Volume 51, Number 21
Pages 1405–1552

November 2, 2026

MISSOURI



REGISTER

Denny Hoskins Secretary of State

per diem and appointment of members by the governor with the advice and consent of the senate—no longer conform to section 334.430, RSMo.

AUTHORITY: sections 334.125, RSMo 2000, and 334.414, RSMo Supp. 2005. This rule originally filed as 4 CSR 150-9.140. Original rule filed Jan. 17, 2006, effective Aug. 30, 2006. Moved to 20 CSR 2150-9.140, effective Aug. 28, 2006. Rescinded: Filed Sept. 17, 2026.

PUBLIC COST: This proposed rescission will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed rescission will not cost private entities more than five hundred dollars ($500) in the aggregate.

NOTICE TO SUBMIT COMMENTS: Anyone may file a statement in support of or in opposition to this proposed rescission with the State Board of Registration for the Healing Arts, 3605 Missouri Blvd, PO Box 4, Jefferson City, MO 65102, by facsimile at (573) 751-3166, or via email at healingarts@pr.mo.gov. To be considered, comments must be received within thirty (30) days after publication of this notice in the ***Missouri Register****. No public hearing is scheduled.*

TITLE 20 — DEPARTMENT OF COMMERCE AND INSURANCE
Division 4240 — Public Service Commission
Chapter 21 — Resource Planning for Electric Utilities

PROPOSED RULE

20 CSR 4240-21.010 General Provisions

PURPOSE: This rule establishes the general provisions for Chapter 21, Resource Planning for Electric Utilities, and supplements the requirements found in section 393.1900, RSMo.

(1) Applicability.

(A) All rules under Chapter 21, Resource Planning for Electric Utilities, shall apply to all electric utilities.

(2) Resource planning objectives.

(A) It is the responsibility of the electric utility to stay informed on evolving resource planning issues and to consider and analyze these issues in a timely manner in its integrated resource plan (IRP).

(B) The requirements under Chapter 21 establish minimum standards to govern resource planning, including —

1. The pre-IRP proceeding, as outlined in section 393.1900.1, RSMo;
2. The IRP filing requirements; and
3. Implementation plan status reports as outlined in 20 CSR 4240-21.065.

(C) The commission shall review the electric utility's integrated resource plan to determine if the preferred resource plan appropriately balances all of the balancing factors.

1. Resource adequacy to serve anticipated peak electric load and seasonal peak demand forecasts, applicable planning reserve margin, local clearing requirements, and the role of energy and capacity markets.
2. Reliability.
3. Rate impacts.
4. The availability for purchase from third parties of affordable and reliable generation, together with any required transmission.
5. Overall cost-effectiveness in providing service.
6. Commodity price risks.
7. Diversity of supply-side resources.
8. Competitive pricing.
9. Participation in regional transmission organization markets.
10. Compliance with applicable state and federal environmental regulations.

AUTHORITY: sections 386.040, 386.250, 386.610, 393.140, RSMo 2016, and section 393.1900, RSMo Supp. 2026. Original rule filed Sept. 18, 2026.

PUBLIC COST: This proposed rule will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed rule will not cost private entities more than five hundred dollars ($500) in the aggregate.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file comments in support of or in opposition to this proposed rule with the Missouri Public Service Commission, Nancy Dippell, Secretary of the Commission, PO Box 360, Jefferson City, MO 65102. To be considered, comments must be received at the commission's offices on or before Dec. 2, 2026, and should include a reference to Commission Case No. EX-2027-0085. Comments may also be submitted via a filing using the commission's electronic filing and information system at https://psc.mo.gov/General/Submit_Comments. A public hearing regarding this proposed rule is scheduled for Dec. 15, 2026, at 10 a.m., in Room 310 of the Governor Office Building, 200 Madison St., Jefferson City, MO. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed rule and may be asked to respond to commission questions. Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 or TDD Hotline 1-800-829-7541.

TITLE 20 — DEPARTMENT OF COMMERCE AND INSURANCE
Division 4240 — Public Service Commission
Chapter 21 — Resource Planning for Electric Utilities

PROPOSED RULE

20 CSR 4240-21.015 Electric Utility Resource Planning Definitions

PURPOSE: This rule establishes definitions of terms used in Chapter 21, Resource Planning for Electric Utilities.

(1) Accredited capacity means the deliverable or firm capacity value as determined and assigned to a resource by the appropriate regional transmission organization or independent system operator (RTO/ISO) for determining resource adequacy.

(2) Alternative resource plan means a schedule of a

combination of supply-side, demand-side, and distribution and transmission resource additions and retirements that the electric utility develops or the commission orders pursuant to 20 CSR 4240-21.020(2)(B)8. and then the electric utility analyzes as part of its integrated resource plan (IRP) to meet its load serving obligations, or with respect to the commission's order to be issued pursuant to 20 CSR 4240-21.020(2)(C)12., a set of conditions used to describe such a schedule, such as retirement of an existing resource by a certain date, or inclusion or exclusions of certain supply-side or demand-side resources.

(3) Annual energy usage means the total amount of energy the electric utility uses combined with the total amount of energy the electric utility's customers use as metered by the appropriate RTO/ISO over a three-hundred-sixty-five- (365-) day time period.

(4) Appropriate regional transmission organization or independent system operator (RTO/ISO) means the Midcontinent Independent System Operator (MISO), or any successor organization, or the Southwest Power Pool (SPP), or any successor organization of which the electric utility is a member.

(5) Approved preferred resource plan means the alternative resource plan the electric utility presents in its IRP as its preferred resource plan, which the commission finds to be a reasonable and prudent means for the electric utility to meet its load serving obligations.

(6) Advanced transmission technology or advanced distribution technology means a technology, including hardware or software solutions, that increases or optimizes the capacity, efficiency, reliability, or safety of existing or new infrastructure such as grid enhancing technologies.

(7) Avoided demand cost means a component of total avoided cost which represents the portion of the electric utility's marginal cost savings that results from reducing the peak demand by season, measured in kilowatts (kW), thereby eliminating or deferring the need for capacity investments for generation, transmission, and distribution, or the corresponding market-based equivalents of those costs. Where appropriate for clarity or precision for larger quantities, values may be expressed in megawatts (MW) or gigawatts (GW), provided the unit of measurement is clearly labeled.

(8) Avoided energy cost means a component of total avoided cost which represents the portion of the electric utility's marginal cost savings that results from reducing the overall energy consumption, measured in kilowatt-hours (kWh), thereby reducing the utility's fuel costs, emission allowance costs, and other variable operation and maintenance costs of generation facilities, adjusted to reflect energy losses on the transmission and distribution systems, or the corresponding market-based equivalents of those costs. Where appropriate for clarity or precision for larger quantities, values may be expressed in megawatt-hours (MWh) or gigawatt-hours (GWh), provided the unit of measurement is clearly labeled.

(9) Avoided costs means the cost savings obtained by substituting demand-side programs for existing and new supply-side resources. Avoided costs include avoided utility costs resulting from demand-side programs' energy savings and demand savings associated with generation, transmission, and distribution facilities including avoided probable environmental compliance costs.

(10) Balancing factors means the factors, as outlined in 20 CSR 4240-21.010(2)(C), that should be balanced in the development of an IRP.

(11) Base-case load forecast means the forecast generated by using the most likely values, generally those representing the fiftieth percentile of the dataset, for each independent variable contained in a forecast model and based on the electric utility's native forecast adjusted for existing large load.

(12) Candidate resource options means the potential demand-side resource options and potential supply-side resource options that advance to be considered for inclusion in alternative resource plans.

(13) Capacity means the maximum capability, measured in megawatts (MW), to continuously produce and deliver electric power.

(14) Capacity expansion model means the optimization software used in developing the IRP to plan the least cost portfolio of supply-side and demand-side resources to be utilized over the planning horizon to meet demand, reliability, and policy goals.

(15) Coincident peak means the demand of a customer, customer class, resource, or electric utility measured during the same hour in which the applicable system, whether the electric utility, the balancing authority, or the RTO/ISO, experiences its maximum demand for the relevant time period.

(16) Cost means the amount or a change in the amount of the electric utility's investments or operational expenditures. The electric utility shall express all costs and benefits in nominal dollars.

(17) Critical uncertain factor means any uncertain factor that is likely to materially affect the outcome of the resource planning decision.

(18) Degree days means a measure of how extreme the weather is at a location is relative to a standard temperature, typically sixty-five degrees Fahrenheit (65 °F) though other standard temperatures may be used. There are two types of degree-days, heating and cooling degree-days. Heating degree-days (HDD) are determined from the average daily temperature (T) (daily maximum temperature plus daily minimum temperature divided by two (2)) using the formula HDD = 65 - T if greater than or equal to zero, and zero (0) otherwise. Cooling degree-days (CDD) are determined by the formula CDD = T - 65 if greater than or equal to zero, and zero (0) otherwise.

(19) Demand means the electrical power consumed at a given point in time, measured in kilowatts (kW). Where appropriate for clarity or precision for larger quantities, values may be expressed in megawatts (MW) or gigawatts (GW), provided the unit of measurement is clearly labeled.

(20) Demand-side program means an organized process for packaging and delivering to a particular market segment a portfolio of end-use measures that is broad enough to include at a minimum of some measures that are appropriate for most

members of the target market segment.

(21) Demand-side resources means the resources designed to reduce electricity consumption, particularly during peak demand times, and can include energy efficiency programs and demand response programs.

(22) Demand response program means a strategy used to manage electricity demand by encouraging consumers to adjust usage patterns based on the price of electricity.

(23) Describe or description means the electric utility's provision of information in any filing, in sufficient detail to inform any stakeholder how the electric utility complies with each applicable requirement of Chapter 21, the approach, and the results.

(24) Descriptive statistics means a set of brief values that describes a dataset's central tendency and dispersion, including but not limited to its mean, median, mode, maximum, minimum, and standard deviation.

(25) Distributed energy resource (DER) means any resource located on the distribution system, any subsystem thereof or behind a customer meter. DER includes but is not limited to energy storage systems (ESS), solar photovoltaic systems, and electric vehicle charging systems.

(26) Distributed Energy Resource Aggregation (DERA) means the assembly of a portfolio of DERs from one (1) or more entities that a single entity, such as an aggregator, manages collectively to provide energy, capacity, and/or ancillary services to the wholesale electricity market. The aggregator acts as the single point of contact, controlling the aggregated resources in response to market signals.

(27) Distributed generation means a grid connected electrical generation system that is sized based on local load requirements and distributed primarily to the local load. Examples of different types of distributed generation include solar photovoltaic, wind, and combined heat and power.

(28) Document or documentation means the electric utility's provision of supporting information prepared by the utility or prepared by a third party and used by the utility to support its IRP, including but not limited to workpapers, analyses, estimates, studies, or forecasts consistent with the standards of 20 CSR 4240-21.025.

(29) Econometric methodology means the use of statistical models such as regression models, time series methods, statistically adjusted end-use (SAE) models, or hybrid models that integrates end-use determinants with econometric, time-series, or other statistical methods.

(30) Electric utility means the electrical corporation as defined in section 386.020, RSMo, but shall not include the electrical corporation as described in section 393.110.2, RSMo.

(31) Electrification means replacing or converting energy-consuming devices, systems, or processes that use non-electric sources of energy with electrically powered equivalents.

(32) End-point means a designated juncture within the electric utility planning model or scenario framework that is the result of applying specific potential outcomes associated with each critical uncertain factor.

(33) Energy service means the specific need that is served by the final use of energy, such as lighting, cooking, space heating, air conditioning, refrigeration, water heating, or motive power.

(34) Energy storage system (ESS) means a system capable of capturing energy, storing it, and dispatching the energy back into the bulk power system or the electric utility's distribution system, that the appropriate RTO/ISO accredits in resource adequacy determinations. ESS may be considered a transmission or generation asset.

(35) End-use forecasting means a bottom-up load forecasting methodology that breaks down total customer energy consumption, both sales and demand, into specific, functional end-uses, such as space heating, cooling, water heating, lighting, or industrial processes, and projects each of those uses separately into the future.

(36) End-use measure means an energy-efficiency measure or an energy-management measure.

(37) Energy means the total amount of electric power that is generated or used over a specified interval of time measured in kilowatt-hours (kWh). Where appropriate for clarity or precision for larger quantities, values may be expressed in megawatts (MW) or gigawatts (GW), provided the unit of measurement is clearly labeled.

(38) Energy efficiency or energy efficiency measure means any device, technology, or operating procedure that makes it possible to deliver an adequate level and quality of end-use energy service while using less energy than would otherwise be required.

(39) Energy management measure means any device, technology, or operating procedure that makes it possible to alter the time pattern of electric usage so as to require less generating capacity or reduce energy usage during times of elevated prices. An energy management measure is sometimes referred to as a demand-response program.

(40) Expected accredited capacity means the electric utility's expectation of accredited capacity in each and every future year, by season, of the planning horizon.

(41) Expected unserved energy means the statistical expectation of the amount of energy per year that the electric utility will be unable to supply its native load without importing emergency power.

(42) Explain or explanation means to provide a clear and complete account of the findings, analyses, methodologies, assumptions, data, and reasoning relied upon in reaching a conclusion, including the relationships among those elements and how they support the conclusion, in sufficient detail to enable any stakeholder to understand the basis for the electric utility's determination.

(43) Firm transmission service means the transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency or an unanticipated facility failure.

(44) Forecast period means an amount of time over which a forecast is made that may have a length exceeding the planning horizon.

(45) Generation attribute means the capacity, energy, and other generating unit capabilities used in regional energy and capacity markets to differentiate services that various types of generating units provide.

(46) Generation technology means the various methods and technologies that the electric utility uses to generate electricity currently and during the planning horizon.

(47) Historical period means the ten (10) most recent years, or the period of time used as the basis of the electric utility's load forecast, whichever is longer.

(48) Implementation period means a four (4) year period that ends three hundred sixty-five (365) days after the electric utility's next commission-scheduled IRP filing date.

(49) Implementation plan means the supply-side resources or quantity of supply-side resources by supply-side resource type, or both, to be constructed or acquired as part of the preferred resource plan over the implementation period and any other information required in accordance with 20 CSR 4240-21.065.

(50) Integrated resource plan (IRP) means the document submitted in accordance with section 393.1900, RSMo, which addresses the requirements outlined in section 393.1900, RSMo, and this chapter.

(51) Integrated resource plan (IRP) filing date means the date the IRP is required to be filed in accordance with 20 CSR 4240-21.020(1).

(52) Justify or justification means to support a proposal, action, estimate, or conclusion with all material facts, data, analyses, assumptions, methodologies, calculations, workpapers, and documentation relied upon by the electric utility. The information provided must be complete, accurate, and sufficiently detailed to permit any stakeholder to independently evaluate, verify, and, where applicable, reproduce the electric utility's analyses, calculations, and conclusions.

(53) Large load means a rate class or customer class as defined in the electric utility's commission approved tariffs in accordance with section 393.130.7, RSMo.

(54) Large load metrics means the following metrics that together describe whether, when, and to what level large load projects materialize and use electricity over time:

(A) Project realization means the rate at which large load projects included in the load forecast are placed in service, that may be expressed as a percentage;

(B) Energization date means the date when a large load will be placed into commercial operation, including anticipated delays;

(C) Load ramping means the monthly or annual forecast of demand during the period between initial project energization and reaching full forecast peak load;

(D) Load realization means the forecast peak load once new large load projects fully ramp from energization to maximum operation and may be expressed as a percentage of requested or contract peak load;

(E) Load factor means the ratio of actual energy used to the maximum possible energy used if peak demand is continuously maintained throughout the time period where the actual energy is measured; and

(F) Load shape means the pattern of energy use over a given time frame, such as a day, month, or year. Typically, this is provided for each hour for the eight thousand seven hundred sixty (8,760) hours in a year.

(55) Large load project means a project that qualifies pursuant to the electric utility's commission-approved tariffs in accordance with section 393.130.7, RSMo.

(55) Legal mandates mean applicable state and federal executive orders, statutes, court decisions, and applicable state and federal administrative agency orders, rules, and regulations affecting electric utility cost recovery mechanisms, loads, resources, or resource plans.

(56) Limited inquiry certificate of convenience and necessity (CCN) means a CCN proceeding in which the commission's inquiry is limited as outlined in section 393.1900.5.(1), RSMo.

(57) Load-building program means the electric utility's organized promotional effort to persuade energy-related decision-makers to choose electricity instead of other forms of energy for the provision of energy service, or to persuade existing customers to increase their use of electricity, by either substituting electricity for other forms of energy or increasing the level or variety of energy services used. This term is not intended to include the provision of technical or engineering assistance, information about filed rates and tariffs, or other forms of routine customer service.

(58) Load impact means the change in energy usage and the change in diversified demand during a specified interval of time due to the implementation of a demand-side resource.

(59) Load management means the process of balancing the supply of electricity on the network with the electrical load by adjusting or controlling the load rather than the generating station.

(60) Load profile means a plot of hourly demand versus chronological hour of the day from the hour ending 1:00 a.m. to the hour ending at midnight.

(61) Local clearing requirements means the minimum amount of capacity needed to ensure reliability within a specific local resource zone or reserve zone. The electric utility shall calculate this capacity consistent with the appropriate RTO/ISO requirements.

(62) Long-run means an analytical framework within which all factors of production are variable.

(63) Loss of load expectation (LOLE) means the measure of how often, on average, the available generation capacity is likely to fall short of the load demand.

(64) Maximum achievable potential means the energy savings and demand savings relative to the electric utility's baseline energy forecast and baseline demand forecast, respectively, resulting from expected program participation and ideal implementation conditions. Maximum achievable potential establishes a maximum target for demand-side savings that

the electric utility can expect to achieve through its demand-side programs and involves incentives that represent a very high portion of total program costs and/or very short customer payback periods. Maximum achievable potential is considered the hypothetical upper boundary of achievable demand-side savings potential, because it presumes conditions that are ideal and are not typically observed.

(65) Measure saturation means the statistical measurement of the percentage of homes or businesses that possess a specific type of electric or gas technology, such as an appliance, mechanical system or control such as central air conditioning, electric water heater, gas furnace, or smart thermostat, within the electric utility's service territory. Measure saturation, along with the Unit Energy Consumption (UEC) for each technology, is used as an independent variable in end-use forecasting models.

(66) Missouri Energy Efficiency Investment Act (MEEIA) means the state law established in section 393.1075, RSMo.

(67) MEEIA demand-side resources means the demand-side resources proposed as a program in accordance with the commission's MEEIA rules: 20 CSR 4240-20.092; 20 CSR 4240-20.093; and 20 CSR 4240-20.094.

(68) Net system load means the hourly electric supply necessary to meet the energy demands of the electric utility's customers and the electric utility's own internal needs net of station use.

(69) Nominal dollars means the future, or then current, dollar values that are not adjusted to remove the effects of anticipated inflation.

(70) Non-coincident peak means the highest energy consumed by a specific customer, a customer class, or a component of the system over a short time period, typically either fifteen (15) or thirty (30) minutes for specific customer or one (1) hour at the system level that occurs at any time during a specified billing period or interval, regardless of the system's total load.

(71) Non-MEEIA demand-side resources means the demand-side resources proposed as a program in accordance with the commission's promotional practice rules: 20 CSR 4240-3.150 and 20 CSR 4240-14.

(72) Participant means an energy-related decision-maker who implements one (1) or more end-use measures as a direct result of a demand-side program.

(73) Planning horizon means a future time period of a minimum of sixteen (16) years over which the costs and benefits of alternative resource plans are evaluated.

(74) Planning reserve margin means the capacity determined by the appropriate RTO/ISO for which the electric utility must have equal to or greater than accredited capacity for the applicable time period.

(75) Preferred resource plan means the alternative resource plan that is contained in the integrated resource plan that the electric utility selects to represent the most prudent and reasonable alternative resource plan to meet its load serving obligations.

(76) Pre-IRP proceeding means the proceeding referenced in 393.1900.1, RSMo, that is initiated forty-five (45) days prior to when the electric utility files the pre-IRP minimum filing requirements and concludes with a commission order specifying the alternative resource plans, scenarios, sensitivities, relevant emerging factors, and any other factors.

(77) Probable environmental compliance cost means the expected cost to the electric utility of complying with new or additional environmental legal mandates, taxes, or other requirements that may be imposed at some point within the planning horizon which would result in compliance costs that could have a significant impact on electric utility rates.

(78) Production cost model means a software tool used to simulate the hourly operation of electric systems to determine the costs associated with electricity production based on various inputs such as supply-side resources, load forecasts, and operational constraints.

(79) Public counsel means the Office of the Public Counsel of the state of Missouri or its designated representative.

(80) Rate class or customer class means as those terms are defined in the electric utility's tariff. Generally, rate classes or customer classes include residential, small general service, large general service, and large power service, but may include additional classes. Each rate class includes all customers served under all variations of the rate schedules available to that class.

(81) Realistic achievable potential means the energy savings and demand savings relative to the electric utility's baseline energy forecast and baseline demand forecast, respectively, resulting from expected program participation and realistic implementation conditions. Realistic achievable potential establishes a realistic target for demand-side savings that the electric utility can expect to achieve through its demand-side programs and involves incentives that represent a moderate portion of total program costs and/or longer customer payback periods when compared to those associated with maximum achievable potential.

(82) Relevant emerging factors means a list of new or evolving topics where the commission in the pre-IRP proceeding determines that additional research and knowledge is needed and that should therefore be addressed in the electric utility's IRP.

(83) Relevant future timeframe means the planning horizon.

(84) Renewable energy means the electricity generated from a source that is classified as a renewable energy source under a state or federal renewable energy standard to which the electric utility is subject.

(85) Resource means supply-side resources and demand-side resources.

(86) Resource planning means the process by which the electric utility evaluates and chooses the appropriate mix and schedule of supply-side, demand-side, and distribution and transmission resource additions and retirements to provide the public with an adequate level, quality, and variety of end-use energy services.

(87) Resource type means the fuel or source used for energy

generation, including but not limited to natural gas, coal, oil, solar, wind, nuclear, hydroelectric, geothermal, pumped storage hydroelectric system, and other energy storage systems when used as a generation asset.

(88) Seasonal coincident peak means the total electric demand of the electric utility system, a customer class, or a specific zone that occurs at the exact hour of the highest overall system demand within a defined seasonal period such as summer, fall, winter, or spring. It is a time-differentiated measure used to determine capacity obligations and to allocate fixed costs.

(89) Scenario means a set of input assumptions and constraints.

(90) Sensitivity means a model run that changes a single key input to understand how that input affects or drives results across scenarios.

(91) Service territory means the area in which the commission approves the electric utility to provide electrical service to customers.

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

(93) Stakeholder means staff, public counsel, and/or any person or entity granted intervention in the pre-IRP proceeding or IRP docket at issue.

(94) Subjective probability means a probability estimate based on an evaluation of available information and circumstances, rather than objective methods such as mathematical models.

(95) Sufficient capacity means owned or contracted-for capacity that meets the planning reserve margin or successor metric established by the appropriate RTO/ISO or established by the commission if the electric utility is not a participant in a regional transmission organization or independent system operator.

(96) Supply-side resource means any device or method by which the electric utility provides to its customers an adequate level and quality of electric power supply, including distributed energy resources and other supply-side resources operated by a third party under a lease, power purchase agreement, or other service contract.

(97) System needs means, but is not limited to, peak demand; energy requirements; reserve-margin requirements; regulatory compliance; reliability; environmental or renewable-energy standards compliance; and system flexibility.

(98) Technical potential means the energy savings and demand savings relative to the electric utility's baseline energy forecast and baseline demand forecast, resulting from a theoretical construct that assumes customers of the electric utility adopt all feasible measures, regardless of cost or customer preference.

(99) Transmission losses means the amount of real power, expressed as a percentage, that is lost in transmission facilities, when delivering energy to load.

(100) Uncertain factor means any event, circumstance, situation, relationship, causal linkage, price, cost, value, response, or other relevant quantity which can materially affect the outcome of resource planning decisions, about which the electric utility has incomplete or inadequate information at the time a decision must be made.

(101) Utility costs means the costs of operating the electric utility system. On an annual basis, utility cost is synonymous with electric utility revenue requirement.

AUTHORITY: sections 386.040, 386.250, 386.610, 393.140, RSMo 2016, and section 393.1900, RSMo Supp. 2026. Original rule filed Sept. 21, 2026.

PUBLIC COST: This proposed rule will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed rule is estimated to cost private entities up to six hundred thousand dollars ($600,000) annually.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file comments in support of or in opposition to this proposed rule with the Missouri Public Service Commission, Nancy Dippell, Secretary of the Commission, PO Box 360, Jefferson City, MO 65102. To be considered, comments must be received at the commission's offices on or before Dec. 2, 2026, and should include a reference to Commission Case No. EX-2027-0085. Comments may also be submitted via a filing using the commission's electronic filing and information system at https://psc.mo.gov/General/Submit_Comments. A public hearing regarding this proposed rule is scheduled for Dec. 15, 2026, at 10 a.m., in Room 310 of the Governor Office Building, 200 Madison St., Jefferson City, MO. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed rule and may be asked to respond to commission questions. Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 or TDD Hotline 1-800-829-7541.

FISCAL NOTE
PRIVATE COST

I. Department Title: Title 20--DEPARTMENT OF COMMERCE AND INSURANCE
Division Title: Division 4240—Public Service Commission
Chapter Title: Chapter 21— Resource Planning for Electric Utilities

Rule Number and Title:	20 CSR 4240-21.015 Definitions
Type of Rulemaking:	Proposed Rule

II. SUMMARY OF FISCAL IMPACT

Estimate of the number of entities by class which would likely be affected by the adoption of the rule:	Classification by types of the business entities which would likely be affected:	Estimate in the aggregate as to the cost of compliance with the rule by the affected entities:
4	Investor-Owned Electrical Corporations	$ 0 to $ 600,000 annually for the estimated five-year (5-year) life of the rule.

III. WORKSHEET

The rule will likely affect four (4) electrical corporations (investor-owned electric utilities). Staff requested input on the anticipated cost to implement the proposed rule from the affected electrical corporations. The feedback that was received was that the proposed rule would have a $ 0 to $ 600,000 cost for the electrical corporations to implement.

IV. ASSUMPTIONS

Staff relied on the input from the four (4) electrical corporations to determine the estimated fiscal impact of this proposed rule. Costs for this rule are associated with documentation requirements related to the terms defined in this rule and throughout all rules in Chapter 21.

In accordance with the Commission's May 22, 2026, order, all four utilities submitted rule comments and estimated costs to comply. The low estimate assumes zero incremental cost to the rule. The high estimate is based on Ameren's revised high cost estimate.

Ameren submitted rule comments and cost of compliance information through the Commission's electronic filing system on June 22, 2026. Staff carefully considered Ameren's rule comments and made significant responsive changes to the rule language. On July 31, 2026, Ameren emailed Staff updated cost estimates based on the revised rule language.

Liberty-Empire submitted rule comments and cost of compliance information through the Commission's electronic filing system on June 22, 2026. Liberty-Empire stated that it could not estimate the cost of a process that has never been undertaken, but the prescriptiveness of the new requirements will result in a significantly higher cost to comply. Staff carefully considered Liberty-Empire's rule comments and made significant responsive changes to the rule language.

Evergy submitted rule comments and cost of compliance information through the Commission's electronic filing system on June 22, 2026. Evergy stated that the prescriptiveness of the new requirements will drive significant costs to comply. Staff carefully considered Evergy's rule comments and made significant responsive changes to the rule language.

Assumptions:

- Rule life: 5 years.
- Annual labor cost: $0 - $200,000
- Number of electric utilities: 3 (Ameren Missouri, Evergy, Liberty-Empire)

Calculation:
Low total cost for all 3 utilities = $0

High total cost for all 3 utilities = (3)*($200,000) = $600,000 year one

TITLE 20 – DEPARTMENT OF COMMERCE AND INSURANCE
Division 4240 – Public Service Commission
Chapter 21 – Resource Planning for Electric Utilities

PROPOSED RULE

20 CSR 4240-21.020 Filing Schedule, Filing Requirements, and the Integrated Resource Plan Proceeding

PURPOSE: This rule establishes the filing schedule, filing requirements, and the schedule of the integrated resource plan proceeding for the electric utility's integrated resource plan and details and supplements the requirements found in section 393.1900, RSMo.

(1) Each electric utility shall file an integrated resource plan (IRP), as required in section 393.1900, RSMo, every four (4) years, or as needed thereafter if ordered by the commission, by the first business day in October of the specified year. Each electric utility shall file its initial IRP on the following schedule:

(A) Union Electric Company d/b/a Ameren Missouri, or its successor, October 2029;

(B) Evergy Metro d/b/a Evergy Missouri Metro, or its successor, October 2030;

(C) Evergy Missouri West d/b/a Evergy Missouri West or its successor, October 2030; and

(D) The Empire District Electric Company d/b/a Liberty, or its successor, October 2031.

(2) Pre-IRP proceeding.

(A) A pre-IRP proceeding shall be conducted to achieve the requirements outlined in section 393.1900.1., RSMo. The output of a pre-IRP proceeding shall –

1. Establish, pursuant to section 393.1900.1(4), RSMo, any commission-prescribed alternative resource plans, scenarios, and sensitivities that the electric utility shall analyze as part of its IRP;

2. Specify relevant emerging factors that the electric utility shall examine in its IRP; and

3. Identify any variances or waivers that may be requested pursuant to 20 CSR 4240-2.205.

(B) Pre-IRP proceeding process.

1. The pre-IRP proceeding shall commence forty-five (45) days prior to filing the pre-IRP minimum filing requirements. To commence the pre-IRP proceeding, the electric utility shall –

A. File notice in the case and the proposed schedule of upcoming activities, as outlined in paragraphs (2)(B)3. and (2)(B)5. of this rule; and

B. Notify all intervenors in the electric utility's most recent general rate case and most recent IRP case of the upcoming activities, as outlined in paragraphs (2)(B)3. and (2)(B)5. of this rule.

2. Following the notification by the electric utility, the commission will issue notice of the case and establish a time period for intervention.

3. One (1) month prior to filing the pre-IRP minimum filing requirements, the electric utility shall meet with stakeholders to present the preliminary pre-IRP minimum filing requirements and public engagement plan for stakeholder feedback.

4. The electric utility shall file the pre-IRP minimum filing requirements, as outlined in subsection (2)(C) of this rule, seventeen (17) months prior to the IRP filing date as outlined in section (1) of this rule, with the exception of the first IRP under subsection (1)(A) of this rule, for which the electric utility shall file the pre-IRP minimum filing requirements no less than twenty-six (26) months prior to the IRP filing date.

5. Within one (1) month of the electric utility filing the pre-IRP minimum filing requirements, the electric utility shall –

A. Hold public engagement meetings to provide the opportunity for public input into the electric utility's resource planning process;

B. File a notice summarizing the feedback received from the public engagement efforts, including a description of how the electric utility may incorporate or consider the feedback in the electric utility's IRP submitted pursuant to section (1) of this rule; and

C. Hold presentations and a series of technical sessions with stakeholders to present the pre-IRP proceeding minimum filing requirements, obtain stakeholder feedback, and develop or refine the proposed inputs and assumptions.

6. Within three (3) months of the electric utility filing the pre-IRP minimum filing requirements, the stakeholders and the electric utility must determine if they are able to reach consensus on the topics outlined in subsection (2)(A) of this rule.

7. The stakeholders and the electric utility shall achieve one (1) of the following outcomes:

A. If consensus is achieved, the stakeholders and the electric utility shall file with the commission the proposed agreed-upon alternative resource plans for analysis, the scenarios and sensitivities as inputs for the electric utility's development of alternative resource plans, relevant emerging factors, and any modifications to the previously filed pre-IRP proceeding minimum filing requirements; or

B. If consensus is not achieved, any party may request a hearing for commission determination on unresolved issues.

8. No later than eight (8) months after the electric utility files the pre-IRP minimum filing requirements, the commission shall issue an order to establish and specify the items and information the electric utility shall address in its IRP. The items and information specified in such order shall be in addition to the electric utility's IRP filing obligations pursuant to 20 CSR 4240-21.025 through 20 CSR 4240-21.065.

9. If the electric utility, staff, or public counsel becomes aware of any information that impacts or could impact any direction provided in the commission's order, issued pursuant to paragraph (2)(B)8. of this rule, the electric utility, staff, or public counsel shall –

A. Notify the stakeholders and electric utility within fourteen (14) days of becoming aware of the impact; and

B. Convene an additional technical session with the stakeholders and the electric utility, if necessary, with the goal of jointly recommending a resolution to the commission, notifying the commission that no recommendation is necessary, or notifying the commission that a resolution could not be reached.

(C) The pre-IRP minimum filing requirements shall include the following:

1. Identification of required and proposed planning reserve margins anticipated over the relevant future timeframe;

2. Identification of current or proposed local clearing requirements anticipated over the relevant future timeframe;

3. Identification of existing federal and state environmental regulations, laws, or rules by resource type, and an explanation of how those regulations, laws, or rules apply to the electric utility;

4. Identification of significant proposed federal and state

environmental regulations, laws, or rules, and an explanation of how those regulations, laws, or rules apply to or impact the applicable resource type, and a description of the expected timeframe when each proposed regulation, law, or rule will take effect;

5. Load forecasts for monthly system energy and monthly non-coincident peak over the planning horizon;

6. Identification of anticipated critical uncertain factors based on annual updates prepared by the electric utility in accordance with 20 CSR 4240-21.065(2)(B)2. or 20 CSR 4240-22.080, including descriptive statistics and probability distribution;

7. Identification of reasonable supply-side and demand-side resources that could address the need for additional energy and capacity including, but not limited to –

A. Type and description of technology for proposed supply-side or demand-side resources;

B. Projected load impact due to load-building programs; and

C. Projected load management and demand response savings;

8. Identification of projected range of total costs of different types of technologies and fuels used for existing and future electric generation, including information on the electric utility's availability of different types of fuels, and the projected total costs shall –

A. Include capital, fixed, and variable operation and maintenance costs, fuel, and any other costs that are relevant for the particular technology; and

B. Reflect costs developed or incurred no more than twelve (12) months prior to the pre-IRP minimum requirements filing date;

9. Identification of information that may be useful in developing alternative resource plans, scenarios, sensitivities, and relevant emerging factors, for stakeholder discussion;

10. The comprehensive database required pursuant to 20 CSR 4240-21.030(1)(B);

11. A capacity balance forecast, included herein, provided in the following specified form:

A. The base-case capacity balance forecast shall be provided for each season as determined by the appropriate RTO/ISO and shall include the following:

(I) Only existing supply-side and demand-side resources through the currently expected life of each asset or contract; and

(II) Expected load growth over the planning horizon without additions of large load customers;

B. The large load addition capacity balance forecast shall include –

(I) Only existing supply-side resources through the currently expected life of each asset or contract; and

(II) Expected load growth over the planning horizon with additions of large load projects that have the required probability of interconnection pursuant to 20 CSR 4240-21.030(6)(C)3.; and

12. Any other factors the commission may order to be considered in developing alternative resource plans.

(D) The pre-IRP minimum filing requirements are not intended to be the finalized inputs or assumptions to be incorporated within the IRP analyses and shall be updated and documented as specified in subparagraph (3)(D)4.A.

(E) To the extent that any information required as part of the pre-IRP minimum filing requirements relies upon prior studies or prior IRPs and would materially impact the outcome of the next IRP, the electric utility shall update the information prior to the pre-IRP process to account for current and expected market conditions, regulatory changes, or other conditions or events that necessitate changes to the assumptions.

(3) IRP content.

(A) The electric utility's IRP shall demonstrate compliance with the provisions of Chapter 21 and section 393.1900, RSMo, and shall include at a minimum –

1. A letter of transmittal;

2. An executive summary;

3. Technical volumes; and

4. Such other information or formatting as the commission may order.

(B) The electric utility's letter of transmittal shall –

1. Express commitment to the preferred resource plan and its implementation plan; and

2. Be signed by an officer of the electric utility having the authority to bind and commit the electric utility to the implementation plan for the preferred resource plan, if the commission determines the preferred resource plan to be reasonable and prudent in whole or in part.

(C) The electric utility's executive summary shall –

1. Be suitable for distribution to the public in an electronic format, with redactions if needed;

2. Describe –

A. The electric utility;

B. Its existing supply-side resources, transmission, and distribution facilities;

C. Existing purchase power arrangements; and

D. Existing demand-side programs;

3. Justify the electric utility's selection of the preferred resource plan, and the strategy for the implementation plan, which shall –

A. Provide a summary of the preferred resource plan to meet expected energy service needs for the planning horizon, clearly showing the distributed energy resources, demand-side and supply-side resources, including additions and retirements for each resource type;

B. Identify the critical uncertain factors affecting the preferred resource plan;

C. Describe the existing legal mandates and approved cost recovery mechanisms, and include the following performance measures for each year of the planning horizon:

(I) Estimated annual revenue requirement;

(II) Estimated annual customer rate impact; and

(III) Estimated company financial ratios as specified in 20 CSR 4240-21.060(1)(C)3.; and

D. Describe the major research projects and programs the electric utility will continue or commence during the implementation period;

4. Be organized by and summarize the contents of the technical volumes; and

5. Include information for each rate class and for the total of all rate classes:

A. The base-case load forecasts for peak demand and for energy for the planning horizon, with and without demand-side resources; and

B. A listing of the economic and demographic assumptions associated with the base-case load forecast as specified in 20 CSR 4240-21.030(4).

(D) The electric utility's technical volumes shall –

1. Justify decisions in developing the alternative resource plans, selecting the preferred resource plan, and developing the implementation plan;

2. Be organized by chapters corresponding to 20 CSR 4240-21.025 through 20 CSR 4240-21.060 and 20 CSR 4240-21.065(1) and include all documentation and information specified in

20 CSR 4240-21.025 through 20 CSR 4240-21.065(1), respectively;

3. Include the capacity balance forecast, in the specified form included herein, for the preferred resource plan and each alternative resource plan the electric utility considered; and

4. Include a stand-alone chapter that –

A. Outlines any differences between the information ordered by the commission in paragraph (2)(B)8. of this rule and the information used by the electric utility in its IRP, along with the reasoning for those differences;

B. Identifies the naming convention of the alternative resource plans selected and identifies the alternative resource plan that the electric utility selected as the preferred resource plan; and

C. Addresses relevant emerging factors ordered by the commission under paragraph (2)(B)8. of this rule.

(4) Cost updates to the electric utility's IRP.

(A) If the electric utility's cost estimates submitted in the IRP have materially changed, the electric utility may file an update to the IRP on or before one hundred fifty (150) calendar days from the IRP's filing date.

(B) If the electric utility files a cost update to the IRP, then the electric utility shall –

1. Include the cost updates in a format with sufficient detail to distinguish any changes in cost and an explanation of any other impacts over the planning horizon for costs specified in 20 CSR 4240-21.060 and 20 CSR 4240-21.065(1);

2. Notify the stakeholders no more than ten (10) days after the electric utility becomes aware that a cost update is needed; and

3. Convene discussions with the stakeholders on the potential for requesting a modified procedural schedule to accommodate the additional review.

(5) Potential modifications to the electric utility's approved preferred resource plan.

(A) Proposed changes or unforeseen events may require changes to the electric utility's approved preferred resource plan or the implementation plan. If, between IRP filings, the electric utility's implementation plan becomes materially inconsistent with the approved preferred resource plan, or if the electric utility determines that the approved preferred resource plan or implementation plan is no longer appropriate, either due to the range pursuant to 20 CSR 4240-21.060(4)(E)2.A. being exceeded or for other reasons, the electric utility shall –

1. File a notification in the IRP case within thirty (30) days of the electric utility's determination of such change; and

2. Serve notice to stakeholders in the most recent IRP case.

(B) The electric utility, within thirty (30) days of its notification filing pursuant to paragraph (5)(A)1. of this rule, shall file –

1. A description of all changes to the approved preferred resource plan and the associated implementation plan;

2. The impact of each change on the annual revenue requirement;

3. The impact of the change on the financial performance measures specified in 20 CSR 4240-21.060(1)(C)3.; and

4. Any impact to the performance measures specified in the last IRP pursuant to 20 CSR 4240-21.060(1).

(C) If the electric utility contends that, despite the proposed changes to its approved preferred resource plan identified in subsection (5)(A) of this rule, certain supply-side resources previously determined by the commission as eligible for a limited inquiry certificate of convenience and necessity (CCN) remain materially consistent with the approved preferred resource plan, the electric utility shall include in its notification –

1. Identification of such supply-side resources or quantities by supply-side resource type;

2. A supporting explanation; and

3. Explanation of any impact on the electric utility's ability to timely meet customer energy needs if such supply-side resources are delayed.

(D) Within twenty (20) days after the electric utility files information in accordance with subsection (5)(B) of this rule, any stakeholder may respond to the electric utility's notice.

(E) Unless otherwise ordered by the commission, within sixty (60) days of the electric utility's filing of the notice required in paragraph (5)(A)1. of this rule, the limited inquiry CCN shall be unaffected by the filing of the notice for the specified supply-side resources or specified quantities of supply-side resource types that the electric utility identified as remaining materially consistent with the approved preferred resource plan.

Forecast of Capacity Balance (MW)

Name of Utility: _____

Year of Electric Utility Resource Planning Filing: _____

	Year 1	Year 2	Year 3	.....	Year 20
A. System Generation Capacity					
Base Capacity					
Unit 1					
Unit 2					
.....					
Unit i					
Total Base Capacity					
Intermediate/Peaking Capacity					
Unit i+1					
Unit i+2					
.....					
Unit j					
Total Intermediate/Peaking Capacity					
Wind					
Solar					
Total Intermittent Capacity					
Percent Accredited Intermittent Capacity					
Total Accredited Intermittent Capacity					
Total Generation Capacity = TGC					
B. Capacity Transactions					
Purchases					
Source 1					
Source 2					
.....					
Source k					
Total Purchases					
less Sales					
Net Transactions = NT					
Total System Capacity = TSC = TGC + NT					
C. System Peaks & Reserves					
Peak Demands					
Forecasted Peak					
less DSM					
Peak Forecast less DSM = PF					
Capacity Reserves = CR = TSC - PF					
D. Capacity Needs					
% Reserve Margin = RM					
% Capacity Margin = CM = RM/(1 + RM)					
Required Capacity = RC = PF/(1-CM)					
Capacity Balance = TSC * RC					

AUTHORITY: sections 386.040, 386.250, 386.610, 393.140, RSMo 2016, and section 393.1900, RSMo Supp. 2026. Original rule filed Sept. 18, 2026.

PUBLIC COST: This proposed rule will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed rule will not cost private entities more than five hundred dollars ($500) in the aggregate.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file comments in support of or in opposition to this proposed rule with the Missouri Public Service Commission, Nancy Dippell, Secretary of the Commission, PO Box 360, Jefferson City, MO 65102. To be considered, comments must be received at the commission's offices on or before Dec. 2, 2026, and should include a reference to Commission Case No. EX-2027-0085. Comments may also be submitted via a filing using the commission's electronic filing and information system at https://psc.mo.gov/General/Submit_Comments. A public hearing regarding this proposed rule is scheduled for Dec. 15, 2026, at 10 a.m., in Room 310 of the Governor Office Building, 200 Madison St., Jefferson City, MO. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed rule and may be asked to respond to commission questions. Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 or TDD Hotline 1-800-829-7541.

TITLE 20 – DEPARTMENT OF COMMERCE AND INSURANCE
Division 4240 – Public Service Commission
Chapter 21 – Resource Planning for Electric Utilities

PROPOSED RULE

20 CSR 4240-21.025 Standards and Dataset Management Requirements

PURPOSE: This rule establishes data standards, data set management requirements, and minimum standards for the documentation of data, assumptions, methods, and analytical tools used to develop the integrated resource plan, and supplements the requirements found in section 393.1900, RSMo.

(1) Standards.

(A) The content of the electric utility's integrated resource plan (IRP) must clearly demonstrate the soundness, reliability, and transparency of the data, assumptions, methods, and analytical tools the electric utility used in the planning process.

(B) The electric utility shall include sufficient detail and documentation in its IRP that explains and justifies to the commission's approval how the electric utility developed the alternative resource plans and selected the preferred resource plan.

(C) The electric utility shall provide all workpapers utilized to support the claims, data, figures, tables, and graphics included in its IRP.

(D) For all materials used to support the electric utility's IRP, whether produced by the electric utility, or on its behalf, the electric utility shall maintain –

1. The document in its entirety; and
2. All supporting workpapers.

(2) Datasets.

(A) The electric utility shall identify all datasets used in each IRP to the extent reasonably necessary to demonstrate the electric utility's forecast and planning conclusions.

(B) The electric utility shall develop shared datasets that reflect the overlapping objectives of transmission system planning, distribution system planning, and generation planning.

(3) Spreadsheet workpapers.

(A) The electric utility's workpapers in spreadsheet form shall be –

1. In their original format;
2. Clearly labeled by the relevant technical volume and descriptive file names;
3. Provided in searchable electronic formats and, where applicable, with all formulas, cell references, and data links intact, to allow full traceability of calculations;
4. Document file sizes shall be sized to upload into the commission's electronic filing system, unless otherwise agreed to by stakeholders;
5. Accompanied with a summary tab that includes the key inputs and their definitions; and
6. Accompanied by citations to the source information utilized.

(B) The electric utility shall provide a summary that indicates the interaction of linked spreadsheet workpapers and the file location.

(4) Model workpapers.

(A) The electric utility shall provide all modeling input and output files as workpapers.

(B) The electric utility shall provide a summary table that includes, but is not limited to, the following information for each model:

1. Name;
2. Purpose;
3. Relevant technical volume and descriptive file names;
4. Input file names;
5. Output file names;
6. Any key input parameters not already included in an input file; and
7. As applicable, identification of model output files that are used as input files for another model.

(C) The electric utility shall provide a process flow diagram that shows the interaction between inputs, modeling software, and results to support the IRP.

(5) Plots.

(A) The electric utility shall label each plot included in the IRP as a stand-alone figure, and shall label the axes with the units of measure.

(B) The electric utility shall provide the data in each plot in tabular form in the workpapers.

(C) The electric utility shall number, reference, and describe all plots and data tables in the text of the technical volumes.

(6) Within two (2) business days of the electric utility submitting the IRP, the electric utility shall make available to stakeholders the datasets specified in subsection (2)(A) of this rule and all workpapers specified in section (3) and section (4) of this rule.

(7) Within two (2) business days of any testimony filed by any party all data, modeling inputs, assumptions, and results used in its analysis shall be transmitted to all parties.

AUTHORITY: sections 386.040, 386.250, 386.610, 393.140, RSMo 2016, and section 393.1900, RSMo Supp. 2026. Original rule filed Sept. 21, 2026.

PUBLIC COST: This proposed rule will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed rule will not cost private entities more than five hundred dollars ($500) in the aggregate.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file comments in support of or in opposition to this proposed rule with the Missouri Public Service Commission, Nancy Dippell, Secretary of the Commission, PO Box 360, Jefferson City, MO 65102. To be considered, comments must be received at the commission's offices on or before Dec. 2, 2026, and should include a reference to Commission Case No. EX-2027-0085. Comments may also be submitted via a filing using the commission's electronic filing and information system at https://psc.mo.gov/General/Submit_Comments. A public hearing regarding this proposed rule is scheduled for Dec. 15, 2026, at 10 a.m., in Room 310 of the Governor Office Building, 200 Madison St., Jefferson City, MO. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed rule and may be asked to respond to commission questions. Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 or TDD Hotline 1-800-829-7541.

TITLE 20 – DEPARTMENT OF COMMERCE AND INSURANCE
Division 4240 – Public Service Commission
Chapter 21 – Resource Planning for Electric Utilities

PROPOSED RULE

20 CSR 4240-21.030 Load Forecasting Requirements

PURPOSE: This rule establishes minimum standards for collecting, maintaining, and updating historical data, documenting the inputs, assumptions, and methodologies used in load forecasting, and supplements the requirements found in section 393.1900, RSMo.

(1) Load forecasting inputs and assumptions.

(A) The electric utility shall develop load forecasts using the best available, transparent, and verifiable data. Where reliable data is not available, the electric utility may use estimates for variables, provided that the electric utility fully justifies and clearly documents the estimates.

(B) The electric utility shall maintain and update a comprehensive database of historical energy usage and demand across its service territory covering a minimum of the most recent five (5) years for hourly data and twenty (20) years for monthly data preceding the IRP filing year. The electric utility shall include in the database all customer classes and capture hourly and monthly energy consumption, monthly customer counts, monthly peak demand levels (coincident and non-coincident peaks by customer class), and annual peak demand (reported separately for summer and winter for both coincident and non-coincident peaks by customer class). The electric utility shall provide access to these inputs to the stakeholders pursuant to 20 CSR 4240-21.025(6).

(C) The electric utility shall weather normalize all weather-sensitive historical load data using statistical methods, and clearly describe the methodology employed, including the treatment of temperature, degree days, or other relevant weather variables. The electric utility shall explain and document the statistical fit and significance for all variables.

(D) The electric utility shall use historical load and weather data to determine the relationship between load and weather variables, including temperature or degree-days. The electric utility shall weather normalize forecasted loads to reflect normal weather conditions derived from these relationships. The electric utility shall explain and document the methodology, data sources, and statistical results of each variable.

(E) Where employing end-use forecasting, the electric utility shall use the most current available data on measure saturation, efficiency trends, and customer adoption of new technologies, including distributed energy resources (DER) and demand-side measures.

(F) The electric utility shall include data for population, households, employment, income, economic growth, and other economic or demographic drivers that materially influence load.

(G) The electric utility shall identify applicable federal, state, and local laws, regulations, and policies that affect energy consumption, including energy efficiency standards, electrification initiatives, and decarbonization requirements and describe how they are reflected in the load forecast assumptions.

(H) The electric utility shall include data and assumptions regarding DER that materially affect system load. The electric utility shall document current penetration rates, forecasted adoption, and the resulting impact on load shapes and net demand as further defined in 20 CSR 4240-21.055.

(I) The electric utility shall ensure the forecast is generally aligned with baseline conditions such as new housing and commercial building starts, measure saturations, employment growth, federal standards, building codes, naturally occurring energy efficiency as produced in the most recent potential study, and program offerings currently approved.

(J) The electric utility shall document data on anticipated adoption of electric vehicles and other electrification technologies, and provide documentation of expected penetration rates, charging or usage profiles, seasonal impacts, and the resulting effects on system load and system non-coincident peak.

(K) The electric utility shall ensure the forecast considers the effects of the real price of electricity, the real price of competitive energy sources, and rate design on customer usage. The electric utility shall include the impacts of approved rate structures, such as time-of-use rates, demand charges, and dynamic pricing mechanisms.

(L) The electric utility shall document descriptive statistics for key data inputs.

(2) Forecasting methodology.

(A) The electric utility shall –

1. Develop its load forecast using transparent, reproducible, and well-documented methods;

2. Describe the forecasting models, the methodology, key assumptions, input variables, data sources, and outputs; and

3. Justify the chosen approach.

(B) The electric utility shall, at minimum –

1. Develop customer class level load forecasts using an econometric methodology as the primary framework; and

2. Where end-use determinants are employed, the electric utility shall demonstrate that measure saturation, efficiency trends, technology adoption, electrification, and customer behavior are explicitly represented in the model.

(C) The electric utility may employ a non-econometric approach such as engineering-based models, machine learning models, or other statistical methods, provided that the approach –

1. Is clearly distinguished from econometric methodologies; and

2. Demonstrates the ability to capture key load drivers, including economic conditions, weather, technology adoption, and policy impacts.

(D) If the electric utility employs an alternative approach, the electric utility shall –

1. Describe the model structure and functional form and document the data inputs and sources;

2. Explain how the methodology differs from an econometric methodology;

3. Justify how the resulting forecast achieves a level of rigor, transparency, and detail that is comparable to an econometric load forecast; and

4. Describe the advantages, tradeoffs, and limitations of the selected methodology.

(E) The electric utility shall provide a comprehensive list of all independent variables used in the model. For each variable the electric utility shall –

1. Provide the definition, unit of measure, data source, historical period covered, forecast values, and forecast method; and

2. Explain the relevance of each variable to load growth and describe how each variable was incorporated into the forecast.

(F) The electric utility shall describe and document the equations, algorithms, or statistical methods used to relate independent variables to load. The electric utility shall document any transformations, such as logarithmic, polynomial, or interaction terms.

(G) The electric utility shall –

1. Describe the estimation techniques used to determine model parameters, including regression methods, statistical procedures, or simulation techniques;

2. Describe any calibration methods used to align model results with historical load data, and describe the diagnostic tests to demonstrate model validity; and

3. Document parameter estimates with standard errors, significance levels, and statistical goodness-of-fit measures.

(H) The electric utility shall describe and document how the model incorporates weather variables and captures the sensitivity of load to key weather variables such as temperature, and degree-days.

(I) The electric utility shall justify all adjustments made outside of model results to –

1. Explain the basis, methodology, and quantitative effect on forecast outcomes; and

2. Document adjustments alongside the unadjusted model results for comparison.

(J) The electric utility shall –

1. Validate the forecast results through benchmarking against historical load patterns and, where applicable, publicly available independent load forecasts published by regional transmission organizations and government agencies to assess the reasonableness of forecast assumptions and results;

2. Describe and document a retrospective analysis of past forecasts, evaluate forecast accuracy, identify sources of significant error or bias, and explain how the electric utility used these findings to improve the current forecast;

3. Document a forecast of net system load profiles for each year of the planning horizon consistent with the electric utility's forecasts of monthly energy and peak demands at the time of summer and winter system peaks for each customer class; and

4. Ensure the forecast –

A. Accounts for the impacts of existing and reasonably anticipated DER, including customer-owned renewable generation, energy efficiency, demand response, beneficial electrification, and energy storage resources; and

B. Evaluates how these resources may reduce, shift, or otherwise modify system peak demand and energy requirements over the planning horizon.

(3) Forecast period.

(A) The electric utility shall prepare forecasts of system peak load and energy consumption under reasonable scenarios.

(B) The electric utility shall express forecasts on an hourly, monthly, and annual basis, and shall report these forecasts separately for each customer class, as well as for the total system.

(C) The electric utility shall extend the forecasts a minimum of sixteen (16) years beyond the electric utility's IRP filing year and shall document the annual energy consumption and system non-coincident peak demand.

(4) Base-case load forecast.

(A) The electric utility shall prepare and file a base-case load forecast. The base-case load forecast shall –

1. Assume normal weather conditions for all components;

2. Incorporate the load impacts of implemented demand-side programs that are in effect at the time of the IRP filing; and

3. Exclude the load impacts of proposed demand-side programs and separately present this data in the demand response forecast.

(B) The electric utility shall develop the base-case load forecast using the data inputs in section (1) of this rule and forecasting methodology required under section (2) of this rule. The electric utility shall use the base-case load forecast as the reference case for all scenario and sensitivity analysis.

(C) The electric utility shall document forecasts of the hourly load profile for each of the electric utility's customer classes, and for the system as a whole, based on a minimum of the most recent five (5) historical years and covering the first five (5) years of the forecast period. These forecasts must reflect daily load patterns, seasonal variability, and separately identify the influence of DER, electrification, and currently approved electric-utility-sponsored programs for energy efficiency and demand response.

(D) For the system and each customer class, for each year of the planning horizon, the electric utility shall document forecasts of –

1. Monthly and annual energy consumption;

2. Customer counts; and

3. Monthly peak demand, including both coincident and non-coincident peak demand.

(E) The electric utility shall disaggregate the forecasts in subsection (4)(D) of this rule by jurisdictional components,

or the electric utility shall justify why disaggregation is not applicable.

(F) The electric utility shall explain how the base-case load forecast incorporates the effects of economic and demographic drivers, including but not limited to electricity prices, real price of competitive energy sources, income, population, and employment. The electric utility shall specify how the methodology explicitly models these factors, or explain how these effects were otherwise accounted for.

(G) The electric utility shall explain how the base-case load forecast incorporates the impacts of applicable legal mandates, regulatory requirements, and policy-driven incentives and mandates that influence the adoption of alternative technologies, electrification of end-uses, and energy efficiency measures. The model shall include inputs such as anticipated customer behavior, technology adoption, and evolving load shapes consistent with legal mandates.

(H) The electric utility shall document the monthly cooling, heating, and non-weather-sensitive components of weather-normalized load by class for the base year of the forecast.

(I) The electric utility shall justify any subjective adjustments applied to statistical or model outputs, including the factors considered, rationale, and their quantitative effect.

(J) The electric utility shall provide graphical plots of the following:

1. Class-level monthly energy consumption and coincident peak demand for the historical period and forecast period;

2. Actual and weather-normalized coincident peak demand for the historical period; and

3. Net system load profiles for the summer and winter peak day for the base year as well as for forecast years four (4), eight (8), and sixteen (16), at a minimum.

(K) The electric utility shall document the net system load profiles in paragraph (4)(J)3. of this rule for the summer and winter peak for each year of the planning horizon in supporting workpapers.

(L) The electric utility shall explain how the base-case load forecast is consistent with historical consumption patterns, end-uses, and efficiency trends identified in the electric utility's prior commission filings. If the electric utility's base-case load forecast differs from recent previous forecasts submitted to the commission, the electric utility shall explain the differences.

(M) The electric utility shall explain how the base-case load forecast incorporates the large load forecast and disaggregates it by categories of maturity, as described in section (6) of this rule.

(5) Large load database.

(A) The electric utility shall maintain and update a large load database consisting of –

1. Anonymized project identifier;

2. Large load project's industry type;

3. Large load project's anticipated service address;

4. Large load metrics defined in 20 CSR 4240-21.015(54) and any pertinent metrics information required by the appropriate Regional Transmission Operator/Independent System Operator (RTO/ISO) for the project; and

5. Large load project's status, including whether the project is no longer viable.

(B) The electric utility shall categorize the maturity of large load projects by the following phases:

1. Study phase – Large load projects in this phase have submitted any required information, preliminary agreements, and deposits in compliance with the electric utility's approved tariffs and business practices and have been submitted to the appropriate RTO/ISO for initial or additional study;

2. Construction agreement phase – Large load projects in this phase have executed relevant construction agreements and made any required payments, but have not yet executed an electric service agreement;

3. Execution phase – Large load projects in this phase have executed an electric service agreement, posted any required security or deposits, and have obtained site control;

4. Initial project energization – Large load projects in this phase receive retail electric service but have not reached full forecast peak load; and

5. Load ramping complete – Large load projects in this phase have reached full forecast peak load.

(6) Large load forecast.

(A) The electric utility shall describe and document distinct forecasts, as a separate additive component, representing large load scenarios that are reasonably anticipated to materially affect the system load shape or resource needs for the planning horizon.

(B) The electric utility shall describe how large load forecasts are not double counted in the base-case load forecast.

(C) For each large load scenario, the electric utility shall –

1. Utilize the large load database in section (5) of this rule;

2. Justify the methodology, data sources, and assumptions used to forecast load to show that assumptions are reasonable, transparent, and based on the best available information;

3. For the first five (5) years of the planning horizon, develop large load scenarios based upon the assigned project maturity phases outlined in subsection (5)(B) of this rule, including at minimum –

A. A high probability scenario that reflects only those projects that meet the criteria stated in paragraphs (5)(B)3., (5)(B)4., and (5)(B)5. of this rule;

B. A medium probability scenario that reflects only those projects that meet the criteria stated in paragraphs (5)(B)2., (5)(B)3., (5)(B)4., and (5)(B)5. of this rule;

C. A low probability scenario that reflects only those projects that meet the criteria stated in paragraphs (5)(B)1., (5)(B)2., (5)(B)3., (5)(B)4., and (5)(B)5. of this rule; and

D. Any scenarios determined to be significant from the electric utility perspective, or as ordered by the commission;

4. Develop large load forecasts to forecast growth for years beyond the first five (5) years of the planning horizon through the remainder of the planning horizon;

5. Explain how large loads will participate in demand response, load management, or flexibility programs, including technical capabilities, contractual commitments, and expected contributions to coincident peak reduction; and

6. Describe and document how the forecast incorporates weather variables and other variables that impact load, including normal conditions, extreme events, and the sensitivity of load to key weather variables such as temperature or degree days.

(7) Analysis of load-building programs.

(A) If the electric utility intends to continue existing load-building programs or implement new ones, the electric utility shall analyze these programs in the context of one (1) or more of the alternative resource plans developed pursuant to 20 CSR 4240-21.060(2), including the preferred resource plan selected pursuant to 20 CSR 4240-21.060(5) as part of its risk and uncertainty analysis pursuant to 20 CSR 4240-21.060(4).

(B) In the analysis, the electric utility shall use the same modeling procedure and assumptions required in 20 CSR 4240-21.060(4). The electric utility shall describe and document its analysis of load-building programs, including the following

elements:

1. An estimation of the impact of load-building programs on the electric utility's seasonal non-coincident peak, as defined by the appropriate RTO/ISO and energy usage;

2. A comparison of annual revenue requirement for the resource plan(s) with and without the load-building program;

3. A comparison of the probable environmental compliance costs of the resource plan(s) in each year of the planning horizon with and without the proposed load-building program;

4. A calculation of the performance measures and risk by year; and

5. An assessment of any other aspects of the proposed load-building programs that affect the public interest.

(8) Sensitivity analysis and scenario development.

(A) The electric utility shall submit a comprehensive set of load forecasts that reflect sensitivity analysis and scenario development. The electric utility's analyses shall demonstrate the robustness of resource planning under uncertainty and ensure that system resources are adequate across a wide range of plausible futures. At a minimum the electric utility shall –

1. Describe and document the sensitivity of the dependent variables of the base case load forecast to variations in the independent variables identified in subsection 20 CSR 4240-21.030(2)(E);

2. Evaluate the sensitivity of system peak load forecasts to extreme weather conditions, such as sustained heat waves or prolonged cold snaps, and shall quantify the incremental peak load attributable to these stress conditions, including but not limited to a scenario that includes a minimum of ninety percent (90%) probability of load under those extreme conditions; and

3. Develop, in addition to the base-case load forecast, a minimum of two (2) bounding scenarios under normal weather assumptions –

A. High-growth scenario that reflects accelerated economic expansion, rapid electrification, or large load additions; and

B. Low-growth scenario that reflects slower economic conditions, delayed technology adoption, or higher-than-expected energy efficiency penetration.

AUTHORITY: sections 386.040, 386.250, 386.610, 393.140, RSMo 2016, and section 393.1900, RSMo Supp. 2026. Original rule filed Sept. 21, 2026.

PUBLIC COST: This proposed rule will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed rule will not cost private entities more than five hundred dollars ($500) in the aggregate.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file comments in support of or in opposition to this proposed rule with the Missouri Public Service Commission, Nancy Dippell, Secretary of the Commission, PO Box 360, Jefferson City, MO 65102. To be considered, comments must be received at the commission's offices on or before Dec. 2, 2026, and should include a reference to Commission Case No. EX-2027-0085. Comments may also be submitted via a filing using the commission's electronic filing and information system at https://psc.mo.gov/General/Submit_Comments. A public hearing regarding this proposed rule is scheduled for Dec. 15, 2026, at 10 a.m., in Room 310 of the Governor Office Building, 200 Madison St., Jefferson City, MO. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed rule and may be asked to respond to commission questions. Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 or TDD Hotline 1-800-829-7541.

TITLE 20 – DEPARTMENT OF COMMERCE AND INSURANCE
Division 4240 – Public Service Commission
Chapter 21 – Resource Planning for Electric Utilities

PROPOSED RULE

20 CSR 4240-21.035 Supply-Side Resource Analysis Requirements

PURPOSE: This rule establishes the minimum standards for the scope and level of detail required in the supply-side resource analysis.

(1) Screening analysis inputs.

(A) The electric utility shall identify and evaluate a variety of potential supply-side resource options for purposes of resource planning, which the electric utility can reasonably expect to use, develop, implement, or acquire. Potential supply-side resource options include but are not limited to –

1. Full or partial ownership of new plants using existing generation technologies;

2. Full or partial ownership of new plants using new generation technologies, including technologies expected to become commercially available within the planning horizon, such as a technology for which an operational pilot of 10 MW or greater is currently in operation or advanced stages of development;

3. Renewable energy resources on the electric utility-side of the meter, including a wide variety of renewable generation technologies;

4. Technologies for distributed generation;

5. Technologies for storage, including various durations and configuration and configurations;

6. Purchased power from bi-lateral transactions and from organized capacity and energy markets, including from resources in the regional transmission operator (RTO) generator interconnection queues that are likely to come online in the plan period;

7. Transmission and distribution system improvements as identified in 20 CSR 4240-21.040;

8. Life extension and refurbishment of assets at existing generating plants, including but not limited to mothballing;

9. Enhancement of the emission controls at existing generating plants; and

10. Generating plant and operational efficiency improvements which reduce the electric utility's own use of energy.

(B) The electric utility shall describe and document, at a minimum, the following for potential supply-side resources:

1. Unit characteristics;

2. Current and expected accredited capacity by season;

3. Licensing status;

4. Current depreciation rates for each generating unit;

5. Currently expected retirement dates; and

6. If applicable, any remaining useful life of each generating unit.

(C) The electric utility shall describe and document a variety of potential supply-side resource options including, but not limited to, anticipated –

1. Unit characteristics and attributes;

2. Accredited capacity by season;

3. Licensing, permitting, and construction timelines;

4. Useful life; and

5. Potential risks and constraints.

(D) The electric utility shall describe and document its analysis including provision of cost and performance information sufficient to fairly analyze and compare each of these existing and potential supply-side resource options established in subsection (1)(A) of this rule, including but not limited to those attributes needed to individually assess the following cost categories by resource:

1. Capital cost, including capital projects that are reasonably expected to result in the extension of the retirement date of each generating unit;

2. Fixed and variable operation and maintenance costs separately identifying estimated commodity prices, fuel transport costs, and fuel storage cost;

3. Probable environmental compliance costs; and

4. Unit characteristics and attributes.

(2) Screening analysis and data provision.

(A) The electric utility shall indicate which potential supply-side resource options it considers to be preliminary supply-side candidate resource options. Any electric utility using the preliminary screening analysis to identify preliminary supply-side candidate resource options shall rank all preliminary supply-side candidate resource options based on estimates of the electric utility costs with and without probable environmental compliance costs.

(B) The electric utility shall provide a summary table showing the following for each potential supply-side resource option:

1. The electric utility's costs associated with existing supply-side resources that may be subject to changes in configuration or operation during the planning horizon, including changes in environmental controls or retirement dates;

2. The estimated cost for each potential supply-side resource option;

3. An assessment of whether each potential supply-side resource option qualifies as a renewable energy resource; and

4. Justification for any potential supply-side resource options that are eliminated from further consideration.

(C) The electric utility shall describe and document its analysis of each existing and potential supply-side resource option. The analysis shall include but not be limited to –

1. Cost rankings of each potential supply-side resource option which shall be based on estimates of the installed capital costs plus fixed and variable operation and maintenance costs;

2. Costs of ancillary and/or back-up supply-side resources required to achieve necessary or assumed capacity accreditation level; and

3. A description of potential environmental legal mandates which may be imposed at some point within the planning horizon, including –

A. The probable environmental compliance costs of each potential supply-side resource option, which shall be quantified by estimating the cost to the electric utility to comply with such environmental legal mandates that may be imposed;

B. A list of environmental pollutants for which legal mandates may be imposed during the planning horizon which would result in compliance costs that could significantly impact electric utility rates;

C. A subjective probability that represents the electric utility's estimated likelihood that legal mandates requiring additional levels of mitigation will be imposed at some point within the planning horizon; and

D. The electric utility's expected mitigation cost, based on these probabilities, for each identified pollutant.

(D) The electric utility shall provide its analysis of the interconnection pursuant to 20 CSR 4240-21.040(1)(G) and any other transmission requirements associated with the preliminary supply-side candidate resource options identified in subsection (2)(A) of this rule.

(E) The electric utility's analysis shall include the identification of transmission constraints, as estimated pursuant to paragraph 20 CSR 4240-21.040(1)(A)2., whether within the appropriate RTO/ISO footprint, on an appropriate interconnected RTO/ISO, or a transmission system that is not part of an appropriate RTO/ISO. The electric utility shall ensure that its analysis reflects a transmission network that is capable of reliably supporting the preliminary supply-side candidate resource options under consideration, that the costs of the transmission system investments associated with preliminary supply-side candidate resource options, as estimated pursuant to subsection 20 CSR 4240-21.040(1)(G), are properly considered and provide an adequate foundation of basic information for decisions, including but not limited to the following:

1. Joint ownership or participation in supply-side resources construction projects;

2. Construction of wholly owned supply-side resources;

3. Participation in major refurbishment, life extension, upgrading, or retrofitting of existing supply-side resources;

4. Improvements, including advanced transmission technology or advanced distribution technology, on the electric utility's transmission and distribution system to increase efficiency, capacity, and/or reduce power losses;

5. Acquisition of existing supply-side resources; and

6. Opportunities for new long-term power purchases and sales, and short-term power purchases that may be required for bridging the gap between other supply-side resource options, both firm and non-firm, that are likely to be available overall or part of the planning horizon.

(F) The electric utility's analysis shall include the identification of any output limitations imposed on existing or new supply-side resources due to transmission and/or distribution system capacity constraints, to ensure that supply-side candidate resource options are evaluated in accordance with any such constraints.

(3) Candidate resource options.

(A) The electric utility shall identify preliminary supply-side candidate resource options which are not eliminated as supply-side candidate resource options. The supply-side candidate resource options that the electric utility passes on for further evaluation in the integration process shall represent a wide variety of supply-side resource options with diverse fuel and generation technologies, including a wide range of renewable technologies and technologies suitable for distributed generation.

(B) The electric utility shall explain its process for identifying and analyzing potential supply-side resource options and preliminary supply-side candidate resource options and for choosing its supply-side candidate resource options to advance to the integration analysis.

(C) The electric utility shall indicate which, if any, of the

preliminary supply-side candidate resource options identified in subsection (2)(A) of this rule are eliminated from further consideration on the basis of the interconnection and other transmission analysis and shall explain the reasons for their elimination.

(D) The electric utility shall include its best estimate of the cost of interconnection and any other transmission requirements, in addition to the electric utility cost and probable environmental compliance cost, in the cost of supply-side candidate resource options advanced for purposes of developing the alternative resource plans required by 20 CSR 4240-21.060(2).

(E) The electric utility shall develop and justify ranges of values and probabilities for several important uncertain factors related to supply-side candidate resource options, including the impact of implementing alternative fuel options. These cost estimates shall include, at a minimum, the following elements, as applicable to the supply-side candidate resource option:

1. Fuel price forecasts, including fuel delivery costs and pipeline interconnection costs if applicable, over the planning horizon for the appropriate type and grade of primary fuel and for any alternative fuel that may be practical as a contingency option;

2. Estimated capital costs including engineering design, construction, testing, startup, and certification of new facilities or major upgrades, refurbishment, or rehabilitation of existing facilities;

3. Estimated annual fixed and variable operation and maintenance costs over the planning horizon for new facilities or for existing facilities that are being upgraded, refurbished, or rehabilitated;

4. Forecasts of the annual cost or value of emission allowances to be used or produced by each generating facility over the planning horizon, if applicable;

5. Annual fixed charges for any facility to be included in the rate base, or annual payment schedule for leased or rented facilities; and

6. Estimated costs of interconnection or other transmission requirements associated with each supply-side candidate resource option.

AUTHORITY: sections 386.040, 386.250, 386.610, 393.140, RSMo 2016, and section 393.1900, RSMo Supp. 2026. Original rule filed Sept. 21, 2026.

PUBLIC COST: This proposed rule will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed rule will not cost private entities more than five hundred dollars ($500) in the aggregate.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file comments in support of or in opposition to this proposed rule with the Missouri Public Service Commission, Nancy Dippell, Secretary of the Commission, PO Box 360, Jefferson City, MO 65102. To be considered, comments must be received at the commission's offices on or before Dec. 2, 2026, and should include a reference to Commission Case No. EX-2027-0085. Comments may also be submitted via a filing using the commission's electronic filing and information system at https://psc.mo.gov/General/Submit_Comments. A public hearing regarding this proposed rule is scheduled for Dec. 15, 2026, at 10 a.m., in Room 310 of the Governor Office Building, 200 Madison St., Jefferson City, MO. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed rule and may be asked to respond to commission questions. Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 or TDD Hotline 1-800-829-7541.

TITLE 20 – DEPARTMENT OF COMMERCE AND INSURANCE
Division 4240 – Public Service Commission
Chapter 21 – Resource Planning for Electric Utilities

PROPOSED RULE

20 CSR 4240-21.040 Transmission and Distribution Analysis Requirements

PURPOSE: This rule establishes the minimum standards for the scope and level of detail required for the transmission and distribution network analysis.

(1) Transmission analysis requirements.

(A) The electric utility shall describe the adequacy of its existing transmission system, including –

1. Age, condition, and efficiency level of its existing transmission system; and

2. Transmission constraints identified through operations or other assessments, if known.

(B) The electric utility shall describe the adequacy of its existing transmission system for any projects anticipated to be completed, using at a minimum, the following scenarios:

1. High-growth scenario load forecast at year five (5) pursuant to 20 CSR 4240-21.030(8)(A)3.A.;

2. Low-growth scenario load forecast at year five (5) pursuant to 20 CSR 4240-21.030(8)(A)3.B.; and

3. The electric utility may also select scenarios to stress-test its transmission system.

(C) The electric utility shall describe and justify the identification, timing, and cost of planned actions and transmission system upgrades over the implementation period, including those actions and upgrades that –

1. Maintain a viable, reliable, and/or resilient transmission network;

2. Affect supply-side resources that were evaluated pursuant to 20 CSR 4240-21.035(1);

3. Relate to the retirement of existing supply-side resources; and

4. Are planned by the appropriate regional transmission organization or independent system operator (RTO/ISO) primarily for economic reasons that may impact the alternative resource plans of the electric utility.

(D) The electric utility shall develop and provide a hosting capacity map to identify areas on its transmission system that may be suitable for new load or new generation sources. The electric utility may satisfy this requirement using similar maps hosted by the appropriate RTO/ISO.

(E) The electric utility shall provide estimates of the portion and amount of costs and revenues of proposed regional transmission upgrades that would be allocated to the electric utility over the implementation period.

(F) The electric utility shall provide an estimate of the amount of revenue requirement of regional transmission assets that would be allocated under the appropriate RTO/ISO

tariff based on load to the electric utility. The electric utility may rely on the appropriate RTO/ISO for this estimate and shall update its estimate should the RTO/ISO provide an updated one to the electric utility.

(G) The electric utility shall provide an analysis for consideration pursuant to 20 CSR 4240-21.035(1)(D) that identifies the physical transmission upgrades needed to interconnect generation and facilitate power purchases and sales and justifies the interconnection costs assumptions used in its integrated resource plan (IRP) analyses.

(H) The utility shall provide its assessment of the most recently completed RTO/ISO expansion plan as it relates to an improvement, justifying the cost to maintain or improve a viable, reliable, and/or resilient transmission network and provide the following:

1. Explanation of its assessment including any assumptions;

2. Identification of transmission constraints relieved by the RTO/ISO expansion plan;

3. Identification of alternatives presented by the electric utility to the RTO/ISO that were adopted in the RTO/ISO expansion plan; and

4. Alternatives presented by the electric utility to the RTO/ISO that were not adopted in the RTO/ISO expansion plan.

(2) Distribution analysis requirements.

(A) The electric utility shall describe the adequacy of its existing distribution system, including –

1. Age, condition, and efficiency level of its existing distribution system;

2. If needed to inform preparation of the IRP filing, all known distribution constraints, including constraints due to real power, reactive power, and power quality, under current peak demand; and

3. If needed to inform preparation of the IRP filing, all known distribution constraints, including constraints due to real power, reactive power, and power quality, under reasonably anticipated additions to peak demand.

(B) The electric utility shall describe and document the adequacy of its existing distribution system under, at a minimum, the following scenarios:

1. High-growth scenario load forecast at year five (5);

2. Low-growth scenario load forecast at year five (5); and

3. Any additional scenarios the electric utility may select to stress-test its distribution system.

(C) The electric utility shall describe and document the identification, timing, and cost of planned actions and distribution system upgrades over the implementation period, including those actions and upgrades that –

1. Maintain a viable distribution network;

2. Affect supply-side resources that were evaluated pursuant to 20 CSR 4240-21.035(2); and

3. Enable future cost-effective distributed energy resources evaluated under 20 CSR 4240-21.055.

(D) The electric utility shall develop and provide a hosting capacity map to provide a general understanding of areas where its distribution system has capacity to serve new load or interconnect distributed energy resources.

(3) Advanced transmission and distribution network technologies.

(A) The electric utility shall assess advanced transmission and distribution technologies that may become available during the planning horizon and facilitate or expand the availability and cost effectiveness of demand-side resources or supply-side resources.

(B) The engineering and cost studies that show the potential cost savings of advanced transmission and distribution technologies compared to the existing technology shall be separately identifiable in the analyses required in section (1) and section (2) of this rule and include –

1. A description of the electric utility's efforts at incorporating advanced grid technologies into its transmission and distribution networks; and

2. A description of the impact of the implementation of transmission and distribution advanced grid technologies on the selection of a resource acquisition strategy.

(4) If the electric utility has an existing Missouri Energy Efficiency Investment Act (MEEIA) portfolio or will propose a MEEIA portfolio during the implementation period, the electric utility shall develop, describe, and document an avoided transmission capacity cost and an avoided distribution capacity cost based upon investments in transmission assets or distribution assets that can be reasonably avoided due to implementation of demand-side management programs. Such analysis must provide time periods identified as well as magnitudes necessary to avoid or minimize necessary transmission and distribution system upgrades. The avoided transmission and distribution capacity costs are components of the avoided demand cost pursuant to 20 CSR 4240-21.050(1)(A)2.

(5) Affiliate relationships and documentation requirements.

(A) If any affiliate of the electric utility intends to build transmission within the electric utility's service territory where the project(s) are partially or fully driven by economic considerations, then the electric utility shall explain why such affiliate-built transmission is in the best interest of the electric utility's Missouri customers and the electric utility shall maintain any analysis performed to determine whether such affiliate-built transmission is in the best interest of the electric utility's Missouri customers.

(B) The electric utility shall describe any affiliate or other relationship with transmission planning, designing, engineering, building, and/or construction management companies that the electric utility impacts or may impact. Any description and documentation in section (1), section (2), section (4), and section (5) of this rule, also applies to any affiliate transmission planning, designing, engineering, building, and/or construction management company or other transmission planning, designing, engineering, building, and/or construction management company currently participating in transmission works or transmission projects for and/or with the electric utility.

(6) Distribution system load forecast.

(A) The electric utility shall describe the methodology used to forecast its distribution substation load and discuss how those forecasts are informed by or aligned with the system level forecast.

(B) The electric utility shall maintain feeder-level loading analysis.

(C) For any substation that is forecasted to grow by more than five megawatts (5 MW) at year five (5), the utility shall –

1. Discuss historical load growth within the geographical area served by each such distribution substation; and

2. Identify any known changes, such as customer additions, in the geographic area served by each such distribution substation.

AUTHORITY: sections 386.040, 386.250, 386.610, 393.140, RSMo 2016, and section 393.1900, RSMo Supp. 2026. Original rule filed

Sept. 21, 2026.

PUBLIC COST: This proposed rule will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed rule is estimated to cost private entities $1,200,000 annually.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file comments in support of or in opposition to this proposed rule with the Missouri Public Service Commission, Nancy Dippell, Secretary of the Commission, PO Box 360, Jefferson City, MO 65102. To be considered, comments must be received at the commission's offices on or before Dec. 2, 2026, and should include a reference to Commission Case No. EX-2027-0085. Comments may also be submitted via a filing using the commission's electronic filing and information system at https://psc.mo.gov/General/Submit_Comments. A public hearing regarding this proposed rule is scheduled for Dec. 15, 2026, at 10 a.m., in Room 310 of the Governor Office Building, 200 Madison St., Jefferson City, MO. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed rule and may be asked to respond to commission questions. Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 or TDD Hotline 1-800-829-7541.

FISCAL NOTE
PRIVATE COST

I. Department Title: Title 20--DEPARTMENT OF COMMERCE AND INSURANCE
Division Title: Division 4240—Public Service Commission
Chapter Title: Chapter 21— Resource Planning for Electric Utilities

Rule Number and Title:	20 CSR 4240-21.040 Transmission and Distribution Analysis Requirements
Type of Rulemaking:	Proposed Rule

II. SUMMARY OF FISCAL IMPACT

Estimate of the number of entities by class which would likely be affected by the adoption of the rule:	Classification by types of the business entities which would likely be affected:	Estimate in the aggregate as to the cost of compliance with the rule by the affected entities:
4	Investor-Owned Electrical Corporations	$ 0 to $ 1,200,000 annually for the five-year (5-year) life of the rule.

III. WORKSHEET

The rule will likely affect four (4) electrical corporations (investor-owned electric utilities). Staff requested input on the anticipated cost to implement the proposed rule from the affected electrical corporations. The feedback that was received was that the proposed rule would have a $ 0 to $ 1,200,000 cost for the electrical corporations to implement.

IV. ASSUMPTIONS

Staff relied on the input from the four (4) electrical corporations to determine the estimated fiscal impact of this proposed rule.

In accordance with the Commission's May 22, 2026, order, all four utilities submitted rule comments and estimated costs to comply. The low estimate assumes no incremental cost to the rule compared to utility existing distribution planning practices. The high estimate is based on Ameren's high cost estimate.

Ameren submitted rule comments and cost of compliance information through the Commission's electronic filing system on June 22, 2026. Staff carefully considered Ameren's rule comments and made significant responsive changes to the rule language. On July 31, 2026, Ameren emailed Staff updated cost estimates based on the revised rule language.

Liberty-Empire submitted rule comments and cost of compliance information through the Commission's electronic filing system on June 22, 2026. Liberty-Empire stated that it

could not estimate the cost of a process that has never been undertaken, but the prescriptiveness of the new requirements will result in a significantly higher cost to comply. Staff carefully considered Liberty-Empire's rule comments and made significant responsive changes to the rule language.

Evergy submitted rule comments and cost of compliance information through the Commission's electronic filing system on June 22, 2026. Evergy stated that the prescriptiveness of the new requirements will drive significant costs to comply. Staff carefully considered Evergy's rule comments and made significant responsive changes to the rule language.

Cost of this rule is related to certain elements of distribution system planning. Staff notes distribution system planning is a function all electric utilities in Missouri must do to provide safe and adequate service to its customers. Staff further revised the rule language to clarify that certain elements are to be completed if needed to inform the preparation of the IRP.

Assumptions:
- Rule life: 5 years
- Annual labor cost: $0 - $400,000
- Number of electric utilities: 3 (Ameren Missouri, Evergy, Liberty-Empire)

Calculation:
Low total cost for all 3 utilities = $0

High total cost for all 3 utilities = (3)*($400,000) = $1,200,000 year one

TITLE 20 – DEPARTMENT OF COMMERCE AND INSURANCE
Division 4240 – Public Service Commission
Chapter 21 – Resource Planning for Electric Utilities

PROPOSED RULE

20 CSR 4240-21.050 Demand-Side Resource Analysis Requirements

PURPOSE: This rule establishes the minimum standards for the scope and level of detail required for the demand-side resource analysis.

(1) Demand-side resources optimization.

(A) In order to properly optimize the amount of demand-side resources, the electric utility shall designate all Missouri jurisdictional demand-side resources as candidate resource options in its capacity expansion model on the basis of estimated seasonal energy, seasonal demand savings, and expected program costs.

1. For purposes of calculating avoided cost for use in 20 CSR 4240-20.092, the electric utility shall compare the capacity expansion model of its preferred resource plan with the same model excluding all demand-side resources as resource options in the first four (4) years.

2. The electric utility's avoided demand cost calculation shall specify generation, transmission, or distribution investments that can be reduced, deferred, or avoided as a result of demand-side program implementation.

(B) The electric utility shall model Missouri Energy Efficiency Investment Act (MEEIA) demand-side resource options separately from non-MEEIA demand-side resource options.

(C) For determining the optimal amount of demand-side resources, the electric utility shall exclude distributed energy resources (DERs) that are included in the 20 CSR 4240-21.055 analysis as a demand-side resource.

(D) The electric utility shall explain and document the assumptions concerning the change in baseline conditions, due to the adoption of energy efficiency measures by customers or consumers outside of any utility-sponsored programs, new housing and commercial building starts, measure saturations, employment growth, federal standards, building codes, and other relevant factors.

(E) The electric utility shall provide an estimate of all changes in peak consumption and energy consumption, separately, due to the factors in subsection (1)(D) of this rule by calendar month consistent with 20 CSR 4240-21.030 and the assumed program costs in each year of the planning horizon for each potential demand-side program.

(2) Non-MEEIA demand-side resources.

(A) The electric utility shall identify potential demand-side resources from which demand-side candidate resource options will be selected for the purposes of developing the alternative resource plans. A potential demand-side resource consists of a demand-side program designed to deliver one (1) or more energy efficiency measures, or energy management measures, including demand response programs. For each potential demand-side resource, the electric utility shall provide –

1. The targeted class of customers;

2. A list of proposed measures and, if applicable –

A. Expected life of the measure and duration of impact;

B. All major end-uses, including the end-uses which are to be considered in the electric utility's load pursuant to 20 CSR 4240-21.030; and

3. An itemized list of all expected program costs of the planning horizon, including but not limited to incentives, administration, and evaluation by year.

(B) The electric utility shall document the assumptions in subsection (2)(A) of this rule, including any prior evaluations.

(C) The electric utility shall describe all demand response programs registered with the electric utility's appropriate regional transmission organization or independent system operator (RTO/ISO).

(3) MEEIA demand-side resources.

(A) The electric utility shall conduct market research studies, customer surveys, test marketing programs, and other activities as necessary to estimate the potential impacts of demand-side resource options, and describe and document the results.

(B) The electric utility shall develop the information necessary to design and implement cost-effective demand-side programs, including –

1. Design research activities to produce reliable information, applicable to the electric utility, about how and by whom energy-related decisions are made, and about the most appropriate and cost-effective methods of influencing these decisions in favor of greater long-run energy efficiency and energy management impacts;

2. Compile existing data or adopt data developed by other entities, including government agencies and other utilities, as long as the adopted data is applicable to its service territory. The electric utility may incorporate and, if incorporated, it shall justify non-energy benefits, other measurable benefits, or the results of other demand side evaluations or tests;

3. Document completed market research studies, customer surveys, pilot programs, pilot rates, test marketing programs, and other studies and identify studies that are planned or in progress and the scheduled completion dates;

4. Identify the time periods of energy and demand savings that are most likely to coincide with reductions, deferrals, or avoided investments;

5. Identify demand-side program savings for the season where there is a near-term need; and

6. Complete an assessment of how the interactions between end-use measures, when bundled with other end-use measures in the potential demand-side program, would affect the stand-alone end-use measure impact estimates.

(C) The electric utility shall identify potential demand-side resources from which demand-side candidate resource options will be selected for the purposes of developing the alternative resource plans. A potential MEEIA demand-side resource consists of a demand-side program designed to modify the net consumption of electricity on the retail customer's side of the electric meter, including but not limited to energy efficiency measures, rate management, demand response, and interruptible or curtailable load. For each MEEIA demand-side resource, the electric utility shall document –

1. The targeted class of customers;

2. A list of proposed measures and rates, if applicable;

3. The expected life of the measure and duration of impact;

4. All major end-uses, including the end-uses which are to be considered in the electric utility's load pursuant to 20 CSR 4240-21.030;

5. An itemized list by year of all expected costs of the program, including but not limited to incentives, administration, and evaluation;

6. An estimate of revenue impacts on the electric utility of the demand-side resource, excluding the impacts of a Demand-Side Investment Mechanism; and

7. An estimate of the rate impacts including earnings opportunity and throughput disincentive for program participants and non-participants, separately and by year.

(D) The electric utility shall document any prior evaluations, to substantiate the assumptions in subsection (3)(B) of this rule.

(E) The electric utility shall describe all demand response programs registered with the electric utility's appropriate RTO/ISO.

(4) The electric utility shall describe and document the evaluation of each potential demand-side program developed pursuant to sections (2) and (3) of this rule, including –

(A) For each year of the planning horizon, calculations of the benefits of each potential demand-side program as the cumulative seasonal coincident peak demand reduction multiplied by the seasonal avoided demand costs plus the cumulative energy savings multiplied by the avoided energy costs. The electric utility shall perform the calculations both with and without the avoided probable environmental compliance costs. The electric utility shall describe and document the methods, data, and assumptions used to develop the avoided costs;

(B) The electric utility's avoided demand cost shall correspond to the expected costs of specific generation, transmission, or distribution investments that can be reduced, deferred, or avoided as a result of demand-side program implementation;

(C) The electric utility's avoided energy cost shall include the fuel costs, emission allowance costs, and other variable operation and maintenance costs of generation facilities, adjusted to reflect energy losses on the transmission and distribution systems, or the corresponding market-based equivalents of those costs; and

(D) The electric utility's avoided probable environmental compliance costs shall include the effects of the probable environmental compliance costs calculated pursuant to subsection (4)(A) of this rule, on the electric utility avoided demand cost and the electric utility avoided energy cost.

AUTHORITY: sections 386.040, 386.250, 386.610, 393.140, RSMo 2016, and section 393.1900, RSMo Supp. 2026. Original rule filed Sept 21, 2026.

PUBLIC COST: This proposed rule will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed rule is estimated to cost private entities up to nine hundred thousand dollars ($900,000) in year one and up to six hundred thousand dollars ($600,000) annually for the remaining life of the rule.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file comments in support of or in opposition to this proposed rule with the Missouri Public Service Commission, Nancy Dippell, Secretary of the Commission, PO Box 360, Jefferson City, MO 65102. To be considered, comments must be received at the commission's offices on or before Dec. 2, 2026, and should include a reference to Commission Case No. EX-2027-0085. Comments may also be submitted via a filing using the commission's electronic filing and information system at https://psc.mo.gov/General/Submit_Comments. A public hearing regarding this proposed rule is scheduled for Dec. 15, 2026, at 10 a.m., in Room 310 of the Governor Office Building, 200 Madison St., Jefferson City, MO. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed rule and may be asked to respond to commission questions. Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 or TDD Hotline 1-800-829-7541.

FISCAL NOTE
PRIVATE COST

I. Department Title: Title 20--DEPARTMENT OF COMMERCE AND INSURANCE
Division Title: Division 4240—Public Service Commission
Chapter Title: Chapter 21— Resource Planning for Electric Utilities

Rule Number and Title:	20 CSR 4240-21.050 Demand-side Resource Analysis Requirements
Type of Rulemaking:	Proposed Rule

II. SUMMARY OF FISCAL IMPACT

Estimate of the number of entities by class which would likely be affected by the adoption of the rule:	Classification by types of the business entities which would likely be affected:	Estimate in the aggregate as to the cost of compliance with the rule by the affected entities:
4	Investor-Owned Electrical Corporations	$0 to $900,000 in year one and $0 to $600,000 annually for the remaining four-year (4-year) life of the rule.

III. WORKSHEET

The rule will likely affect four (4) electrical corporations (investor-owned electric utilities). Staff requested input on the anticipated cost to implement the proposed rule from the affected electrical corporations. The feedback that was received was that the proposed rule would have a $0 to $900,000 cost for the electrical corporations to implement.

IV. ASSUMPTIONS

Staff relied on the input from the four (4) electrical corporations to determine the estimated fiscal impact of this proposed rule.

In accordance with the Commission's May 22, 2026, order, all four utilities submitted rule comments and estimated costs to comply. The low estimate assumes zero incremental cost to the rule. The high estimate is based on Ameren's response assuming the cost is comparable to all four electric utilities.

Ameren submitted rule comments and cost of compliance information through the Commission's electronic filing system on June 22, 2026. Staff carefully considered Ameren's rule comments and made significant responsive changes to the rule language. On July 31, 2026, Ameren emailed Staff updated cost estimates based on the revised rule language.

Liberty-Empire submitted rule comments and cost of compliance information through the Commission's electronic filing system on June 22, 2026. Liberty-Empire stated that it could not estimate the cost of a process that has never been undertaken, but the prescriptiveness of the new requirements will result in a significantly higher cost to comply. Staff carefully considered Liberty-Empire's rule comments and made significant responsive changes to the rule language.

Evergy submitted rule comments and cost of compliance information through the Commission's electronic filing system on June 22, 2026. Evergy stated that the prescriptiveness of the new requirements will drive significant costs to comply. Staff carefully considered Evergy's rule comments and made significant responsive changes to the rule language.

Costs for this rule are associated with proposed 20 CSR 4240-21.050(3)(C)7 that contemplates a rate impact analysis related to Missouri Energy Efficiency Investment Act (MEEIA) demand-side programs. Demand-side planning occurs during integrated resource planning. The MEEIA statute (section 393.1075, RSMo.) provides an opportunity for electric utilities to collect additional incentives through rates that are not available in non-MEEIA DSM programs, providing that the programs are "beneficial to all customers in the customer class…regardless of whether the programs are utilized by all customers". Section 393.1900, RSMo, requires the electrical corporation's integrated resource plan filing to include projections of rate impacts, and for the Commission to balance rate impacts as a factor.

Assumptions:

- Rule life: 5 years.
- Annual labor cost: $0 - $200,000
- One-time software cost: $0 - $100,000
- Number of electric utilities: 3 (Ameren Missouri, Evergy, Liberty-Empire)

Calculation:

Low total cost for all 3 utilities = $0

High total cost for all 3 utilities = 3($200,000 + $100,000) = $900,000 year one

High total cost for all 3 utilities = 3($200,000) = $600,000 annually years 2-5

TITLE 20 – DEPARTMENT OF COMMERCE AND INSURANCE
Division 4240 – Public Service Commission
Chapter 21 – Resource Planning for Electric Utilities

PROPOSED RULE

20 CSR 4240-21.055 Distributed Energy Resource Analysis Requirements

PURPOSE: This rule establishes the minimum standards for the scope and level of detail required for the distributed energy resource analysis.

(1) Distributed energy resources (DER) database.

(A) For those systems that have applied for interconnection to the electric utility, the electric utility shall create and maintain a database of information on DER and distributed energy resource aggregation (DERA) for purposes of evaluating current penetration and planning for future changes in the levels of DER, containing at a minimum the following information:

1. Existing DER and DERA interconnected to the electric utility's distribution system regardless of ownership;
2. Information characterizing the interconnection location by distribution circuit;
3. Sum of DER capacity for each circuit and annual peak load of each circuit; and
4. Identification of the relevant interconnection standard that specifies DER performance capabilities such as voltage regulation, grid disturbance ride-through, and interoperability communication protocols.

(B) To the extent that the electric utility is not in possession of all of the information required, the electric utility shall state which information it does not possess and why, and how the electric utility plans to obtain the information for future integrated resource plan (IRP) filings.

(2) DER adoption potential study.

(A) The electric utility shall describe and document, at a minimum, potential DER and DERA within the electric utility's service territory over the planning horizon.

(B) With respect to all DERs, except electric utility-incentivized DER, the electric utility may satisfy the study requirement by relying upon assessments developed as part of the electric utility's supply-side resource analysis pursuant to 20 CSR 4240-21.035, the electric utility's transmission and distribution analysis pursuant to 20 CSR 4240-21.040, and/or the electric utility's demand-side resource analysis pursuant to 20 CSR 4240-21.050, provided that references to such analyses are included in the study.

(3) Evaluating DERs as part of the IRP filing.

(A) If not fully covered by the electric utility's DER Adoption Potential Study, the electric utility shall include in the IRP filing the methodologies used to develop low, medium, and high DER penetration scenarios separately for DERs the electric utility sponsors and those that are non-electric utility sponsored, including –

1. Subjective probabilities;
2. Adoption rates;
3. Geographic deployment assumptions;
4. DER and DERA load profiles; and
5. Any other relevant assumptions factored into the DER penetration scenario.

(B) The electric utility shall describe and document the evaluation of the DER penetration scenarios developed in subsection (3)(A) of this rule and integration of DER and DERA onto the electric utility's distribution system.

(C) The electric utility's evaluation shall consider system reliability, beneficial modification of customer energy consumption, potential need for additional distribution assets, and changes to supply-side resource additions.

(D) The electric utility shall provide an estimate of the reduction or increase in transmission and distribution line losses as a result of DER deployment. The electric utility may focus its analysis on portions of its transmission and distribution systems based on factors including, but not limited to, the need for location-specific upgrades.

(E) The electric utility shall provide a cost-benefit analysis of deployment of DERs or DERAs as an alternative to traditional resources.

AUTHORITY: sections 386.040, 386.250, 386.610, 393.140, RSMo 2016, and section 393.1900, RSMo Supp. 2026. Original rule filed Sept. 21, 2026.

PUBLIC COST: This proposed rule will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed rule is estimated to cost private entities up to $1,350,000 in year one and up to six hundred thousand dollars ($600,000) annually for the remaining life of the rule.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file comments in support of or in opposition to this proposed rule with the Missouri Public Service Commission, Nancy Dippell, Secretary of the Commission, PO Box 360, Jefferson City, MO 65102. To be considered, comments must be received at the commission's offices on or before Dec. 2, 2026, and should include a reference to Commission Case No. EX-2027-0085. Comments may also be submitted via a filing using the commission's electronic filing and information system at https://psc.mo.gov/General/Submit_Comments. A public hearing regarding this proposed rule is scheduled for Dec. 15, 2026, at 10 a.m., in Room 310 of the Governor Office Building, 200 Madison St., Jefferson City, MO. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed rule and may be asked to respond to commission questions. Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 or TDD Hotline 1-800-829-7541.

FISCAL NOTE
PRIVATE COST

I. Department Title: Title 20--DEPARTMENT OF COMMERCE AND INSURANCE
Division Title: Division 4240—Public Service Commission
Chapter Title: Chapter 21— Resource Planning for Electric Utilities

Rule Number and Title:	20 CSR 4240-21.055 Distributed Energy Resource Analysis Requirements
Type of Rulemaking:	Proposed Rule

II. SUMMARY OF FISCAL IMPACT

Estimate of the number of entities by class which would likely be affected by the adoption of the rule:	Classification by types of the business entities which would likely be affected:	Estimate in the aggregate as to the cost of compliance with the rule by the affected entities:
4	Investor-Owned Electrical Corporations	$ 1,050,000 to $ 1,350,000 in year one (1) and $300,000 to $600,000 annually for the remaining four-year (4-year) life of the rule.

III. WORKSHEET

The rule will likely affect four (4) electrical corporations (investor-owned electric utilities). Staff requested input on the anticipated cost to implement the proposed rule from the affected electrical corporations. The feedback that was received was that the proposed rule would have a $ 1,050,000 to $ 1,350,000 cost for the electrical corporations to implement.

IV. ASSUMPTIONS

Staff relied on the input from the four (4) electrical corporations to determine the estimated fiscal impact of this proposed rule.

In accordance with the Commission's May 22, 2026, order, all four utilities submitted rule comments and estimated costs to comply. The low estimate is based on Ameren's compliance costs estimates. The high estimate is undetermined due to lack of information.

Ameren submitted rule comments and cost of compliance information through the Commission's electronic filing system on June 22, 2026. Staff carefully considered Ameren's rule comments and made significant responsive changes to the rule language. On July 31, 2026, Ameren emailed Staff updated cost estimates based on the revised rule language.

Liberty-Empire submitted rule comments and cost of compliance information through the Commission's electronic filing system on June 22, 2026. Liberty-Empire stated that it could not estimate the cost of a process that has never been undertaken, but the prescriptiveness of the new requirements will result in a significantly higher cost to comply. Staff carefully considered Liberty-Empire's rule comments and made significant responsive changes to the rule language.

Evergy submitted rule comments and cost of compliance information through the Commission's electronic filing system on June 22, 2026. Evergy stated that the prescriptiveness of the new requirements will drive significant costs to comply. Staff carefully considered Evergy's rule comments and made significant responsive changes to the rule language.

Costs for this rule are associated with developing a database of distributed energy resources and includes labor, software costs, and ongoing software maintenance.

Assumptions:

- Rule life: 5 years.
- Annual labor cost: $100,000 - $200,000
- One-time software cost: $250,000
- Number of electric utilities: 3 (Ameren Missouri, Evergy, Liberty-Empire)

Calculation:
Low total cost for all 3 utilities = (3)*($100,000 + $250,000) = $1,050,000 year-one

High total cost for all 3 utilities = (3)*($200,000 + $250,000) = $1,350,000 year-one

Low total cost for all 3 utilities = (3)*($100,000) = $300,000 annually years 2-5

High total cost for all 3 utilities = (3)*($200,000) = $600,000 annually years 2-5

TITLE 20 – DEPARTMENT OF COMMERCE AND INSURANCE
Division 4240 – Public Service Commission
Chapter 21 – Resource Planning for Electric Utilities

PROPOSED RULE

20 CSR 4240-21.060 Alternative Resource Plan and Preferred Resource Plan Requirements

PURPOSE: This rule establishes the minimum standards for the scope and level of detail to develop, analyze, and evaluate alternative resource plans, and select a preferred resource plan, and supplements the requirements of section 393.1900, RSMo.

(1) Specification of performance measures.

(A) The electric utility shall use the performance measures specified in subsection (1)(C) of this rule at the appropriate stages of the integrated resource plan (IRP) analysis to determine the relative performance of alternative resource plans.

(B) All performance measures shall be transparent, reproducible, and enable an objective comparison of the alternative resource plans analyzed in the electric utility's IRP.

(C) The electric utility's performance measures shall include the following, at a minimum:

1. Reliability metrics that demonstrate the adequacy, flexibility, and operational reliability of the resource portfolio, including but not limited to –

A. Loss of Load Expectation (LOLE), expressed in days per year;

B. Expected Unserved Energy (EUE), expressed in megawatt-hours per year;

C. Portfolio planning reserve margin by season as determined by the appropriate regional transmission operator/independent system operator (RTO/ISO); and

D. Any other generation attributes as required by the appropriate RTO/ISO or legal mandates;

2. Quantitative cost metrics, including but not limited to –

A. Annual revenue requirements, with and without any authorized financial or performance incentives for demand-side resources;

B. Demand-side program costs and forecasted Missouri Energy Efficiency Investment Act (MEEIA) rates, if applicable;

C. Annual rate impact for non-participants in demand-side programs;

D. Annual customer rate impact; and

E. Metrics that assess market exposure, including dependence on volatile fuel prices and market purchases;

3. Current and forecasted annual financial or other credit metrics, not necessarily based on the electric utility's financial plan, that assess the electric utility's ability to finance and sustain the implementation of an alternative resource plan, including, but not limited to –

A. Total debt-to-capital ratio;

B. Funds From Operations (FFO)-to-Debt ratio;

C. Debt-to-Earnings Before Interest, Taxes, Depreciation, and Amortization (EBITDA) ratio; and

D. Any other credit metric indicative of the electric utility's ability to finance an alternative resource plan;

4. Environmental and policy metrics including measures of environmental impact and policy compliance, including but not limited to –

A. Probable environmental compliance costs by resource type and by year;

B. Probable policy costs, such as the Missouri Renewable Energy Standard or any state or federal net-zero policy, by resource type and by year; and

C. Annual and cumulative emissions of regulated pollutants;

5. Other metrics the commission orders for assessing the performance of alternative resource plans as part of the pre-IRP proceeding; and

6. Other metrics the electric utility believes are appropriate for assessing the performance of alternative resource plans including the rationale for the additional metrics.

(2) Development of alternative resource plans.

(A) The electric utility shall describe the specific generation attributes that are required to provide sufficient capacity and energy resources in order to satisfy forecasted system needs, including forecasted planning reserve margins and the electric utility's share of any local clearing requirements of the appropriate RTO/ISO applicable in each season of each year for the planning horizon.

(B) The electric utility shall explain all uncertain factors, assumptions, and risks that could materially affect the performance of alternative resource plans over the planning horizon. These shall include, but are not limited to –

1. Load –

A. The range of future load growth represented by the low-case and high-case load forecasts;

B. Changes in industrial and large loads, and whether those changes are reflected in a load forecast scenario or alternative resource plan;

C. Future load impacts of demand-side programs; and

D. Increased load from any load-building programs, as identified in 20 CSR 4240-21.030(7);

2. Costs and financial impacts –

A. Future interest rate levels and other credit market conditions that can affect the electric utility's cost of capital and access to capital;

B. Fuel procurement including but not limited to pipeline reservation, timelines, and capacity, fuel purchasing and estimates of variable fuel expense and risk of volatility in fuel expense prices;

C. Siting, interconnection, and permitting costs and schedules for new supply-side resources and supply-side-related transmission facilities for the electric utility, for the appropriate RTO/ISO, and/or other transmission systems;

D. Construction costs and schedules for new generation and generation-related transmission facilities for the electric utility, for the appropriate RTO/ISO, and/or other transmission systems; and

E. Fixed operation and maintenance costs for new and existing supply-side resources;

3. Operational factors –

A. Purchased power availability, terms, cost, optionality, and other benefits;

B. Equivalent or full- and partial-forced outage rates for new and existing supply-side resources;

C. Price of emission allowances, including, at a minimum, any regulated pollutants; and

D. Change in reliability requirement or reserve margin;

4. Extreme weather;

5. Economic downturn;

6. Potential future changes in legal mandates;

7. Any other uncertain factors that the electric utility determines may be critical to the performance of alternative resource plans; and

8. Any other uncertain factors the commission orders the electric utility to analyze for assessing uncertainty with respect to scenarios or alternative resource plans as part of the pre-IRP proceeding.

(C) The electric utility shall develop, describe, and document alternative resource plans, in addition to the alternative resource plans ordered by the commission pursuant to 20 CSR 4240-21.020(2). Collectively the electric utility's alternative resource plans shall demonstrate a reasonable range of strategies, including timing of resources, to meet the system needs identified under subsection (2)(A) of this rule.

(D) The electric utility shall justify the methodology used to develop each alternative resource plan, including how scenarios were defined and how assumptions were applied.

(E) Each electric utility's alternative resource plan shall reasonably consider the balancing factors pursuant to 20 CSR 4240-21.010(2)(C).

(F) Each alternative resource plan shall include –

1. Consistent, transparent, and verifiable assumptions and at a minimum meet the needs identified in subsection (2)(A) of this rule;

2. Resources from the comprehensive set of candidate resources as developed pursuant to 20 CSR 4240-21.035(3) and demand-side resources from 20 CSR 4240-21.050;

3. All existing supply-side resources, together with any planned retirements, life extensions, environmental retrofits, or major refurbishments known or expected at the time of the IRP filing; and

4. Demand savings, energy savings, and program costs for previously approved demand-side programs.

(G) The electric utility shall use a capacity expansion model to develop alternative resource plans based on uncertain factors identified as critical in its last IRP filing, or as ordered by the commission, for the following scenarios:

1. A base scenario that represents the most probable outcome for each uncertain factor included in the model;

2. Additional scenarios that represent a reasonable high and low value for each included uncertain factor while keeping the values of the other uncertain factors at base levels; and

3. Additional scenarios the electric utility chooses to examine, or as ordered by the commission during the pre-IRP proceeding.

(H) The electric utility shall explain how it evaluated the adequacy of the capacity expansion modeling by addressing –

1. How the electric utility uses its capacity expansion optimization software for the development of alternative resource plans;

2. How the model identifies least-cost resource combinations under binding operational and reliability constraints;

3. How reserve margins are enforced in the model and how it is consistent with enforcement by the appropriate RTO/ISO along with an explanation of the possible penalties and negative outcomes for not meeting those requirements;

4. Whether supply-side resource selection results are sensitive to fuel and technology cost assumptions;

5. The degree to which the model's capacity expansion logic is stable under multiple sensitivities;

6. How candidate resources are screened, shortlisted, and represented in the optimization process; and

7. Any limits or constraints placed on resource adoption.

(I) The electric utility shall describe any known limitations of the modeling tools and explain their potential effect on the results of the analysis.

(J) For each alternative resource plan developed with the use of a capacity expansion model, the electric utility shall provide the following information:

1. A description of each alternative resource plan, including the type and size of each demand-side resource and supply-side resource addition;

2. The sequence and schedule for the retirement of existing supply-side and demand-side resources; and

3. The sequence and schedule for the acquisition of each new supply-side resource and demand-side resource.

(K) The electric utility may utilize alternative modeling techniques in addition to the requirements in subsection (2)(G) of this rule to develop additional alternative resource plans.

(L) For any alternative resource plan developed without the use of a capacity expansion model, the electric utility shall provide the following information over the planning horizon:

1. Describe the alternative resource plan and schedule of new additions and retirements as required in subsection (2)(J) of this rule;

2. Explain why the alternative resource plan was developed without the use of a capacity expansion model;

3. Explain the system needs being addressed and the rationale for each;

4. For each environmental compliance or policy need driven by legal mandates –

A. A citation for each applicable statute, administrative code, regulatory or judicial order, or policy;

B. A brief, clear explanation of how the proposed resource or resources help meet the cited requirement, including the specific time-period during which compliance is necessary; and

C. The discrete time-period during which the need is forecasted; and

5. For each anticipated environmental compliance or policy need not driven by legal mandates –

A. An explanation for each anticipated policy or requirement that specifies its source and intended outcome;

B. A brief, clear explanation of how the proposed resource or resources help meet the requirement, including the specific time-period during which compliance is necessary; and

C. The discrete time-period during which the need is forecasted.

(M) The electric utility's alternative resource plans developed at this stage shall not include load-building programs, which the electric utility shall analyze as required in paragraph (2)(B)1. of this rule.

(3) Analysis of alternative resource plans.

(A) The electric utility shall perform an analysis of the alternative resource plans developed under section (2) of this rule over the planning horizon to further refine the set of alternative resource plans to be included for risk analysis pursuant to section (4) of this rule.

(B) The electric utility's analysis shall –

1. Treat supply-side and demand-side resources on a logically consistent and economically equivalent basis utilizing comparable data sources, such that the same types or categories of costs, benefits, performance assumptions, and risks shall be considered and such that these factors shall be quantified at a similar level of detail and precision for all resource types; and

2. Use a capacity expansion model, a production cost model, and any other model the electric utility deems appropriate for this analysis, which shall be integrated or sequentially linked, to evaluate the operational performance of each plan and –

A. The production cost model shall simulate hourly system operation over a representative period, accounting for transmission constraints, renewable variability, and fuel dispatch economics;

B. The electric utility shall explain how the modeling tools used are appropriate for the system size, complexity, and market participation of the electric utility and are consistent with current industry practices;

C. The electric utility shall use consistent modeling software, input data, and scenario structures across all alternative resource plans, and provide justification for any deviations;

D. Each model pursuant to paragraph (3)(B)2. of this rule utilized by the electric utility shall be capable of evaluating fuel diversity, demand-side participation, market transactions, and appropriate RTO/ISO participation; and

E. The electric utility shall explain the model structure, optimization methods, and algorithms used for capacity expansion and production cost analysis.

(C) Based on the analysis conducted in subsection (3)(B) of this rule, the electric utility shall describe the methodology and document the results of the analysis of the alternative resource plans developed in section (2) of this rule, including –

1. A table summarizing each alternative resource plan's annual performance measures over the planning horizon, as set forth in section (1) of this rule, except for the following performance measures:

A. Reliability metrics specified in subparagraphs (1)(C)1.A., (1)(C)1.B., and (1)(C)1.C. of this rule; and

B. Quantitative cost metrics specified in subparagraphs (1)(C)2.C., (1)(C)2.D., and (1)(C)2.E. of this rule;

2. If the electric utility performs a screening analysis of the alternative resource plans based on the performance measures and determines that any alternative resource plans could be eliminated from further consideration and analysis, the electric utility shall provide justification for the elimination. Alternative resource plans ordered by the commission in accordance with 20 CSR 4240-21.020, or alternative resource plans created in accordance with paragraphs (2)(G)1. and (2)(G)2. of this rule shall not be eligible to be eliminated from further consideration; and

3. The electric utility shall include, for each remaining alternative resource plan, graphical plots over the planning horizon of the following information:

A. The combined impact of all demand-side resources on the base-case load forecast of seasonal peak demands;

B. The composition, by demand-side measure and program, of the assumed demand savings by demand-side resources, by season;

C. The composition, by supply-side resource, of the accredited capacity supplied to the transmission system provided by supply-side resources;

D. The composition, by supply-side resource or distributed energy resource (DER), of the capacity supplied directly to the distribution system provided by supply-side resources or DER;

E. The combined impact of all demand-side resources on the base-case load forecast of annual energy usage;

F. The composition, by supply-side resource, of the annual energy supplied to the transmission system, less transmission losses;

G. Annual emissions of regulated environmental pollutants;

H. Annual probable environmental compliance costs; and

I. Resulting capacity balance forecast, in the specified form included in 20 CSR 4240-21.020(2)(C)11.

(4) Risk and uncertainty analysis.

(A) The electric utility shall identify a comprehensive list of the risks and uncertainties associated with each alternative resource plan. The electric utility's analysis shall evaluate the potential variability in cost, performance, and reliability outcomes arising from critical uncertain factors, and determine the robustness and flexibility of each alternative resource plan across a range of plausible outcomes.

(B) The electric utility shall justify the methodology used to conduct its risk and uncertainty analysis. The justification shall –

1. Include a clear explanation of the selected analytical framework, modeling tools, probability techniques, and data sources used to evaluate risk;

2. Explain how the chosen approach captures the range, probability, and interactions of critical uncertain factors; and

3. Be reproducible, transparent, and consistent with the analytical assumptions used in the development and evaluation of the alternative resource plans.

(C) The electric utility shall conduct a sensitivity analysis to evaluate how variations in the uncertain factors affect the performance measures of each alternative resource plan. The electric utility shall describe and document and provide a summary statement of the risk scenarios and the results of the sensitivity analysis.

(D) The electric utility shall model a representative set of risk scenarios reflecting a range of plausible futures, incorporating each of the uncertain factors identified in subsection (2)(B) of this rule.

1. The electric utility shall support each performance measure with quantitative analysis to the extent practicable and with qualitative justification where necessary.

2. The electric utility shall perform additional sensitivity analysis to test the effects of –

A. Advancing or delaying deployment of specific resources to assess plan resilience to timing changes;

B. Risk scenarios that isolate the contribution of each uncertain factor identified in subsection (2)(B) of this rule;

C. Accelerated build requirements needed to address near-term reliability or compliance needs; and

D. Any relevant emerging factors the commission has ordered as part of the pre-IRP proceeding.

(E) The electric utility shall explain all critical uncertain factors based on the sensitivity analysis.

1. Based on the critical uncertain factors, the electric utility shall conduct a risk analysis.

2. Based on the risk analysis, for each critical uncertain factor, the electric utility shall –

A. Specify the range of potential outcomes and probability distribution used;

B. Describe the data sources and assumptions supporting that range and provide any data sources relied upon for the assumptions;

C. Provide justification for inclusion or exclusion of each variable; and

D. Explain the impacts and interrelationships of critical uncertain factors using a correlation matrix.

(F) The electric utility shall provide an updated table for each alternative resource plan that has undergone risk analysis, summarizing each alternative resource plan's annual performance measures over the planning horizon, as set forth in section (1) of this rule.

(G) After performing the risk analysis, the electric utility shall assess the alternative resources plans by the balancing

factors, select its top four (4), and provide justification for the selection of each.

(H) The electric utility shall analyze and report LOLE and EUE metrics for year five (5) of the planning horizon for each of the top four (4) alternative resource plans identified in subsection (4)(G) of this rule, or for additional years when the electric utility expects large changes to the system.

(I) If during the risk analysis, the electric utility determines that any of the top four (4) alternative resource plans would result in estimated financial ratios below investment-grade in any year, the electric utility shall explain why it would be reasonable to proceed with such alternative resource plan and the steps the electric utility would take to mitigate or address this risk. The electric utility shall maintain documentation for any other alternative resource plans that result in below-investment-grade financial ratios in any year and shall provide such documentation upon request.

(5) Evaluation and selection of the preferred resource plan.

(A) The electric utility shall select a preferred resource plan from among the alternative resource plans analyzed in section (3) of this rule and pursuant to section 393.1900, RSMo.

(B) Contingency analysis.

1. The electric utility shall develop and justify a contingency analysis of the preferred resource plan to address significant deviations from base assumptions, including but not limited to –

A. Market price changes for key components of selected resource types;

B. Market price changes for capacity, energy, and ancillary services;

C. Changes to tax incentives for the selected resource types;

D. Restrictions on generation output from selected supply-side resource types;

E. Load assumptions; and

F. Ongoing litigation regarding existing resources.

2. Based on the contingency analysis, the electric utility shall –

A. Describe the expected risk mitigation strategies that may be employed as a result of the contingency analysis; and

B. Explain which alternative resource plans would best satisfy the performance measures in response to the contingency analysis.

(C) The electric utility's evaluation shall integrate the results of the risk and uncertainty analysis and contingency analysis and shall demonstrate the relative strengths and weaknesses of the preferred resource plan under expected and stressed system conditions.

1. The electric utility shall not rely on a single performance metric as the sole determinant in selecting a preferred resource plan.

2. The electric utility shall include a graphical comparison showing the preferred resource plan's performance relative to each of the top four (4) alternative resource plans across each performance measure and risk scenarios.

3. The electric utility shall clearly explain tradeoffs among performance measures and explain how the preferred resource plan balances the balancing factors pursuant to 20 CSR 4240-21.010(2)(C).

4. The electric utility shall demonstrate that the preferred resource plan remains robust under the sensitivity and scenario analyses conducted pursuant to section (4) of this rule and explain any conditions under which the preferred resource plan would require reconsideration or adjustment.

(D) The electric utility shall justify its selection of its preferred resource plan. To support the justification, the electric utility shall –

1. Describe the criteria, weighting factors, or scoring methods used to rank or compare plans;

2. Provide a summary of key findings from quantitative analysis and documentation underlying the analysis;

3. Describe stakeholder feedback that influenced preferred resource plan selection;

4. Explain how the preferred resource plan reflects the electric utility's acceptable levels of risk, reliability, and rate impact;

5. Specify the ranges or combinations of outcomes for the critical uncertain factors that define the limits the electric utility used to select the preferred resource plan and explain how these limits were determined;

6. Provide an assessment of whether, and under what circumstances, other uncertain factors associated with the preferred resource plan could materially affect the performance of the preferred resource plan relative to alternative resource plans;

7. Quantify the expected value of better information concerning the critical uncertain factors that affect the performance of the preferred resource plan, as measured by annual utility revenue requirements; and

8. Provide a tabulation of the key quantitative results of that analysis conducted under paragraph (5)(D)6. of this rule and a discussion of how those findings will be incorporated in ongoing research activities.

(E) The electric utility shall summarize the results of its evaluation for the top four (4) alternative resource plans using a comparative scorecard or equivalent matrix that presents all the performance measures pursuant to section (1) of this rule and risk scenarios in a clear, reproducible format. The scorecard shall –

1. Display both expected values and measures of risk or variability for each metric;

2. Describe tradeoffs among cost, reliability, risk, and environmental outcomes;

3. Clearly distinguish modeled results from qualitative assessments;

4. Present results for both the implementation period and full planning horizon;

5. Include the reliability metrics specified in subparagraphs (1)(C)1.A. and (1)(C)1.B. of this rule based on studies conducted for years three (3), five (5), and ten (10) of the planning horizon;

6. Include financial performance measures specified in paragraph (1)(C)3. of this rule annually through year ten (10) of the planning horizon;

7. Include expected total transmission costs, including potential upgrades for load and interconnection of supply-side resources; and

8. Include expected total distribution costs, including potential upgrades for load and interconnection of distributed energy resources.

(F) The electric utility shall quantify the forecasted rate impacts of the top four (4) alternative resource plans, based on the scorecard required in subsection (5)(E) of this rule, including the preferred resource plan, over the planning horizon.

1. Annual rate impact estimates, specified in subparagraph (1)(C)2.D. of this rule, shall include –

A. Base rates and fuel cost components;

B. Anticipated changes in revenue requirements; and

C. Estimated annual percentage rate impact.

(G) The electric utility shall provide the value for each cost-related performance measure by endpoint in its workpapers.

AUTHORITY: sections 386.040, 386.250, 386.610, 393.140, RSMo 2016, and section 393.1900, RSMo Supp. 2026. Original rule filed Sept. 21, 2026.

PUBLIC COST: This proposed rule will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed rule will not cost private entities more than five hundred dollars ($500) in the aggregate.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file comments in support of or in opposition to this proposed rule with the Missouri Public Service Commission, Nancy Dippell, Secretary of the Commission, PO Box 360, Jefferson City, MO 65102. To be considered, comments must be received at the commission's offices on or before Dec. 2, 2026, and should include a reference to Commission Case No. EX-2027-0085. Comments may also be submitted via a filing using the commission's electronic filing and information system at https://psc.mo.gov/General/Submit_Comments. A public hearing regarding this proposed rule is scheduled for Dec. 15, 2026, at 10 a.m., in Room 310 of the Governor Office Building, 200 Madison St., Jefferson City, MO. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed rule and may be asked to respond to commission questions. Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 or TDD Hotline 1-800-829-7541.

TITLE 20 – DEPARTMENT OF COMMERCE AND INSURANCE
Division 4240 – Public Service Commission
Chapter 21 – Resource Planning for Electric Utilities

PROPOSED RULE

20 CSR 4240-21.065 Implementation Plan Development and Reporting Requirements

PURPOSE: This rule establishes the minimum standards for the scope and level of detail required for developing the implementation plan for the preferred resource plan and supplements the requirements of sections 393.1900.4 and 393.1900.5, RSMo.

(1) Implementation plan development.

(A) The electric utility shall develop an implementation plan for its preferred resource plan, which shall be filed as part of its integrated resource plan (IRP), as required in 20 CSR 4240-21.020(3).

(B) For each specified supply-side resource, or specified quantity of supply-side resource by supply-side resource type for which construction is expected to begin during the implementation period, the electric utility shall describe, if known, and document, if applicable, the following:

1. The supply-side resource or quantity of supply-side resource by supply-side resource type, including generation type(s) and capacity;

2. Location;

3. Acquisition approach, including any negotiated or signed power purchase agreement or build-transfer agreement to purchase a supply-side resource(s) from a third party;

4. Schedule, including –

A. Estimated schedule to bring the supply-side resource on-line;

B. A schedule for all acquisition or engineering and construction phases; and

C. Identification of critical paths and major milestones, including decision points for committing to major expenditures;

5. Estimated project costs, which shall include –

A. Detailed capital cost estimates, covering all engineering and construction phases, including –

(I) Expected transmission interconnection costs and potential for increased costs;

(II) Expected fuel supply interconnection costs; and

(III) Expected fuel costs and expected alternative fuel costs;

B. Estimated annual operation and maintenance costs, divided into fixed and variable costs;

C. The source of any project cost information, including copies of procurement documents, construction or purchase agreements; and

D. A sufficient level of detail to assess the economic feasibility of each supply-side resource;

6. Identification of any environmental permits, granted or planned;

7. The appropriate regional transmission organization or independent system operator (RTO/ISO) generation interconnection agreement status and expected finalization date;

8. Performance information for the supply-side resource, including information related to existing supply-side resources, and needed to individually assess the following cost categories by resource:

A. Capital cost, including for capital projects that are reasonably expected to result in the extension of the retirement date of each generating unit;

B. Fixed and variable operation and maintenance costs;

C. Probable environmental compliance costs; and

D. Unit characteristics and attributes; and

9. Any other attributes that may be applicable or unique to the supply-side resource.

(C) The electric utility's implementation plan shall be part of the technical volumes and include the following documentation:

1. A description of competitive procurement policies the electric utility uses in the development, planning, engineering, construction, and acquisition of supply-side resources;

2. The electric utility's process for monitoring the critical uncertain factors on an ongoing basis and reporting the impact of significant changes in a timely fashion to those managers or officers who have the authority to initiate corrective actions when the specified limits for uncertain factors are exceeded;

3. The electric utility's process for monitoring the progress made implementing the preferred resource plan in accordance with the schedules and milestones set out in the implementation plan and for reporting significant deviations in a timely fashion to those managers or officers who have the authority to initiate corrective actions to ensure the supply-side resources are implemented as scheduled;

4. An explanation of any differences between the supply-side related investment levels reflected in the general categories of capital expenditure contained in the electric utility's five- (5-) year capital investment plan submitted under section 393.1400.4, RSMo, and the investment levels

underlying the electric utility's preferred resource plan;

5. Short-term capacity needs, specifically –

A. For short-term capacity needs forecasted within the implementation period, the electric utility shall develop short-term alternatives sufficient to maintain reliability until long-term resources are available;

B. For each short-term alternative, the electric utility shall describe and provide supporting documentation relied upon together with a summary table including the –

(I) Cost of acquisition, including contract payments, fuel, operations, and any associated ancillary services;

(II) Operational characteristics, including expected availability, reliability, ramp rates, start-up and shut-down times, and any limitations on continuous operation;

(III) Term of the resource, including contract length, start and end dates, and any provisions for renewal, extension, or early termination; and

(IV) Analysis of the risk and uncertainty, including potential variability in availability, fuel supply, or market pricing; and

C. The electric utility shall not exclude from consideration any economically feasible short-term alternative capacity resource without documented justification; and

6. A schedule and explanation of ongoing and planned research activities to update and improve the quality of data used in load analysis and forecasting.

(2) Implementation plan status report.

(A) The electric utility shall submit an implementation plan status report by February 15 following the commission's order for the applicable electric utility's IRP filing and every year thereafter, or more frequently if ordered by the commission.

(B) The implementation plan status report shall include, but is not limited to –

1. Status of the electric utility's approved preferred resource plan;

2. Status of the filed critical uncertain factors pursuant to 20 CSR 4240-21.060(4)(E), including a discussion of any significant deviations from the forecasted values for each critical uncertain factor;

3. Any changing conditions or potential changing conditions that may impact any aspect of the implementation plan or the preferred resource plan;

4. The electric utility's progress in implementing each specified supply-side resource and each quantity of supply-side resources by resource type identified in its implementation plan, which shall include viability metrics such as qualitative and quantitative measures that assess the practicality and readiness of each resource identified in the implementation plan, and shall include –

A. Siting and permitting feasibility, including interconnection, transmission access, transmission constraints, and availability of fuel;

B. Updated project costs, as required in paragraph (1)(B)5. of this rule;

C. Construction and acquisition timelines;

D. Supply chain and workforce availability;

E. Alignment with the electric utility's implementation schedule and procurement capabilities;

F. Scope changes to any resource; and

G. Environmental compliance costs; and

5. For each short-term capacity resource identified pursuant to paragraph (1)(C)5. of this rule, the electric utility shall provide –

A. An updated summary table as required by subparagraph (1)(C)5.B. of this rule;

B. Any information the commission orders; and

C. Any other information the electric utility determines is appropriate.

AUTHORITY: sections 386.040, 386.250, 386.610, 393.140, RSMo 2016, and section 393.1900, RSMo Supp. 2026. Original rule filed Sept. 21, 2026.

PUBLIC COST: This proposed rule will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed rule will not cost private entities more than five hundred dollars ($500) in the aggregate.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file comments in support of or in opposition to this proposed rule with the Missouri Public Service Commission, Nancy Dippell, Secretary of the Commission, PO Box 360, Jefferson City, MO 65102. To be considered, comments must be received at the commission's offices on or before Dec. 2, 2026, and should include a reference to Commission Case No. EX-2027-0085. Comments may also be submitted via a filing using the commission's electronic filing and information system at https://psc.mo.gov/General/Submit_Comments. A public hearing regarding this proposed rule is scheduled for Dec. 15, 2026, at 10 a.m., in Room 310 of the Governor Office Building, 200 Madison St., Jefferson City, MO. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed rule and may be asked to respond to commission questions. Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 or TDD Hotline 1-800-829-7541.