## Chapter 29 Integrated Resource Planning and Reporting

## Rule 29

**100 Purpose**

The Integrated Resource Planning and Reporting ("IRP") Rules set forth in Sections 104 through 106, *infra*, shall be used by jurisdictional investor-owned electric utilities regulated by the Mississippi Public Service Commission ("Commission") in the development and reporting of long-term resource plans. The IRP reporting requirements established herein are intended to allow electric utilities the necessary flexibility to formulate plans that reflect their specific circumstances and best meet the needs of their customers, while providing a level of transparency that furthers the public policy goals of this Commission and the State of Mississippi. Comprehensive IRP should include an analysis of supply and demand-side resources, and consider transmission needs, in order to satisfy the utility's load requirements while balancing costs, energy reliability and efficiency, environmental responsibility, risk mitigation and reasonably priced service for customers. Yet the process should remain flexible to account for changing conditions that affect the planning process.

An efficient delivery system is also integral to overall energy efficiency. For electric utilities, the energy grid is moving from what has historically involved primarily unidirectional energy flows into a more fully integrated energy network, where energy flows bi-directionally between retail customers and utilities. Delivery efficiency and maintaining adequate reliability potentially become more challenging and increasingly important as the system becomes more complex. For natural gas utilities, technology is also advancing in areas such as system integrity and energy efficiency. Consequently, all regulated gas and electric utilities shall report to the Commission annually, as described in Section 500 of this Rule, on their efforts to improve energy delivery, through modernization of existing infrastructure, improvements to lower energy delivery costs (*e.g.*, by expanding access to supply alternatives or relieving congestion in the delivery system), and/or through the expansion of energy delivery to additional customers.

**101 Definitions**

**1. Demand-Side:**

**a. Management** – Activities or programs undertaken to influence the amount and timing of electricity use. Note that the term "demand-side management" is often used in a general way to refer to all energy efficiency and load-management programs.

**b. Measure** – Any device, technology, or operating procedure that makes it possible to deliver an equivalent level and quality of energy service while permitting the customer to use less energy or peak demand than would otherwise be required.

**c. Program** – A collection of demand-side measures designed to operate as a single program, which serves to reduce a utility's capacity or energy requirements.

d. **Portfolio** – The totality of a utility's efforts to promote demand-side management.

2. **Demand Response:**
   Load management programs and/or practices that have the intended goal of reducing or shifting load from hours with high electricity costs and/or reliability problems. Demand Response programs may include but are not limited to direct load control (such as air conditioners and water heaters), or- incentive rates designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

3. **Energy Efficiency:**
   Reducing the demand (in kW) and the ~~rate at~~ amount of ~~which~~ energy (in kWh) ~~is used~~ consumed by equipment and/or processes while maintaining or improving the customer's existing level of comfort and end-use functionality. Such reductions may be achieved by substituting more advanced technology or by reorganizing the process to reduce waste, reduce waste cooling, or improve the thermal properties of a building. Energy efficiency also includes the reduction of energy through behavior-based programs that may reduce peak load but have little to no associated energy savings, typically known as demand response.

   **Commented [BB1]:** Energy efficiency can also reduce demand (kW) in addition to energy (kWh)

4. **Integrated Resource Planning:**
   IRP is a type of utility planning process that develops long-range resource plans by seeking to identify an optimal combination of resources (including traditional supply sources, emerging supply sources such as distributed energy resources, demand-side resources, energy efficiency, conservation, and possibly other options) to meet forecasted load requirements at the lowest reasonable total cost, subject to various objectives and constraints, including but not limited to reliability, planning, regulatory, environmental and operational requirements. The resource planning process should also define and assess various costs, benefits, and potential risks as they appear and are known in the market.

5. **Planning Period/Horizon:**
   The period for which resources must be planned to meet customer load requirements. The default planning period/horizon for the Utility Resource Plan, described *infra*, is twenty (20) years.

6. **Power Purchase:**
   A transaction to purchase capacity and/or energy from another electric power supplier.

7. **Stakeholders:**
   This includes any interested party eligible to appear and/or intervene in Commission proceedings pursuant to Rule 6-121 of the Commission's Public Utility Rules of Practice and Procedure.

8. **Supply-side Resource:**

An electric generating unit, either owned or operated by the utility, or a capacity purchase. Capacity upgrades and retirements of existing supply-side resources are issues typically considered in a utility's IRP.

**9. Utility:**
Any electric utility furnishing electricity service within the State of Mississippi and subject to the jurisdiction of the Commission.

**102 Relationship of the Commission and Utilities to IRP**

The periodic filing by a utility of an IRP report provides transparency for the Commission, Mississippi ratepayers, and other interested stakeholders. IRP filing requirements do not change the fundamental regulatory relationship between the utilities and the Commission, or otherwise relieve such utilities from their statutory obligation to provide reasonably adequate service at just and reasonable rates. These obligations require that utilities maintain local control of their resource planning process and decision-making, because utilities are the entities that will be held accountable for their planning decisions by the Commission.

The IRP reporting requirements embodied in this Rule are not intended to drive any specific outcome or dictate any specific utility investment decisions. To that end, these IRP reporting requirements do not supplant or equate with a prudence determination or otherwise replace the Commission's existing regulatory processes for petition and approval of requisite certificates of convenience and necessity for new resources. Consistency between a utility's filed IRP and subsequent Commission proceedings will, however, be a factor for the Commission to consider in evaluating the prudence of utility investments, construction of infrastructure, and rate applications. Any changed circumstances that occur after the IRP has been developed and filed will also be considered in such proceedings.

**103 Required Reports**

The required reporting under this Rule shall be comprised of ~~three~~ five separate components: (1) the Utility Resource Plan: Methodology and Inputs Report; (~~1~~2) the Utility Resource Plan: Analysis; (~~2~~3) Near-term Action Plan; (4) the Mid-point Supply-side Update; and (~~3~~5) the Annual Energy Delivery Plan.

**104 Utility Resource Plan**

The Utility Resource Plan must contain the elements set forth below, and shall be filed by all regulated electric utilities in accordance with the time frame and deadlines established herein.

1. **Methodology and Inputs Report**
   The Methodology and Inputs Report shall be subject to stakeholder feedback in accordance with Section 105, such that any interested party may file comments addressing the proposed Methodology and Inputs.

   a. **Statement of Objectives**

**Commented [BB2]:** Customers of vertically integrated utilities have little to no choice over the generation resource decisions made on their behalf. As such, the opportunity for stakeholder groups that represent these customers and other interests to weigh in on the resource planning process is critical.

This iterative process allows for meaningful stakeholder engagement to take place, ensuring transparency, accountability, and accuracy.

See 25x'25 Comments re Proposed IRP Rule, 4.1.2, page 7.

The utility shall clearly state and support the objectives for its IRP, which ~~may~~ shall include but are not limited to: reliable, ~~adequate~~safe, and reasonably-priced service. In addition to these primary objectives, the IRP should also articulate how it contributes towards other objectives including but not limited to; economic efficiency; financial integrity of the utility; impact to customer bills; equal consideration of ~~available and~~ commercially-~~proven~~available -demand-side and supply-side resources; reasonable mitigation of potential risks; consideration of future environmental impacts and associated costs; and consistency with governmental regulations and policies. In meeting its defined objectives, the utility should put itself in a position to respond to reasonably anticipated economic conditions, technological advancements and changes, and customer demand for energy services. Any utility-specific objectives must comply with the Commission's overall objective of ensuring transparent evaluation of a comprehensive set of potential resource options to determine a base or reference resource plan that offers the most economic and reliable combination of resources satisfying the forecasted load requirements.

**Commented [BB3]:** It should be articulated which objectives are the priority objectives and which are secondary objectives. Otherwise, secondary objectives may result in bias in the IRP process. See 25x'25 Comments re Proposed IRP Rule, 4.I.1, page 7.

**b. Modeling Protocol**

The utility shall clearly state and support its methodology for analysis of identified resource portfolios. To the extent that the analysis depends on software/modeling tools to determine resource additions and retirements, such software with all assumed inputs should be made available for use by the Commission and Public Utilities Staff ("Staff").

**Commented [BB4]:** 25x'25 is concerned that without this text the modeling exercise conducted by the utility will be a "black box," which would not provide the level of transparency desired by the Commission.
See 25x'25 Comments on Development of IRP Rule, 2.7, page 14.

**~~b.~~c. Development of a Range of Demand Forecasts**

A forecast of peak load and energy requirements over a planning period/horizon of twenty (20) years shall be developed, and the amount of capacity required to serve those forecasted load requirements shall be determined, taking into consideration the utility's reliability requirements and~~,~~ existing ~~supply-and~~ demand-side resources~~, and any planned additions to and/or retirements of existing resources (both supply-side and demand-side)~~. A reasonable set of assumptions for econometric and/or end use variables should be considered in the development of a range of outcomes (futures) that complement the long-term forecasts of energy demand and energy consumption. A planning period/horizon of 20 years shall be used.

**Commented [BB5]:** Demand forecasts are independent of the resources needed to meet that demand. A review of IRP best practices indicate that the demand forecast shall be developed prior to the consideration of resource portfolios. Through the IRP analysis, the demand forecast will serve as a basis for determining the amount, type, and timing of resources needed. See 25x'25 Comments on Development of IRP Rule, 2.1, page 9.

**~~c.~~d. Identifying and Characterizing Supply-Side and Demand-Side Resources**

For purposes of the entire 20-year planning horizon, the utility should assess its supply-side and demand-side resources based on their cost effectiveness and risk exposure~~,~~ and considering both the utility's planning objectives and the Commission's stated policy goals. For incremental capacity additions, reasonably useful, commercially-~~proven~~available, and economic supply-side and demand-side resources that may be available to a utility should be considered, including but not limited to energy efficiency, demand response, and distributed energy resources ("DER"). The utility's filed ~~IRP Report~~ Methodology & Inputs Report should, at a minimum, include an evaluation and discussion of the following:

**Commented [BB6]:** Utilities should be required to consider components beyond cost, such as risk. Consideration of risk is of particular importance when comparing long-term and short-term resource contracts. This is discussed in detail in 25x'25 Comments re Proposed IRP Rule, 4.III.2, page 12.

**Commented [BB7]:** The text as currently proposed may allow the utility to eliminate viable resources based on their sole discretion. Resources that may be available in the near future or have limited commercial deployment should be considered in the resource portfolios. Discussion on whether a resource is to be considered viable and determination of such for the purposes of the IRP should occur during the stakeholder process described in Section 105. See 25x'25 Comments re Proposed IRP Rule, 4.II.2, page 10.

i. **Existing Supply-Side Resources**

The utility shall identify, evaluate and discuss in its IRP Report all existing supply-side resources, including but not limited to:

1. Utility-owned generation – The utility shall include in this section an evaluation and discussion of any planned additions and/or retirements to legacy fleet.

2. Power-purchase transactions of any type, one year or longer in duration;

3. Unsolicited written, term sheet offers for firm power of 50 MW or more, including analysis, determination of whether the offer was rejected and the reason for rejection;

4. Sale transactions of any type, one year or longer in duration;

5. Exchange energy;

6. Cogeneration;

7. Existing Distributed Energy Resources;

~~8. Interruptible capacity;~~

~~9.~~8. Pooling or coordination agreements that reduce resource requirements; and

~~10.~~9. Any other supply-side resources

**Commented [BB8]:** Interruptible capacity should be considered a demand-side resource rather than a supply-side resource.

ii. **Existing Demand-Side Resources**

The utility shall identify, evaluate and discuss in its IRP Report all existing demand-side resources, including existing energy efficiency programs.

iii. **Existing Transmission**

To the extent a utility utilizes transmission resources to meet or reduce its forecasted load requirements, the utility shall evaluate and discuss in its IRP Report the condition of its existing transmission system.

iv. **Viable Alternative Supply-Side Options**

A wide range of potentially viable supply-side resource alternatives, including renewable and non-renewable options and energy storage, shall be identified for further evaluation to meet the utility's resource requirements.

v. **Viable Alternative Demand-Side Options**
A wide range of potentially viable demand-side options, including but not limited to energy efficiency, shall be identified for further evaluation to meet the utility's resource requirements.

vi. **Viable Alternative Transmission Options**
Any potentially viable transmission resources that may be utilized by a utility to meet or reduce its forecasted load requirements, shall be identified and discussed.

**e. Preliminary Resource Screening**
Identified resource additions should be analyzed to determine costs, effectiveness, and other attributes such as potential future emission control or allowance costs to the extent they are quantifiable. Resources that do not otherwise meet minimum criteria including cost-effectiveness, risk mitigation, ~~reliability~~, environmental, and/or other governmental rules or policy ~~should~~ may be proposed for eliminationed from further consideration in the applicable planning cycle. A written explanation of such removal, including the basis therefore, shall be provided in the Utility Resource Plan: Methodology and Inputs Report. To the extent circumstances change, resources may be reevaluated. Elimination of resources in the preliminary screening stage should be minimal and shall not be the only basis on which resource portfolios are developed. The preliminary screening shall further inform but not overly limit the set of resource options.

**Commented [BB9]:** A resource's impact on system reliability is challenging to determine prior to formal analysis. Discussion on whether a resource can reasonable meet system needs should be held through the stakeholder process. See 25x'25 Comments on Proposed IRP Rule, 4.II.2, page 10.

**Commented [BB10]:** The preliminary screening should eliminate only resources that do not meet **minimum** criteria such that the resulting set of resources contains a reasonable range of resources. See 25x'25 Comments on Proposed IRP Rule, 4.II.1, page 6.

## 2. Analysis

~~d.~~a. **Development and Analysis of Multiple Resource Portfolios**
The Utility Resource Plan shall be based on a planning process that identifies multiple a minimum of three (3) potential resource portfolios using scenario planning and sensitivity analyses, with at least one portfolio based on stakeholder input. Each portfolio shall meet reliability criteria and objectives established in the planning process. The objective of scenario planning and sensitivity analysis is for the utility to evaluate the robustness of its Resource Plan(s) against potential futures by varying key uncertainties impacting the planning process. The sensitivity and scenario analyses utilized shall be described in the Utility Resource Plan. -Though other assumptions may be considered, the following ~~are often~~ shall be evaluated in scenario and sensitivity analyses ~~in utility IRP studies~~:

**Commented [BB11]:** This number is based on best practices in IRP planning. See 25x'25 Initial Comments on Development of IRP Rule, 2.4, page 11.

**Commented [BB12]:** Utilities should conduct sensitivity analyses to cover a number of future scenarios and risks. See 25x'25 Comments on Proposed IRP Rule, 4.II.1, page 9.

**A.** Fuel prices;

**B.** Changes in load;

**C.** Technology costs;

**D.** Environmental regulations;

E. Inflation;

F. Capital costs; and

G. Future O&M costs

**b. Comparison of Multiple Resource Portfolios**

The portfolios identified should be compared based on the utility's ability to meet its identified planning objectives as described in accordance with Section 104.1.a. Each portfolio's performance in meeting these objectives ~~across varying potential outcomes~~ over the planning horizon shall be quantified using relevant metrics, including but not limited to ~~comparison of~~:

i. the net present values of total revenue requirements of each portfolio;
ii. the Loss of Load Expectation (LOLE) or another standard reliability metric;
iii. monthly costumer bill impact for average residential customer;
iv. total gallons or acre-feet of water consumed;
v. tons of emissions (e.g. nitrogen oxides or NOx, sulfur oxides or SOx, atmospheric carbon or CO2, etc.);
vi. percentage of energy mix reasonably achieved through use of renewable energy;
vii. percentage of energy mix generated by local, in-state resource;
viii. total annual cost and portion of portfolio cost spent on new capital projects;
ix. and total annual cost and portion of portfolio cost spent on fuel.

The portfolios identified shall also be compared based on the risks associated with contract durations for non-utility-owned resources. The utility shall include an evaluation and discussion of existing utility-owned generation and determine cost-effectiveness of continued operation of existing supply compared with procurement of alternative supply-side or demand-side resources.

**c. Indication of Utility's Preferred Portfolio**

The utility shall summarize the results of its resource portfolio evaluation ~~in an action plan, if applicable,that identifies~~ and identify one ~~or more~~ preferred portfolio that provides long-range guidance for the Commission and represent potentially viable resource options in the future.

**~~5.~~3. Near-term Action Plan**

The utility shall develop an action plan ~~is not necessarily a specific plan for~~that specifies near-term actions over the next five (5) years. The action plan shall include the size, timing, and type of planned resource additions and retirements, including both supply side resources and the ~~, unless specifically identified within the Utility Resource Plan. A utility's action plan does not in any way relieve the utility of its statutory obligations concerning certificates of public convenience and necessity,~~

**Commented [BB13]:** These metrics are based on best practices in IRP planning. See 25x'25 Comments on Development of IRP Rule, 2.5, page 11.

**Commented [BB14]:** Utilities should be required to consider components beyond cost, such as risk, when comparing long-term and short-term resource contracts. Thi is discussed in detail in 25x'25 Comments re Proposed IRP Rule, 4.III.2, page 12.

**Commented [BB15]:** It can be more cost-effective to procure alternative supply or demand resources than to continue operating existing supply (even including certain stranded costs). New resources should be compared to cost projections for currently operating assets. See 25x'25 Comments on Proposed IRP Rule, 4.II.2, page 11.

~~prudency, or any other regulatory requirements.~~adoption of customer programs (e.g., demand side management) that align with the results of the Utility Resource Plan.

105 **IRP Schedule and Stakeholder Participation**

The following schedule is applicable to the Utility Resource Plan Reporting Requirements set forth herein:

1. Electric Utilities subject to the provisions of this Rule shall file their ~~first~~ Utility Resource Plan: Methodology and Inputs Report no later than ~~twelve~~ six (~~12~~6) months after issuance of the Commission's Final Order Approving this Rule. Each successive Utility Resource Plan process shall begin ~~filed~~ no later than three (3) years thereafter. The ~~Utility~~ utility ~~Resource Plan~~ shall ~~include~~ make a good faith effort to make data and information included in its Methodology and Inputs Report available to the public. The utility may file a confidential set of work papers containing any confidential commercial and financial information and trade secrets.~~as a confidential appendix a set of work papers showing the key inputs used by the utility in developing the Plan.~~ Copies of these work papers may be obtained in accordance with the Confidentiality provisions of this Rule.

2. Within fifteen (15) days of a utility filing its Methodology and Inputs Report, a meeting shall be established for the utility to present its proposed Methodology and Inputs Report to interested stakeholders and solicit feedback. The utility shall be responsible for coordinating meeting time, location, and teleconference access. The utility shall be responsible for maintaining a webpage to publicize this and other information relevant to any interested party.

3. Within forty-five (45) days of a utility filing its ~~Utility Resource Plan~~Methodology and Inputs Report, any interested party may file comments addressing the ~~Utility Resource Plan~~Methodology and Inputs Report.

4. Within thirty (30) days of the filing deadline for stakeholder comments on the Methodology and Inputs Report, the utility shall incorporate any feedback they deem appropriate. If utilities reject specific comments, interested parties may protest within fifteen (15) days. In this case, the Commission should ultimately decide and release an order for a course of action. Following the completion of the Methodology and Inputs Report development, the utility shall begin to conduct its Analysis.

5. Within fifteen (15) days of a utility filing its Analysis, a meeting shall be established for the utility to present its Analysis to interested stakeholders and solicit feedback. The utility shall be responsible for coordinating meeting time, location, and teleconference access. The utility shall be responsible for maintaining a webpage to publicize this and other information relevant to any interested party.

6. Within forty-five (45) days of a utility filing its Analysis, any interested party may file comments addressing the Analysis.

**Commented [BB16]:** An IRP must provide a meaningful link to actual resource procurement decisions, otherwise an IRP development process will be futile. The 5-year term and inclusion of customer programs is based on best practices in IRP planning. See 25x'25 Comments on Proposed IRP Rule 4.III.1, page 11, and 25x'25 Comments on Development of IRP Rule, 3.2, page 16.

**Commented [BB17]:** Customers of vertically integrated utilities have little to no choice over the generation resource decisions made on their behalf. As such, the opportunity for stakeholder groups that represent these customers and other interests to weigh in on the resource planning process is critical.

This iterative process allows for meaningful stakeholder engagement to take place, ensuring transparency, accountability, and accuracy.

See 25x'25 Comments on Proposed IRP Rule, 4.I.2, page 7

**Commented [BB18]:** As drafted, the schedule allows for the Utility Resource Planning cycle to begin 12 months after Final Order Approving this Rule and be concluded 120 days after that, for a total of approximately 16 months. 25x'25 recommends a timeline that would also conclude the first planning cycle at this 16 month mark, although it suggests a cycle start date of 6 months following the Final Order Approving this Rule.

~~6.~~7. Within thirty (30) days of filing deadline for stakeholder comments on the Analysis, the utility shall review and selectively adopt stakeholder feedback. If utilities reject specific comments, interested parties may protest within fifteen (15) days. In this case, the Commission should ultimately decide and release an order for a course of action.

~~7.~~8. Following a utility's incorporation of stakeholder feedback into its Analysis, ~~The~~ the Staff shall have sixty (60) days to evaluate and file any comments on the ~~Plan~~Analysis. ~~Data requests may be served upon the utility within fifteen (15) days of the utility filling its Utility Resource Plan.~~ If the Staff believes the use of consultants is necessary or helpful in its review of any Utility Resource Plan, the utility may be required to pay for the cost of such consultants and to recover said costs in rates.

~~8. Utilities may provide a response to any such comments no later than ninety (90) days after the filing of its Plan.~~

9. Within fifteen (15) days of the Staff evaluation of the Analysis, any interested party may file comments addressing the Staff evaluation.

~~9.~~10. The Commission shall review the Utility Resource Plan ~~and note any deficiencies within one hundred twenty (120) days after its submittal by the utility~~and ultimately render a decision either approving the Plan's preferred resource portfolio, approving it subject to stated conditions, approving one of the alternative resource portfolios, approving it in part and rejecting it in part, rejecting it as filed, or provide an alternative plan within sixty (60) days after the Plan's submittal by the utility. The Public Utilities Staff ("Staff") shall assist the Commission with its review.

~~10.~~11. The Commission may require the utility to re-evaluate and resubmit its Utility Resource Plan for the current planning cycle to address any concerns raised in the comments or expressed by the Staff or Commission.

~~11.~~12. ~~Absent deficiencies, t~~The Utility Resource Plan cycle is concluded a minimum of ~~one hundred twenty (120)~~two hundred eighty-five (285) days after submittal of the Utility Resource Plan Methodology and Inputs Report by the utility.

**106 Mid-Point Supply-Side Update**

At approximately the mid-point of the utility's three-year planning cycle, regulated electric utilities shall file a written report containing updated information and data ~~describing any material changes to the Utility Resource Plan,~~ including but not limited to the following: an overview of all generation assets; data outlining the last three years performance; information on anticipated future output levels; investments in operations and maintenance; and any material changes in economic assumptions (*e.g.*, future natural gas price forecasts or alternative technology costs) and ~~or~~ forecasted load requirements. Any previously undisclosed capacity needs that are identified in the Mid-Point Supply Side Update shall be supported by good cause explanation. In the event a Mid-Point Supply-Side Update identifies a previously undisclosed need for capacity in excess of 75 MW, then the Update shall also include a description of and timeline associated with the

**Commented [BB19]:** The text as proposed provides an opportunity for significant resource procurement decisio[n] be made outside of the regular IRP process and therefore outside of acceptable levels of transparency and stakehol[der] input. The Mid-Point Supply-Side Update should includ[e] information to enable the Commission, Staff, and stakeholders to ensure prudency of any resource procure[ment] decisions.

See 25x'25 Comments on Proposed IRP Rule, 4.III.2, p[a] 11.

utility's plan to secure such resource. Any self-build option identified in the Mid-Point Supply-Side Update must be compared to other available market opportunities, which ~~can~~ shall be satisfied through a competitive solicitation for engineering, procurement, and construction services. Submission of the Mid-Point Supply Side Update in no way affects or relieves a utility of its separate obligation to obtain regulatory approval for the acquisition of any resource(s) described therein.

**Commented [BB20]:** The text as proposed allows utilities to hold a competitive solicitation but does not require them to do so, which could lead to self-build options being selected without consideration of cost-effective competitive options. See 25x'25 Comments on Proposed IRP Rule, 4.III.2, page 11.

**107. Annual Energy Delivery Plan**

All regulated gas and electric utilities shall report to the Commission annually on their efforts to improve energy delivery, through modernization of existing infrastructure, improvements to lower energy delivery costs (*e.g.*, by expanding access to supply alternatives or relieving congestion in the delivery system), and/or through expansion of energy delivery to additional customers.

Within sixty (60) days the Commission's final approval of this Rule, utilities subject to the provisions herein shall present for Commission approval a proposed plan or schedule according to which the utility will meet the reporting requirements of the Annual Energy Delivery Plan. At a minimum, the Annual Energy Delivery Plan shall include the information referenced in Subsections 1-6 below, and each utility's Annual Energy Delivery Plan shall be reviewed by the Staff. If the Staff believes the use of consultants is necessary or helpful in its review of a utility's Annual Energy Delivery Plan, the utility may be required to pay for the cost of such consultants and to recover said costs in rates.

**1. Demand Response and Energy Efficiency ("Demand-Side Management")**

**a. Design**

Utilities regulated by the Commission shall implement reasonable demand response and energy efficiency options for customers that are designed to achieve cost-effective energy and/or demand savings, considering factors such as: quantifiable and achievable savings, customer reliability benefits, cost effectiveness, rate impacts, and customer interest and participation potential. The Annual Energy Delivery Plan shall include a description of all such programs.

Well- designed demand-side management offerings provide opportunities for customers of all types to adopt energy efficiency and demand saving measures to increase control and provide greater opportunities to reduce their energy bills. For purposes of this rule, demand-side management includes energy conservation, energy efficiency, demand response, and strategic load growth.

Energy conservation and efficiency include educating customers about practical tips and ideas to reduce energy usage (e.g., suggested winter and summer thermostat settings) and reducing the rate at which energy is used by equipment and/or processes while maintaining or improving the customer's existing level of comfort and end-use functionality. Such reductions in energy usage may be achieved, for example, by substituting more advanced technology or improving the thermal properties of a building. Energy conservation programs can be included in portfolios of energy efficiency plans.

Demand response offerings lower peak demand. Options include direct load control efforts (*e.g.*, via air conditioner cycling) and interruptible rates (providing rate discounts in exchange for the right to reduce a customer's energy demand during a specified number of hours each year coinciding with high energy demand and/or emergency conditions). New or advanced technologies (*e.g.*, energy storage) are another option.

Strategic load growth benefits customers through increased use of utility services without increasing peak demand resulting in ~~potentially~~ decreased customer rates. Strategic load growth may occur as a result of new customers being added to the utility's system (e.g., through economic development), or it may consist of growth in the loads of existing customers (e.g., electric vehicles or industrial electric process equipment that is more economical for a customer). As sales increase, there is an increase of billing determinants that leads to downward pressure on rates, because there are more unit sales over which to spread fixed costs. This benefits all customers. The purpose of strategic load growth programs is to incentivize the more efficient usage of utility infrastructure and resources. Load growth activities leading to an increase in peak demand should not be permitted, as they do not incentivize the more efficient usage of utility infrastructure and resources.

**Commented [BB21]:** "Strategic load growth" typically refers to an increase in end-use consumption. Any referenc to strategic load growth must specify that the load growth will not be associated with an increase in peak load. Increases in peak load do not constitute strategic load grov and do not benefit all customers.
See 25x'25 Comments on Proposed IRP Rule, 4.III.4.A, page 13.

Strategic load growth may also address the Commission's statutory policy objective to foster, encourage, enable and facilitate economic development in the State, and to support and augment economic development activities, and to take every opportunity to advance the economic development of the State. This may include the encouragement of universal access to utility services through infrastructure expansion to areas that currently do not have such services.

**b. Evaluation of Demand-Side Management Offerings**

Cost-effectiveness tests measure and value the benefits and costs of demand-side management investments relative to long-term supply options. Evaluation of cost-effectiveness is only one aspect of long-term integrated resource and energy delivery planning; enhancing reliability and managing potential risks must also be considered in the planning process.

Utilities must demonstrate that they have evaluated the proposed demand-side management investments using at least three industry-accepted tests, including the Total Resource Cost test and the Utility Cost Test, and provide results of the analysis within the Annual Energy Delivery Plan filing. The results of the analyses should also provide details on the reliability and risk impacts of the utility's planned demand-side management investments.

The inputs and assumptions used, as well as the precise utilization of cost-effectiveness tests and the definitive balancing of perspectives, shall be developed by the individual utility. The near-term and longer-term impacts on customers and on utility financial integrity must be factored into the final decision to proceed or not to proceed with any demand-side management investment.

c. **Cost Recovery for Demand-Side Management**

The primary goal of demand-side management is to defer or avoid energy usage and for customers to achieve the concomitant savings without requiring them to involuntarily sacrifice comfort or reliability, or accept undue risks. Additionally, demand-side management can be useful in reducing customer demands which, in the long run, may reduce or delay investments in fixed costs needed to meet peak demands (e.g., generation, bulk transmission). Further goals include providing new and innovative options to customers to help meet their energy needs, mitigating environmental impacts, and fostering increased modernization of the energy grid. The Commission recognizes and accepts that this goal of avoiding energy usage, if not properly addressed, can be detrimental to utilities and their owners under traditional cost-of-service ratemaking, especially where utilities are adequately meeting their obligation of producing low-cost, reliable energy services. The Commission recognizes, further, that accomplishing the goals of demand-side management requires actions on the part of both the utility and its customers, which is different from actions associated with a utility adding a new supply resource. Therefore, utilities shall be allowed an opportunity to recover the reasonable and prudent costs incurred by them in making demand-side management investments, including an opportunity to earn a reasonable return, comparable to the utility's weighted average cost of capital, thereon.

In its Formula Rate Plan, each utility may propose an approach to earn a return on demand-side management investments, as capitalized costs rather than expensed, to place such investments on more equal footing with other supply-side resource and infrastructure investments on which utilities earn a return. Demand-side management investments shall include, but not be limited to, equipment, incentives and rebates, marketing and delivery, direct installation costs (including plumbing installations), and any administration costs. Incentives may include information, technical assistance, leasing programs, product promotions and direct financial inducements. Financial inducements may include, but are not limited to, rebates, discounted products and services, appliances and alternative financing arrangements. Any financial inducements undertaken by a utility intended to be reflected in the utility's rates, including traditional promotional practices of the utilities contemplated in MPSC Docket No. 1994-UA-115, must be incorporated

**Commented [BB22]:** If demand-side management investments are earning a rate of return, it should be ma[de] clear that they are capitalized and not expensed. If this construct is being used, then the rules should also clarif[y] the utility would need to request the Commission treat [t]he investment as a regulatory asset with a rate of return comparable to the weighted average cost of capital.

This is a significant issue from a ratemaking perspectiv[e] should be addressed in its own proceeding, as it has implications for the overall ratemaking construct of the Commission. 25x'25 strongly recommends that MPSC a separate docket and proceeding to consider the cost recovery of DSM investments.

See 25x'25 Comments on Proposed IRP Rule, 4.III.4, 13.

under and meet the cost effectiveness requirements described in this rule to the extent that such financial inducement allows the customer to make a decision between using natural gas or electricity.

Utilities may also propose a mechanism to adjust budgets and cost recovery to respond to customer demand, to take advantage of market opportunities, to deal with oversubscriptions and to avoid stop-start funding.

Cost recovery should be addressed in each utility's formula rate plan and demand-side management expenditures, including any over or under recovery of spending in an annual period~~, will be allowed in the formula rate plan test year on a prospective basis (e.g., as a known and measurable change)~~. ~~The estimated reduction in energy usage resulting from implementation of the proposed demand-side management investments also may be reflected prospectively in the formula rate plan test year as a change to future test year utility revenues. The intent of this provision is to provide a reasonable opportunity to the utility to fully recover its expenditures for demand-side management.~~

Utilities ~~may~~ shall not ~~further~~ propose in their Annual Energy Delivery Plans to add demand-side management as a metric to any performance-based rate adjustment, as this would not be necessary if they are already earning a return on demand-side management investments. Sales shall not be used as a measure of performance due to the potential for beneficial electrification, economic growth, and increased customer demand, which could mask the effectiveness of demand-side management.

**Commented [BB23]:** 25x'25 recommends an annual tr[...] up for demand-side management (DSM) investments, an[...] believes that a true-up based on future delivery of DSM [...] fraught with potential risks.

See 25x'25 Comments on Proposed IRP Rule, 4.III.4, pa[...] 13.

Third-party evaluation, measurement and verification ("EM&V") shall not be required where the utility offers to provide its analyses used in evaluating demand-side management investments to the Staff and any public witnesses in conjunction with the Evaluation of Demand-Side Management Offerings. Where a utility chooses not to make its analyses available, the utility shall contract with an independent third-party vendor to conduct EM&V, utilizing accepted industry standards, and shall file the report of the third- party vendor with the Commission.

2. **Distributed Energy Resources ("DER")**
In the context of this Rule, DER means utility-owned (or controlled) equipment (i.e., physical assets) used to generate, adjust, store, or sometimes deliver energy performed by a variety of devices at the distribution system-level. Anticipated investments in DERs should be included as an appendix to the Annual Energy Delivery Plan developed by each utility. Recovery of demand-side management investments should be addressed in each utility's formula rate plan as a known and measurable change.

All regulated electric utilities shall also include as an Appendix to their Annual

Energy Delivery Plan the annual avoided cost calculations utilized in connection with the Mississippi Renewable Energy Net Metering Rule.

3. **Transmission and Distribution Systems**
Each utility shall also include in its Annual Energy Delivery Plan a list of new transmission lines and other associated facilities which are under construction or for which there are specific plans to be constructed during the relevant planning horizon, including capacity and voltage levels, location, cost estimates and schedules for completion and operation, to the extent such have been developed. This includes reporting relevant collaborative transmission planning projects occurring within the context of any regional planning organization such as the Midcontinent Independent System Operator or the Southeastern Regional Transmission Planning group.

To the extent practical, the utility shall include similar information about its distribution plans. The utility shall also include a discussion of the adequacy of its transmission and distribution systems, including the reliability, resiliency and storm hardened condition of the transmission and distribution systems.

Reasonable and appropriate vegetation management is essential to ensuring the resilience, as well as protecting the safety, of the energy grid and related environment. Effective vegetation management, along with other grid resiliency measures, are important factors in the prevention of and recovery from electric system outages. The Commission, however, recognizes that factors outside the utility's control, such as weather, can significantly impact the need to change vegetation spending from year-to-year. Similarly, federal mandates to address grid resiliency are also often outside the utility's control.

To emphasize the importance placed by the Commission on the reliability, resiliency and safety of the transmission system and to allow the utilities to effectively manage the quality of the service they provide, the Commission shall allow utilities exact recovery of any vegetation management and inspection related costs associated with North American Electric Reliability Corporation ("NERC") compliance rules, plans, programs, or requirements, including costs associated with critical infrastructure protection plans ("NERC CIP"). Utilities shall be allowed to remove these NERC costs from base rates and reflect them through a proposed alternative cost recovery mechanism and may choose to defer and amortize any such costs over five years.

To allow utilities to effectively manage vegetation growth and to more quickly improve grid resiliency at the distribution level, the Commission shall allow utilities exact recovery of all such related costs. Therefore, utilities may remove all vegetation management costs and Commission-approved grid resiliency costs from base rates and reflect them through alternative cost recovery mechanism and may choose to defer and amortize such costs over five years.

Any such costs treated pursuant to this Section that are approved for alternative cost recovery shall be audited by the Staff in its review of the utility's Annual Energy

Delivery Plan. Every four years, unless modified by the Commission, the Staff shall review and comment on the vegetation management plans of each electric utility. If the Staff believes the use of a consultant is necessary or helpful in its review of a utility's vegetation management plan, the utility may be required to pay for the cost of such consultant and to recover said costs in rates.

4. **Customers**
In its Annual Energy Delivery Plan, the utility shall address how it proposes to reach low-income customers in relation to planned demand-side management and DER investments. The utility shall also address whether it proposes to provide demand-side management offerings directly or indirectly through financial support of programs for low-income households. To foster increased demand-side management and DER investments that will benefit low-income customers, the Commission shall exempt from the proscriptions set out in Chapter 22 of these Rules and allow recovery as cost of service of up to ~~$350,000~~a set amount per year of utility charitable contributions to organizations that directly aid low-income customers to foster increased access to demand-side management and DER options. The amount to be recovered shall be determined by the Commission through a separate, robust evaluation to ensure prudency. To further workforce and economic development, utilities shall be allowed to recoup as cost of service ~~an additional $350,000~~set amount per year of utility charitable contributions for STEM scholarships for minorities and scholarships for training in the utility industry and to non-profit and state or local governmental entities that provide early childhood education, workforce development, and career and technical training. The amount to be recovered shall be determined by the Commission through a separate, robust evaluation to ensure prudency. The separate evaluations shall be based on benefit-cost analysis principles to ensure these exemptions are in alignment with transparency standards and public policy goals.

**Commented [BB24]:** 25x'25 has deep concerns regard the exemption of expenditures from prudency review or cost/benefit analyses. As drafted, these exemptions are n alignment with the purpose of the Proposed IRP Rule. 25x'25 strongly recommends the MPSC open a separate docket and proceeding to consider the monetary disbursements as outlined in Section 107.4.

See 25x'25 Comments on Proposed IRP Rule, 4.III.4, p 13.

The Commission also recognizes that, for many customers, lacking access to affordable capital impedes adoption of demand-side management and DER. To encourage the development by utilities of tariffed on-bill offerings and on-bill financing options, any Commission-approved tariffed on-bill offering or on-bill financing program that focuses on demand-side management or DER[1] shall be exempt from Rule 8.125.2 of the Commission's Rules and Regulations Governing Public Utility Service.

5. **Enabling Technology**
The Commission recognizes that existing and emerging technologies and information, and the data such technologies provide, may enable more efficient, cost-effective, and reliable service. Increased broadband access and the security, storage, and use of data are two examples. The Commission recognizes the benefits of utilities accumulating, storing, and utilizing customer data to improve service, enhance reliability, and provide new and innovative offerings to customers, and therefore recognizes that customer data is affected with the public interest.

[1] Any such programs require and shall continue to require to separate Commission approval prior to implementation.

Recognizing that customer data has inherent value and should be protected from public disclosure, public utilities are hereby entrusted as the custodians of customer data and should seek to capture that value for the benefit of customers as approved by the Commission. Utilities also must ensure that customer data is reasonably secure. Customers may request immediate, no-charge access to data they generate and provide to the utility, and the utility shall provide them with such upon request. Within the Annual Energy Delivery Plan filing, the utility shall set out its perspective on the availability and benefits of existing and emerging technology and how the utility is utilizing customer data as it relates to enhancing utility service.

While ensuring service at the lowest, reasonable cost is a hallmark of the Commission, the public interest is served by improving reliability (e.g., resiliency and storm recovery and hardening and grid modernization), promoting economic development (e.g., attracting businesses to locate or expand) and providing customer access to enhanced services (e.g., expanding natural gas service, new technologies and broadband). The Commission encourages utilities to make new investments that incorporate, in some measure, all three components. For example, reasonable investment that induces affordable access to fiber-to-the-home, which provides a sufficient level of download/upload speeds, encompasses all three components and would be deemed in the public interest.

To encourage investment of the type mentioned above and which are hereby deemed to promote the public interest, the Commission shall determine in a separate, robust evaluation options to incent utilities to make such investments. ~~creates by operation of this Rule what~~ that shall be known as Enhanced Grid Investments ("EGI"). ~~Utilities are authorized under this provision to make EGI up to $25 million annually.~~ Anticipated EGI shall be designated as such in the Annual Energy Delivery Plan, and the Staff shall review EGI to confirm that the designated EGI is reasonably likely to improve reliability, promote economic development and improve customer access to modern service during the depreciable life of the investment. EGI implemented pursuant to this provision shall not require a facilities certificate, unless comprised of new generation and transmission. EGI investment shall be depreciated over the life of the asset but in no event sooner than 10 years from the in-service date. ~~Nothing herein precludes a utility from proposing in its Annual Energy Delivery Plan additional investments supporting reliability, economic development or new technologies in excess of the amount described in this provision.~~

Expansion of broadband, particularly rural broadband, is of particular importance to the Commission because such expansion is consistent with a number of policy drivers that underlie public utility regulation, including the availability of adequate and reliable service, continued service to customers consistent with the level of service needed to promote the public welfare, and with the authorization and empowerment provided by the Legislature to the Commission to take every opportunity to advance the economic development of the state. As with reliability benefits, the benefits of broadband expansion – while real – are difficult to quantify.

To allow utilities to more quickly expand broadband access, utilities that are rate regulated by the Commission may, on an annual basis, make up to ~~$15 million~~ an amount to be determined by the Commission in direct or indirect investments in a project or company (with particular emphasis on and due consideration given to those types of endeavors authorized by the Mississippi Broadband Enabling Act) that has as its direct purpose the expansion of broadband service (or other technology that enables internet access) to underserved customers in Mississippi. Any such investment shall be recorded to a regulatory asset to be included in the utility's rate base, subject to Commission approval, and shall be amortized over a period no longer than ten years. Because of the inherent, yet difficult to quantify, benefits of such investments, no cost/benefit analysis shall be required. Any such expenditures made by a rate regulated utility under this paragraph shall be used to provide services only to customers of the utility providing such investment. The utility making the investment may rely on the representations of the entity receiving the funds and no independent verification is required of the funding utility.

This section shall be revisited five (5) years after the effective date of this Rule.

**Commented [BB25]:** 25x'25 has deep concerns regarding the exemption of expenditures from prudency review or cost/benefit analyses. As drafted, these exemptions are not i alignment with the purpose of the Proposed IRP Rule. 25x'25 strongly recommends the MPSC open a separate docket and proceeding to consider the monetary disbursements as outlined in Section 107.5.

See 25x'25 Comments on Proposed IRP Rule, 4.III.4, page 13.

6. **Annual Reporting Requirements**

Anticipated investments in demand-side management and DERs shall be included as Appendix A to the Annual Energy Delivery Plan developed by each utility in accordance with this Rule. This report also shall include:

a. The amounts actually invested in demand-side management and DER offerings for the prior year;

b. A measure of the savings resulting from demand-side management; and

c. A detailed description of any changes proposed to take place during the next year, along with rationale supporting such changes.

If Staff finds, after reviewing a utility's Appendix A, that a demand-side performance measure is not sufficiently promoting adequate investment, then Staff may recommend that the Commission establish an individual savings target for the utility. The Commission may hear the matter after proper notice and issue an appropriate order.

**108. Confidentiality**

The Commission recognizes that resource planning involves the use and analysis of confidential commercial and financial information and trade secrets. The protection of confidential information benefits utility customers by ensuring that the rates they pay are not unnecessarily increased due to the dissemination of market-sensitive data. Therefore, the public interest requires that confidential commercial and financial information and trade secrets of public utilities be protected to the full extent of the law.

Each electric utility subject to this Rule shall submit to the Commission a non-disclosure agreement for the Commission to maintain on file. Any interested party may obtain the confidential work papers of the utility filed pursuant to this Rule upon filing with the Commission and serving upon the utility an executed copy of the relevant utility non-disclosure agreement on file with the Commission.

109. **Waiver**
Exemptions from this Rule may be granted by the Commission in accordance with the Commission's Rules of Practice and Procedure.