Rules of
Department of Economic Development
Division 240—Public Service Commission
Chapter 20—Electric Utilities

Title 4—DEPARTMENT OF ECONOMIC DEVELOPMENT
Division 240—Public Service Commission
Chapter 20—Electric Utilities

4 CSR 240-20.010 Rate Schedules
(Rescinded April 30, 2003)

AUTHORITY: section 393.140, RSMo 1986. Original rule filed Dec. 19, 1975, effective Dec. 29, 1975. Amended: Filed May 16, 1977, effective Dec. 11, 1977. Rescinded: Filed Aug. 16, 2002, effective April 30, 2003.

4 CSR 240-20.015 Affiliate Transactions

PURPOSE: This rule is intended to prevent regulated utilities from subsidizing their nonregulated operations. In order to accomplish this objective, the rule sets forth financial standards, evidentiary standards and record-keeping requirements applicable to any Missouri Public Service Commission (commission) regulated electrical corporation whenever such corporation participates in transactions with any affiliated entity (except with regard to HVAC services as defined in section 386.754, RSMo Supp. 1998, by the General Assembly of Missouri). The rule and its effective enforcement will provide the public the assurance that their rates are not adversely impacted by the utilities' nonregulated activities.

(1) Definitions.

(A) Affiliated entity means any person, including an individual, corporation, service company, corporate subsidiary, firm, partnership, incorporated or unincorporated association, political subdivision including a public utility district, city, town, county, or a combination of political subdivisions, which directly or indirectly, through one (1) or more intermediaries, controls, is controlled by, or is under common control with the regulated electrical corporation.

(B) Affiliate transaction means any transaction for the provision, purchase or sale of any information, asset, product or service, or portion of any product or service, between a regulated electrical corporation and an affiliated entity, and shall include all transactions carried out between any unregulated business operation of a regulated electrical corporation and the regulated business operations of a electrical corporation. An affiliate transaction for the purposes of this rule excludes heating, ventilating and air conditioning (HVAC) services as defined in section 386.754 by the General Assembly of Missouri.

(C) Control (including the terms "controlling," "controlled by," and "common control") means the possession, directly or indirectly, of the power to direct, or to cause the direction of the management or policies of an entity, whether such power is exercised through one (1) or more intermediary entities, or alone, or in conjunction with, or pursuant to an agreement with, one or more other entities, whether such power is exercised through a majority or minority ownership or voting of securities, common directors, officers or stockholders, voting trusts, holding trusts, affiliated entities, contract or any other direct or indirect means. The commission shall presume that the beneficial ownership of ten percent (10%) or more of voting securities or partnership interest of an entity constitutes control for purposes of this rule. This provision, however, shall not be construed to prohibit a regulated electrical corporation from rebutting the presumption that its ownership interest in an entity confers control.

(D) Corporate support means joint corporate oversight, governance, support systems and personnel, involving payroll, shareholder services, financial reporting, human resources, employee records, pension management, legal services, and research and development activities.

(E) Derivatives means a financial instrument, traded on or off an exchange, the price of which is directly dependent upon (i.e., "derived from") the value of one or more underlying securities, equity indices, debt instruments, commodities, other derivative instruments, or any agreed-upon pricing index or arrangement (e.g., the movement over time of the Consumer Price Index or freight rates). Derivatives involve the trading of rights or obligations based on the underlying product, but do not directly transfer property. They are used to hedge risk or to exchange a floating rate of return for a fixed rate of return.

(F) Fully distributed cost (FDC) means a methodology that examines all costs of an enterprise in relation to all the goods and services that are produced. FDC requires recognition of all costs incurred directly or indirectly used to produce a good or service. Costs are assigned either through a direct or allocated approach. Costs that cannot be directly assigned or indirectly allocated (e.g., general and administrative) must also be included in the FDC calculation through a general allocation.

(G) Information means any data obtained by a regulated electrical corporation that is not obtainable by nonaffiliated entities or can only be obtained at a competitively prohibitive cost in either time or resources.

(H) Preferential service means information or treatment or actions by the regulated electrical corporation which places the affiliated entity at an unfair advantage over its competitors.

(I) Regulated electrical corporation means every electrical corporation as defined in section 386.020, RSMo, subject to commission regulation pursuant to Chapter 393, RSMo.

(J) Unfair advantage means an advantage that cannot be obtained by nonaffiliated entities or can only be obtained at a competitively prohibitive cost in either time or resources.

(K) Variance means an exemption granted by the commission from any applicable standard required pursuant to this rule.

(2) Standards.

(A) A regulated electrical corporation shall not provide a financial advantage to an affiliated entity. For the purposes of this rule, a regulated electrical corporation shall be deemed to provide a financial advantage to an affiliated entity if—

1. It compensates an affiliated entity for goods or services above the lesser of—

A. The fair market price; or

B. The fully distributed cost to the regulated electrical corporation to provide the goods or services for itself; or

2. It transfers information, assets, goods or services of any kind to an affiliated entity below the greater of—

A. The fair market price; or

B. The fully distributed cost to the regulated electrical corporation.

(B) Except as necessary to provide corporate support functions, the regulated electrical corporation shall conduct its business in such a way as not to provide any preferential service, information or treatment to an affiliated entity over another party at any time.

(C) Specific customer information shall be made available to affiliated or unaffiliated entities only upon consent of the customer or as otherwise provided by law or commission rules or orders. General or aggregated customer information shall be made available to affiliated or unaffiliated entities upon similar terms and conditions. The regulated electrical corporation may set reasonable charges for costs incurred in producing customer information. Customer information includes information provided to the regulated utility by affiliated or unaffiliated entities.

(D) The regulated electrical corporation shall not participate in any affiliated transactions which are not in compliance with this rule, except as otherwise provided in section (10) of this rule.

(E) If a customer requests information from the regulated electrical corporation about goods or services provided by an affiliated entity, the regulated electrical corporation may provide information about its affiliate but must inform the customer that regulated services are not tied to the use of an affiliate provider and that other service providers may be available. The regulated electrical corporation may provide reference to other service providers or to commercial listings, but is not required to do so. The regulated electrical corporation shall include in its annual Cost Allocation Manual (CAM), the criteria, guidelines and procedures it will follow to be in compliance with this rule.

(F) Marketing materials, information or advertisements by an affiliate entity that share an exact or similar name, logo or trademark of the regulated utility shall clearly display or announce that the affiliate entity is not regulated by the Missouri Public Service Commission.

(3) Evidentiary Standards for Affiliate Transactions.

(A) When a regulated electrical corporation purchases information, assets, goods or services from an affiliated entity, the regulated electrical corporation shall either obtain competitive bids for such information, assets, goods or services or demonstrate why competitive bids were neither necessary nor appropriate.

(B) In transactions that involve either the purchase or receipt of information, assets, goods or services by a regulated electrical corporation from an affiliated entity, the regulated electrical corporation shall document both the fair market price of such information, assets, goods and services and the FDC to the regulated electrical corporation to produce the information, assets, goods or services for itself.

(C) In transactions that involve the provision of information, assets, goods or services to affiliated entities, the regulated electrical corporation must demonstrate that it—

1. Considered all costs incurred to complete the transaction;
2. Calculated the costs at times relevant to the transaction;
3. Allocated all joint and common costs appropriately; and
4. Adequately determined the fair market price of the information, assets, goods or services.

(D) In transactions involving the purchase of goods or services by the regulated electrical corporation from an affiliated entity, the regulated electrical corporation will use a commission-approved CAM which sets forth cost allocation, market valuation and internal cost methods. This CAM can use benchmarking practices that can constitute compliance with the market value requirements of this section if approved by the commission.

(4) Record Keeping Requirements.

(A) A regulated electrical corporation shall maintain books, accounts and records separate from those of its affiliates.

(B) Each regulated electrical corporation shall maintain the following information in a mutually agreed-to electronic format (i.e., agreement between the staff, Office of the Public Counsel and the regulated electrical corporation) regarding affiliate transactions on a calendar year basis and shall provide such information to the commission staff and the Office of the Public Counsel on, or before, March 15 of the succeeding year:

1. A full and complete list of all affiliated entities as defined by this rule;
2. A full and complete list of all goods and services provided to or received from affiliated entities;
3. A full and complete list of all contracts entered with affiliated entities;
4. A full and complete list of all affiliate transactions undertaken with affiliated entities without a written contract together with a brief explanation of why there was no contract;
5. The amount of all affiliate transactions by affiliated entity and account charged; and
6. The basis used (e.g., fair market price, FDC, etc.) to record each type of affiliate transaction.

(C) In addition, each regulated electrical corporation shall maintain the following information regarding affiliate transactions on a calendar year basis:

1. Records identifying the basis used (e.g., fair market price, FDC, etc.) to record all affiliate transactions; and
2. Books of accounts and supporting records in sufficient detail to permit verification of compliance with this rule.

(5) Records of Affiliated Entities.

(A) Each regulated electrical corporation shall ensure that its parent and any other affiliated entities maintain books and records that include, at a minimum, the following information regarding affiliate transactions:

1. Documentation of the costs associated with affiliate transactions that are incurred by the parent or affiliated entity and charged to the regulated electrical corporation;
2. Documentation of the methods used to allocate and/or share costs between affiliated entities including other jurisdictions and/or corporate divisions;
3. Description of costs that are not subject to allocation to affiliate transactions and documentation supporting the nonassignment of these costs to affiliate transactions;
4. Descriptions of the types of services that corporate divisions and/or other centralized functions provided to any affiliated entity or division accessing the regulated electrical corporation's contracted services or facilities;
5. Names and job descriptions of the employees from the regulated electrical corporation that transferred to a nonregulated affiliated entity;
6. Evaluations of the effect on the reliability of services provided by the regulated electrical corporation resulting from the access to regulated contracts and/or facilities by affiliated entities;
7. Policies regarding the availability of customer information and the access to services available to nonregulated affiliated entities desiring use of the regulated electrical corporation's contracts and facilities; and
8. Descriptions of and supporting documentation related to any use of derivatives that may be related to the regulated electrical corporation's operation even though obtained by the parent or affiliated entity.

(6) Access to Records of Affiliated Entities.

(A) To the extent permitted by applicable law and pursuant to established commission discovery procedures, a regulated electrical corporation shall make available the books and records of its parent and any other affiliated entities when required in the application of this rule.

(B) The commission shall have the authority to—

1. Review, inspect and audit books, accounts and other records kept by a regulated electrical corporation or affiliated entity for the sole purpose of ensuring compliance with this rule and making findings available to the commission; and
2. Investigate the operations of a regulated electrical corporation or affiliated entity and their relationship to each other for the sole purpose of ensuring compliance with this rule.

(C) This rule does not modify existing legal standards regarding which party has the burden of proof in commission proceedings.

(7) Record Retention.

(A) Records required under this rule shall be maintained by each regulated electrical corporation for a period of not less than six (6) years.

(8) Enforcement.

(A) When enforcing these standards, or any order of the commission regarding these standards, the commission may apply any remedy available to the commission.

(9) The regulated electrical corporation shall train and advise its personnel as to the requirements and provisions of this rule as appropriate to ensure compliance.

(10) Variances.

(A) A variance from the standards in this rule may be obtained by compliance with paragraphs (10)(A)1. or (10)(A)2. The granting of a variance to one regulated electrical corporation does not constitute a waiver respecting or otherwise affect the required compliance of any other regulated electrical corporation to comply with the standards. The scope of a variance will be determined based on the facts and circumstances found in support of the application.

1. The regulated electrical corporation shall request a variance upon written application in accordance with commission procedures set out in 4 CSR 240-2.060(11); or

2. A regulated electrical corporation may engage in an affiliate transaction not in compliance with the standards set out in subsection (2)(A) of this rule, when to its best knowledge and belief, compliance with the standards would not be in the best interests of its regulated customers and it complies with the procedures required by subparagraphs (10)(A)2.A. and (10)(A)2.B. of this rule—

A. All reports and record retention requirements for each affiliate transaction must be complied with; and

B. Notice of the noncomplying affiliate transaction shall be filed with the secretary of the commission and the Office of the Public Counsel within ten (10) days of the occurrence of the non-complying affiliate transaction. The notice shall provide a detailed explanation of why the affiliate transaction should be exempted from the requirements of subsection (2)(A), and shall provide a detailed explanation of how the affiliate transaction was in the best interests of the regulated customers. Within thirty (30) days of the notice of the noncomplying affiliate transaction, any party shall have the right to request a hearing regarding the noncomplying affiliate transaction. The commission may grant or deny the request for hearing at that time. If the commission denies a request for hearing, the denial shall not in any way prejudice a party's ability to challenge the affiliate transaction at the time of the annual CAM filing. At the time of the filing of the regulated electrical corporation's annual CAM filing the regulated electrical corporation shall provide to the secretary of the commission a listing of all non-complying affiliate transactions which occurred between the period of the last filing and the current filing. Any affiliate transaction submitted pursuant to this section shall remain interim, subject to disallowance, pending final commission determination on whether the noncomplying affiliate transaction resulted in the best interests of the regulated customers.

(11) Nothing contained in this rule and no action by the commission under this rule shall be construed to approve or exempt any activity or arrangement that would violate the antitrust laws of the state of Missouri or of the United States or to limit the rights of any person or entity under those laws.

AUTHORITY: sections 386.250, RSMo Supp. 1998, and 393.140, RSMo 1994. Original rule filed April 26, 1999, effective Feb. 29, 2000.*

**Original authority: 386.250, RSMo 1963, amended 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996 and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-20.017 HVAC Services Affiliate Transactions

PURPOSE: This rule prescribes the requirements for HVAC services affiliated entities and regulated electric corporations when such electric corporations participate in affiliated transactions with an HVAC affiliated entity as set forth in sections 386.754, 386.756, 386.760, 386.762 and 386.764, RSMo by the General Assembly of the State of Missouri.

(1) Definitions.

(A) Affiliated entity means any entity not regulated by the Public Service Commission which is owned, controlled by or under common control with a utility and is engaged in HVAC services.

(B) Control (including the terms "controlling," "controlled by," and "common control") means the possession, directly or indirectly, of the power to direct, or to cause the direction of the management or policies of an entity, whether such power is exercised through (1) one or more intermediary entities, or alone, or in conjunction with, or pursuant to an agreement with, one (1) or more other entities, whether such power is exercised through a majority or minority ownership or voting of securities, common directors, officers or stockholders, voting trusts, holding trusts, affiliated entities, contract or any other direct or indirect means. The commission shall presume that the beneficial ownership of more than ten percent (10%) of voting securities or partnership interest of an entity confers control for purposes of this rule. This provision, however, shall not be construed to prohibit a regulated electric corporation from rebutting the presumption that its ownership interest in an entity confers control.

(C) Fully distributed cost means a methodology that examines all costs of an enterprise in relation to all the goods and services that are produced. Fully distributed cost requires recognition of all costs incurred directly or indirectly used to produce a good or service. Costs are assigned either through a direct or allocated approach. Costs that cannot be directly assigned or indirectly allocated (e.g. general and administrative) must also be included in the fully distributed cost calculation through a general allocation.

(D) HVAC services means the warranty, sale, lease, rental, installation, construction, modernization, retrofit, maintenance or repair of heating, ventilating and air conditioning (HVAC) equipment.

(E) Regulated electric corporation means an electrical corporation as defined in section 386.020, RSMo, subject to commission regulation pursuant to Chapter 393, RSMo.

(F) Utility contractor means a person, including an individual, corporation, firm, incorporated or unincorporated association or other business or legal entity, that contracts, whether in writing or not in writing, with a regulated electric corporation to engage in or assist any entity in engaging in HVAC services, but does not include employees of a regulated electric corporation.

(2) A regulated electric corporation may not engage in HVAC services, except by an affiliated entity, or as provided in section (8) or (9) of this rule.

(3) No affiliated entity or utility contractor may use any vehicles, service tools, instruments, employees, or any other regulated electric corporation assets, the cost of which are recoverable in the regulated rates for regulated electric corporation service, to engage in HVAC services unless the regulated electric corporation is compensated for the use of such assets at the fully distributed cost to the regulated electric corporation.

(A) The determination of a regulated electric corporation's cost in this section is defined in subsection (1)(D) of this rule.

(4) A regulated electric corporation may not use or allow any affiliated entity or utility contractor to use the name of such regulated electric corporation to engage in HVAC services unless the regulated electric corporation, affiliated entity or utility contractor discloses, in plain view and in bold type on the same page as the name is used on all advertisements or in plain audible language during all solicitations of such services, a disclaimer that states the services provided are not regulated by the commission.

(5) A regulated electric corporation may not engage in or assist any affiliated entity or utility contractor in engaging in HVAC services in a manner which subsidizes the activities of such regulated electric corporation, affiliated entity or utility contractor to the extent of changing the rates or charges for the regulated electric corporation's services above or below the rates or charges that would be in effect if the regulated electric corporation were not engaged in or assisting any affiliated entity or utility contractor in engaging in such activities.

(6) Any affiliated entities or utility contractors engaged in HVAC services shall maintain accounts, books and records separate and distinct from the regulated electric corporation.

(7) The provisions of this rule shall apply to any affiliated entity or utility contractor engaged in HVAC services that is owned, controlled or under common control with a regulated electric corporation providing regulated services in the state of Missouri or any other state.

(8) A regulated electric corporation engaging in HVAC services in the state of Missouri five (5) years prior to August 28, 1998, may continue providing, to existing as well as new customers, the same type of services as those provided by the regulated electric corporation five (5) years prior to August 28, 1998.

(A) To qualify for this exemption, the regulated electric corporation shall file a pleading before the commission for approval.

1. The commission may establish a case to determine if the regulated electric corporation qualifies for an exemption under this rule.

(9) The provisions of this section shall not be construed to prohibit a regulated electric corporation from providing emergency service, providing any service required by law or providing a program pursuant to an existing tariff, rule or order of the commission.

AUTHORITY: sections 386.760.1, RSMo Supp. 1998 and 393.140, RSMo 1994. Original rule filed Dec. 17, 1998, effective Aug. 30, 1999.*

**Original authority: 386.760.1, RSMo 1998 and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-20.020 Residential Electric Underground Distribution Systems
(Rescinded August 15, 1983)

AUTHORITY: section 386.310, RSMo 1978. Original rule filed June 28, 1971, effective July 14, 1971. Amended: Filed Oct. 26, 1971, effective Nov. 4, 1971. Amended: Filed May 27, 1975, effective June 6, 1975. Rescinded: Filed Jan. 12, 1983, effective Aug. 15, 1983.

4 CSR 240-20.030 Uniform System of Accounts—Electrical Corporations

PURPOSE: This rule directs electrical corporations within the commission's jurisdiction to use the uniform system of accounts prescribed by the Federal Energy Regulatory Commission for major electric utilities and licensees, as modified herein. Requirements regarding the submission of depreciation studies, databases and property unit catalogs are found at 4 CSR 240-3.160 and 4 CSR 240-3.175.

(1) Beginning January 1, 1994, every electrical corporation subject to the commission's jurisdiction shall keep all accounts in conformity with the Uniform System of Accounts Prescribed for Public Utilities and Licensees subject to the provisions of the Federal Power Act, as prescribed by the Federal Energy Regulatory Commission (FERC) and published at 18 CFR Part 101 (1992) and 1 FERC Stat. & Regs. paragraph 15,001 and following (1992), except as otherwise provided in this rule. This uniform system of accounts provides instruction for recording financial information about electric utilities. It contains definitions, general instructions, electric plant instructions, operating expense instructions, and accounts that comprise the balance sheet, electric plant, income, operating revenues, and operation and maintenance expenses.

(2) When implementing section (1), each electrical corporation subject to the commission's jurisdiction shall—

(A) Keep its accounts in the manner and detail specified for electric utilities and licensees classified as major at Part 101 General Instructions 1.A. and paragraph 15,011.1.A.; and

(B) Assemble by July 1, 1996, and maintain after that, a property unit catalog which contains for each designated property unit, in addition to the provisions of Part 101 General Instructions 6. and paragraph 15,016—

1. A description of each unit;
2. An item list; and
3. Accounting instructions, including instructions for distinguishing between operations expense, maintenance expense and capitalized plant improvements.

(3) Regarding plant acquired or placed in service after 1993, when implementing section (1), each electrical corporation subject to the commission's jurisdiction shall—

(A) Maintain plant records of the year of each unit's retirement as part of the "continuing plant inventory records," as the term is otherwise defined at Part 101 Definitions 8. and paragraph 15,001.8.;

(B) State the detailed electric plant accounts (301 to 399, inclusive) on the basis of original cost, estimated if not known, when implementing the provisions of Part 101 Electric Plant Instructions 1.C. and paragraph 15,051.1.C.;

(C) Record electrical plant acquired as an operating unit or system at original cost, estimated if not known, except as otherwise provided by the text of the intangible plant accounts, when implementing the provisions of Part 101 Electric Plant Instructions 2.A. and paragraph 15,052.2.A.;

(D) Account for the cost of items not classified as units of property as it would account for the cost of individual items of equipment of small value or of short life, as provided in Part 101 Electric Plant Instructions 3.A.(3) and paragraph 15,053.3.A.(3);

(E) Include in equipment accounts any hand or other portable tools which are specifically designated as units of property, when implementing the provisions of Part 101 Electric Plant Instructions 9.B. and paragraph 15,059.9.B.;

(F) Use the list of retirement units contained in its property unit catalog when implementing the provisions of Part 101 Electric Plant Instructions 10.A. and paragraph 15,060.10.A.;

(G) Estimate original cost with an appropriate average of the original cost of the units by vintage year, with due allowance for any difference in size and character, when it is impracticable to determine the original cost of each unit, when implementing the provisions of Part 101 Electric Plant Instructions 10.D. and paragraph 15,060.10.D.;

(H) Charge original cost less net salvage to account 108., when implementing the provisions of Part 101 Electric Plant Instructions 10.F. and paragraph 15,060.10.F.;

(I) Keep its work order system so as to show the nature of each addition to or retirement of electric plant by vintage year, in addition to the other requirements of Part 101 Electric Plant Instructions 11.B. and paragraph 15,061.11.B.;

(J) Maintain records which classify, for each plant account, the amounts of the annual additions and retirements so as to show the number and cost of the various record units or retirement units by vintage year, when implementing the provisions of Part 101 Electric Plant Instructions 11.C. and paragraph 15,061.11.C.;

(K) Maintain subsidiary records which separate account 108. according to primary plant accounts or subaccounts when implementing the provisions of Part 101 Balance Sheet Account 108.C. and paragraph 15,110.108.C.;

(L) Maintain subsidiary records which separate account 111. according to primary plant accounts or subaccounts when implementing the provisions of Part 101 Balance Sheet Accounts 111.C. and paragraph 15,113.111.C.; and

(M) Keep mortality records of property and property retirements as will reflect the average life of property which has been retired and will aid in estimating probable service life by actuarial analysis of annual additions and aged retirements when implementing the provisions of Part 101 Income Accounts 403.B. and paragraph 15,404.403.B.

(4) In prescribing this system of accounts, the commission does not commit itself to the approval or acceptance of any item set out in any account for the purpose of fixing rates or in determining other matters before the commission. This rule shall not be construed as waiving any recordkeeping requirement in effect prior to 1994.

(5) The commission may waive or grant a variance from the provisions of this rule, in whole or in part, for good cause shown, upon a utility's written application.

AUTHORITY: sections 386.250 and 393.140, RSMo 2000. Original rule filed Dec. 19, 1975, effective Dec. 29, 1975. Amended: Filed April 26, 1976, effective Sept. 11, 1976. Amended: Filed Feb. 5, 1993, effective Oct. 10, 1993. Amended: Filed March 19, 1996, effective Oct. 30, 1996. Amended: Filed Aug. 16, 2002, effective April 30, 2003.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996 and 393.140, 1939, amended 1949, 1967.*

4 CSR 240-20.040 Minimum Filing Requirements
(Rescinded October 10, 1993)

AUTHORITY: section 393.140, RSMo 1986. Original rule filed Dec. 10, 1979, effective Sept. 1, 1980. Rescinded: Filed Feb. 4, 1993, effective Oct. 10, 1993.

4 CSR 240-20.045 Electric Utility Applications for Certificates of Convenience and Necessity

PURPOSE: This proposed rule outlines the requirements for applications to the commission, pursuant to section 393.170.1 and 393.170.2, RSMo, requesting that the commission grant a certificate of convenience and necessity to an electric utility for a service area or to operate or construct an electric generating plant, an electric transmission line, or a gas transmission line that facilitates the operation of an electric generating plant.

(1) Definitions. As used in this rule, the following terms mean:

(A) Asset means:

1. An electric generating plant, or a gas transmission line that facilitates the operation of an electric generating plant, that is expected to serve Missouri customers and be included in the rate base used to set their retail rates regardless of whether the item(s) to be constructed or operated is located inside or outside the electric utility's certificated service area or inside or outside Missouri; or

2. Transmission and distribution plant located outside the electric utility's service territory, but within Missouri;

(B) Construction means:

1. Construction of new asset(s); or

2. The improvement, retrofit, or rebuild of an asset that will result in a ten percent (10%) increase in rate base as established in the electric utility's most recent rate case;

(C) Construction does not include:

1. The construction of an energy generation unit that has a capacity of one (1) megawatt or less; or

2. The construction of utility-owned solar facilities as required under section 393.1665, RSMo;

3. Periodic, routine, or preventative maintenance; or

4. Replacement of equipment or devices with the same or substantially similar items due to failure or near term projected failure as long as the replacements are intended to restore the asset to an operational state at or near a recently rated capacity level.

(2) Certificate of convenience and necessity.

(A) An electric utility must obtain a certificate of convenience and necessity prior to—

1. Providing electric service to retail customers in a service area pursuant to section 393.170.2, RSMo;

2. Construction of an asset pursuant to section 393.170.1, RSMo; or

3. Operation of an asset pursuant to section 393.170.2, RSMo.

(B) The commission may, by its order, impose upon the issuance of a certificate of convenience and necessity such condition or conditions as it may deem reasonable and necessary.

(C) In determining whether to grant a certificate of convenience and necessity, the commission may, by its order, make a determination on the prudence of the decision to operate or construct an asset subject to the commission's subsequent review of costs and applicable timelines.

(D) An electric utility must exercise the authority granted within two (2) years from the grant thereof.

(3) In addition to the general requirements of 4 CSR 240-2.060(1), the following additional general requirements apply to all applications for a certificate of convenience and necessity, pursuant to sections 393.170.1 and .2, RSMo:

(A) The application shall include facts showing that granting the application is necessary or convenient for the public service;

(B) If an asset to be operated or constructed is outside Missouri, the application shall include plans for allocating costs, other than regional transmission organization/independent system operator cost sharing, to the applicable jurisdiction; and

(C) If any of the items required under this rule are unavailable at the time the application is filed, the unavailable items may be filed prior to the granting of authority by the commission, or the commission may grant the certificate subject to the condition that the unavailable items be filed before authority under the certificate is exercised.

(4) If the application is for authorization to provide electric service to retail customers in

a service area for the electric utility under section 393.170.2, RSMo, the application shall also include:

(A) A list of those entities providing regulated or nonregulated retail electric service in all or any part of the service area proposed, including a map that identifies where each entity is providing retail electric service within the area proposed;

(B) If there are ten (10) or more residents or landowners, the name and address of no fewer than ten (10) persons residing in the proposed service area or of no fewer than ten (10) landowners, in the event there are no residences in the area, or, if there are fewer than ten (10) residents or landowners, the name and address of all residents and landowners;

(C) The legal description of the service area to be certificated;

(D) A plat of the proposed service area drawn to a scale of one-half inch (1/2") to the mile on maps comparable to county highway maps issued by the state's Department of Transportation or a plat drawn to a scale of two thousand feet (2,000') to the inch; and

(E) A feasibility study containing plans and specifications for the utility system, plans for financing, proposed rates and charges, and an estimate of the number of customers, revenues, and expenses during the first three (3) years of operations.

(5) If the application is for authorization to operate assets under section 393.170.2, RSMo, the application shall also include:

(A) A description of the asset(s) to be operated;

(B) The value of the asset(s) to be operated;

(C) The purchase price and plans for financing the operation; and

(D) Plans and specifications for the asset, including as-built drawings.

(6) If the application is for authorization to construct an asset under section 393.170.1, RSMo, the application shall also include:

(A) A description of the proposed route or site of construction;

(B) A list of all electric, gas, and telephone conduit, wires, cables, and lines of regulated and nonregulated utilities, railroad tracks, and each underground facility, as defined in section 319.015, RSMo, which the proposed construction will cross;

(C) A description of the plans, specifications, and estimated costs for the complete scope of the construction project that also clearly identifies what will be the operational features of the asset once it is fully operational and used for service;

(D) The projected beginning of construction date and the anticipated fully operational and used for service date of the asset;

(E) A description of any common plant to be included in the construction project;

(F) Plans for financing the construction of the asset;

(G) A description of how the proposed asset relates to the electric utility's adopted preferred plan under 4 CSR 240-22;

(H) An overview of the electric utility's plan for this project regarding competitive bidding, although competitive bidding is not required, for the design, engineering, procurement, construction management, and construction of the asset;

(I) An overview of plans for operating and maintaining an asset;

(J) An overview of plans for restoration of safe and adequate service after significant, unplanned/forced outages of an asset; and

(K) An affidavit or other verified certification of compliance with the following notice requirements to landowners directly affected by electric transmission line routes or transmission substation locations proposed by the application. The proof of compliance shall include a list of all directly affected landowners to whom notice was sent.

1. Applicant shall provide notice of its application to the owners of land, or their designee, as stated in the records of the county assessor's office, on a date not more than sixty (60) days prior to the date the notice is sent, who would be directly affected by the requested certificate, including the preferred route or location, as applicable, and any known alternative route or location of the proposed facilities. For purposes of this notice, land is directly affected if a permanent easement or other permanent property interest would be obtained over all or any portion of the land or if the land contains a habitable structure that would be within three hundred (300) feet of the centerline of an electric transmission line.

2. Any letter sent by applicant as notice of the application shall be on its representative's letterhead or on the letterhead of the utility, and it shall clearly set forth–

A. The identity, address, and telephone number of the utility representative;

B. The identity of the utility attempting to acquire the certificate;

C. The general purpose of the proposed project;

D. The type of facility to be constructed; and

E. The contact information of the Public Service Commission and Office of the Public Counsel.

3. If twenty-five (25) or more persons in a county would be entitled to receive notice of the application, applicant shall hold at least one (1) public meeting in that county. The meeting shall be held in a building open to the public and sufficient in size to accommodate the number of persons in the county entitled to receive notice of the application. Additionally—

A. All persons entitled to notice of the application shall be afforded a reasonable amount of time to pose questions or to state their concerns;

B. To the extent reasonably practicable, the public meeting shall be held at a time that allows affected landowners an opportunity to attend; and

C. Notice of the public meeting shall be sent to any persons entitled to receive notice of the application.

4. If applicant, after filing proof of compliance, becomes aware of a person entitled to receive notice of the application to whom applicant did not send such notice, applicant shall, within twenty (20) days, provide notice to that person by certified mail, return receipt requested, containing all the required information. Applicant shall also file a supplemental proof of compliance regarding the additional notice.

(7) Provisions of this rule do not create any new requirements for or affect assets, improvements, rebuilds, or retrofits already in rate base as of the effective date of this rule. Provisions of this rule may be waived by the commission for good cause shown.

AUTHORITY: section 386.250, RSMo 2016. Original rule filed April 5, 2018, effective Nov. 30, 2018.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996.*

4 CSR 240-20.050 Individual Electric Meters—When Required

PURPOSE: This rule prescribes individual metering for new multiple occupancy buildings and new mobile home parks for all electric corporations under the jurisdiction of the Public Service Commission. This rule is aimed at compliance with Sections 113(b)(1) and 115(d) of Title I of the Public Utility Regulatory Policies Act of 1978 (PURPA), PL 95-617, 16 USC 2601.

PUBLISHER'S NOTE: The secretary of state has determined that the publication of the entire text of the material which is incorporated by reference as a portion of this rule would be unduly cumbersome or expensive. Therefore, the material which is so incorporated is on file with the agency who filed this *rule, and with the Office of the Secretary of State. Any interested person may view this material at either agency's headquarters or the same will be made available at the Office of the Secretary of State at a cost not to exceed actual cost of copy reproduction. The entire text of the rule is printed here. This note refers only to the incorporated by reference material.*

(1) For the purposes of this rule—

(A) A building is defined as a single structure, roofed and enclosed within exterior walls, built for permanent use, erected, framed of component structural parts and unified in its entirety both physically and in operation for residential or commercial occupancy;

(B) Commercial adjacent buildings are defined as buildings on a contiguous plot of land owned by one (1) person, which buildings are occupied and used by one (1) person for single type of commercial operation. A person for the purpose of this definition includes any type of business entity;

(C) A commercial unit is defined as that portion of a building or premises which by appearance, design or arrangement is normally used for commercial purposes, whether or not actually so used;

(D) Construction begins when the footings are poured;

(E) A mobile home park is defined as a contiguous parcel of land which is used for the accommodation of occupied mobile homes;

(F) A multiple-occupancy building is defined as a building or premises which is designed to house more than one (1) residential or commercial unit; and

(G) A residential unit is defined as one (1) or more rooms for the use of one (1) or more persons as a housekeeping unit with space for eating, living and sleeping, and permanent provisions for cooking and sanitation.

(2) Each residential and commercial unit in a multiple-occupancy building construction of which has begun after June 1, 1981 shall have installed a separate electric meter for each residential or commercial unit.

(3) Each mobile home unit in a mobile home park, construction of which has begun after June 1, 1981 shall have installed a separate electric meter for each mobile home unit.

(4) For the purposes of carrying out the provisions of sections (2) and (3), the following exceptions apply and separate metering will not be required:

(A) For transient multiple-occupancy buildings and transient mobile home parks—for example, hotels, motels, dormitories, rooming houses, hospitals, nursing homes, fraternities, sororities, campgrounds and mobile home parks which set aside, on a permanent basis, at least eighty percent (80%) of their mobile home pads or comparable space for use by travel trailers;

(B) Where commercial unit space is subject to alteration with change in tenants as evidenced by temporary versus permanent type of wall construction separating the commercial unit space—for example, space at a trade fair;

(C) For commercial adjacent buildings;

(D) For that portion of electricity used in central space heating, central hot water heating, central ventilating and central air-conditioning systems;

(E) For buildings or mobile home parks where alternative renewable energy resources are utilized in connection with central space heating, central hot water heating, central ventilating and central air-conditioning systems; or

(F) For all portions of electricity in commercial units in buildings with central space heating, ventilating and air-conditioning systems.

(5) Any person or entity affected by this rule may file an application with the commission seeking a variance from all or parts of this rule (4 CSR 240-20.050) and for good cause shown, variances may be granted as follows:

(A) The variance request shall be filed in writing and directed to the secretary of the commission;

(B) If the commission deems it in the public interest, a hearing may be held by the commission as in complaint hearings before the commission; and

(C) A variance committee consisting of two (2) members of the commission's utility division staff and a member of the commission's general counsel's office shall be established by the commission within thirty (30) days from September 28, 1981. The public counsel shall be an *ex officio* member of this committee.

1. The variance committee shall consider all variance applications filed by utilities and shall make a written recommendation of its findings to the commission for its approval.

2. Each applicant for a variance shall have ten (10) days from the date of the variance committee's findings to either accede or request a formal hearing before the commission.

3. If applicant accedes, the commission may adopt the variance committee's findings or set the matter for formal hearing upon the application of any interested person or upon the commission's own motion.

(6) The commission, in its discretion, may approve tariffs filed by an electric corporation which are more restrictive of master metering than the provisions of this rule.

AUTHORITY: section 386.250, RSMo Supp. 1991. Original rule filed March 13, 1980, effective Dec. 15, 1980. Emergency amendment filed May 13, 1981, effective May 31, 1981, expired Sept. 28, 1981. Amended: Filed May 13, 1981, effective Sept. 28, 1981.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991.*

4 CSR 240-20.060 Cogeneration

PURPOSE: This rule implements Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 with regard to small power production and cogeneration. The objective of Sections 201 and 210 of Public Utility Regulatory Policies Act is to provide a mechanism to set up a cogeneration program for Missouri for regulated utilities. Additional requirements regarding this subject matter are also found at 4 CSR 240-3.155.

(1) Definitions. Terms defined in the Public Utility Regulatory Policies Act of 1978 (PURPA) shall have the same meaning for purposes of this rule as they have under PURPA, unless further defined in this rule.

(A) Avoided costs means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, that utility would generate itself or purchase from another source.

(B) Back-up power means electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

(C) Interconnection costs means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent those costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

(D) Interruptible power means electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.

(E) Maintenance power means electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.

(F) Purchase means the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

(G) Qualifying facility means a cogeneration facility or a small power production facility which is a qualifying facility under Subpart B of Part 292 of the Federal Energy Regulatory Commission's (FERC) regulations.

(H) Rate means any price, rate, charge or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity or any rule or practice respecting any such rate, charge or classification and any contract pertaining to the sale or purchase of electric energy or capacity.

(I) Sale means the sale of electric energy or capacity or both by an electric utility to a qualifying facility.

(J) Supplementary power means electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.

(K) System emergency means a condition on a utility's system which is likely to result in imminent significant disruption of service to consumers or is imminently likely to endanger life or property.

(2) Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978.

(A) Applicability. This section applies to the regulation of sales and purchases between qualifying facilities and electric utilities.

(B) Negotiated Rates or Terms. Nothing in this section—

1. Limits the authority of any electric utility or any qualifying facility to agree to a rate for any purchase or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required by this rule; or

2. Affects the validity of any contract entered into between a qualifying facility and an electric utility for any purchase.

(C) Every regulated utility which provides retail electric service in this state shall enter into a contract for parallel generation service with any customer which is a qualifying facility, upon that customer's request, where that customer may connect a device to the utility's delivery and metering service to transmit electrical power produced by that customer's energy generating system into the utility's system.

1. The utility shall supply, install, own and maintain all necessary meters and associated equipment used for billing. The costs of any such meters and associated equipment which are beyond those required for service to a customer which is not a qualifying facility shall be borne by the customer. The utility may install and maintain, at its expense, load research metering for monitoring the customer's energy generation and usage.

2. The customer shall supply, install, operate and maintain, in good repair and without cost to the utility, the relays, locks and seals, breakers, automatic synchronizer, a disconnecting device and other control and protective devices required by the utility to operate the customer's generating system parallel to the utility's system. The customer also shall supply, without cost to the utility, a suitable location for meters and associated equipment used for billing, load research and disconnection.

3. The customer shall be required to reimburse the utility for the cost of any equipment or facilities required as a result of connecting the customer's generating system with the utility's system.

4. The customer shall notify the utility prior to the initial testing of the customer's generating system and the utility shall have the right to have a representative present during the testing.

5. Meters and associated equipment used for billing, load research and connection and disconnection shall be accessible at all times to utility personnel.

6. A manual disconnect switch for the qualifying facility must be provided by the customer which will be under the exclusive control of the utility dispatcher. This manual switch must have the capability to be locked out of service by the utility-authorized switchmen as a part of the utility's workman's protection assurance procedures. The customer must also provide an isolating device which the customer has access to and which will serve as a means of isolation for the customer's equipment during any qualifying facility maintenance activities, routine outages or emergencies. The utility shall give notice to the customer before a manual switch is locked or an isolating device used, if possible; and otherwise shall give notice as soon as practicable after locking or use.

(D) No customer's generating system or connecting device shall damage the utility's system or equipment or present an undue hazard to utility personnel.

(E) If harmonics, voltage fluctuations or other disruptive problems on the utility's system are directly attributable to the operation of the customer, these problems will be corrected at the customer's expense.

(F) Every contract shall provide fair compensation for the electrical power supplied to the utility by the customer. If the utility and the customer cannot agree to the terms and conditions of the contract, the Public Service Commission (PSC) shall establish the terms and conditions upon the request of the utility or the customer. Those terms and conditions will be established in accordance with Section 210 of the Public Utility Regulatory Policies Act of 1978 and the provisions of this rule.

(3) Electric Utility Obligations Under This Rule.

(A) Obligation to Purchase From Qualifying Facilities. Each electric utility shall purchase, in accordance with section (4), any energy and capacity which is made available from a qualifying facility—

1. Directly to the electric utility; or

2. Indirectly to the electric utility in accordance with subsection (3)(D) of this rule.

(B) Obligation to Sell to Qualifying Facilities. Each electric utility shall sell to any qualifying facility, in accordance with section (5) of this rule, any energy and capacity requested by the qualifying facility.

(C) Obligation to Interconnect.

1. Subject to paragraph (3)(C)2. of this rule, any electric utility shall make interconnections with any qualifying facility as may be necessary to accomplish purchases or sales under this rule. The obligation to pay for any interconnection costs shall be determined in accordance with section (6) of this rule.

2. No electric utility is required to interconnect with any qualifying facility if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under Part II of the Federal Power Act.

(D) Transmission to Other Electric Utilities. If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from a qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which energy or capacity is transmitted shall purchase energy or capacity under this subsection (3)(D) as if the qualifying facility were supplying energy or capacity directly to the electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to paragraph (4)(E)4. of this rule and shall not include any charges for transmission.

(E) Parallel Operation. Each electric utility shall offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with any applicable standards established in accordance with section (8) of this rule.

(4) Rates for Purchases.

(A) Rates for purchases shall be just and reasonable to the electric consumer of the electric utility and in the public interest and shall not discriminate against qualifying cogeneration and small power production facilities. Nothing in this rule requires any electric utility to pay more than the avoided costs for purchases.

(B) Relationship to Avoided Costs.

1. For purposes of this section, new capacity means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.

2. Subject to paragraph (4)(B)3. of this rule, a rate for purchases satisfies the requirements of subsection (4)(A) of this rule if the rate equals the avoided costs determined after consideration of the factors set forth in subsection (4)(E) of this rule.

3. A rate for purchases (other than from new capacity) may be less than the avoided cost if the PSC determines that a lower rate is consistent with subsection (4)(A) of this rule and is sufficient to encourage cogeneration and small power production.

4. Rates for purchases from new capacity shall be in accordance with paragraph (4)(B)2. of this rule, regardless of whether the electric utility making the purchases is simultaneously making sales to the qualifying facility.

5. In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for the purchases do not violate this paragraph if the rates for the purchases differ from avoided costs at the time of delivery.

(C) Standard Rates for Purchases.

1. There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of one hundred (100) kilowatts or less.

2. There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than one hundred (100) kilowatts.

3. The standard rates for purchases under this subsection shall be consistent with subsections (4)(A) and (E) of this rule, and may differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(D) Purchases as Available or Pursuant to a Legally Enforceable Obligation. Each qualifying facility shall have the option either—

1. To provide energy as the qualifying facility determines this energy to be available for the purchases, in which case the rates for the purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

2. To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for the purchases, at the option of the qualifying facility exercised prior to the beginning of the specified term, shall be based on either the avoided costs calculated at the time of delivery or the avoided costs calculated at the time the obligation is incurred.

(E) Factors Affecting Rates for Purchases. In determining avoided costs, the following factors, to the extent practicable, shall be taken into account:

1. The data provided pursuant to 4 CSR 240-3.155, including PSC review of any such data;

2. The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

A. The ability of the utility to dispatch the qualifying facility;

B. The expected or demonstrated reliability of the qualifying facility;

C. The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for noncompliance;

D. The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

E. The usefulness of energy and the capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

F. The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

G. The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities;

3. The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (4)(E)2. of this rule, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of oil use; and

4. The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

(F) Periods During Which Purchases not Required.

1. Any electric utility which gives notice pursuant to paragraph (4)(F)2. of this rule will not be required to purchase electric energy or capacity during any period which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make the purchases, but instead generated an equivalent amount of energy itself.

2. Any electric utility seeking to invoke paragraph (4)(F)1. of this rule must notify, in accordance with applicable state law or rule, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility.

3. Any electric utility which fails to comply with the provisions of paragraph (4)(F)2. of this rule will be required to pay the same rate for the purchase of energy or capacity as would be required had the period described in paragraph (4)(F)1. of this rule not occurred.

4. A claim by an electric utility that this period has occurred or will occur is subject to verification by the PSC as the PSC determines necessary or appropriate, either before or after the occurrence.

(5) Rates for Sales.

(A) Rates for sales shall be just and reasonable and in the public interest and shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility. Rates for sales which are based on accurate data and consistent system-wide costing principles shall not be considered to discriminate against any qualifying facility to the extent that those rates apply to the utility's other customers with similar load or other cost-related characteristics.

(B) Additional Services to be Provided to Qualifying Facilities.

1. Upon request of a qualifying facility, each electric utility shall provide supplementary power, back-up power, maintenance power and interruptible power.

2. The PSC may waive any requirement of paragraph (5)(B)1. of this rule if, after notice in the area served by the electric utility and after opportunity for public comment, the electric utility demonstrates and the PSC finds that compliance with that requirement will impair the electric utility's ability to render adequate service to its customers or place an undue burden on the electric utility.

(C) Rates for Sale of Back-Up and Maintenance Power. The rate for sales of back-up power or maintenance power—

1. Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously or during the system peak or both; and

2. Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

(6) Interconnection Costs.

(A) If the utility and the qualifying facility cannot reach agreement as to the amount or the manner of payment of the interconnection costs to be paid by the qualifying facility, the PSC, after hearing, shall assess against the qualifying facility those interconnection costs to be paid to the utility, on a nondiscriminatory basis with respect to other customers with similar load characteristics or shall determine the manner of payments of the interconnection costs, which may include reimbursement over a reasonable period of time, or both. In determining the terms of any reimbursement over a period of time, the commission shall provide for adequate carrying charges associated with the utility's investment and security to insure total reimbursement of the utility's incurred costs, if it deems necessary.

(7) System Emergencies.

(A) Qualifying Facility Obligation to Provide Power During System Emergencies. A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent provided by agreement between the qualifying facility and electric utility or ordered under section 202(c) of the Federal Power Act.

(B) Discontinuance of Purchases and Sales During System Emergencies. During any system emergency, an electric utility may discontinue purchases from a qualifying facility if those purchases would contribute to the emergency and sales to a qualifying facility, provided that discontinuance is on a nondiscriminatory basis.

(8) Standards for Operating Reliability. The PSC may establish reasonable standards to ensure system safety and reliability of interconnected operations. Those standards may be recommended by any electric utility, any qualifying facility or any other person. If the PSC establishes standards, it shall specify the need for the standards on the basis of system safety and reliability.

(9) Exemption to Qualifying Facilities From the Public Utility Holding Company Act and Certain State Law and Rules.

(A) Applicability. This section applies to qualifying cogeneration facilities and qualifying small power production facilities which have a power production capacity which does not exceed thirty (30) megawatts and to any qualifying small power production facility with a power production capacity over thirty (30) megawatts if that facility produces electric energy solely by the use of biomass as a primary energy source.

(B) A qualifying facility described in subsection (1)(A) shall not be considered to be an electric utility company as defined in section 2(a)(3) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(3).

(C) Any qualifying facility shall be exempted (except as otherwise provided) from Missouri PSC law or rule respecting the rates of electric utilities and the financial and organizational regulation of electric utilities. A qualifying facility may not be exempted from Missouri PSC law and rule implementing subpart C of PURPA.

AUTHORITY: sections 386.250 and 393.140, RSMo 2000. Original rule filed Oct. 14, 1980, effective May 15, 1981. Amended: Filed Aug. 16, 2002, effective April 30, 2003.*

**Original authority: 386.250, RSMo 1939, amended 1963,1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996 and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-20.065 Net Metering

PURPOSE: This rule implements the Net Metering and Easy Connection Act (section 386.890, RSMo Supp. 2008) and establishes standards for interconnection of qualified net metering units (generating capacity of one hundred kilowatts (100 kW) or less) with distribution systems of electric utilities.

(1) Definitions.

(A) Avoided fuel cost means avoided costs described in 4 CSR 240-20.060 used to calculate the electric utility's cogeneration rate filed in compliance with 4 CSR 240-3.155. The information used to calculate this rate is provided to the commission biennially and maintained for public inspection.

(B) Commission means the Public Service Commission of the state of Missouri.

(C) Customer-generator means the owner or operator of a qualified electric energy generation unit that meets all of the following criteria:

1. Is powered by a renewable energy resource;

2. Is an electrical generating system with a capacity of not more than one hundred kilowatts (100 kW);

3. Is located on premises that are owned, operated, leased, or otherwise controlled by the customer-generator;

4. Is interconnected and operates in parallel phase and synchronization with an electric utility and has been approved for interconnection by said electric utility;

5. Is intended primarily to offset part or all of the customer-generator's own electrical energy requirements;

6. Meets all applicable safety, performance, interconnection, and reliability standards established by the National Electrical Code, the National Electrical Safety Code, the Institute of Electrical and Electronics Engineers, Underwriters Laboratories, the Federal Energy Regulatory Commission, and any local governing authorities; and

7. Contains a mechanism that automatically disables the unit and interrupts the flow of electricity onto the electric utility's electrical lines whenever the flow of electricity to the customer-generator is interrupted.

(D) Distribution system means facilities for the distribution of electric energy to the ultimate consumer thereof.

(E) Electric utility means every electrical corporation as defined in section 386.020(15), RSMo 2000, subject to commission regulation pursuant to Chapter 393, RSMo.

(F) Net metering means using metering equipment sufficient to measure the difference between the electrical energy supplied to a customer-generator by an electric utility and the electrical energy supplied by the customer-generator to the electric utility over the applicable billing period.

(G) Operational means all of the major components of the on-site system have been purchased and installed on the customer-generator's premises and the production of rated net electrical generation has been measured by the electric utility. If a customer has satisfied all of the System Completion Requirements by June 30 of indicated years, but the electric utility is not able to complete all of the company's steps needed to establish an Operational Date on or before June 30, the rebate rate will be determined as though the Operational Date was June 30. If it is subsequently determined that the customer of the system did not satisfy all Completion Requirements required of the customer on or before June 30, the rebate rate will be determined based on the Operational Date.

(H) REC means Renewable Energy Credit or Renewable Energy Certificate which is tradable, and represents that one (1) megawatt-hour of electricity has been generated from a renewable energy resource.

(I) Renewable energy resources means, when used to produce electrical energy, the following: wind, solar thermal sources, hydroelectric sources, photovoltaic cells and panels, fuel cells using hydrogen produced by one (1) of the above-named electrical energy sources, and other sources of energy that become available after August 28, 2007, and are certified as renewable by the Missouri Department of Natural Resources or the Missouri Department of Economic Development's Division of Energy.

(J) Staff means the staff of the Public Service Commission of the state of Missouri.

(2) Applicability. This rule applies to electric utilities and customer-generators.

(3) REC Ownership. RECs associated with customer-generated net-metered renewable energy resources shall be owned by the customer-generator; however, as a condition of receiving solar rebates for systems operational after August 28, 2013, customers transfer to the electric utility all right, title, and interest in and to the RECs associated with the new or expanded solar electric system that qualified the customer for the solar rebate for a period of ten (10) years from the date the electric utility confirmed the solar electric system was installed and operational.

(4) Electric Utility Obligations.

(A) Net metering shall be available to customer-generators on a first-come, first-served basis until the total rated generating capacity of net metering systems equals five percent (5%) of the electric utility's Missouri jurisdictional single-hour peak load during the previous year. The commission may increase the total rated generating capacity of net metering systems to an amount above five percent (5%). However, in a given calendar year, no electric utility shall be required to approve any application for interconnection if the total rated generating capacity of all applications for interconnection already approved to date by said electric utility in said calendar year equals or exceeds one percent (1%) of said electric utility's single-hour peak load for the previous calendar year.

(B) A tariff or contract shall be offered that is identical in electrical energy rates, rate structure, and monthly charges to the contract or tariff that the customer would be assigned if the customer were not an eligible customer-generator but shall not charge the customer-generator any additional standby, capacity, interconnection, or other fee or charge that would not otherwise be charged if the customer were not an eligible customer-generator.

(C) The availability of the net metering program shall be disclosed annually to each of its customers with the method and manner of disclosure being at the discretion of the electric utility.

(D) For any cause of action relating to any damages to property or person caused by the generation unit of a customer-generator or the interconnection thereof, the electric utility shall have no liability absent clear and convincing evidence of fault on the part of the supplier.

(E) Any costs incurred under this rule by an electric utility not recovered directly from the customer-generator, as identified in (6)(F), shall be recoverable in that electric utility's rate structure.

(F) No fee, charge, or other requirement not specifically identified in this rule shall be imposed unless the fee, charge, or other requirement would apply to similarly situated customers who are not customer-generators.

(5) Customer-Generator Liability Insurance Obligation.

(A) Customer-generator systems greater than ten kilowatts (10 kW) shall carry no less than one hundred thousand dollars ($100,000) of liability insurance that provides for coverage of all risk of liability for personal injuries (including death) and damage to property arising out of or caused by the operation of the net metering unit. Insurance may be in the form of an existing policy or an endorsement on an existing policy.

(B) Customer-generator systems ten kilowatts (10 kW) or less shall not be required to carry liability insurance.

(6) Qualified Electric Customer-Generator Obligations.

(A) Each qualified electric energy generation unit used by a customer-generator shall meet all applicable safety, performance, interconnection, and reliability standards established by any local code authorities, the National Electrical Code, the National Electrical Safety Code, the Institute of Electrical and Electronics Engineers (IEEE), and Underwriters Laboratories (UL) for distributed generation; including, but not limited to, IEEE 1547, UL 1703, and UL 1741.

(B) The electric utility may require that a customer-generator's system contain a switch, circuit breaker, fuse, or other easily accessible device or feature located in immediate proximity to the customer-generator's metering equipment that would allow an electric utility worker the ability to manually and instantly disconnect the unit from the electric utility's distribution system.

(C) No customer shall connect or operate an electric generation unit in parallel phase and synchronization with any electric utility without written approval by said electric utility that all of the requirements under subsection (9)(C) of this rule have been met. For a customer-generator who violates this provision, an electric utility may immediately and without notice disconnect the electric facilities of said customer-generator and terminate said customer-generator's electric service.

(D) A customer-generator's facility shall be equipped with sufficient metering equipment that can measure the net amount of electrical energy produced and consumed by the customer-generator. If the customer-generator's existing meter equipment does not meet these requirements or if it is necessary for the electric utility to install additional distribution equipment to accommodate the customer-generator's facility, the customer-generator shall reimburse the electric utility for the costs to purchase and install the necessary additional equipment. At the request of the customer-generator, such costs may be initially paid for by the electric utility, and any amount up to the total costs and a reasonable interest charge may be recovered from the customer-generator over the course of up to twelve (12) billing cycles. Any subsequent meter testing, maintenance, or meter equipment change necessitated by the customer-generator shall be paid for by the customer-generator.

(E) Each customer-generator shall, at least once every year, conduct a test to confirm that the net metering unit automatically ceases to energize the output (interconnection equipment output voltage goes to zero (0)) within two (2) seconds of being disconnected from the electric utility's system. Disconnecting the net metering unit from the electric utility's electric system at the visible disconnect switch and measuring the time required for the unit to cease to energize the output shall satisfy this test.

(F) The customer-generator shall maintain a record of the results of these tests and, upon request, shall provide a copy of the test results to the electric utility.

1. If the customer-generator is unable to provide a copy of the test results upon

request, the electric utility shall notify the customer-generator by mail that the customer-generator has thirty (30) days from the date the customer-generator receives the request to provide the results of a test to the electric utility.

2. If the customer-generator's equipment ever fails this test, the customer-generator shall immediately disconnect the net metering unit.

3. If the customer-generator does not provide the results of a test to the electric utility within thirty (30) days of receiving a request from the electric utility or the results of the test provided to the electric utility show that the unit is not functioning correctly, the electric utility may immediately disconnect the net metering unit.

4. The net metering unit shall not be reconnected to the electric utility's electrical system by the customer-generator until the net metering unit is repaired and operating in a normal and safe manner.

(7) Determination of Net Electrical Energy. Net electrical energy measurement shall be calculated in the following manner:

(A) For a customer-generator, an electric utility shall measure the net electrical energy produced or consumed during the billing period in accordance with normal metering practices for customers in the same rate class, either by employing a single, bidirectional meter that measures the amount of electrical energy produced and consumed, or by employing multiple meters that separately measure the customer-generator's consumption and production of electricity;

(B) If the electricity supplied by the electric utility exceeds the electricity generated by the customer-generator during a billing period, the customer-generator shall be billed for the net electricity supplied by the supplier in accordance with normal practices for customers in the same rate class;

(C) If the electricity generated by the customer-generator exceeds the electricity supplied by the electric utility during a billing period, the customer-generator shall be billed for the appropriate customer charges for that billing period in accordance with section (4) of this rule and shall be credited with the product of the excess kilowatt-hours generated during the billing period and the rate identified in the electric utility's net metering tariff sheet filed with the commission in the following billing period. This rate is calculated from the electric utility's avoided fuel cost; and

(D) Any credits granted by this subsection shall expire without any compensation at the earlier of either twelve (12) months after their issuance, or when the customer-generator disconnects service or terminates the net metering relationship with the electric utility.

(8) Net Metering Rates. Each electric utility shall file on or before January 15 of each odd-numbered year for the commission's approval in the electric utility's tariff, a rate schedule with a net metering rate that is the same rate as the utility's cogeneration rate. The electric utility's cogeneration rate is filed for the commission's approval in the electric utility's tariff on or before January 15 of every odd-numbered year as required in 4 CSR 240-3.155 Requirements for Electric Utility Cogeneration Tariff Filings section (4). The cogeneration rate is stated in dollars per kilowatt-hour or cents per kilowatt-hour on the cogeneration rate tariff sheet and, likewise, the net metering rate shall be stated in dollars per kilowatt-hour or cents per kilowatt-hour on the net metering rate tariff sheet.

(9) Interconnection Application/Agreement.

(A) Each customer-generator and electric utility shall enter into the interconnection agreement included herein.

1. If the electric utility so chooses, it may allow customers to apply electronically through the electric utility's website.

A. The interconnection application/agreement on the electric utility's website shall substantially be the same as the interconnection application/agreement included herein.

B. The electronic application/agreement shall be submitted to the manager of the Energy Unit of the staff for review by staff prior to being placed on the electric utility's website.

C. The electric utility shall notify the manager of the Energy Unit of the staff of any revisions to the electronic application/agreement on its website within ten (10) working days of when the electronic agreement is revised.

(B) References to a solar rebate in the interconnection application/agreement included herein are not required for electric utilities that are not required to offer solar rebates.

(C) Applications by a customer-generator for interconnection of a qualified electric energy generation unit to the distribution system shall be accompanied by the plan for the customer-generator's electrical generating system including, but not limited to, a wiring diagram and specifications for the generating unit, and shall be reviewed and responded to by the electric utility within thirty (30) days of receipt for systems ten kilowatts (10 kW) or less and within ninety (90) days of receipt for all other systems. Prior to the interconnection of the qualified generation unit to the electric utility's system, the customer-generator will furnish the electric utility a certification from a qualified professional electrician or engineer that the installation meets the requirements of subsections (6)(A) and (6)(B). If the application for interconnection is approved by the electric utility and the customer-generator does not complete the interconnection within one (1) year after receipt of notice of the approval, the approval shall expire and the customer-generator shall be responsible for filing a new application.

(D) Upon the change in ownership of a qualified electric energy generation unit, the new customer-generator shall be responsible for filing a new application/agreement.

(10) Electric Utility Reporting Requirements. Each year prior to April 15, every electric utility shall—

(A) Submit an annual net metering report to the commission and make said report available to a consumer of the electric utility upon request, including the following information for the previous calendar year:

1. The total number of customer-generator facilities connected to its distribution system;

2. The total estimated generating capacity of customer-generators that are connected to its distribution system; and

3. The total estimated net kilowatt-hours received from customer-generators; and

(B) Supply to the manager of the energy department of the commission a copy of the standard information regarding net metering and interconnection requirements provided to customers or posted on the electric utility's website.

INTERCONNECTION APPLICATION/AGREEMENT FOR NET METERING SYSTEMS WITH CAPACITY OF ONE HUNDRED KILOWATTS (100 kW) OR LESS

[Utility Name and Mailing Address]

For Customers Applying for Interconnection:

If you are interested in applying for interconnection to [Utility Name]'s electrical system, you should first contact [Utility Name] and ask for information related to interconnection of parallel generation equipment to [Utility Name]'s system and you should understand this information before proceeding with this Application.

If you wish to apply for interconnection to [Utility Name]'s electrical system, please complete sections A, B, C, and D, and attach the plans and specifications, including, but not limited to, describing the net metering, parallel generation, and interconnection facilities (hereinafter collectively referred to as the "Customer-Generator's System") and submit them to [Utility Name] at the address above. The company will provide notice of approval or denial within thirty (30) days of receipt by [Utility Name] for Customer-Generators of ten kilowatts (10 kW) or less and within ninety (90) days of receipt by [Utility Name] for Customer-Generators of greater than ten kilowatts (10 kW). If this Application is denied, you will be provided with the reason(s) for the denial. If this Application is approved and signed by both you and [Utility Name], it shall become a binding contract and shall govern your relationship with [Utility Name].

For Customers Who Have Received Approval of Customer-Generator System Plans and Specifications:

After receiving approval of your Application, it will be necessary to construct the Customer-Generator System in compliance with the plans and specifications described in the Application, complete sections E and F of this Application, and forward this Application to [Utility Name] for review and completion of section G at the address above. Prior to the interconnection of the qualified generation unit to [Utility Name] system, the Customer-Generator will furnish [Utility Name] a certification from a qualified professional electrician or engineer that the installation meets the plans and specification described in the application. If a local Authority Having Jurisdiction (AHJ) requires permits or certifications for construction or operation of the qualified generation unit, a customer generator must show the permit number and approval certification to the [Utility Name] prior to interconnection. If the application for interconnection is approved by [Utility Name] and the Customer-Generator does not complete the interconnection within one (1) year after receipt of notice of the approval, the approval shall expire and the Customer-Generator shall be responsible for filing a new application.

Within 21 days of when the customer-generator completes submission of all required post construction documentation, including sections E&F, other supporting documentation and local AHJ inspection approval (if applicable) to the electric utility, the electric utility will make any inspection of the customer-generators interconnection equipment or system it deems necessary and notify the customer-generator:

1. That the net meter has been set and parallel operation by customer-generator is permitted; or

2. That the inspection identified no deficiencies and the net meter installation is pending; or
3. That the inspection identified no deficiencies and the timeframe anticipated for the electric utility to complete all required system or service upgrades and install the meter; or
4. Of all deficiencies identified during the inspection that need to be corrected by the customer-generator before parallel operation will be permitted; or
5. Of any other issue(s), requirement(s), or condition(s) impacting the installation of the net meter or the parallel operation of the system.

For Customers Who Are Installing Solar Systems:

Customer-Generators who are Missouri electric utility retail account holders will receive a solar rebate, if available, based on the capacity stated in the application, or the installed capacity of the Customer-Generator System if it is lower, if the following requirements are met:

a. The [Utility Name] must have confirmed the Customer-Generator's System is operational; and
b. Sections H and I of this Application must be completed.

The amount of the rebate will be based on the system capacity measured in direct current. The rebate will be based on the schedule below up to a maximum of 25,000 watts (25kW).

$2.00 per watt for systems operational on or before June 30, 2014;
$1.50 per watt for systems operational between July 1, 2014 and June 30, 2015;
$1.00 per watt for systems operational between July 1, 2015 and June 30, 2016;
$0.50 per watt for systems operational between July 1, 2016 and June 30, 2019;
$0.25 per watt for systems operational between July 1, 2019 and June 30, 2020;
$0.00 per watt for systems operational after June 30, 2020.

For Customers Who Are Assuming Ownership or Operational Control of an Existing Customer-Generator System:

If no changes are being made to the existing Customer-Generator System, complete sections A, D, and F of this Application/Agreement and forward to [Utility Name] at the address above. [Utility Name] will review the new Application/Agreement and shall approve such, within fifteen (15) days of receipt by [Utility Name] if the new Customer-Generator has satisfactorily completed Application/Agreement, and no changes are being proposed to the existing Customer-Generator System. There are no fees or charges for the Customer-Generator who is assuming ownership or operational control of an existing Customer-Generator System if no modifications are being proposed to that system.

A. Customer-Generator's Information
Name on [Utility Name] Electric Account:
____
Service/Street Address: ________________________________

City: ______________________________ State: ________ Zip Code: ________

Mailing Address (if different from above):
____
City: _______________________________ State: ________ Zip Code: _______

E-mail address (if available):
____

Electric Account Holder Contact Person:
____

Daytime Phone: _______________ Fax: _____________
Email: ___________________

Emergency Contact
Phone:____
[Utility Name] Account No. (from Utility Bill):
____
If account has multiple meters, provide the meter number to which generation will be connected: _______

[Utility Name] Account No. (from Utility Bill): [Shall be inserted at the top of each page.]

B. Customer-Generator's System Information
Manufacturer Name Plate Power Rating: ____________ kW AC or DC (circle one)
[Voltage: ________ Volts]
System Type: __Wind __Fuel Cell __Solar Thermal __Photovoltaic __Hydroelectric __Other (describe)
____
____
Inverter/Interconnection Equipment Manufacturer:
____
Inverter/Interconnection Equipment Model No.:
____
Outdoor Manual/Utility Accessible & Lockable Disconnect Switch Distance from Meter:
____
Certify that the disconnect switch will be located adjacent to the Customer-Generator's electric service meter or explain where and why an alternative location of disconnect switch is being requested:
____
____

Existing Electrical Service Capacity: ______ Amperes Voltage: ______ Volts
Service Character: __ Single Phase __ Three Phase
Total capacity of existing Customer-Generator System (if applicable):______kW

System Plans, Specifications, and Wiring Diagram must be attached for a valid application.

C. Installation Information/Hardware and Installation Compliance
Company Installing System: _______________________
Contact Person of Company Installing System: ____________________ Phone Number:_______________
Contractor's License No. (if applicable):
____
Approximate Installation Date:
____
Mailing Address:
____
City: ____ State: _________
Zip Code: _________
Daytime Phone: ___________________ Fax: _______________
Email: ____________________________
Person or Agency Who Will Inspect/Certify Installation:
____
The Customer-Generator's proposed System hardware complies with all applicable National Electrical Safety Code (NESC), National Electrical Code (NEC), Institute of Electrical and Electronics Engineers (IEEE), and Underwriters Laboratories (UL) requirements for electrical equipment and their installation. As applicable to system type, these requirements include, but are not limited to, UL 1703, UL 1741 and IEEE 1547. The proposed installation complies with all applicable local electrical codes and all reasonable safety requirements of [Utility Name]. The proposed system has a lockable, visible AC disconnect device, accessible at all times to [Utility Name] personnel and switch is located adjacent to the Customer-Generator's electric service meter (except in cases where the Company has approved an alternate location). The system is only required to include one lockable, visible disconnect device, accessible to [Utility Name]. If the interconnection equipment is equipped with a visible, lockable, and accessible disconnect, no redundant device is needed to meet this requirement. The Customer-Generator's proposed system has functioning controls to prevent voltage flicker, DC injection, overvoltage, undervoltage, overfrequency, underfrequency, and overcurrent, and to provide for system synchronization to [Utility Name]'s electrical system. The proposed system does have an anti-islanding function that prevents the generator from continuing to supply power when [Utility Name]'s electric system is not energized or operating normally. If the proposed system is designed to provide uninterruptible power to critical loads, either through energy storage or back-up generation, the proposed system includes a parallel blocking scheme for this backup source that prevents any backflow of power to [Utility Name]'s electrical system when the electrical system is not energized or not operating normally.

Signed (Installer): Printed Name____
Signature:____
Date:_____________________

D. Additional Terms and Conditions

In addition to abiding by [Utility Name]'s other applicable rules and regulations, the Customer-Generator understands and agrees to the following specific terms and conditions:

1) Operation/Disconnection

If it appears to [Utility Name], at any time, in the reasonable exercise of its judgment, that operation of the Customer-Generator's System is adversely affecting safety, power quality, or reliability of [Utility Name]'s electrical system, [Utility Name] may immediately disconnect and lock-out the Customer-Generator's System from [Utility Name]'s electrical system. The Customer-Generator shall permit [Utility Name]'s employees and inspectors reasonable access to inspect, test, and examine the Customer-Generator's System.

2) Liability

Liability insurance is not required for Customer-Generators of ten kilowatts (10 kW) or less. For generators greater that ten kilowatts (10 kW), the Customer-Generator agrees to carry no less than one hundred thousand dollars ($100,000) of liability insurance that provides for coverage of all risk of liability for personal injuries (including death) and damage to property arising out of or caused by the operation of the Customer-Generator's System. Insurance may be in the form of an existing policy or an endorsement on an existing policy. Customer-Generators, including those whose systems are ten kilowatts (10 kW) or less, may have legal liabilities not covered under their existing insurance policy in the event the Customer-Generator's negligence or other wrongful conduct causes personal injury (including death), damage to property, or other actions and claims.

3) Metering and Distribution Costs

A Customer-Generator's facility shall be equipped with sufficient metering equipment that can measure the net amount of electrical energy produced or consumed by the Customer-Generator. If the Customer-Generator's existing meter equipment does not meet these requirements or if it is necessary for [Utility Name] to install additional distribution equipment to accommodate the Customer-Generator's facility, the Customer-Generator shall reimburse [Utility Name] for the costs to purchase and install the necessary additional equipment. At the request of the Customer-Generator, such costs may be initially paid for by [Utility Name], and any amount up to the total costs and a reasonable interest charge may be recovered from the Customer-Generator over the course of up to twelve (12) billing cycles. Any subsequent meter testing, maintenance, or meter equipment change necessitated by the Customer-Generator shall be paid for by the Customer-Generator.

4) Ownership of Renewable Energy Credits or Renewable Energy Certificates (RECs)

RECs created through the generation of electricity by the Customer-Owner are owned by the Customer-Generator; however, if the Customer-Generator receives a solar rebate, the Customer-Generator transfers to the [Utility Name] all right, title, and interest in and to the RECs associated with the new or expanded solar electric system that qualified the Customer-Generator for the solar rebate for a period of ten (10) years from the date the electric utility confirms the solar electric system is installed and operational.

5) Energy Pricing and Billing

The net electric energy delivered to the Customer-Generator shall be billed in accordance with the Utility's Applicable Rate Schedules [Utility's Applicable Rate Schedules]. The value of the net electric energy delivered by the Customer-Generator to [Utility Name] shall be credited in accordance with the net metering rate schedule(s) [Utility's Applicable Rate Schedules]. The Customer-Generator shall be responsible for all other bill components charged to similarly situated customers.

Net electrical energy measurement shall be calculated in the following manner:

(a) For a Customer-Generator, a retail electric supplier shall measure the net electrical energy produced or consumed during the billing period in accordance with normal metering practices for customers in the same rate class, either by employing a single, bidirectional meter that measures the amount of electrical energy produced and consumed, or by employing multiple meters that separately measure the Customer-Generator's consumption and production of electricity;

(b) If the electricity supplied by the supplier exceeds the electricity generated by the Customer-Generator during a billing period, the Customer-Generator shall be billed for the net electricity supplied by the supplier in accordance with normal practices for customers in the same rate class;

(c) If the electricity generated by the Customer-Generator exceeds the electricity supplied by the supplier during a billing period, the Customer-Generator shall be billed for the appropriate customer charges as specified by the applicable Customer-Generator rate schedule for that billing period and shall be credited an amount for the excess kilowatt-hours generated during the billing period at the net metering rate identified in [Utility Name]'s tariff filed at the Public Service Commission, with this credit applied to the following billing period; and

(d) Any credits granted by this subsection shall expire without any compensation at the earlier of either twelve (12) months after their issuance, or when the Customer-Generator disconnects service or terminates the net metering relationship with the supplier.

6) Terms and Termination Rights

This Agreement becomes effective when signed by both the Customer-Generator and [Utility Name], and shall continue in effect until terminated. After fulfillment of any applicable initial tariff or rate schedule term, the Customer-Generator may terminate this Agreement at any time by giving [Utility Name] at least thirty (30) days prior written notice. In such event, the Customer-Generator shall, no later than the date of termination of Agreement, completely disconnect the Customer-Generator's System from parallel operation with [Utility Name]'s system. Either party may terminate this Agreement by giving the other party at least thirty (30) days prior written notice that the other party is in default of any of the terms and conditions of this Agreement, so long as the notice specifies the basis for termination, and there is an opportunity to cure the default. This Agreement may also be terminated at any time by mutual agreement of the Customer-Generator and [Utility Name]. This agreement may also be terminated, by approval of the commission, if there is a change in statute that is determined to be applicable to this contract and necessitates its termination.

7) Transfer of Ownership

If operational control of the Customer-Generator's System transfers to any other party than the Customer-Generator, a new Application/Agreement must be completed by the person or persons taking over operational control of the existing Customer-Generator System. [Utility Name] shall be notified no less than thirty (30) days before the Customer-Generator anticipates transfer of operational control of the Customer-Generator's System. The person or persons taking over operational control of Customer-Generator's System must file a new Application/Agreement, and must receive authorization from [Utility Name], before the existing Customer-Generator System can remain interconnected with [Utility Name]'s electrical system. The new Application/Agreement will only need to be completed to the extent necessary to affirm that the new person or persons having operational control of the existing Customer-Generator System completely understand the provisions of this Application/Agreement and agree to them. If no changes are being made to the Customer-Generator's System, completing sections A, D, and F of this Application/Agreement will satisfy this requirement. If no changes are being proposed to the Customer-Generator System, [Utility Name] will assess no charges or fees for this transfer. [Utility Name] will review the new Application/Agreement and shall approve such, within fifteen (15) days if the new Customer-Generator has satisfactorily completed the Application/Agreement, and no changes are being proposed to the existing Customer-Generator System. [Utility Name] will then complete section G and forward a copy of the completed Application/Agreement back to the new Customer-Generator, thereby notifying the new Customer-Generator that the new Customer-Generator is authorized to operate the existing Customer-Generator System in parallel with [Utility Name]'s electrical system. If any changes are planned to be made to the existing Customer-Generator System that in any way may degrade or significantly alter that System's output characteristics, then the Customer-Generator shall submit to [Utility Name] a new Application/Agreement for the entire Customer-Generator System and all portions of the Application/Agreement must be completed.

8) Dispute Resolution

If any disagreements between the Customer-Generator and [Utility Name] arise that cannot be resolved through normal negotiations between them, the disagreements may be brought to the Missouri Public Service Commission by either party, through an informal or formal complaint. Procedures for filing and processing these complaints are described in 4 CSR 240-2.070. The complaint procedures described in 4 CSR 240-2.070

apply only to retail electric power suppliers to the extent that they are regulated by the Missouri Public Service Commission.

9) Testing Requirement

IEEE 1547 requires periodic testing of all interconnection related protective functions. The Customer-Generator must, at least once every year, conduct a test to confirm that the Customer-Generator's net metering unit automatically ceases to energize the output (interconnection equipment output voltage goes to zero) within two (2) seconds of being disconnected from [Utility Name]'s electrical system. Disconnecting the net metering unit from [Utility Name]'s electrical system at the visible disconnect switch and measuring the time required for the unit to cease to energize the output shall satisfy this test. The Customer-Generator shall maintain a record of the results of these tests and, upon request by [Utility Name], shall provide a copy of the test results to [Utility Name]. If the Customer-Generator is unable to provide a copy of the test results upon request, [Utility Name] shall notify the Customer-Generator by mail that Customer-Generator has thirty (30) days from the date the Customer-Generator receives the request to provide to [Utility Name], the results of a test. If the Customer-Generator's equipment ever fails this test, the Customer-Generator shall immediately disconnect the Customer-Generator's System from [Utility Name]'s system. If the Customer-Generator does not provide results of a test to [Utility Name] within thirty (30) days of receiving a request from [Utility Name] or the results of the test provided to [Utility Name] show that the Customer-Generator's net metering unit is not functioning correctly, [Utility Name] may immediately disconnect the Customer-Generator's System from [Utility Name]'s system. The Customer-Generator's System shall not be reconnected to [Utility Name]'s electrical system by the Customer-Generator until the Customer-Generator's System is repaired and operating in a normal and safe manner.

I have read, understand, and accept the provisions of section D, subsections 1 through 9 of this Application/Agreement.

Signed (Customer-Generator): Printed Name__________________________________
Signature:____
Date: _______________
Must be signature of [Utility Name] account holder (customer)

E. Electrical Inspection
If a local Authority Having Jurisdiction (AHJ) governs permitting/inspection of project:
Authority Having Jurisdiction (AHJ):
____
Permit Number: ____

Applicable to all installations:
The Customer-Generator System referenced above satisfies all requirements noted in section C.
Inspector Name
(print):____

Inspector Certification: Licensed Engineer in Missouri ___ Licensed Electrician in Missouri ___
License
No.____

Signed (Inspector):
____
Date: ________________

F. Customer-Generator Acknowledgement

I am aware of the Customer-Generator System installed on my premises and I have been given warranty information and/or an operational manual for that system. Also, I have been provided with a copy of [Utility Name]'s parallel generation tariff or rate schedule (as applicable) and interconnection requirements. I am familiar with the operation of the Customer-Generator System.

I agree to abide by the terms of this Application/Agreement and I agree to operate and maintain the Customer-Generator System in accordance with the manufacturer's recommended practices as well as [Utility Name]'s interconnection standards. If, at any time and for any reason, I believe that the Customer-Generator System is operating in an unusual manner that may result in any disturbances on [Utility Name]'s electrical system, I shall disconnect the Customer-Generator System and not reconnect it to [Utility Name]'s electrical system until the Customer-Generator System is operating normally after repair or inspection. Further, I agree to notify [Utility Name] no less than thirty (30) days prior to modification of the components or design of the Customer-Generator System that in any way may degrade or significantly alter that system's output characteristics. I acknowledge that any such modifications will require submission of a new Application/Agreement to [Utility Name].

I agree not to operate the Customer-Generator System in parallel with [Utility Name]'s electrical system until this Application/Agreement has been approved by [Utility Name].

System Installation Date: __________________

Printed name (Customer-Generator):
____

Signed (Customer-Generator): ___________________________________
Date:_____________

G. Utility Application/Agreement Approval (*completed by* [Utility Name])

[Utility Name] does not, by approval of this Application/Agreement, assume any responsibility or liability for damage to property or physical injury to persons due to malfunction of the Customer-Generator's System or the Customer-Generator's negligence.

This Application is approved by [Utility Name] on this _____day of _____________(month), _____(year).

[Utility Name] Representative Name (print):
____
Signed [Utility Name] Representative:
____

H. Solar Rebate (For Solar Installations only)
Solar Module Manufacturer:__________________ Inverter Rating:
___________________kW
Solar Module Model No.:____________________ Number of Modules/Panel:
____
Module rating: _______________DC Watts System rating (sum of solar panels):____kW
Module Warranty: _____ years (circle on spec sheet)
Inverter Warranty: _____ years (circle on spec sheet)
Location of modules: ____Roof ___Ground Installation type: ____ Fixed ___Ballast

Solar system must be permanently installed on the applicant's premises for a valid application

Required documents to receive solar rebate to be attached OR provided before [Utility Name] authorizes the rebate payment:

Copies of detail receipts/invoices with purchase date circled
Copies of detail spec sheets on each component
Copies of proof of warranty sheet (minimum of 10 year warranty)
Photo(s) of completed system
Completed Taxpayer Information Form

I. Solar Rebate Declaration (For Solar Installations only)

I understand that the complete terms and conditions of the solar rebate program are included in [Utility Name] [solar rebate tariff name].

I understand that this program has a limited budget, and that application will be accepted on a first-come, first-served basis, while funds are available. It is possible that I may be notified I have been placed on a waiting list for the next year's rebate program if funds run out for the current year. This program may be modified or discontinued at any time without notice from [Utility Name].

I understand that the solar system must be permanently installed and remain in place on premises for a minimum of 10 years and the system shall be situated in a location where a minimum of eighty-five percent (85%) of the solar resource is available to the solar system.

I understand the equipment must be new when installed, commercially available, and carry a minimum 10 year warranty.

I understand a rebate may be available from [Utility Name] in the amount of**:**

$2.00 per watt for systems operational on or before June 30, 2014;
$1.50 per watt for systems operational between July 1, 2014 and June 30, 2015;
$1.00 per watt for systems operational between July 1, 2015 and June 30, 2016;
$0.50 per watt for systems operational between July 1, 2016 and June 30, 2019;
$0.25 per watt for systems operational between July 1, 2019 and June 30, 2020;

$0.00 per watt for systems operational after June 30, 2020.

I understand an electric utility may, through its tariff, require applications for solar rebates to be submitted up to one hundred eighty-two (182) days prior to the applicable June 30 operational date for the solar rebate.

I understand that a maximum of 25 kilowatts of new or expanded system capacity will be eligible for a rebate.

I understand the DC wattage rating provided by the original manufacturer and as noted in section H will be used to determine rebate amount.

I understand I may receive an IRS Form related to my rebate amount. (Please consult your tax advisor with any questions.)

I understand that as a condition of receiving a solar rebate, I am transferring to [Utility Name] all right, title, and interest in and to the solar renewable energy credits (SRECs) associated with the new or expanded system for a period of ten (10) years from the date [Utility Name] confirmed that the system was installed and operational, and during this period, I may not claim credit for the SRECs under any environmental program or transfer or sell the SRECs to any other party.

The undersigned warrants, certifies, and represents that the information provided in this form is true and correct to the best of my knowledge; and the installation meets all Missouri Net Metering and Solar Electric Rebate program requirements.

______________________________	______________________________
Applicant's Signature	Installer's Signature
______________________________	______________________________
Print Solar Rebate Applicant's Name	Print Installer's Name

AUTHORITY: section 386.250, RSMo 2000, and section 386.890.9., RSMo Supp. 2013. Original rule filed March 11, 2003, effective Aug. 30, 2003. Amended: Filed June 17, 2008, effective Feb. 28, 2009. Amended: Filed Feb. 20, 2009, effective Oct. 30, 2009. Amended: Filed Jan. 26, 2012, effective Aug. 30, 2012. Amended: Filed March 25, 2015, effective Nov. 30, 2015.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996 and 386.890, RSMo 2007.*

4 CSR 240-20.070 Decommissioning Trust Funds

PURPOSE: This rule is promulgated pursuant to section 393.292, RSMo to—1) govern the review and authorization of changes to the rates and charges contained in the tariff(s) of an electric corporation as a result of a change in the level or annual accrual of funding necessary for its nuclear power plant decommissioning trust fund, 2) govern the procedure for the submission, examination, hearing, and approval for the tariff changes, and 3) ensure that the amounts collected from ratepayers and paid into the trust funds will be neither greater nor lesser than the amounts necessary to carry out the purposes of the trust. Additional requirements pertaining to this subject matter are also found at 4 CSR 240-3.185.

(1) As used in this rule, decommissioning means those activities undertaken in connection with a nuclear generating unit's retirement from service to ensure that the final removal, disposal, entombment, or other disposition of the unit and of any radioactive components and materials associated with the unit, are accomplished in compliance with all applicable laws, and to ensure that the final disposition does not pose any undue threat to the public health and safety. Decommissioning includes the removal and disposal of the structures, systems, and components of a nuclear generating unit at the time of decommissioning.

(2) As used in this rule, decommissioning costs means all reasonable costs and expenses incurred in connection with decommissioning, including all expenses to be incurred in connection with the preparation for decommissioning, including, but not limited to, engineering and other planning expenses; and to be incurred after the actual decommissioning occurs, including, but not limited to, physical security and radiation monitoring expenses, less proceeds of insurance, salvage or resale of machinery, construction equipment, or apparatus the cost of which was charged as a decommissioning expense.

(3) As used in this rule, utility(ies) means all electrical corporations subject to the jurisdiction of the Missouri Public Service Commission (commission) that own, in whole or in part, or operate nuclear generating units in Missouri or elsewhere and that have costs of these units reflected in the rates charged to Missouri ratepayers.

(4) Every three (3) years, utilities with decommissioning trust funds shall perform and file with the commission cost studies detailing the utilities' latest cost estimates for decommissioning their nuclear generating unit(s) along with the funding levels necessary to defray these decommissioning costs. These studies shall be filed along with appropriate tariff(s) effectuating the change in rates necessary to accomplish the funding required. In addition, the commission, at any time for just cause, may require a utility to file an updated decommissioning cost study, funding requirement, and associated tariff(s).

(5) Each utility shall establish a tax-qualified externally managed trust fund for the purpose of collecting funds to pay for decommissioning costs. The tax-qualified trust shall be established and maintained in accordance with the provisions of the *Internal Revenue Code*. If the utility has collected funds in excess of the Internal Revenue Service's (IRS) tax-qualified amount, a nontax-qualified externally managed trust fund shall be established and maintained for all these funds. These trust funds shall be administered pursuant to the following requirements:

(A) Each utility shall submit a copy of the decommissioning trust agreement and any other agreement entered into between the utility, trustee, and investment manager(s) for approval by the commission. The listing of trustee fees shall be contained in or attached to the trust agreement itself. Any change in the trust agreement, trustee, or investment manager(s) also shall be submitted to the commission for approval;

(B) The commission shall have the authority to require each utility to change the trustee or investment manager(s) of a decommissioning trust for good cause shown. The commission shall be informed of any significant disputes between the utility, the trustee, or investment manager(s);

(C) Each utility shall maintain separate tax qualified trusts for each nuclear generating unit. All decommissioning trusts shall be maintained to show the amounts contributed annually by Missouri jurisdictional customers. Amounts to be contributed annually for Missouri jurisdictional customers shall be computed based on the jurisdictional allocator used in the company's last general rate proceeding unless otherwise ordered by the commission;

(D) The decommissioning trust shall be funded through no less than quarterly payments by the utility. The tax-qualified trust shall be funded with the lesser of the utility's decommissioning costs reflected in its cost of service or the maximum amount allowable by the IRS. All funds in excess of the IRS's ruling amount shall be placed in a nonqualified trust;

(E) The trustee or investment manager(s) shall invest the tax-qualified trust assets and nontax-qualified trust assets only in assets that are prudent investments for assets held in trust and in a manner designed to maximize the after-tax return on funds invested, consistent with the conservation of the principal, subject to the limitations specified as follows:

1. The trustee and investment manager(s) shall not invest any portion of the tax-qualified or nontax-qualified trust's funds in the securities or assets of the following:

A. Any owner or operator of a nuclear power plant;

B. Any index fund, mutual fund, or pooled fund in which more than fifteen percent (15%) of the assets are issued by owners or operators of nuclear power plants;

C. Any affiliated company of the utility; or

D. The trustee or investment manager's(s') company or affiliated companies (This limitation does not include time or demand deposits offered through the trustee or investment manager's(s') affiliated banking operations.);

2. The nontax-qualified trust shall be subject to the prohibitions against self-dealing applicable to the tax qualified trust as specified in the *Internal Revenue Code*; and

3. A utility's total book value of investments in equity securities in all of its decommissioning trusts shall not exceed sixty-five percent (65%) of the trust funds' book value; and

(F) All income earned by a trust's funds shall become a part of that trust's funds.

(6) The utility shall take every reasonable action to provide reasonable assurance that adequate funds are available at the nuclear generating unit's termination of operation, so that decommissioning can be carried out in a safe and timely manner, and that lack of funds does not result in delays that may cause undue health and safety hazards.

(7) The utility shall maintain its nuclear generating unit(s) in a manner calculated to minimize the utility's total cost of maintenance and decommissioning, consistent with the prudent operation of the unit.

(8) At the time a tariff(s) is filed by a utility, which proposes any change in rates due to changes in the estimate of decommissioning cost or the funding level of its nuclear decommissioning trust fund(s), the utility shall file the following minimum information in support of the need for changes in its tariff rates:

(A) An updated decommissioning cost study which estimates the cost of decommissioning and the funding levels necessary to defray these costs. This study shall contain the following information:

1. Detailed quantities and unit prices in current dollars for each system of the nuclear generating unit to be decommissioned;

2. A detailed breakdown between radioactive contaminated systems and those systems which are not contaminated by radioactivity;

3. Funding levels which are computed on a levelized basis and which accrue future decommissioning costs over the remaining licensed life of the nuclear generating unit. The utility shall include the earnings rate and inflation rate assumed in the cost study as compared to those assumed in any previous study;

4. A detailed description of any facilities that were added to or deleted from the cost study filed in the previous case;

5. The beginning date for the expenditure of funds for decommissioning assumed in the study shall be no later than the expiration date of the unit's current Nuclear Regulatory Commission (NRC) license; and

6. The study shall consider and evaluate all reasonable practices or procedures which would reduce the ultimate cost of decommissioning; and

(B) A summary description of the reasons (for example, changes in regulation, technology, or economics) that brought on the need to change the decommissioning cost estimate.

(9) Upon the filing of the appropriate tariff(s) as set forth in this rule, the commission shall establish a schedule of proceedings which shall be limited in scope to the following issues:

(A) The extent of any change in the level or annual accrual of funding necessary for the utility's decommissioning trust fund; and

(B) The changes in rates which would reflect any change in the funding level or accrual rate.

(10) For a fund intended to be tax qualified, after receipt of any commission order modifying the annual decommissioning funding requirements, the affected utility shall apply for an adjusted IRS ruling in a timely manner, seeking deductibility of the new annual decommissioning cost accruals consistent with the effective dates given in the order. Pending final IRS approval, the utility shall be authorized to continue funding at the level which existed prior to the commission order provided that the utility will take all appropriate action to preserve the tax deduction of the amounts subsequently approved in the IRS ruling.

(11) Distributions may be made from a nuclear decommissioning trust fund only to satisfy the liabilities of the utility for nuclear decommissioning costs relating to the nuclear generating unit for which the decommissioning fund was established and to pay administrative costs, income taxes, and other incidental expenses of the trust fund. The utility shall not use proceeds of the trust for the purpose of filing for an updated tax ruling or to qualify the trust.

(12) Each utility shall file with the commission the detailed plan required by the Nuclear Regulatory Commission (NRC) for the decommissioning of its nuclear generating unit when that plan is filed with the NRC. Before any distribution of decommissioning trust funds are made for the decommissioning of its nuclear generating unit, the utility must notify and obtain commission approval of its intent to make this distribution.

(13) The utility or the trustee shall file reports quarterly to the commission. The reports shall contain the following information:

(A) A total of all jurisdictional balances of the trust fund(s) based on a carrying cost (book) value;

(B) A total of all jurisdictional balances of the trust fund(s) based on a market value;

(C) A Missouri jurisdictional balance of the trust fund(s) based on a carrying cost (book) value;

(D) A Missouri jurisdictional balance of the trust fund(s) based on a market value;

(E) A summary of the trust account including the utility's contributions, incomes, expenses, and a weighted average after-tax return for the quarter;

(F) A portfolio summary per asset class by amount and percentage;

(G) A detailed report of daily transactions; and

(H) Any other information the commission orders the utility or trustee to provide.

(14) The utility or the trustee shall file reports annually to the commission that contain the following information:

(A) An asset maturity schedule;

(B) A summary of the trust's portfolio of investments including a listing of each security detailing the carrying cost, current market value, maturity date, estimated annual income, and the yield to maturity;

(C) A copy of all correspondence including income tax returns and tax exempt rulings concerning the trust with the Internal Revenue Service (IRS) or any state revenue agency; and

(D) Any other information the commission orders the utility or trust to provide.

(15) The utility shall conduct the decommissioning of its nuclear generating unit in accordance with NRC requirements and must not knowingly allow any procedure that would unreasonably endanger human life or the environment.

(16) Upon termination of the trust, the utility shall file with the commission the appropriate tariff(s) to reflect the termination of payments into the decommissioning trust fund, as well as refund or credit any over collection of these funds.

(17) Upon proper application and after due notice and hearing, the commission may waive any provision of this rule for good cause shown.

(18) The commission may adopt further amendments as it deems necessary for the sound management of the trust fund(s), consistent with the purpose of this rule.

AUTHORITY: sections 386.250 and 393.292, RSMo 2016. Original rule filed Nov. 27, 1989, effective March 26, 1990. Amended: Filed May 4, 1993, effective Dec. 9, 1993. Amended: Filed Aug. 16, 2002, effective April 30, 2003. Amended: Filed Nov. 7, 2018, effective July 30, 2019.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996 and 393.292, RSMo 1989.*

4 CSR 240-20.080 Electrical Corporation Reporting Requirements for Certain Events
(Rescinded April 30, 2003)

AUTHORITY: section 393.140, RSMo 1986. Original rule filed March 1, 1991, effective Sept. 30, 1991. Rescinded: Filed Aug. 16, 2002, effective April 30, 2003.

4 CSR 240-20.090 Fuel and Purchased Power Rate Adjustment Mechanisms

PURPOSE: This rule sets forth the definitions, structure, operation, and procedures relevant to the filing and processing of applications to reflect prudently incurred fuel and *purchased power costs through an interim energy charge or a fuel adjustment clause which allows periodic rate adjustments outside general rate proceedings.*

(1) The following subsections define various terms as used in this rule:

(A) Accumulation period means the time period set by the commission in the general rate proceeding over which historical fuel and purchased power costs and fuel-related revenues are accumulated for purposes of determining the actual net energy costs (ANEC). An accumulation period may be a time period from three (3) to twelve (12) months with the timing and number of accumulation periods to be determined in the general rate proceeding establishing, continuing, or modifying the FAC;

(B) Actual net energy costs (ANEC) means prudently incurred fuel and purchased power costs net of fuel-related revenues of a rate adjustment mechanism (RAM) during the accumulation period;

(C) Base energy costs means the fuel and purchased power costs net of fuel-related revenues determined by the commission to be included in a RAM that are also included in the revenue requirement used to set base rates in a general rate case;

(D) Base factor (BF) means base energy costs rate or rates that are established in a general rate proceeding and are included in the utility's fuel adjustment clause (FAC). The base factor rates may vary within a year;

(E) Base rates means the tariffed rates that do not change between general rate proceedings;

(F) Electric utility or utility means electrical corporation as defined in section 386.020, RSMo, subject to commission regulation pursuant to Chapters 386 and 393, RSMo;

(G) EFIS means the electronic filing and information system of the commission;

(H) FAC charge means the positive or negative dollar amount on each utility customer's bill, which in the aggregate is to recover from or return to customers the fuel and purchased power adjustment (FPA) amount;

(I) Fuel adjustment clause (FAC) means a mechanism established in a general rate proceeding which is designed to recover from or return to customers the fuel and purchased power adjustment (FPA) amounts through periodic changes to the fuel adjustment rates (FAR) made outside a general rate proceeding;

(J) Fuel adjustment rate (FAR) means the rate used to determine the FAC charge on each utility customer's bill during a recovery period of a FAC. The FAR shall be designed to recover from or return to customers the recovery period FPA. The FAR may be positive or negative;

(K) Fuel and purchased power adjustment (FPA) amount means the dollar amount intended to be recovered from or returned to customers during a given recovery period of a FAC. The FPA may be positive or negative. It includes:

1. The difference between the ANEC and NBEC of the corresponding accumulation period taking into account any incentive ordered by the commission;

2. True-up amount(s) ordered by the commission prior to or on the same day as commission approval of the FAR adjustment;

3. Prudence adjustment amount(s) ordered by the commission since the last adjustment to the FAR;

4. Interest; and

5. Any other adjustment amount(s) ordered by the commission;

(L) Fuel and purchased power costs means prudently incurred and used fuel and purchased power costs, including transportation costs. Prudently incurred costs do not include any increased costs resulting from negligent or wrongful acts or omissions by the utility.

1. If off-system sales revenues are not reflected in the rate adjustment mechanism (RAM), fuel and purchased power costs shall only reflect the prudently incurred fuel and purchased power costs necessary to serve the electric utility's Missouri retail customers.

2. Unless otherwise approved by the commission, fuel and purchased power costs do not include environmental costs as defined in 4 CSR 240-20.091(1) or renewable energy standard compliance costs as defined in 4 CSR 240-20.100(1). If such costs are included in fuel and purchased power costs, they shall not be included in another rate adjustment mechanism.

(M) Fuel-related revenues means those revenues related to the generation, sale, or purchase of energy or capacity. Fuel-related revenues may include, but are not limited to, off-system sales, emission allowance sales, and renewable energy credits or certificates whenever such renewable energy credits or certificates are not included in a Renewable Energy Standard Rate Adjustment Mechanism (RESRAM) in compliance with 4 CSR 240-20.100;

(N) General rate proceeding means a general rate increase proceeding or complaint proceeding before the commission in which all relevant factors that may affect the costs, or rates and charges of the electric utility are considered by the commission;

(O) Interest means monthly interest at the utility's short-term borrowing rate to accurately and appropriately remedy any over- or under-billing of the FPA amount during an accumulation period and recovery period, and any commission ordered refund of imprudently incurred costs;

(P) Interim energy charge (IEC) means a mechanism that includes a refundable fixed amount billed through an interim energy rate (IER) established in a general rate proceeding that permits an electric utility to recover some or all of its fuel and purchased power costs separate from the fuel and purchased power costs included in its base rates. Base energy cost in the base rates is the floor of the IEC. The base energy cost plus the fuel and purchased power costs billed through the IER is the ceiling of the IEC. An IEC may or may not include fuel-related revenues and costs related to those revenues;

(Q) Megawatt (MW) is one million (1,000,000) watts;

(R) Megawatt hour (MWh) is one million (1,000,000) watt hours or one thousand (1,000) kilowatt hours (kWh);

(S) MCF is one thousand (1,000) cubic feet of natural gas;

(T) MMBtu is one million (1,000,000) British thermal units (Btus);

(U) Net base energy costs (NBEC) means the fuel and purchased power costs net of fuel-related revenues billed during the accumulated period in base rates;

(V) Other parties means any party to the applicant's most recent general rate proceeding in which the RAM at issue was established, continued, or modified;

(W) Rate adjustment mechanism (RAM) refers to either a commission-approved fuel adjustment clause (FAC) or a commission-approved interim energy charge (IEC);

(X) Rebase base energy costs means the base energy cost as reset in each general rate proceeding in which the FAC is continued or modified;

(Y) Recovery period means the period over which the FAR is applied to retail customers' bills to recover the FPA. A recovery period is determined in a general rate case and shall not be longer than twelve (12) billing months;

(Z) Staff means the staff of the Public Service Commission; and

(AA)True-up amount means—

1. For a FAC, the true-up amount shall be the difference between the FPA and the utility's aggregate FAC charges billed for a recovery period.

A. If the aggregate FAC charges billed for recovery period are more than the FPA, the true-up amount will be negative.

B. If the aggregate FAC charges billed for a recovery period are less than the FPA, the true-up amount will be positive.

C. The electric utility may request in its general rate case to use the final Regional Transmission Organization (RTO) determinants to update the FPA for its true-up if the electric utility belongs to an RTO where the RTO may, after the beginning of the recovery period, finalize the determinants used to calculate the FPA for the recovery period.

2. For an IEC, the true-up amount shall be determined as follows for each consecutive

twelve- (12-) month period—

A. If the actual fuel and purchased power cost is greater than the IEC ceiling, the true-up amount shall be zero;

B. If the actual fuel and purchased power cost is less than the IEC ceiling and greater than the IEC floor, the true-up amount shall be the difference between the actual fuel and purchased power cost and the combined IEC billed plus the base energy cost. The customers will be credited/refunded this amount; or

C. If the actual fuel and purchased power cost is less than the IEC floor, the true-up amount shall be the aggregate IEC billed. The customers will be credited/refunded this amount.

(2) Establishment, Continuance, or Modification of a RAM. An electric utility may only file a request with the commission to establish, continue, or modify a RAM in a general rate proceeding and must rebase base energy costs in each general rate proceeding in which the FAC is continued or modified. Any party in a general rate proceeding may seek to continue, modify, or oppose the RAM. The commission shall approve, modify, or reject such request only after providing the opportunity for a full hearing in a general rate proceeding. The commission shall consider all relevant factors that may affect the costs or overall rates and charges of the petitioning electric utility.

(A) The electric utility shall file the following supporting information, in electronic format, where available, with all links and formulas intact, as part of, or in addition to, its direct testimony:

1. An example of the notice to be provided to customers during the pendency of the general rate proceeding where the RAM is under consideration, which shall be approved by the commission. The notice shall include a description of how its proposed RAM shall be applied to monthly bills, the amount of the proposed change in base rates caused by the rebase of energy costs, and the estimated impact on a typical residential customer's bill resulting from the rebase of energy costs;

2. An example customer bill(s) covering all of the electric utility's rate classes showing how the proposed RAM shall be separately identified on affected customers' bills in accordance with section (12);

3. Proposed RAM tariff sheets;

4. A detailed description of the design and intended operation of the proposed RAM;

5. A detailed explanation of how the proposed RAM is reasonably designed to provide the electric utility a sufficient opportunity to earn a fair return on equity;

6. A detailed explanation of how the proposed FAC shall be trued-up for over- and under-billing, or how and when the refundable portion of the proposed IEC shall be trued-up;

7. A detailed description of how the electric utility's monthly short-term borrowing rate will be defined and how it will be applied, during the accumulation period and the recovery period, to over- and under-billed amounts and prudence disallowances;

8. A detailed description of how the proposed RAM is compatible with the requirement for prudence reviews in section (11);

9. A detailed explanation of the fuel and purchased power costs, including transportation, that are to be considered in determining the amount to be recovered under the proposed RAM with identification of the specific account and any other designation ordered by the commission where that cost will be recorded on the electric utility's book and records.

10. A detailed explanation of the fuel-related revenues that are to be considered in determining the amount to be recovered under the proposed RAM with identification of the specific account and any other designation ordered by the commission where that revenue will be recorded on the electric utility's books and records;

11. A detailed explanation of any incentive feature in the proposed RAM with the expected benefit and cost each feature is intended to produce for both the electric utility and its Missouri retail customers;

12. A detailed explanation of any rate volatility mitigation feature in the proposed RAM;

13. A detailed explanation of any feature of the proposed RAM and any existing electric utility policy, procedure, or practice that ensures only prudent fuel and purchased power costs and fuel-related revenues are recovered through the proposed RAM, including, but not limited to, utilization of competitive bidding or other sourcing or sales practices;

14. A detailed explanation of any change to the electric utility's business risk resulting from implementation of the proposed RAM, in addition to any other changes in business risk the electric utility may experience;

15. A level of efficiency for each of the electric utility's generating units determined by the results of heat rate/efficiency tests or monitoring that were conducted or obtained on each of the electric utility's steam generators, including nuclear steam generators, heat recovery steam generators, steam turbines and combustion turbines within twenty-four (24) months preceding the filing of the general rate increase case.

A. The results should be filed in a table format by generating unit type, rated megawatt (MW) output rating, the numerical value of the latest result and the date of the latest result;

B. The electric utility shall provide documentation of the actual test/monitoring procedures. The electric utility may, in lieu of filing the documentation of these procedures with the commission, provide them to the staff, OPC, and to other parties as part of the workpapers it provides in connection with its direct case filing. If the electric utility submits the results in workpapers, it will provide a statement in its testimony as to where the results can be found in workpapers;

16. Information that shows that the electric utility has in place a long-term resource planning process;

17. If the electric utility proposes to include emissions allowances costs or sales revenue in the proposed FAC and not in an environmental cost recovery mechanism, a detailed explanation of its emissions management policy, and its forecasted environmental investments, emissions allowances purchases, and emissions allowances sales;

18. For each power generating unit the electric utility owns or controls, in whole or in part, the electric utility shall file graphs, accompanied by the data supporting the graphs, for each month over the immediately preceding five (5) years, showing the monthly equivalent availability factor, the monthly equivalent forced outage rate, and the length and timing of each planned outage of that unit; and

19. Authorization for the staff to release to all parties to the general rate proceeding in which the establishment, continuation, or modification of a RAM is requested, the previous five (5) years of historical surveillance monitoring reports the electric utility submitted in EFIS.

(B) In lieu of providing copies of information, an electric utility filing for modification or continuance of a RAM in which the information required in subsection (2)(A) has been previously filed with the commission as part of a general rate proceeding and has not changed in any manner, may certify that the information has not changed and provide to all parties the general rate case number and location in EFIS, including the EFIS item and page number where the information can be found. If there are parties to the RAM proceeding that would not have access to the rate case information, the electric utility must provide copies of the information to that party.

(C) An electric utility filing to continue or modify a RAM must also provide to all parties any additional information the commission ordered the electric utility to provide when seeking to continue or modify its RAM.

(D) The commission may approve the establishment, continuation, or modification of a RAM and associated tariff sheets provided that it finds that the RAM is reasonably designed to provide the electric utility with a sufficient opportunity to earn a fair return on equity and so long as the tariff sheets that implement the RAM conform to the RAM approved by the commission. In its determination, the commission may consider, but is not limited to, considering—

1. Fuel and purchased power costs, fuel-related revenues that would flow through the RAM, or other factors it deems appropriate;

2. Any change in business risk of the utility resulting from establishment, continuation, or modification of the RAM in setting the electric utility's allowed return on equity in any general rate proceeding, in addition to any other changes in business risk experienced by the electric utility; and

3. In determining which fuel and purchased power cost types and fuel-related revenue types to include in a RAM, the commission may consider the magnitude of each cost or revenue type, the ability of the utility to manage each cost or revenue type, the volatility of each cost or revenue type and the incentive provided to the utility as a result of the inclusion or exclusion of each cost or revenue type. The commission may, in its discretion, determine what portion of prudently incurred fuel and purchased power costs and fuel-related revenues may be recovered from and/or returned to customers through a RAM and what portion shall be included in the determination.

(E) Any party to the general rate proceeding may oppose any RAM and/or may propose alternative RAMs for the commission's consideration.

(F) The RAM, and any adjustments to the FARs if a FAC is approved, shall be based on historical fuel and purchased power costs and fuel-related revenues.

(G) For an electric utility requesting a FAC, the utility shall include in its proposed tariff sheets provisions which shall accurately and appropriately remedy any true-up amount as part of the electric utility's determination of its FPA for a change to its FARs. The proposed tariff sheets shall include, at a minimum:

1. When the electric utility will file for a true-up;

2. How the true-up amount will be determined including, but not limited to, any recalculation of the FPA; and

3. How and when the true-up amount will be recovered.

(H) For an electric utility with an IEC mechanism, a true-up must be filed within sixteen (16) months of the operation of law date of the IEC and be filed annually thereafter.

(I) Any party to the general rate proceeding may propose a cap on the periodic changes to the fuel adjustment rate (FAR), to mitigate volatility in rates, provided it proposes a method for the utility to recover all of the costs it would be entitled to recover in the FAC, together with interest thereon.

(3) Discontinuance of a RAM. The tariff sheets that define and implement a RAM shall only be discontinued and withdrawn after the opportunity for a full hearing in a general rate proceeding. The commission shall consider all relevant factors which may affect the costs or overall rates and charges of the petitioning electric utility.

(A) When an electric utility files a general rate proceeding in which it requests that its RAM be discontinued, the electric utility shall file with the commission, and serve on the parties, the following supporting information, in electronic format, where available, with all links and formulas intact, as part of, or in addition to, its direct testimony:

1. An example of the notice to be provided to customers during the pendency of the general rate proceeding in which discontinuation is being proposed. The notice shall be approved by the commission and should include a description of why the utility believes the RAM should be discontinued;

2. A detailed explanation of how the electric utility proposes to discontinue its RAM.

A. If requesting to discontinue its FAC, the electric utility shall include the following in its explanation:

(I) The ending date of the last FAC accumulation period;

(II) The beginning and ending dates of the recovery period for that accumulation period; and

(III) The procedure for the true-up associated with the recovery period for that accumulation period.

B. If requesting to discontinue its IEC, the electric utility shall include a detailed explanation of how any over-billing will be returned to the electric utility's retail customers;

3. A detailed explanation of why the RAM is no longer necessary to provide the electric utility a sufficient opportunity to earn a fair return on equity;

4. A detailed explanation of any impact on setting the electric utility's allowed return on equity in any rate proceeding as a result of the change to the electric utility's business risk resulting from discontinuation of its RAM, in addition to any other changes in business risk experienced by the electric utility; and

5. Any additional information that the commission ordered the electric utility to provide when seeking to discontinue its RAM.

(B) Any party to the general rate proceeding may oppose the discontinuation of a RAM on the grounds that the utility is opportunistically discontinuing the RAM due to declining fuel or purchased power costs and/or increasing fuel-related revenues. If the commission finds that the utility is opportunistically seeking to discontinue the RAM for any of these reasons, the commission shall not allow the RAM to be discontinued, and shall order its continuation or modification. In addition to other remedies provided by law, the commission may reject the utility's request for discontinuance of a RAM if it finds that the utility has not complied with this rule in its request to discontinue its RAM. To continue or modify the RAM under such circumstances, the commission must find that it provides the electric utility with a sufficient opportunity to earn a fair rate of return on equity and the tariff sheets filed to implement the RAM must conform to the RAM approved by the commission. Any RAM and periodic adjustments to the FAR shall be based on historical fuel and purchased power costs.

(C) The commission may take into account any change in business risk of the electric utility resulting from discontinuance of the RAM in setting the electric utility's allowed return on equity in any general rate proceeding in addition to any other changes in the electric utility's business risk.

(4) Requirements for Electric Utilities that have a RAM. If the commission grants, modifies, or continues an electric utility's RAM, the electric utility shall—

(A) Upon thirty (30) days prior written notice to the electric utility, provide for review by staff at its corporate headquarters, or some other place mutually agreed upon by the electric utility and staff, a copy of each and every nuclear fuel, coal, natural gas, and fuel transportation contract (to the extent related to generation of electricity), the utility's hedging policies and the utility's internal policy for participating in a Regional Transmission Organization (RTO) ancillary services market (if applicable), including every amendment and modification to each such contract or policy that was in effect during a RAM for the electric utility; and

(B) Notify the staff through EFIS of every new nuclear fuel, coal, natural gas, and fuel transportation contract and every new amendment and every new modification to currently existing contracts or to the policies referenced in subsection (4)(A) above within thirty (30) days of the effective date of the contract, amendment, or modification. The notification shall include where the contracts, amendments, modifications, and related competitive bidding materials may be reviewed.

(5) Periodic Reports. So long as it has a RAM in effect, each electric utility shall submit a monthly report through EFIS and to staff, OPC, and other parties. Each periodic report shall be verified by the affidavit of an electric utility representative(s) who has knowledge of the subject matter and who attests to both the veracity of the information and his/her knowledge of it. The information identified in this section shall be provided in electronic format, where available, with all links and formulas intact. Each periodic report shall contain the following information by month:

(A) The billing month actual energy usage in kWh by rate class and voltage level;

(B) Net base energy costs billed in base rates by rate class and voltage level along with workpapers with all links and formulas intact detailing the calculation;

(C) Revenues from billed FARs by voltage level along with workpapers (with formulas intact) detailing the calculation;

(D) The fuel and purchased power costs and fuel related revenues for each month, year-to-date, and prior calendar year by account and any other designation ordered by the commission. If accounts, sub- accounts, and other designations are not comparable to costs and revenues listed in the electric utility's FAC tariff sheets, the electric utility shall also include the costs as listed in the tariff sheets;

(E) Energy.

1. RTO market transactions—

A. Revenue net of the cost of any energy purchases in the RTO market;

B. MWh's net of the MWh's for any energy purchases in the RTO market.

2. Physical bilateral transactions—

A. Total MWh's;

B. Total revenues and costs;

(F) Capacity.

1. If sold within an RTO market—

A. MW capacity sold net of MW capacity purchased;

B. Revenue received net of the cost of capacity purchased.

2. Third party bilateral transactions—

A. Total MW;

B. Total revenue and costs;

(G) Reason for the purchase of capacity in the RTO markets;

(H) The following information for the period, by generation facility, by fuel type, and by total for the electric utility:

1. Quantity of fuel burned, with the designation of the units in which the quantity is reported (e.g., tons, MCF, MMBtu);

2. MMBtu of fuel burned;

3. Average cost of fuel per MMBtu, by fuel type;

4. Aggregate megawatt hours (MWhs) of net energy generated by the generating facility at each generation station, where net energy generated is the gross generation net of the station use;

5. Average cost of fuel per MWh;

6. Excluding nuclear fuel, the cost of fuel purchased by fuel type and, a breakdown between the cost of the commodity, cost of freight and cost of transportation by fuel type; and

7. Other fuel cost types designated in the RAM.; and

(I) A detailed description of the accounts or other designations utilized by the electric utility or ordered by the commission, where each fuel and purchased power cost or fuel-related revenue is recorded. The report shall identify any changes since the last periodic report to accounts or other designations of costs and revenue types utilized by the utility or otherwise ordered to be used by the commission in the general rate proceeding where the RAM was approved;

(J) Each revision to the electric utility's internal policy for participating in—

1. RTO ancillary services market, if the RTO in which the electric utility participates has such a market;

2. RTO energy markets by RTO;

3. RTO capacity markets by RTO;

4. Financial swaps or other financial-only transactions (if such financial transactions are included in the electric utility's RAM);

(K) Any additional information that the commission has ordered the electric utility to provide in its periodic reports.

(6) Surveillance Monitoring Reports. So long as it has a RAM in effect, each electric utility shall submit in EFIS and submit to staff, OPC, and other parties, a surveillance monitoring report with all links and formulas intact, within fifteen (15) days after each of the electric utility's United States Securities and Exchange Commission (SEC) 10-Q and 10-K filings are due. If an electric utility with foreign ownership has a RAM but does not file with the SEC, then the surveillance monitoring reports shall be filed in quarterly intervals as identified in the electric utility's general rate proceedings. The surveillance monitoring report shall be verified by the affidavit of an electric utility representative(s) who has knowledge of the subject matter and who attests to both the veracity of the information and his/her knowledge of it. These surveillance monitoring reports are confidential.

(A) There are six (6) parts to the electric utility surveillance monitoring report. Each part, except Part I—Rate Base Quantifications, shall contain information for the last twelve- (12-) month period and the last quarter based on total company electric operations data and on Missouri jurisdictional operations data. Part I—Rate Base Quantifications, shall contain only information as of the ending date of the period being reported. The content of the surveillance monitoring report follows:

1. Part I—Rate Base Quantifications. The quantification of rate base items in Part I shall be consistent with the methods and procedures used in the electric utility's most recent rate proceeding before the commission, unless otherwise specified by the commission. Part I shall consist of specific quantifications of the following rate base items:

A. Plant-in-service;

B. Reserve for depreciation;

C. Materials and supplies;

D. Cash working capital;

E. Fuel inventory;

F. Prepayments;

G. Other regulatory assets;

H. Customer advances;

I. Customer deposits;

J. Accumulated deferred income taxes;

K. All other items included in the electric utility's rate base from its most recent general rate proceeding before the commission;

L. Net operating income from Part III; and

M. Calculation of the overall return on rate base;

2. Part II—Capitalization Quantifications. Part II shall consist of specific quantifications of the following capitalization-related items:

A. Common stock equity (net);

B. Preferred stock (par or stated value outstanding);

C. Long-term debt (including current maturities);

D. Short-term debt; and

E. Weighted cost of capital including component costs;

3. Part III—Income Statement. Part III shall consist of an income statement containing specific quantifications of—

A. Operating revenues, including revenues from sales to industrial, commercial, and residential customers, sales for resale and all other components of total operating revenues;

B. Operating and maintenance expenses in fuel expense, production expense, purchased power energy, and purchased power capacity;

C. Transmission expense;

D. Distribution expense;

E. Customer accounts expense;

F. Customer service and information expense;

G. Sales expense;

H. Administrative and general expense;

I. Depreciation, amortization, and decommissioning expense;

J. Taxes other than income taxes;

K. Income taxes; and

L. Quantification of heating degree and cooling degree days, both actual and normal;

4. Part IV—Jurisdictional Allocation Factors. Part IV shall consist of a list of the jurisdictional allocation factors used for determining the electric utility's rate base, capitalization quantification, and income statement;

5. Part V—Financial Data Notes. Part V shall consist of notes to the reported financial data including, but not limited to:

A. Out-of-period adjustments;

B. Specific quantification of material variances between actual and budget financial performance;

C. Specific identification and quantification of material variances between current twelve- (12-) month period and prior twelve- (12-) month period revenue;

D. The expense levels of each item the commission has ordered be tracked in the RAM;

E. Budgeted capital projects; and

F. Events that materially affect debt or equity surveillance components;

6. Part VI—Missouri Energy Efficiency and Investment Act (MEEIA). An electric utility with approved MEEIA demand-side management programs and/or an approved demand-side programs investment mechanism shall include all filing requirements of 4 CSR 240-20.093(10) for the entire period of program delivery approved by the commission, the last twelve- (12-) month period, and the last quarter.

(B) Each surveillance monitoring report shall include any additional information the commission has ordered be provided.

(C) If the electric utility has any other approved cost recovery mechanisms that require submission of surveillance monitoring reports, the electric utility shall submit a single surveillance monitoring report incorporating these reporting requirements for all cost recovery mechanisms.

(7) Budget Report. Annually the electric utility shall submit in EFIS and provide to staff, OPC, and other parties, its approved budget for the upcoming budget year, in electronic format with all links and formulas intact and in a layout similar to its surveillance monitoring report. The budget submission shall provide a quarterly and annual quantification of the electric utility's income statement. The budget report shall be submitted within thirty (30) days of when the electric utility's budget is approved by the electric utility's management or within sixty (60) days of the beginning of the electric utility's fiscal year, whichever is earliest. The budget submission shall be designated "confidential" and treated accordingly.

(8) Periodic Changes to Fuel Adjustment Rates. An electric utility that has a FAC shall file proposed tariff sheet(s) to adjust its FARs following each accumulation period. The FARs shall be designed to bill the electric utility's customers, in the aggregate, the FPA if the FPA is positive, or return the FPA to the utility's customers if the FPA is negative.

(A) When an electric utility files with the commission tariff sheet(s) to change its fuel adjustment rates and serves it upon parties, the filed tariff sheet(s) shall be accompanied by—

1. Prefiled testimony that shall include:

A. The proposed FARs;

B. The change in the FARs;

C. The impact of the proposed FARs on the monthly bill of the electric utility's typical residential customer, together with the definition of typical residential customer used to determine that impact;

D. The accumulation period NBEC, ANEC, and FPA; and

E. An explanation that details the factors which contributed to the FPA amount.

2. The following information in electronic format, where available, with formulas intact:

A. For the period of historical costs which are being used to propose the fuel adjustment rates—

(I) The calendar month actual energy sales in kWh by rate class and voltage level;

(II) The actual fuel costs designated in the FAC, listed by generating station and fuel type;

(III) The MWh and actual purchased power costs, as purchased power is defined in the electric utility's FAC, differentiated between energy costs and demand costs;

(IV) Transmission costs designated in the electric utility's FAC;

(V) Net off-system sales revenues;

(VI) Fuel-related revenues other than off-system sales revenues separated by type of fuel-related revenue;

(VII) Net base energy costs collected in permanent rates;

(VIII) Any additional requirements the commission ordered;

(IX) Calculation of each of the proposed fuel adjustment rates;

(X) Calculations of the voltage differentiation in the proposed FAC rates, if any, to account for differences in line losses by service voltage level; and

(XI) Extraordinary costs not to be passed through, if any, due to such costs being an insured loss, or subject to reduction due to litigation or for any other reason;

B. The electric utility's monthly short-term borrowing rate, along with—

(I) An explanation of how that rate was determined;

(II) The calculation of the short-term borrowing rate;

(III) Identification of any changes in the basis(es) used for determining the short-term borrowing rate since the last FAC rate adjustment;

(IV) If there is a change in the basis(es) used for determining the short-term borrowing rate, a copy(ies) of the changed basis(es) or identification of where it/they may be reviewed;

3. Workpapers, in electronic format, where available, with all links and formulas intact, supporting all items in paragraphs (8)(A)1. and (8)(A)2. that are not provided in the electric utility's section (5) periodic monthly report submissions shall be submitted through EFIS and provided to staff, OPC, and other parties;

(B) The electric utility shall initiate a new case with an ER designation for each periodic adjustment of its FARs;

(C) An electric utility with a FAC shall file an adjustment to its FARs within two (2) months of the end of each accumulation period after the effective date of the FAC;

(D) The tariff sheets reflecting the RAM define the costs and revenues that can be included in the RAM, subject to the following:

1. If an RTO implements a new market settlement type or schedule covering a cost or revenue that the electric utility or another party believes possesses the characteristics of, and is of the nature of, an RTO revenue or cost approved by the commission for inclusion in the electric utility's FAC in the previous general rate proceeding, the costs or revenues covered by the new market settlement type or schedule will be included in the utility's FAC if the following requirements are met:

A. The party proposing the inclusion of costs or revenues covered by a new market settlement type or schedule shall make a filing before the commission in the case in which the electric utility's then-current FAC was approved giving notice of the new market settlement type or schedule no later than sixty (60) days prior to the due date for the electric utility's next FAR filing made to adjust the electric utility's FAR;

B. The filing shall include, but is not be limited to:

(I) Identification of the account affected by the change;

(II) A description of the new market settlement type or schedule demonstrating that the cost or revenue it covers possesses the characteristics of, and is of the nature of, a cost or revenue allowed in the electric utility's FAC by the commission in the most recent general rate proceeding; and

(III) Identification of the preexisting schedule, or market settlement type which the new settlement type or schedule replaces or supplements;

C. To challenge the inclusion of a new market settlement type or schedule, a party shall make a filing before the commission including the reasons why it believes the electric utility did not show that the cost or revenue covered by the new market settlement type or schedule possesses the characteristics of, and is of the nature of, a cost or revenue included in the electric utility's FAC that was approved by the commission in the preceding general rate proceeding.

(I) The filing shall be made within thirty (30) days of the electric utility's filing.

(II) The party requesting the inclusion of costs or revenues covered by a new market settlement type or schedule shall bear the burden of proof to show that the costs or revenues possess the characteristics of, and are of the nature of, costs or revenues allowed in the electric utility's FAC by the commission in the most recent general rate proceeding.

(III) If a party challenges the inclusion of the costs or revenues covered by the new market settlement type or schedule, the challenge will not delay the FAR filing schedule.

(IV) If the challenge is upheld by the commission, the costs will be refunded or revenues returned along with interest in the next periodic adjustment;

(E) The electric utility must be current on its submission of its surveillance monitoring reports;

(F) Staff shall review the information filed and submitted by the electric utility in accordance with this rule and additional information obtained through discovery, if any, to determine if the proposed adjustment to the FARs is in accordance with the provisions of this rule, section 386.266, RSMo, and the FAC mechanism established, continued, or modified in the utility's most recent general rate proceeding. In filings to adjust the FAR, the twenty- (20-) and ten- (10-) day time limits in 4 CSR 240-2.090(2) shall be reduced to fifteen (15) and seven (7) days, respectively. Within thirty (30) days after the electric utility files its testimony and tariff sheet(s) to adjust its FARs, the staff shall submit a recommendation regarding its examination and analysis to the commission;

(G) OPC and other parties may file a response to the electric utility's proposed FAR adjustment within forty (40) days after the electric utility files its testimony and tariff sheet(s) to adjust its FARs;

(H) Within sixty (60) days after the electric utility files its testimony and tariff sheet(s) to adjust its FARs, the commission shall either—

1. Issue an interim rate adjustment order approving the tariff sheet(s) and the adjustments to the FARs;

2. Allow the tariff sheet(s) and the adjustments to the FARs to take effect without commission order; or

3. If it determines the adjustment to the FARs is not in accordance with the provisions of this rule, section 386.266, RSMo, and the FAC mechanism established in the electric utility's most recent general rate proceeding, reject the proposed rate sheets, suspend the timeline of the FAR adjustment filing, set a prehearing date, and order the parties to propose a procedural schedule. The commission may order the electric utility to file tariff sheet(s) to implement interim adjusted FARs to reflect any part of the proposed adjustment that is not in question;

(I) If the staff, OPC, or other party which receives the information that the electric utility is required to submit by this rule and as ordered by the commission in a previous proceeding, believes the information is insufficient to make a recommendation regarding the electric utility's proposed FAR, it shall notify the electric utility within ten (10) business days of the electric utility's filing of tariff sheet(s) to adjust the FARs and identify the information required and not submitted in compliance with that rule or order. The electric utility shall supply the information identified by the party, or shall notify the party that it believes the information provided was in compliance with the requirements of this rule and the commission's most recent order establishing, continuing, or modifying the FAC, within ten (10) business days of the request. If the electric utility does not timely supply the information, the party asserting the failure to provide the required information must timely file a motion to compel with the commission.

1. While the commission is considering the motion to compel, the processing timeline for the adjustment to increase the FARs shall be suspended. If the commission then issues an order requiring the information be provided, the time necessary for the information to be provided shall further extend the processing timeline for the adjustment to increase the FARs. If the commission issues an order compelling discovery, interest will not be accrued by the utility from the time the commission receives a motion to compel until the time that the utility provides the requested information. For good cause shown the commission may further suspend this timeline.

2. Except as provided herein, any delay in providing sufficient information in compliance with this rule and the commission's most recent order establishing, continuing, or modifying the FAC in a request to decrease the FARs shall not alter the processing timeline.

(9) True-Ups of RAMs. The purpose of a true-up case is to accurately and appropriately remedy any over- billing or under-billing during a recovery period, including the interest accrued at the utility's short-term borrowing rate to be returned to or collected from customers through a periodic change to FAR under section (8).

(A) When an electric utility files with the commission to true-up its RAM the filing shall be accompanied by—

1. Pre-filed testimony that includes a discussion detailing the material factors which contributed to the true-up amount;

2. The following information in electronic format, where available, with all links and formulas intact:

A. Any revision to the calculation of the net base energy cost for the accumulation period;

B. Any other proposed adjustments or refunds not related to the calculation of the net base energy cost for the accumulation period;

C. The calculation of the monthly amount that was over- billed or under-billed through its RAM;

D. The electric utility's monthly short-term borrowing rate along with—

(I) An explanation of how that rate was determined;

(II) The calculation of the short-term borrowing rate;

(III) Identification of any changes in the basis(es) used for determining the short-term borrowing rate since the last RAM rate adjustment; and

(IV) If there is a change in the basis(es) used for determining the short-term borrowing rate, a copy(ies) of the changed basis(es) or identification of where it/they may be reviewed;

E. Any additional information that the commission has ordered the electric utility to include in its RAM true-up filing;

3. Workpapers, in electronic format, where available, with all links and formulas intact, supporting all items in this subsection, shall be submitted in EFIS and provided to staff, OPC, and other parties.

(B) The electric utility shall initiate a new file in EFIS designated as an "electric other" (EO) file number for each true-up of its RAM.

(C) The electric utility must be current on its submission of its periodic reporting requirements as required by section (5) and surveillance monitoring reports at the time that it files its true-up of its RAM in order for the commission to process the electric utility's requested true-up of any over- or under-billing.

(D) The staff shall examine and analyze the information filed and submitted by the electric utility pursuant to this rule and additional information obtained through discovery and as ordered by the commission, to determine whether the true-up amount is in accordance with the provisions of this rule, section 386.266, RSMo, and the RAM established in the electric utility's most recent general rate proceeding. In filings to adjust the FAR, the twenty- (20-) and ten- (10-) day time limits in 4 CSR 240-2.090(2) shall be reduced to fifteen (15) and seven (7) days, respectively. The staff shall submit a recommendation regarding its examination and analysis to the commission not later than thirty (30) days after the electric utility files for a true-up amount.

(E) OPC and other parties may file a response to the proposed true-up amount within forty (40) days of the electric utility true-up filing.

(F) Within sixty (60) days of the electric utility's true-up filing the commission shall issue an order—

1. Approving the true-up filing and the true-up amount; or

2. If it determines that the true-up amount is incorrect, rejecting the proposed tariff sheet(s) containing the true-up amount, suspending the timeline of the true-up filing, setting a prehearing date, and ordering the parties to propose a procedural schedule. The commission shall allow the electric utility to file tariff sheet(s) to implement interim FARs reflecting any part of the true-up amount that is not in question, and questions about the correctness of the true-up amount will not delay adjustments to FAR rates unrelated to the true-up.

(G) If the staff, OPC or other party which receives the information that the electric utility is required to submit by this rule and as ordered by the commission in a previous proceeding, believes the information is insufficient to make a recommendation regarding the electric utility's true-up filing, it shall notify the electric utility within ten (10) days of the electric utility's filing and identify the information required. The electric utility shall supply the information identified by the party, or shall notify the party that it believes the information provided was responsive to the requirements, within ten (10) days of the request. If the electric utility does not timely supply the information, the party asserting the failure to provide the required information must timely file a motion to compel with the commission.

1. While the commission is considering the motion to compel, the processing timeline for the determination of the true-up amount shall be suspended. If the commission then issues an order requiring the information to be provided, the time necessary for the information to be provided shall further extend the processing timeline. If the commission issues an order compelling discovery, interest will not be accrued by the utility from the time the commission receives a motion to compel until the time that the utility provides the requested information. For good cause shown the commission may further suspend this timeline.

2. If the party requesting the information can demonstrate to the commission that the true-up amount will result in a reduction in the FAR, the processing timeline shall continue with the best information available. When the electric utility provides the necessary information, the FAR shall be adjusted again, if necessary, to reflect the additional information provided by the electric utility.

(10) Duration of RAMs and Requirement for General Rate Case. Once a RAM is approved by the commission, it shall remain in effect for a term of not more than four (4) years unless the commission earlier authorizes the modification, extension, or discontinuance of the RAM in a general rate proceeding, although an electric utility may submit proposed rate sheets to implement periodic adjustments to its FAC rates between general rate proceedings.

(A) If the commission approves a RAM for an electric utility, the electric utility must file a general rate case with the effective date of new rates to be no later than four (4) years after the effective date of the commission order implementing the RAM, assuming the maximum statutory suspension of the rates so filed.

1. The four- (4-) year period shall not include any periods in which the electric utility is prohibited from collecting any charges under the RAM, or any period for which charges collected under the RAM must be fully refunded. In the event a court determines that the RAM is unlawful and all monies collected are fully refunded as a result of such a decision, the electric utility shall be relieved of any obligation to file a general rate case. The term fully refunded as used in this section does not include amounts refunded as a result of reductions in fuel or purchased power costs minus fuel-related revenues or prudence adjustments.

(11) Prudence Reviews Respecting RAMs. A prudence review of the costs and revenues subject to the RAM shall be conducted no less frequently than at eighteen- (18-) month intervals.

(A) All amounts ordered refunded by the commission shall include interest at the electric utility's short-term borrowing rate.

(B) The staff shall file notice within ten (10) days of starting its prudence review and shall submit a recommendation regarding its examination and analysis to the commission not later than one hundred eighty (180) days after initiating its prudence review. Parties to the prudence review proceeding shall have ten (10) days after the staff files its recommendation to request a hearing. The commission shall issue an order not later than thirty (30) days after the staff files its recommendation if no party requests a hearing.

1. If the staff, OPC, or other party auditing the RAM believes that insufficient information has been supplied to make a recommendation regarding the prudence of the electric utility's RAM, it may utilize discovery to obtain the information it seeks. If the electric utility does not timely supply the information, the party asserting the failure to provide the required information must timely file a motion to compel with the commission. While the commission is considering the motion to compel the processing timeline shall be suspended. If the commission then issues an order requiring the information to be provided, the time necessary for the information to be provided shall further extend the processing timeline. For good cause shown the commission may further suspend this timeline.

2. If the timeline is extended due to an electric utility's failure to timely provide sufficient responses to discovery and a refund is due to the customers, the electric utility shall refund all imprudently incurred costs plus interest at the electric utility's short-term borrowing rate.

(12) Disclosure on Customers' Bills. Any amounts charged under a commission-approved RAM shall be separately disclosed on each customer's bill. Proposed language regarding this disclosure shall be submitted to the commission for the commission's approval in the general rate proceeding establishing, modifying, or continuing the RAM.

(13) Rate Design of the RAM. The design of the RAM rates shall reflect differences in losses incurred in the delivery of electricity at different voltage levels for the electric utility's different rate classes as determined by periodically conducting Missouri jurisdictional system loss studies.

(A) When the electric utility initially seeks authority to use a RAM, the end of the twelve- (12-) month period of actual data collected that is used in its Missouri jurisdictional system loss study must be within twenty-four (24) months of the date the utility files its general rate proceeding first requesting a RAM.

(B) When the electric utility seeks to continue or modify its RAM, the end of the twelve- (12-) month period of actual data collected that is used in its Missouri jurisdictional system loss study must be no earlier than four (4) years before the date the utility files the general rate proceeding seeking to continue or modify its RAM.

(14) Incentive Mechanism or Performance-Based Program. During a general rate proceeding in which an electric utility has proposed establishment or modification of a RAM, or in which a RAM may be allowed to continue in effect, any party may propose for the commission's consideration incentive mechanisms or performance- based programs to improve the efficiency and cost effectiveness of the electric utility's fuel and purchased power procurement activities and/or off-system sales activities.

(A) The incentive mechanisms or performance-based programs may or may not include some or all components of base energy costs.

(B) Any incentive mechanism or performance-based program shall be structured to align the interests of the electric utility's customers and shareholders. The anticipated benefits to the electric utility's customers from the incentive or performance-based program shall equal or exceed the anticipated costs of the mechanism or program to the electric utility's customers. Customer rates shall include the cost of an incentive mechanism or performance-based program in any time period above what they would be without the incentive mechanism or performance-based program.

(C) If the commission approves an incentive mechanism or performance-based program, such incentive mechanism or performance-based program shall be binding on the commission for the entire term of the incentive mechanism or performance-based program. If the commission approves an incentive mechanism or performance-based program, such incentive mechanism or performance based program shall be binding on the electric utility for the entire term of the incentive mechanism or performance-based program unless otherwise ordered or conditioned by the commission.

(15) Pre-Existing Adjustment Mechanisms, Tariffs, and Regulatory Plans. The provisions of this rule shall not affect—

(A) Any adjustment mechanism, tariff, incentive plan, or other ratemaking mechanism that was approved by the commission and in effect prior to the effective date of this rule; and

(B) Any experimental regulatory plan that was approved by the commission and in effect prior to the effective date of this rule.

(16) Nothing in this rule shall preclude a complaint case from being filed, as provided by law. If a complaint is filed on the grounds that an electric utility is acting in violation of its approved RAM tariff sheets or on the grounds that its rates have become unjust and unreasonable, the commission shall issue a procedural schedule that includes a clear delineation of the case timeline no later than sixty (60) days from the date the complaint is filed.

(17) Party status and rights in RAM proceedings.

(A) Each party to the most recent general rate proceeding in which the commission established, continued, or modified the electric utility's RAM shall be a party to each subsequent related RAM rate adjustment proceeding, RAM true-up proceeding, and RAM prudence review proceeding, without applying to the commission for intervention, and shall be provided access to the periodic reports and surveillance monitoring reports required by this rule during the period of time when they are entitled to be a party to such proceedings without applying for intervention. In any subsequent general rate proceeding, such person or entity must seek and be granted status as an intervenor to be a party to that case and to consequently be a party, without seeking and being granted status as an intervenor to RAM-related proceedings initiated after that case.

(B) Anyone may seek to intervene, pursuant to 4 CSR 240-2.075, in any RAM rate adjustment proceeding, RAM true-up proceeding, RAM prudence review proceeding, or general rate proceeding to modify, continue, or discontinue a RAM. If no party objects to the intervention request within ten (10) days of when it is filed, then the applicant for intervention shall be deemed to have been granted intervention without a specific commission order, unless within the above-referenced ten- (10-) day period the commission denies the application for intervention on its own motion. If an objection to the application for intervention is filed on or before the end of the above-referenced ten- (10-) day period, the commission shall rule on the application and the objection within ten (10) days of the filing of the objection.

(18) Discovery. Each discovery response that a party obtains in general rate proceedings where the commission approves, modifies, rejects, continues, or discontinues a RAM and in related subsequent RAM rate adjustment proceedings, RAM true-up proceedings, and RAM prudence review proceedings may be offered as evidence in any subsequent RAM rate adjustment proceeding, RAM true-up proceeding, RAM prudence review proceeding, or general rate proceeding to modify, continue, or discontinue its RAM as if the response were made to a discovery request in that proceeding without requiring the party who made the request to resubmit the same discovery request (data request, interrogatory, request for production, request for admission, or deposition), subject to commission ruling on any evidentiary objection(s). Unless the commission orders otherwise, *sua sponte* or on a party's motion, the discovery response shall have the same protection it was last afforded, by rule or by commission order.

(19) Supplementing and updating discovery responses in subsequent related proceedings. A party who provided a discovery response in a prior case as described in section (18) shall be under no obligation to supplement or update that response in a subsequent proceeding, unless the requesting party issues a discovery request in the subsequent case which clearly identifies the particular discovery requests to be supplemented or updated and the particular period to be covered by the updated response. A party responding to a request to supplement or update a prior proceeding discovery response shall supplement or update the discovery response where the responding party has learned or subsequently learns its response is in some material respect insufficiently detailed or incorrect.

(20) The commission shall establish a new case for each general rate proceeding, RAM rate adjustment proceeding, RAM true-up proceeding, and RAM prudence review proceeding.

(21) Right to Discovery Unaffected. In addressing certain discovery matters and the provision of certain information by electric utilities, this rule is not intended to restrict the discovery rights of any party.

(22) Waiver of Provisions of this Rule. Provisions of this rule may be waived by the commission for good cause.

AUTHORITY: sections 386.250, 386.266, and 393.140, RSMo 2016. Original rule filed June 15, 2006, effective Jan. 30, 2007. Amended: Filed May 24, 2018, effective Jan. 30, 2019.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.266, RSMo 2005; and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-20.091 Electric Utility Environmental Cost Recovery Mechanisms

PURPOSE: This rule allows the establishment of an Environmental Cost Recovery Mechanism, which allows periodic rate adjustments to reflect net increases or decreases in an electric utility's prudently *incurred costs directly related to compliance with any federal, state, or local environmental law, regulation, or rule.*

(1) Definitions. As used in this rule, the following terms mean as follows:

(A) Electric utility means electrical corporation as defined in section 386.020, RSMo, subject to commission regulation pursuant to Chapters 386 and 393, RSMo;

(B) Environmental Cost Recovery Mechanism (ECRM) means a mechanism established in a general rate proceeding that allows periodic rate adjustments, outside a general rate proceeding, to reflect the net increases or decreases in an electric utility's incurred environmental costs;

(C) Environmental costs means prudently incurred costs, both capital and expense, directly related to compliance with any federal, state, or local environmental law, regulation, or rule.

1. Environmental costs do not include fuel and purchased power costs as defined in 4 CSR 240-20.090(1)(B).

2. Prudently incurred costs do not include any increased costs resulting from negligent or wrongful acts or omissions by the utility;

(D) The environmental revenue requirement shall be comprised of the following:

1. All expensed environmental costs (other than taxes and depreciation associated with capital projects) that are included in the electric utility's revenue requirement in the general rate proceeding in which the ECRM is established; and

2. The costs (i.e., the return, taxes, and depreciation) of any major capital projects whose primary purpose is to permit the electric utility to comply with any federal, state, or local environmental law, regulation, or rule. Representative examples of such capital projects to be included (as of the date of adoption of this rule) are electrostatic precipitators, fabric filters, nitrous oxide emissions control equipment, and flue gas desulfurization equipment. The costs of such capital projects shall be those identified on the electric utility's books and records as of the last day of the test year, as updated, utilized in the general rate proceeding in which the ECRM is established;

(E) General rate proceeding means a general rate increase proceeding or complaint proceeding before the commission in which all relevant factors that may affect the costs, or rates and charges, of the electric utility are considered by the commission;

(F) Rate class is a customer class as defined in an electric utility's tariff. Generally, rate classes include Residential, Small General Service, Large General Service, and Large Power Service, but may include additional rate classes. Each rate class includes all customers served under all variations of the rate schedules available to that class;

(G) Staff means the staff of the Public Service Commission; and

(H) True-up year means the twelve (12)-month period beginning on the first day of the first calendar month following the effective date of the commission order approving an ECRM unless the effective date is on the first day of the calendar month. If the effective date of the commission order approving a rate mechanism is on the first day of a calendar month, then the true-up year begins on the effective date of the commission order. The first annual true-up period shall end on the last day of the twelfth calendar month following the effective date of the commission order establishing the ECRM. Subsequent true-up years shall be the succeeding twelve (12)-month periods. If a general rate proceeding is concluded prior to the conclusion of a true-up year, the true-up year may be less than twelve (12) months. If the commission approves both a fuel adjustment clause mechanism and an ECRM for the electric utility, the true-up year will be the same for both.

(2) Applications to Establish, Continue, or Modify an ECRM. Pursuant to the provisions of this rule, 4 CSR 240-2.060, and section 386.266, RSMo, only an electric utility in a general rate proceeding may file an application with the commission to establish, continue, or modify an ECRM by filing tariff schedules. Any party in a general rate proceeding in which an ECRM is in effect or proposed may seek to continue, modify, or oppose the ECRM. The commission shall approve, modify, or reject such applications to establish an ECRM only after providing the opportunity for a full hearing in a general rate proceeding. The commission shall consider all relevant factors that may affect the costs or overall rates and charges of the petitioning electric utility.

(A) The commission may approve the establishment, continuation, or modification of an ECRM and rate schedules implementing an ECRM provided that it finds that the ECRM it approves is reasonably designed to provide the electric utility with a sufficient opportunity to earn a fair return on equity. Any rate schedule approved to implement an ECRM must conform to the ECRM approved by the commission.

(B) The commission may take into account any change in business risk to the utility resulting from establishment, continuation, or modification of the ECRM in setting the electric utility's allowed return in any rate proceeding, in addition to any other changes in business risk experienced by the electric utility.

(C) In determining which environmental cost components to include in an ECRM, the commission will consider, but is not limited to only considering, the magnitude of the costs, the ability of the utility to manage the costs, the incentive provided to the utility as a result of the inclusion or exclusion of the cost, and the extent to which the cost is related to environmental compliance.

(D) The commission may, in its discretion, determine what portion of prudently incurred environmental costs may be recovered in an ECRM and what portion shall be recovered in base rates.

(E) Any party to the general rate proceeding may oppose the establishment, continuation, or modification of an ECRM and/or may propose alternative ECRMs for the commission's consideration, including but not limited to modifications to the electric utility's proposed ECRM.

(F) The ECRM shall be based on known and measurable environmental costs that have been incurred by the electric utility.

(G) If an ECRM is approved, the commission shall determine the base environmental revenue requirement.

(H) If costs are requested to be recovered through the ECRM and the revenue to be collected in the ECRM rate schedules exceeds two and one-half percent (2.5%) of the electric utility's Missouri annual gross jurisdictional revenues, the electric utility cannot subsequently request that any cost identified as an environmental cost be recovered through a fuel rate adjustment mechanism.

(I) The electric utility shall include in its initial notice to customers regarding the general rate case, a commission approved description of how the costs passed through the proposed ECRM requested shall be applied to monthly bills.

(J) The electric utility shall meet the filing requirements in 4 CSR 240-3.162(2), in conjunction with an application to establish an ECRM, and 4 CSR 240-3.162(3), in conjunction with an application to continue or modify an ECRM.

(3) Application for Discontinuation of an ECRM. The commission shall allow or require the rate schedules that define and implement an ECRM to be discontinued and withdrawn only after providing the opportunity for a full hearing in a general rate proceeding. The commission shall consider all relevant factors that affect the cost or overall rates and charges of the petitioning electric