

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 Rules set forth in Sections 107 through 109 shall apply to both electric and natural gas utilities as defined herein.

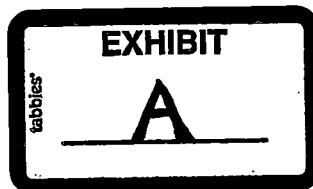
The IRP reporting requirements established in Section 102 and Sections 104 through 106 herein are intended to allow jurisdictional, investor-owned electric utilities the necessary flexibility to formulate plans that reflect their specific circumstances and best meet the needs of their customers, while providing a level of transparency that furthers the public policy goals of this Commission and the State of Mississippi. A 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 jurisdictional, investor-owned natural gas utilities, technology is also advancing in areas such as system integrity and energy efficiency. Consequently, all jurisdictional, rate-regulated gas and electric utilities shall report to the Commission annually, as described in Section 107 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 energy 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. For purposes of these Rules, Demand-Side Management includes energy conservation, energy efficiency, demand response, distributed energy resources, and strategic load growth as defined herein.



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 programs used 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 energy 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 energy use at times of high wholesale market prices or when system reliability is jeopardized.

3. Distributed Energy Resources ("DER")

A DER is a resource sited close to customers that can provide all or some of their immediate electric power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles, microgrids, and energy efficiency (EE). For purposes of this Rule, DER also includes 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.

4. Energy Efficiency:

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 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.

5. Integrated Resource Planning ("IRP"):

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.

6. Planning Period/Horizon:

The period for which resources must be planned to meet customer electric load requirements. The default planning period/horizon for the Integrated Resource Plan, described *infra*, is twenty (20) years.

7 Power Purchase:

A transaction to purchase capacity and/or energy from another electric power supplier.

8. Stakeholders:

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.

9. 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.

10. Electric Utility:

Any investor-owned utility furnishing electricity service within the State of Mississippi and subject to rate regulation by the Commission.

11. Gas Utility:

Any investor-owned utility furnishing natural gas service to at least ten thousand (10,000) customers within the State of Mississippi and subject to rate regulation by the Commission.

102 Relationship of the Commission and Utilities to IRP

The periodic filing by electric utilities 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 electric 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 electric 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 an electric 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

For electric utilities, the required reporting under this Rule shall be comprised of three separate components: (1) the Integrated Resource Plan; (2) the Mid-point Supply-side Update; and (3) the Annual Energy Delivery Plan. Gas utilities are only required to file the Annual Energy Delivery Plan.

104 Integrated Resource Plan

The Integrated 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. Statement of Objectives

The electric utility shall clearly state and support the objectives for its IRP, which may include but are not limited to: reliable, adequate, and reasonably-priced service; economic efficiency; financial integrity of the utility; equal consideration of available and commercially-proven 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.

2. 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 electric utility's reliability requirements, 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.

3. Identifying and Characterizing Supply-Side and Demand-Side Resources

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

a. Existing Supply-Side Resources

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

- i. Utility-owned generation – The utility shall include in this section an evaluation and discussion of any planned additions and/or retirements to legacy fleet.
- ii. Energy-purchase transactions of any type, one year or longer in duration;
- iii. 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;
- iv. Sale transactions of any type, one year or longer in duration;
- v. Exchange energy;
- vi. Cogeneration;
- vii. Existing Utility-Owned Distributed Energy Resources;
- viii. Interruptible capacity;
- ix. Pooling or coordination agreements that reduce resource requirements; and
- x. Any other supply-side resources

b. Existing Demand-Side Resources

The electric utility shall identify, evaluate and discuss in its IRP Report all existing demand-side resources, including existing energy efficiency programs. This information and analysis should incorporate and reflect the

information reported in the electric utility's Annual Energy Delivery Plan, with any substantial variation or departure explained in writing.

c. Existing Transmission

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

d. 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 electric utility's resource requirements.

e. 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 electric utility's resource requirements.

f. Viable Alternative Transmission Options

Any potentially viable transmission resources that may be utilized by an electric utility to meet or reduce its forecasted load requirements, shall be identified and discussed.

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 be eliminated from further consideration in the applicable planning cycle. A written explanation of such removal, including the basis therefore, shall be provided in the Integrated Resource Plan. To the extent circumstances change, resources may be reevaluated.

4. Development and Analysis of Multiple Resource Portfolios

The Integrated Resource Plan shall be based on a planning process that identifies multiple potential resource portfolios using scenario planning and sensitivity analyses. 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 Integrated Resource Plan. Though other assumptions may be considered, the following are often evaluated in scenario and sensitivity analyses in utility IRP studies:

A. Fuel prices;

B. Changes in load;

- C. Technology costs;
- D. Environmental regulations;
- E. Inflation;
- F. Capital costs; and
- G. Future O&M costs

The portfolios identified should be compared based on the electric utility's ability to meet its identified planning objectives across varying potential outcomes over the planning horizon, including but not limited to comparison of the net present values.

5. Action Plan

The electric utility shall summarize the results of its resource portfolio evaluation in an action plan, if applicable, that identifies one or more preferred portfolios that provide long-range guidance for the Commission and represent potentially viable resource options in the future. The action plan is not necessarily a specific plan for near-term action, unless specifically identified within the Integrated 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, prudence, or any other regulatory requirements.

105 IRP Schedule and Stakeholder Participation

The following schedule is applicable to the Integrated Resource Plan reporting requirements set forth herein:

1. Within thirty (30) days of the Commission's final approval of this Rule, each electric utility subject to the IRP provisions of this Rule shall file a "Notice of IRP Cycle" in a new Commission docket. The filing of such Notice shall initiate the IRP planning and reporting cycle described herein. Interested parties may move to intervene in a specific electric utility's IRP docket in accordance with Rule 6-121 of the Commission Rules of Practice and Procedure. Interested parties may also proceed with the execution of utility nondisclosure agreements in accordance with Section 108 of this Rule at any time after the filing of a Notice of IRP Cycle.
2. Within thirty (30) days of filing a Notice of IRP Cycle, each electric utility subject to the IRP provisions of this Rule shall notice and conduct an initial public workshop for interested parties to take place in the Commission's hearing room in Jackson, Mississippi. The purpose of the initial workshop is for the electric utility and interested parties to exchange pertinent information concerning the IRP process, such as resource options, planning assumptions and inputs that may be used in the development of a utility's Integrated Resource Plan. Any interested party that attends the public workshop may also provide written feedback to the electric utility and the Commission within twenty-five (25) days following the workshop.

3. No later than forty-five (45) days prior to an electric utility filing its Integrated Resource Plan, the electric utility shall notice and conduct a technical conference for those interested parties that have executed a nondisclosure agreement in accordance with Section 108 of this Rule. The technical conference shall also take place in the Commission's hearing room in Jackson, Mississippi. The purpose of the technical conference is for the electric utility to provide an overview of the process, planning assumptions and inputs ultimately used to develop its Integrated Resource Plan, and to answer questions related thereto. Interested parties that participate in the technical conference may provide additional written feedback to the utility and the Commission within twenty-five (25) days following the technical conference.
4. Electric Utilities subject to the provisions of this Rule shall file their first Integrated Resource Plan in their respective IRP dockets no later than twelve (12) months after issuance of the Commission's Final Order Approving this Rule. Each successive Integrated Resource Plan shall be filed in the same IRP docket no later than three (3) years thereafter. Each successive IRP cycle shall begin with the filing of a Notice of IRP Cycle and shall follow the schedule provided herein.
5. The filed Integrated Resource Plan shall include as a confidential appendix a set of work papers showing the key inputs used by the utility in developing the Plan. Interested parties may obtain copies of these work papers in accordance with the Confidentiality provisions of Section 108 of this Rule.
6. Within sixty (60) days of a utility filing its Integrated Resource Plan, any interested party may file comments addressing the Integrated Resource Plan. The Mississippi Public Utilities Staff ("Public Utilities Staff" or "Staff") shall have eighty (80) days from the IRP filing date to file any comments on the Plan. Initial Data Requests may be served upon the utility within thirty (30) days of the utility filing its Integrated Resource Plan.
7. Utilities may provide a response to any such comments no later than one hundred (100) days after the filing of its Plan.
8. The Commission shall review the Integrated Resource Plan and note any deficiencies within one hundred twenty (120) days after its submittal by the utility. The Public Utilities Staff shall assist the Commission with its review. If the Staff believes the use of consultants is necessary or helpful in its review of any Integrated Resource Plan, the utility shall be required to pay for the cost of such consultants and allowed to recover said costs in rates.
9. The Commission may require the utility to re-evaluate and resubmit its Integrated Resource Plan for the current planning cycle to address any concerns raised in the comments or expressed by the Staff or Commission.

10. Absent deficiencies, the Integrated Resource Plan review is concluded one hundred twenty (120) days after submittal of the Integrated Resource Plan by the utility.

106 Mid-Point Supply-Side Update

At approximately the mid-point of the electric utility's three-year planning cycle, regulated electric utilities shall file in their respective IRP dockets a written report describing any material changes to the Integrated Resource Plan, including material changes in economic assumptions (*e.g.*, future natural gas price forecasts or alternative technology costs), environmental rules and regulations, regional transmission organization rules, 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 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 be satisfied through a competitive solicitation for engineering, procurement, and construction services or long-term power purchase agreements. 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.

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 of the Commission's final approval of this Rule, each utility 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 shall be required to pay for the cost of such consultants and allowed to recover said costs in rates.

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

a. Design

Electric and Gas Utilities regulated by the Commission shall implement a Demand Side Management ("DSM") Portfolio for customers that is 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

programs in the DSM portfolio.

Well- designed DSM 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, distributed energy resources, and strategic load growth as specifically defined herein.

Energy conservation and efficiency may 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 may 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). Distributed energy resources (e.g., energy storage) are another option.

Strategic load growth may benefit customers through increased use of utility services 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). The purpose of strategic load growth programs should be to incentivize the more efficient usage of utility infrastructure and resources. In order to ensure that strategic load growth programs are beneficial to all customers and do not conflict with energy efficiency policies established in this Rule, any strategic load growth project or program shall require Commission approval.

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.

Electric and Gas Utilities must demonstrate that they have evaluated the cost-effectiveness of their proposed demand-side management investments at a portfolio level 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.

Electric and Gas Utilities shall also include in their Annual Energy Delivery Plans the inputs and assumptions used in their cost-effectiveness analyses. 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. For utilities operating under formulary rate plans, reduced revenues resulting from energy efficiency measures are already addressed in the existing plans. 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, where applicable, an opportunity to earn a reasonable return thereon.

In its Energy Delivery Plan, each utility may propose an approach to earn a return on demand-side management investments in its Formula Rate Plan in order to place such investments on more equal footing with other supply-side resource and infrastructure investments on which utilities earn a return. Each year, the utility shall identify in its Energy Delivery Plan the specific demand-side management investments on which the utility seeks to earn a return as well as the specific demand-side management costs the utility intends to expense in the upcoming calendar year. The method reflected in the Energy Delivery Plan shall also be reflected in each utility's annual Formula Rate Plan filing and subject to approval by the Commission as part of the annual Formula Rate Plan review.

Demand-side management investments may include, but are not 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, must be incorporated under and meet the cost effectiveness requirements described in this rule.

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 prudently incurred over or under recovery of actual expenditures in an annual period, may be allowed in the formula rate plan test year.

Every three years, unless modified by the Commission, the Staff may review and comment on the cost recovery approach(es) utilized by each utility with respect to demand-side management investments and expenditures.

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. If Staff believes the use of consultants is necessary or helpful in its review of a utility's EM&V analyses, the utility shall be required

to pay for the cost of such consultants and allowed to recover said costs in rates.

2. Distributed Energy Resources (“DER”)

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 electric 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 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 contract work costs. Therefore, utilities may remove all vegetation management contract work costs and Commission-approved grid resiliency costs from base rates and reflect them through an alternative exact cost recovery mechanism. If a utility continues recovery in its Formula Rate Plan, such utility may defer and amortize such costs over five years with Commission approval.

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 per year of utility charitable contributions to non-affiliated organizations that directly aid low-income customers to foster increased access to demand-side management and DER options. To further workforce and economic development, utilities shall be allowed to recoup as cost of service an additional \$350,000 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 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 DER¹ 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. 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. Within the Annual Energy Delivery Plan filing, the utility shall set out its

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

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 and new technologies to aid in providing public utility service). The Commission encourages utilities to make new investments that incorporate, in some measure, all three components.

To encourage investment of the type mentioned above and which are hereby deemed to promote the public interest, the Commission creates by operation of this Rule what 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 fiber optic infrastructure 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 fiber optic infrastructure – while real – are difficult to quantify. To allow utilities to more quickly modernize their services and communications through fiber infrastructure expansion, utilities that are rate regulated by the Commission may, on an annual basis, invest up to \$10 million in fiber infrastructure (or other utility communication technology that could, as a secondary benefit, enable internet access) that extends to the utility’s customers’ premises. Such investment shall be recorded to a regulatory asset to be included in the utility’s rate base, subject to Commission approval in the utility’s annual formula rate plans, 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.

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

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.

Within thirty (30) days of the effective date of this Rule, each electric utility subject to the Rule shall submit to the Commission a non-disclosure agreement for the Commission to maintain on file. Any interested party may obtain a copy of the electric utility's confidential IRP work papers upon filing with the Commission and serving upon the utility an executed copy of the relevant utility non-disclosure agreement. Interested parties may execute such non-disclosure agreements at any time once an electric utility has filed its Notice of IRP Cycle, and are encouraged to do so in advance of the stakeholder technical conference(s) required by this Rule.

109. Waiver

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