportionately impacted communities, and how the utility has incorporated community climate, equity and resilience goals and priorities into the DSP and action plan.

3530. Distribution System Forecasts.

(a) Forecast requirements. The utility shall prepare demand forecasts for each year within the ten-year planning period. The utility shall also prepare ten-year forecasts for load growth on the distribution grid, including the growth of various types of DERs connected to the distribution grid. Forecasts should be based on at least two growth scenarios (State Policy and High), including reasonably detailed predictions of the expected geographic areas of substantial growth within the distribution substation grid area and impacts on planning for the transmission and distribution system, including impacts due to DER adoption and increased demand flexibility and demand response within the utility's service territory. Forecasted growth should include the following:

(I) peak load growth at each substation, by year;

(II) peak load growth at each substation transformer by year;

(III) peak load growth on each feeder, by year;

(IV) coincident peak and non-coincident peak load growth at substations, transformers, and feeders, by voltage class;

(V) load growth associated with beneficial electrification, by substation transformer and by feeder under each scenario in subparagraph 3530(a)(X);

(VI) load growth due to new planned neighborhoods or housing developments,

(VII) net load impacts due to DER adoption under each scenario in subparagraph 3530(a)(X);

(VIII) net load impacts due to demand side management, demand response, and demand flexibility;

(IX) approved CSG capacity in RES Plans and anticipated CSG capacity additions beyond the current effective RES plans;

(X) forecasts of DERs and NWA should include ten-year scenarios that project expected growth of DERs and NWA, including expected geographic dispersion at the distribution feeder level and impacts on distribution planning. Scenarios shall be designed to meet or exceed current state policy such as those related to greenhouse gas (GHG) reductions, increased use of DERs, electrification, distribution reliability, resiliency, and transmission system needs. Scenarios shall include key inputs including growth of peak exported generation or net generation from distributed solar generation; growth of peak exported generation or net generation from distributed battery storage systems; and growth of peak exported generation or net generation from all other distributed generation. Scenarios shall be based on the following criteria:

(A) State Policy Goal Scenario: Adopts a current forecast case for DER and NWA deployment for distribution planning at the feeder level, assuming compliance with current state policy goals.

(B) High Growth Scenario: Adopts a high growth case for DERs. This scenario should exceed state policy goals, which may include long-term GHG reductions, and beneficial electrification at levels higher or faster than required in state statute or incurrent state policy goals. Additionally, the High Growth Scenario may improve upon performance in areas of demand flexibility, distribution reliability, resiliency, and transmission system needs beyond a business as usual projection.

(b) The utility shall provide all assumptions and methodologies that are inputs into the forecasting scenarios in paragraph 3530(a).

3531. Assessment of Existing Distribution System.

(a) System overview and substation historical data.

(I) To identify and assess needs on the distribution system, each utility shall provide a map of existing and planned substations within its service territory, as well as tabular information about the current design capacity, and performance of each substation and substation transformer. The assessment should also include the status of advanced metering infrastructure deployment which may be made by reference to other reports or filings. At a minimum, this should include the following information for each substation and substation transformer on the utility's distribution grid:

(A) maximum rated capacity of each substation transformer;

(B) peak hourly demand on each substation transformer for the past three years;

(C) capacity margin for each substation transformer;

(D) advanced functionality capabilities of each substation transformer;

(E) number of feeders served by each substation and substation transformer;

(F) maximum rated capacity of each feeder;

(G) peak hourly demand on each feeder for the past three years;

(H) capacity margin for each feeder;

(I) percentage of grid availability;

(J) minimum daytime load;

(K) aggregate miles of underground and overhead wires, categorized by voltage class;

(L) monitoring capabilities and data collection on the distribution system, such as the substations and feeders for which the utility has real-time supervisory control and data acquisition (SCADA) capability;

(M) amount of distributed generation installed on the system (number of systems and nameplate capacity in kilowatts (kW) by generator types, organized by substation or feeder);

(N) description of NWA on the system, organized by substation or feeder; including annual cost savings and greenhouse gas emissions reductions;

(O) amount and locations of distributed storage installed on the system (number of systems and ratings, measured in kilowatts and kilowatt-hours (kW and kWh));

(P) estimated number of EVs and Level 2 and DCFC EV charging stations organized by substation or feeder;

(Q) estimated demand flexibility capacity on the system and historic utilization of those flexibility capabilities;

(R) voltage and power quality data for the past three years; and

(S) location of highly seasonal circuits as defined by subparagraph 3667(a)(IV).

(II) Hosting capacity analysis.

(A) As part of its DSP, each utility shall develop a hosting capacity analysis of the distribution system.

(B) The analysis shall determine the hosting capacity on a particular feeder, feeder section or substation at a given time under existing and forecasted grid conditions and operations without adversely impacting safety, power quality, reliability, or other operational criteria.

(C) The hosting capacity analysis shall be performed using a load flow analysis and forecasted distribution facilities and their capacity, configuration, loading, and voltage data gathered at the substation, feeder, and primary node levels where available.

(D) The utility shall perform scenario analysis to evaluate hosting capacity need under normal, planned contingency, and unplanned contingency conditions, for both the State Policy and High Growth scenario.

(E) The utility shall provide a detailed description of the methods and outcomes it used to perform the hosting capacity analysis.

(F) The hosting capacity analysis shall reflect that which appears in the web portal as described in rule 3541. The utility shall also provide a detailed narrative describing the utility's progress towards advancements to the accuracy and value of the hosting capacity analysis and providing real-time hosting capacity data. This should include a description of how its hosting capacity analysis currently advances customer-sited DER (in particular distributed renewable electric generation and energy storage systems), how the utility anticipates the hosting capacity analysis will aid in identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources, and any other method in which the utility anticipates customer benefit stemming from the hosting capacity analysis.

(G) For their first DSP filing, utilities with 500,000 or fewer customers shall provide an Excel spreadsheet (or equivalent format) by feeder of either daily daytime minimum load or, if daytime minimum load is not available, daily peak load with the time granularity specified. If daytime minimum load or daily peak load data are unavailable, the utility shall explain why the data are unavailable.

3532. Grid Needs Assessment.

(a) The utility shall provide a summary analysis of the energy, capacity, ancillary services, and reliability needs and constraints on a utility's distribution system and solutions to those needs.

(b) The grid needs assessment shall include an analysis regarding the suitability of non-wires alternatives to mitigate identified needs and recommendations for the deployment of utility infrastructure upgrade solutions versus the procurement of non-wires alternative solutions to address any identified needs.

(c) The grid needs assessment shall address existing and forecasted needs over a ten-year planning period that could result in a major distribution grid project.

(d) The grid needs assessment shall include each of the following parts.

(I) An assessment of critical needs.

(A) The utility shall provide an assessment of critical capacity and reliability needs that must be addressed within the ten-year planning horizon.

(B) The assessment shall include a review of all planned, proposed and potential major distribution grid projects which will be required to address constraints related to substation transformers and feeders that are forecasted to have insufficient capacity to adequately serve peak load or reliability needs over the next ten years.

(C) The assessment shall be divided into two parts – one detailing short-term needs within zero to three years, and one detailing longer-term needs in four to ten years.

(D) The data used for the assessment shall be provided in megawatt values in tables, in a logical spreadsheet form (both printed and functional Excel spreadsheet formats) and graphically as a map in executable ARC GIS or similar format.

(E) The assessment of critical needs will be provided via the web portal, described in rule 3541. Any notable updates to the web portal should also be made in this section of the DSP.

(F) The assessment shall include a review of the capability of the distribution system and any needs incurred to interconnect approved CSG capacity in the utility's current SGIP queue. The assessment shall include an estimate of the potential benefits and costs of infrastructure upgrades. The assessment shall also include a good faith effort by the utility to assess any needs to interconnect capacity approved in its most recent RES Plan but not yet acquired, and a reasonable expectation of future CSG capacity during the DSP planning period for targeted development areas. The utility will work with stakeholders to assess the level of interest for targeted development at specific locations for future CSG capacity and the corresponding potential benefits and costs of infrastructure upgrade needs at those specific locations.

(II) The utility's current distribution plan for distribution grid investments, as well as the total capital budget including the past three years and the next five years of projected budget. Budgets shall be broken down by relevant budget categories.

(III) Fast charging locations for electric vehicles. The utility shall use the results of the grid needs assessment to identify locations where substation transformers and feeders have sufficient capacity for hosting multiple direct current fast chargers for electric vehicles. Utilities will also assess vehicle-to-grid (V2G) opportunities as potential NWA projects.

(IV) An identification of any long-term needs identified in the grid needs assessment for which ratable procurement may avoid or defer the anticipated need driven by steady load growth, including geographically targeted deployment of demand flexibility, demand response, and energy efficiency measures.

3533. Grid Innovation.

(a) The DSP shall address DSP pilots and programs that are either in progress, planned, or have been suggested by other parties and found to have merit by the utility. The DSP shall identify any barriers to deployment of DERs and NWA. Such barriers may include but not be limited to integration or interconnection of DERs and NWAs, barriers that limit the ability of a DER and NWA to provide benefits, and barriers related to distribution system operation and infrastructure capability. This section shall include, but not be limited to:

(I) Within each DSP, the utility may propose new pilots and programs designed to gain experience integrating DER, NWA or other new distribution technologies in a way that improves system performance, minimizes system costs, increases system resiliency and/or reliability, and/or reduces greenhouse gas emissions including from reduced curtailment of renewable energy. Such pilots and programs may be proposed as solutions to help solve identified grid needs identified under rule 3532.

(II) New proposed pilots. Within each DSP, the utility may propose new pilots. Pilots shall not be required to pass a cost-benefit test; however, the Commission shall determine that the pilot can be implemented at a reasonable cost and rate impact. Each of the proposed pilots shall, at a minimum, include:

(A) a description of what the utility seeks to learn through the pilot with specific goals and metrics;

(B) an explanation of how the pilot can be scaled to enable the utility to achieve objectives described in the plan pursuant to rule 3529;

(C) the specific DER and NWA technology or technologies eligible for the pilot, including any operational requirements;

(D) a description of any geographic or locational focus of the pilot;

(E) the customer classes that may participate in the pilot;

(F) a description of the potential benefits the utility expects the pilot technology to demonstrate;

(G) a description of the costs of the pilot, including a cap on costs for each pilot;

(H) criteria for evaluation of the pilot and an evaluation plan that includes a calculation of pilot costs, schedule, and a summary of pilot benefits, including quantified benefits, as available;

(I) a description of the use of any targeted incentive payments, or other incentives, provided to participants;

(J) a description of the mechanism to acquire equipment, technologies, vendors, and participants in the pilot; and

(K) a description of how the pilot will provide health, safety, environmental, or financial benefits to disproportionately impacted communities.

(III) New proposed programs. Within its DSP, the utility may seek approval for a new program to better integrate DER and NWA or other distribution technologies into its business practices in a way that improves system performance, minimizes costs, increases system resiliency and reliability, or reduces emissions. Proposed programs may be successors of completed pilots; however, a utility does not need to have conducted a pilot in order to seek approval for a new program.

(IV) The utility may propose pilots or programs developed internally and shall also accept third-party proposals for pilots and programs at any time. For a third-party pilot or program to be considered in a DSP, it must be received by the utility at least six months prior to the DSP filing deadline. When seeking approval for such pilots or programs, the utility shall provide an overview of all pilots and program proposals considered and an explanation for its proposed selections and rejections. For any proposal not considered, the utility shall explain why it was not considered.

(V) Updates on existing pilots and programs. Within its DSP, the utility shall provide a narrative status update on all active pilots and programs approved in prior DSPs. The utility may also seek reauthorization of existing programs within a DSP. As part of its first DSP, the utility is encouraged to evaluate whether any existing reporting obligations outside the DSP related to distribution system pilots, programs, or projects should be centralized within the DSP process. Upon Commission approval, and notice filed within the original proceeding, such reporting obligations shall be transferred to DSP proceedings.

(b) NWAs and pilots may include the use of targeted incentive payments to encourage DER adoption or optimize the use of existing DERs by customers in specific locations, to provide locational value to the system. Such incentives shall be accounted for in the cost benefit analysis as described in rule 3535 and shall be recovered in a manner similar to other distribution-grid related expenditures.

3534. NWA Suitability Screening.

(a) Major distribution grid projects identified to be necessary in the grid needs assessment conducted pursuant to rule 3532 shall be subject to an NWA suitability screening to determine if a NWA may be a suitable alternative to traditional utility infrastructure solutions.

(b) The NWA suitability screening is performed by the utility and includes the following criteria:

(I) the project is anticipated to occur during the ten-year planning horizon;

(II) the constraint is due to thermal loading, voltage, capacity or reliability issues and could be resolved by a DER, a reduction in peak demand loading, a reduction in energy consumption, or load shifting on the transmission or distribution facilities; and

(III) the conventional solution is still within the planning or design stage, with no major equipment on order, received, or installed that cannot be repurposed for other uses.

(c) The utility may seek a waiver from these requirements on a case-by-case basis, if necessary, to preserve reliability, serve economic development needs, or to meet other unforeseen circumstances where the utility expects a non-wires alternative cannot adequately resolve or the planning constraint. Such requests should be substantiated to show why the NWA suitability screening is not possible or could not reasonably result in an alternative to traditional utility infrastructure. Should the utility assert that a NWA is infeasible due to the urgency of the grid need, the utility shall also explain why the grid need was not previously identified.

(d) For all major distribution grid projects identified as meeting all the NWA suitability screening, the utility shall conduct a technology-neutral competitive solicitation for NWAs to defer, reduce, or avoid the costs of the major distribution grid projects.

3535. NWA Cost Benefit Analysis.

(a) In order to assess the cost-effectiveness of a potential NWA solution that meets the NWA Suitability Screening in rule 3534, the utility shall:

(I) develop and publish a cost benefit methodology that will be provided in the utility's DSP;

(II) assess the proposed NWA solution using a cost-benefit methodology that considers the approach as put forward in the National Standard Practice Manual and specifically including the following costs and benefits: avoided or deferred costs associated with an NWA solution, sub-transmission, substation transformer additions or upgrades, feeder capital and operating costs, distribution power quality equipment, reliability and resiliency costs, energy and capacity value of generation, capacity value of storage, greenhouse gas emissions including the Commission approved social cost of carbon useful life of NWA and traditional solutions, and dispatchability and availability of the technology. If the utility is proposing a performance incentive as part of cost recovery for the NWA pursuant to paragraph 3538(d), it shall include the cost-benefit analysis both with and without the performance incentive included as a cost of the project;

(III) provide a description of DSP goals, compliance with statute, rules, and requirements, and additional relevant principles; and

(IV) assess the proposed distribution system costs, direct system benefits, indirect system benefits, and system sensitivity analysis.

(b) The utility may also propose an alternative or adjusted cost-benefit methodology if it does not believe that the full costs and benefits of the NWA solution are being counted.

3536. Action Plan.

(a) The utility shall provide a five-year action plan for distribution system investments and activities within its Phase I DSP which will serve as an application for the Commission and stakeholders to rely upon when evaluating distribution system planning projects, pilots, and programs.

(b) The Phase I action plan shall include the sequence of events and timelines for each action that will not require a solicitation process following Phase I, including:

(I) the implementation of NWAs to address grid needs not classified as major distribution system projects, and the implementation of NWAs approved in prior DSPs;

(II) the implementation of proposed pilots and programs as specified in rule 3533;

(III) the implementation of major distribution grid projects that were determined to be the best option to address grid needs;

(IV) system interoperability and communications strategy;

(V) costs and plans associated with obtaining data necessary for the evaluation of NWAs, pilots and programs (for example, energy efficiency load shapes, solar output profiles with and without battery storage, capacity impacts of DR combined with energy efficiency, electric vehicle charging profiles);

(VI) interaction of planned or proposed investments with other utility programs and the effects on existing utility programs and tariffs; and

(VII) the implementation of major distribution projects intended to cost-effectively interconnect the approved and reasonably forecasted CSG capacity, including that approved by RES Plans in effect during the planning period.

(c) Subject to paragraph 3528(b), the utility shall provide an updated action plan with its Phase II DSP. This plan shall include the sequence of events and timelines for NWAs identified in the solicitation process, including:

(I) the implementation of NWAs identified through the NWA analysis process;

(II) an updated system interoperability and communications strategy;

(III) costs and plans associated with obtaining data necessary for the evaluation of NWAs (for example, energy efficiency load shapes, solar output profiles with and without battery storage, capacity impacts of DR combined with energy efficiency, electric vehicle charging profiles); and

(IV) interaction of planned or proposed NWA investments with other utility programs and the effects on existing utility programs and tariffs.

3537. NWA Solicitation Process (Phase II).

(a) The utility shall propose in its DSP (Phase I) Application appropriate timelines for the release of the RFP(s), the receipt of bids, evaluation of bids, the utility's proposal to the Commission, the filing of the independent evaluator report, party comments in response to the independent evaluator report, and the Commission decision. These timelines should consider similar timelines as expressed in the Electric Resource Planning Rules, specifically rule 3613. The timelines proposed by the utility and approved by the Commission in the DSP (Phase I) shall describe an appropriately expedited, comment-based NWA Solicitation Process (Phase II) to facilitate timely decisions and implementation of NWA bids.

(b) For projects which meet the Major Distribution or Major Transmission grid threshold and NWA suitability screening criteria, an Independent Evaluator (IE) shall be retained.

(I) The utility shall file for Commission approval the name of the independent evaluator. The Commission shall approve an independent evaluator by written decision during Phase I.

(II) The utility shall pay for the services provided by the independent evaluator pursuant to a contract approved by the Commission. In its Phase I DSP Application, the utility shall specify the level and structure of any bid fees proposed to offset the independent evaluator and solicitation costs. The terms of such contract shall prohibit the independent evaluator from assisting any entity making proposals to the utility for subsequent resource acquisitions for three years.

(III) The utility shall work cooperatively with the independent evaluator and shall provide the independent evaluator immediate and continuing access to all documents and data reviewed, used, or produced by the utility in the preparation of its projects which meet the Major Distribution or Major Transmission grid threshold and NWA suitability screening criteria and in its bid solicitation, evaluation, and selection processes. The utility shall make available the appropriate utility staff to meet with the independent evaluator to answer questions and, if necessary, discuss the prosecution of work. The utility shall provide to the independent evaluator, in a timely manner to facilitate the deadlines outlined in these rules, bid evaluation results and modeling runs so that the independent evaluator can verify these results and can investigate options that the utility did not consider. If the independent evaluator notes a problem or a deficiency in the bid evaluation process, the independent evaluator should notify the utility.

(IV) All parties in the DSP proceeding other than the utility are restricted from initiating contacts with the independent evaluator. The independent evaluator may initiate contact with the utility and other parties. For all contacts with parties in the DSP proceeding, including those with the utility, the independent evaluator shall maintain a log that briefly identifies the entities communicating with the independent evaluator, the date and duration of the communication, the means of communication, the topics discussed, and the materials exchanged, if any.

(V) The independent evaluator shall generally serve as an advisor to the Commission and shall generally not be a party to the proceedings. As such, the independent evaluator shall not be subject to discovery and cross-examination at hearing.

(VI) Within 30 days of a utility selecting an NWA bidder to advance to Phase II, the independent evaluator shall file a report. The independent evaluator shall address in its report whether the utility's competitive acquisition procedures and bidding policy, including the assumptions, criteria, and models, were sufficient to solicit and evaluate bids in a fair and reasonable manner, with any deficiencies specifically noted. The independent evaluator shall provide confidential versions of these reports to Commission staff and the UCA.

(c) All solicitations, unless requested by the Commission, or requested by the utility and approved by the Commission, shall be conducted in a technology neutral manner.

(d) The utility may require prospective bidders to sign non-disclosure agreements to obtain information deemed confidential or highly confidential.

(e) After final NWA bids have been selected by the utility, the utility shall update the elements of the Action Plan that pertain to NWAs.

3538. Approvals and Cost Recovery.

(a) The utility may seek Commission approval of a NWA, pilot, or program in its DSP application filing. Should such an approval be sought, the Commission may require a hearing specifically on the NWA pilot, or program in addition to the process described in rule 3536. The Commission may require the utility to demonstrate satisfactory compliance with appropriate benchmarks or performance metrics outlined in the Commission's decision approving pilots, programs or NWA or other components of the DSP. Utilities may seek approval to implement an NWA, pilot, or program not classified as major distribution grid projects without performing a competitive solicitation. New pilots or programs should meet the standards and requirements set forth in paragraph 3533(a).

(b) A utility may seek any necessary approvals for a NWA, pilot or program in other proceedings, including, but not limited to:

(I) demand side management planning;

(II) renewable energy standard compliance planning;

(III) transportation electrification planning; or

(IV) innovative technology pilot programs or demonstrations.

(c) The Commission shall approve a utility's investment in NWAs, pilots, or programs if the Commission finds the investment to be in the public interest. In considering whether the investment is in the public interest, the Commission shall determine whether the utility's ratepayers realize benefits from the NWA, pilot, or program and whether the associated costs are just and reasonable. The utility may seek approval to implement NWAs, pilot, or program not classified as major distribution grid projects without performing a competitive solicitation.

(d) In the application for approval of a DSP, the utility shall address how it anticipates recovering costs associated with the investments put forward in its DSP in accordance with subparagraph 3529(a)(XI).

(I) Investments made to implement an approved DSP shall be deemed to made in the ordinary course of business and shall be recovered through the normal implementation of the utilities rate mechanisms.

(II) The utility shall demonstrate that the investments made to implement an approved DSP do not undermine equitable access to other utility programs and do not materially impact the related utility program's targeted performance.

(III) The utility may propose a performance incentive for implementing any NWA, pilot, or program as a component of its cost recovery proposal. The performance mechanism, if proposed, shall also be included as part of the cost-benefit analysis specified in rule 3535. A performance incentive may include allocating to the utility a share of the cost-savings derived from NWA implementation as compared to the avoided capital investment.

(IV) For costs the Commission deems to be incurred outside the ordinary course of business, the utility may seek approval of a regulatory asset for recovery as part of the utility's next rate case or may be placed in another cost recovery mechanism as proposed by the utility. The Commission shall establish the authorized rate of return on any regulatory asset created pursuant to this paragraph.

(e) The Commission shall issue written decisions approving, conditioning, modifying, or rejecting the utility's DSP filing. The Commission may modify any plan, as appropriate, to optimize overall system costs and ratepayer benefits, to improve services derived from the distribution grid, and to achieve state policy goals pursuant to rule 3526. These decisions create a presumption that utility actions consistent with the decisions are prudent.

(f) The utility shall file a final DSP, which may include required modifications, within 60 days of the Commission's final decision.

3539. Security Assessment.

(a) The utility shall provide a narrative assessment of the reliability and resilience of the distribution grid with respect to cybersecurity and physical security, including:

(I) current status of distribution grid reliability and plans for improving reliability, including areas of the grid where reliability problems have been identified, with plans for resolving them. Distribution grid reliability metrics (SAIDI and SAIFI at a minimum) should be provided for each year for the past three years for each substation;

(II) list of major outages, including cause and duration, involving 10,000 customers or more for each year for the past three years;

(III) analysis of cyber security issues or other threats to the distribution system and what efforts the utility is taking to ensure the distribution system is secure;

(IV) analysis of risks by substation posed by natural disasters such as wildfires, floods, severe storms, and a detailed description of efforts the utility is taking to increase system resiliency in the response to these risks;

(V) other plans aimed at improving distribution system resiliency; and

(VI) any pilots or programs, existing or proposed, aimed at increasing reliability and resiliency, using microgrids or other technology, should be discussed within the Grid Innovation section of the Phase I DSP, as described in rule 3533.

(VII) The utility may incorporate by reference any other filings or applications made to the Commission that are relevant to a discussion of distribution system reliability and resilience.

3540. Data Access, Privacy and Confidentiality.

(a) The utility shall disclose data necessary to implement these rules with appropriate levels of protection, considering sensitivity and public benefit. The utility shall identify and address the treatment of sensitive information in consideration of the objectives of DSP and as required by these rules.

(b) The utility shall not disclose personal information, as defined in paragraph 1004(x), or customer data, as defined in paragraph 3001(i). Paragraph 3033(b) shall not apply to data releases under this rule.

(c) In each DSP application filing made pursuant to rule 3529, the utility shall file a list of the information related to the resource plan proceeding that the utility claims is confidential and a list of the information that the utility claims is highly confidential, and its proposed treatment of the information. For good cause shown, the utility may seek to protect information as confidential or highly confidential by filing the appropriate motion under rule 1101 of the Commission's Rules of Practice and Procedure in a timely manner.

3541. Web Portal.

(a) The utility shall make available a web portal that provide map-based and tabular data that is publicly available or access-restricted as further defined under this rule. Such web portal shall be designed to meet the objectives of the DSP and shall allow users to download data in tabular and geospatial formats

(b) The utility may only deny access to its web portal if visitors and/or registrants violate the terms of service or other agreed upon terms of access. To ensure the appropriate level of protection of sensitive information, the utility may require visitors to the web portal to take actions, including:

(I) requiring visitors to acknowledge terms of service associated with its use, provided those terms do not preclude academic or public policy purposes; and

(II) establishing registration processes, including the creation of a username and password, and/or the use of multifactor authentication for access to sensitive information.

(c) A web portal shall include at least the following information:

(I) consistent with subparagraph 3531(a)(II), the utility's hosting capacity analysis;

(II) publicly available summaries, data, or links to existing information on the utility's website related to programs approved by the Commission that address the deployment of DERs, including, without limitation, pilots, tariffs, and incentives; and

(III) any additional content as directed by the Commission.

(d) Implementation of the web portal.

(I) Prior to filing its first DSP application pursuant to rule 3529, the utility shall engage potential users of the web portal from multiple sectors to develop a proposal for implementation of the web portal to be filed with the application.

(II) In its first DSP application pursuant to rule 3529, the utility shall present a proposal and timeline for developing a web portal that meets the requirements of this rule and includes:

(A) a summary of its process for identifying and engaging potential users of the web portal and the results of that process;

(B) a description of use cases that will be implemented through the web portal to meet the objectives of DSP;

(C) an evaluation of the data required in a DSP application pursuant to rule 3529 that addresses what data will be provided on the web portal and at what level of granularity, an evaluation of the risks and benefits associated with providing such data, proposals for treatment of sensitive information, and identifying any data for which confidential or highly confidential treatment is sought under the process provided in paragraph 3540(c);

(D) a proposal for providing functionalities that enhance the user experience, such as color-coding of substations, circuits, and feeders or ability to change the year of the data being displayed;

(E) a proposal for what information is currently available and can be provided on a web portal and what information requires approval by the Commission for incorporation onto a web portal;

(F) a proposal for updating data provided through the web portal, specifically addressing the quarterly updating of the utility's hosting capacity analysis as described in subparagraph 3531(a)(II);

(G) a proposal for enabling Application Programming Interface (API) capabilities where reasonable and appropriate; and

(H) a proposal for collecting user feedback on an ongoing basis.

(III) In subsequent DSP application proceedings, the utility shall provide an update on the status of implementing the web portal and any proposed changes to functionality and treatment of data. Prior to each application pursuant to rule 3529, the utility is encouraged to engage with stakeholders including users of the web portal, to identify changes.

(IV) The utility shall file an annual compliance report in the most recent DSP application proceeding that provides an update on the status of implementing the web portal, summarizes user feedback, and describes how the utility addressed that feedback, including any updates or revisions to the functionality of the web portal that are anticipated to occur prior to its next DSP application filing.

3542. Evaluation and Reporting.

(a) An assessment of the existing distribution system, as described in rule 3531.

(b) An assessment of Distribution Grid Security, as described in rule 3539.

(c) Starting with its second DSP application, the utility shall describe the past implementation of NWAs, a review of the NWA cost benefit analysis methodology used, as well as proposed performance metrics and benchmarks to track successful implementation of the plan.

(d) The utility shall report lessons learned from the DSP process and identify ways to improve methodologies through research before the next filing.

(e) Should the utility receive approval for an NWA, a DSP related pilot, or a DSP-related program in a proceeding other than a DSP application, for active projects the utility shall provide in subsequent DSPs:

(I) the name of the project;

(II) a brief description of the project;

(III) the number of the proceeding in which the utility is seeking or has received approval for the project;

(IV) the number(s) of any other proceedings that contain reporting for the project;

(V) the date of project approval, if applicable;

(VI) the total proposed or approved budget; and

(VII) a description of the proposed or approved budget by funding source.

3543. – 3549. [Reserved].