BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of a Working Case for the Development of Rules Regarding Integrated Resource Planning for Electrical Corporations as Required by Section 393.1900, RSMo.	)))))	**Case No. EW-2026-0091**

ORDER ISSUING DRAFT RULES, REGISTRATION AND AGENDA FOR WORKSHOP AND TECHNICAL SESSIONS

Issue Date: March 11, 2026 Effective Date: March 11, 2026

The Commission opened this working case to collect input from stakeholders during the development of new integrated resource planning (IRP) rules for electrical corporations in accordance with Section 393.1900, RSMo.

To facilitate informed and productive discussions at the upcoming workshop and technical sessions in April 2026, the Commission is providing a discussion draft of the IRP rules, which can be found as Attachment A to this order. An outline of the structure of the proposed IRP rules is set out below.

21.010 General Provisions
21.015 Electric Utility Resource Planning Definitions
21.020 Filing Schedule, Filing Requirements, and Integrated Resource Planning Proceeding
21.025 Standards and Dataset Management Requirements
21.030 Load Forecasting Requirements
21.035 Supply-Side Resources Analysis
21.040 Transmission and Distribution Analysis
21.050 Demand-Side Resource Analysis
21.055 Distributed Energy Resource Analysis and Reporting Requirements
21.060 Alternative Resource Plans and Preferred Resource Plan Requirements
21.065 Implementation Plan Development and Reporting Requirements

Along with the discussion draft of the IRP rules, the Commission is also providing process flow charts in Attachment B, which visually represents Section 393.1900, RSMo, and Rule 21.020.

The Commission has scheduled a workshop and three technical sessions, which are planned as set forth below:

Session	Date and time	Location	IRP Rule Covered
Workshop	April 16, 2026, 9:30 a.m. to 4:00 p.m.	Governor Office Building Room 450 200 Madison Street Jefferson City, MO 65102 (IN-PERSON ONLY)	21.010 21.015 21.020
Technical Session A	April 21, 2026, 9:00 a.m. to 5:00 p.m.	Virtual Only Via Webex	21.060 21.030 (if time allows)
Technical Session B	April 23, 2026, 9:00 a.m. to 5:00 p.m.	Virtual Only Via Webex	21.015 21.030 21.035 21.040 21.065
Technical Session C	April 30, 2026, 9:00 a.m. to 5:00 p.m.	Virtual Only Via Webex	21.015 21.025 21.050 21.055

Workshop Registration: IRP Workshop participants must register by April 10 on the Commission's website under the "How Do I …" section or use the following link https://psc.mo.gov/General/IRPRulesWorkshop. Registration will close on April 10.

Technical Session Participation: The three technical sessions will focus on the technical topics contained in the discussion draft of the IRP rules. Stakeholders or organizations interested in participating in the technical sessions, should send an email to irprules@psc.mo.gov to request more information about participation. Webex access details to participate in the technical sessions will be provided in advance of the technical sessions.

Submitting Questions or Topics: Interested stakeholders and organizations may submit questions, concerns, or topics for the Commission to address in the upcoming workshop and technical sessions by sending an email to irprules@psc.mo.gov at least five days prior to the workshop and each technical sessions.

THE COMMISSION ORDERS THAT:

1. A workshop meeting and three technical sessions are scheduled as set forth in the body of this order.

2. This order shall be effective when issued.

BY THE COMMISSION

Nancy Dippell

Nancy Dippell
Secretary

John T. Clark, Senior Regulatory Law Judge,
by delegation of authority pursuant to
Section 386.240, RSMo 2016.

Dated at Jefferson City, Missouri,
on this 11th day of March, 2026.

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

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 each 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) filings.

(B) The requirements under Chapter 21 establish minimum standards to govern the resource planning process, including the IRP proceeding, as outlined in section 393.1900.1, RSMo, the IRP filing requirements, and implementation plan status reports as outlined in this chapter.

(C) Integrated resource plans shall be reviewed to determine if they appropriately balance all of the following factors, consistent with section 393.1900.4, RSMo:

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; and
10. Compliance with applicable state and federal environmental regulations.

20 CSR 4240-21.015 Electric Utility Resource Planning Definitions

PURPOSE: This rule defines terms used in the rules comprising Chapter 21, Resource Planning for Electric Utilities, and supplements those definitions found in sections 386.020 and 393.1900, RSMo.

(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 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 developed and analyzed by an electric utility as part of its integrated resource plan to meet its load serving obligations.

(3) Annual energy usage means the total amount of energy used by an electric utility and its customers as metered by the appropriate RTO/ISO over a three-hundred- and sixty-five-day time period.

(4) Appliance saturation means the statistical measure of the percentage of homes or businesses that possess a specific type of electric or gas appliance (e.g., central air conditioning, electric water heater, gas furnace, smart thermostat, etc.) within an electric utility's service territory. Appliance saturation, along with the Unit Energy Consumption (UEC) for each appliance, is used as an independent variable in end-use forecasting models.

(5) 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 the electric utility is a member of.

(6) Approved preferred resource plan means the alternative resource plan presented by the electric utility in its IRP filing as its preferred resource plan, which has been found by the commission to be a reasonable and prudent means for the electric utility to meet its load serving obligations.

(7) Avoided demand cost is a component of total avoided cost which represents the portion of an 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.

(8) Avoided costs or avoided utility 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. The utility shall use the integrated resource plan and risk analysis used in its most recently adopted preferred resource plan to calculate its avoided costs.

(9) Base-case forecast means the forecast generated by using the most probable values, generally those representing a fifty (50) percentile probability, for each independent variable contained in a forecast model.

(10) Candidate resource options mean the potential demand-side and supply-side resource options that advance to be included in one (1) or more alternative resource plans.

(11) Capacity means the maximum capability to continuously produce and deliver electric power.

(12) Capacity expansion model means use of optimization software to plan the least cost supply-supply side resources to be utilized over the planning horizon to meet demand, reliability, and policy goals.

(13) Coincident peak means the demand at the time the system experiences maximum demand during the applicable time period. Coincident peak may refer to the peak of a specific customer, customer class, or component of the system relative to the electric utility or the electric utility's peak relative to the appropriate RTO/ISO depending on the situation being considered.

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

(15) Deficiency means concerns, shortcomings, missing information or any failure identified by the commission in the electric utility's compliance with the provisions of this chapter.

(16) Degree-days means a measure of how extreme the weather is at a location is relative to a standard temperature, typically sixty-five degrees (65°) Fahrenheit. 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. Cooling degree-days (CDD) are determined by the formula CDD = T – 65.

(17) Demand means the electrical power consumed at a given point in time measured in kilowatts (kW).

(18) 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 least some measures that are appropriate for most members of the target market segment.

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

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

(21) Describe and document refers to the demonstration of compliance with each provision of this chapter. Describe means the provision of information in the technical volume(s) of the quadrennial compliance filing, in sufficient detail to inform the stakeholders how the electric utility complied with each applicable requirement of chapter 21, why that approach was chosen, and the results of its approach. The description in the technical volume(s), including narrative text, graphs, tables, and other pertinent information, shall be written in a manner that would allow a stakeholder to thoroughly assess the electric utility's analysis and each of its components. Document means the provision of all of the supporting information relating to the analysis.

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

(23) Distributed energy resources (DER) mean 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, solar photovoltaic systems, and electric vehicles.

(24) Distributed energy resource (DER) aggregation means the assembly of a portfolio of DERs from one or more entities that are managed collectively by a single entity (i.e. aggregator) 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.

(25) 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.

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

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

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

(29) 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.

(30) Energy storage system 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, and accredited by the appropriate RTO/ISO in resource adequacy determinations. ESS may be considered a transmission or generation asset.

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

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

(33) Energy means the total amount of electric power that is generated or used over a specified interval of time measured in kilowatt-hours (kWh).

(34) 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 that would otherwise be required.

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

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

(37) 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 failure of a facility.

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

(39) Generation attribute means the capacity, energy, and other generating unit capabilities used in regional energy and capacity markets to differentiate services that can be provided by various types of generating units.

(40) Generation technology is various methods and technologies that an electric utility plans to use to generate electricity.

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

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

(43) Implementation plan means descriptions, costs, and schedules for 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.

(44) Information means any fact, relationship, insight, estimate, or expert judgment that narrows the range of uncertainty surrounding key decision variables or has the potential to substantially influence or alter resource planning decisions.

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

(46) Integrated resource plan (IRP) filing means the IRP submitted to the commission in accordance with section 393.1900, RSMo.

(47) Integrated resource plan (IRP) proceeding is the proceeding initiated by the Commission's schedule for the electric utility every four years or as needed as specified in 393.1900.1 and results in requirements for the electric utility to include its IRP filing.

(48) Large load refers to an electric utility's qualifying threshold amount of annual peak demand as defined in its commission approved tariffs in accordance with section 393.130, RSMo.

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

(50) Load-building program means an organized promotional effort by the electric utility 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, either by substituting electricity for other forms of energy or by 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.

(51) 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.

(52) 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.

(53) 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 12:00 midnight.

(54) Local clearing requirements means a formula used to determine the amount of capacity needed to ensure reliability within a specific local resource zone or reserve zone. It shall be calculated consistent with the appropriate RTO/ISO requirements.

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

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

(57) Lost revenues means the reduction between rate cases in billed energy (kWh) due to installed end-use measures, multiplied by the fixed-cost margin of the appropriate rate component.

(58) Materially changed means a change in cost, scope, or conditions that is significant enough to reasonably influence the decision or judgment of the commission or alter the commission's evaluation of the plan's prudence or cost-effectiveness.

(59) Maximum achievable potential means energy savings and demand savings relative to an 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 an 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 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.

(60) Net system load is 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.

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

(62) Non-coincident peak is 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.

(63) 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.

(64) Planning horizon means a future time period of a minimum of sixteen (16) years from the electric utility's IRP filing year over which the costs and benefits of alternative resource plans are evaluated.

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

(66) Preferred resource plan means the alternative resource plan that is contained in the integrated resource plan that has been selected by the electric utility to represent the most prudent and reasonable alternative resource plan to meet its load serving obligations.

(67) Probable environmental cost means the expected cost to the electric utility of complying with new or additional environmental legal mandates, taxes, or other requirements that, in the judgment of the electric utility decision-makers, 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.

(68) 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.

(69) Public counsel means the public counsel of the state of Missouri or their designated representative.

(70) Rate class or customer class is as defined in an 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.

(71) Realistic achievable potential means energy savings and demand savings relative to an 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 an electric utility can expect to achieve through its demand-side programs and involves incentives that represent a moderate portion of total program costs and longer customer payback periods when compared to those associated with maximum achievable potential.

(72) Relevant emerging factors means a list of new or evolving topics where the commission has determined that additional research and knowledge is needed to support decisions in an electric utility IRP filing.

(73) Relevant future timeframe means the planning horizon defined in section (64) of this rule.

(74) Renewable energy means 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.

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

(76) Resource planning means the process by which an 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.

(77) 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, and pumped storage hydroelectric system.

(78) 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 (typically Summer, Fall, Winter, or Spring). It is a time-differentiated measure used to determine capacity obligations and to allocate fixed costs.

(79) Service territory means the area in which the electric utility has been approved by the commission to provide electrical service to customers.

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

(81) Stakeholder group means—
   (A) Staff, public counsel, and any person or entity granted intervention in a prior Chapter 22 proceeding of an electric utility. Such persons or entities shall be a party to any subsequent related Chapter 21 proceeding of the electric utility without the necessity of applying to the commission for intervention; and
   (B) Any person or entity granted intervention in a current Chapter 21 proceeding of the electric utility.

(82) Subjective probability means the judgmental likelihood that the outcome will actually occur.

(83) 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.

(84) Supply-side resource means any device or method by which an electric utility can provide to its customers an adequate level and quality of electric power supply, including distributed energy resources.

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

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

(87) Transmission losses means the amount of power, expressed as a percentage, that is lost during the transmission of electricity from generation resources to an electric utility's interconnection point.

(88) Total resource cost test means a test of the cost-effectiveness of demand-side programs that compares the sum of avoided utility costs plus avoided probable environmental costs to the sum of all incremental costs related to the end-use measures that are implemented due to the program or related to the rates (including both electric utility and participant contributions), plus utility costs to administer, deliver, and evaluate each demand-side program to quantify the net savings obtained by substituting the demand-side program for supply-side resources.

(89) 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 electric utility planners and decisionmakers have incomplete or inadequate information at the time a decision must be made.

(90) Utility costs mean the costs of operating the electric utility system and developing and implementing an alternative resource plan that are incurred and paid by the electric utility. On an annual basis, utility cost is synonymous with electric utility revenue requirement.

(91) Utility cost test means a test of the cost effectiveness of demand-side programs that compares the avoided utility costs to the sum of all electric utility incentive payments, plus utility costs to administer, deliver, and evaluate each demand-side program to quantify the net savings obtained by substituting the demand-side program for supply-side resources.

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

PURPOSE: This rule specifies the filing schedule, filing requirements, and integrated resource plan proceeding for an electric utility's Integrated Resource Plan and supplements the requirements found in Section 393.1900 of the Missouri Revised Statutes.

(1) Each electric utility shall file an integrated resource plan (IRP) with the commission every four (4) years, or as otherwise ordered by the commission, on the first business day in October of the specified year. The electric utilities shall submit their first IRP filing on the following schedule and every four years thereafter:
  (A) Union Electric Company d/b/a Ameren Missouri, or its successor, first business day of October 2029;
  (B) Evergy Metro d/b/a Evergy Missouri Metro, or its successor, first business day of October 2030;
  (C) Evergy Missouri West d/b/a Evergy Missouri West or its successor, first business day of October 2030; and
  (D) The Empire District Electric Company d/b/a Liberty, or its successor, first business day of October 2031.

(2) An IRP proceeding, as outlined in section 393.1900.1, RSMo, shall be conducted to establish alternative resource plans and the factors that each electric utility shall take into account in its IRP filing made pursuant to section (1) of this rule.
  (A) Each IRP proceeding shall commence with the electric utility making a filing consistent with the minimum filing requirements found in section (3) of this rule.
  (B) The IRP proceeding shall occur no less than eighteen (18) 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), which shall commence no less than twenty-seven (27) months prior to the IRP filing date.
  (C) Within three (3) months of filing in accordance with subsection (2)(A) of this rule, the electric utility shall convene public engagements to provide the opportunity for public input into the electric utility's resource planning process and shall file a notice summarizing the feedback received from its public outreach efforts, including a description of how feedback may be incorporated or considered into its IRP filing submitted pursuant to section (1) of this rule.
  (D) Within one (1) month of filing in accordance with subsection (2)(A) of this rule, the electric utility shall convene the stakeholder group for presentations and a series of technical sessions to present the IRP proceeding minimum filing requirements, obtain feedback from the stakeholder group, and develop or refine the proposed inputs and assumptions.
  (E) Stakeholders and the electric utility must determine within four (4) months of the electric utility's filing in accordance with subsection (2)(A) if they are able to reach consensus through the process outlined in subsection (2)(D).

1. If consensus is achieved, the stakeholder group and the electric utility shall file with the commission the proposed agreed upon alternative resource plans for analysis, scenario(s) as input for the development of alternative resource plans by the electric utility, relevant emerging factors, and any modifications to the previously filed IRP proceeding minimum filing requirements, submitted pursuant to subsection (2)(A) of this rule.
2. If consensus is not achieved as contemplated in (2)(E)1, any party may request a hearing.

(F) The commission shall issue an order no later than nine (9) months from the filing date of the IRP proceeding minimum filing requirements in accordance with subsection (2)(A) of this rule.

(G) If the electric utility or staff becomes aware of any information that impacts or could impact any direction provided in the commission's order, issued pursuant to subsection (2)(F) of this rule, the electric utility or staff shall:

1. Notify the stakeholder group and electric utility within fourteen (14) days of being aware of the impact; and
2. Convene an additional stakeholder group technical session, if necessary, with the goal of jointly recommending a resolution to the commission, if necessary, or notifying the commission that no recommendation is necessary or that one could not be reached.

(3) The IRP proceeding minimum filing requirements shall include the following:

(A) Identification of required and proposed planning reserve margins anticipated over the relevant future timeframe;

(B) Identification of applicable, required, or proposed, local clearing requirements anticipated over the relevant future timeframe;

(C) Identification of existing federal and state environmental regulations, laws or rules by resource type;

(D) Identification of significant proposed federal and state environmental regulations, laws or rules, an explanation of how regulations law, or rule applies to the applicable resource type, and a description of the expected timeframe when proposed regulation, law or rule will take effect;

(E) Future load forecasts for monthly system energy and monthly non-coincident peak over the planning horizon;

(F) Identification of anticipated critical uncertain factors, including descriptive statistics and probability distribution;

(G) Identification of reasonable supply-side and demand-side resources that could address the need for additional energy and capacity including, but not limited to:

1. Type and description of technology for proposed supply-side or demand-side resources;
2. Projected load impact due to load-building programs, such as electrification or economic development projects; and
3. Projected load management and demand response savings;

(H) Identification of projected range of costs of different types of technologies and fuels used for existing and future electric generation, including information on the availability of different types of fuels to the electric utility;
(I) Considerations for developing alternative resource plans for contemplation by the stakeholder group;
(J) The comprehensive database required pursuant to 20 CSR 4240-21.030(1)(B);
(K) A capacity balance forecast, included herein, provided in the following specified form:
1. The base case capacity balance forecast includes the existing supply-side resources through the currently expected life of each asset or contract, expected load growth over the planning horizon without additions of large load customers, and no resource additions.
2. The large load addition capacity balance forecast includes existing supply-side resources through the currently expected life of each asset or contract, expected load growth over the planning horizon with additions of large load customers that have the required probability of interconnection pursuant to 20 CSR 4240-21.030(6)(D)6., and no resource additions; and
(L) Any other information the commission may order be provided.

(4) The electric utility's IRP filing shall demonstrate compliance with the provisions of Chapter 21 and section 393.1900, RSMo and include at a minimum—
(A) A letter of transmittal expressing commitment to the preferred resource plan and its implementation plan, 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 determined by the commission to be reasonable and prudent in whole or in part;
(B) An explanation of any differences and why the differences exist between the electric utility's preferred resource plan and its capital budget pursuant to section 393.1400, RSMo;
(C) Technical volumes shall describe and document the electric utility's assumptions, inputs, analysis, and decisions in developing the alternative resource plans, selecting its preferred resource plan, and developing its implementation plan;
1. The technical volumes shall —
A. Be organized by chapters corresponding to 20 CSR 4240-21.025 through 20 CSR 4240-21.065 and include all documentation and information specified in 20 CSR 4240-21.025 through 20 CSR 4240-21.065, respectively;
B. Include a stand-alone chapter that identifies the naming convention of the alternative resource plans selected and clearly identifies the alternative resource plan that is selected as the preferred resource plan; and
C. A separate chapter shall be designated to address relevant emerging factors ordered by the commission under section (2) of this rule.

(D) Capacity balance forecast in the specified form, included herein, for the preferred resource plan and each alternative resource plan considered by the electric utility;

(E) The executive summary shall provide the electric utility's justification of the preferred resource plan and implementation plan—

1. The executive summary shall be suitable for distribution to the public in electronic format.
2. The executive summary shall be organized by and summarize the contents of the technical volumes and include:

A. A brief introduction describing the electric utility, its existing supply-side resources and transmission and distribution facilities, existing purchase power arrangements, existing demand-side programs, existing demand-side rates, and its reasoning for selecting its preferred resource plan, and the strategy for the implementation plan;

B. For each rate class and for the total of all rate classes, provide the following:

(I) The base load forecasts for peak demand and for energy for the planning horizon, with and without utility demand-side resources, and

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

C. For the preferred resource plan—

(I) 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;

(II) Identification of critical uncertain factors affecting the preferred resource plan;

(III) For existing legal mandates and approved cost recovery mechanisms, the following performance measures of the preferred resource plan for each year of the planning horizon:

(a) Estimated annual revenue requirement;

(b) Estimated level of average retail rates by rate class and percentage of change from the prior year; and

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

D. If the estimated company financial ratios provided in accordance with 20 CSR 4240-21.060(1)(C)3 are below investment grade in any year of the planning horizon, a description of any changes in legal mandates and cost recovery mechanisms necessary for the utility to maintain an investment grade credit rating in each year of the planning horizon and the resulting performance measures of the preferred resource plan; and

E. A description of the major research projects and programs the utility will continue or commence during the implementation period.

(F) Such other information or format as the commission may determine.

(5) Cost Updates to IRP Filing.
   (A) An electric utility may submit an update to the IRP filing on or before one hundred fifty (150) calendar days from the receipt date of the electric utility's IRP filing, if the cost estimates have materially changed.
   (B) Updates to the cost estimates shall be in the format specified in 20 CSR 4240-21.060 and 20 CSR 4240-21.065, along with an identification and explanation of the change in cost over the planning horizon.
   (C) If an electric utility intends to update the cost estimates, it will notify the parties to the case as soon as possible and convene discussions on the potential for requesting a modified procedural schedule to accommodate the additional review.

(6) After a hearing is conducted, the commission shall issue a report and order no later than three hundred sixty days from the date the IRP filing was submitted, unless an extension is granted for good cause by the commission.
   (A) If the commission determines that the preferred resource plan is a reasonable and prudent means of meeting the electric utility's load serving obligations, such determination shall constitute the commission's permission for the electric utility to construct or acquire the specified supply-side resources, or a specified quantity of supply-side resources by supply-side resource type, or both, identified by the commission, that were reflected in the implementation plan submitted in accordance with 20 CSR 4240-21.065.
   (B) If the commission determines that the preferred resource plan, in whole or in part, is not a reasonable and prudent means of meeting the electric utility's load serving obligations, the commission shall specify in its report and order the deficiencies in the preferred resource plan and may require the electric utility to make a further filing within sixty (60) days after issuance of the report and order to address the deficiencies. The electric utility shall file a revised IRP addressing the deficiencies and may propose modifications to its original preferred resource plan.
      1. Any other party to the IRP docket shall have sixty (60) days to respond to the electric utility's updated IRP filing, unless the commission grants an extension for good cause.
      2. Within sixty days after the deadline for such other parties' filings, the commission shall issue a report and order indicating whether the deficiencies have been cured by the electric utility's revised IRP filing and the commission may approve the electric utility's modified preferred resource plan and may approve specific supply-side resources, or a specified quantity of supply-side resources by supply-side resource type, or both.
   (C) If the commission finds continued deficiencies in the electric utility's revised preferred resource plan:
      1. The commission may initiate a complaint proceeding pursuant to the provisions of section 393.270 RSMo; and

2. The electric utility shall not be eligible for a limited inquiry in any proceeding under section 393.170 RSMo as set forth in section 393.1900 RSMo.

(7) Proposed changes or unforeseen events that may require changes to the approved preferred resource plan or its implementation plan—

(A) 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 identified pursuant to 20 CSR 4240-21.060(I)(E)1. being exceeded or for other reasons, the electric utility shall file in the commission's electronic filing information system (EFIS) in the IRP docket a notice within thirty (30) days of the electric utility's determination of such change and shall serve notice to all parties in the most recent IRP docket.

(B) The notification shall include a description of all changes to the preferred resource plan and implementation plan, the impact of each change on the annual revenue requirement, and all other performance measures specified in the last IRP filing pursuant to 20 CSR 4240-21.060(1) and the rationale for each change in the performance measure. Further proceedings, if necessary, as determined by the commission, shall be conducted in accordance with 20 CSR 4240-2.010, et seq.

20 CSR 4240-21.025 Standards and Dataset Management Requirements

PURPOSE: This rule establishes data standards and data set management requirements and specifies minimum standards for the documentation of all data, assumptions, methods, and analytical tools used in the planning process submitted as part of Chapter 21, Resource Planning for Electric Utilities, and supplements the requirements found in Section 393.1900, Missouri Revised Statutes.

(1) The IRP filing must include sufficient detail and documentation that establishes to the commission's satisfaction that it demonstrates how the alternative resource plans were developed, the selection process and rationale for the preferred resource plan, as well as to enable the commission to evaluate the soundness, reliability, and transparency of the data, assumptions, methods, and analytical tools used in the planning process.

(2) Datasets.

(A) The electric utility shall describe and document all datasets used in each integrated resource plan (IRP) filing.

(B) The electric utility shall align common datasets for use in its transmission system planning, distribution system planning, and generation planning.

(3) Workpapers.

(A) The electric utility shall provide all workpapers utilized to support the claims, data, figures, tables, and graphics included in the IRP filing. These workpapers shall be—

1. Clearly labeled with descriptive and consistent file names;
2. Directly cited in the relevant sections of the IRP filing or testimony, demonstrating how the data supports the overall analysis and conclusions;
3. Provided in searchable electronic formats (e.g., Excel) with all formulas, cell references, and data links intact, to allow full traceability of calculations; and
4. Reproducible, transparent, and consistent with the stated assumptions used in their development.

(B) The electric utility shall provide a process flow diagram that provides graphical representation of the interaction between workbooks, modeling software, and any other work product that is produced in support of the IRP. The process flow diagram should help reviewers understand the logical flow from raw data through to decision-making process and plan recommendations.

(C) The electric utility shall provide a summary workbook that indicates the interaction of linked workpapers provided in support of the IRP filing, including the sources of information utilized for each process and the file location in which the underlying information has been provided.

(D) Linked workpapers must be functional, and file sizes should be managed to ensure access by the commission and staff.

(E) The electric utility shall provide justification for any assumptions made within the workpapers and citations for any hardcoded numbers.

(F) Each workpaper shall include an inputs tab that includes at least the following information for each variable utilized in each workbook or model:

1. Identification of each variable utilized;
2. Clear definition of the variable;
3. Variable value range; and
4. Citations of source information utilized to develop the variable value range.

(G) For all materials used to support its IRP filing, whether produced by the electric utility itself, its affiliates, outside entities, or contractors, it shall:

1. Provide the entire document, as well as specific citations to the page; and
2. All supporting workpapers.

(4) Plots.

(A) Each plot included in the IRP filing shall be labeled as a stand-alone figure, whose axis shall be labeled with units.

(B) The data presented in each plot also shall be provided in tabular form in the technical volumes and in workpapers. Data tables will be labeled, including the identification of the corresponding plot.

(C) The plots and data tables shall be numbered, referenced, and explained in the text of the technical volumes and in workpapers.

(5) Citations within text.

(A) All scenario and sensitivity assumptions, data inputs, modeling assumptions, modeling files and results, and rationale for inclusion or exclusion shall be clearly documented to enable review, replication, and independent evaluation by the stakeholder group.

(B) For every data point referenced in the IRP filing, the electric utility shall provide a specific citation to the underlying workpaper file name, tab, and cell from which the data was sourced.

(6) All costs and benefits shall be expressed in nominal dollars.

(7) The electric utility shall make available to the stakeholder group all data, modeling inputs, assumptions, and results for the preferred resource plan and for all major scenarios and sensitivity analyses, not solely for a single base case.

(8) Staff and public counsel shall be granted reasonable access to modeling software, tools, standards, formatting and data files used by the electric utility for the purpose of verifying results or performing independent modeling runs, as designated by the commission in conformance with section 393.1900.1(5) RSMo. The cost of compliance for this section shall be borne by the electric utility.

20 CSR 4240-21. 030 Load Forecasting Requirements

PURPOSE: This rule establishes minimum standards for the collection, maintenance, and updating of historical data, and for the documentation of all inputs, assumptions, and methodologies used in load forecasting. Forecasts prepared under this rule shall provide reliable and transparent projections of future energy and capacity needs, including load management, demand response, electrification impacts, and peak demand reduction, found in Section 393.1900 of the Missouri Revised Statutes.

(1) Forecasting Inputs and Assumptions.

- (A) The electric utility shall develop load forecasts using the best available, transparent, and verifiable data. The electric utility shall document that it is using the best available data. Where reliable data is not available, the electric utility may use estimates only for variables involving customer behavior, new technologies, or market trends for which no historical data exists, provided that the variables are fully justified and clearly documented.
- (B) The electric utility shall maintain and annually update a comprehensive database of historical energy usage and demand across its service territory covering at least the most recent five (5) years for hourly data and twenty (20) years for monthly data preceding the filing year approved by the commission. The database shall include all customer classes and service voltages and capture hourly, daily, and monthly energy consumption, 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). Access to these inputs shall be provided to the stakeholder group pursuant to 20 CSR 4240-21.025(7).
- (C) All historical load data shall be weather normalized using statistical methods and clearly describe the methodology employed, including the treatment of temperature, degree days, and other relevant weather variables. The statistical fit, significance, and justification for all variables shall also be described and documented.
- (D) The electric utility shall use historical load and weather data to determine the relationship between load and weather variables, including temperature, and degree-days. Forecasted loads shall be weather normalized to reflect normal weather conditions derived from these relationships. The electric utility shall describe and document the methodology, data sources, variables, and statistical results, including the mean and standard deviation of each input.
- (E) Where end-use forecasting is employed, the electric utility shall use the most current available data on appliance saturation, efficiency trends, and customer adoption of new technologies, including distributed energy resources (DER) and demand-side measures. Descriptive statistics for each end-use variable shall be described and documented.

(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) Existing large load customers, including, but not limited to, data centers, industrial manufacturing facilities, and other customers expected to materially affect system demand and include documentation on assumptions regarding load size, seasonal load shape, timing, and probability.

(H) Applicable federal, state, and local laws, regulations, and policies that affect energy consumption, including energy efficiency standards, electrification initiatives, and decarbonization requirements. The electric utility shall quantify and document the expected load impacts of each applicable policy or mandate.

(I) The forecast 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.

(J) The forecast shall be internally consistent with the energy efficiency potential assessment, including alignment of baseline conditions such as new housing and commercial building starts, appliance saturations, employment growth, federal standards, building codes, and program offerings.

(K) The electric utility shall provide explicit data on anticipated adoption of electric vehicles, electrified heating (e.g., heat pumps), and other electrification technologies along with the documentation of expected penetration rates, charging or usage profiles, seasonal impacts, and the resulting effects on system load and system non-coincident peak.

(L) The forecast shall account for the effects of electricity prices, competing fuel prices, and rate design on customer usage. This shall include price elasticity of demand, demand response programs, and the impacts of approved or pending rate structures such as time-of-use rates, demand charges, and dynamic pricing mechanism.

(M) For each of the data inputs described above, the electric utility shall provide descriptive statistics.

(2) Forecasting Methodology.

(A) The electric utility shall develop its load forecast using transparent, reproducible, and well-documented methods, including a complete description of the forecasting models, the methodology, key assumptions, input variables, data sources, and outputs, along with the rationale for the chosen approach. The description shall be detailed enough to permit independent replication and evaluation as outlined in 20 CSR 4240-21.025.

(B) The electric utility shall, at minimum—

1. Develop customer class level load forecasts using an econometric methodology as the primary framework, or an alternative approach that integrates end-use determinants with econometric, time-series, or other

statistical methods. If an alternative approach is employed, the electric utility shall —

A. Describe and document the alternative approach; and

B. Where end-use determinants are used, demonstrate that appliance saturation, efficiency trends, technology adoption, electrification, and customer behavior are explicitly represented in the model; and,

C. Show that the resulting forecast achieves a level of rigor, transparency, and detail that is at least comparable to an end-use forecast;

2. Provide a comprehensive list of all independent variables used in the model. For each variable the electric utility shall—

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

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

3. Describe and document in detail the equations, algorithms, or statistical methods used to relate independent variables to load. Any transformations (e.g., logarithmic, polynomial, interaction terms) shall be explicitly identified and justified;

4. Describe and document the estimation techniques used to determine model parameters, including regression methods, statistical procedures, or simulation techniques and include—

   A. Parameter estimates with standard errors, significance levels, and statistical goodness-of-fit measures; and

   B. Calibration methods used to align model results with historical load data shall be described, and diagnostic tests shall be presented to demonstrate model validity;

5. Describe and document how the model incorporates weather variables, including normal conditions, extreme events and identify the statistical methods employed to normalize historical loads, and the sensitivity of load to key weather variables such as temperature, humidity, and degree-days;

6. Identify and quantify all adjustments made outside of model results and—

   A. Provide the basis, justification, methodology, and quantitative effect on forecast outcomes;

   B. Adjustments shall be presented alongside the unadjusted model results for comparison;

7. Provide full documentation of all methodologies, assumptions, and data sources sufficient for replication, as outlined in 20 CSR 4240-21.025. Additionally—

   A. The forecast results shall be validated through benchmarking against historical load patterns and against independent forecasts published by regional transmission organizations, government agencies, or other credible sources.

   B. The documentation shall include a retrospective analysis of past forecasts, evaluating forecast accuracy, identifying sources of error or bias, and explaining how these findings were used to improve the current forecast.

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

(3) Forecast Period.

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

(B) Forecasts shall be expressed on an hourly, monthly, and annual basis, and shall be reported separately for each customer class, as well as for the total system.

(C) Forecasts shall extend at least sixteen (16) years beyond the electric utility's filing year and shall present annual energy consumption and system non-coincident peak demand.

(D) The electric utility shall disaggregate its load forecasts into base load forecasts, representing expected energy consumption and system non-coincident peak absent each demand-side resource as identified in 20 CSR 4240 21.050. The electric utility shall separately provide forecasted demand and energy impacts for each demand-side resource, representing the expected load impacts of demand-side measures during the anticipated hours, seasons, and years, on reducing or shifting load.

(4) Base Case Forecast.

(A) The electric utility shall prepare and file a base case load forecast representing its best estimate of future system load under a reasonable scenario and it shall be based on forecasts of the independent variables that the electric utility's decision-makers believe to be most likely.

(B) All components of the base-case load forecast shall assume normal weather conditions.

(C) The load impacts of implemented demand-side programs and rates that are in effect at the time of filing, shall be incorporated in the base case load forecast.

(D) The load impacts of proposed demand-side programs and rates shall not be included in the base case forecast but shall be presented separately in the demand response forecast.

(E) The base case shall be developed using the data inputs in section (1) of this rule and forecasting methodology required under section (2) of this rule and shall serve as the reference case for all scenario and sensitivity analysis.

(F) The base case load forecast shall describe and document the following:

1. Forecasts of the hourly load profile for each of the electric utility's customer classes, as well as for the system as a whole, based on at least the most

recent five (5) historical years and covering the first eight (8) years of the forecast period as approved by the commission. These forecasts must adequately reflect daily load patterns, seasonal variability, and separately identify the influence of DER, electrification, and electric utility sponsored programs for energy efficiency and demand response.

2. Forecasts of monthly and annual energy consumption for the system and for each customer class, for every year within the planning horizon based on a minimum of twenty (20) years of historical data. Where applicable, these forecasts should be disaggregated by jurisdictional components.
3. Forecasts of monthly peak demand for each customer class and for the system as a whole, for every year of the planning horizon based on a minimum of twenty (20) years of historical data. For each of these, both coincident and non-coincident peak demand by customer class shall be provided. Where applicable, these forecasts shall be disaggregated by jurisdictional components.
4. How the forecast incorporates the effects of economic and demographic drivers, including, but not limited to, electricity prices, prices of alternative energy sources, income, population, and employment. If the methodology does not explicitly model these factors, the electric utility shall explain how their effects were otherwise accounted for.
5. How the 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 forecast shall reflect anticipated customer behavior, technology adoption and evolving load shapes consistent with legal mandates.
6. Estimates of the monthly cooling, heating, and non-weather-sensitive components of weather-normalized load by class for the base year of the forecast.
7. Identification and explanation of any judgmental adjustments applied to statistical or model outputs, including the factors considered, rationale, and their quantitative effect.
8. Graphical plots of—
   - A. Class-level monthly energy consumption and coincident peak demand for the historical period and forecast period;
   - B. Actual and weather normalized coincident peak demand for the historical period; and
   - C. Net system load profiles for the summer and winter peak day for the base year as well as the fourth, eighth, and sixteen forecast years (at a minimum). Additional years shall be included in supporting workpapers.
9. The models and methods used to develop independent variable forecasts, including the rationale for model selection, the functional form of the models, and any judgmental adjustments applied.

10. Describe and document how the forecast is consistent with historical consumption patterns, end uses, and efficiency trends identified in prior filings. If the base case forecast differs from recent previous forecasts submitted by the electric utility to the commission, the electric utility shall provide an explanation for such differences.
11. Describe and document how the base forecast incorporates a large load forecast representing a ninety-nine (99) percent (%) probability of interconnection.

(5) Identification of Large Load Drivers.

(A) The electric utility shall provide a list of committed large loads within that electric utility's service territory that would be eligible for service under the electric utility's large load tariff approved in accordance with section 393.130.7., RSMo. The information provided shall include at a minimum:

1. Anonymized project identifier;
2. The customer's industry type;
3. The anticipated service location;
4. The expected load shape (daily, seasonal, and annual); and
5. The anticipated peak and annual energy requirements including when the electric utility expects contracted load to appear or change over the implementation plan period

(6) Large Load Forecast.

(A) The electric utility shall prepare and file distinct forecasts of potential large load customer scenarios that are reasonably anticipated to materially affect the system load shape or resource needs for the planning horizon.

(B) The electric utility shall demonstrate that large load forecasts are not double counted in the base demand forecast.

(C) The large load forecast shall be provided as a separate, additive component.

(D) For each large load customer scenario, the electric utility shall—

1. Describe and document the methodology, data sources, and assumptions used to forecast load along with justification showing that assumptions are reasonable, transparent, and based on the best available non-speculative information;
2. Provide a table listing the industry type, location, expected load shape (daily, seasonal, and annual), anticipated peak and annual energy requirements;
3. Assess and document the certainty of probable large load customers;
4. Describe the expected load profile by month;
5. Identify changes in project certainty or status compared with prior forecasts and explain the criteria or information that led to recategorization;

6. Incorporate alternative forecasts reflecting the interconnection of large load customers in the first eight (8) years of the planning horizon based upon the estimation of probability of interconnection—
   A. Ninety-five (95) percent (%) probability of interconnection;
   B. Ninety (90) percent (%) probability of interconnection;
   C. Fifty (50) percent (%) probability of interconnection; and
   D. A stress scenario reflecting early termination of a large load customer or other stress scenarios determined to be significant from the electric utility perspective;
7. For each of the alternative scenarios listed in paragraph (6)(D)(6), the electric utility shall describe and document the methodology used to determine the interconnection probability;
8. Provide information on 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
9. Describe and document how the model incorporates weather variables and other variables that impact load, including normal conditions, extreme events, and identify the statistical methods employed to normalize historical loads, and the sensitivity of load to key weather variables such as temperature, humidity, and degree-days.

(7) Analysis of Load-Building Programs.

(A) If the electric utility intends to continue existing load-building programs or implement new ones, it 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) of this rule, 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) This analysis shall use the same modeling procedure and assumptions described 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. 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 rates in each year of the planning horizon for each rate class based upon the most recently proposed class cost of service allocation 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 both sensitivity analysis and scenario development. These 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—

1. The electric utility shall quantify the sensitivity of its base-case forecast to changes in key independent variables, including, but not limited to, economic growth, electricity prices, customer adoption of new technologies, energy efficiency improvements, and electrification of end uses. Each sensitivity shall isolate the impact of a single driver, with results expressed as percentage changes in non-coincident peak and energy consumption relative to the base case.
2. The electric utility shall 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, a scenario that includes a 90% probability of load under those extreme conditions.
3. The electric utility shall develop, in addition to the base case, at least two bounding scenarios under normal weather assumptions—
   - A. High-growth scenario that reflects accelerated economic expansion, rapid electrification, or large load additions.
   - B. Low-growth scenario that reflects slower economic conditions, delayed technology adoption, or higher-than-expected energy efficiency penetration.

(B) For each scenario, the electric utility shall provide a load forecast for each of the distribution substations affected by the overall load growth. The electric utility shall describe and document the methodology used to forecast the distribution substation load, and should include a discussion of historical load growth within the geographical area served by each distribution substation, as well as any known changes, such as customer additions, in the geographic area served by each distribution substation.

20 CSR 4240-21.035 Supply-Side Resource Analysis

PURPOSE: This rule establishes minimum standards for the scope and level of detail required in 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;
  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;
  6. Purchased power from bi-lateral transactions and from organized capacity and energy markets;
  7. Upgrading of the transmission and distribution systems as identified in 20 CSR 4240-21.040;
  8. Life extension and refurbishment at existing generating plants;
  9. Enhancement of the emission controls at existing generating plants; and
  10. Generating plant efficiency improvements which reduce the electric utility's own use of energy.
- (B) In identifying and evaluating potential supply-side resources, the electric utility shall describe and document its existing supply-side resources including but not limited to:
  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) In identifying and evaluating potential supply-side resources, 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, for 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;
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 and also on electric utility costs plus probable environmental compliance costs. The electric utility shall—
1. Provide a summary table showing each potential supply-side resource option and the electric utility's cost and the probable cost for each potential supply-side resource option and an assessment of whether each potential supply-side resource option qualifies as a renewable energy resource; and
2. Explain which potential supply-side resource options are eliminated from further consideration and justification for their elimination.
(B) The electric utility shall describe and document its analysis of each existing and potential supply-side resource option including, but not limited to:
1. Cost rankings of each potential supply-side resource option shall be based on estimates of the installed capital costs plus fixed and variable operation and maintenance costs.
2. The electric utility shall include the costs of ancillary and/or back-up supply-side resources required to achieve necessary reliability levels or assumed capacity accreditation level in connection with variable sources of generation; and
3. The electric utility shall identify potential environmental legal mandates which may be imposed at some point within the planning horizon.
A. The probable environmental compliance costs of each potential supply-side resource option shall be quantified by estimating the cost to the electric utility to comply with such environmental legal mandates that may be imposed.
B. The electric utility shall identify a list of environmental pollutants for which, in the judgment of the electric utility decision-makers, legal mandates may be imposed during the planning horizon which would

result in compliance costs that could significantly impact electric utility rates.

C. The electric utility shall calculate an expected mitigation cost for each identified pollutant under each compliance scenario.

D. The electric utility shall specify a subjective probability that represents electric utility decision-maker's judgment of the likelihood that legal mandates requiring additional levels of mitigation will be imposed at some point within the planning horizon.

E. The electric utility, based on these probabilities, shall calculate an expected mitigation cost for each identified pollutant.

(C) The electric utility shall describe and document 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.

1. The analysis shall include the identification of transmission constraints, as estimated pursuant to subsection 20 CSR 4240-21.040(1)(A)2., whether within the appropriate RTO/ISO footprint, on an interconnected RTO/ISO, or a transmission system that is not part of an appropriate RTO/ISO. The purpose of this analysis shall be to ensure that the transmission network 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 to provide an adequate foundation of basic information for decisions to include, but not be limited to, the following:

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

B. Construction of wholly-owned supply-side resources;

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

D. Improvements on its transmission and distribution system to increase efficiency and reduce power losses;

E. Acquisition of existing supply-side resources; and

F. 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.

2. This 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, in order to ensure that supply-side candidate resource options are evaluated in accordance with any such constraints.

(3) Candidate Resource Options.

(A) All preliminary supply-side candidate resource options which are not eliminated shall be identified 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 describe and document 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 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 describe and document, ranges of values and probabilities for several important uncertain factors related to supply-side candidate resource options. These cost estimates shall include at least 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.

(F) The electric utility shall develop, describe and document, ranges of values and probabilities for the factors related to the impact of implementing alternative fuel options considered for supply-side candidate resource options on the assumptions.

20 CSR 4240-21.040 Transmission and Distribution Analysis

PURPOSE: This rule specifies the minimum standards for the scope and level of detail required for the electric utility's transmission and distribution network analysis.

(1) Transmission Analysis Requirements.

(A) The electric utility shall describe and document the adequacy of its existing transmission system including:

1. Age, condition, and efficiency level of its existing transmission system; and
2. All known transmission constraints due to real power, reactive power, and power quality under current peak demand.

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

1. High-growth scenario load forecast at year 8 pursuant to 20 CSR 4240-21.030(8)(A)3.A.;
2. Low-growth scenario load forecast at year 8 pursuant to 20 CSR 4240-21.030(8)(A)3.B.; and
3. Scenarios the electric utility selects to stress-test its transmission system.

(C) The electric utility shall describe and document 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 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.

(E) The electric utility shall estimate 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 estimate the amount of revenue requirement of regional transmission assets that would be allocated based on load to the electric utility and describe and document those costs consistent with the scenarios in subsection (1)(B).

(G) The electric utility shall provide a report for consideration in 20 CSR 4240-21.035(2)(C) that identifies the physical transmission upgrades needed to interconnect generation, facilitate power purchases and sales, and otherwise maintain a viable, reliable, and/or resilient transmission network, including:

1. A list of the transmission upgrades needed to physically interconnect a generation source within the appropriate RTO/ISO footprint;

2. A list of the transmission upgrades needed to enhance deliverability from a point of delivery within the appropriate RTO/ISO including requirements for firm transmission service from the point of delivery to the electric utility's load and requirements for financial transmission rights from a point of delivery within the appropriate RTO/ISO to the electric utility's load;
3. A list of transmission upgrades needed to physically interconnect a generation source located outside the appropriate RTO/ISO footprint;
4. A list of the transmission upgrades needed to enhance deliverability from a generator located outside the appropriate RTO/ISO footprint, including requirements for firm transmission service to a point of delivery within the appropriate RTO/ISO footprint and requirements for financial transmission rights to a point of delivery within the appropriate RTO/ISO footprint;
5. The estimated total cost of each transmission upgrade; and
6. The estimated fraction of the total cost and amount of each transmission upgrade allocated to the electric utility.

(2) Distribution Analysis Requirements.

(A) The electric utility shall describe and document the adequacy of its existing distribution system including:

1. Age, condition, and efficiency level of its existing distribution system;
2. All known distribution constraints, including constraints due to real power, reactive power, and power quality, under current peak demand; and
3. All known distribution constraints, including constraints due to real power, reactive power, and power quality, under reasonably anticipated additions to peak demand (i.e. new subdivision, large customer).

(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 8 pursuant to 20 CSR 4240-21.030(8)(A)3.A.;
2. Low-growth scenario load forecast at year 8 pursuant to 20 CSR 4240-21.030(8)(A)3.B.; and
3. A scenario the electric utility selects 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 identify areas on its distribution system that may be suitable for 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 cost benefit analysis of advanced transmission and distribution technologies shall be separately identifiable in the analyses required in section (2) and section (3) 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) 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)1.

(5) Affiliate relationships.
   (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 describe and document the analysis performed by the electric utility to determine whether such affiliate-built transmission is in the best interest of the electric utility's Missouri customers.
   (B) The electric utility shall identify and describe any affiliate or other relationship with transmission planning, designing, engineering, building, and/or construction management companies that impact or may be impacted by the electric utility. Any description and documentation in section (1), section (2), section (4), and section (5) of this rule, also apply 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.

20 CSR 4240-21.050 Demand-Side Resource Analysis

PURPOSE: This rule specifies the principles by which potential demand-side resource options shall be developed and analyzed by electric utilities for cost effectiveness, and requires the selection of demand-side candidate resource options that shall be included in the integrated resource plan.

(1) Demand-Side Resources Optimization.
   (A) In order to properly optimize the amount of demand-side resources, the electric utility will designate all demand-side resources as candidate resource options in its capacity expansion model.
      1. For purposes of calculating avoided cost, the electric utility will compare the capacity expansion model of its preferred resource model with the same model excluding demand-side resources as resource options in the first four years. The avoided demand cost calculation must identify specific generation, transmission, or distribution investments that can be reduced, deferred, or avoided as a result of demand-side program implementation;
      2. The electric utility will model Missouri energy efficiency investment act (MEEIA, Sec. 393.1075, RSMo) demand-side resource options separately from non-MEEIA demand-side resource options. For determining optimal demand-side resources, the electric utility will also exclude distributed energy resources as a demand-side resource.
   (B) Each electric utility will describe and document its 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, appliance saturations, employment growth, federal standards, building codes, and other relevant factors. The electric utility will also provide an estimate of all changes in peak consumption and energy consumption, separately, due to the factors above by calendar month consistent with 20 CSR 4240-21.030 and the assumed electric utility costs in each year of the planning horizon for each potential demand-side program.

(2) Non-MEEIA Demand-Side Resources.
   (A) All proposed Non-MEEIA Demand-Side Resource Programs must meet the rules governing non-MEEIA Demand-Side Resources, as specified in 20 CSR 4240-3.150 and 20 CSR 4240-14.
   (B) The electric utility shall identify potential demand-side resources from which demand-side candidate resource options will be identified 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, energy management measures, including demand response programs. For each demand-side resource, the electric utility must provide:
      1. The targeted class of customers;

2. List of proposed measures and rates, if applicable;
3. Expected life of the measure and duration of impact;
4. All major end uses, including at least 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 of all expected costs of the program, including, but not limited to incentives, administration, and evaluation by year; and
6. An estimate of the rate impacts to each customer class by year that includes and identifies an assumption of the timing of the electric utility's general rate cases.

(C) The electric utility must provide all documentation, including any prior evaluations, to substantiate the assumptions in subsection (2)(B) of this rule.

(D) The electric utility shall identify and provide details concerning all demand response programs registered with the electric utility's appropriate regional transmission organization or independent system operator.

(3) MEEIA Demand-Side Resources.

(A) All proposed MEEIA demand-side resource programs must meet the rules governing MEEIA demand-side resources, as specified in 20 CSR 4240-20.092, 20 CSR 4240-20.093, and 20 CSR 4240-20.094.

(B) The electric utility shall conduct, describe, and document market research studies, customer surveys, test marketing programs, and other activities as necessary to estimate the maximum achievable potential, technical potential, and realistic achievable potential of potential demand-side resource options for the electric utility and develop the information necessary to design and implement cost-effective demand-side programs—

1. These research activities shall be designed to provide a solid foundation of 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. The electric utility may compile existing data or adopt data developed by other entities, including government agencies and other utilities, as long as the electric utility verifies the applicability of the adopted data to its service territory;
2. The electric utility shall provide copies of completed market research studies, customer surveys, pilot programs, pilot rates, test marketing programs, and other studies as required by this rule and descriptions of those studies that are planned or in progress and the scheduled completion dates;
3. To identify the time periods of energy and demand savings that are most likely to coincide with reductions, deferrals, or avoided investments;
4. To identify demand-side program savings for the season identified where there is a near-term need; and
5. 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 identified for the purposes of developing the alternative resource plans with a goal of achieving all cost-effective demand-side savings. 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 must provide:

1. The targeted class of customers;
2. List of proposed measures and rates, if applicable;
3. Expected life of the measure and duration of impact;
4. All major end uses, including at least 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 to 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 to each customer class, and separately for program participants and non-participants in each customer class, by year that includes and identifies an assumption of the timing of the electric utility's general rate cases, inclusion of any electric utility's proposed earnings opportunity, and Demand-Side Investment Mechanism rate cases. The identified earnings opportunity shall be based on specific investments that can be reduced, deferred, or avoided as a result of demand-side program implementation.

(D) The electric utility must provide all documentation, including any prior evaluations, to substantiate the assumptions in subsection (3)(C).

(E) The electric utility shall identify and provide details concerning all demand response programs registered with the electric utility's appropriate regional transmission organization or independent system operator.

(4) The electric utility shall describe and document its evaluation of the cost effectiveness of each potential demand-side program developed pursuant to section (3) of this rule.

(A) In each year of the planning horizon, the benefits of each potential demand-side program shall be calculated 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. These calculations shall be performed both with and without the avoided probable environmental compliance costs. The electric utility shall describe and document the methods, data, and assumptions it used to develop the avoided costs.

(B) The electric utility 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 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.

(D) The avoided probable environmental compliance costs include the effects of the probable environmental compliance costs calculated pursuant to paragraph (1)(B)2., of this rule, on the electric utility avoided demand cost and the electric utility avoided energy cost.

(E) The electric utility shall describe and document how it developed the information in subsection (4)(B) of this rule.

(5) The total resource cost test and electric utility cost test shall be used to evaluate the cost effectiveness of the potential demand-side programs and demand-side measures.

(A) For the total resource cost test, in each year of the planning horizon—

1. The costs of each potential demand-side program shall be calculated as the sum of all incremental costs of end-use measures that are implemented due to the program (including both electric utility and participant contributions) plus electric utility costs to administer, deliver, and evaluate each potential demand-side program; and
2. For purposes of this test, the costs of potential demand-side programs shall not include lost revenues or electric utility incentive payments to customers.

(B) For the electric utility cost test, in each year of the planning horizon—

1. The costs of each potential demand-side program shall be calculated as the sum of all electric utility incentive payments plus electric utility costs to administer, deliver, and evaluate each potential demand-side program;
2. For purposes of this test, the costs of potential demand-side programs shall not include lost revenues; and
3. The costs shall include, but separately identify, the costs of any rate of return or incentive included in the electric utility's recovery of demand-side program costs.

(C) The electric utility shall provide results of the total resource cost test and the electric utility cost test for each potential demand-side program evaluated pursuant to subsection (5)(A) and (B) of this rule, including a tabulation of the benefits (avoided costs), demand-side resource costs, and net benefits or costs.

(D) If the electric utility calculates values for other tests to assist in the design of demand-side programs, the electric utility shall describe and document the tests and provide the results of those tests.

(E) The electric utility shall describe and document how it performed the cost effectiveness assessments pursuant to section (4) of this rule, and shall describe and document its methods and its sources and quality of information.
(F) The electric utility shall quantify net benefits or costs for non-participating customers by rate-class for each of the demand-side programs.
(G) The electric utility shall describe and document all differences in the treatment of energy and demand reductions associated with demand-side resources utilized in appropriate regional transmission organization or independent system operator forecasting and the assumptions utilized for the IRP filing.

20 CSR 4240-21.055 Distributed Energy Resource Analysis and Reporting Requirements

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

(1) Distributed Energy Resources (DER) Database.

(A) The electric utility shall create, and update annually, a database of information on DER for purposes of evaluating current penetration and planning for future changes in the levels of DER.

1. The electric utility shall be responsible for maintaining the following information in the database:

A. Existing DER and DER aggregations interconnected to the electric utility's distribution system regardless of ownership;

B. Information characterizing the location according to Geographic Information System coordinates on the distribution circuits where DER are connected;

C. Aggregated capacity of DER for each circuit and annual peak load of each circuit;

D. Relevant interconnection standard and standby service requirements, as applicable, that specify DER performance capabilities; and

E. Summaries of the electric utility's past DER Adoption Potential Studies performed to comply with section (2) and the DER planning process evaluation under section (3).

2. To the extent that the electric utility is not in possession of all of the information required herein, it shall state which information it does not possess, the reason the information is not possessed, and how the electric utility plans to obtain the information for future filings for planning purposes.

(2) Distributed Energy Resource (DER) Adoption Potential Study.

(A) The electric utility shall describe and document, at a minimum, potential DER and DER aggregations within its service territory over the planning horizon to ensure compliance with 20 CSR 4240-21.060.

(B) With respect to all DERs, except electric utility-incentivized DER, the study requirement can be satisfied by relying upon assessments developed as part of the electric utility's supply-side resource analysis pursuant to section 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 described herein.

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

(A) The electric utility shall include methodologies used to develop low, medium, and high DER penetration scenarios, including:

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

(B) The electric utility shall describe and document its evaluation of the DER penetration scenarios developed in subsection (3)(A) and integration of DER and DER aggregations 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 resources 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 DER or DER aggregations as an alternative to traditional resources.

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

PURPOSE: This rule requires the electric utility to develop, analyze, and evaluate alternative resource plans, including the selection of a preferred resource plan, as required under Section 393.1900 of the Missouri Revised Statutes. It establishes minimum standards for the scope and level of detail necessary for transparent, data-driven resource planning that ensures reliable and affordable electric service through cost-effective and flexible resource portfolios. The rule further requires the identification and quantification of critical uncertain factors and risks affecting plan performance.

(1) Specification of Performance Measures.
  (A) The electric utility shall specify, describe and document a set of quantitative measures for assessing the performance of all alternative resource plans developed under this rule.
  (B) All performance measures shall be transparent, reproducible, and provide an objective comparison of alternative resource plans analyzed in the electric utility's integrated resource plan (IRP) filings.
  (C) Performance measures shall include at least the following:
    1. Reliability metrics that demonstrate the adequacy, flexibility, and operational reliability of the resource portfolio, including:
      A. Loss of Load Expectation (LOLE), expressed in days per year;
      B. Expected Unserved Energy (EUE), expressed in megawatt-hours per year;
      C. Expected accredited capacity of each resource by season and total portfolio planning reserve margin; and
      D. Any other generation attributes as required by the appropriate RTO/ISO or legal mandates.
    2. Quantitative cost metrics by end-point over the planning horizon, 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 by rate class based upon the electric utility's most recently proposed class cost of service study allocation or allocation method;
      E. Expected cost and market exposure, including dependence on volatile fuel prices and market purchases;
      F. Expected transmission costs, including potential upgrades for load and interconnection of supply-side resources; and
      G. Expected distribution costs, including potential upgrades for load and interconnection of distributed energy resources.

3. Current and forecasted annual financial or other credit metrics that assess the electric utility's ability to finance and sustain the implementation of an alternative resource plan, including but not limited to:
    A. Pretax interest coverage ratio;
    B. Total debt-to-capital ratio;
    C. Net cash flow to capital expenditure;
    D. Funds From Operations (FFO)-to-Debt ratio;
    E. Debt-to-Earnings Before Interest, Taxes, Depreciation, and Amortization (EBITDA) ratio;
    F. FFO to cash interest ratio;
    G. EBITDA to interest ratio;
    H. Cash Flow from Operations (CFO) to debt ratio (as a percentage);
    I. Free Operating Cash Flow (FOCF) to debt ratio (as a percentage);
    J. Defined Cash Flow measure (DCF) to debt ratio (as a percentage); and
    K. 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 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 as appropriate for assessing the performance of alternative resource plans as part of the 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 identify, describe and document, 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 local clearing requirements applicable in each season of each year for the planning horizon.

(B) The electric utility shall identify, describe and document 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. Increased industrial and large loads;
    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. Relative real fuel 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;
   E. Fixed operation and maintenance costs for new and existing supply-side resources; and
   F. Electric utility marketing and delivery costs for demand-side programs.
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. Potential future changes in legal mandates; and
6. Any other uncertain factors that the electric utility determines may be critical to the performance of alternative resource plans.

(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), if applicable. Collectively the alternative resource plans shall demonstrate a reasonable range of strategies, including timing of resources, to meet the system needs identified under subsection (2)(A) in this rule.

(D) The electric utility shall provide a clear explanation of the methodology used to construct each alternative resource plan, including how scenarios were defined and how assumptions were applied.

(E) Each alternative resource plan shall include—
1. Consistent, transparent, and verifiable assumptions and at a minimum meet the needs identified in subsection (2)(A) in this rule;
2. Reasonable consideration of the balancing of the resource planning objectives pursuant to 20 CSR 4240-21.010(2)(C);

3. Resources from the comprehensive set of candidate resources as developed pursuant to 20 CSR 4240-21.035(1)(C) and demand-side resources from 20 CSR 4240-21.050; and
4. All existing supply-side resources and demand-side programs, together with any planned retirements, life extensions, environmental retrofits, or major refurbishments known at the time of the IRP filing.

(F) The electric utility shall use a capacity expansion model to develop alternative resource plans, including at a minimum—
1. A base alternative resource plan that represents the most probable outcome for each critical uncertain factor;
2. Additional alternative resource plans that represent a reasonable high and low value for each critical uncertain factor while keeping the values of the other critical uncertain factors at base levels; and
3. Additional alternative resource plans as deemed necessary by the electric utility or the commission.

(G) The electric utility shall describe and document how it evaluated the adequacy of its capacity expansion modeling by covering—
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 margin and local clearing requirements are enforced in the model and 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; and
6. How candidate resources are screened, shortlisted, and represented in the optimization process.

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

(I) For each alternative resource plan created 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. Sequence and schedule for the retirement of existing supply-side and demand-side resources; and
3. Sequence and schedule for the acquisition of each new supply-side resource and demand-side resource.

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

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

1. Provide the same description of the alternative resource plan and schedule of new additions and retirements as those required in subsection (2)(H) of this rule;
2. Justify, describe and document why alternative resource plans developed without the use of a capacity expansion model could not be developed with a capacity expansion model:
3. Clearly state the system needs being addressed, differentiate between the system needs, and justify any system need identified that cannot be quantified;
4. For each environmental compliance or policy need driven by legal mandates—
   A. A citation for each applicable statute, administrative code, or regulatory or judicial order;
   B. A brief, clear explanation of how the proposed resource helps meet the cited requirement, including the specific time-period during which compliance is necessary;
   C. The discrete time-period during which the need is forecasted; and
   D. An explanation of how the proposed resources satisfy the need; and
5. For each anticipated environmental compliance or policy need—
   A. A citation for each applicable statute, administrative code, or regulatory or judicial order;
   B. A brief, clear explanation of how the proposed resource helps meet the cited requirement, including the specific time-period during which compliance is necessary;
   C. The discrete time-period during which the need is forecasted; and
   D. An explanation of how the proposed resources satisfy the need.

(L) The alternative resource plans developed at this stage shall not include load-building programs, which shall be analyzed as required by 20 CSR 4240-21.060(4)(C).

(3) Analysis of Alternative Resource Plans.

(A) The electric utility shall perform an analysis of the alternative resource plans developed under section (2) over the planning horizon to further refine the alternative resource plans.

(B) The analysis shall—

1. Treat supply-side and demand-side resources on a logically consistent and economically equivalent basis, such that the same types or categories of costs, benefits, 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. Models shall be integrated or sequentially linked, to evaluate the operational performance of each plan.
   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 demonstrate that the modeling tools used are appropriate for the system size, complexity, and market participation of the electric utility and are consistent with current industry's best practices.
   C. The electric utility shall use consistent modeling software, input data, and scenario structures across all alternative resource plans, unless deviations are justified, described and documented.
   D. All models shall be capable of evaluating fuel diversity, demand-side participation, market transactions, and appropriate RTO/ISO participation.
   E. The electric utility shall describe and document the model structure, optimization methods, and algorithms used for capacity expansion and production cost analysis.

(C) Based on the analysis conducted in subsection (B), the electric utility shall describe and document the methodology and the results of the analysis of the alternative resource plans developed in section (2) of this rule, including a table summarizing each alternative resource plan's annual performance measures over the planning horizon, as set forth in section (1) of this rule.

1. 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 must 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)(F)(1) and (2)(F)(2) of this rule shall not be eligible to be eliminated from further consideration.
2. The electric utility shall include, for each remaining alternative resource plan, a graphical plot over the planning horizon of the following information—
   A. The combined impact of all demand-side resources on the base-case forecast of seasonal peak demands;
   B. The composition, by performance 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 DER, of the capacity supplied to the distribution system provided by supply-side resources or DER;

E. The combined impact of all demand-side resources on the base-case 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.

(4) Risk and Uncertainty Analysis.

(A) The electric utility shall describe and document a comprehensive assessment of the risks and uncertainties associated with each alternative resource plan. The purpose of this analysis is to evaluate the potential variability in cost, performance, and reliability outcomes arising from critical uncertain factors, and to determine the robustness and flexibility of each alternative resource plan across a range of plausible outcomes.

(B) The electric utility shall justify, describe and document the methodology used to conduct its risk and uncertainty analysis.

1. The justification shall include a clear explanation of the selected analytical framework, modeling tools, probability techniques, and data sources used to evaluate risk.
2. The electric utility shall identify how the chosen approach captures the range, probability, and interactions of critical uncertain factors.
3. The methodology shall be reproducible, transparent, and consistent with the analytical assumptions used in the development and evaluation of alternative resource plans.

(C) The electric utility shall conduct 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 its scenarios and the results of the sensitivity analysis.

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

1. Each performance measure shall be supported by quantitative analysis to the extent practicable and by 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. Scenarios that isolate the contribution of each uncertain factor identified in subsection (2)(B);
C. Accelerated build requirements needed to address near-term reliability or compliance needs;
D. Reasonable rate case timing scenarios to evaluate the effect of early, delayed, or staggered cost recovery on forecasted revenue requirements

and customer rate trajectories, where the results shall demonstrate how timing assumptions influence affordability and plan selection; and

E. Any other factors the commission has ordered.

(E) The electric utility shall identify, describe and document all critical uncertain factors that have been identified based on the sensitivity analysis and other factors.

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 and document the data sources and assumptions supporting that range;

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

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

(F) If during the risk analysis, the electric utility determines that any of the 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.

(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 (4) of this rule and pursuant to section 393.1900, RSMo. Whether the preferred resource plan is a reasonable and prudent means of reliably meeting load serving obligations at just and reasonable rates over the planning horizon is subject to the discretion of the commission.

(B) Contingency Analysis.

1. Contingency analysis of the preferred resource plan shall be included 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 all 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. Identify, describe and document the expected risk mitigation strategies that may be employed as a result of the contingency analysis; and

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

(C) The 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 alternative resource plan across each performance measure and risk scenarios.
3. The electric utility shall clearly identify tradeoffs among performance measures and explain how competing objectives (e.g., cost vs. reliability, near-term vs. long-term risk) were balanced in the selection of the preferred resource plan.
4. The electric utility shall demonstrate that the preferred resource plan remains robust under the sensitivity and scenario analyses conducted pursuant to the risk and uncertainty section and identify any conditions under which the plan would require reconsideration or adjustment.

(D) The electric utility shall describe and document its internal decision-making process for selecting the preferred resource plan, including:

1. A description of decision criteria, weighting factors, or scoring methods used to rank or compare plans;
2. A summary of key findings from quantitative analysis and stakeholder group feedback that influenced preferred resource plan selection;
3. An explanation of how the preferred resource plan reflects the electric utility's judgment regarding acceptable levels of risk, reliability, and rate impact;
4. Specification of the ranges or combinations of outcomes for the critical uncertain factors that define the limits within which the preferred resource plan is judged to be appropriate and explain how these limits were determined;
5. 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;
6. Quantification of the expected value of better information concerning at least the critical uncertain factors that affect the performance of the preferred resource plan, as measured by annual utility revenue requirements; and
7. A tabulation of the key quantitative results of that analysis conducted under paragraph (4)(D)6. 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 using a comparative scorecard or equivalent matrix that presents all of the performance measures 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. Identify tradeoffs among cost, reliability, risk, and environmental outcomes;
3. Clearly distinguish modeled results from qualitative assessments; and
4. Present results for both the implementation period and full planning horizon.

(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, in total and per class, shall include:
   A. Base rates and fuel cost components;
   B. Anticipated changes in revenue requirements;
   C. Estimated annual percentage change in rates by class based upon the electric utility's most recently proposed class cost of service allocation factors;
   D. Reasonable rate case timing scenarios; and
   E. Inclusion of regulatory treatments of cost that the electric utility intends to request.
2. Discuss how the impacts of rate changes on future electric loads were modeled and how elasticity assumptions were derived.

(G) The electric utility shall demonstrate that the preferred resource plan appropriately balances the factors that are enumerated in 20 CSR 4240-21.010(2)(C).

20 CSR 4240-21.065 Implementation Plan Development and Reporting Requirements

PURPOSE: This rule specifies the requirements for the development of an implementation plan for the electric utility's preferred resource plan pursuant to Sections 393.1900.4 and 393.1900.5, of the Missouri Revised Statutes and sets forth requirements for reporting.

(1) Implementation Plan Development.

(A) The electric utility shall develop an implementation plan for its preferred resource plan that specifies the major tasks, schedules, and milestones necessary to implement the supply-side resources over the implementation period.

(B) The electric utility shall describe and document its implementation plan, which shall contain—

1. A schedule and description of all supply-side resources for the development and planning, engineering, retirement, acquisition, and construction activities, including research to meet expected environmental regulations;
2. Specific costs and performance information for all supply-side resources, including those related to existing supply-side resources, expected to commence within the implementation period including, but not limited to, those attributes 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;
3. Identification of critical paths and major milestones for implementation of each resource, including decision points for committing to major expenditures;
4. A description of competitive procurement policies to be used in the development, planning, engineering, construction and acquisition of supply-side resources;
5. A 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; and
6. A 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.

(C) 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.

1. For each short-term alternative, the electric utility shall describe and document and provide a summary table including the:
   A. Cost of acquisition, including contract payments, fuel, operations, and any associated ancillary services;
   B. Operational characteristics, including expected availability, reliability, ramp rates, start-up and shut-down times, and any limitations on continuous operation;
   C. Term of the resource, including contract length, start and end dates, and any provisions for renewal, extension, or early termination; and
   D. Analysis of the risk and uncertainty, including potential variability in availability, fuel supply, or market pricing.

(D) The electric utility shall not exclude any economically feasible short-term alternative capacity resource unless it demonstrates, with supporting documentation, that the resource is unavailable, technically infeasible, or prohibited by law.

(E) The electric utility shall provide a schedule and description 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 its IRP filing and every year thereafter, or more frequently as ordered by the commission.

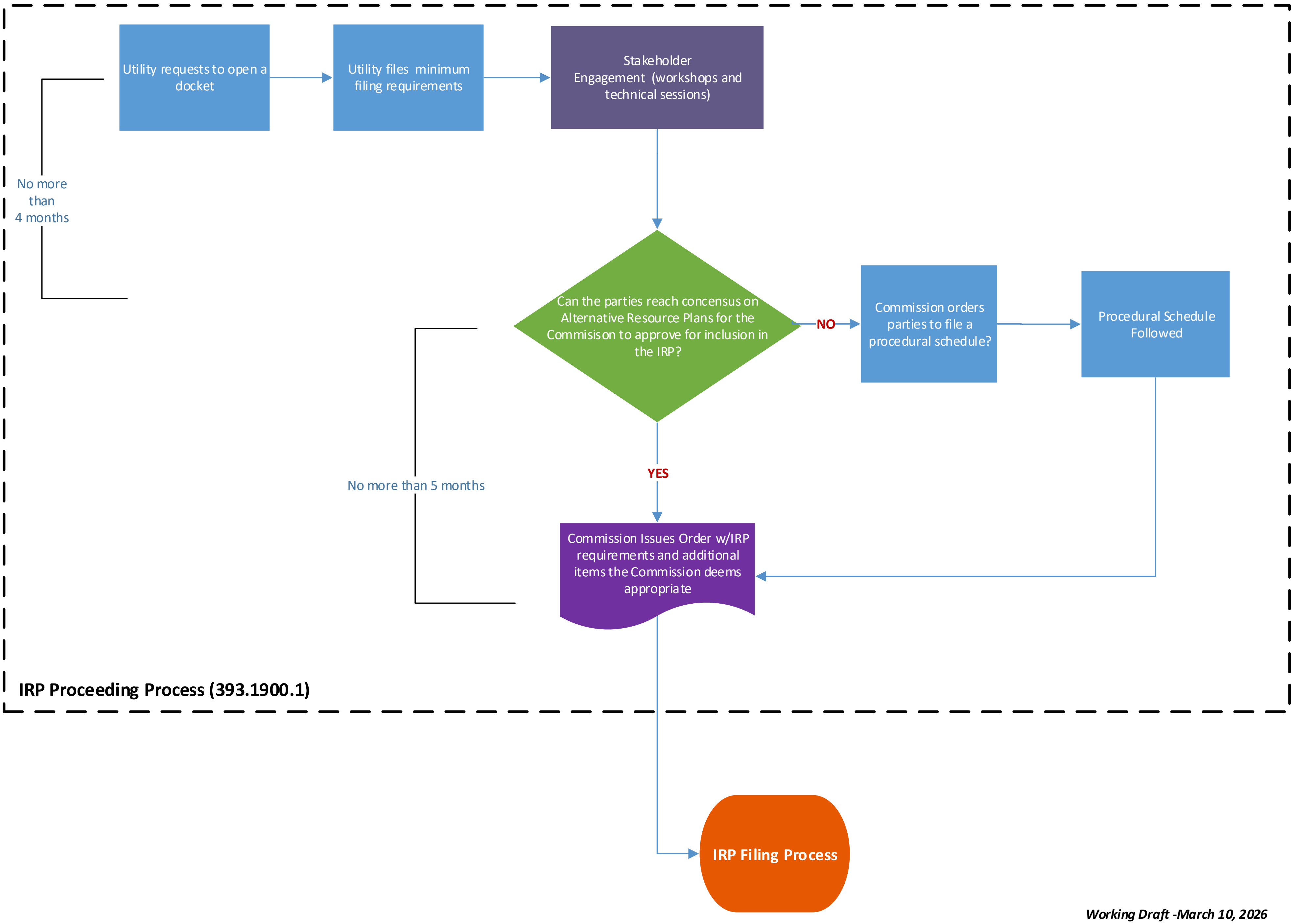
(B) The implementation plan status report shall include, but is not limited to:

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)(D), 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 supply-side resource identified in its implementation plan, which shall include viability metrics including qualitative and quantitative measures that assess the practicality and readiness of each resource identified in the implementation plan. This shall include:
   A. Siting and permitting feasibility, including interconnection, transmission access, transmission constraints, and availability of fuel;
   B. Construction and acquisition timelines;
   C. Supply chain and workforce availability;
   D. Alignment with the electric utility's implementation schedule and procurement capabilities;

E. Scope changes to any resource; and
F. Environmental compliance costs;

5. For each short-term capacity resource identified pursuant to paragraph (1)(C) of this rule, the electric utility shall provide an updated summary table as required by subparagraph (1)(C)1. of this rule;
6. Any information directed by the commission; and
7. Any other information the electric utility determines is appropriate.

IRP PROCEEDING PROCESS (393.1900.1)



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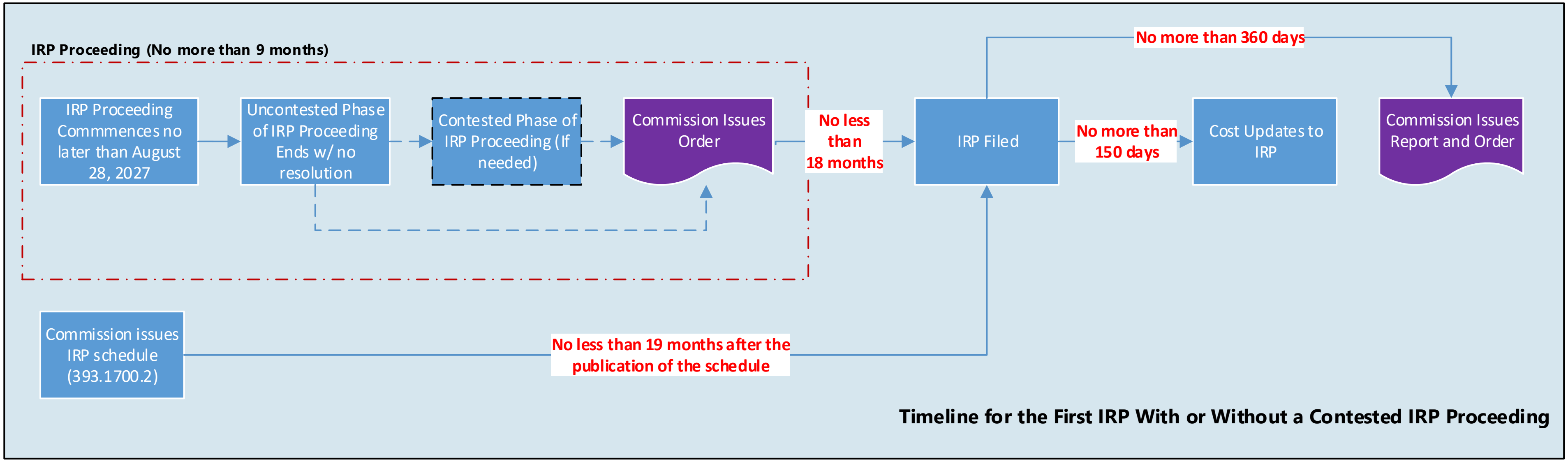
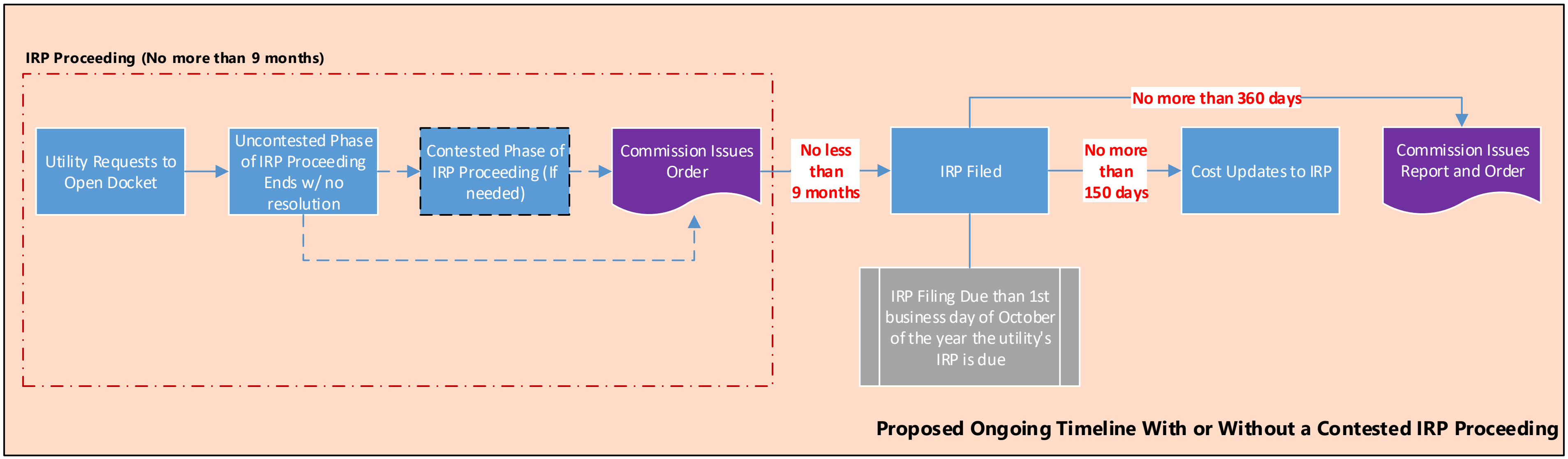
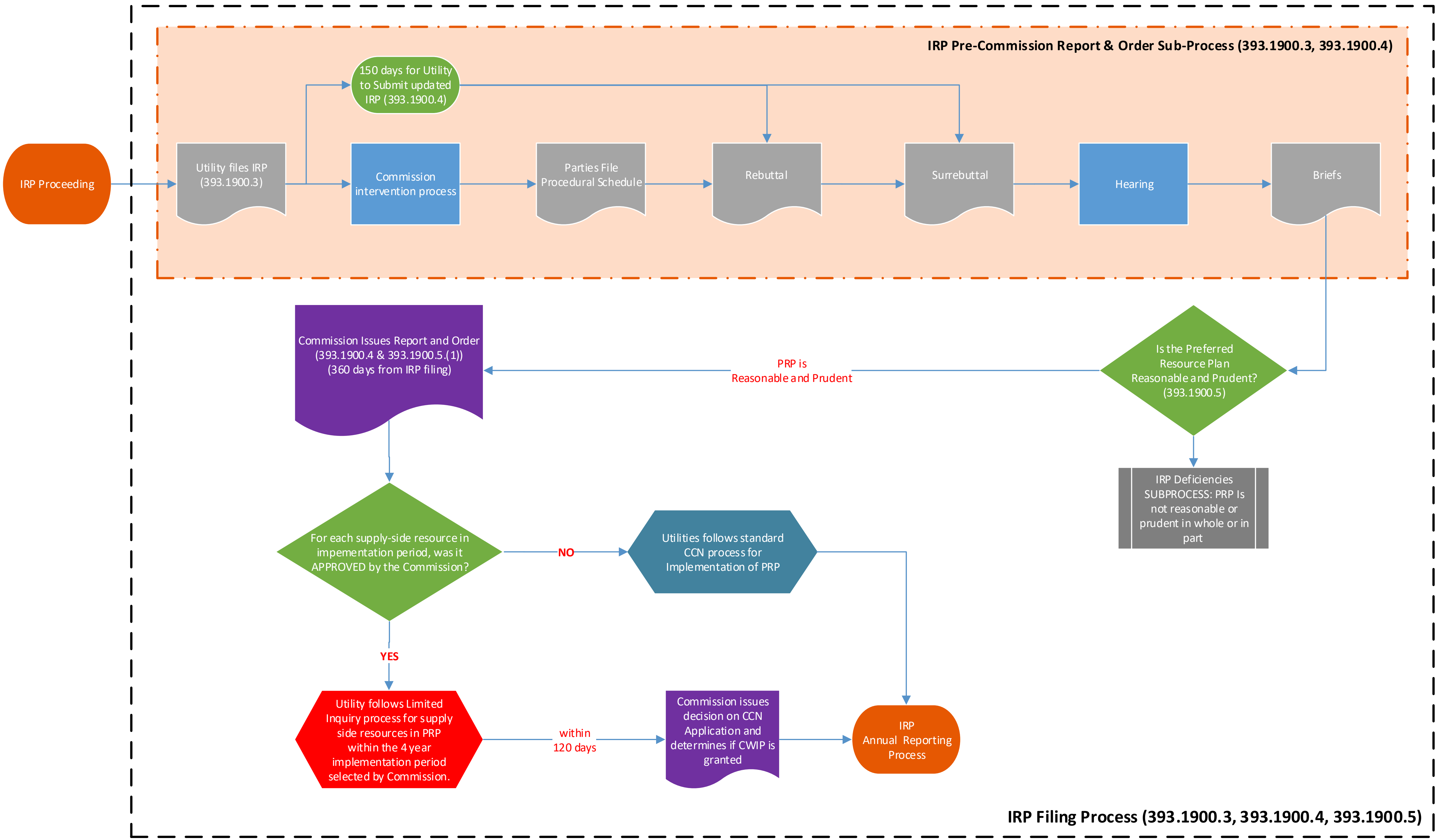
IRP Timeline

Working Draft -March 10, 2026





IRP FILING PROCESS (393.1900.3 through 393.1900.5)



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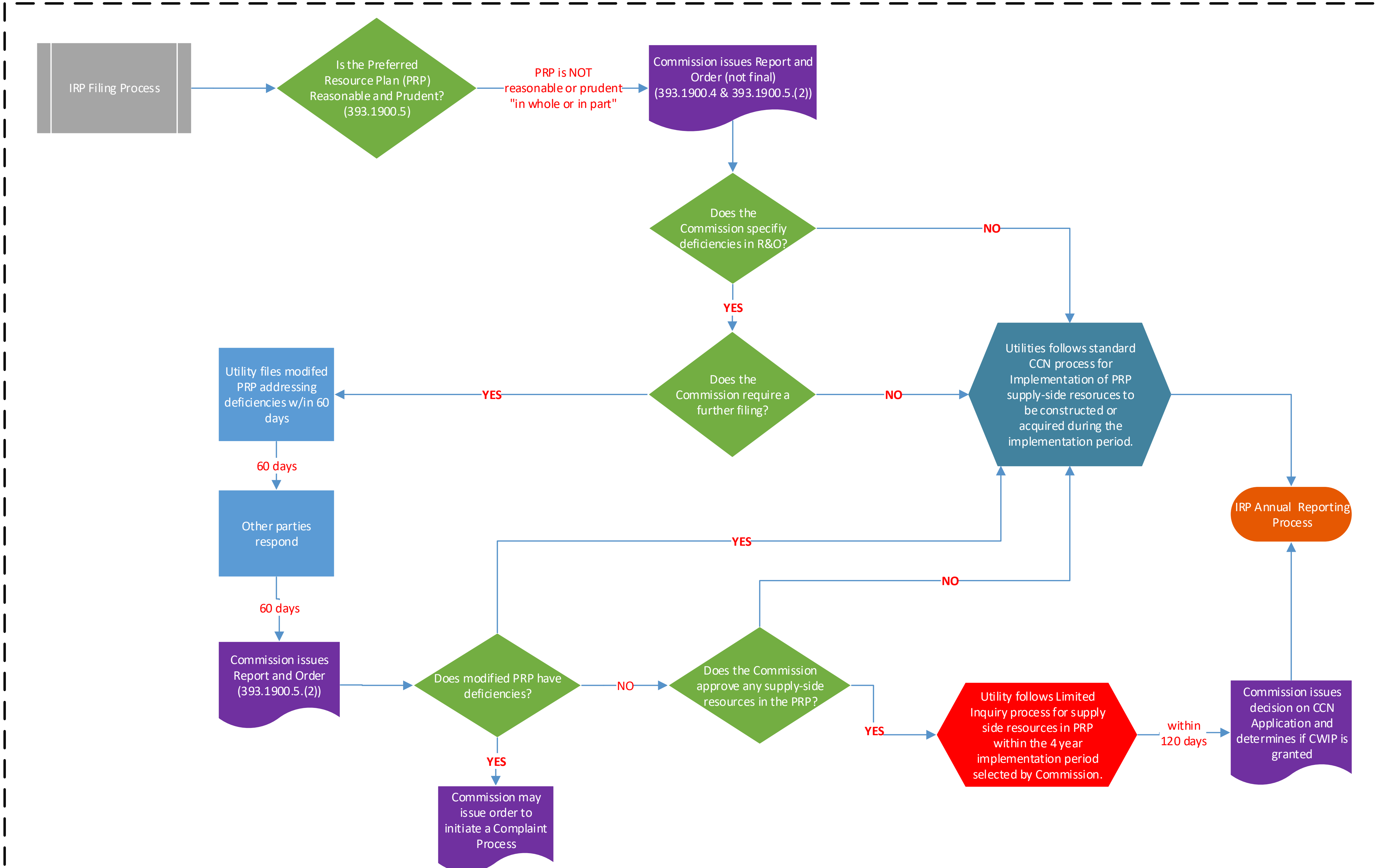
IRP DEFICIENCIES SUBPROCESS (393.1900.3 through 393.1900.5)



IRP Deficiencies SubProcess (393.1900.4, 393.1900.5)

Working Draft -March 10, 2026

STATE OF MISSOURI

OFFICE OF THE PUBLIC SERVICE COMMISSION

I have compared the preceding copy with the original on file in this office and I do hereby certify the same to be a true copy therefrom and the whole thereof.

WITNESS my hand and seal of the Public Service Commission, at Jefferson City, Missouri, this 11th day of March 2026.

Nancy Dippell

Nancy Dippell
Secretary

MISSOURI PUBLIC SERVICE COMMISSION

March 11, 2026

File/Case No. EW-2026-0091

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Enclosed find a certified copy of an Order or Notice issued in the above-referenced matter(s).

Sincerely,

Nancy Dippell

Nancy Dippell
Secretary

Recipients listed above with a valid e-mail address will receive electronic service. Recipients without a valid e-mail address will receive paper service.