COLORADO DEPARTMENT OF REGULATORY AGENCIES
Public Utilities Commission

4 CODE OF COLORADO REGULATIONS (CCR) 723-3

PART 3
RULES REGULATING ELECTRIC UTILITIES

* * * *

[indicates omission of unaffected rules]

DISTRIBUTION SYSTEM PLANNING

3525. Applicability

This rule shall apply to all electric utilities in the state of Colorado except municipally owned electric utilities and cooperative electric associations.

3526. Overview and Purpose.

The purpose of this rule is to require electric utilities to file a Distribution System Plan (DSP) pursuant to § 40-2-132, C.R.S. A DSP shall review the utility's investments in the distribution grid to ensure that they cost-effectively support grid adequacy, reliability and resilience, while simultaneously supporting diversification of energy supply through distributed energy resources, expanding the utilization of non-wire alternatives that reduce the need for conventional distribution grid investment, and prepare for new expectations upon the system.

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) "Capacity need" means a distribution grid capacity constraint or shortfall projected within a ten-year period due to load growth.

(b) "Demand flexibility" uses communication and control technology to shift electricity use across hours of the day while delivering end-use services (e.g., air conditioning, domestic hot water, electric vehicle charging) at the same or better quality but lower cost.

(c) "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.

(d) “Distributed energy resources” or “DER” may include, but are not limited to, distributed renewable electric generation, energy storage systems connected to the distribution grid, electric vehicles, microgrids, 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.

(e) “Distribution system plan” or “DSP” means the compliance plan filed every two years in accordance with rule 3528.

(f) “Energy efficiency measures” are actions that result in the decrease in electricity usage of customers without detriment to end-use services.

(g) “Energy storage systems connected to the distribution grid” or “energy storage system” means any commercially available system, including batteries that may be paired with onsite generation, that does not generate energy but that is capable of retaining, storing, and delivering energy by chemical, thermal, mechanical, or other means.

(h) “Hosting capacity” means the amount of distributed generation, including distributed generation paired with battery storage, that can be accommodated on a particular section of 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 significant infrastructure upgrades.

(i) “Locational value” means a cost-benefit analysis of distributed resources that incorporates location-specific net benefits to the electric grid.

(j) “Major distribution grid project” means planned construction, reconfiguring, or upgrade of any electric distribution line, substation, or ancillary structure that meets the following criteria: (1) is 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, feeders associated with that a substation, transformers, or on back office software or hardware that interacts with the distribution grid. This is the threshold for the size of a new distribution or transmission and distribution project for which a utility must conduct a Non-Wires Alternative Suitability Screening.

(k) “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.

(l) “N-1 event” means an outage event of one distribution or transmission element such as a transformer, feeder, or transmission line that causes 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.

(m) “Non-Wires Alternative” or “NWA” means the strategic deployment of distributed energy resources and associated control systems and technologies intended to cost-effectively defer or avoid the need for Major Distribution Grid Projects by reliably reducing load, congestion or other constraints at times of peak demand in targeted locations on the grid. NWAs can include one or multiple DER, including demand response measures, energy efficiency, energy storage, and distributed generation.

(n) "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.

(o) "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.

(p) "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.

(q) "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) The utility shall file a DSP as an application, every two years, with the first DSP to be submitted on or before October 1, 2021.

(b) Each DSP shall conform to the application requirements contained in rules 3002 and 1303.

(c) 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).

(d) For data filing requirements set forth in this rule which the utility claims are not yet practicable or is 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;

(II) how the information could be obtained, at what estimated cost, and timeframe;

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

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

(e) The Commission shall issue a written decision approving, conditioning, modifying, or rejecting the utility's DSP application, which decision shall establish the final DSP. The decision creates a presumption that utility actions consistent with that decision are prudent.

(f) The utility may file, at any time, an application to amend the contents of a plan approved pursuant to paragraph 3528(e). 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.

3529. Contents of the Distribution System Plan.

(a) The utility shall file a 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 plan shall include the following:

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

(II) a description of how the distribution grid will evolve over the next five and ten years due to various factors, such as increasing DER penetration, the expansion of beneficial electrification, advanced metering infrastructure, increasing demand flexibility 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) distribution system forecasts, as described in rule 3530;

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

(V) an assessment of grid need, as described in rule 3532;

(VI) a description of grid innovations, as described in rule 3533;

(VII) a NWA cost benefit methodology, as described in rule 3534;

(VIII) an action plan, as described in rule 3535;

(IX) a NWA suitability screening, as described in rule 3536;

(X) a proposal for cost recovery, which may include an incentive, as described in rule 3537; and

(XI) a security assessment, as described in rule 3538.

3530. Distribution System Forecasts.

(a) Forecast requirements. The utility shall prepare energy and demand forecasts for each year within the planning period. A ten-year forecast for load growth on the distribution grid, the growth of DER connected to the distribution grid, and NWA. Forecasts should be based on at least three growth scenarios (low, medium 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 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 + non-coincident peak load growth at substations, transformers, and feeders, by class;

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

(VI) load growth due to new housing developments, business complexes and other large, new developments with expected peak load over 1 MW;

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

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

(IX) forecasts of DERs and NWA should include three 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. The three scenarios shall be based on the following criteria:

(A) Low Scenario: Adapts a business as usual case for DER and NWA deployment for distribution planning at the feeder lever, down to each line section;

(B) Medium Scenario: Adapts a High Growth case for DER and NWA adoption but also incorporates additional information from 3rd party DER - NWA owners, and DER - NWA vendors;

(C) High Scenario: Based on very high potential growth in the use of DERs and NWA to meet potential state policy goals, which may include long-term greenhouse gas (GHG) reductions, demand flexibility, distribution reliability, resiliency, and transmission system needs, with key inputs drawn from achieving goals such as:

(i) growth of peak exported generation from distributed solar generation;

(ii) growth of peak exported generation from distributed battery storage systems;

(iii) growth of peak exported generation from all other distributed generation; and

(iv) growth of electricity consumption from beneficial electrification, including electric vehicles, building electrification and natural gas switching.

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 maps should be made available on the utility's web portal as described in rule 3542. The assessment should also include the status of advanced metering infrastructure deployment by customer class and updates on meter data management systems. 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;

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

(I) capacity margin for each feeder;

(J) miles of underground and overhead wires, categorized by voltage;

(K) 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;

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

(M) amount of NWA on the system (number of NWA and nameplate capacity in kilowatts (kW) by types, organized by substation or feeder);

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

(O) estimated number of EVs and EV charging stations organized by substation or feeder;

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

(Q) 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 distributed generation 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.

(D) The utility shall perform scenario analysis to evaluate hosting capacity under normal and planned and unplanned contingency conditions.

(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 3542. The utility shall also provide a detailed narrative describing the utility's progress towards providing publicly-available, real-time hosting capacity data. This should include discussion on how its hosting capacity analysis currently advances customer-sited DER (in particular PV and electric storage systems), how the utility anticipates the hosting capacity analysis 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 annual hosting capacity analysis.

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 of non-wires alternatives suitability to mitigate identified needs and recommendations for the deployment of utility infrastructure upgrade solutions and non-wires alternative solutions to 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 produce 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 results of the assessment will be provided via the web portal, described in rule 3542. Any notable updates to the web portal should also be made in this section of the plan.

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

(III) A description of the major distribution grid projects that meet the NWA suitability screening criteria in rule 3536. If major distribution grid projects do meet these criteria, it will trigger an RFP to be issued by the utility to gather bids on potential NWA solutions to the identified grid needs.

(IV) A description of the major distribution grid projects that are projected to meet the criteria of the NWA cost benefit methodology in rule 3534. The utility shall conduct a cost benefit analysis to compare the lowest NWA bids to the business as usual solution identified by the utility, and provide a report with recommendations for what type of solution the utility should pursue to meet the identified grid need.

(V) 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 fast charging stations for electric vehicles.

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. This section shall include, but not be limited to:

(I) New proposed pilots. With each DSP, the utility may propose new pilots designed to gain experience integrating DER and NWA 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. A pilot 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 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; and

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

(II) New proposed programs. Within its DSP, the utility may seek approval for a new program to better integrate DER and NWA 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.

(III) 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 with a DSP.

(IV) Identification of barriers. The DSP shall identify any barriers to deployment of DERs and NWA. The DSP shall focus on three categories of barriers:

(A) barriers to integration or interconnection of DERs and NWA onto the distribution grid;

(B) barriers that limit the ability of a DER and NWA to provide benefits; and

(C) barriers related to distribution system operational and infrastructure capability to enable DER- and NWA-provided value, such as advanced protection and control systems, and telecommunications.

(b) NWAs and pilots may include the use of targeted incentive payments to encourage DER adoption by customers in specific locations, in order to provide locational value to the system. Such incentives shall be accounted for in the cost benefit analysis as described in rule 3534 and shall be recovered in a manner similar to other distribution-grid related expenditures.

3534. NWA Cost Benefit Analysis.

(a) In order to assess the cost-effectiveness of a potential NWA solution to a traditional utility investment, the utility shall provide in the DSP:

(I) an assessment of the proposed NWA solution using the cost-benefit methodology 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. If the utility is proposing a performance incentive as part of cost recovery for the NWA pursuant to paragraph 3537(d), it shall include present the cost-benefit analysis both with and without the performance incentive included as a cost of the project; and

(II) a cost benefit analysis of the traditional utility investment.

(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 accounted for.

3535. Action Plan.

(a) The utility shall provide a five-year action plan for distribution system investments and activities, which will serve as a guiding document for the Commission and stakeholders to rely upon when evaluating distribution system planning and investment decisions.

(b) The action plan shall include the sequence of events and timelines for each action taken, including:

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

(II) the implementation of proposed pilots and programs;

(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); and

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

3536. 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 suitable alternatives to conventional solutions.

(b) The NWA suitability screening is performed by the utility to determine if a NWA may be a suitable alternative to conventional solutions, 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, or reliability issues and could be resolved by 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) For all major distribution grid projects identified as meeting all of 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.

3537. Approvals and Cost Recovery.

(a) A utility may seek any necessary approvals for a NWA or pilot from a DSP through one of the following processes:

(I) within the same DSP proceeding;

(II) demand side management planning proceedings;

(III) renewable energy standard planning proceedings;

(IV) transportation electrification planning proceedings;

(V) an application for a pilot programs or other innovative technology demonstration; or

(VI) another appropriate regulatory mechanism.

(b) The utility may seek Commission approval to construct and invest in a NWA project(s) in its DSP. Should such an approval be sought, the Commission may require a hearing specifically on the NWA project(s) requested in addition to the process described in rule 3536.

(c) Utilities may also seek approval to implement NWAs and pilots for projects that are not classified as major distribution grid projects, without performing a competitive solicitation.

(d) A utility shall address the means by which it anticipates recovering costs associated with the investments put forward in its DSP. The utility may propose a performance incentive 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 3534.

(e) Costs associated with NWAs proposed for approval by a utility in a DSP, may be placed in 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.

(f) A utility may seek its authorized rate of return on any regulatory asset created pursuant to this rule.

(g) The commission shall approve a qualifying retail utility's investment in non-wires alternatives if the commission finds the investment to be in the public interest.

(h) The Commission shall determine whether a qualifying retail utility's ratepayers would realize benefits from a non-wires alternative investment and whether the associated costs are just and reasonable.

(i) 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.

3538. 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 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 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, through the use of microgrids or other technology, should be discussed within the Grid Innovation section of the 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.

3539. Data Privacy and Confidentiality.

(a) DSP application. The DSP application filed pursuant to rule 3529 is presumed non-confidential and the Commission's Rules on Customer Data Access and Confidentiality do not apply. The utility shall file a motion for extraordinary protection for any information for which it seeks treatment as confidential or highly confidential, the basis for that claim, and its proposed alternative treatment of the information to allow full and fair public consideration of the DSP.

(b) NWA competitive solicitation. The utility shall hire a bid monitor for the NWA competitive solicitation. The purpose of the bid monitor is to ensure that the utility releases sufficient information to prospective bidders in order to enable them to produce responses, and to mediate requests for additional information. The utility may require prospective bidders to sign non-disclosure agreements in order to obtain information deemed confidential or highly confidential.

(c) Utility web portal. The data presented in the utility web portal, as described in rule 3645, shall not include personal information or customer data, as defined in rules 1004 and 3001, except that anonymized customer data may be included in the web portal. The utility may require visitors to its web portal to acknowledge terms of service associated with its use, provided those terms do not preclude academic or public policy purposes. A utility may not deny access to its web portal.

3540. Evaluation and Reporting.

(a) 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.

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

3541. Commission Approval of a DSP.

(a) The Commission shall review each DSP and approve, modify, or reject the plan. 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 pursuant to rules 3601 and 3526 from investments in the distribution grid and DER.

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

3542. Web Portal.

(a) The utility shall make available a publicly accessible website that provides map-based and tabular data reporting the utility's hosting capacity analysis and grid needs assessment.

(b) The DSP web portal shall provide a map-based view available through a publicly available mapping portal. The map should color code the substations, circuits, and feeders so users can easily identify which are approaching their maximum capacity. Upon request of parties to a DSP proceeding, the utility should also provide information associated with the grid needs assessment and hosting capacity analysis in executable ARC GIS or similar format, and should allow users to change the year of the data, should include past data and forecasts, and should allow users to switch between grid needs assessment and hosting capacity analysis. Updates to the distribution system hosting capacity analysis shall be made publicly available at least quarterly per year, on the DSP web portal available on the utility's website.

(c) The user of the DSP web portal shall be able to access numeric hosting capacity analysis data for individual substations, circuits, and feeders by clicking on the map. The web portal should also allow users to download data from the hosting capacity analysis and grid needs assessment in logical, tabular format.

(d) The utility shall post a user guide explaining how to use the DSP web portal.

(e) Data portals shall have Application Programming Interface (API) capability that allows users to access data in a functional format from back-end servers in bulk.

(f) In addition to the data from hosting capacity analysis and grid needs assessment, the DSP web portal should include the following summaries, data, or links to available information on the utility's website:

(I) existing distribution characteristics at substation and feeder-level — coincident and noncoincident peaks/ capacity levels/ outage data/ projected investment needs;

(II) estimates of electric vehicle and charging station populations;

(III) existing DER population characteristics;

(IV) customer DER adoption forecasts;

(V) DSP load forecasts, based on forecasting scenarios proposed elsewhere in the DSP;

(VI) existing programs approved by the Commission that address the deployment of DER, including, without limitation, pilots, tariffs and incentives; and

(VII) ability for users to provide feedback on the accuracy of the HCA and that feedback is used in the utility ongoing hosting capacity analysis verification.

(g) Additional content as directed by the Commission in its decision approving a DSP.

3543. – 3549. [Reserved].