COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

4 *CODE OF COLORADO REGULATIONS* (CCR) 723-3

PART 3
RULES REGULATING ELECTRIC UTILITIES

BASIS, PURPOSE, AND STATUTORY AUTHORITY.

The basis and purpose of these rules is to describe the electric service to be provided by jurisdictional utilities and master meter operators to their customers; to designate the manner of regulation over such utilities and master meter operators; and to describe the services these utilities and master meter operators shall provide. In addition, these rules identify the specific provisions applicable to public utilities or other persons over which the Commission has limited jurisdiction. These rules address a wide variety of subject areas including, but not limited to, service interruption, meter testing and accuracy, safety, customer information, customer deposits, rate schedules and tariffs, discontinuance of service, master meter operations, flexible regulation, procedures for administering the Low-Income Energy Assistance Act, electric service low-income program, cost allocation between regulated and unregulated operations, recovery of costs, the acquisition of renewable energy, small power producers and cogeneration facilities, and appeals regarding local government land use decisions. The statutory authority for these rules can be found at §§ 29-20-108, 40-1-103.5, 40-2-108, 40-2-124(2), 40-3-102, 40-3-103, 40-3-104.3, 40-3-106, 40-3-111, 40-3-114, 40-4-101, 40-4-106, 40-4-108, 40-4-109, 40-5-103, 40-7-113.5, 40-7-116.5, 40-8.7-105(5), and 40-9.5-107(5), C.R.S.

GENERAL PROVISIONS

3000. Scope and Applicability.

(a) Absent a specific statute, rule, or Commission Order which provides otherwise, all rules in this Part 3 (the 3000 series) shall apply to all jurisdictional electric utilities and electric master meter operators and to Commission proceedings concerning electric utilities or electric master meter operators providing electric service.

(b) The following rules in this Part 3 shall apply to cooperative electric associations which have elected to exempt themselves from the Public Utilities Law pursuant to § 40-9.5-103, C.R.S.

(I) Paragraphs 3002 (a)(I), (a)(II), (a)(IV), (a)(V), (a)(XVI), (b), and (c) concerning the filing of applications for certificate of public convenience and necessity for franchise or service territory, for certificate amendments, to merge or transfer, or for appeals of local government actions.

(II) Paragraphs 3005 (a)(III), (IV), (d), (e), (g), and (h) concerning records under RUS accounting system and preservation of records.

(III) Paragraphs 3006 (a), (b), (c), (d), and (e) concerning the filing of annual reports, designation for service of process, and election of applicability of Title 40, Article 8.5.

(IV) Paragraphs 3008 (b) and (d) concerning incorporation by reference.

(V) Rules 3100 and 3103 concerning application for and amendment of a certificate of public convenience and necessity relating to a franchise.

(VI) Rules 3101 and 3103 concerning application for and amendment of a certificate of public convenience and necessity relating to service territory.

(VII) Rule 3104 concerning application to transfer assets, to obtain a controlling interest, or to merge with another entity.

(VIII) Rule 3204 concerning incidents occurring in connection with the operation of facilities.

(IX) Paragraphs 3207 (a) and (b) concerning construction and expansion of distribution facilities.

(X) Rules 3250 through 3253 concerning major event reporting.

(XI) Rule 3411 concerning the Low-Income Energy Assistance Act unless the cooperative electric association has exempted themselves pursuant to paragraph 3411(a).

(XII) Rules 3650(b), 3651, 3652, 3654(b), (d) through (i), and (l); 3655(h)-(m); 3659(a)(I) through (a)(V), (b) and (d) through (i), 3660(l), 3661(b), (c), (g), and (i), 3662(a)(I), (a)(II), (a)(IV) through (a)(X), (a)(XIII), (a)(XV), (b), (d) and (e), and 3667.

(XIII) Rules 3700 through 3707 concerning appeals of local governmental land use decisions actions.

(c) The following rules in this Part 3 shall apply to **cooperative electric generation and transmission associations**.

(I) Paragraphs 3002 (a)(III), (a)(XVI), (b), and (c) concerning the filing of applications for certificates of public convenience and necessity for facilities or for appeals of local government actions.

(II) Paragraph 3006(j) concerning the filing of electric resource planning reports.

(III) Rule 3102 concerning applications for certificates of public convenience and necessity for facilities.

(IV) Rule 3103 concerning amendments to certificates of public convenience and necessity for facilities.

(V) Rule 3104 concerning application to transfer, to obtain a controlling interest, or to merger with another entity.

(VI) Rule 3200 concerning construction, installation, maintenance, and operation of facilities.

(VII) Rule 3204 concerning incidents occurring in connection with the operation of facilities.

(VIII) Rule 3205 concerning construction or expansion of generating capacity.

(IX) Rule 3206 concerning construction or extension of transmission facilities.

(X) Paragraph 3253(a) concerning major event reporting.

(XI) Rules 3602, 3605, and 3618(a) concerning electric resource planning.

(XII) Rules 3650(e), 3651, 3652, 3662(f), and 3668(d) concerning the RES.

(XIII) Rules 3700 through 3707 concerning appeals of local government actions.

(d) The following rules in this Part 3 shall apply to municipally owned utilities that are qualifying retail utilities:

(I) Rules 3650(c), 3651, 3652, 3653, 3654(b), (c), (d) through (i) and (l); 3659(a)(I) through (a)(V), (b), (d) through (i), 3666, and 3668(d).

(e) The following rules in this Part 3 shall apply to municipally owned utilities that are not qualifying retail utilities.

(I) Paragraph 3650(d).

3001. Definitions.

The following definitions apply throughout this Part 3, except where a specific rule or statute provides otherwise. In addition to the definitions here, the definitions found in the Public Utilities Law and Part 1 apply to these rules. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply. In the event of a conflict between these definitions and a definition in Part 1, these definitions shall apply.

(a) "Affiliate" of a utility means a subsidiary of a utility, a parent corporation of a public utility, a joint venture organized as a separate corporation or partnership to the extent of the individual utility's involvement with the joint venture, a subsidiary of a parent corporation of a utility or where the utility or the parent corporation has a controlling interest over an entity.

(b) "Aggregated data" means customer data, alone or in combination with non-customer data, resulting from processing (e.g., average of a group of customers) and/or the compilation of customer data of one or more customers from which all unique identifiers and personal information has been removed.

(c) "Applicant for service" means a person who applies for utility service and who either has taken no previous utility service from that utility or has not taken utility service from that utility within the most recent 30 days.

(d) "Basis point" means one-hundredth of a percentage point (100 basis points = one percent).

(e) "Benefit of service" means the use of utility service by each person of legal age who resides at a premises to which service is delivered and who is not registered with the utility as the customer of record.

(f) "Biomass" means nontoxic plant matter consisting of agricultural crops or their byproducts, urban wood waste, mill residue, slash, or brush; animal wastes and products of animal wastes; or methane produced at landfills or as a by-product of the treatment of wastewater residuals. With respect to nontoxic plant matter obtained from forests, both slash and brush shall mean products and materials derived from forest restoration and management, including, but not limited to, harvesting residues, pre-commercial thinning, and materials removed as part of a federally recognized timber sale or removed to reduce hazardous fuels, to reduce or contain disease or insect infestation, or to restore ecosystem health.

(g) “Coal mine methane” means methane captured from inactive coal mines where the methane is escaping to the atmosphere or from active coal mines where the methane vented in the normal course of mine operations is naturally escaping to the atmosphere.

(h) "Commission" means the Colorado Public Utilities Commission.

(i) “Contracted agent” means any person that has contracted with a utility in compliance with rule 3030 to assist in the provision of regulated utility services (e.g., an affiliate or vendor).

(j) "Customer" means any person who is currently receiving utility service. Any person who moves within a utility’s service territory and obtains utility service at a new location within 30 days shall be considered a "customer." Unless stated in a particular rule, "customer" applies to any class of customer as defined by the Commission or by utility tariff.

(k) “Customer data” means customer-specific data or information, excluding personal information as defined in paragraph 1004(x), that is:

(I) collected from the electric meter by the utility and stored in its data systems (e.g., kWh, kW, voltage, VARs and power factor);

(II) combined with customer-specific energy usage information on bills issued to the customer for regulated utility service when not publicly or lawfully available to the general public; or

(III) about the customer’s participation in regulated utility programs, such as renewable energy, demand-side management, load management, or energy efficiency programs.

(l) "Distribution facilities" are those lines designed to operate at the utility's distribution voltages in the area as defined in the utility’s tariffs including substation transformers that transform electricity to a distribution voltage and also includes other equipment within a transforming substation which is not integral to the circuitry of the utility's transmission system.

(m) "Eligible energy" means renewable energy, recycled energy, or greenhouse gas neutral electricity generated by a facility using coal mine methane or synthetic gas.

(n) "Eligible energy resources" are renewable energy resources or facilities that generate recycled energy or greenhouse gas neutral electricity generated using coal mine methane or synthetic gas.

(o) "Energy assistance organization" means the nonprofit corporation established for low-income energy assistance pursuant to § 40-8.5-104, C.R.S.

(p) "Financial security" includes any stock, bond, note, or other evidence of indebtedness.

(q) "Greenhouse gas neutral electricity" means electricity generated by facilities using coal mine methane or synthetic gas that the Commission has determined to be greenhouse gas neutral on a CO_2 equivalent basis pursuant to § 40-2-124(1)(a)(IV), C.R.S.

(r) "Heavy load" means not less than 60 percent, but not more than 100 percent, of the nameplate-rated capacity of a meter.

(s) "Informal complaint" means an informal complaint as defined and discussed in the Commission's Rules Regulating Practice and Procedure.

(t) "Light load" means approximately five to ten percent of the nameplate-rated capacity of a meter.

(u) "Load" means the power consumed by an electric utility customer over time (measured in terms of either demand or energy or both).

(v) "Local government" means any Colorado county, municipality, city and county, home rule city or town, home rule city and county, or city or town operating under a territorial charter.

(w) "Local office" means any Colorado office operated by a utility at which persons may make requests to establish or to discontinue utility service. If the utility does not operate an office in Colorado, "local office" means any office operated by a utility at which persons may make requests to establish or to discontinue utility service in Colorado.

(x) "Main service terminal" means the point at which the utility's metering connections terminate. .

(y) "Major event" means an event as defined in and consistent with IEEE Standard Number 1366-2003, Guide for Electric Power Distribution Reliability Indices.

(z) "MVA" means mega-volt amperes and is the vector sum of the real power and the reactive power.

(aa) "Non-standard customer data" means all customer data that are not standard customer data.

(bb) "On-site solar system" means a solar renewable energy system that qualifies as retail renewable distributed generation.

(cc) "Output" means the energy and power produced by a generation system.

(dd) "Past due" means the point at which a utility can affect a customer's account for regulated service due to non-payment of charges for regulated service.

(ee) "Principal place of business" means the place, in or out of the State of Colorado, where the executive or managing principals who directly oversee the utility's operations in Colorado are located.

(ff) "Property owner" means the legal owner of government record for a parcel of real property within the service territory of a utility. A utility may rely upon the records of a county clerk for the county within which a parcel of property is located to determine ownership of government record.

(gg) "Pyrolysis" means the thermochemical decomposition of material at elevated temperatures without the participation of oxygen.

(hh) "Recycled energy" means energy produced by a generation unit with a nameplate capacity of not more than fifteen MW that converts the otherwise lost energy from the heat from exhaust stacks or pipes to electricity and that does not combust additional fossil fuel. Recycled energy does not include energy produced by any system that uses energy, lost or otherwise, from a process whose primary purpose is the generation of electricity, including, without limitation, any process involving engine-driven generation or pumped hydroelectricity generation.

(ii) "Reference standard" means suitable indicating electrical equipment permanently mounted in a utility's laboratory and used for no purpose other than testing rotating standards.

(jj) "Regulated charges" means charges billed by a utility to a customer if such charges are approved by the Commission or contained in a tariff of the utility.

(kk) "Renewable distributed generation" means retail renewable distributed generation and wholesale renewable distributed generation.

(ll) "Renewable energy" means energy generated from renewable energy resources including renewable distributed generation.

(mm) "Renewable energy credit" or "REC" means a contractual right to the full set of non-energy attributes, including any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, directly attributable to a specific amount of electric energy generated from a renewable energy resource. One REC results from one MWH of electric energy generated from a renewable energy resource. For the purposes of these rules, RECs acquired from on-site solar systems before August 11, 2010 shall qualify as RECs from retail renewable distributed generation for purposes of demonstrating compliance with the renewable energy standard. RECs acquired from off-grid on-site solar systems prior to August 11, 2010 shall also qualify as RECs from retail renewable distributed generation for purposes of demonstrating compliance with the renewable energy standard.

(nn) "Renewable energy resource" means facilities that generate electricity by means of the following energy sources: solar radiation, wind, geothermal, biomass, hydropower, and fuel cells using hydrogen derived from eligible energy resources. Fossil and nuclear fuels and their derivatives are not eligible energy resources. Hydropower resources in existence on January 1, 2005 must have a nameplate rating of 30 MW or less. Hydropower resources not in existence on January 1, 2005 must have a nameplate rating of ten MW or less.

(oo) “Renewable energy standard” or “RES” means the electric resource standard for eligible energy resources specified in § 40-2-124, C.R.S.

(pp) “Renewable energy standard adjustment” or “RESA” means a forward-looking cost recovery mechanism used by an investor owned QRU to provide funding for implementing the RES.

(qq) “Retail renewable distributed generation” means a renewable energy resource that is located on the premises of an end-use electric consumer and is interconnected on the end-use electric consumer’s side of the meter. For the purposes of this definition, the non-residential end-use electric customer, prior to the installation of the renewable energy resource, shall not have its primary business being the generation of electricity for retail or wholesale sale from the same facility. In addition, at the time of the installation of the renewable energy resource, the non-residential end-use electric customer must use its existing facility for a legitimate commercial, industrial, governmental, or educational purpose other than the generation of electricity. Retail renewable distributed generation shall be sized to supply no more than 120 percent of the average annual consumption of electricity by the end-use electric consumer at that site. The end-use electric consumer’s site shall include all contiguous property owned or leased by the consumer, without regard to interruptions in contiguity caused by easements, public thoroughfares, transportation rights-of-way, or utility rights-of-way.

(rr) "Rotating standard" means a portable meter used for testing service meters.

(ss) "RUS" means the Rural Utilities Service of the United States Department of Agriculture, or its successor agencies.

(tt) "Service connection" is the location on the customer’s premises/facilities at which a point of delivery of power between the utility and the customer is established. For example, in the case of a typical residential customer served from overhead secondary supply, this is the location at which the utility’s electric service drop conductors are physically connected to the customer’s electric service entrance conductors.

(uu) “Standard customer data” means customer data maintained by a utility in its systems in the ordinary course of business.

(vv) “Synthetic gas” means gas fuel produced through the pyrolysis of municipal solid waste.

(ww) “Third-party” means a person who is not the customer, an agent of the customer who has been designated by the customer with the utility and is acting of the customer’s behalf, a regulated utility serving the customer, or a contracted agent, of the utility.

(xx) "Transmission facilities" are those lines and related substations designed and operating at voltage levels above the utility's voltages for distribution facilities , including but not limited to related substation facilities such as transformers, capacitor banks, or breakers that are integral to the circuitry of the utility’s transmission system.

(yy) “Unique identifier” means a customer’s name, mailing address, telephone number, or email address that is displayed on a bill.

(zz) "Unregulated charges" means charges that are billed by a utility to a customer and that are not regulated or approved by the Commission, are not contained in a tariff filed with the Commission, and are for service or merchandise not required as a condition of receiving regulated utility service.

(aaa) "Utility" means any public utility as defined in § 40-1-103, C.R.S., providing electric, steam, or associated services in the state of Colorado.

(bbb) "Utility service" or "service" means a service offering of a utility, which service offering is regulated by the Commission.

(ccc) “Whole building data” means the sum of the monthly electric use for either all meters at a building on a parcel or real property or all buildings on a parcel of real property.

(ddd) “Wholesale renewable distributed generation” means a renewable energy resource with a nameplate rating of 30 MW or less that does not qualify as retail renewable distributed generation.

3002. Applications.

(a) Any person may seek Commission action regarding any of the following matters through the filing of an appropriate application to request a(n):

   (I) issuance or extension of a certificate of public convenience and necessity for a franchise, as provided in rule 3100;

   (II) issuance or extension of a certificate of public convenience and necessity for service territory, as provided in rule 3101;

   (III) issuance of a certificate of public convenience and necessity for construction of facilities, as provided in rule 3102;

   (IV) amendment of a certificate of public convenience and necessity in order to change, extend, curtail, abandon, or discontinue any service or facility, as provided in rule 3103;

   (V) transfer of a certificate of public convenience and necessity, to obtain a controlling interest in any utility, to transfer assets within the jurisdiction of the Commission or stock, or to merge a utility with another entity, as provided in rule 3104;

   (VI) issuance, or assumption of any financial security or to create a lien pursuant to § 40-1-104, as provided in rule 3105;

   (VII) flexible regulatory treatment to provide service without reference to tariffs, as provided in rule 3106;

   (VIII) approval of an air quality improvement program, as provided for in rule 3107;

(IX) amendment of a tariff on less than statutory notice, as provided in rule 3109;

(X) variance of voltage standards, as provided in rule 3202;

(XI) approval of meter and equipment testing practices, as provided in rule 3303;

(XII) approval of a meter sampling program, as provided in rule 3304;

(XIII) approval of a refund plan, as provided in rule 3410;

(XIV) approval of a Low-Income Energy Assistance Plan, as provided in rule 3411;

(XV) approval of a cost assignment and allocation manual, as provided in rule 3503;

(XVI) approval of or for amendment to a least-cost resource plan, as provided in rules 3603, 3618, and 3619;

(XVII) approval of a compliance plan, as provided in rule 3657;

(XVIII) appeal of local government land use decision, as provided in rule 3703; or

(XIX) matter not specifically described in this rule, unless such matter is required to be submitted as a petition under rule 1304, as a motion, or as some other specific type of submittal.

(b) In addition to the requirements of specific rules, all applications shall include, in the following order and specifically identified, the following information, either in the application or in appropriately identified attachments:

(I) the name and address of the applying utility;

(II) the name(s) under which the applying utility is, or will be, providing service in Colorado;

(III) the name, address, telephone number, and e-mail address of the applying utility's representative to whom all inquiries concerning the application should be made;

(IV) a statement that the applying utility agrees to answer all questions propounded by the Commission staff concerning the application;

(V) a statement that the applying utility shall permit the Commission or Commission staff to inspect the applying utility's books and records as part of the investigation into the application;

(VI) a statement that the applying utility understands that, if any portion of the application is found to be false or to contain material misrepresentations, any authorities granted pursuant to the application may be revoked upon Commission order;

(VII) in lieu of the separate statements required by subparagraphs (b)(IV) through (VI) of this rule, a utility may include a statement that it has read, and agrees to abide by, the provisions of subparagraphs (b)(IV) through (VI) of this rule;

(VIII) a statement describing the applying utility's existing operations and general service area in Colorado;

(IX) for applications listed in subparagraphs (a)(I), (II), (III), (V), and (VI) of this rule, a copy of the applying utility's or parent company's and consolidated subsidiaries' most recent audited balance sheet, income statement, statement of retained earnings, and statement of cash flows so long as they provide Colorado specific financial information;

(X) a statement indicating the town or city, and any alternative town or city, in which the applying utility prefers any hearings be held; and

(XI) acknowledgment that, by signing the application, the applying utility understands that:

(A) the filing of the application does not by itself constitute approval of the application;

(B) if the application is granted, the applying utility shall not commence the requested action until the applying utility complies with applicable Commission rules and any conditions established by Commission order granting the application;

(C) if a hearing is held, the applying utility must present evidence at the hearing to establish its qualifications to undertake, and its right to undertake, the requested action; and

(D) in lieu of the statements contained in subparagraphs (b)(XI)(A) through (C) of this rule, an applying utility may include a statement that it has read, and agrees to abide by, the provisions of subparagraphs (b)(XI)(A) through (C) of this rule.

(XII) An attestation which is made under penalty of perjury; which is signed by an officer, a partner, an owner, an employee of, an agent for, or an attorney for the applying utility, as appropriate, who is authorized to act on behalf of the applying utility; and which states that the contents of the application are true, accurate, and correct. The application shall contain the title and the complete address of the affiant.

(c) In addition to the requirements of specific rules, all applications shall include the information listed in subparagraphs (a)(I) through (V) of rule 1310. Applying utilities may either include the information in the application itself, or incorporate the information by reference to the miscellaneous proceeding created under rule 1310.

(d) Customer notice. Except as required or permitted by § 40-3-104, C.R.S., if the applicant is required by statute, Commission rule, or order to provide notice to its customers of the application, the applicant shall, within seven days after filing an application with the Commission, cause to have published notice of the filing of the application in each newspaper of general circulation in the municipalities impacted by the application. The applicant shall provide proof of such customer notice within 14 days of the publication in the newspaper. Failure to provide such notice or failure to provide the Commission with proof of notice may cause the Commission to deem the application incomplete. The applicant may also be required by statute, Commission rule, or order to provide additional notice to its customers of the application by first-class mailing or by hand-delivery. Both the newspaper notice and any additional customer notice(s) shall include the following.

(I) The title “Notice of Application by [Name of the Utility] to [Purpose of Application]”.

(II) State that [Name of Utility] has applied to the Colorado Public Utilities Commission for approval to [Purpose of Application]. If the utility commonly uses another name when conducting business with its customers, the “also known as” name should also be identified in the notice to customers.

(III) Provide a brief description of the proposal and the scope of the proposal, including an explanation of the possible impact upon persons receiving the notice.

(IV) Identify which customer class(es) will be affected and the monthly customer rate impact by customer class, if customers’ rates are affected by the application.

(V) Identify the proposed effective date of the application.

(VI) Identify that the application was filed on less than statutory notice or if the applicant requests an expedited Commission decision, as applicable.

(VII) State that the filing is available for inspection in each local office of the applicant and at the Colorado Public Utilities Commission.

(VIII) Identify the proceeding number, if known at the time the customer notice is provided.

(IX) State that any person may file written comment(s) or objection(s) concerning the application with the Commission. As part of this statement, the notice shall identify both the address and e-mail address of the Commission and shall state that the Commission will consider all written comments and objections submitted prior to the evidentiary hearing on the application.

(X) State that if a person desires to participate as a party in any proceeding before the Commission regarding the filing, such person shall file an intervention in accordance with the rule 1401 of the Commission’s Rules of Practice and Procedure or any applicable Commission order.

(XI) State that the Commission may hold a public hearing in addition to an evidentiary hearing on the application and that if such a hearing is held members of the public may attend and make statements even if they did not file comments, objections or an intervention. State that if the application is uncontested or unopposed, the Commission may determine the matter without a hearing and without further notice.

(XII) State that any person desiring information regarding if and when hearings may be held shall submit a written request to the Commission or, alternatively, shall contact the External Affairs section of the Commission at its local or toll-free phone number. Such statement shall also identify both the local and toll-free phone numbers of the Commission's External Affairs section.

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[indicates omission of unaffected rules]

ELECTRIC RESOURCE PLANNING

3600. Applicability.

This rule shall apply to all jurisdictional electric utilities in the state of Colorado that are subject to the Commission's regulatory authority. Cooperative electric associations engaged in the distribution of electricity (i.e., rural electric associations) are exempt from these rules. Cooperative electric generation and transmission associations are subject only to reporting requirements as specified in rule 3605.

3601. Overview and Purpose.

(a) The purpose of these rules is to establish a process to determine the need for additional electric resources by electric utilities subject to the Commission's jurisdiction and to develop cost-effective resource portfolios to meet such need reliably.

(b) An electric resource plan proceeding is conducted in two phases. In Phase I, the Commission reviews and renders a decision on the utility's proposed electric resource plan, which includes an assessment of the need for resources and a proposal to acquire resources to meet this need. The Commission also approves the process for evaluating bids to the utility's competitive solicitation and establishes the modeling parameters, including inputs and assumptions, the utility shall use for the presentation and consideration of potential cost-effective resource portfolios. In Phase II, the utility solicits bids and evaluates potential resources in accordance with the Commission's determinations in Phase I and the Commission renders a decision establishing a final cost-effective resource plan.

(c) It is the policy of the state of Colorado that a primary goal of electric utility resource planning is to minimize the net present value of revenue requirements. It is also the policy of the state of Colorado that the Commission gives the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies.

3602. Definitions.

The following definitions apply to rules 3600 through 3617. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Availability factor" means the ratio of the time a generating facility is available to produce energy at its rated capacity, to the total amount of time in the period being measured.

(b) "Annual capacity factor" means the ratio of the net energy produced by a generating facility in a year, to the amount of energy that could have been produced if the facility operated continuously at full capacity year round.

(c) "Cost-effective resource plan" means a designated combination of new resources that the Commission determines can be acquired and operated at a reasonable cost and rate impact.

(d) "Demand-side resources" means energy efficiency, energy conservation, load management, and demand response or any combination of these measures.

(e) "Electric resource plan" or "plan" means a utility plan consisting of the elements set forth in rule 3604.

(f) "End-use" means the light, heat, cooling, refrigeration, motor drive, or other useful work produced by equipment that uses electricity or its substitutes.

(g) "Energy conservation" means the decrease in electricity requirements of specific customers during any selected time period, resulting in a reduction in end-use services.

(h) "Energy efficiency" means the decrease in electricity requirements of specific customers during any selected period with end-use services of such customers held constant.

(i) "Generic resource" means the representation of a potential new utility resource for benchmarking or modeling purposes that embodies the estimated cost and performance of the represented technology without regard to a specific site location. A generic resource is generally represented by: capacity (nameplate and summer peak); capital and fixed operations and maintenance costs; transmission interconnection and grid upgrade costs; fuel and other variable operations and maintenance costs; book (useful) life; heat rate or production curves; forced outage rates; typical annual maintenance requirements; emission rates; and indicative pricing (levelized energy costs) if the resource were contracted.

(j) "Heat rate" means the ratio of energy inputs used by a generating facility expressed in BTUs (British Thermal Units), to the energy output of that facility expressed in kWh.

(k) "Modeling error or omission" means any incorrect, incomplete, or improper input to computer-based modeling performed by the utility, for evaluating a proposed resource that materially alters the model results.

(l) "Net present value of revenue requirements" means the current worth of the total expected future revenue requirements associated with a particular resource portfolio, expressed in dollars in the year the electric resource plan is filed as discounted over the planning period by the appropriate discount rate.

(m) "Planning period" means the future period over which the costs and benefits of new resources are evaluated. The planning period defines the time when net present value of revenue requirements for resources is calculated. For purposes of this rule, the planning period begins no later than the January 1 following the date the utility files its plan with the Commission and extends either through the 20-year period following the last year of the resource acquisition period or the last year of the proposed contract term length in the proposed request for proposals filed pursuant to paragraph 3614(d), whichever is longer.

(n) “Potential resource” means an electric generation facility bid into a competitive acquisition process in accordance with an approved electric resource plan.

(o) "Resource acquisition period" means the first six to eight years of the planning period, in which the utility acquires specific resources to meet projected electric system demand and energy requirements. The resource acquisition period begins no later than the January 1 following the date the utility files its electric resource plan with the Commission.

(p) "Resources" means supply-side resources and demand-side resources used to meet electric system requirements.

(q) "Supply-side resources" means resources that provide electrical energy or capacity to the utility. Supply-side resources include utility owned generating facilities and energy or capacity purchased from other utilities and non-utilities.

3603. Electric Resource Plan Filing Requirements.

(a) Jurisdictional electric utilities shall file an electric resource plan pursuant to these rules every four years beginning February 1, 2020. Such filing initiates a Phase I proceeding.

(b) In addition to the required four-year cycle, a utility may file an interim plan, pursuant to rule 3604. If a utility chooses to file an interim plan more frequently than the required four-year cycle, its application must state the reasons and changed circumstances that justify the interim filing.

(c) Each jurisdictional electric utility shall contemporaneously file with its electric resource plan submitted under paragraph 3603(a), a motion or motions seeking extraordinary protection of information listed as highly confidential pursuant to paragraph 3604(j) and consistent with rule 1101 of the Commission’s Rules of Practice and Procedure. The utility shall specifically address appropriate confidentiality protections and nondisclosure requirements for modeling inputs and assumptions that may be used to evaluate a potential resource and that reasonably relate to that facility. The utility’s motion or motions shall specify that response time shall run concurrently with the intervention deadline established in the plan proceeding. Finally, during the course of the plan proceeding, a utility may file additional motions seeking extraordinary protection of information for good cause shown.

3604. Contents of the Electric Resource Plan.

The utility shall file an electric resource plan with the Commission that contains the information specified below. When required by the Commission, the utility shall provide work-papers to support the information contained in the plan. The plan shall include the following.

(a) A statement of the utility-specified resource acquisition period. The utility shall consistently use the specified resource acquisition and planning periods throughout the entire electric resource plan and resource acquisition process. The utility shall include a detailed explanation as to why the specific period was chosen in light of the assessment of the needs of the utility system.

(b) An annual electric demand and energy forecast developed pursuant to rule 3606.

(c) An assessment of existing resources developed pursuant to rule 3607.

(d) An assessment of transmission resources pursuant to rule 3608.

(e) An assessment of planning reserve margins and contingency plans for the acquisition of additional resources developed pursuant to rule 3609.

(f) An assessment of the need for additional resources developed pursuant to rule 3610 and the utility's plan for acquiring these resources for Commission review in Phase I. The utility shall include a loads and resources table for the resource acquisition period and a generic expansion plan for the entire resource planning period.

(g) A description of the projected emissions, in terms of pounds per MWH and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its electric resource plan.

(h) The annual water consumption for each of the utility's existing generation resources, and the water intensity (in gallons per MWH) of the existing generating system as a whole, as well as the projected water consumption for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its electric resource plan.

(i) The proposed Requests for Proposals (RFPs) the utility intends to use to solicit bids for energy and capacity resources to be acquired through a competitive acquisition process, including model contracts, pursuant to paragraph 3614(d).

(j) A list of the information related to the electric resource plan proceeding that the utility claims is confidential and a list of the information related to the plan proceeding that the utility claims is highly confidential. The utility shall also list the information that it will provide to owners or developers of a potential resource under paragraphs 3613(a) and (b). The utility shall further explicitly list the protections it proposes for bid prices, other bid details such as best value employment metrics, information concerning a new resource that the utility proposes to build and own as a rate base investment, other modeling inputs and assumptions, and the results of bid evaluation and selection. The protections sought by the utility for these items shall be specified in the motion(s) submitted under paragraph 3603(b). For good cause shown the utility may seek to protect additional 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.

(k) An assessment of potential cost-effective early retirements of utility-owned resources with retirement dates during the planning period, including the costs associated with incremental depreciation expenses and estimated operational and capital savings. For each early retirement reviewed, the utility shall describe the replacement resource need, possible system reliability impacts, and corrective actions for such impacts.

(l) An assessment of the costs and benefits of the integration of intermittent renewable energy resources on the utility's system consistent with the amounts of renewable energy resources the utility proposes to acquire.

(m) Studies, including updates to studies relied upon by the utility in previous electric resource plan proceedings, commissioned or prepared by the utility to support the development of its Phase I filing pursuant to rule 3604 or to inform the bid evaluation and modeling in Phase II.

(n) A detailed listing and explanation of the information the utility will provide in its 120-day report regarding potential resources, proposed utility-owned resources, and the modeling of portfolio combinations of resources to support the development of cost-effective resource plans.

3605. Cooperative Electric Generation and Transmission Association Reporting Requirements.

Pursuant to the schedule established in rule 3603, each cooperative electric generation and transmission association shall report its forecasts, existing resource assessment, planning reserves, and needs assessment, consistent with the requirements specified in rules 3606, 3607, 3609(a) and 3610. Each cooperative generation and transmission association shall also file annual reports pursuant to paragraph 3616(a) and subparagraphs 3616(b)(I) through (b)(VI).

3606. Electric Energy and Demand Forecasts.

(a) Forecast requirements. The utility shall prepare the following energy and demand forecasts for each year within the planning period.

(I) Annual sales of energy and coincident summer and winter peak demand in total and disaggregated among Commission jurisdictional sales, FERC jurisdictional sales, and sales subject to the jurisdiction of other states.

(II) Annual sales of energy and coincident summer and winter peak demand on a system wide basis for each major customer class.

(III) Annual energy and capacity sales to other utilities; and capacity sales to other utilities at the time of coincident summer and winter peak demand.

(IV) Annual intra-utility energy and capacity use at the time of coincident summer and winter peak demand.

(V) Annual and coincident summer and winter peak system losses. To the extent available, the utility shall provide the allocation of such losses to the transmission and distribution components of the systems.

(VI) The electric demand placed on the utility's system for each hour of the day for each major customer class. This information shall be provided for peak-day, average-day, and representative off-peak days for each calendar month.

(b) Range of forecasts. The utility shall develop and justify a range of forecasts of coincident summer and winter peak demand and energy sales that its system may reasonably be required to serve during the planning period. The range shall include base case, high, and low forecast scenarios of coincident summer and winter peak demand and energy sales, based on alternative assumptions about the determinants of coincident summer and winter peak demand and energy sales during the planning period.

(c) Required detail.

(I) In preparing forecasts, the utility shall develop forecasts of energy sales and coincident summer and winter peak demand for each major customer class. The utility shall use end-use, econometric or other supportable methodology as the basis for these forecasts.

(II) The utility shall maintain, as confidential, information reflecting historical and forecasted demand and energy use for individual customers in those cases when an individual customer is responsible for the majority of the demand and energy used by a particular rate class. However, when necessary in the electric resource plan proceedings, such information may be disclosed to parties who intervene in accordance with the terms of non-disclosure agreements approved by the Commission and executed by the parties seeking disclosure.

(d) Historical data. The utility shall compare the annual forecast of coincident summer and winter peak demand and energy sales made by the utility to the actual coincident peak demand and energy sales experienced by the utility for the five years preceding the year in which the electric resource plan under consideration is filed. In addition, the utility shall compare the annual forecasts in its most recently filed plan to the annual forecasts in the current plan.

(e) Description and justification. The utility shall fully explain, justify, and document the data, assumptions, methodologies, models, determinants, and any other inputs upon which it relied to develop its coincident peak demand and energy sales forecasts pursuant to this rule, as well as the forecasts themselves.

(f) Format and graphical presentation of data. The utility shall include graphical presentation of the data to make the data more understandable to the public, and shall make the data available to requesting parties in such electronic formats as the Commission shall reasonably require.

3607. Assessment of Existing Resources.

(a) Existing generation resource assessment. The utility shall describe its existing resources, all utility-owned generating facilities for which the utility has obtained a CPCN from the Commission pursuant to § 40-5-101, C.R.S., at the time the electric resource plan is filed, and existing or future purchases from other utilities or non-utilities pursuant to agreements effective at the time the plan is filed. The description shall include, when applicable, the following.

(I) Name(s) and location(s) of utility-owned and contracted generation facilities.

(II) Rated capacity and net dependable capacity of utility-owned and contracted generation facilities.

(III) Fuel type, average and marginal heat rates, quick-start capability, minimum operating requirements, annual capacity factors and availability factors projected for utility-owned and contracted generation facilities over the resource acquisition period.

(IV) Estimated in-service dates for utility-owned generation facilities for which a CPCN has been granted but which are not in service at the time the electric resource plan under consideration is filed.

(V) Estimated remaining useful lives of existing generation facilities and any significant new investment or maintenance expense relating to the existing generation facilities.

(VI) The amount of capacity, energy, and demand-side resources purchased from utilities and non-utilities, the duration of such purchase contracts and a description of any contract provisions that allow for modification of the amount of capacity and energy purchased pursuant to such contracts.

(VII) The amount of capacity and energy provided pursuant to wheeling or coordination agreements, the duration of such wheeling or coordination agreements, and a description of any contract provisions that allow for modification of the amount of capacity and energy provided pursuant to such wheeling or coordination agreements.

(VIII) The projected emissions, in terms of pounds per MWH and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for the resources identified under this paragraph 3607(a).

(IX) The expected demand-side resources during the resource planning period from existing measures installed through utility-administered programs; and, from measures expected to be installed in the future through utility-administered programs in accordance with a Commission-approved demand-side management plan.

(b) Coordination of plan filings. Utilities required to comply with these rules shall coordinate their electric resource plan filings such that the amount of electricity purchases and sales between utilities during the planning period is reflected uniformly in their respective plans. Disputes regarding the amount, timing, price, or other terms and conditions of such purchases and sales shall be fully explained in each utility's plan. If a utility files an interim plan as specified in rule 3603, the utility is not required to coordinate that filing with other utilities.

(c) Benchmarking. For the purpose of identifying existing resources that potentially are not performing cost-effectively as compared to other resources available in the market, the utility shall compare the costs and performance of each of its existing resources (utility-owned and contracted) to the costs and performance of the generic resources.

(d) Ancillary services assessment. The utility shall identify its existing resources that provide various ancillary services necessary to support its distribution and transmission systems, including load following, reactive power-voltage regulation, system protective services, loss compensation service, system control, load dispatch services, and energy imbalance services.

3608. Transmission Resources.

(a) The utility shall report its existing transmission capabilities, and future needs during the planning period, for facilities of 115 kilovolts and above, including associated substations and terminal facilities. The utility shall generally identify the location and extent of transfer capability limitations on its transmission network that may affect the future siting of resources.

(b) With respect to future needs, the utility shall submit a description of all transmission lines and facilities appearing in its most recent report filed with the Commission pursuant to § 40-2-126, C.R.S., and rule 3627 that, as identified in such reports, could reasonably be placed into service during the resource acquisition period.

(c) For each transmission line or facility identified in paragraph (b), the utility shall include the following information detailing assumptions to be used for resource planning and bid evaluation purposes:

(I) length and location;

(II) estimated in-service date;

(III) injection capacity;

(IV) estimated costs;

(V) terminal points; and

(VI) voltage and megawatt rating.

(d) In order to equitably compare possible resource alternatives, the utility shall consider the transmission costs required by, or imposed on the system by, and the transmission benefits provided by a particular resource as part of the bid evaluation criteria.

(e) The electric resource plan shall describe and shall estimate the cost of all new transmission facilities associated with any specific resources proposed for acquisition other than through a competitive acquisition process.

3609. Planning Reserve Margins and Contingency Plans.

(a) The utility shall provide a description of, and justification for, the means by which it assesses the desired level of reliability on its system throughout the planning period (e.g., probabilistic or deterministic reliability indices).

(b) The utility shall develop and justify planning reserve margins for the resource acquisition period for the base case, high, and low forecast scenarios established under rule 3606, to include risks associated with: the development of generation; losses of generation capacity purchase of power; losses of transmission capability; risks due to known or reasonably expected changes in environmental regulatory requirements; and, other risks. The utility shall develop planning reserve margins for its system over the planning period beyond the resource acquisition period for the base case forecast scenario. The utility shall also quantify the recommended or required reliability performance criteria for reserve groups and power pools to which the utility is a party.

(c) Since actual circumstances may differ from the most likely estimate of future resource needs, the utility shall develop contingency plans for the resource acquisition period. As a part of its plan, the utility shall provide, under seal, a description of its proposed contingency plans for the acquisition of additional resources if actual circumstances deviate from the most likely estimate of future resource needs developed pursuant to rule 3610; or, replacement resources in the event that resources are not developed in accordance with a Commission-approved plan under rule 3617. The Commission will consider approval of contingency plans only after the utility receives bids, as described in subparagraph 3615(b)(V). The provisions of subparagraph 3615(e)(III) shall not apply to the contingency plans unless explicitly ordered by the Commission.

3610. Assessment of Need for Resources.

(a) The utility shall assess the need to acquire additional resources during the resource acquisition period based on the electric energy and demand forecasts developed pursuant to rule 3606, the assessment of existing resources developed pursuant to rule 3607, planning reserve margins developed pursuant to rule 3609, and other factors including, but not limited to, the factors listed in paragraph 3610(b).

(b) In assessing its need to acquire resources, the utility shall also:

(I) determine the additional eligible energy resources, if any, the utility will need to acquire to comply with the Commission's RES rules;

(II) take into account the demand-side resources it must acquire to meet the energy savings and peak demand reduction goals established under § 40-3.2-104, C.R.S. To that end, the Commission shall permit the utility to implement cost-effective demand-side resources to reduce the need for additional resources that would otherwise be met through a competitive acquisition process pursuant to rule 3611; and

(III) address the benefits of potential emission reductions.

(c) The Commission may give consideration of the likelihood of new environmental regulations and the risk of higher future costs associated with the emission of greenhouse gases such as carbon dioxide when it considers utility proposals to acquire additional resources during the resource acquisition period.

3611. Exemptions and Exclusions.

(a) The following resources need not be included in an approved electric resource plan prior to acquisition.

(I) Emergency maintenance or repairs made to utility-owned generation facilities.

(II) Capacity and/or energy from newly-constructed, utility-owned, supply-side resources with a nameplate rating of not more than 20 MW.

(III) Capacity and/or energy from the generation facilities of other utilities or from non-utility generators pursuant to agreements for not more than a two year term (including renewal terms) or for not more than 20 MW of capacity.

(IV) Improvements or modifications to existing utility generation facilities that change the production capability of the generation facility site in question, by not more than 20 MW, based on the utility's share of the total power generation at the facility site and that have an estimated cost of not more than $30 million.

(V) Interruptible service provided to the utility’s electric customers.

(VI) Modification to, or amendment of, existing power purchase agreements provided the modification or amendment does not extend the agreement more than four years, does not add more than 20 MW of capacity to the utility's system, and is cost effective in comparison to other supply-side alternatives available to the utility.

(VII) Utility investments in emission control equipment at existing generation plants.

(VIII) Utility administered demand-side programs implemented in accordance with § 40-3.2-104, C.R.S.

(b) If the utility evaluates an existing or proposed electric generating facility offered in a competitive bidding process conducted outside of an approved resource plan, the utility shall provide the owner or developer of the electric generation facility in writing by e-mail the modeling inputs and assumptions that reasonably relate to the facility or to the transmission of electricity from that facility to the utility within 14 calendar days of the utility’s decision to advance the potential resource to computer-based modeling.

3612. Confidential Information Regarding Electric Generation Facilities

(a) In any proceeding related to an electric resource plan filed under rule 3603, an amendment to an approved plan filed under rule 3617, or pursuant to a request for information made under paragraph 3611(b), the provisions regarding confidential information set forth in rules 1100 through 1103 of the Commission’s Rules of Practice and Procedure shall apply, in addition to this rule 3612.

(b) The utility shall provide information claimed to be highly confidential under paragraph 1101(b) to a reasonable number of attorneys representing a party in the electric resource plan proceeding, provided that those attorneys file appropriate non-disclosure agreements containing the terms listed in subparagraph 3612(b)(I). The utility shall also provide information claimed to be highly confidential under paragraph 1101(b) to a reasonable number of subject matter experts representing a party in the plan proceeding, provided that the attorney representing the party files the appropriate non-disclosure agreements for the subject matter experts containing the terms in subparagraph 3612(b)(II) and the subject matter experts’ curriculum vitae.

(I) Attorney highly confidential nondisclosure agreement terms.

I [attorney name] state that I have read the protective provisions relating to confidential information contained in 4 Code of Colorado Regulations 723-1-1100 through 1103. With respect to all information claimed to be confidential and all information claimed to be highly confidential that is produced in, or arises in, the course of this proceeding in Proceeding No. [ ], I agree to be bound by the terms of the protective provisions contained in 4 Code of Colorado Regulations 723-1-1100. I hereby state that I will oversee the processes that any subject matter expert to whom I have authorized access to highly confidential information uses in order to assure that extraordinary confidentiality provisions are properly implemented and maintained. I hereby state that I will assure that extraordinary confidentiality provisions are properly implemented and maintained within my firm. I agree that all highly confidential information shall not be used or disclosed for purposes of business or competition, or for any other purpose other than for purposes of the proceeding in which the information is produced. I hereby state that I will not disclose or disseminate any highly confidential information in this Proceeding No. [ ] to any third party other than those specifically authorized to review such highly confidential information, including any third party who is or may become a bidder responding to future electric resource planning solicitations or otherwise relating to the acquisition of, contracting for, or retirement of electric generation facilities in Colorado.

(II) Subject Matter Expert highly confidential nondisclosure agreement terms.

I [subject matter expert's name] state that I have read the protective provisions relating to confidential information contained in 4 Code of Colorado Regulations 723-1-1100 through 1103. With respect to all information claimed to be confidential and all information claimed to be highly confidential that is produced in, or arises in the course of this proceeding in Proceeding No. [ ], I agree to be bound by the terms of the protective provisions contained in 4 Code of Colorado Regulations 723-1-1100. I hereby state that I will work with my attorney, [attorney name], to assure that extraordinary confidentiality provisions are properly implemented and maintained. I hereby state that I did not and will not develop or assist in the development of any power supply proposals associated with this proceeding. I agree that all highly confidential information shall not be used or disclosed for purposes of business or competition, or for any other purpose other than for purposes of the proceeding in which the information is produced. I hereby state that I will not disclose or disseminate any highly confidential information in this Proceeding No. [ ] to any third party other than those specifically authorized to review such highly confidential information, including any third party who is or may become a bidder responding to future electric resource planning solicitations or otherwise relating to the acquisition of, contracting for, or retirement of electric generation facilities in Colorado.

(c) Paragraph 3612(b) is only applicable to proceedings related to an electric resource plan filed pursuant to rule 3603, an amendment to an approved plan filed under rule 3617, or to a request for information made under paragraph 3611(b).

(d) In order to expedite access to confidential information at the beginning of the resource planning proceeding, an entity may file for intervention at any time during the 30-day notice period established in paragraph 1401(a) of the Commission's Rules of Practice and Procedure. If the entity requests an expedited decision on its motion it shall include in the title of its motion for intervention "REQUEST FOR EXPEDITED TREATMENT AND FOR SHORTENED RESPONSE TIME TO FIVE BUSINESS DAYS, PURSUANT TO PARAGRAPH 3612(d)." The movant shall concurrently provide an electronic copy of the motion to the utility. Response time to any such motion is automatically shortened to five business days.

3613. Best Value Employment Metrics

Best value employment metric information regarding each proposed new utility resource shall include:

(a) The availability of training programs, including training through apprenticeship programs registered with the United States Department of Labor, Office of Apprenticeship and Training. The utility or bidder shall provide, for example and as applicable, the following information for each craft the utility anticipates will work on the project:

(I) availability of training programs;

(II) the names of specific training programs available;

(III) the curriculum of the specific training programs;

(IV) the cost of worker training;

(V) the duration of the training programs;

(VI) the total number of hours of on-the-job training required;

(VII) the total number of classroom hours required;

(VIII) the licenses and certifications obtained, if any;

(IX) the training program standards for each training program; and

(X) a statement whether the training programs are United States Department of Labor registered apprenticeship programs and are accredited to award college credits.

(b) The employment of Colorado workers as compared to importation of out-of-state workers. The utility or bidder shall provide, for example and as applicable, the following information for each craft the utility anticipates will work on the project:

(I) estimated number of workers by job classification;

(II) estimated length of time of service, including total man hours, by job classification;

(III) percentage of Colorado workers by job classification; and

(IV) percentage of project man hours earned by Colorado workers by job classification.

(c) Long-term career opportunities. The utility or bidder shall provide, for example and as applicable, the following information for each craft the utility anticipates will work on the project: job classifications, licenses, certifications and skills that will be applied and the long-term career opportunities for each job classification; and

(d) Industry-standard wages, health care, and pension benefits. The utility or bidder shall provide, for example and as applicable, the following information for each craft the utility anticipates will work on the project:

(I) range of wages by job classification;

(II) healthcare benefits by job classification;

(III) pension benefits by job classification;

(IV) prevailing wages and fringe benefits (healthcare benefits, pension benefits and other compensation) based on industry standards and the current Colorado labor agreements by job classification; and

(V) wages and fringe benefits (healthcare benefits, pension benefits and other compensation) by job classification.

3614. Phase I.

(a) Review on the merits.

(I) The utility's electric resource plan shall be filed as an application; shall meet the requirements of paragraphs 3002(b) and 3002(c); and shall be administered pursuant to the Commission's Rules Regulating Practice and Procedure.

(II) The Commission may hold a hearing for the purpose of reviewing, and rendering a decision regarding, the contents of the utility's filed electric resource plan.

(b) Competitive bidding.

(I) It is the Commission's policy that a competitive acquisition process will normally be used to acquire resources.

(II) The competitive bid process should afford all resources an opportunity to bid. All bids and utility resource proposals (including the early retirement of existing resources) will be compared in order to determine a cost-effective resource plan (i.e., an all-source solicitation).

(III) The utility may participate in a competitive resource acquisition process by proposing the development of a new utility resource that the utility shall own as a rate base investment. The utility shall provide in detail all capital and operating costs for the proposed resource, as well as a firm, all-in point cost in support of its proposal such that the Commission can reasonably compare the utility’s proposal to alternative bids. In the event a utility proposes a rate base investment, the utility shall also propose a cost cap and explain how it intends to compare the utility rate based proposal(s) with non-utility bids. The Commission may also address the regulatory treatment of such costs with respect to future recovery. If the utility proposes to acquire resources from a bidder after new construction (e.g., a build-own transfer), the utility shall propose a method for establishing an all-in point cost such that the Commission can reasonably compare the utility's proposal to alternative bids in Phase II.

(IV) Each utility shall propose a written bidding policy as part of its filing under rule 3603, including the assumptions, criteria, and models that will be used to solicit and evaluate bids in a fair and reasonable manner. The utility shall specify the competitive acquisition procedures that it intends to use to obtain resources including a schedule of bid fees graduated by the size of the proposed resources. The utility shall also propose, and other interested parties may provide input as part of the electric resource plan proceeding, criteria for evaluating the costs and benefits of resources such as the valuation of emissions and non-energy benefits, including, for example, benefits associated with best value employment metrics.

(c) Alternative plan for acquiring resources.

(I) Notwithstanding the Commission's preference for all-source bidding for the acquisition of all new utility resources under these rules, the utility may propose in its filing under rule 3603, an alternative plan for acquiring the resources to meet the need identified in rule 3610. The utility shall specify the portion of the resource need that it intends to meet through an all-source competitive acquisition process and the portion that it intends to meet through an alternative method of resource acquisition.

(II) The utility may develop and own as utility-rate based property certain eligible energy resources through an alternative method of resource acquisition pursuant to § 40-2-124(1)(f)(I), C.R.S.

(A) A utility shall be allowed to develop and own as utility rate-based property, without being required to comply with the competitive bidding requirements in this rule up to twenty-five percent of the total new eligible energy resources that the utility acquires from entering into power purchase agreements and from developing and owning resources after March 27, 2007, if the Commission determines that the proposed resource can be constructed at a reasonable cost compared to the cost of similar eligible energy resources available in the market.

(B) A utility shall be allowed to develop and own as utility rate-based property, without being required to comply with the competitive bidding requirements in this rule, up to fifty percent of the total new eligible energy resources that the utility acquires from entering into power purchase agreements and from developing and owning resources after March 27, 2007, if the Commission determines that the proposed resource can be constructed at a reasonable cost compared to the cost of similar eligible energy resources available in the market and that the proposed new eligible energy resource would provide significant economic development, employment, energy security, or other benefits to the state of Colorado.

(C) The utility shall be allowed to develop and own as utility rate-based property more than the percentages of total new eligible energy resources set forth in subparagraphs 3614(c)(II)(A) and 3614(c)(II)(B), if the utility bids to own the new eligible energy resources in the competitive solicitation and is selected as a winning bidder.

(D) The utility may develop and own new eligible energy resources either solely or jointly with other owners. If the utility owns the new eligible energy resource jointly, the entire jointly owned resource shall count toward the percentage limitations set forth in subparagraph 3614(c)(II). For purposes of this rule, participation by any parent, affiliate or subsidiary of a utility in a utility's owned new eligible energy resource shall count towards the percentage limitations. The utility's rate base portion of any new eligible energy resource is limited to only the utility's ownership percentage in the new eligible energy resource.

(III) If the utility proposes that a portion of the resource need be met through an alternative method of resource acquisition, the utility shall identify the specific resource(s) that it wishes to acquire and the reason the specific resource(s) should not be acquired through an all-source competitive acquisition process. With the exception of certain eligible energy resources qualified for acquisition without competitive bidding pursuant to § 40-2-124(1)(f)(I), C.R.S., the utility shall provide a cost-benefit analysis to demonstrate the reason(s) why the public interest would be served by acquiring the specific resource(s) through an alternative method of resource acquisition. Although competitive bidding is not required for utility-owned resources pursuant to § 40-2-124(1)(f)(I), C.R.S., the Commission may consider the competitive bidding results in Phase II when establishing whether the resource can be constructed at reasonable cost compared to the cost of similar eligible energy resources available in the market.

(IV) Although the utility may propose a method for acquiring new utility resources other than all-source competitive bidding, as a prerequisite, the utility shall nonetheless include in its electric resource plan the necessary bid policies, RFPs, and model contracts necessary to satisfy the resource need identified under rule 3610 exclusively through all-source competitive bidding.

(V) In the event that the utility proposes an alternative method of resource acquisition that involves the development of a new renewable energy resource or new supply-side resource that the utility shall own as a rate base investment, the utility shall file, simultaneously with its electric resource plan, an application for a CPCN for such new resource. The Commission may consolidate, in accordance with the Commission's Rules of Practice and Procedure, the proceeding addressing that application for a CPCN with the resource planning proceeding. The utility shall provide a detailed estimate of the cost of the proposed facility to be constructed and information on alternatives studied, costs for those alternatives, and criteria used to rank or eliminate those alternatives.

(VI) In the event that the utility proposes to acquire specific resources through an alternative method of resource acquisition that involves the development of a new renewable energy resource or new supply-side resource that the utility shall own as a rate base investment, the utility shall provide the Commission with the best value employment metric information set forth in rule 3613 regarding each resource.

(d) Request for Proposals (RFPs).

(I) The proposed RFP(s) filed by the utility shall be designed to solicit competitive bids to acquire resources pursuant to paragraph 3614(b). To minimize bidder exceptions and to enhance bid comparability, the utility shall include in its proposed RFP(s) a model contract.

(II) The proposed RFP(s) shall include the bid evaluation criteria the utility will use in ranking the bids received. The utility shall also include in its proposed RFP(s): details concerning its resource needs; reasonable estimates of transmission costs for resources located in different areas pursuant to rule 3608, including a detailed description of how the costs of future transmission will apply to bid resources; the extent and degree to which resources must be dispatchable, including the requirement, if any, that resources be able to operate under automatic dispatch control; the utility's proposed model contract(s) for the acquisition of resources; proposed contract term lengths; discount rate; general planning assumptions; and, any other information necessary to implement a fair and reasonable bidding program.

(III) The utility shall request from bidders the best value employment metrics for each bid resource as set forth in rule 3613.

(e) Independent evaluator.

(I) During the course of the Phase I, and no later than two weeks prior to the start of the hearing, the utility shall file for Commission approval the name of the independent evaluator who the utility, the Staff of the Commission, and the OCC jointly propose. The Commission shall approve the independent evaluator in the Phase I decision.

(II) The utility shall pay for the services provided by the independent evaluator pursuant to a contract approved by the Commission. 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.

(f) Phase I decision.

(I) Based upon the evidence of record, the Commission shall issue a written decision approving, disapproving, or ordering modifications, in whole or in part, to the utility's electric resource plan filed in accordance with rule 3604.

(II) The Phase I decision approving or denying the electric resource plan shall address the contents of the utility's plan filed in accordance with rule 3604. If the record contains sufficient evidence, the Commission shall specifically approve or modify: the utility's assessment of need for additional resources in the resource acquisition period; the utility's plans for acquiring additional resources through an all-source competitive acquisition process or through an alternative acquisition process; and components of the utility's proposed RFP, such as the model contracts and the proposed evaluation criteria.

(III) The Phase I decision will set forth the information the utility shall provide in its 120-day report regarding potential resources, proposed utility-owned resources, and the modeling of portfolio combinations of resources to support the development of cost-effective resource plans.

(IV) If the Commission declines to approve a utility's electric resource plan, either in whole or in part, the utility shall make changes to the plan in response to the Commission's decision. Within 90 days of the Commission's rejection of a plan, the utility shall file an amended plan with the Commission and shall provide the amended plan to all parties who participated in the application proceeding concerning the utility's plan. All such parties may participate in any hearings regarding the amended plan.

3615. Phase II.

(a) Independent evaluator.

(I) 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 electric resource plan 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 so as 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. In the event that the independent evaluator notes a problem or a deficiency in the bid evaluation process, the independent evaluator should notify the utility.

(II) All parties in the electric resource plan proceeding other than the utility and the Staff of the Commission are restricted from initiating contacts with the independent evaluator. The independent evaluator may initiate contact with the utility and other parties. Staff may inquire about changes to (1) bid eligibility screening, (2) initial economic evaluations, and (3) computer bid evaluation and modeling, including but not limited to changes in modeling inputs, assumptions, conventions, and programming, made by the utility with or without the consent of the independent evaluator. For all contacts with parties in the plan proceeding, including those initiated by Staff or 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. Such log shall be posted weekly on the Commission's website for the duration of the independent evaluator's contract.

(III) The independent evaluator 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.

(b) Competitive solicitation.

(I) When issuing its RFP, the utility shall provide potential bidders with the Commission's order or orders specifying the form of nondisclosure agreement necessary to obtain access to confidential and highly confidential modeling inputs and assumptions provided by the utility pursuant to subparagraph 3615(c)(II). The utility shall also provide potential bidders with an explanation of the process by which disputes regarding inputs and assumptions to computer-based modeling will be addressed by the Commission pursuant to subparagraph 3615(c)(II).

(II) The utility shall require bidders to provide the contact name of the owner or developer designated to receive notice pursuant to subparagraph 3615(c)(I).

(III) The utility shall inform bidders that certain bid information submitted in response to the RFP will be made available to the public through the posting of certain bid information on the utility's website upon the completion of the competitive acquisition process pursuant to subparagraph 3615(e)(VI).

(IV) Within 30 days after bids are received in response to the RFP(s), the utility shall report: the identity of the bidders and the number of bids received; the quantity of MW offered by bidders; a breakdown of the number of bids and MW received by resource type; and, a description of the prices of the resources offered.

(V) If, upon examination of the bids, the utility determines that the proposed resources may not meet the utility's expected resource needs, the utility shall file, within 30 days after bids are received, an application for approval of a contingency plan. The application shall include the information required by paragraphs 3002(b) and 3002(c), the justification for need of the contingency plan, the proposed action by the utility, the expected costs, and the expected timeframe for implementation.

(c) Bid evaluation

(I) Upon the receipt of bids to its competitive solicitation, the utility shall investigate whether each potential resource meets the requirements specified in the resource solicitation and shall perform an initial assessment of the bids, including an assessment whether the owner or developer provided the required documentation of best value employment metrics. Within 45 days of the utility's receipt of bids, the utility shall provide notice in writing by e-mail to the owner or developer of each potential resource stating whether its bid is advanced to computer-based modeling to evaluate the cost or the ranking of the potential resource, and, if not advanced, the reasons why the utility will not further evaluate the bid using computer-based modeling. If, after the utility issues notice to an owner or developer that the potential resource was not advanced to computer-based modeling, the utility subsequently advances that potential resource to computer-based modeling, the utility shall provide notice in writing by e-mail to the owner or developer of that potential resource within three business days of the utility's decision to advance the potential resource to computer-based modeling.

(II) For bids advanced to computer-based modeling, the utility shall, contemporaneously with the notification in subparagraph 3615(c)(I), also provide to the owner or developer the modeling inputs and assumptions that reasonably relate to that potential resource or to the transmission of electricity from that facility to the utility. The utility shall provide such information so that modeling errors or omissions may be corrected before the competitive acquisition process is completed. Such information shall explain to the owner or developer how its facility will be represented in the computer-based modeling and what costs, in addition to the bid information, will be assumed with respect to the potential resource. In the event that this information contains confidential or highly confidential information, the owner or developer shall execute an appropriate nondisclosure agreement prior to receiving this information.

(III) Within seven calendar days after receiving the modeling inputs and assumptions from the utility pursuant to subparagraph 3615(c)(II), the owner or developer of a potential resource shall notify the utility in writing by electronic mail the specific details of any potential dispute regarding these modeling inputs and assumptions. The owner or developer shall attempt to resolve this dispute with the utility. However, if the owner or developer and utility cannot resolve the dispute within three calendar days, the utility shall immediately notify the Commission with a filing in the electric resource plan proceeding also served on the affected owner or developer. If the owner or developer is not already a party to the proceeding, the owner or developer shall file a notice of intervention as of right pursuant to paragraph 1401(b) of the Commission's Rules of Practice and Procedure, within two business days of the utility's filing of its notice of dispute to the Commission, for the limited purpose of resolving the disputed modeling inputs and assumptions related to the potential resource. An Administrative Law Judge will expeditiously schedule a technical conference at which the utility and the owner or developer shall present their dispute for resolution. The ALJ will enter an interim order determining whether corrections to the modeling inputs and assumptions are necessary. If the ALJ determines that corrections to the modeling inputs and assumptions are necessary, the utility shall, within three business days of the issuance of the ALJ's interim decision, provide the corrected information to both the owner or developer and the independent evaluator. In its report submitted under paragraph 3613(d), the utility shall also confirm by performing additional modeling as necessary, that the potential resource is fairly and accurately represented.

(d) 120-day report process.

(I) Within 120 days of the utility's receipt of bids in its competitive acquisition process, the utility shall file a report with the Commission presenting cost-effective resource plans in accordance with the Commission's Phase I decision. The utility shall identify its preferred cost-effective resource plan. The report shall also provide the Commission with the best value employment metrics information provided by bidders under subparagraph 3614(d)(III) and by the utility pursuant to subparagraph 3614(c)(VI).

(II) Within 30 days after the filing of the utility's 120-day report, the independent evaluator shall separately file a report that contains the independent evaluator's analysis of whether the utility conducted a fair bid solicitation and bid evaluation process, with any deficiencies specifically reported. The independent evaluator shall provide confidential versions of these reports to Commission staff and the OCC.

(III) Within 45 days after the filing of the utility's 120-day report, the parties in the electric resource plan proceeding may file comments on the utility's report and the independent evaluator's report.

(IV) Within 60 days after the filing of the utility's 120-day report, the utility may file comments responding to the independent evaluator's report and the parties' comments.

(e) Phase II decision.

(I) Within 90 days after the receipt of the utility's 120-day report under paragraph 3613(d), the Commission shall issue a written decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan, which decision shall establish the final cost-effective resource plan. In rendering the decision on the final cost-effective resource plan, the Commission shall weigh the public interest benefits of competitively bid resources provided by other utilities and non-utilities as well as the public interest benefits of resources owned by the utility as rate base investments. In accordance with §§ 40-2-123, 40-2-124, 40-2-129, and 40-3.2-104, C.R.S, the Commission shall also consider renewable energy resources; resources that produce minimal emissions or minimal environmental impact; energy-efficient technologies; and resources that affect employment and the long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

(II) The utility shall pursue the final cost-effective resource plan either with a due diligence review and contract negotiations, or with applications for CPCNs (other than those CPCNs provided in subparagraph 3614(c)(V), as necessary.

(III) The Phase I and Phase II decisions create a presumption that utility actions consistent with those decisions are prudent.

(A) In a proceeding concerning the utility's request to recover the investments or expenses associated with new resources.

(i) The utility must present prima facie evidence that its actions were consistent with Commission decisions specifically approving or modifying components of the electric resource plan.

(ii) To support a Commission decision to disallow investments or expenses associated with new resources on the grounds that the utility's actions were not consistent with a Commission approved electric resource plan, an intervenor must present evidence to overcome the utility's prima facie evidence that its actions were consistent with Commission decisions approving or modifying components of the plan. Alternatively, an intervenor may present evidence that, due to changed circumstances timely known to the utility or that should have been known to a prudent person, the utility's actions were not proper.

(B) In a proceeding concerning the utility's request for a CPCN to meet customer need specifically approved by the Commission in its decision on the final cost-effective resource plan, the Commission shall take administrative notice of its decision on the plan. Any party challenging the Commission's decision regarding need for additional resources has the burden of proving that, due to a change in circumstances, the Commission's decision on need is no longer valid.

(IV) The utility must complete Phase II by executing contracts for potential resources within 18 months after the utility's receipt of bids to its RFP(s). The utility may file a motion in the electric resource plan proceeding requesting to extend this deadline for good cause. The utility must execute final contracts for the potential resources prior to the completion of Phase II to receive the presumption of prudence afforded by subparagraph 3615(e)(III).

(V) Upon completion of Phase II, and consistent with the subsequent requirement for website posting of bids and utility proposals as required in subparagraph 3615(e)(VI), protected information that was filed in the electric resource plan proceeding will be refiled as non-confidential or public information as specified in the Commission order described below. To satisfy this requirement the utility shall file a proposal that addresses the public release of all confidential and highly confidential information related to bids for potential resources and resources the utility proposed to build and own as a rate base investment. At a minimum the utility shall address the public release of highly confidential and confidential information in its 120-day report, the independent evaluator's report, and all documents related to these reports filed by the utility, parties, or the independent evaluator. The utility shall file its proposal in the plan proceeding within 14 months after the receipt of bids to its RFP(s). Parties will have 30 calendar days after the utility files its proposal to file responses. The utility then may reply to any responses filed within ten calendar days. The Commission shall issue an order specifying to the utility and other parties the documents that shall be refiled as public information.

(VI) Upon completion of Phase II, the utility shall post on its website the following information from all bids and utility proposals: bidder name; bid price and utility cost, stated in terms that allow reasonable comparison of the bids with utility proposals; generation technology type; size of facility; contract duration or expected useful life of facility for utility proposals; and whether the proposed power purchase contract includes an option for the utility to purchase the facility during or at the end of the contract term.

3616. Annual Reports.

(a) The utility shall file with the Commission, and shall provide to all parties to the most recent electric resource plan proceeding, annual progress reports after submission of its plan application. The annual progress reports will inform the Commission of the utility's efforts under the approved plan and the emerging resource needs and potential utility proposals that may be part of the utility's next plan filing.

(b) Annual progress reports shall contain the following, for a running ten-year period beginning at the report date:

(I) an updated annual electric demand and energy forecast developed pursuant to rule 3606;

(II) an updated evaluation of existing resources developed pursuant to rule 3607;

(III) an updated evaluation of planning reserve margins and contingency plans developed pursuant to rule 3609;

(IV) an updated assessment of need for resources developed pursuant to rule 3610;

(V) an updated report of the utility's plan to meet the resource need developed pursuant to paragraphs 3614(b) and 3614(c) and the resources the utility has acquired to date in implementation of the electric resource plan; and

(VI) in addition to the items required in subparagraphs(b)(I) through (b)(V), a cooperative electric generation and transmission association shall include in its annual report a full explanation of how its future resource acquisition plans will give fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities, bearing in mind the beneficial contributions such technologies make to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

3617. Amendment of an Approved Electric Resource Plan.

The utility may file, at any time, an application to amend the contents of an electric resource plan approved pursuant to rules 3614 and 3615. 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.

3618. – 3624. [Reserved]

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[indicates omission of unaffected rules]

RENEWABLE ENERGY STANDARD

3650. Applicability.

(a) Rules 3650 through 3665 shall apply to all investor owned jurisdictional electric utilities in the state of Colorado that are subject to the Commission's regulatory authority.

(b) Rules 3651, 3652, 3654(b), (c), (e), (g) through (j), and (l), 3658(a)(I) through (a)(V), (b), (d) through (h), 3655(f) through (k), 3659(c), 3661(b), (c), (f),and (i), 3662(a),(c)(I), (c)(II), (c)(IV) through (c)(IX), (c)(XV), (c)(XVIII), (d), (f), and (g), 3664, and 3665(d) shall apply to cooperative electric associations in the state of Colorado.

(c) Rules 3651, 3652, 3653, 3654(b), (d), (f) through (j) and (l), 3658(a)(I) through (a)(V), (b), (d) through (h) shall apply to municipally owned electric utilities in the state of Colorado, which are QRUs.

(d) The board of directors of each municipally owned electric utility not subject to these rules may, at its option, submit the question of whether to be subject to these rules to its consumers on a one meter equals one vote basis. Approval by a majority of those voting in the election shall be required for such inclusion, providing that a minimum of 25 percent of eligible consumers participates in the election.

(I) Within 45 days of the conclusion of any vote to be subject to these rules, the municipally owned electric utility shall provide written notification of the outcome of the vote to the Director of the Commission.

(e) Rules 3650, 3651, 3652, 3662(h), and 3665(d) shall apply to cooperative electric generation and transmission associations.

(f) Nothing in these rules is intended to expand the Commission's regulatory oversight and powers over municipally owned electric utilities, cooperative electric associations, or cooperative electric generation and transmission associations.

3651. Overview and Purpose.

The purpose of these rules is to establish a process to implement the RES for qualifying retail utilities in Colorado, pursuant to §§ 40-2-124 and 40-2-127, C.R.S.

Energy is critically important to Colorado's welfare and development, and its use has a profound impact on the economy and environment. Growth of the state's population and economic base will continue to create a need for new energy resources, and Colorado's renewable energy resources are currently underutilized.

Therefore, in order to save consumers and businesses money, attract new businesses and jobs, promote development of rural economies, minimize water use for electricity generation, diversify Colorado's energy resources, reduce the impact of volatile fuel prices, and improve the natural environment of the state, it is in the best interests of the citizens of Colorado to develop and utilize renewable energy resources, including those paired with energy storage, to the maximum practicable extent.

It is the policy of this State to encourage local ownership of renewable energy generation facilities to improve the financial stability of rural communities.

3652. Definitions.

The following definitions apply only to rules 3650 – 3668. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Annual compliance report" means the report a QRU is required to file annually with the Commission pursuant to rule 3662 to demonstrate compliance with the RES.

(b) "Community-based project" means a project that meets the following three conditions: the project is owned by individual residents of a community, by an organization or cooperative that is controlled by individual residents of the community, by a local government entity, or by a tribal council; the project's generating capacity does not exceed 30 MW; and, there exists a resolution of support adopted by the local governing body of each local jurisdiction in which the project is to be located.

(c) "Compliance plan" means the annual plan a QRU is required to file with the Commission pursuant to rule 3656.

(d) "Compliance year" means a calendar year for which the RES is applicable.

(e) "Early eligible energy resources" are eligible energy resources, excluding retail renewable distributed generation, where the utility certifies that the resource is commercially operational and can produce energy under the terms of its contract, prior to January 1, 2015.

(f) "Qualifying retail utility" or "QRU" means any provider of retail electric service in the state of Colorado other than municipally owned electric utilities that serve 40,000 customers or fewer.

(g) "Qualifying wholesale utility" means a generation and transmission cooperative electric association that provides wholesale electric service directly to Colorado cooperative electric associations that are its members.

(h) "Renewable energy credit contract" means a contract for the sale of renewable energy credits without the associated energy.

(i) "Renewable energy supply contract" means a contract for the sale of renewable energy and the RECs associated with such renewable energy. If the contract is silent as to renewable energy credits, the renewable energy credits will be deemed to be combined with the energy transferred under the contract.l

(j) "Retail electricity sales" means electric energy sold to retail end-use electric consumers by a QRU or an electric utility that is eligible to become a QRU pursuant to § 40-2-124(5)(b), C.R.S.

(k) "Rural renewable project" means a renewable energy resource with a nameplate rating of 30 MW or less that interconnects to electric transmission or distribution facilities owned by a cooperative electric association or municipally owned utility at a point of interconnection of 69 kV or less.

(l) "Standard rebate offer" or "SRO" means the rebate offered by investor owned QRUs pursuant to § 40-2-124(1)(e), C.R.S.

3653. Municipal Utilities.

(a) Each municipally owned QRU implementing a RES substantially similar to the provisions of § 40-2-124, C.R.S., shall submit a statement to the Commission that demonstrates its RES program, at a minimum, meets the following criteria:

(I) the eligible energy resources shall be limited to those identified in subsection § 40-2-124(1)(a);

(II) the percentage requirements shall be equal to or greater in the same years than those identified in subsection § 40-2-124(1)(c)(V) and counted in the manner allowed by rule 3654; and

(III) the utility must have an optional pricing program in effect that allows retail customers the option to support through utility rates emerging renewable energy technologies.

(b) The statement to be submitted by a municipally owned QRU is for information purposes only and is not subject to approval by the Commission. Upon filing of the certification statement, the municipally owned QRU shall have no further obligations under these rules.

(c) Nothing in this section prohibits a municipally owned electric utility from buying and selling RECs.

3654. Renewable Energy Standard.

(a) Each investor owned QRU shall generate or cause to be generated (through purchase, incentive, or net metering) eligible energy, including the renewable distributed generation required under paragraphs 3655(a) and (b), in the following minimum amounts:

(I) twenty percent of its retail electricity sales in Colorado for the 2019 compliance year; and

(II) thirty percent of its retail electricity sales in Colorado for each of the compliance years beginning in 2020 and continuing thereafter.

(b) Each cooperative electric association QRU that serves fewer than 100,000 meters and municipally owned QRU shall generate or cause to be generated eligible energy in the following minimum amounts:

(I) six percent of its retail electricity sales in Colorado for each of the compliance years 2015 through 2019; and

(II) ten percent of its retail electricity sales in Colorado for each of the compliance years beginning in 2020 and continuing thereafter

(c) Each cooperative electric association QRU that serves 100,000 or more meters shall generate or cause to be generated eligible energy in amounts that are at least 20 percent of its retail electricity sales in Colorado for each of the compliance years beginning in 2020 and continuing thereafter.

(d) For municipal utilities that become municipally owned QRUs after December 31, 2006, the minimum percentage requirements of eligible energy shall begin in the first calendar year following qualification as follows:

(I) years one through three: One percent of retail electricity sales;

(II) years four through seven: Three percent of retail electricity sales;

(III) years eight through 12: Six percent of retail electricity sales; and

(IV) years 13 and thereafter: Ten percent of retail electricity sales.

(e) For purposes of cooperative electric association QRU compliance with the RES specified in paragraphs 3654(b) and (c), each kWh of eligible energy generated from solar electric generation technology shall be counted as 3.0 kWh of eligible energy, provided that the solar electric generation technology commenced producing electricity prior to July 1, 2015. For solar electric generation technology that commenced producing electricity on or after July 1, 2015, each kWh of eligible energy generated from solar electric generation technology shall be counted as 1.0 kWh of eligible energy for compliance purposes.

(f) For purposes of municipally owned QRU compliance with the RES specified in paragraphs 3653(a) and 3654(d), each kWh of eligible energy generated from solar electric generation technology shall be counted as 3.0 kWh of eligible energy, provided that the solar electric generation technology was under contract for development prior to August 1, 2015 and commenced producing electricity prior to December 31, 2016. For solar electric generation technology that either was not under contract for development prior to August 1, 2015 or commenced producing electricity on or after December 31, 2016, each kWh of eligible energy generated from solar electric generation technology shall be counted as 1.0 kWh of eligible energy for compliance purposes.

(g) For purposes of compliance with the RES, each kWh of eligible energy generated by an early eligible energy resource shall be counted as 1.25 kWh of eligible energy. Eligible energy generated by retail renewable distributed generation for which a QRU has entered into a purchase transaction prior to August 11, 2010 shall also be counted as 1.25 kWh of eligible energy.

(h) For purposes of compliance with the RES, each kWh of eligible energy generated from a community-based project shall be counted as 1.5 kWh of eligible energy.

(i) For purposes of compliance with the RES, each kWh of eligible energy generated from a rural renewable project may be counted as two kWh of eligible energy subject to the restrictions on rural renewable projects in rule 3666.

(j) For purposes of compliance with the RES, each kWh of eligible energy shall be subject to only one of the compliance multipliers in paragraphs 3654(e), (f), (g) or (h).

(k) For purposes of compliance with the RES, a QRU may generate, or cause to be generated, and count eligible energy or RECs for compliance:

(I) for the compliance year immediately preceding the compliance year during which they were generated, provided that such eligible energy or RECs are generated no later than July 1 of the calendar year immediately following the end of the compliance year for which they are being counted;

(II) for the compliance year during which they were generated; or

(III) for the five compliance years immediately following the compliance year during which they were generated.

(l) For purposes of compliance with this RES, a QRU may substitute the equivalent RECs for eligible energy.

(m) For purposes of compliance with this RES, there shall be no “double counting” of eligible energy or RECs. RECs shall be used for a single purpose only, and shall be retired upon use for that purpose. Notwithstanding the foregoing, eligible energy and RECs generated or acquired by a QRU and counted toward compliance with a federal RES may also be counted by the QRU toward compliance with the state RES.

(n) RECs associated with eligible energy sold by the investor owned QRU under an optional renewable energy pricing program shall be retired by the investor owned QRU and may not be counted by the investor owned QRU toward compliance with the RES.

(o) For purposes of compliance with this RES, if a generation system uses a combination of fossil fuel and eligible energy resources to generate electricity, a QRU may count only as eligible energy the proportion of the total electric output of the generation system that results from the use of eligible energy resources. The QRU shall include in its compliance plan the method of calculation used to determine the proportion of eligible energy.

(p) The QRU may generate, or cause to be generated, eligible energy without regard to economic dispatch procedures.

(q) For the purpose of compliance with the RES, a QRU shall cause eligible energy to be generated through payment for the eligible energy by contract or tariff, through net metering, through payment for the RECs produced with renewable energy, or through the payment of an incentive.

3655. Renewable Distributed Generation.

(a) In conjunction with the RES set forth in paragraph 3654(a), each investor owned QRU shall generate or cause to be generated (through purchase, incentive, or net metering) renewable distributed generation in the following minimum amounts, unless the Commission amends such minimum amounts under paragraph 3655(c):

(I) two percent of its retail electricity sales in Colorado in the 2019 compliance year; and

(II) three percent of its retail electricity sales in Colorado for each of the compliance years beginning in 2020 and continuing thereafter.

(b) Of the amounts of renewable distributed generation set forth in paragraph 3655(a), at least one-half shall be derived from retail renewable distributed generation unless modified by the Commission under paragraph 3655(c).

(c) The Commission may change the minimum amounts of retail renewable distributed generation and wholesale renewable distributed generation applicable to an investor owned QRU as compared to the amounts set forth in paragraphs 3655(a) and (b) pursuant to a filing by the QRU under rule 3656. The Commission may reduce the minimum amounts of retail renewable distributed generation and wholesale renewable distributed generation set forth in paragraphs 3655(a) and (b) for effect after December 31, 2014 upon finding that those minimum amounts are no longer in the public interest. In the event that the Commission finds that the public interest requires an increase in such minimum amounts after December 31, 2014, the Commission shall report such findings to the Colorado General Assembly.

(d) Renewable energy credits produced by retail renewable distributed generation and wholesale renewable distributed generation may be used to comply with the renewable distributed generation requirements as set forth in this rule 3655. Renewable energy produced by retail renewable distributed generation operating under net metering may be used to comply with the renewable distributed generation requirements as set forth in this rule 3655. Eligible energy and

RECs produced by renewable distributed generation shall be governed by rules 3654 and 3658, unless otherwise exempt from those provisions.

(e) In a final decision concerning the investor owned QRU's compliance plan, as between residential and nonresidential retail renewable distributed generation, the Commission shall direct the investor owned QRU to allocate its expenditures for the acquisition of retail renewable distributed generation according to the proportion of RESA revenues derived from each of these customer groups; except that the investor owned QRU may acquire retail renewable distribution generation at levels that differ from these group allocations based upon market response to the QRU's programs.

(f) In conjunction with the RES set forth in paragraph 3654(b), each cooperative electric association QRU that serves 10,000 or more meters but less than 100,000 meters shall generate or cause to be generated renewable distributed generation in amounts that are at least one percent of its retail electricity sales in Colorado for each of the compliance years beginning in 2020 and continuing thereafter. At least one-half of the renewable distributed generation shall be derived from retail renewable distributed generation.

(g) In conjunction with the RES set forth in paragraph 3654(b), each cooperative electric association QRU that serves fewer than 10,000 meters may generate or cause to be generated renewable distributed generation in amounts that are at least three-fourths percent of its retail electricity sales in Colorado for each of the compliance years beginning in 2020 and continuing thereafter. At least one-half of the renewable distributed generation shall be derived from retail renewable distributed generation.

(h) In conjunction with the RES set forth in paragraph 3654(c), each cooperative electric association QRU that serves 100,000 or more meters shall generate or cause to be generated renewable distributed generation in amounts that are at least one percent of its retail electricity sales in Colorado for each of the compliance years beginning in 2020 and continuing thereafter. At least one-half of the renewable distributed generation shall be derived from retail renewable distributed generation.

(i) For the purposes of a cooperative electric association QRU's compliance with paragraphs 3655(f), 3665(g), and 3655(h), a cooperative electric association QRU may subtract industrial retail sales from total retail sales in calculating its minimum retail renewable distributed generation requirement.

(j) For the purposes of a cooperative electric association QRU's compliance with paragraphs 3655(f), 3655(g), and 3655(h), an electric generation facility constitutes retail renewable distributed generation if it: is a renewable energy resource; has a nameplate rating of two MW or less; is located within the service territory of the cooperative electric association; generates electricity for the beneficial use of subscribers who are members of the cooperative electric association; and has at least four subscribers if the facility has a nameplate rating of 50 KW or less and at least ten subscribers if the facility has a nameplate rating of more than 50 kW. A subscriber's share of the production from the facility may not exceed 120 percent of the subscriber's average annual electricity consumption at the premise to which the subscription is attributed. Each cooperative electric association may establish, in the manner it deems appropriate, the requirements and terms associated with the electric generation facilities:

subscriber; subscription; pricing, including consideration of low-income members; metering; accounting; REC ownership; and other requirements and terms.

(k) Notwithstanding that rule 3665 does not apply to cooperative electric associations, a community solar garden constitutes retail renewable distributed generation for the purposes of a cooperative electric association QRU's compliance with paragraphs 3655(f), 3655(g), and 3655(h).

3656. RES Compliance Plan.

(a) It is the Commission's policy that utilities should meet the RES in the most cost-effective manner. To this end, the competitive acquisition provisions of the Commission's Electric Resource Planning Rules shall apply to the acquisition of eligible energy resources greater than 20 MW of nameplate capacity.

(b) Every four years beginning February 10, 2020, the investor owned QRU shall file a RES compliance plan detailing how the QRU intends to comply with these rules during the resource acquisition period addressed in the electric resource plan the QRU filed pursuant to rule 3603, with a focus on the QRU's programs for retail renewable distributed generation, community solar gardens, and voluntary offerings during the first four years of that resource acquisition period. The plan shall be filed as an application; shall meet the requirements of paragraphs 3002(b) and 3002(c); and shall be administered pursuant to the Commission's Rules Regulating Practice and Procedure. In addition to the required four-year cycle, the investor owned QRU may file an interim RES compliance plan by application at the Commission explaining the reasons and changed circumstances that justify the interim plan. An interim RES compliance plan shall address the same resource acquisition period as the QRU's most recently filed electric resource plan.

(c) Each investor owned QRU RES compliance plan shall include.

(I) A determination of the retail rate impact pursuant to rule 3661 over a period no less than the applicable resource acquisition period. The maximum retail rate impact shall not exceed two percent of the total retail bill annually for each customer. To the extent the RES plan exceeds this maximum retail rate impact, the investor owned QRU shall modify the RES plan to limit the acquisition of eligible energy resources so as not to exceed the maximum retail rate impact.

(II) A presentation of the projected costs of the eligible energy generated or caused to be generated and the associated revenues to be collected through retail rates to cover these costs (by rate mechanism, such as base rates, the fuel charge, and the RESA), any related expenditures for compliance with the RES, and any related deferred account balances (both positive and negative) over the applicable resource acquisition period.

(III) An estimate of its retail electricity sales over the applicable resource acquisition period.

(IV) An estimate of the eligible energy and RECs that the QRU already has acquired and the QRU's estimate of the additional eligible energy and RECs that will be needed to meet both the RES under rule 3654 and the requirements for renewable distributed generation under rule 3655 over the applicable resource acquisition period.

(V) The QRU's plan to acquire additional eligible energy and RECs given the constraints of the retail rate impact specified at rule 3661, if any, over the applicable resource acquisition period.

(VI) The programs the investor owned QRU intends to offer customers to comply with the RES or otherwise to encourage the development of cost-effective retail renewable distributed generation during the first four years of the applicable resource acquisition period. The QRU shall include the application forms, standard agreements, and general procedures for the QRU's programs and for the interconnection of renewable energy resources pursuant to the Interconnection Rules and Standards.

(VII) The QRU's plan for purchases from community solar gardens during the first four years of the applicable resource acquisition period and the QRU's proposed minimum and maximum purchases for the Commission to consider pursuant to § 40-2-127(5)(a)(IV), C.R.S.

(d) The Commission shall either approve the investor owned QRU's RES compliance plan or order modifications to the compliance plan. Investor owned QRU actions under an approved compliance plan shall carry a rebuttable presumption of prudence.

(e) The investor owned QRU may apply to the Commission at any time for approval of amendments to an approved RES compliance plan.

3657. Standard Rebate Offer, REC Purchases, and Contracts.

(a) In accordance with § 40-2-124(1)(e), C.R.S., each investor owned QRU shall make available to its retail electricity customers a standard rebate offer (SRO) expressed in terms of dollars per watt for on-site solar systems that become operational on or after December 1, 2004. The SRO shall be $0.00 per watt.

(b) For the purpose of demonstrating compliance with the RES, an investor owned QRU may establish one or more standard offers to purchase RECs from on-site solar systems that are eligible for net metering, so long as the on-site solar system is 500 kW or less in size. Subject to the retail rate impact in rule 3661:

(I) the investor owned QRU shall design standard offers that allow consumers of all income levels to obtain the benefits offered by on-site solar systems and that extend participation to consumers in all market segments; and

(II) the QRU shall have the discretion to determine, in a nondiscriminatory manner, the price it will pay for RECs from on-site solar systems that are no larger than 500 kW.

(c) The standard offers to purchase RECs from on-site solar systems shall meet the following requirements:

(I) the investor owned QRU need not purchase RECs from an on-site solar system smaller than 500 watts; and

(II) the standard offer to purchase RECs must be made available to all retail utility customers of the investor owned QRU on a non-discriminatory, first-come, first-served basis, based upon the date of contract execution.

(d) Except for on-site solar systems of commercial tenants, the on-site solar system installed must remain in place on the customer's premises for the duration of the SRO contract life. However, all customer equipment must have electrical connections in accordance with industry practice for permanently installed equipment, and it must be secured to a permanent surface (e.g., foundation, roof, etc.). Any indication of portability, including, but not limited to, wheels, carrying handles, dolly, trailer or platform, will render any on-site solar system ineligible for participation and payments under the SRO program.

(e) If a commercial customer that received an SRO is in a leased facility, such commercial tenant customer may relocate the on-site solar system to a substitute premise reasonably acceptable to the investor owned QRU at any time during the term of the SRO agreement, provided that:

(I) payment for all RECs shall be made by the investor owned QRU on a metered basis;

(II) the new location is within the investor owned QRU's service territory;

(III) the on-site solar system is not out of operation for more than 90 days due to such relocation;

(IV) the agreement is extended for the period of time the on-site solar system is out of operation; and

(V) the customer bears the cost of relocating the production meter, or the costs of setting a new production meter, at the new location.

(f) If the on-site solar system of a commercial customer that received an SRO is out of operation for more than 90 days, the investor owned QRU may terminate the SRO agreement and upon such termination the customer must repay the pro rata share of the rebate based on the number of years remaining in the term of the agreement.

(g) The purchase of RECs from an on-site solar system by an investor owned QRU shall be determined by the specifically metered renewable energy output from the on-site solar system.

(h) Renewable energy supply contracts entered into after July 2, 2006:

(I) shall be for the acquisition of both renewable energy and the associated RECs;

(II) may reflect a fixed price, or a price that varies by year;

(III) shall have a minimum term of 20 years (or shorter at the sole discretion of the seller); and

(IV) shall require the seller to relinquish all REC ownership associated with contracted renewable energy to the buyer.

(i) Renewable energy credit contracts entered into after July 2, 2006:

(I) shall be for the acquisition of RECs only;

(II) may reflect a fixed price, or a price that varies by time period; and

(III) shall have a minimum term of 20 years if the REC is from an on-site solar system, except that such contracts for on-site solar systems of between 100 KW and one MW may have a different term if mutually agreed to by the parties.

3658. Renewable Energy Credits.

(a) Renewable energy credits may be used to comply with the RES and may include:

(I) RECs generated by renewable energy resources owned by the QRU or by a QRU affiliate;

(II) RECs acquired by the QRU pursuant to renewable energy supply contracts;

(III) RECs acquired by the QRU pursuant to renewable energy credit contracts;

(IV) RECs acquired by the QRU pursuant to RES compliance programs or other programs to encourage the development of cost-effective retail renewable distributed generation;

(V) RECs acquired through a system of tradable renewable energy credits, from exchanges or from brokers

(VI) RECs carried forward from previous compliance years, pursuant to rule 3654; and

(VII) RECs borrowed forward from future compliance years, pursuant to rule 3654.

(b) RECs representing electricity generated at renewable energy resources shall be counted for compliance purposes consistent with the compliance multipliers in paragraphs 3654(e), (f), (g), or (h).

(c) The Commission shall not restrict the investor owned QRU's ownership of RECs if the investor owned QRU complies with both the RES established in rule 3654 and the requirements for renewable distributed generation established in rule 3655 and if the investor owned QRU complies with the retail rate impact established in rule 3661.

(d) All contracts between QRUs and the owners of renewable energy resources entered into after the effective day of these rules shall clearly specify the entity who shall own the RECs associated with the energy generated by the facility.

(e) A REC shall expire at the end of the fifth calendar year following the calendar year during which it was generated.

(f) RECs shall be used for a single purpose only, and shall expire or be retired upon use for that purpose. All RECs utilized by the QRU to comply with the RES:

(I) may not be sold or otherwise exchanged with any other party, or in any other state or jurisdiction;

(II) may not be included within a blended energy product certified to include a fixed percentage of renewable energy in any other state or jurisdiction; and

(III) may be counted simultaneously toward compliance with a federal renewable portfolio standard and with the RES.

(g) RECs that are generated with fuel cell energy using hydrogen derived from an eligible energy resource are eligible for compliance purposes only to the extent that the energy used to generate the hydrogen did not create renewable energy credits.

(h) If a renewable energy system uses a renewable energy resource in combination with a nonrenewable energy source to generate electricity, only the RECs associated with the proportion of the total electric output of the renewable energy system that results from the use of renewable energy resources shall be eligible to count toward compliance with the RES.

(i) If an on-site solar system of ten kW or below has received a one-time REC payment from a QRU, the QRU shall be entitled to count the anticipated RECs purchased by the one-time REC payment for compliance with the RES even if the on-site solar systems is removed or becomes inoperable.

(j) All renewable energy resources located in the region covered by the Western Electricity Coordinating Council (WECC) that generate RECs used by an investor owned QRU for compliance with the RES shall be registered with the Western Renewable Energy Generation Information System (WREGIS) and shall record their RECs in WREGIS with the exception of retail renewable distributed generation facilities less than one MW.

(k) All investor owned QRUs shall register in WREGIS. The investor owned QRU shall recover through its RESA the costs associated with WREGIS that are allocated to its retail customers.

(l) To the extent that the investor owned QRU acquires RECs from renewable energy resources that are not recorded in WREGIS, the investor owned QRU shall record such RECs in a central database. The database shall include, but not be limited to, a list of the renewable distributed generation whose RECs the investor owned QRU intends to use for compliance with the RES under rule 3654 and the requirements for renewable distributed generation under rule 3655, including its type, location, owner, operator, and start of operation. The database shall also record the RECs generated and the ownership, transfer and retirement of those RECs.

(m) An investor owned QRU may own and use for compliance with the RES RECs generated by renewable energy resources that the Commission has designated as new energy technologies or demonstration projects under § 40-2-123(1)(a), C.R.S., and that are therefore not subject to the retail rate impact established in rule 3661.

(n) The investor owned QRU shall have the discretion to sell or trade RECs at any time as long as the investor owned QRU generates or causes to be generated eligible energy to comply with the RES under rule 3654 and the requirements for renewable distributed generation under rule 3655. Proceeds from the sales of RECs shall be credited to retail customers. The investor owned QRU may seek approval in a compliance plan filing under rule 3657 or by separate application to retain as earnings a percentage of the funds from REC sales that the investor owned QRU expects to have available to acquire eligible energy and RECs under the retail rate impact in rule 3661 for the compliance year. In considering the percentage of funds to be retained as earnings by the investor owned QRU, the Commission shall take into account the development of the REC market and the expected value added by the investor owned QRU in marketing and trading the RECs.

3659. Cost Recovery.

(a) The investor owned QRU shall be entitled to timely cost recovery through retail rate mechanisms for all funds prudently expended to comply with these rules, including the costs the QRU incurs to administer the acquisitions of eligible energy and RECs. The QRU shall be entitled to recover its investment and expenses associated with these rules through appropriate adjustment clauses, including the RESA, that allow recovery of expenditures without the full resetting of electric rates.

(b) The Commission may authorize the investor owned QRU to implement a Renewable Energy Standard Adjustment (RESA) as a forward-looking cost recovery mechanism to provide funding for implementing the RES. (d) Each QRU shall separately identify the RESA on its customers' bills.

(e) At the request of the QRU, the Commission may approve an advance of funds from year to year by the QRU to augment the RESA amounts collected from retail customers, where such funds shall be repaid from future retail rate collections, with interest calculated at the QRU's after-tax weighted average cost of capital, so long as the QRU complies with limit on the retail rate impact under paragraph 3661(a).

(f) Each wholesale energy provider shall offer to its wholesale customers that are cooperative electric associations the opportunity to purchase their load ratio share of the wholesale energy provider's electricity from eligible energy resources. If a wholesale customer agrees to pay the full costs associated with the acquisition of eligible energy resources and associated renewable energy credits by its wholesale provider by providing notice of its intent to pay the full costs within 60 days after the wholesale provider extends the offer, the wholesale customer shall be entitled to receive the appropriate credit toward the RES as well as any associated renewable energy credits. To the extent that the full costs are not recovered from wholesale customers, a qualifying retail utility shall be entitled to recover those costs from retail customers.

3660. Incentives.

(a) If the investor owned QRU incurs costs in acquiring eligible energy to meet the RES, the QRU shall be entitled to carry forward these costs to a future year for cost recovery so long as the investor owned QRU complies with limit on the retail rate impact under rule 3661.

(b) The investor owned QRU shall be entitled to earn an extra profit on the QRU's ownership investment in a specific eligible energy resource if that eligible energy resource provides net economic benefits to customers. For these investments, the QRU shall be entitled to a return equal to the QRU's most recent authorized rate of return on rate base plus a bonus limited to 50 percent of the of the net economic benefit as long as the QRU is in compliance with these rules implementing the RES. If the QRU's investment in a specific eligible renewable energy resource does not provide a net economic benefit to customers, the QRU shall be entitled to a return equal to the QRU's most recent authorized rate of return on rate base.

(I) For the purposes of this rule 3660, net economic benefit shall mean that the specific eligible energy resource in which the QRU has made an ownership investment results in an average retail rate impact less than the rate impact that would have resulted from the acquisition of the alternative eligible energy resource meeting the same component of the RES that would have been selected absent the QRU's investment. The QRU shall set forth its calculation of the proposed net economic benefit either at the time of a compliance plan filing, an annual compliance report filing, a QRU rate filing or by application. The Commission shall determine the level of the net economic benefit and the level of the bonus after review of the utility's filing. The Commission may set the matter for hearing if appropriate under the Commission's Rules of Practice and Procedure.

(II) To the extent that a QRU uses computer modeling in its analysis of net economic benefit, the QRU shall use the same methodologies and assumptions it used in its most recently approved electric resource planning case, except as otherwise approved by the Commission. Confidential information may be protected in accordance with rules 1100 through 1103 of the Commission's Rules of Practice and Procedure.

(III) Any net economic benefit for which the QRU qualifies to receive a bonus shall be charged against the RESA account.

(c) When an investor owned QRU applies for a certificate of public convenience and necessity, the Commission shall consider rate recovery mechanisms that provide for earlier and timely recovery of costs prudently and reasonably incurred by the QRU in developing, constructing, and operating the eligible energy resource, including: rate adjustment clauses until the costs of the eligible energy resource can be included in the utility's base rates; and, a current return on the utility's capital expenditures during construction at the utility's most recently authorized weighted average cost of capital, including its cost of debt and its most recently authorized rate of return on equity, during the construction, startup, and operation phases of the eligible energy resource.

(d) The investor owned QRU is entitled to recover through rates, its prudently incurred expenditures. While not the exclusive method for establishing prudence, if the Commission approves a renewable energy supply contract or a renewable energy credit contract, the expenditures of the investor owned QRU under the contract shall be deemed to be prudent expenditures.

(e) If the investor owned QRU recovers fuel and purchased energy expense through an incentive adjustment clause, the QRU shall not receive a benefit from the incentive adjustment clause for the energy generated from QRU-owned eligible renewable energy resources, but the QRU shall be entitled to recover all the fuel and purchased energy costs associated with the eligible energy resource.

3661. Retail Rate Impact.

(a) The net retail rate impact of actions taken by an investor owned QRU to comply with the RES shall not exceed two percent of the total electric bill annually for each customer of that QRU.

(b) The net retail rate impact of actions taken by a cooperative electric association QRU to comply with the RES shall not exceed two percent of the total electric bill annually for each customer of that QRU.

(c) The QRU expenditures used in the determination of the net retail rate impact shall include the prudently incurred direct and indirect costs of all actions by a QRU to meet the RES, including, but not limited to, program administration, rebates and performance-based incentives, payments under renewable energy supply contracts, payments under renewable energy credit contracts, payments made for RECs purchased through brokers or exchanges, computer modeling and analysis time, QRU investment in and return on investment for eligible energy resources, and purchases from CSGs.

(d) The administrative costs of a QRU to implement these rules are capped at ten percent per year of the total annual expenditures used in the determination of the net retail rate impact.

(e) In its RES compliance plans and RES compliance reports, the investor owned QRU must demonstrate that the retail rate impact established in this rule does not exceed the two percent cap in § 40-2-124(1)(g)(I)(A), C.R.S. In its compliance plan filed under rule 3656, the investor owned QRU shall estimate the retail rate impact of its plan to comply with the RES over a period no less than the applicable resource acquisition period (the “RES planning period”) and shall submit a report detailing the development of the retail rate impact estimate. The compliance plan shall identify the funds that need to be made available to the QRU to comply with the RES under rule 3654, the requirements for renewable distributed generation under rule 3655, and the retail rate impact under this rule 3661.

(f) The retail rate impact shall be determined net of new alternative sources of electricity supply from non-eligible energy resources that are reasonably available at the time of the determination.

(g) For purposes of calculating the retail rate impact, the investor owned QRU shall use the same methods and assumptions it used in its most recently approved electric resource plan under the Commission’s Electric Resource Planning Rules, unless otherwise approved by the Commission. Confidential information may be protected in accordance with rules 1100 through 1102 of the Commission’s Rules of Practice and Procedure.

(h) The basic method for investor owned QRUs for performing the estimate of the retail rate impact cap is as follows.

(I) The QRU shall determine all commercially available resources to the QRU, either through ownership or by contract, for the RES planning period. The projected costs of these available resources shall be reflected in both of the scenarios analyzed under this paragraph.

(II) The QRU shall determine the QRU’s capacity and energy requirements over the RES planning period. The QRU shall develop two scenarios to estimate the resource composition of the QRU’s future electric system and the cost and benefits of that system over the RES planning period. The first scenario, a RES plan or “RES plan” should reflect the QRU’s plans and actions to acquire new eligible energy resources necessary to meet the RES. The second scenario, a “No RES plan” should reflect the QRU’s resource plan that replaces the new eligible energy resources in the RES plan with new nonrenewable resources reasonably available.

(III) Eligible energy resources whose acquisition commenced prior to July 2, 2006 shall be included in both the RES and No RES plans. Eligible energy resources acquired pursuant to a Commission-approved electric resource plan as new energy technologies or demonstration projects under § 40-2-123(1)(a), C.R.S., shall be included in both the RES and No RES plans.

(IV) The QRU shall compare the costs and benefits of the two plans to project the estimated annual net retail rate impact for the RES planning period. In calculating the net retail rate impact, the QRU shall take into account the projected net retail rate impact of the new eligible energy resources and the sum of the on-going annual net incremental costs of all eligible energy resources that the investor owned QRU has contracted to acquire under its programs to encourage the development of cost-effective retail renewable distributed generation and all eligible energy from resources that were constructed by the investor owned QRU or contracted for by the investor owned QRU after July 2, 2006.

(V) The on-going annual net incremental costs used in the retail rate impact calculation under subparagraph 3661(h)(IV) shall be established in each compliance plan filed under rule 3657. These costs shall then be locked down until the Commission issues a final decision regarding the investor owned QRU's next compliance plan filing when such costs shall be unlocked and reset to reflect changes in methods and assumptions used by the investor owned QRU under the Commission's Electric Resource Planning Rules, unless otherwise approved by the Commission.

(VI) If, in a compliance plan filed under rule 3657, the Commission approves a calculation of the retail rate impact that differs from a calculation in an earlier approved plan, the Commission shall allow the investor owned QRU to fully recover the costs of eligible energy resources and RECs already acquired by the investor owned QRU through one or more adjustment clauses.

(i) If the retail rate impact does not exceed the maximum percent level, a QRU may acquire more than the minimum amount of eligible energy resources and RECs required under the RES.

3662. RES Compliance Reporting.

(a) Each cooperative electric association QRU shall file an annual RES compliance report no later than June 1 to report on the status of the QRU's compliance with the RES for the most recently completed compliance year. The Commission will open an administrative proceeding each year to receive the compliance reports.

(b) Each investor owned QRU shall file an annual RES compliance report no later than February 10 to report on the status of the QRU's compliance with the RES for the most recently completed compliance year. In addition, each investor owned QRU shall file a quarterly RES report no later than the following dates: May 15 for the first quarter; August 15 for the second quarter; and November 15 for the third quarter. Unless otherwise directed by the Commission, the QRU shall file the annual and quarterly reports in the same proceeding as the corresponding RES compliance plan submitted by the QRU pursuant to rule 3656.

(c) Unless expressly noted otherwise, the annual RES compliance report of each investor owned and cooperative electric association QRU shall provide the following information for the most recently completed compliance year.

(I) The total MWH sold by the QRU to its retail customers in Colorado and the associated eligible energy required for compliance with the RES, including the requirements for retail renewable distributed generation and wholesale renewable distributed generation, as applicable.

(II) The total amount and source of eligible energy and RECs acquired by the QRU during the compliance year for to meet the RES, including the requirements for retail renewable distributed generation and wholesale renewable distributed generation, as applicable. The QRU shall separately identify and quantify amounts of eligible energy and RECs by each type of resource, including residential retail renewable distributed generation and nonresidential renewable distributed generation, as applicable. The QRU shall also separately identify eligible energy and RECs generated by early eligible energy resources.

(III) The total amount of RECs by category acquired by the investor owned QRU during the compliance year and the total amount and source of eligible energy generated by the QRU-owned eligible energy resources.

(IV) The total amount of eligible energy and RECs borrowed forward, pursuant to rule 3654, in previous compliance years that were made up during the compliance year to achieve compliance with each component of the RES.

(V) The total amount of eligible energy and RECs borrowed forward, pursuant to rule 3654, from future compliance years to achieve compliance with each component of the RES in the compliance year.

(VI) The total amount and source of eligible energy and RECs the QRU is carrying back from the year following the compliance year under rule 3654 to achieve compliance with each component of the RES in the compliance year.

(VII) The total amount of eligible energy and RECs the QRU has carried forward from prior calendar years under rule 3654 to apply in the compliance year for each component of the RES.

(VIII) The total amount of eligible energy and RECs the QRU has acquired in the compliance year that the QRU proposes to carry forward under rule 3654 to future years for each component of the RES.

(IX) The total amount of eligible energy and RECs the QRU has counted toward compliance with the RES, including the requirements for retail renewable distributed generation and wholesale renewable distributed generation, as applicable, in the compliance year.
The QRU shall separately identify amounts of renewable energy by each type of resource and eligible energy or RECs generated by early eligible energy resources.

(X) The total amount of renewable energy or RECs acquired by the QRU during the compliance year pursuant to the QRU's program programs to encourage the development of cost-effective retail renewable distributed generation.

(XI) The total amount of renewable energy generated by retail renewable distributed generation systems that are net metered.

(XII) The total amount of renewable energy or RECs acquired by the QRU during the compliance year from community solar gardens.

(XIII) The total amount of RECs retired by the investor owned QRU during the compliance year pursuant to a voluntary green pricing program.

(XIV) The total amount of RECs sold or traded by the investor owned QRU during the compliance year along with the profit and losses of such transactions and the method for calculating these margins.

(XV) Whether the QRU has invested in any eligible energy resource and whether that resource is under construction or in operation.

(XVI) The costs of the eligible energy generated or caused to be generated and the associated revenues collected through retail rates to cover these costs, any related expenditures for compliance with the RES, and any related deferred account balances (both positive and negative).

(XVII) The retail rate impact of the eligible energy and RECs acquired by the investor owned QRU. If the investor owned QRU has not acquired sufficient eligible energy and RECs to meet the RES under rule 3654 or the requirements for renewable distributed generation under rule 3655 due to the retail rate impact cap under rule 3661, the retail rate impact cap shall be recalculated based on the actual compliance year values. To the extent the recalculation of the retail rate impact cap demonstrates that additional funds are available based on actual compliance year values, the investor owned QRU shall use those additional funds to acquire RECs, to the extent necessary, to achieve the compliance levels set forth in rules 3654 and 3655 or until the additional funds have been spent if the investor owned QRU intends to claim that the retail rate impact cap prevented it from achieving compliance with the standard.

(XVIII) A description of the method used to develop the retail rate impact calculation.

(XIX) The proposed calculation of on-going annual net incremental costs for eligible energy resources that will come on line prior to the end of the following compliance year that have not been locked down pursuant to an investor owned QRU's compliance plan filing.

(XX) The funds advanced by the investor owned QRU during the compliance year, if any, pursuant to § 40-2-124(1)(g)(I)(B), C.R.S.

(XXI) The average hourly incremental cost of electricity during the compliance year, the total number of CSG kWh that were unsubscribed for each CSG during that period, and the total kWh and corresponding billing credits paid to CSG subscribers during the compliance year by each retail rate class for each CSG.

(XXII) The number of customers, by rate class, that have installed retail renewable distributed generation. The QRU shall report the number of low-income customers separate from other residential customers. The QRU shall report the number of customers who participated in the QRU's programs to encourage the development of cost-effective retail renewable distributed generation and the number of customers whose retail renewable distributed generation is net metered without participation in the QRU's programs.

(XXIII) The number of customers, by rate class, who are subscribers to community solar gardens and the amount of capacity subscribed per rate class. The QRU shall report the number of low-income customers separate from other residential customers.

(d) In the annual RES compliance report filed by the investor owned or cooperative electric association QRU, the QRU must explain whether it achieved compliance with the RES, including the requirements for retail renewable distributed generation and wholesale renewable distributed generation, as applicable, during the most recently completed compliance year, or explain why the QRU had difficulty meeting the RES or the requirements for retail renewable distributed generation and wholesale renewable distributed generation, as applicable.

(e) If, in its annual RES compliance report, the investor owned QRU did not comply with its RES as a direct result of absolute limitations within a requirements contract from a wholesale electric supplier, then the QRU must explain whether it acquired a sufficient amount of either eligible RECs or documented and verified energy savings through energy efficiency and/or conservation programs, or both to rectify the noncompliance so as to excuse the investor owned QRU from any administrative fine or other administrative action.

(f) On the same date that the investor owned or cooperative electric association QRU files its annual RES compliance report, the QRU shall post its annual compliance report excluding confidential material on its website to facilitate public access and review.

(g) On the same date that the investor owned or cooperative electric association QRU files its annual RES compliance report, if the QRU did not file using the Commission's E-Filings System, it shall provide the Commission with an electronic version of its annual compliance report excluding confidential material. The Commission may place the non-confidential portion of each QRU's annual compliance report on the Commission's website in order to facilitate public review.

(h) Each qualifying wholesale utility shall submit an annual report to the Commission no later than June 1 of each year. In addition, the qualifying wholesale utility shall post each annual report on its website. In each annual report, the qualifying wholesale utility shall:

(I) describe the steps it took during the most recently completed compliance year to comply with the RES of 20 percent of retail sales by 2020 as established in § 40-2-124(8), C.R.S.;

(II) for the compliance years before 2020, describe whether it is making sufficient progress toward meeting the standard in 2020 or is likely to meet the 2020 standard early. If it is not making sufficient progress toward meeting the standard of 20 percent in 2020, it shall explain why and shall indicate the steps it intends to take to increase the pace of progress; and

(III) for the 2020 compliance year and each compliance year thereafter, describe whether it has achieved compliance with the RES established in § 40-2-124(8), C.R.S., and whether it anticipates continuing to do so. If it has not achieved such compliance or does not anticipate continuing to do so, it shall explain why and shall indicate the steps it intends to take to meet the standard and by what date.

(i) The investor owned QRU quarterly report shall include the following information:

(I) the costs of the eligible energy generated or caused to be generated and the associated revenues collected through retail rates to cover these costs, any related expenditures for compliance with the RES, and any related deferred account balances (both positive and negative) for the quarter;

(II) the incremental and cumulative capacity of retail renewable distributed generation installed by customer class, where low-income customers are reported separately;

(IV) the incremental and cumulative number of customers, by class, that have installed retail renewable distributed generation, where customers participating in the QRU's programs are reported separately from customers taking net metering outside of the QRU's programs; and

(V) the incremental and cumulative capacity and location of community solar gardens from which the QRU is making purchases and the number of customers, by class, with shares in those community solar gardens, where low-income customers are reported separately.

3663. RES Compliance Report Review.

(a) Commission staff and the intervening parties to the proceeding in which the investor owned QRU files its annual RES and compliance report shall have 30 days after the filing of the annual report within which to file a request that the Commission set the report for hearing. The QRU shall have fourteen days to reply to any request for a hearing on the annual compliance report.

(b) If no request for hearing is filed within 30 days, the Commission will issue an order stating that:

(I) the QRU complied with the RES during the most recently completed compliance year;

(II) the QRU satisfied the requirements for renewable distributed generation during the most recently completed compliance year;

(III) the QRU has correctly calculated the retail rate impact for the compliance year pursuant to rule 3661; and

(IV) the number of excess RECs which the QRU has available to carry forward from that compliance year or use for any other legal purpose.

(c) If the Commission sets an investor owned QRU's annual RES compliance report for hearing, the Commission will determine whether the QRU complied with its RES and with its requirements for renewable distributed generation during the most recently completed compliance year. As necessary, the Commission will determine whether the QRU failed to meet the RES because of the retail rate impact limit in § 40-2-124-(1)(g), C.R.S.

(I) At the hearing, if the QRU asserts that the RES or the requirements for renewable distributed generation was not met due to the retail rate impact, it will have the burden of proof that it failed to comply with its RES or its requirements for renewable distributed generation during the most recently completed compliance year because of the retail rate impact.

(II) At the hearing, any party that advocates that the QRU failed to comply with the QRU's RES or its requirements for renewable distributed generation during the most recently completed compliance year is the proponent of a Commission order finding non-compliance, and that party shall have the burden of proof that the QRU failed to comply with the RES or the requirements for renewable distributed generation during the most recently completed compliance year. The QRU may assert that the RES or the requirements for renewable distributed generation were not met due to events beyond the reasonable control of the QRU that could not have been reasonably mitigated.

(III) If the Commission determines that the QRU did not correctly calculate the retail rate impact pursuant to rule 3661, the Commission will determine the retail rate impact calculation.

(d) After notice and hearing, if the Commission determines that the investor owned QRU did not fully comply with its RES or with its requirements for renewable distributed generation during the most recently completed compliance year, the Commission shall determine what, if any, administrative penalties should be assessed against the QRU for its failure to meet the RES or the requirements for renewable distributed generation. In assessing penalties, the Commission may take one or more of the following actions.

(I) Determine the cost that would have been incurred by the QRU to fully comply with the RES or the requirements for renewable distributed generation through the acquisition of RECs and assess all or part of this amount as part of an administrative penalty.

(II) No administrative penalties shall be assessed against a QRU if the amount of the shortfall is attributable to the retail rate impact limit.

(III) Assess no administrative penalties against a QRU if the failure to meet the RES or the requirements for renewable distributed generation results from events beyond the reasonable control of the QRU that could not have been reasonably mitigated including, but not limited to, failures to perform by counterparties to renewable energy supply contracts and renewable energy credit contracts, events that delay the construction or commercial operation of QRU-owned eligible renewable energy resources, and lack of customer interest in the QRU's programs to encourage the development of retail renewable distributed generation.

(IV) The cost of such administrative penalties shall not be recovered from retail customers through the QRU's rates.

3664. Rural Renewable Projects.

(a) QRUs may take advantage of REC multiplier for rural renewable projects described in paragraph 3654(h) subject to the following restrictions.

(I) Interconnection must be completed and commercial operation achieved by December 31, 2014.

(II) For investor owned QRUs, rural renewable projects for which this REC multiplier is claimed may not be counted toward the distributed generation requirements in rule 3655.

(III) Any entity that owns or develops a rural renewable project that will take advantage of the aforementioned compliance multiplier, must notify the Commission on a Commission-provided form within 30 days after signing a power purchase agreement with a QRU and also within 30 days after beginning commercial operations. Such forms will minimally require the MW of nameplate electric capacity from installed rural renewable projects or the capacity that is subject to power purchase agreements, as applicable.

(IV) For QRUs that are not investor owned QRUs, the compliance multiplier may be applied only to the aggregate first 100 MW of nameplate capacity projects statewide that report having achieved commercial operation to the Commission.

(V) The Commission will maintain a publicly available listing of projects that have submitted notifications in accordance with subparagraph 3666(a)(III) and shall provide notice to the first 100 MW of projects that are providing energy and RECs to non-investor owned QRUs that they may take advantage of the compliance multiplier.

3665. Environmental Impacts.

(a) Eligible energy resources must meet all applicable federal, state, and local environmental permitting requirements.

(b) For eligible energy resources larger than two MW that are not net-metered or any wind turbine structures extending over 50 feet in height, the QRU shall require project developers to include in the bid package written documentation that consultation occurred with appropriate governmental agencies (for example, the Colorado Division of Wildlife or the U.S. Fish and Wildlife Service) responsible for reviewing potential project development impacts to state and federally listed wildlife species, as well as species, habitats, and ecosystems of concern.

(c) For eligible energy resources larger than two MW that are not net-metered or any wind turbine structures extending over 50 feet in height, the QRU renewable energy supply contract shall require project developers to certify the following as a condition precedent to achieving commercial operation:

(I) the developer has performed site specific wildlife surveys (referred to herein as the Environmental Surveys) which are conducted on the facility's site prior to construction;

(II) the developer, with good faith effort, used the results of the Environmental Surveys and available monitoring in developing the design, construction plans, and management plans of the facilities to avoid, minimize, and/or mitigate any adverse environmental impacts to state and federally listed species, to species of special concern, to sites shown to be local bird migration pathways, to critical habitat, to important ecosystems, and to areas where birds or other wildlife are highly concentrated and are considered at risk;

(III) the results of the pre-construction Environmental Surveys shall be shared with the Colorado Division of Wildlife (CDOW) prior to project construction; and

(IV) a summary report of these results shall be made available to CDOW at the time the project achieves commercial operation.

(d) The Commission shall determine whether the electricity generated by coal mine methane or a synthetic gas is greenhouse gas (GHG) neutral on a case-by-case basis, measuring greenhouse gasses in terms of carbon dioxide equivalent.

3666. – 3674. [Reserved].

NET METERING

3675. Applicability.

This rule shall apply to all investor owned jurisdictional electric utilities in the state of Colorado that are subject to the Commission's regulatory authority. Cooperative electric associations engaged in the distribution of electricity (i.e., rural electric associations) and cooperative electric generation and transmission associations are exempt from these rules.

3676. Overview and Purpose.

The purpose of these rules is to allow qualified retail customers to implement net metering where the customer's retail electricity consumption is offset by the electricity generated from retail renewable distributed generation.

3677. Definitions.

The following definitions apply to rules 3675 through 3682. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Service entrance capacity" means the capacity of the utility's electric service conductors that are physically connected to the customer's electric service entrance conductors.

3678. Eligible Retail Renewable Distributed Generation.

(a) The retail renewable distributed generation shall be sized to supply no more than 120 percent of the customer's average annual electricity consumption at that site, where the site includes all contiguous property owned or leased by the consumer, without regard to interruptions in contiguity caused by easements, public thoroughfares, transportation rights-of-way, or utility rights-of-way. An energy storage system may be paired with the retail renewable distributed generation.

(b) The rated capacity of the retail renewable distributed generation shall not exceed the customer's service entrance capacity.

(c) The customer shall enter into an interconnection agreement with the utility pursuant to the Commission's Interconnection Procedures and Standards.

(d) A commercial customer in a leased facility must obtain the approval of the utility, which shall not be unreasonably conditioned, delayed or withheld, and either permission from the commercial customer's landlord, or other documentation evidencing the tenant's unequivocal right to install retail renewable distributed generation.

(e) Retail renewable distributed generation installed on an apartment building must either be owned and operated by the owner of the building or the owner of the facility must provide documentation of the right to install and maintain the retail renewable distributed generation on the apartment building premises. Each on-site solar system must be dedicated to a specific meter and the load at the meter must meet the size limits for net metering in paragraph 3678(a).

(f) Retail renewable distributed generation installed on condominiums must be owned by the condominium owner, or by a third party on behalf of the condominium owner, and metered to that owner's unit. The owner must provide documentation that the owner has the legal right to install and maintain the retail renewable distributed generation at the site.

(g) Sales of electricity may be made by an owner or operator of retail renewable distributed generation to the end-use electric consumer located at the site of the retail renewable distributed generation.

3679. Net Metering Credits.

(a) If a customer with retail renewable distributed generation generates renewable energy pursuant to rule 3678 in excess of the customer's consumption, the excess kWh shall be carried forward from month to month and credited at a ratio of 1:1 against the customer's retail kWh consumption in subsequent months.

(b) Within 60 days of the end of each calendar year, or within 60 days of when the customer terminates its retail service, the utility shall compensate the customer for any accrued excess kWh credits, at the utility's average hourly incremental cost of electricity supply over the most recent calendar year. For customers taking retail service on time-of-use rates, the utility shall track when the excess energy was generated, apply the accumulated excess energy against the customer's retail kWh consumption for the same time periods that the excess energy was generated, and, at the end of the year, compensate the customer for any excess kWh credits at the average hourly incremental cost notwithstanding the time periods in which the excess energy was generated.

(c) The customer may make a one-time election, in writing, on or before the end of a calendar year, to request that the excess kWh be rolled over as a credit from month to month indefinitely until the customer terminates service with the utility, at which time no payment shall be required from the utility for any remaining excess kWh credits supplied by the customer.

(d) For the purpose of applying rolled-over kWh credits as dollar credits in customer bills, the utility shall:

(I) not offset the monthly service and facilities charge;

(II) multiply the excess kWh by billing period to be applied against the customer's retail kWh consumption times the energy components (per kWh) of the rates under which the customer receives retail service; and

(III) for customers on a time-of-use rate, track when the excess energy was generated and apply the prevailing energy components (per kWh) of the rates for the same time periods that the excess energy was generated.

3680. Metering Requirements.

(a) A customer's retail renewable distributed generation shall be equipped with metering equipment that can measure the flow of electric energy in both directions. If the customer's existing electric meter does not meet this requirement, the utility shall install and maintain a new meter for the customer, at the utility's expense. Any subsequent meter change necessitated by the customer shall be paid for by the customer.

(b) The utility may place a second meter to measure the output of the retail renewable distributed generation:

(I) if the retail renewable distributed generation is owned by the electric consumer, the customer shall pay the cost of installing the production meter.

(II) if the retail renewable distributed generation is not owned by the electric consumer, the owner or operator of the retail renewable distributed generation shall pay the cost of installing the production meter.

(c) If more than one meter is used to measure the electricity consumption of a customer with retail renewable distributed generation at the premises where the retail renewable distributed generation is installed, the following provisions apply.

(I) The utility must, upon request from such customer, aggregate for billing purposes a meter to which the retail renewable distributed generation is physically attached (the designated meter) with one or more meters (the additional meters) in the manner set out in this paragraph when:

(A) each additional meter is located on the customer's contiguous property; and

(B) each additional meter is used to measure only the customer's own electricity consumption.

(II) A net metering customer must give at least 30 days' notice to the utility to request that additional meters be aggregated pursuant to this paragraph. The specific designated and additional meters must be identified at the time of such request. In the event that more than one additional meter is identified, the utility shall apply the net metering kWh credits to the sum of the kWh consumption as measured by the designated and additional meters.

(III) If, in a monthly billing period, the customer's retail renewable distributed generation generates more renewable energy than the customers' consumption as measured by the designated and additional meters, the excess kWh credits will be rolled over as a credit from month to month indefinitely until the customer terminates service with the utility, at which time no payment shall be required from the utility for any remaining excess kWh credits supplied by the customer.

(IV) All meters aggregated pursuant to this paragraph must be on the same rate schedule.

(d) For eligible energy resources greater than 250 kW, the owner shall provide, at the utility's request, real time electronic access to the utility to system operation data. In the event that an eligible energy resource greater than 250 kW also collects meteorological data, the owner shall provide, at the QRU's request, real time electronic access to the utility to such meteorological data.

3681. Rates for Net Metering.

(a) The utility shall provide net metering service at non-discriminatory rates to customers with retail renewable distributed generation.

(b) A customer shall not be required to change the rate under which the customer received retail service in order for the customer to install retail renewable distributed generation. The rate under which the customer received retail service prior to installing the retail renewable distributed generation shall be the applicable rate used by the utility for calculating the net metering credits pursuant to rule 3679.

(c) The utility may request changes in the applicable rates under which the customer receives retail service at any time. The applicable rate used by the utility for calculating the net metering credits pursuant to rule 3679 shall be equivalent to the applicable rate for retail service that would be received by the customer in the absence of the retail renewable distributed generation. The utility may not prohibit a customer from electing to take service on a time-of-use rate.

(d) Unless the Commission approves under § 40-2-124(1)(g)(IV)(B), C.R.S., an alternative surcharge for net metered customers served by the utility, the utility shall bill a retail customer receiving net metering service a surcharge to supplement that customer's contribution toward the utility's RESA account.

(I) For retail renewable distributed generation that is production metered, the surcharge shall increase the customer's total contribution to the utility's RESA account to the calculated level it would have been had all of the customer's consumption been billed at the utility's applicable rates.

(II) For retail renewable distributed generation that is not production metered, the utility shall estimate the production from the retail renewable distributed generation to calculate the surcharge as follows, based upon the size of the customer's system.

(A) For customers with a system that is from 500 watts to five kW, a 500 kWh volume proxy shall be used. The 500 kWh volume proxy will be multiplied by the current monthly per kWh effective residential energy rate and effective riders. That product will then be multiplied by the effective RESA to obtain the customer's RESA contribution amount.

(B) For customers with a system that is from five kW up to ten kW, a 1,000 kWh volume proxy shall be used. The 1,000 kWh volume proxy will be multiplied by the current monthly per kWh effective residential energy rate and effective riders. That product will then be multiplied by the effective RESA to obtain the customer's RESA contribution amount.

(C) For customers with a system that is from ten kW up to 25 kW, a 2,000 kWh volume proxy shall be used. The 2,000 kWh volume proxy will be multiplied by the current monthly per kWh effective residential energy rate and effective riders. That product will then be multiplied by the effective RESA to obtain the customer's RESA contribution amount.

3682. Colorado Division of Parks and Outdoor Recreation.

(a) Pursuant to § 24-33-115(2), C.R.S., for the Colorado Division of Parks and Outdoor Recreation (CDPOR) as the customer of the utility, the utility may, on a case-by-case or project-by-project basis:

(I) waive any existing limits on the net metering of electricity generated on contiguous property constituting the CDPOR customer's site;

(II) waive any existing limits on generating capacity or customer service entrance capacity if the customer proposes to make any necessary upgrades to its service entrance capacity at its own expense; and

(III) have the right of first refusal to purchase, and the right not to purchase, electricity from retail renewable distributed generation that is sized to provide more than 120 percent of the average annual consumption of electricity by the CDPOR customer at that site. If the utility exercises its option to purchase excess generation under this subparagraph 3682(a)(III), it may claim the RECs based on such purchases.

(IV) This paragraph does not confer upon CDPOR the right to make retail sales of electricity or distribute electricity to other state agencies or to noncontiguous properties.

3683. – 3699. [Reserved].

* * * *

[indicates omission of unaffected rules]

3806. – 3849. [Reserved].

INTERCONNECTION PROCEDURES AND STANDARDS.

3850. Applicability.

The following interconnection procedures shall apply to all retail renewable distributed generation and other distributed energy resources connected to the utility. Each utility shall also provide, on its web site, interconnection standards or other technical guidance not included in these procedures. This rule largely tracks the 2013 FERC amended version of the FERC 2006 Small Generator Interconnection Procedures.

3851. Overview and Purpose.

Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. The Commission expects all utilities, market participants, and Interconnection Customers interconnected with electric systems to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and best practice recommendations from the electric reliability authority. All utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

The purpose of these rules is to establish reasonable interconnection and insurance requirements for retail renewable distributed generation and other distributed energy resources that connect to a utility's system.

3852. Definitions.

The following definitions apply only to rules 3850 to 3858.

(a) "Business day" means Monday through Friday, excluding federal holidays.

(b) "Distributed energy resource" or "DER" means the interconnection customer's source of electric power, including retail renewable distributed generation, other small generation facilities for the production of electricity, and energy storage systems, as identified in the interconnection request, but shall not include the interconnection facilities not owned by the interconnection customer. An interconnection system or a supplemental DER device that is necessary for compliance with IEEE 1547 and is owned by the interconnection customer is part of a DER.

(c) "Distribution system" means the utility's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby DER or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

(d) “Distribution upgrades” means the additions, modifications, and upgrades to the utility's distribution system at or beyond the point of interconnection to facilitate interconnection of the DER and render the service necessary to effect the interconnection customer's operation of DER. Distribution upgrades do not include interconnection facilities.

(e) “Highly seasonal circuit” means a circuit with a ratio of annual peak load to off-season peak load greater than six.

(f) “Interconnection agreement” means a legally binding contract between the interconnection customers and the utility that formally documents terms and conditions related to the operation and maintenance of any DER in accordance with the utility’s tariffs on file with the Commission.

(g) “Interconnection customer” or “IC” means any entity, including the utility, any affiliates or subsidiaries of either, that proposes to interconnect its DER with the utility's system.

(h) “Interconnection facilities” means the utility's interconnection facilities and the interconnection customer's interconnection facilities. Collectively, interconnection facilities include all facilities and equipment between the DER and the point of interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the DER to the utility's system. Interconnection facilities are sole use facilities and shall not include distribution upgrades.

(i) “Interconnection request” means the interconnection customer's request, in accordance with any applicable utility tariff, to interconnect a new small generating facility, or to increase the capacity of, or make a material modification to the operating characteristics of, an existing DER that is interconnected with the utility’s system.

(j) “Minimum daytime loading” means the lowest daily peak in the year on the line section.

(k) “Minor modifications” means modifications to the utility’s distribution system or to the interconnection facilities that do have a material impact on the cost or on the timing of an interconnection request.

(l) “Party” or “Parties” means the utility, interconnection customer, or any combination of the above.

(m) “Point of interconnection” means the point where the interconnection facilities connect with the utility's system.

(n) “Study process” means the procedure for evaluating an interconnection request that includes the Level 3 scoping meeting, feasibility study, system impact study, and facilities study.

(o) “System” means the facilities owned, controlled, or operated by the utility that are used to provide electric service under the tariff.

(p) “Upgrades” means the required additions and modifications to the utility's system at or beyond the point of interconnection. Upgrades do not include interconnection facilities.

3853. General Interconnection Procedures.

(a) Pre-application procedures.

(I) Prior to submitting its interconnection request, the interconnection customer may ask the utility interconnection contact employee or office whether the proposed interconnection is subject to these procedures. The utility shall respond within 15 business days.

(II) The utility shall designate an employee or office from which information on the application process and on an affected system can be obtained through informal requests from the interconnection customer presenting a proposed project for a specific site. The name, telephone number, and e-mail address of such contact employee or office shall be made available on the utility's Internet web site.

(III) In response to an informal pre-application request, the utility shall provide electric system information for specific locations, feeders, or small areas to the interconnection customer and may include relevant system studies, interconnection studies, and other materials useful to an understanding of an interconnection at a particular point on the utility's system, to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements. The utility shall comply with reasonable requests for such information unless such information is proprietary or confidential and cannot be provided pursuant to a confidentiality agreement.

(IV) An interconnection customer may submit a formal written request for a pre-application report on a proposed interconnection at a specific site using a form supplied by the utility, unless such information is proprietary or confidential and cannot be provided pursuant to a confidentiality agreement. The utility may charge a fee for the pre-application report.

(A) The utility shall provide the pre-application report to the interconnection customer within 20 business days of receipt of the completed request form and payment of the fee.

(B) The pre-application report shall be non-binding on the utility and shall not confer any rights to the interconnection customer. The provided information shall not guarantee that an interconnection may be completed. Data provided in the pre-application report may become outdated at the time of the submission of the complete interconnection request.

(C) The pre-application report need only include existing information. A pre-application report request does not obligate the utility to conduct a study or other analysis of the proposed DER in the event that data is not readily available.

(D) If the utility cannot complete all or some of a pre- application report due to lack of available data, the utility nonetheless shall provide the interconnection customer with a pre- application report that includes the data that is available.

(E) Notwithstanding any of the provisions of this section, the utility shall, in good faith, include data in the pre- application report that represents the best available information at the time of reporting. The pre-application report will include the following information:

(i) total capacity (in MW) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed point of interconnection;

(ii) existing aggregate generation DER capacity (in MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of DER online) likely to serve the proposed point of interconnection;

(iii) aggregate queued DER capacity (in MW) for a substation/area bus, bank or circuit (i.e., amount of DER in the queue) likely to serve the proposed point of interconnection;

(iv) available capacity (in MW) of substation/area bus or bank and circuit likely to serve the proposed point of interconnection (i.e., total capacity less the sum of existing aggregate DER capacity and aggregate queued DER capacity);

(v) substation nominal distribution voltage and/or transmission nominal voltage, if applicable;

(vi) nominal distribution circuit voltage at the proposed point of interconnection;

(vii) approximate circuit distance between the proposed point of interconnection and the substation;

(viii) relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load as described in the supplemental review minimum load screen section (c)(III)(G)(i) and absolute minimum load at the time of DER production, when available;

(ix) number and rating of protective devices and number and type (standard, bi-directional) of voltage regulating devices between the proposed point of interconnection and the substation/area. Identify whether the substation has a load tap changer;

(x) number of phases available at the proposed point of interconnection. If a single phase, distance from the three- phase circuit;

(xi) limiting conductor ratings from the proposed point of interconnection to the distribution substation;

(xii) whether the point of interconnection is located on a spot network, grid network, or radial supply; and

(xiii) existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks, based on the proposed point of interconnection.

(b) Capacity of the DER.

(I) If the interconnection request is for an increase in capacity for an existing DER, the interconnection request shall be evaluated on the basis of the new total capacity of the DER.

(II) If the interconnection request is for a DER that includes multiple components at a site for which the interconnection customer seeks a single point of interconnection, the interconnection request shall be evaluated on the basis of the aggregate capacity of the multiple components.

(III) The interconnection request shall be evaluated using the maximum rated capacity of the DER. At the utility's discretion, the interconnection request may be evaluated using less than the maximum rated capacity of the DER if the utility determines that the DER is only capable of injecting less power into the utility's system.

(c) Interconnection requests.

(I) The interconnection customer shall submit its interconnection request to the utility, together with the processing fee or deposit specified in the interconnection request. A single request to interconnect may be submitted by the interconnection customer for DER that combines small generation facilities for the production of electricity and energy storage systems. Such DER may be subject to one interconnection agreement.

(II) The interconnection request shall be date- and time-stamped upon receipt. The original date- and time-stamp applied to the interconnection request at the time of its original submission shall be accepted as the qualifying date- and time-stamp for the purposes of any timetable in these procedures.

(III) The interconnection customer shall be notified of receipt by the utility within three business days of receiving the interconnection request which notification may be to an e-mail address or fax number provided by the IC.

(IV) The utility shall notify the interconnection customer within ten business days of the receipt of the interconnection request as to whether the interconnection request is complete or incomplete. If the interconnection request is incomplete, the utility shall provide, along with the notice that the interconnection request is incomplete, a written list detailing all information that must be provided to complete the interconnection request. The interconnection customer will have ten business days after receipt of the notice to submit the listed information or to request an extension of time to provide such information. If the IC does not provide the listed information or a request for an extension of time within the deadline, the interconnection request will be deemed withdrawn.

(V) An interconnection request will be deemed complete upon submission of the listed information to the utility.

(VI) Any modification to DER data or equipment configuration or to the interconnection site of the DER that has a material impact on the cost or timing of the interconnection request may be deemed a withdrawal of the interconnection request and may require submission of a new interconnection request. A new interconnection request shall not be required for minor modifications to DER data or equipment configuration or to the interconnection site of the DER.

(VII) Documentation of site control must be submitted with the interconnection request. Site control may be demonstrated through:

(A) ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the DER;

(B) an option to purchase or acquire a leasehold site for such purpose; or

(C) an exclusivity or other business relationship between the IC and the entity having the right to sell, lease, or grant the IC the right to possess or occupy a site for such purpose.

(VIII) The utility shall place interconnection requests in a first come, first served order per feeder, per substation transfer, and per substation based upon the date- and time-stamp of the interconnection request. The order of each interconnection request will be used to determine the cost responsibility for the upgrades necessary to accommodate the interconnection. At the utility's option, interconnection requests may be studied serially or in clusters for the purpose of the system impact study.

(d) Evaluation of interconnection requests.

(I) A request to interconnect DER no larger than ten kW shall be evaluated under the Level 1 Process.

(II) A request to interconnect DER shall be evaluated under the Level 2 process (Fast Track) in accordance with the eligibility requirements in paragraph 3855(a).

(III) A request to interconnect DER that does not pass the Level 1 or Level 2 process shall be evaluated under the Level 3 process.

(e) Interconnection agreements.

(I) Any DER operating in parallel with the utility’s system is required to have an interconnection agreement with the utility to ensure safety, system reliability, and operational compatibility. DER is considered to be operating in parallel with the utility’s system when it is connected to the utility’s system and can supply electricity to the interconnection customer simultaneously with the utility’s supply of electricity. References in these procedures to interconnection agreement are to the utility’s interconnection agreement as provided on its web site.

(II) Interconnection agreements shall survive transfer of ownership of the DER to a new owner when the new owner agrees in writing to comply with the terms of the agreement and so notifies the utility.

(III) After receiving an interconnection agreement from the utility, the IC shall have 30 business days or another mutually agreeable time-frame to sign and return the interconnection agreement, or request that the utility file an unexecuted interconnection agreement with the Commission. If the IC does not sign the interconnection agreement, or ask that it be filed unexecuted by the utility within 30 business days, the interconnection request shall be deemed withdrawn. The utility shall provide the IC a fully executed interconnection agreement within two business days after receiving a signed interconnection agreement from the IC. After the interconnection agreement is signed by the parties, the interconnection of the DER shall proceed under the provisions of the interconnection agreement.

(lV) Once the DER has been authorized by the utility to commence operation in parallel with the utility system, the interconnection customer shall abide by all rules and procedures pertaining to parallel operation in the utility's tariffs and in the interconnection agreement.

(V) The interconnection customer shall be responsible for the utility's reasonable and necessary cost for the purchase, installation, operation, maintenance, testing, repair and replacement of utility upgrades or utility interconnection facilities not required to serve other utility customers. Such upgrades or facilities shall be specified in the interconnection agreement unless otherwise covered by the utility's tariff or excluded by interconnection agreement.

(f) Reasonable efforts. The utility shall make reasonable efforts to meet all time frames provided in these procedures unless the utility and the IC agree to a different schedule. If the utility cannot meet a deadline provided herein, it shall notify the IC explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

(g) Disputes.

(I) The parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.

(II) In the event of a dispute, either party shall provide the other party with a written notice of dispute. Such notice shall describe in detail the nature of the dispute. If the dispute has not been resolved within five business days after receipt of the notice, either party may contact a mutually agreed upon third party dispute resolution service for assistance in resolving the dispute.

(III) The dispute resolution service will assist the parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical expert) to assist the parties in resolving their dispute.

(IV) Each party agrees to conduct all negotiations in good faith and will be responsible for one-half of any costs paid to neutral third-parties.

(V) If neither party elects to seek assistance from the dispute resolution service, or if the attempted dispute resolution fails, then either party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of the agreements between the parties or it may seek resolution at the Commission.

(h) Interconnection metering. Except as otherwise required by the Commission's Net Metering Rules or by the terms of a Commission-approved program offered by the utility for the purpose of encouraging the development of cost effective retail renewable distributed generation, any metering necessitated by the use of the DER shall be installed at the IC's expense in accordance with Commission requirements or the utility's specifications.

(i) Commissioning tests. Commissioning tests of the IC's installed DER shall be performed pursuant to applicable codes and standards, including IEEE1547.1 "IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems". The utility must be given at least five business days' written notice, or as otherwise mutually agreed to by the parties, of the tests and may be present to witness the commissioning tests. The utility shall be compensated by the IC for its expense in witnessing Level 2 and Level 3 commissioning tests. The utility shall provide to the IC an operational approval letter within three business days after notification that the commissioning test has been successfully completed. Such letter may be provided via e-mail.

(j) Confidentiality.

(I) Confidential information shall mean any confidential and/or proprietary information provided by one party to the other party that is clearly marked or otherwise designated "Confidential." All design, operating specifications, and metering data provided by the IC shall be deemed confidential information regardless of whether it is clearly marked or otherwise designated as such.

(II) Confidential information does not include information previously in the public domain, required to be publicly submitted or divulged by governmental authorities (after notice to the other party and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce an agreement between the parties. Each party receiving confidential information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the party providing that information, except to fulfill obligations under agreements between the parties, or to fulfill legal or regulatory requirements.

(A) Each party shall employ at least the same standard of care to protect confidential information obtained from the other party as it employs to protect its own confidential information.

(B) Each party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of confidential information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

(III) Notwithstanding anything in this article to the contrary, if the Commission, during the course of an investigation or otherwise, requests information from one of the parties that is otherwise required to be maintained in confidence, the party shall provide the requested information to the Commission, within the time provided for in the request for information. In providing the information to the Commission, the party may request that the information be treated as confidential and non-public by the Commission and that the information be withheld from public disclosure. Parties are prohibited from notifying the other party prior to the release of the confidential information to the Commission. The party shall notify the other party when it is notified by the Commission that a request to release confidential information has been received by the Commission, at which time either of the parties may respond before such information would be made public.

(k) Comparability. The utility shall receive, process, and analyze all interconnection requests in a timely manner as set forth in this rule. The utility shall use the same reasonable efforts in processing and analyzing interconnection requests from all interconnection customers, whether the DER is owned or operated by the utility, its subsidiaries or affiliates, or others.

(l) Record retention. The utility shall maintain for three years records, subject to audit, of all interconnection requests received under these procedures, the times required to complete interconnection request approvals and disapprovals, and justification for the actions taken on the interconnection requests.

(m) Coordination with affected systems. The utility shall coordinate the conduct of any studies required to determine the impact of the interconnection request on affected systems with affected system operators and, if possible, include those results (if available) in its applicable interconnection study within the time frame specified in this rule. The utility will include such affected system operators in all meetings held with the IC as required by this rule. The IC will cooperate with the utility in all matters related to the conduct of studies and the determination of modifications to affected systems. A utility which may be an affected system shall cooperate with the utility with which interconnection has been requested in all matters related to the conduct of studies and the determination of modifications to affected systems.

(n) Insurance.

(I) For systems of ten kW or less, the customer, at its own expense, shall secure and maintain in effect during the term of the interconnection agreement liability insurance with a combined single limit for bodily injury and property damage of not less than $300,000 for each occurrence. For DER above ten kW and up to 500 kW, customer, at its own expense, shall secure and maintain in effect during the term of the interconnection agreement liability insurance with a combined single limit for bodily injury and property damage of not less than $1,000,000 for each occurrence. For DER above 500 kW and up to two MW, customer, at its own expense, shall secure and maintain in effect during the term of the interconnection agreement liability insurance with a combined single limit for bodily injury and property damage of not less than $2,000,000 for each occurrence. Insurance coverage for DER greater than two MW shall be determined on a case-by-case basis by the utility and shall reflect the size of the installation and the potential for system damage.

(II) For DER over 500 kW, the utility shall be named as an additional insured by endorsement to the insurance policy and the policy shall provide that written notice be given to the utility at least 30 days prior to any cancellation or reduction of any coverage.

Such liability insurance shall provide, by endorsement to the policy, that the utility shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for the payment of premium of such insurance. For all DER, the liability insurance shall not exclude coverage for any incident related to the subject DER or its operation.

(III) Certificates of Insurance evidencing the requisite coverage and provision(s) shall be furnished to utility prior to the date of interconnection of the DER. Utilities shall be permitted to periodically obtain proof of current insurance coverage form the interconnection customer in order to verify proper liability insurance coverage. Customer will not be allowed to commence or continue interconnected operations unless evidence is provided that satisfactory insurance coverage is in effect at all times.

3854. Level 1 Process (10 kW Inverter Process).

This rule establishes the procedures for evaluating an interconnection request for a certified inverter-based DER no larger than ten kW. The application process uses an all-in-one document (application) that includes a simplified interconnection request, simplified procedures, and a brief set of terms and conditions.

(a) General Level 1 procedures.

(I) The IC completes application and submits it to the utility.

(II) The utility acknowledges to the customer receipt of the application within three business days of receipt.

(III) The utility evaluates the application for completeness and notifies the customer within ten business days of receipt that the application is or is not complete and, if not, advises what material is missing.

(IV) Within 15 days, the utility shall verify whether the DER can be interconnected safely and reliably using the same screens as applied in Level 2 process as set forth in rule 3855. If the interconnection fails these screens, the utility shall consider this a failure of the Level 2 Process screens in rule 3855. The utility shall continue the interconnection review under the Level 2 Process, starting at paragraph 3855(c), provided that the IC pays the difference in the Level 2 process application fee and deposit requirements. The utility may perform supplemental reviews within the 15 day period to address highly seasonal circuits.

(V) Provided all the criteria of this rule 3854 are met, unless the utility determines and demonstrates that the DER cannot be interconnected safely and reliably, the utility approves and executes the Application and returns it to the customer.

(VI) After installation, the customer returns the certificate of completion to the utility. Prior to parallel operation, the utility may inspect the DER for compliance with standards, which may include a witness test, and may schedule appropriate metering replacement, if necessary.

(VII) The utility shall notify the customer that interconnection of the DER is authorized within five business days. If the witness test is not satisfactory, the utility has the right to disconnect the DER. The customer has no right to operate in parallel until a witness test has been performed, or previously waived on the application. The utility is obligated to complete this witness test within ten business days of the receipt of the certificate of completion.

(b) Level 1 application.

(I) The customer must provide in the application the contact information for the legal applicant (i.e., the interconnection customer). If another entity is responsible for interfacing with the utility, that contact information must be provided on the application.

(II) The application is considered complete when it provides all applicable and correct information as required below. Additional information to evaluate the application may be required.

(III) The application shall state the following:

Processing fee:

A fee of ____________ must accompany this application.

Interconnection customer:

Name:

Contact Person:

Address:

City: State: Zip:

Telephone (Day): (Evening):

Fax: E-Mail Address:

Engineering firm or installer (If applicable):

Contact Person:

Address:

City: State: Zip:

Telephone:

Fax: E-Mail Address:

Contact (if different from Interconnection Customer):

Name:

Address: City: State: Zip:

Telephone (Day): (Evening):

Fax: E-Mail Address:

Owner of the facility (include percent ownership by any electric utility):

DER information:

Location (if different from above):

Utility:

Account number:

DER components:

Inverter manufacturer: ____________Model

Nameplate rating: (kW) (kVA) (AC Volts)

Single phase ________ Three phase________

System design capacity: __________ (kW) ________ (kVA)

Prime mover: Photovoltaic Reciprocating Engine Fuel Cell Turbine Other

Energy source: Solar Wind Hydro Diesel Natural Gas Fuel Oil Other (describe)

Is the equipment UL1741 Listed? Yes ____ No ____

If Yes, attach manufacturer's cut-sheet showing UL1741 listing.

Estimated installation date: __________ Estimated in-service date: _____________

The ten kW inverter process is available only for inverter-based DER no larger than ten kW that meet the codes, standards, and certification requirements of paragraphs (h) and (i) of this rule, or the utility has reviewed the design or tested the proposed DER and is satisfied that it is safe to operate.

List components of the small generating facility equipment package that are currently certified:

Equipment type certifying entity:

1.

2.

3.

4.

5.

Interconnection customer signature: ________________________

I hereby certify that, to the best of my knowledge, the information provided in this Application is true. I agree to abide by the Terms and Conditions for Interconnecting an Inverter-Based DER No Larger than 10kW and return the Certificate of Completion when the DER has been installed.

Signed: ____

Title: Date:

Contingent approval to interconnect the small generating facility.

(For company use only)

Interconnection of the small generating facility is approved contingent upon the terms and conditions for interconnecting an inverter-based small generating facility no larger than ten kW and return of the certificate of completion.

Company signature: ____

Title: Date:

Application ID number: _________________

Company waives inspection/witness test? Yes ____ No ____

(c) Level 1 terms and conditions.

(I) Construction of the facility. The interconnection customer may proceed to construct the DER when the utility approves the interconnection request (the application) and returns it to the IC.

(II) Interconnection and operation. The IC may operate the DER and interconnect with the utility's electric system once all of the following have occurred:

(A) upon completing construction, the interconnection customer will cause the DER to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction;

(B) the customer returns the certificate of completion to the utility; and

(C) the utility has completed its inspection of the DER. All inspections must be conducted by the utility, at its own expense, within ten business days after receipt of the certificate of completion and shall take place at a time agreeable to the parties. The utility shall provide a written statement that the DER has passed inspection or shall notify the customer of what steps it must take to pass inspection as soon as practicable after the inspection takes place.

(D) The utility has the right to disconnect the DER in the event of improper installation or failure to return the certificate of completion.

(III) Safe operations and maintenance. The interconnection customer shall be fully responsible to operate, maintain, and repair the DER as required to ensure that it complies at all times with the interconnection standards to which it has been certified.

(IV) Access. The utility shall have access to the disconnect switch and metering equipment of the DER at all times. The utility shall provide reasonable notice to the customer when possible prior to using its right of access.

(V) Disconnection. The utility may temporarily disconnect the DER as allowed in the interconnection agreement and upon the following conditions:

(A) for scheduled outages per notice requirements in the utility's tariff or Commission rules;

(B) for unscheduled outages or emergency conditions pursuant to the utility's tariff or Commission rules; or

(C) if the DER does not operate in the manner consistent with these terms and conditions.

(D) The utility shall inform the interconnection customer in advance of any scheduled disconnection, or as is reasonable after an unscheduled disconnection.

(VI) Indemnification. The parties shall at all times indemnify, defend, and save the other party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other party's action or inactions of its obligations under this agreement on behalf of the indemnifying party, except in cases of gross negligence or intentional wrongdoing by the indemnified party.

(VII) Insurance. The interconnection customer, at its own expense, shall secure and maintain in effect during the term of this agreement, liability insurance with a combined single limit for bodily injury and property damage of not less than $300,000 each occurrence. Such liability insurance shall not exclude coverage for any incident related to the DER or its operation. The policy shall include that written notice be given to the utility at least 30 days prior to any cancellation or reduction of any coverage. A copy of the liability insurance certificate must be received by the utility prior to DER operation. Certificates of insurance evidencing the requisite coverage and provision(s) shall be furnished to utility prior to date of interconnection of the DER. Utilities shall be permitted to periodically obtain proof of current insurance coverage from the interconnection customer in order to verify proper liability insurance coverage. The interconnection customer will not be allowed to commence or continue interconnected operations unless evidence is provided that satisfactory insurance coverage is in effect at all times.

(VIII) Limitation of liability. Each party's liability to the other party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of the interconnection agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either party be liable to the other party for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever, except as allowed under subparagraph (c)(VI) of this rule.

(IX) Termination. The interconnection agreement to operate in parallel may be terminated under the following conditions.

(A) By the customer by providing written notice to the utility.

(B) By the utility if the DER fails to operate for any consecutive 12 month period or the customer fails to remedy a violation of these terms and conditions.

(C) Permanent disconnection. In the event the interconnection agreement is terminated, the utility shall have the right to disconnect its facilities or direct the customer to disconnect its DER.

(D) Survival rights. The interconnection agreement shall continue in effect after termination to the extent necessary to allow or require either party to fulfill rights or obligations that arose under the agreement.

(X) Assignment/Transfer of ownership of the facility. The interconnection agreement shall survive the transfer of ownership of the small generating facility to a new owner when the new owner agrees in writing to comply with the terms of the agreement and so notifies the utility.

3855. Level 2 Process (Fast Track).

This fast track process is available to an IC proposing to interconnect its DER with the utility's system if the DER meets the eligibility provisions in this rule 3855.

(a) Eligibility.

(I) Eligibility for the Level 2 process is determined based upon the type and size of the DER as well as the voltage of the utility line and the location of and the type of utility line at the point of interconnection. An interconnection customer may determine whether the DER is eligible for the Level 2 process by requesting a pre-application report pursuant to subparagraph 3853(a)(IV).

(II) For certified inverter-based systems, the size limit of the DER varies according to the voltage of the utility line at the proposed point of interconnection. Certified inverter-based DER facilities located within 2.5 electrical circuit miles of a substation and on a mainline are eligible for the Level 2 process under the higher thresholds pursuant to this rule 3856.

Level 2 Process Eligibility for Inverter-Based Systems			
Line Voltage	**Eligibility Regardless of Location**	**Eligibility Meeting Location Requirements (Mainline and Substation)**	
< 5 kV	≤ 500 kW	≤ 500 kW	
≥ 5 kV and < 15 kV	≤ 2 MW	≤ 3 MW	
≥ 5 kV and < 30 kV	≤ 3 MW	≤ 4 MW	
≥ 30 kV and < 69 kV	≤ 4 MW	≤ 5 MW	

(III) All synchronous and induction facilities must be no larger than 2 MW to be eligible for the Level 2 process, regardless of location.

(IV) In addition to the size threshold, the DER must meet the codes, standards, and certification requirements of the Commission's Interconnection Procedures and Standards.

(b) Initial Review. Within 15 business days after the utility notifies the interconnection customer it has received a complete interconnection request, the utility shall perform an initial review using the screens set forth below, shall notify the interconnection customer of the results, and include with the notification copies of the analysis and data underlying the utility's determinations under the following:

(I) The proposed DER's point of interconnection must be on a portion of the utility's distribution system that is subject to the utility's tariffs. Proposed DER on highly seasonal circuits shall also be subject to the supplemental review pursuant to paragraph 3855(d).

(II) For interconnection of a proposed DER to a radial distribution circuit, the aggregated generation, including the proposed DER, on the line section(s) shall not exceed 15 percent of the line section's annual peak load as most recently measured at the substation or calculated for the line section(s). A line section is that portion of a utility's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. A fuse is not an automatic sectionalizing device.

(III) The proposed DER, in aggregation with other generation on the distribution circuit, shall not contribute more than ten percent to the distribution circuit's maximum fault current at the point on the distribution feeder voltage (primary) level nearest the proposed point of change of ownership.

(IV) The proposed DER, in aggregate with other DER on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or interconnection customer equipment on the system to exceed 87.5 percent of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5 percent of the short circuit interrupting capability.

(V) The proposed DER shall meet the rapid voltage charge and flicker requirements of IEEE 1453 and IEEE 1457 based on the appropriate test.

(VI) The type of interconnection to a primary distribution line shall be determined based on the table below, including a review of the type of electrical service provided to the interconnection customer, line configuration, and the transformer connection to limit the potential for creating over-voltages on the utility's electric power system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	**Type of Interconnection to Primary Distribution Line**	**Result/Criteria**
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass screen
Three-phase, four wire	Effectively-grounded 3 phase or Single-phase, line-to-neutral	Pass screen

(VII) If the proposed DER is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed small generating facility, shall not exceed 20 kW.

(VIII) If the proposed DER is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20 percent of the nameplate rating of the service transformer.

(IX) No construction of facilities by the utility on its own system shall be required to accommodate the small generating facility.

(X) For interconnection of a proposed DER to the load side of spot network protectors serving more than a single customer, the proposed DER must utilize an inverter-based equipment package and, together with the aggregated other inverter-based DER, shall not exceed the smaller of five percent of a spot network's maximum load or 300 kW. For spot networks serving a single customer, the DER must use inverter-based equipment package and either meet the requirements above or shall use a protection scheme or operate the generator so as not to exceed on-site load or otherwise prevent nuisance operation of the spot network protectors.

(XI) For interconnection of a proposed DER to the load side of area network protectors, the proposed DER must utilize an inverter-based equipment package and, together with the aggregated other inverter-based DER, shall not exceed the smaller of ten percent of an area network's minimum load or 500 kW.

(c) Customer options meeting.

(I) If the proposed interconnection fails the screens, but the utility does not or cannot determine from the initial review that the DER may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the IC is willing to consider minor modifications or further study, the utility shall provide the IC with the opportunity to attend a customer options meeting.

(II) If the utility determines the interconnection request cannot be approved without minor modifications at minimal cost; without a supplemental study or other additional studies or actions; or without significant costs to address safety, reliability, or power quality problems, the utility shall notify the IC within the five business day period after the determination and provide the data and analyses underlying its conclusion. Within ten business days of the utility's determination, the utility shall offer to convene a customer options meeting with the utility to review possible IC facility modifications or the screen analysis and related results, to determine what further steps are needed to permit the small generating facility to be connected safely and reliably. At the time of notification of the utility's determination, or at the customer options meeting, the utility shall:

(A) offer to perform facility modifications or minor modifications to the utility's electric system (e.g., changing meters, fuses, relay settings) and provide a non-binding good faith estimate of the limited cost to make such modifications to the utility's electric system;

(B) offer to perform a supplemental review pursuant to paragraph 3855(d) and provide a non-binding good faith estimate of the costs and time of such review; or

(C) obtain the interconnection customer's agreement to continue evaluating the interconnection request under the Level 3 Study Process.

(d) Supplemental review.

(I) To accept a utility's offer to conduct a supplemental review, the interconnection customer, within 15 business days of the offer, shall agree in writing to the supplemental review and submit a deposit for the estimated costs. If the written agreement and deposit have not been received by the utility within the 15 days, the interconnection request shall continue to be evaluated under the Level 3 Process, unless the request is withdrawn by the IC. The IC shall be responsible for the utility's actual costs for conducting the supplemental review. The IC must pay any review costs that exceed the deposit within 20 business days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the utility will return such excess within 20 business days of the invoice without interest.

(II) Within 30 business days following receipt of the deposit for a supplemental review, the utility will perform a supplemental review of the proposed DER using the screens set forth below, notify the interconnection customers of the results of the screens in writing, and include with the notification copies of the analysis and data underlying the utility's determinations.

(III) The interconnection customer may specify the order in which the utility completes the supplemental review screens.

(IV) The utility shall notify the interconnection customer of the failure of the DER in any supplement review screen or of the utility's inability to perform any screen for the DER. Within two business days of the receipt of such notice, the interconnection customer may grant the utility permission:

(A) to continue evaluating the proposed interconnection under this paragraph 3855(d);

(B) to continue evaluating the proposed interconnection under this paragraph 3855(d) subject to the utility's determination of minor modifications;

(C) to terminate the supplemental review and instead to continue evaluating the DER under the Level 3 Process; or

(D) to terminate the supplemental review upon withdrawal of the interconnection request by the interconnection customer.

(V) Minimum load, minimum loading, and minimum load data shall be specific to time(s) that the DER exports active power to the utility.

(VI) Supplemental review screens.

(A) Minimum load screen.

(i) The DER capacity on the line section(s) shall be less than 100 percent of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed DER.

(ii) This screen shall be determined using 12 months of line section(s) minimum load data (including onsite load but not station service load served by the proposed DER), calculated minimum load data, or estimated minimum load data using existing data a power flow model. If minimum load data is not available or the minimum load data cannot be calculated estimated, the utility shall include the reason(s) that it is unable to calculate, estimate or determine minimum load in its supplemental review results notification under subparagraph 3855(d)(IV).

(iii) The type of DER shall be taken into account when calculating or estimating circuit or line section(s) minimum load. The utility shall use daytime minimum load for solar photovoltaic (PV) DER with no battery storage (i.e.,10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for PV systems utilizing tracking systems). The utility shall use absolute minimum load for all other types of DER.

(iv) Only the net injection into the utility's electric system shall be considered as part of the DER when this screen is applied to DER serving some station service load.

(v) The utility shall not consider as part of the DER the capacity known to be already reflected in the minimum load data.

(B) Voltage and power quality screen.

(i) In aggregate with existing DER on the circuit and line section(s), the voltage regulation on the circuit and line section(s) shall be maintained in compliance with relevant requirements under all system conditions;

(ii) In aggregate with existing DER on the circuit and line section(s), the voltage fluctuation shall be within acceptable limits as defined by IEEE Standard 1453 and, by utility practice conforming with IEEE Standard 1453, and by the limits defined by IEEE standard 1547; and

(iii) In aggregate with existing DER on the circuit and line section(s), the harmonic levels shall meet IEEE Standard 519 limits.

(C) Safety and reliability screen.

(i) The location of the proposed DER and the aggregate DER capacity on the line section(s) shall not create impacts to safety or reliability that cannot be adequately addressed without application of the Level 3 process.

(ii) Minimum load, minimum loading and minimum load data shall be specific to time(s) of DER production.

(iii) The utility shall consider whether the line section(s) has significant minimum loading levels dominated by a small number of customers (e.g., several large commercial customers).

(iv) The utility shall consider whether the loading along the line section(s) is uniform or even given the sources of the screening data.

(v) The utility shall consider whether the proposed DER is located in close proximity to a substation (i.e., less than 2.5 electrical circuit miles) and whether the line section(s) from the substation to the point of interconnection is a mainline rated for normal and emergency ampacity.

(vi) The utility shall consider whether the proposed DER incorporates a time delay function to prevent reconnection of the DER to the utility’s system until system voltage and frequency are within normal limits for a prescribed time.

(vii) The utility shall consider whether operational flexibility is reduced by the proposed DER, such that transfer of the line section(s) of the DER to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

(viii) The utility shall consider whether the proposed DER employs equipment or systems certified by a recognized standards organization to address technical issues such as, but not limited to, islanding, reverse power flow, and voltage quality.

(VII) If the supplemental screening meets utility determined adequacy with minor modifications, the utility shall provide a non-binding good faith estimate of the limited cost to make such modifications to the utility's electric system upon notification of review results.

(e) Interconnection agreements.

(I) If the proposed interconnection passes the screens, the interconnection request shall be approved and the utility will provide the IC an executable interconnection agreement within five business days after the determination.

(II) If the proposed interconnection fails the screens, but the utility determines that the small generating facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the utility shall provide the IC an executable interconnection agreement within five business days after the determination.

(III) If the interconnection customer agrees to pay for the modifications to the utility’s electric system as identified by the utility pursuant to subparagraph 3855(c)(II)(A), the utility will provide the interconnection customer with an executable interconnection agreement within ten business days of the customer options meeting.

(IV) If the interconnection customer agrees to pay for the modifications to the utility's electric system as identified by the utility pursuant to subparagraph 3855(d)(VII), the utility will provide the interconnection customer with an executable interconnection agreement within five business days of IC agreement to pay.

3856. Level 3 Process (Study Process).

This study process shall be used by an interconnection customer proposing to interconnect its DER with the utility's system if the DER is no larger than 20 MW; is not certified; or, is certified but did not pass the Level 1 process or Level 2 process.

(a) Scoping meeting.

(I) A scoping meeting will be held within ten business days after the interconnection request is deemed complete, or as otherwise mutually agreed to by the parties. The utility and the interconnection customer will bring to the meeting personnel, including system engineers and other resources as may be reasonably required to accomplish the purpose of the meeting.

(II) The purpose of the scoping meeting is to discuss the interconnection request. The parties shall further discuss whether the utility should perform a feasibility study or proceed directly to a system impact study, or a facilities study, or an interconnection agreement. If the parties agree that a feasibility study should be performed, the utility shall provide the IC, as soon as possible, but not later than five business days after the scoping meeting, a feasibility study agreement including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

(III) The scoping meeting may be omitted by mutual agreement. In order to remain in consideration for interconnection, an IC who has requested a feasibility study must return the executed feasibility study agreement within 15 business days. If the parties agree not to perform a feasibility study, the utility shall provide the IC, no later than five business days after the scoping meeting, a system impact study agreement including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

(IV) Feasibility studies, scoping studies, and facility studies may be combined or waived for simpler projects by mutual agreement of the utility and the IC. If all such studies are waived, the utility shall provide the IC an executable interconnection agreement within ten business days after the scoping meeting. If the scoping meeting is also omitted by mutual agreement, the utility shall provide the IC an executable interconnection agreement within ten business days after the interconnection request is deemed complete and this Level 2 process is completed.

(b) Feasibility study.

(I) The feasibility study shall identify any potential adverse system impacts that would result from the interconnection of the DER. At its discretion, the utility may use the Level 2 supplemental review as described in paragraph 3855(d) as the feasibility study.

(II) A deposit of the lesser of 50 percent of the good faith estimated feasibility study costs or earnest money of $1,000 may be required from the interconnection customer.

(III) The scope of and cost responsibilities for the feasibility study are described in the feasibility study agreement.

(IV) If the feasibility study shows no potential for adverse system impacts, the utility shall send the Interconnection Customer a facilities study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

(V) If the feasibility study shows the potential for adverse system impacts, the review process shall proceed to the appropriate system impact study(s).

(VI) If no system impact study is required and no facilities study is required for the DER, the utility shall provide the IC an executable interconnection agreement within five business days after the completion of the feasibility study.

(c) System impact study.

(I) A system impact study shall identify and detail the electric system impacts that would result if the proposed DER were interconnected without project modifications or electric system modifications, focusing on the adverse system impacts identified in the feasibility study, or to study potential impacts, including but not limited to those identified in the scoping meeting. A system impact study shall evaluate the impact of the proposed interconnection on the reliability of the electric system.

(II) If no transmission system impact study is required, but potential electric power distribution system adverse system impacts are identified in the scoping meeting or shown in the feasibility study, a distribution system impact study must be performed. The utility shall send the IC a distribution system impact study agreement within 15 business days of transmittal of the feasibility study report, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or following the scoping meeting if no feasibility study is to be performed.

(III) In instances where the feasibility study or the distribution system impact study shows potential for adverse impacts on the utility’s transmission system, within five business days following transmittal of the feasibility study report, the utility shall send the IC a transmission system impact study agreement, including an outline of the transmission-supplied scope of the study and a transmission-supplied non-binding good faith estimate of the cost to perform the study, if such a study is required.

(IV) If a transmission system impact study is not required, but electric power distribution system adverse system impacts are shown by the feasibility study to be possible and no distribution system impact study has been conducted, the utility shall send the IC a distribution system impact study agreement.

(V) If the feasibility study shows no potential for transmission system or distribution system adverse system impacts, the utility shall send the IC either a facilities study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or an executable interconnection agreement, as applicable.

(VI) In order to remain under consideration for interconnection, the IC must return executed system impact study agreements, if applicable, within 30 business days.

(VII) A deposit of the good faith estimated costs for each system impact study may be required from the IC.

(VIII) The scope of and cost responsibilities for a system impact study are described in the system impact study agreement.

(IX) Where transmission systems and distribution systems have separate owners, such as is the case with transmission-dependent utilities (TDUs) – whether investor-owned or not – the IC may apply to the nearest utility (Transmission Owner, Regional Transmission Operator, or Independent utility) providing transmission service to the TDU to request project coordination. Affected systems shall participate in the study and provide all information necessary to prepare the study.

(X) If no facilities study is required for the DER, the utility shall provide the IC an executable interconnection agreement within five business days after the completion of the system impact study.

(d) Facilities study.

(I) Once the required system impact study(s) is completed, a system impact study report shall be prepared and transmitted to the IC along with a facilities study agreement within five business days, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the facilities study. In the case where one or both impact studies are determined to be unnecessary, a notice of the fact shall be transmitted to the IC within the same timeframe.

(II) In order to remain under consideration for interconnection, or, as appropriate, in the utility's interconnection queue, the IC must return the executed facilities study agreement or a request for an extension of time within 30 business days.

(III) The facilities study shall specify and estimate the cost of the equipment, engineering, procurement, and construction work (including overheads) needed to implement the conclusions of the system impact study(s).

(IV) Design for any required interconnection facilities and/or upgrades shall be performed under the facilities study agreement. The utility may contract with consultants to perform activities required under the facilities study agreement. The IC and the utility may agree to allow the IC to separately arrange for the design of some of the interconnection facilities. In such cases, facilities design will be reviewed and/or modified prior to acceptance by the utility, under the provisions of the facilities study agreement. If the parties agree to separately arrange for design and construction, and provided security and confidentiality requirements can be met, the utility shall make sufficient information available to the IC in accordance with confidentiality and critical infrastructure requirements to permit the IC to obtain an independent design and cost estimate for any necessary facilities.

(V) A deposit of the good faith estimated costs for the facilities study may be required from the IC.

(VI) The scope of and cost responsibilities for the facilities study are described in a facilities study agreement.

(VII) Upon completion of the facilities study, and with the agreement of the IC to pay for interconnection facilities and upgrades identified in the facilities study, the utility shall provide the IC an executable interconnection agreement within five business days.

3857. Certification Codes and Standards.

ANSI C84.1-2016 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

ANSI/NEMA MG 1--2016, Motors and Generators

IEEE Std C37.90.1-2012, IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems

IEEE Std C37.90.2-2004, IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-2002, IEEE Guide for the Protection of Network Transformers

IEEE Std C57.12.44-2014, IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002/Cor 1-2012, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits Corrigendum 1: Deletion of Table A.2 and Associated Text

IEEE Std C62.45-2002, IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits

IEEE Std 100-2000, The Authoritative Dictionary of IEEE Standards Terms, Seventh Edition

IEEE Std 519-2014, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

IEEE Std 1453-2015 IEEE Recommended Practice for the Analysis of Fluctuating Installation on Power Systems

IEEE Std 1547-2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces

IEEE Std 1547.1-2005, IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems

NFPA 70 (2017), National Electrical Code

UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

3858. Certification of DER Packages.

(a) Small generating facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in paragraph (h); it has been labeled and is publicly listed by such NRTL at the time of the interconnection application; and, such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

(b) The interconnection customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

(c) Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the parties to the interconnection nor follow-up production testing by the NRTL.

(d) If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

(e) Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of interconnectoin shall be required to meet the requirements of this interconnection procedure.

(f) An equipment package does not include equipment provided by the utility.

3859. – 3874. [Reserved].

COMMUNITY SOLAR GARDENS

3875. Applicability.

The following rules shall apply to all community solar gardens (CSGs) developed pursuant to § 40-2-127, C.R.S. These rules shall not apply to cooperative electric associations or to municipally owned utilities.

3876. Overview and Purpose.

The purpose of this rule is to implement the development and deployment of CSGs: to provide opportunities to utility customers to participate in solar generation in addition to on-site solar systems; to allow renters, low-income utility customers, and agricultural producers to own interests in solar generation facilities; to allow interests in solar generation facilities to be portable and transferrable; and to leverage solar generating capacity through economies of scale.

3877. Definitions.

The following definitions apply to rules 3877 through 3883. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Community solar garden" or "CSG" means a solar electric generation facility with a nameplate rating of two MW or less that is located in or near a community served by a utility where the beneficial use of the renewable energy generated by the facility belongs to the subscribers of the CSG. A CSG shall have at least ten CSG subscribers. A CSG shall be deemed to be located on the site of each subscribing customer's facilities for the purpose of crediting the CSG subscribers' bills for the renewable energy purchased from the CSG by the utility. The renewable energy generated by a CSG shall be sold only to the utility serving the geographic area where the CSG is located. The renewable energy generated by a CSG shall constitute retail renewable distributed generation under paragraph 3001(qq).

(b) "CSG owner" means the owner of the solar generation facilities installed at a CSG that contracts to sell the unsubscribed renewable energy and RECs generated by the CSG to a utility. A CSG subscriber organization operating a CSG not owned by it will be deemed to be a CSG owner for purposes of these rules. A CSG owner may be the utility or any other for-profit or nonprofit entity or organization, including a CSG subscriber organization.

(c) "CSG subscriber" means a retail customer of a utility who owns a subscription to a CSG and who has identified one or more premises served by the utility to which the CSG subscription shall be attributed.

(d) "CSG subscriber organization" means any for-profit or nonprofit entity permitted by Colorado law and whose sole purpose shall be:

(I) to beneficially own and operate the CSG; or

(II) to operate the CSG that is built, owned, and operated by a third party under contract with such CSG subscriber organization.

(e) "CSG subscription" means a proportionate interest in the beneficial use of the electricity generated by the CSG, including without limitation, the renewable energy and RECs associated with or attributable to the CSG.

(f) "Eligible low-income CSG subscriber" means:

(I) a residential customer of a utility who has a household income at or below 165 percent of the current federal poverty level, as published each year in the federal register by the U.S. Department of Health and Human Services; or

(II) a residential customer of a utility who otherwise meets the eligibility criteria set forth in rules of the Colorado Department of Human Services adopted pursuant to § 40-8.5-105, C.R.S.; or

(III) an operator of affordable housing where at least 60 percent of the residents are either below the income level in this definition or meet the eligibility criteria in § 40-8.5-105, C.R.S.

3878. CSG Subscriptions, Subscribers, and Subscriber Organizations.

(a) No CSG subscriber may own more than a 40 percent interest in the beneficial use of the electricity generated by the CSG, including without limitation, the renewable energy and RECs associated with or attributable to the CSG.

(b) Each CSG subscription shall be sized to represent at least one kW of the CSG's nameplate rating and supply no more than 120 percent of the CSG subscriber's average annual electricity consumption at the premise to which the subscription is attributed, with a deduction for the amount of any existing retail renewable distributed generation at such premise. The minimum one kW sizing requirement herein shall not apply to subscriptions owned by an eligible low-income CSG subscriber.

(c) The premise to which a subscription is attributed by a CSG subscriber shall be served by the utility and shall be within the same county as, or a county adjacent to, the CSG. The CSG subscriber may change from time to time the premise to which the CSG subscription shall be attributed, so long as the premise is served by the utility and is within the same county as, or a county adjacent to, the CSG.

(d) No CSG subscriber organization may own more than a 40 percent interest in the beneficial use of the electricity generated by the CSG, including without limitation, the renewable energy and RECs associated with or attributable to the CSG, after the CSG has operated commercially for 18 months.

3879. Share Transfers and Portability.

(a) A CSG subscription may be transferred or assigned to the associated CSG subscriber organization or to any person or entity who qualifies to be a subscriber in the CSG.

(b) A CSG subscriber who desires to transfer or assign all or part of his subscription to the CSG subscriber organization, in its own name or to become unsubscribed shall notify the CSG subscriber organization and the transfer of the subscription to the CSG subscriber organization shall be effective upon such notification, unless the CSG subscriber specifies a later effective date.

(c) A CSG subscriber who desires to transfer or assign all or part of his subscription to an eligible utility customer desiring to purchase a subscription may do so only in compliance with the terms and conditions of the subscription and will be effective in accordance therewith.

(d) If the CSG is fully subscribed, the CSG subscriber organization shall maintain a waiting list of eligible utility customers who desire to purchase subscriptions. The CSG subscriber organization shall offer the CSG subscription of the CSG subscriber desiring to transfer or assign their interest, or a portion thereof, on a first-come, first-serve basis to customers on the waiting list.

(e) The CSG subscriber organization and the utility shall jointly verify that each CSG subscriber is eligible to be a subscriber in the CSG pursuant to rule 3878. The CSG subscriber roll shall include, at a minimum, the percentage share owned by the CSG subscriber, the effective date of the ownership of that percentage share, and the meters at the premises to which the CSG subscription is attributed for the purpose of applying billing credits. Changes in the CSG subscriber roll shall be communicated by the CSG subscriber organization to the utility, in written or electronic form, as soon as practicable, but on no less than a monthly basis.

(f) Prices paid for subscriptions in a CSG shall not be subject to regulation by the Commission.

3880. Production Data.

(a) The amount of renewable energy and RECs generated by each CSG shall be measured by a production meter installed by the utility or the CSG owner and paid for by the CSG owner.

(b) The owner of a CSG with a nameplate rating of one MW or greater shall register the CSG and report the CSG's production data to the WREGIS in accordance with paragraph 3658(j).

(c) CSGs are required to provide real time reporting of production as specified by the utility. For CSGs greater than 250 kW, the CSG owner shall provide real time electronic access to production and system operation data. In the event that a CSG greater than 250 kW also collects meteorological data, the CSG owner shall provide, at the QRU's request, real time electronic access to the utility to such meteorological data. A utility may require different real time reporting for CSGs 250 kW and smaller.

(d) Production from the CSG shall be reported by the CSG subscriber organization to its CSG subscribers at least monthly. To facilitate the tracking of production data by CSG subscribers, CSG owners or CSG subscriber organizations are encouraged to provide website access to subscribers showing real time output from the CSG, if practicable, as well as historical production data.

3881. Billing Credits and Unsubscribed Renewable Energy.

(a) Compensation to the CSG subscriber for its share of the renewable energy generated by a CSG shall take the form of a billing credit paid to the CSG subscriber by the utility or, if authorized by the CSG subscriber, contributed to the nonprofit corporation established for low-income energy assistance pursuant to § 40-8.5-104, C.R.S.

(I) The billing credit shall be calculated by multiplying the CSG subscriber's share as a percentage of the renewable energy generated by the CSG times the utility's total aggregate retail rate, including all billed components except for the transmission, distribution, and RESA rate components, as charged to the CSG subscriber.

(II) For the purpose of calculating the billing credit for a commercial or industrial customer on a demand tariff:

(A) the total aggregate retail rate shall be determined by dividing the total electric charges to be paid by the customer to the utility for the most recent calendar year (including demand charges) by the customers' total electricity consumption for that year for subscriptions to CSGs planned for purchases by the utility after January 1, 2016. In the event that the designated premises to which the CSG subscription is attributed has less than one year of billing history, an estimate of the total annual charges shall be made by the utility; and

(B) the total aggregate retail rate shall be determined using the average charges and usage for the subscriber's rate class for subscriptions to CSGs planned for purchases by the utility after January 1, 2016.

(III) Billing credits shall be reflected in the CSG subscriber's bill from the utility no later than the 60th day after the utility receives the information required to calculate the billing credit from the CSG subscriber organization.

(IV) The utility may assess a Commission-approved charge to cover the utility's costs of delivering to the CSG subscriber's premises the renewable energy generated by the CSG, integrating the generation from the CSG into the utility's system, and administering the contracts with CSG owners and billing credits. This charge shall be a fixed amount and shall not reflect costs that are already recovered by the utility from CSG subscribers through other charges. The utility may seek a revision of this charge no more frequently than once per year.

(b) If, in a monthly billing period, the CSG subscriber's billing credit associated with a CSG subscription exceeds the customer's bill from the utility, the excess billing credit will be rolled over as a credit from month to month indefinitely until the customer terminates service with the utility, at which time no payment shall be required from the utility for any remaining billing credits associated with the customer's CSG subscription; however, nothing in this rule precludes the CSG subscriber or the utility from contributing the remaining bill credits to the nonprofit corporation established for low-income energy assistance pursuant to § 40-8.5-104, C.R.S.

(c) In lieu of the rolling over of billing credits from month to month pursuant to paragraph 3881(b), the CSG subscriber may contribute the excess billing credit at the end of the monthly billing cycle to the nonprofit corporation established for low-income energy assistance pursuant to § 40-8.5-104, C.R.S.

(d) For RECs purchased by the utility, the utility and the CSG owner shall agree on whether subscribers will be compensated by a credit on each CSG subscriber's bill from the QRU or by a payment to the CSG owner.

(e) The utility shall purchase from the CSG owner the unsubscribed renewable energy and RECs at a rate equal to the utility's average hourly incremental cost of electricity supply over the immediately preceding calendar year.

3882. Purchases from CSGs.

(a) The Commission shall establish the minimum and maximum purchases of renewable energy from newly installed CSG generation (new CSGs) by the utility for each year in accordance with §40-2-127(5)(a)(IV), C.R.S. The Commission shall establish such minimum and maximum levels of purchases in consideration of an acquisition plan for purchases from CSGs filed by the utility pursuant to rule 3656. Not less than 50 percent of the established purchases shall be reserved for residential, agricultural, and small commercial customers. The utility may propose a standard offer price for the purchase of RECs from residential, agricultural, and small commercial customers.

(b) The utility shall acquire renewable energy and RECs by entering into contracts with CSG owners. A CSG whose owner enters into a contract with the utility shall be deemed to be part of the utility's Commission-approved acquisition plan if the cumulative total of the nameplate capacity of the acquired new CSGs does not exceed the maximum purchases established by the Commission for that year.

(c) The utility shall conduct due diligence on proposed contracts with new CSG owners to reasonably assure that the CSG owner and CSG subscriber organization have sufficient resources to successfully construct and commence operations of the CSG.

(I) Except for CSGs owned by governmental, quasi-governmental, or non-profit entities, the utility shall be deemed to have conducted sufficient due diligence by requiring from the CSG owner documentation of escrowed funds of not less than $100 per kW of the CSG's nameplate rating. The escrow shall be maintained by its terms until such time as the CSG commences commercial operation as certified by the utility's acceptance of renewable energy generated by the CSG.

(II) If a CSG owner properly documents escrowed funds consistent with this paragraph, the utility may not refuse to enter into a contract with the CSG owner for failure to demonstrate sufficient resources to reasonably assure successful construction and commencement of CSG operations.

(d) In each plan for purchases from CSGs, the utility shall reserve, to the extent there is demand for such ownership, at least five percent of its renewable energy purchases from new CSGs for eligible low-income CSG subscribers.

(I) CSG subscriber organizations and investor owned QRUs may rely on certification by the Colorado Department of Human Services for acceptance in the Colorado Low-Income Energy Assistance Program (LEAP) as evidence of eligibility as an eligible low-income CSG subscriber in a CSG or other reliable verification methods from low-income services and service providers.

(II) CSGs for eligible low-income CSG subscribers may be either dedicated low-income CSGs or low-income set asides within other CSGs.

(e) For investments in a new CSG, the utility shall be eligible for the incentives in rule 3660 and be subject to the ownership limitations set forth in §40-2-124(1)(f)(I), C.R.S.; however such incentive payments shall be excluded from the retail rate impact under rule 3661. Notwithstanding the exclusion from the retail rate impact of such incentives, the acquisition of renewable energy and RECs from CSGs shall be subject to the retail rate impact under rule 3661. Utility expenditures for unsubscribed energy and RECs generated by CSGs shall be included in the calculations of retail rate impact under that rule.

3883. Financing and Operating CSGs.

(a) Contracts signed by utilities with CSG owners shall be a matter of public record and shall be filed with the Commission by the utility.

(b) CSG subscriber organizations shall issue public annual reports as of the end of the calendar or other fiscal year containing, at a minimum, the energy produced by the CSG; audited financial statements including a balance sheet, income statement, and sources and uses of funds statement; and the management and ownership of the CSG and the CSG subscriber organization, if different. Individual subscribers shall receive, in addition to the annual report of the CSG subscriber organization, a report of the energy, multiplier (e.g., aggregate retail rate), and net metering credits attributed to the CSG subscriber's account.

(c) CSG subscriber funds, collected by the CSG in advance of commercial operation of the CSG, shall be held in escrow. The escrow shall be maintained by its terms until such time as the CSG commences commercial operation as certified by utility acceptance of energy from the CSG.

3884. – 3899. [Reserved].

SMALL POWER PRODUCERS AND COGENERATORS

3900. Applicability.

Rules 3900 through 3905 apply to utilities which purchase power from small power producers and cogenerators. These rules also apply to small power producers and cogenerators which sell power to utilities.

3901. Overview and Purpose

The purpose of these rules is to implement Sections 201 and 210 of the federal Public Utility Regulatory Policies Act of 1978 (PURPA) in conjunction with the entirety of the provisions in the Commission's Rules Regulating Electric Utilities.

3902. Definitions.

The following definitions apply to rules 3900 through 3905, except where a specific rule or statute provides otherwise. In addition to the definitions stated here, the definitions found in the Public Utilities Law, PURPA, and in the federal regulations which are incorporated by reference apply to these rules. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Avoided cost" means the incremental or marginal cost to an electrical utility of electrical energy or capacity, or both, which, but for the purchase of such energy and/or capacity from qualifying facility or qualifying facilities, the utility would generate itself or would purchase from another source.

(b) "Qualifying facility" means any small power production facility or cogeneration facility which is a qualifying facility under federal law.

(c) "Rate" means any price, rate, charge, or classification made, demanded, observed, or received with respect to the sale or purchase of electrical energy or capacity; any rule or practice respecting any such rate, charge, or classification; and any contract pertaining to the sale or purchase of electrical energy or capacity.

3903. Obligation to Purchase

(a) For qualifying facilities with a design capacity greater than 20 MW, the utility is obligated to purchase capacity or energy from the qualifying facility if the qualifying facility is awarded a contract pursuant to the competitive bidding provisions in the Commission's Electric Resource Planning Rules. If the Commission determines that such competitive bidding is reasonably accessible to qualifying facilities smaller than 20 MW, the utility likewise is obligated to purchase capacity or energy from a qualifying facility within the Commission-determined range if the qualifying facility is awarded a contract pursuant to the competitive bidding. The Commission's findings with respect to obligations to purchase from qualifying facilities smaller than 20 MW shall be set forth in its decision rendered pursuant to paragraph 3614(f).

(b) Each utility shall file tariffs for purchases from certain qualifying facilities with a design capacity no greater than 20 MW or some lesser amount as the Commission determines in its decision rendered pursuant to paragraphs 3903(a) and 3614(f). Such tariffs shall ensure that the obligation to purchase does not arise until such time as the qualifying facility is viable as determined by the utility pursuant to the tariffs. The utility may file separate tariffs for purchases from qualifying facilities with a design capacity of 100 kW or less.

(c) Energy purchases from a qualifying facility shall result in the transfer of RECs generated with the purchased energy from the qualifying facility to the utility.

3904. Avoided Costs.

(a) Each utility shall pay qualifying facilities a rate for energy and capacity purchases based on the utility's avoided costs. The avoided costs shall be reduced by integration costs, including, but not limited to, costs associated with additional reserves, systems operation impacts, and curtailments.

(b) Each electric utility shall file tariffs setting forth standard rates for purchases from qualifying facilities with a design capacity of 100 KW or less. The utility shall determine the avoided cost rate in a transparent fashion. The avoided cost rate shall take into account any savings provided by a qualifying facility to the utility's distribution and transmission systems. The avoided cost rates shall be recalculated and refiled no less than once each year.

(c) A utility shall establish its avoided costs for qualifying facilities with a design capacity of greater than 20 MW through the competitive bidding process pursuant to the Commission's Electric Resource Planning Rules. In accordance with paragraph 3903(a), the Commission may reduce such minimum design capacity below 20 MW if the smaller qualifying facilities are eligible to participate in the competitive bidding process.

Option A:

(d) The utility's tariffs for purchases from qualifying facilities with a design capacity greater than 100 kW and less than or equal to 20 MW, or less than or equal than some other amount determined by the Commission pursuant to paragraph 3903(b), shall set forth a method for calculating the utility's avoided costs using computer-based modeling given the inputs, assumptions, and results from the bid evaluation and selection from the competitive bidding process implemented by the utility pursuant to the Commission's Electric Resource Planning Rules.

Option B:

(d) The utility's tariffs for purchases from qualifying facilities with a design capacity greater than 100 kW and less than or equal to 20 MW, or less than or equal than some other amount determined by the Commission pursuant to paragraph 3903(b), shall set forth a method for calculating the utility's avoided costs using a market-based mechanism such as the results from the competitive bidding implemented by the utility pursuant to the Commission's Electric Resource Planning Rules.

(I) Rates for purchases with scheduled delivery of firm power or power-producing capacity for a specified term shall be determined either at the time of delivery or under a fixed priced contract.

(II) Rates for as-available purchases without scheduled delivery shall be determined at the time of delivery accounting for the time and quantity of the purchases.

(e) If a utility can demonstrate to the Commission that a qualifying facility should receive a different rate from that established by these rules, the Commission may authorize such. The burden of establishing such different rate shall be on the utility, and the rate shall be based on the utility's system wide costing principles and other appropriate load and cost data.

(f) Nothing in this rule requires a utility to pay more than its avoided costs of energy and capacity, of energy, or of capacity for purchases from qualifying facilities.

3905. Interconnection and Operations.

(a) A qualifying facility seeking to interconnect to a utility's transmission system shall seek network resource interconnection service pursuant to the utility's Open Access Transmission Tariff (OATT).

(b) A qualifying facility seeking to interconnect to a utility's distribution system shall be subject to the provisions in the Commission's interconnection standards and procedures and the applicable utility tariffs.

(c) Each qualifying facility shall pay the cost of interconnecting with an electric utility for purchases and sales of capacity and energy. To the extent that interconnection costs can be determined in advance of interconnection, each electric utility shall establish the cost of interconnection for purchases of energy and capacity. The interconnection costs shall be fair, reasonable, and nondiscriminatory to each qualifying facility.

(d) The utility and qualifying facility may agree to an installment payment arrangement for interconnection costs.

(e) The rights and obligations of a qualifying facility shall be set forth in the awarded contract based on the model contract reviewed by the Commission in Phase I of the utility's electric resource plan proceeding.

(f) For purchases from qualifying facilities pursuant to the utility's tariffs, the tariffs shall include a standard contract with the same terms as the applicable model contract reviewed by the Commission in Phase I of the utility's electric resource plan proceeding.

3906. – 3975. [Reserved].