BEFORE THE
LOUISIANA PUBLIC SERVICE COMMISSION

DOCKET NO. R- R-36227

LOUISIANA PUBLIC SERVICE COMMISSION, EX PARTE

In re: Assessment of Louisiana's current electric utility infrastructure for resilience and hardening for future storm events.

FINAL PROPOSED RULE

OVERVIEW AND PROCEDURAL HISTORY

This docket was opened based upon a directive made at the November 17, 2021 Business and Executive Session ("B&E") whereby Commissioner Greene directed Staff to: "... open a docket and use whatever means necessary, including but not limited to, the hiring of an independent engineering firm to assess the current electric utility infrastructure in Louisiana and proposed a plan of resilience and hardening that could better prepare Louisiana's electric grid for future storms and interruptions.." Pursuant to that directive, Docket No. R-36227 was opened on December 22, 2021, with notice being published in the Commission's Official Bulletin dated December 23, 2021. David Williams was hired by the Commission at the March 30, 2022 B&E, while CSRS was hired by the Commission at the April 27, 2022 B&E, both to assist Staff with this docket.

On notice that Docket No. R-36227 was opened, timely interventions were received from Cleco Power, LLC (Cleco Power), the Association of Electric Cooperative Members (ALEC), Southwest Louisiana Electric Membership Corporation (SLEMCO), Lafayette Utilities System (LUS), Louisiana Energy Users Group (LEUG), Packaging Corporation of America (PCA),

(LUS), Louisiana Energy Users Group (LEUG), Packaging Corporation of America (PCA), Southwestern Electric Power Company (SWEPCO), the Alliance for Affordable Energy (Alliance), Northeast Louisiana Power Cooperative (NELPCO), Entergy Louisiana, LLC (ELL). Untimely interventions were filed by International Paper Company (IP), Together Louisiana (TLA), and the Environmental Defense Fund (EDF), which were granted. The Internet and Television Association (LCTA) and the City of New Orleans requested Interested Party Status, which was also granted.

On January 10, 2023, Staff filed its *Request for Information from ELL, Request for Information from Cleco Power, and Request for Information from SWEPCO.* Staff received responses from multiple Intervenors, as well as from the subjects of the *Requests*. On April 14, 2023, Staff filed its *Draft Rules Regarding Electric Utility Grid Resilience Plans and Related Review*. Multiple Intervenors filed comments in response. In response to those comments, on June 15, 2023, Staff filed its *Draft Proposed Rule*. On August 2, 2023, Staff held a Technical Conference, attended by multiple Intervenors. On August 4, 2023, Staff informally provided a working draft of the Rule to all of the Parties.

Taking into account all comments received on the Draft Proposed Rule, Staff proposes the Final Proposed Rule ("Final Rule"), attached hereto as Attachment A for Commission consideration at an upcoming B&E. A copy of the Final Rule in tracked changes from Staff's Draft Proposed Rule is attached hereto as Attachment B.

ANALYSIS

General Comments

Several Intervenors expressed support for the Commission's efforts to require electric utilities to develop Grid Resilience Plans (GRPs) and to include in the Rule guidelines and requirements for the methods to be used and components to be included in such plans. Other Intervenors proposed alternate methods, while other Intervenors opposed the implementation of the Rule in general.

Section 101: Definitions

This section includes the key terms and definitions used throughout the Rule including any newly established terms such as GRPs, Grid Resilience, and Grid Interruption but also many existing terms previously established by the Commission in prior rulemaking and relevant to this Rule. One important distinction made in the definitions section and throughout the Rule is difference between Grid Reliability and Grid Resilience. The Louisiana Energy Users Group requested that the definition for Forced Interruption/Grid Interruption include reference to equipment failures that arise from improper operation or maintenance of equipment or human error. Staff did not amend this definition as the intent and focus of this Rule is on outside influences on the electrical grid such as extreme weather events, physical attacks, and other factors outside of operations and maintenance.

SECTION 201. Requirement to File a Grid Resilience Plan

This section directs each Utility to file a GRP no later than December 31, 2024, and describes how the Commission will treat each filing as a docketed proceeding with a procedural

schedule based on the initial filing date, which will include the Commission's review, evaluation, possible modifications, working towards Commission Acknowledgment. Intervenors shall also be allowed to participate in the docket through written comments, technical conferences, and formal discovery. Collaborative provision of information by the Utilities on their analysis and plans is highly encouraged and expected. Utilities shall be allowed to present revisions and resubmissions of their GRP after receipt of comments from the Commission and stakeholders.

Several Intervenors expressed concern that stakeholders with an interest in any Utility's GRP, especially the potential costs to ratepayers that may result, have ample opportunity to have their interests heard and addressed. Staff ensured that clear and detailed language was included in this section clarifying the rights of Intervenors to participate in each docketed proceeding that would be carried out from a Utility's GRP filing.

SECTION 301. Utility Scope of Responsibility

This section describes how each Utility required to file a GRP must assess all assets and systems under its ownership and/or direct management or control within its designated service area but are not responsible for developing solutions for assets or systems outside of their designated service area. However, each Utility is expected to contemplate how any dependencies on partner companies for grid services such as generation and/or transmission may impact the resilience of the electrical grid in their service area, and conversely, how its proposed actions may benefit or negatively impact partner utilities operating outside of its service area.

SECTION 401. Minimum Standards

In this section, the Rule describes how the standards and requirements included shall be considered the minimum level of responsibility required by each regulated Electric Utility and that Utilities are invited and encouraged to develop and submit GRPs that exceed the standards referenced herein.

SECTION 501. Review and Evaluation Procedure

This section lays out the process whereby the Commission will review and evaluate the filed plan. This section clarified that the Commission will first review and evaluate the plan to determine if it meets the standards and requirements of a GRP as stated in the Rule. After review by the Commission, including any revisions and resubmissions by the Utility, the Commission shall acknowledge whether or not the Utility has completed the GRP submission as required by this Rule. The determination of whether Utility proposals for individual projects within the GRP, project spending levels and cost recovery from ratepayers is prudent and in the public interest shall be addressed by the Commission in subsequent certification proceedings to be conducted under the LPSC Rules of Practice and Procedure.

This section was the subject of many written comments from Intervenors and discussion during the technical conference, held on August 3, 2023. In response to these comments from several Intervenors, Staff revised the original language to clarify that acknowledgement by the Commission shall not constitute approval of the GRP or any of the projects, project spending, or cost recovery proposed therein. Further, Staff clarified that if, and only if the Utility requested

additional ratepayer funds to implement its GRP, would a subsequent certification proceeding be conducted.

SECTION 601. Reporting, Monitoring, & Accountability

This section describes how, to the extent the Commission grants certification of a Utility's projects and proposals submitted in its GRP application, the Commission will require reporting by the Utility on implementation progress and associated metrics, not less than semi-annually.

Some Intervenors discussed how the reporting requirements could significantly raise the costs of carrying out a GRP plan and its implementation. Others raised concerns about how to develop performance metrics to measure resilience. The Staff addressed these concerns by providing significant control and leeway to Utilities to propose their own reporting metrics to track their plan's implementation and measure its outcomes and benefits.

SECTION 701. Planning Cycle

This section requires each Utility use a 10-year outlook for the proposed resilience investments and activities in its GRP and include a five-year implementation plan detailing the proposed schedule of the specific projects and activities to be completed in the first five years and the associated costs and benefits of each project, where applicable. Utilities shall provide an estimated implementation budget for both the ten-year outlook and five-year implementation plan.

SECTION 801. Confidentiality

This section clarified that Utilities may pursue confidentiality protections for portions of their GRP and certification application as may be appropriate pursuant to Rule 12.1 of the Commission's Rules of Practice and Procedure.

SECTION 901. Required Elements of a Grid Resilience Plan (GRP)

This section describes how the following are required elements of a GRP and Appendix I. provides detailed instructions and guidance on the means and methods to be used in carrying out each element of the plan.

1. Risk Assessment with Quantitative Risk Modeling
2. Vulnerability Assessment
3. Consequence Scenarios Assessment
4. Final Grid Resilience Projects List & Map with Project BCA and BCR
5. Estimate of Proposed Funding and Financing
6. Performance Metrics and Regular Reporting

There was detailed discussion in the technical conference and extensive comments from Intervenors on the various required elements of the Rule. In each case, Staff reviewed the comments and either acknowledged the comment without a corresponding revision or made revisions to address the comment or concern. The greatest areas of concern included ensuring that the Utilities adequately demonstrated that the proposed investments provided commensurate benefits, that the requirements on Utilities were not overly onerous and that Utilities could, subject to Commission approval, recover the expenses associated the implementation of the plan. Staff addressed these and other concerns by providing flexibility within the Rule for the Utility to

customize their plans accordingly while placing the responsibility on the Utility to develop a plan that meets the needs of their service area, customers, and business model.

STAFF RECOMMENDATION

Based on the foregoing analysis and the analysis included in Staff's Initial Proposed Rule and Revised Proposed Rule, Staff proposes the Final Rule attached hereto as Attachment A for Commission consideration and adoption. **The attached Final Rule is anticipated to be considered at the Commission's September 20, 2023 Business and Executive Session.**

Respectfully submitted,

W. Noah Hoggatt (No. 36987)
Louisiana Public Service Commission
602 N. Fifth Street, Galvez Bldg., 12th Fl.
Baton Rouge, Louisiana 70802
Ph. (225) 342-9888

CERTIFICATE OF SERVICE

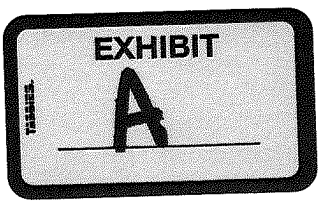
I hereby certify that a copy of the above and foregoing has been served upon all parties of record by email properly addressed on this 30th day of August, 2023.

W. NOAH HOGGATT

ATTACHMENT A

RULES REGARDING ELECTRIC UTILITY

GRID RESILIENCE PLANS



LOUISIANA PUBLIC SERVICE COMMISSION

RULES REGARDING ELECTRIC UTILITY

GRID RESILIENCE PLANS AND RELATED REVIEW

PURPOSE

The Louisiana Public Service Commission ("Commission" or "LPSC") hereby promulgates the following rules (the "Rules") in an effort to establish formal procedures applicable to Electric Utilities subject to the jurisdiction of the Commission. These Rules are intended to set the guidelines and requirements for utilities to develop Grid Resilience Plans ("GRP"s).

Consequently, the Commission finds it necessary to establish these Rules to require Electric Utilities to develop and provide the Commission with GRPs to enhance the state's potential collective ability to withstand, adapt to, and recover from risks posed to the electrical generation, transmission, and distribution systems, thereby potentially reducing the negative impacts of Forced Interruptions to ratepayers, customers, critical facilities, and the general public by reducing restoration costs, economic impacts, and secondary consequences of Grid Interruptions, especially those caused by low-probability/high-consequence events.

Each Electric Utility shall have its own GRP, which shall encompass the Electric Utility's Risk, Vulnerability, and Consequence Assessments, Grid Resilience Projects List, Proposed Funding Plan, and any other elements as determined by the Commission.

AUTHORITY

Article IV, Section 21 of the Louisiana Constitution of 1974 provides the Commission with the following authority:

> B. **Powers and Duties.** The Commission shall regulate all common carriers and public utilities and have such other regulatory authority as provided by Law. It shall adopt and enforce reasonable rules, regulations and procedures necessary for the discharge of its duties, and shall have other powers and perform other duties as provided by Law.

Consistent with the above authority, the Commission has adopted the following rules and regulations that apply to all Electric Utilities under its jurisdiction.

Rule-making Context and Background

Louisiana has experienced several extensive, multi-day electric Grid Interruption events in recent years, resulting in massive economic damages and loss of life. There is broad consensus that these events have been caused by a combination of factors, including Louisiana's risk profile as a place with a relatively higher likelihood of receiving the most intense and direct impacts of widespread disasters1 and an Electrical Grid which has not been designed, constructed, or upgraded to adequately mitigate these risks including the strength to withstand extreme winds, the elevation to avoid flood damages, and the winterization to minimize the impacts of extreme freeze events.

As a result, Louisiana ratepayers are now experiencing the increasing costs of restoration from several major extreme weather events. In 2022 and 2023 alone, the Commission has approved over

[1] NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2023).

$4B in storm restoration costs, all of which are passed through to ratepayers through cost recovery riders in conjunction with the securitization process. It is generally acknowledged that there is potential that these costs could be reduced in future extreme weather events by proactively and reasonably investing in equipment replacements and upgrades, system modernization, enhanced vegetation management, and operational improvements. It is also possible that the impacts of outages could possibly be further mitigated with the addition of redundancy throughout the system in the form of distributed generation and/or energy storage to provide backup grid services. These investments, collectively, could potentially reduce restoration costs by decreasing the amount of damage the systems sustain, reducing the time and materials required to conduct this restoration, and reducing the price of materials and labor as improvements would be conducted proactively, rather than reactively. Further, these improvements would potentially reduce the economic and social costs to households, businesses, and governments by reducing the extent and duration of major Grid Interruptions.

While the risks to infrastructure of all kinds from natural and human-made causes appear to be increasing, so too is the science and practice of resilience, or "the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents." 2 The Commission's effort in this rulemaking aligns with the trend around the United States wherein public Utility commissions are increasingly requiring utilities to develop plans to mitigate future risks. Further, the federal government is making substantial investments in Grid Resilience within the Infrastructure Investment and Jobs Act (IIJA) and this rule-making initiative

[2] Presidential Policy Directive 21 (PPD-21): Critical Infrastructure Security and Resilience

can position Louisiana communities and utilities to better compete for those funds. The ultimate goal of this initiative is to mitigate the impacts of a broad range of risks to Louisiana's Electrical Grid and the associated economic and social consequences that can result from these impacts.

With this Rule, the Commission intends to set the guidelines and requirements for GRPs and to ensure that Utilities develop GRPs that meet the Commission's requirements while customizing the strategies, investments, and activities to their organization, service area, and particular challenges and opportunities. Since Utilities are the entities with the most knowledge of and expertise in their systems and service areas, they are in the best position to assess the risks, vulnerabilities, and opportunities for improvement. This Rule provides the procedures for the Commission to receive and review the Utilities' GRP, allow for Stakeholder participation and input, and acknowledge whether or not the Utilities have completed the required GRP submission. The Rule further establishes certification procedures through which Utilities shall pursue Commission approval of GRP projects, project spending levels and any cost recovery plans, and to determine whether they are prudent and in the public interest. Nothing in this Rule predetermines whether GRP project spending by Utilities is prudent or in the public interest, or commits the Commission to grant certification approval of any GRP project, GRP spending, or cost recovery proposals. Further, the Commission does not intend for this rule to interrupt, displace, or replace any existing practices, systems, or strategies that Utilities use to carry out their regular operations but to augment the Utilities' practices to include Grid Resilience, especially as a distinct activity from Reliability.

Reliability, as defined herein, can generally be considered the ability of the power system to deliver Electrical Energy as demanded by users, under circumstances other than extreme or extraordinary operating conditions. In other words, Reliability means that Energy is available when expected.

Under extreme or extraordinary operating conditions, uninterrupted delivery of Electrical Energy cannot always reasonably be expected. The probability of extreme weather conditions requires that the Commission and Utilities look beyond the current standards, practices, and metrics required by Reliability standards and regulations to focus on low-probability/high-consequence events and what additional measures are needed to mitigate the impact of these events, recognizing that entirely eliminating Grid Interruptions under these extreme circumstances is not likely to be feasible. While some Reliability standards and metrics can be useful and applicable to Grid Resilience, they must be adapted to reasonably consider extraordinary circumstances. While Reliability metrics, standards, and regulations have been well-established and in effect for many years, the science and practice of Grid Resilience is relatively new and without equivalent national standards. By promulgating this Grid Resilience Rule, the Commission intends to start the process of defining how Utilities should undertake Grid Resilience planning and investment, recognizing that these requirements and practices will need to be refined over time as the state of Grid Resilience science and practice evolves.

SECTION 101. Definitions

1. Acknowledgment - A GRP will be deemed Acknowledged when the Commission determines that the submitted plan sufficiently adheres to the requirements set forth herein. Acknowledgment solely constitutes the Commission's Acknowledgement and recognition that the Utility's submission complies with the filing requirements set forth herein. Acknowledgment does not constitute approval, authorization, or a determination of prudence or public interest of the assessments, plans, actions, budgets, or any other component of the GRP.

2. Advanced Metering Infrastructure (AMI) - Systems that use two-way communications to read Utility meter data remotely and automatically, and perform other related functions.

3. Assets/Electrical Assets - Equipment used primarily for the generation, transmission, distribution, and delivery of electricity, including generation facilities, interconnection facilities, electrical substations, power lines, transmission towers, distribution poles, switches, meters, and other similar electrical infrastructure assets.

4. Benefit-Cost Analysis (BCA) - A systematic process for identifying, quantifying, and comparing expected benefits and costs of an investment, action, or initiative.

5. Benefit-Cost Ratio (BCR) - The ratio of the benefits of a project, expressed in monetary terms, relative to its costs, also expressed in monetary terms, typically expressed in discounted present values.

6. Catastrophe (CAT) modeling - A probabilistic tool used to estimate losses and simulate potential financial catastrophes using computer-assisted calculations. Insurance companies often use CAT models to evaluate and manage devastating risks from natural disasters like hurricanes, earthquakes, floods, and wildfires.

7. Commission/LPSC - The Louisiana Public Service Commission.

8. Customer - A (i) natural person or (ii) a single juridical entity, including any of its affiliated companies which are affiliated through common ownership, who receive, and pay for, Service from an Electric Utility.

9. Interruption Duration - The period of time that begins when electrical service is lost to a customer and ends when service has been restored to that customer.

10. Customer Minutes Interrupted (CMI) - The number of minutes a customer loses electrical service.

11. Demand/Electricity Demand - The rate at which electrical energy is delivered to or by a system, part of a system, or piece of equipment, at a given instant or averaged over any designated period of time. Electricity Demand is usually measured in kilowatts (kW). Rate Schedules and Rate Riders may utilize varying definitions of Demand as necessary for billing purposes.

12. Demand-side Management - Includes but is not limited to energy efficiency, demand response, distributed generation and storage, smart grid, water-energy measures, electric vehicle hardware, and innovative rate design.

13. Distributed Energy Resource (DER) - Geographically-distributed energy generation and storage, usually connected to a distribution grid.

14. Distributed Generation (DG) - Electricity generation that is not centralized and connected to transmission, but rather is decentralized and connected to distribution. DG individual units are typically much smaller in generation capacity than centralized generation plants.

15. Distribution System - That portion of an electrical system that delivers Electric Energy from transformation points on the transmission system to the customer. The distribution system is

generally considered to be anything from the distribution substation fence to the customer meter.

16. Electrical Grid - The electrical power system network comprised of the generation, transmission, and distribution systems and all their component parts and integrated operating systems including software, switches, transformers, substations, meters, etc.

17. Energy/Electrical Energy - The amount of electricity used or consumed by a Customer for a specific period, usually measured in kilowatt hours (kWh) or megawatt hours (MWh).

18. Electric Utility/Utility - any person furnishing electrical service within this state, the parish of Orleans excepted, including any electric cooperative transacting business in this state, provided, however, that said term shall not be construed to apply to any person owning, leasing and/or operating an electricity generation facility provided such person is not primarily engaged in the generation, transmission, distribution, and/or sale of electricity, and provided that such person: (a) consumes all of the electric power and energy generated by such facility for its own use at the site of generation or at some other location if mutually acceptable agreements to transport such electric power and energy can be reached with each electric public Utility whose transmission facilities would be electrically utilized therefor, provided, however, notwithstanding any provision contained herein, there shall be no obligation or duty, expressed or implied, to purchase, to sell, to transport, or to engage in any other type of transaction with respect to the electric power and energy that may be generated by such person, imposed upon any public Utility by this Section except as shall be provided in the cogeneration rules and regulations adopted by the Louisiana Public Service

Commission pursuant to the Public Utility Regulatory Policies Act of 1978; or, (b) only consumes a portion thereof in such manner and sells the entire remaining portion of such electric power and energy generated to an electric public Utility as herein defined; or, (c) sells the entire production of electric power and energy generated by such facility to an electric public Utility as herein defined. Notwithstanding anything to the contrary, an Electric Utility shall not include any Municipal entity providing electric service to its citizens, unless it elected to be regulated by the Commission pursuant La. Constitution Art. 4 Section 21(C).

19. Forced Interruption/Grid Interruption - An Interruption that results from conditions or forces originating from outside of the Electrical Grid (wind, flooding, lightning, ice, vegetation, animals, cyber- or physical attacks, or unknown sources, etc.) or an interruption caused by improper operation of equipment or human error, or improper maintenance of equipment, or an intentional interruption required to relieve stress on a primary energy source or for safety purposes (load shed event).

20. Generation - The production or storage, or both, of Electrical Energy with the intent of enabling practical use or commercial sale of the available energy. This includes photovoltaic, wind-farm, hydroelectric, etc., as well as normal commercial and industrial thermal sources.

21. Grid Resilience - The ability of a physical Electrical Grid system and/or its operators to prepare for, adapt to, withstand, and recover from deliberate attacks, accidents, naturally occurring threats, or extreme weather events.

22. Grid Resilience Plan (GRP) - A filing before the Louisiana Public Service Commission, submitted by a Utility, as required by the rules herein and associated order, intended to meet the standards and requirements detailed herein.

23. Intelligent Grid/Smart Grid - An electrical power system that utilizes information exchange and control technologies, distributed computing and associated sensors and actuators.

24. Interruption - The loss of electrical service to one or more customers.

25. Load/Electrical Load - An electrical component or portion of a circuit that consumes (active) Electrical Energy.

26. Microgrid - Electricity distribution systems containing Loads and Distributed Energy Resources (such as distributed generators, storage devices, or controllable loads) that can be operated in a controlled, coordinated way either while connected to the main power network or while islanded.

27. Non-Wires Alternative (NWA) - an electrical grid investment that is intended to provide a substitute for or remove the need to construct or upgrade components of a distribution and/or transmission system.

28. Numerical Weather Model (NWM) - a quantitative tool that uses weather data to forecast different types of weather, including wind speeds, precipitation, temperature, barometric pressure, and other meteorological elements. NWMs can be customized to create visual representations depending on specific meteorological needs.

29. Quantitative Risk Modeling/Modeling - A method for risk analysis where numerical values are assigned to both impact and likelihood based on statistical probabilities and monetarized valuation of loss or gain.

30. Rate - Any compensation, charge, fare, toll, rental, or classification that is observed, charged, or collected by an Electric Utility for a Service, product or commodity it provides as allowed by law.

31. Rate Rider - An additional Rate or charge to be applied to a Customer bill that is separate and distinct from the basic Rates paid under the Customer's applicable Rate Schedule. Typically, Rate Riders are applied to more than one Rate Schedule, although that is not a requirement. Commonly used Rate Riders include, but are not limited to:

    a. Formula Rate Plan Rider (FRP) - A Rate Rider that defines the procedure by which the Rates contained in Rate Schedules may be periodically adjusted.

    b. Fuel Adjustment Clause (FAC) - A mechanism, the inputs to which are updated on a monthly basis, that provides for recovery of an Electric Utility's fuel costs.

32. Rate Schedule - A schedule included within an Electric Utility's Tariff, which provides the various Rates for particular classes for which the Utility anticipates offering Services under. Each specific Rate Schedule shall include: 1) Type of electric Service provided under the Schedule; 2) Rates and charges associated with Service under the Schedule; 3) All classification(s) of Customers which could be included under the Schedule; and 4) All practices, rules or regulations which specifically apply to the Services under the Schedule.

33. Reliability - The probability that a system will perform its intended functions without loss of service, within design parameters, under specific operating conditions, and for a specific period of time. In the Utility industry, reliability is often expressed as system reliability indices, for example Customer Average Interruption Duration Index (CAIDI), Average Service Unavailability Index (ASUI), and many others.

34. Scheduled Interruption - An Interruption that results when a component of the Electric Grid is deliberately taken out of service at a selected time for purposes of construction, preventive maintenance, or repair.

35. Substation - An assemblage of equipment for purposes other than generation or consumption, through which electric energy in bulk is passed for the purpose of modifying its characteristics. Service equipment, distribution transformer installations, or other minor distribution or transmission equipment are not classified as substations. A substation is of such size or complexity that it incorporates one or more buses, a multiplicity of circuit breakers, and usually is either the sole receiving point of commonly more than one supply circuit, or it sectionalizes the transmission circuits passing through it by means of circuit breakers.

36. System Average Interruption Duration Index (SAIDI) - The average amount of time a customer's service is interrupted during the reporting year. SAIDI = Sum of all Customer Interruption Durations divided by Total Number of Customers.

37. System Average Interruption Frequency Index (SAIFI) - The average number of times that a customer's service is interrupted during the reporting year. SAIFI = Total Number of Customer Interruptions divided by Total Number of Customers.

38. Tariff - The all-encompassing document filed with and approved by the Commission, to which an Electric Utility provides Service. An Electric Utility's Tariff contains rules to address the responsibilities and authorities of the Utility as it relates to its various Customer classes. Such rules shall address, but are not limited to: Rates, allocation of costs for line extensions, and allocation of costs for new Customer connections. The Tariff shall also include other issues which define the responsibilities and authorities of the Electric Utility. The Tariff shall include, but is not limited to: Rate Schedules, Rate Riders, and Terms of Service.

39. Terms of Service - Terms included within an Electric Utility's Tariff that are intended to facilitate the rendering of uniform, efficient and adequate Service to the various Customer classes of the Utility. Specifically, the Terms of Service defines the responsibilities, obligation, and authorities the Utility possesses in exchange for its provision of Service to Customers, as well as the responsibilities and obligations of Customers in exchange for receiving Service.

40. Service - The sale or distribution of Electric Energy by a public Utility in the performance of the Electric Utility's responsibilities.

41. Transmission System - An interconnected group of electric transmission lines and associated equipment for the movement or transfer of electric energy in bulk between points of supply and points for delivery.

SECTION 201. Requirement to File a Grid Resilience Plan

For reasons of the health, welfare, and safety of Louisiana citizens, each Electric Utility is hereby directed to develop and submit a Grid Resilience Plan (GRP) as soon as possible. Each Utility required to submit a GRP shall file their initial plan no later than December 31, 2024. The Commission will establish a procedural schedule based on the initial filing date, which will include the Commission's review, evaluation, and possible modifications, working towards Commission Acknowledgment. Stakeholders shall also be allowed to participate in the docket through written comments, formal discovery, and technical conferences, when deemed appropriate. Collaborative provision of information by the Utilities on their analysis and plans is highly encouraged and expected. Utilities shall be allowed to present revisions and resubmissions of their GRP after receipt of comments from the Commission and stakeholders. After review by the Commission, including any revisions and resubmissions by the utility, the Commission shall acknowledge whether or not the utility has completed the GRP submission as required by this rule. Acknowledgement by the Commission shall not constitute approval of the GRP or any of the projects, project spending, or cost recovery proposed therein. The determination of whether utility proposals for individual projects within the GRP, project spending levels and cost recovery from ratepayers is prudent and in the public interest shall be addressed by the Commission in subsequent certification proceedings to be conducted under the LPSC Rules of Practice and Procedure.

SECTION 301. Utility Scope of Responsibility

Unless otherwise determined by the Commission, each Utility required to file a GRP must assess all assets and systems under its ownership and/or direct management or control within its designated service area. Utilities are not responsible for developing solutions for assets or systems outside of their designated service area but are expected to contemplate how any dependencies on partner companies for grid services such as generation and/or transmission may impact the resilience of the electrical grid in their service area, and conversely, how its proposed actions may benefit or negatively impact partner utilities operating outside of its service area.

SECTION 401. Minimum Standards

The standards and requirements included in this rule shall be considered the minimum level of responsibility required by each regulated Electric Utility. Utilities are invited and encouraged to develop and submit GRPs which exceed the standards referenced herein; provided however, that any project and spending proposals by the Utility that exceed the minimum standards shall be identified and include cost/benefit justifications for consideration by the Commission.

SECTION 501. Review and Evaluation Procedure

Upon the filing of a Utility's GRP, the Commission will review and evaluate the filed plan and may involve in this review any additional outside counsel, engineers, and/or consultants, as determined at the Commission's sole discretion. The Commission reserves the right to Acknowledge any plan, in sum or in part, and to require specific revisions, additions, and/or supplementary information in order to comply with the minimum requirements of this rule. The Commission may, at its sole discretion, require as many rounds of revision and re-submission as it deems necessary for a plan to meet the requirements of this Rule. The Commission also reserves the right to not Acknowledge a

submitted GRP. The Commission will consider the completeness and quality of each GRP in this review and evaluation process. A checklist of required and optional GRP elements and sub-elements is included in Appendix V for the Utilities' convenience.

After the Commission has acknowledged that the Utility has completed the GRP submission as required by this rule, the Utility shall file an application with the Commission seeking certification of any GRP projects, project spending levels, and any cost recovery plans that pertain to the initial five year implementation plan set forth in the GRP, and such applications shall be docketed and considered under the Commission's Rules of Practice and Procedure. The Commission may involve in this review any additional outside counsel, engineers, and/or consultants, as determined necessary by the Commission.

The Utility shall bear the burden-of-proof in such proceedings that its GRP projects, project spending levels, and any cost recovery plans, are prudent and in the public interest. Nothing in this Rule commits the Commission to determine that GRP project spending by utilities is prudent or in the public interest or to grant certification approval of any GRP project spending or cost recovery proposals.

SECTION 601. Reporting, Monitoring, & Accountability

To the extent the Commission grants certification of a Utility's projects and proposals submitted in its GRP application in whole or part, the Commission shall require reporting by the Utility on implementation progress and associated metrics. Implementation progress reports shall be filed with the Commission not less than semi-annually. Stakeholders participating in the certification proceedings shall receive copies thereof subject to appropriate confidentiality protections.

SECTION 701. Planning Cycle

Each Utility shall use a 10-year outlook for the proposed resilience investments and activities in its GRP and shall include a five-year implementation plan detailing the proposed schedule of the specific projects and activities to be completed in the first five years and the associated costs and benefits of each project, where applicable. Utilities shall provide an estimated implementation budget for both the ten-year outlook and five-year implementation plan.

SECTION 801. Confidentiality

Utilities may pursue confidentiality protections for portions of their GRP and certification application as may be appropriate pursuant to Rule 12.1 of the Commission's Rules of Practice and Procedure.

SECTION 901. Required Elements of a Grid Resilience Plan (GRP)

Unless otherwise determined by the Commission, the following shall be required elements of a GRP:

1. Risk Assessment with Quantitative Risk Modeling
2. Vulnerability Assessment
3. Consequence Scenarios Assessment
4. Final Grid Resilience Projects List & Map with Project BCA and BCR
5. Estimate of Proposed Funding and Financing
6. Performance Metrics and Regular Reporting

The rigor of these requirements is tiered based on Utility size. The table below describes the required and optional elements for utilities above and below this threshold.

	Required GRP Element	Annual Sales > 4M MWh[3]	Annual Sales < 4M MWh
1.	Risk Assessment with Quantitative Risk Modeling	Required	Quantitative Risk Modeling Optional
2.	Vulnerability Assessment	Required	Required
3.	Consequence Scenarios Assessment	Required	Required
4.	Grid Resilience Projects List & Map with Project Benefit-Cost Analyses, where feasible	Required	Required
5.	Estimate of Proposed Funding and Financing	Required	Required
6.	Performance Metrics and Regular Reporting	Required	Required

Each of the required elements of a GRP is detailed in Appendix I, accompanied by prescriptive steps for each Utility to follow. Each Utility is expected to follow these steps but customize the approaches, analysis, data, and solutions to the characteristics of its service area, assets, and systems in a manner that best serves their customers.

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APPENDIX I

Minimum Standards for the Required Elements of a Grid Resilience Plan

Risk, Vulnerability, and Consequence Assessments

This first component of a GRP assesses the risks to the grid, their potential impact on electrical assets and systems, and the consequence of these impacts on ratepayers and communities. These components are composed of three distinct but related sections: a risk assessment, a vulnerability assessment, and a consequence assessment. Risks are threats that can cause damage to the grid or its components and/or interrupt electrical service and must be assessed for their potential severity and the probability that they will occur. Vulnerability is the amount of exposure various grid assets have to those risks and their susceptibility to being affected by those risks. Vulnerability can vary even if the risks are the same. For instance, two transmission towers in similar locations might face the same wind load risk but if one is built to newer, stronger standards and the other is older or not as strong, they have different levels of vulnerability to the same risk. Lastly, consequences, or the impacts of a Grid Interruption event can vary widely depending on who they affect and for how long.

Each of the three assessments described herein – risk, vulnerability, and consequence – should be conducted with sufficient granularity to provide a comprehensive assessment at the distribution feeder level. That is, the assessment should provide visibility into the specific conditions for each distribution circuit or feeder, thus identifying specific upgrades or solutions that are specific to the risks, vulnerabilities, and consequences at a granular level. Additionally, these assessments shall incorporate and describe how they have considered the increasing frequency and severity of extreme weather events.

Risk Assessment

The risk assessment component should be conducted as an all-hazards approach, meaning that any potential threat should be considered, even if only one or more risks is selected for mitigating activities. The assessment should not just focus only on the most recent or most severe risk experienced but should contemplate other types of risk that may have occurred less recently, less frequently, and even those that have never been experienced by the system but are potential risks nonetheless. While Utilities are expected to consider a broad range of risks, they are only required to develop and submit a complete risk assessment for at least one risk type and are expected to focus on the risk, or risks, that are most likely to cause widespread and/or long-duration Grid Interruptions.

A.1 Risk Assessment Instructions:

Step 1. List the ten largest grid interruption events, as measured in CMI, experienced in the service area over the five years preceding the year in which the GRP is being developed and include their causes. Include the total number of customers impacted by the Grid Interruption event, total CMI for each event and how these events compare to the Utility's annual SAIDI statistical mean for the past five years.

Step 2. List all potential risks that could cause major Grid Interruption events and rank them by relative importance from greatest threat to least threat.

Step 3. Identify the risks on the list that are likely to change in the future due to environmental or human factors, and the causes for changes in risk.

Step 4. Select the risk (or risks) to be assessed using Quantitative Risk Modeling. The Utility may choose to model more than one risk type (extreme heat, freeze events, high winds, floods, etc.) and should select the risks that are the most likely to create extended Grid Interruption and/or wide scale Grid Interruptions, with the greatest negative impact as measured by SAIDI scores. To be modeled

effectively, Utilities must acquire or generate data on event probability and impact. Each Utility must include their rationale for selecting the risks to be modeled. There is not yet a uniform modeling tool that can be mandated for assessing Grid Resilience. Utilities may use a reasonable estimate for expected Grid Interruption reductions derived from a model or source of their choosing; however, each Utility must provide all assumptions and inputs used to determine how Grid Interruption durations are expected to be reduced during various events as part of its submission.

Step 5. Model the risks and their probabilities, endeavoring to use the latest science and data available, to project future grid interruption events and their likely impacts. Demonstrate how the model accounts for projected risk increases due to environmental factors. Map these risks and their probabilities to the service area to visualize the spatial elements of the risk type. For instance, map floodplain areas or areas likely to be inundated in a 1% annual return interval for rainfall and/or storm surge events, and map areas with likelihood of experiencing tropical storm force winds. Where a risk type does not vary spatially across the service area or where this spatial analysis cannot be performed due to a lack of data or predictability, apply the risk uniformly across the entire service area. Types of models that Utilities may choose to use include but are not limited to are Numerical Weather Models and Catastrophe, or CAT, models. Utilities may use existing systems and platforms to conduct quantitative risk modeling provided these systems can adequately project the probability of future risk scenarios and thereby provide input to BCAs with reasonable rigor and accuracy.

NOTE: this step is required of Utilities with total annual sales of 4 million MWh but optional for those Utilities with less than 4 million MWh of annual sales.

Step 6. If cyber security is not among the top risks listed, provide a description of the Utility's activities to detect and address cyber threats to the Utility's systems. This description may be a summary drawn from other public reporting as required by the Commission and/or federal regulatory agencies or standards.

B. Vulnerability Assessment

In this step, each Utility evaluates the vulnerability of various assets under different risk types. This is done by applying the risk types to the current system and calculating the likely impacts. Current asset data on the various components of the system is critical for vulnerability assessment. Since factors such as vegetation levels, asset design, the age and condition of assets, elevation, soils, and many others affect the exposure and performance of an asset under threat, these factors must be known to assess vulnerability.

The Utility should apply the quantitative risk models to the Utility's current system to project the impacts of the risks on the system. Utilities that are not required to model the risks may estimate probabilities of occurrence and severity based on historical events and apply these risks uniformly across their service area. Utilities should apply this analysis across all elements of the system and all types of facilities and assets. Assumptions on the threshold for the failure of each asset, given its design and condition, and intensity of the threat, should be calculated based on recent events and current Utility asset data. The Utility can then determine what assets are expected to withstand certain conditions and where failure is expected.

Based on this analysis, several calculations can be made that will be necessary for developing BCAs, including the approximate time needed to restore power, the cost to repair or replace the asset to

current or higher design standards, and the number and type of customers that will be affected. If assets must be replaced, upgrades should also be evaluated and BCAs presented for both base replacement and upgrade of equipment to demonstrate whether the upgrade is cost-justified to customers. These estimates will be critical in determining which solutions are the best for mitigating the negative impacts of Grid Interruptions.

B.1 Vulnerability Assessment Instructions

Step 1. Using a geographic information systems (GIS) tool, map all Utility assets across generation, transmission, and distribution against the risk types that have spatial components to identify areas of risk, where applicable, and which assets have what level of exposure to these threats.

Step 2. Develop a set of assumptions for the threshold of failure of each asset given its design, age, condition, or other relevant factors, and the intensity of the threat. Include the assumptions used to establish the thresholds of failure.

Step 3. Run all assets through various risk scenarios included in the risk model and compare the results, showing which assets are projected to fail under which risk scenarios and event types. For Utilities not required to conduct quantitative risk modeling, identify and include in the GRP a list of assets most at risk of failure, the threats under which they are most vulnerable, and thresholds at which they are assumed to fail.

C. Consequence Assessment

This assessment should describe the consequences of Grid Interruptions by their impacts on different geographies within the service area, different types of customers, and the cascading impacts on downstream infrastructure systems.

C.1 Consequence Assessment Instructions

Step 1. Provide a map (using a GIS tool) showing critical infrastructure in the Utility's service area. For more resources on identifying critical infrastructure types, see Appendix II.

Step 2. Assess social vulnerability and the relative impacts of Grid Interruptions throughout the Utility's service area by mapping the risks and vulnerabilities onto a map of social vulnerability factors. For more resources on identifying vulnerable communities and populations, see Appendix II.

Step 3. Overly the maps of the Risk Assessment, the Vulnerability Analysis, and the Consequence Assessment, and identify in a list and accompanying map(s), critical loads, critical infrastructure and/or facilities, and disadvantaged communities and their associated risks.

NOTE: As part of developing the Grid Resilience solutions, as described in the following section, each Utility will develop a method by which to prioritize Grid Resilience investments and demonstrate how the prioritized activities support critical loads that serve infrastructure or facilities that provide essential response and recovery services, disadvantaged communities and/or customers, and/or enable other resilience investments that support one or both efforts.

D. Grid Resilience Projects List

The Utility shall compile a list of projects and initiatives for the various types of investments and improvements that could mitigate the impacts of the assessed risks and vulnerabilities. The investments and activities shall be organized into discrete projects and activities and prioritized on their cost-effectiveness for delivering the most resilience benefit. Appendix III. Grid Resilience

Project Types, contains a list of example projects types that Utilities can use in the development of their GRPs.

D.1 Preliminary Grid Resilience Projects List

Developing a more resilient Electrical Grid must be pursued across a range of scales, systems, equipment, and technology. Utilities are therefore encouraged to consider a range of strategies and project types and develop a comprehensive list of options, or a Preliminary Grid Resilience Projects List, before selecting a subset of investments to include in the Final Grid Resilience Projects List. The process of selecting, grouping, and assessing investments can be done iteratively with the benefit-cost analysis, where feasible, since some projects may have greater or lesser impact depending on how they are implemented in relationship to other investments.

As part of this process, Utilities are encouraged, but not required, to conduct an alternatives analysis to determine different ways to achieve similar outcomes and demonstrate why the proposed project is the best alternative to address the challenge. Similarly, Utilities are encouraged, but not required, to conduct a dependency analysis to identify which, if any, of the projects should be done together to yield the most benefits or completed in a specific order to facilitate others. Lastly, Utilities are encouraged, but not required, to consider the voluntary adoption of higher minimum standards to be used in all future restoration, upgrade, or replacement activities. Utilities are required to consider Non-wires Alternatives that are likely to provide Grid Resilience services including energy storage, microgrids, and other similar solutions as part of the Preliminary Grid Resilience Projects List.

Utilities are not required to include Non-wires Alternatives projects in their Final Grid Resilience Projects List but must provide an explanation of why these types of projects were not selected as proposed investments if not included.

D.2 Non-Wires Alternatives & Customer-based Solutions Request for Information

As part of the development of the Preliminary Grid Resilience Projects List, Utilities are encouraged, but not required, to solicit proposals for Non-Wires Alternatives and customer-based solutions through a request for information process. In doing so, the Utility could identify the communities and feeders most vulnerable to Grid Interruptions based on the Risk, Vulnerability, and Consequence Assessments, and publicly solicit proposed solutions through a Request for Information (RFI) for non-wires solutions to mitigate these risks and vulnerabilities and to increase customer and Grid Resilience. The Utility could also invite proposed solutions to mitigate risks at critical facilities beyond those identified as most vulnerable communities and feeders but which provide a localized resilience benefit.

The RFI could solicit proposals for mitigating the risks through third-party and customer-based solutions, including distributed energy resources (DERs), virtual power plants (VPPs), Microgrid, energy storage, and other solutions that can provide short-term and long-term Grid Resilience benefits to customers. The RFI could solicit from respondents the interconnection requirements in order to support the solution proposed. Based on these identified interconnection requirements, the Utility could identify any required infrastructure upgrades or improvements required to support the proposed non-wires solutions. The Utility could prepare a report summarizing the findings of the RFI to be included in GRP. The summary report would describe which, if any, of the proposed non-

wires solutions the Utility considers feasible and describe the Utility's proposed strategy to incorporate these non-wires solutions into its GRP.

D.3 Final Grid Resilience Projects List

Having evaluated the potential Grid Resilience investments, their costs, benefits, and contribution to the state's goals, Utilities will then compile their capital plan for Grid Resilience. While many, or even most, projects will be capital projects, some Grid Resilience investments may include non-physical improvements such as software or SCADA systems, capacity building and training for Utility staff and partners, plans and studies, or similar activities. The Utility's GRP should propose, in detail, the specific projects to be implemented, the method of implementation (directly by the Utility, via a 3rd party contractor, or partnership), the estimated timeline and sequence for implementation, and the detailed benefit-cost analysis information for each proposed project, if applicable. The Utility should be transparent in showing how it came to the calculations presented for each project and the method of project selection and prioritization used to develop the GRP.

Since adapting large infrastructure systems to future risks is a long-term process, GRPs should propose capital investments over 10 years. However, because costs, technology, regulations, and best practices are rapidly changing, the specific proposed investments for implementation should be proposed for a shorter period of five years. This will allow the Utility to update the GRP at least every five years, updating the methods and approaches and specific investment plans to adopt the best available science and technology.

D.4 Grid Resilience Projects List Instructions

Step 1. The Utility will organize proposed Grid Resilience activities into discrete projects to evaluate them for feasibility, costs, and benefits. Individual projects may be grouped into project packages by geography or by grid sub-components such as circuits, feeders, laterals, rights-of-way or similar, according to the Utility's rationale, which shall be outlined and explained.

Step 2. Where required, the Utility will then conduct BCA for each project to estimate the projected costs and benefits. This BCA will then be used to inform the alternatives analysis and prioritization of projects for the final projects list.

Step 3. For each project, the Utility should conduct an alternatives analysis, comparing various Grid Resilience investments that could address the same challenge and then demonstrate why the proposed project in the Final Grid Resilience Projects List is the best solution to this particular problem.

Step 4. The Utility should then conduct a dependency analysis to identify which, if any, of the projects should be implemented at the same time to yield the most benefits or completed in a specific sequence to facilitate others.

Step 5. The Utility will compile this information into the Final Grid Resilience Projects List, laying out the details of each proposed Grid Resilience investment and project. In its GRP, the Utility must present its proposed Grid Resilience investments and projects in at least as much detail as is described below, for every proposed project, program, or investment.

Step 6. The Utility will also display project information in a map format within the plan, showing the spatial distribution of proposed projects across its service area.

Final Grid Resilience Projects List format

Project name. A unique name for the initiative / investment / project.

Project number. A unique number associated with the project. This can be a sequential number of the projects in the list (1,2,3, etc.) or a unique identifier as defined by the Utility.

Resilience Challenge. A short description describing the risk(s) to be mitigated and the threat they pose to the grid and customers.

Project/Program Description. A synopsis describing what the proposed investment is and what it will do to build Grid Resilience.

Project Location. This can be in the form of an address if applicable, latitude-longitude coordinates if an address is not relevant and must, at a minimum include the Parish(es) and the LPSC region(s) in which the investment is located. System-wide investments such as a SCADA system upgrade or a demand-side management program offered throughout the service area can be listed as "System-wide" and do not require a specific geographic location.

Estimated Project Costs. The Utility's best available estimate of the project costs based on reasonable due diligence, presented in US dollars at their current value at the time the plan is developed, along with a short description of what efforts were made to estimate these costs and what variables may cause them to change in the next five years, and the class level of accuracy of the estimate, e.g. +/- 100%, 50%, etc.

Description & Calculation of Direct Benefits. A qualitative description of the specific types of benefits expected from the project, the extent of these benefits, and to whom they accrue, with a particular focus on benefits that accrue to disadvantaged communities, low-income communities and/or ratepayers, and critical infrastructure facilities / critical loads. For every project with a quantitative benefit-cost analysis, a detailed description of the calculations, assumptions, term, discount rates, escalation rates, average service life of project, and other inputs and methods used to develop the benefit calculation is required, along with the amount of benefits expected over the lifecycle of the project, expressed in US Dollars. Any benefits that cannot be quantified and/or monetized can also be discussed in qualitative terms. Each project with a quantified benefit-cost must also list its BCR. See the Benefit-Cost Analyses Resources section in Appendix II for additional information.

Note: Utilities are allowed to submit proposed projects with benefit-cost ratios of less than 1.0.

Description of Co-Benefits

Beyond the cost reduction and cost avoidance included in the standard BCA calculation, the Utility is encouraged but not required to include a qualitative discussion of any additional indirect benefits, or co-benefits, whether or not they can be quantified. Examples of co-benefits that a project could facilitate include grid modernization, remote management, increased safety features, energy storage, decarbonization, electrification, renewable generation and/or transmission, distributed generation, demand-side management, energy efficiency, and electric vehicle charging infrastructure, among others. Projects could facilitate these co-benefits by providing enhanced capacity for generation, transmission, or distribution, by improving automation and controls or remote management, or other

pathways as detailed by the Utility. Projects that provide these co-benefits may be prioritized for implementation by the Utility due to these merits.

D.5 Benefit-Cost Analyses

Conducting a BCA for individual projects and initiatives can be a critical step in the development of any resilience plan. Since resilience investments do not provide mitigation benefits in the form of reduced recovery costs, avoided losses, or the mitigation of other negative consequences unless and until the system is threatened, there is not a guarantee of the delivery of modeled benefits as there often is in an energy efficiency project where the projected benefits are more predictable. However, using the best available science on risks, the best available asset data on the system's design and current condition, and the most current data on costing and the benefits of avoided consequences, a Utility can make robust estimates of the potential benefit that a resilience investment can deliver. Utilities shall include project BCAs, wherever feasible, and wherever a BCA is not included, shall explain why a BCA cannot feasibly be calculated.

The goal of conducting a BCA is to demonstrate to those providing the investment, whether they be ratepayers, private investors, or government agencies, that the benefits of the project justify the costs. The additional goal for regulators is to be able to compare the relative benefits and cost-effectiveness of resilience investments across the Utilities under their jurisdiction. By having a common approach and methodology, regulators can be assured that they are authorizing commensurate investments across the various service areas, and that any cost recovery they may approve is defensible and beneficial.

Since many projects will not yet be scoped in detail at the time the Utility is first developing its GRP, the Commission expects planning-level BCAs using the best available costing and benefit data. Utilities are expected to develop their own BCA methods and disclose the methods and assumptions used to develop each project BCA, including discount rates, project lifespans, and similar variables typically used in BCA calculations.

There are various approaches and methods to develop a benefit-cost analysis. Some types of Grid Resilience projects require different methods because they offer additional benefits beyond reduced damages and avoided Interruption costs such as increased generation or storage, which can provide benefits under 'blue sky' conditions. Furthermore, as some benefits are hard to quantify and impossible to monetize, this rule allows for the inclusion of such benefits in the overall evaluation of a project's merits.

Benefit Calculations for Projects with BCAs

Direct benefits that must be calculated for projects with BCAs include the following components:

1. Avoided restoration costs
2. Avoided customer interruption costs

Restoration costs consist of capital and operational costs related to restoring power to customers after Grid Interruption events. The second category, avoided customer interruption costs, includes the economic burden that customers (of all types) incur due to the loss of electrical service. The Commission recognizes the inherent variability and uncertainty when estimating both avoided restoration costs and, especially, avoided customer interruption costs. Therefore, it is incumbent upon the Utility to provide the data sources, calculations, and assumptions that were used to estimate these costs and to ensure that they are reasonable. Avoided Utility lost revenues from avoided lost

customer load may not be included as a benefit in the BCA. See Appendix II for more resources on the Benefit Cost Analyses.

D.6 Redundant Power Programs or Projects

Since it is impossible to eliminate the risk of Grid Interruptions, it is critical that backup energy, or redundant power, be developed wherever feasible. This is especially true for facilities that provide essential services during an emergency and/or an extended Grid Interruption, and vulnerable communities. Utilities are therefore encouraged, but not required, to include redundant power programs or projects in their GRPs. Such programs or projects could offer the installation of on-site backup Electrical Energy generation and/or storage for the critical loads to be supported in the event of a Grid Interruption. Such programs should focus on providing backup power for facilities that provide critical services such as hospitals, nursing homes, pharmacies, grocery stores, fueling stations and electric vehicle charging stations, restaurants, and large retailers, and/or public and civic institutions which provide critical services during extended Interruptions such as police and fire stations, recreation centers used as temporary housing or recovery centers, transit centers, faith-based institutions, and other non-profit recovery centers. Any Utility including a redundant power program or project(s) in its Final Grid Resilience Project list must provide a description of the proposed program and/or projects, what facility(ies) or types of facility(ies) it is intended to serve, and how the proposed program or project(s) will be funded. Redundant facilities that would provide benefits beyond their redundancy, i.e., benefits to other customers on the grid, should be identified and explained.

E. Proposed Funding and Financing

Each Utility's GRP will include a funding and financing element which describes in detail the total proposed budget and the method and sources the Utility proposes to use to fund the implementation of the GRP. All potential sources should be considered including ratepayer funds, federal funds, private debt and equity, and funding provided by the Utility. The Utility shall demonstrate how the proposed funding and financing plan provides the best value to their customers and ratepayers and is equitable such that the cost burdens are distributed fairly, commensurate with the benefits.

Utilities may propose new revenue sources and/or a cost recovery mechanism as part of their GRPs. For any proposed use of ratepayer funds, the Utility must detail the proposed cost recovery mechanism, whether it be rate based or a rider, the term of a proposed addition to rate base or rider, whether it is volume-based or a flat rate by customer class, whether it seeks recovery on an equal percentage base revenue basis or other basis, whether it distinguishes cost recovery as between utility distribution and transmission system investments and the customers which use each such part of the system, and the approximate projected monthly costs to residential customers with monthly average consumption of 1,000 kWh, 1,500 kWh, and 2,000 kWh. The Utility must project the anticipated revenue from the cost recovery mechanism over the implementation timelines of the GRP. Further, the Utility must disclose its proposed rate of return for investments to be funded by the cost recovery mechanism. Utilities are not required to propose the use of additional revenue but, if so, must demonstrate how they propose to fund the proposed Grid Resilience investments without the use of additional revenue.

E.1 Existing Rate Mechanisms

Any Utility proposing the use of additional ratepayer funds to implement Grid Resilience investments which have existing rate mechanisms, or proposed rate mechanisms pending before the Commission, which provide funding for any activity, or similar activity, that is also proposed within the Utility's GRP, such as vegetation management, equipment upgrades, replacements to or hardening of the transmission and/or distribution systems, grid modernization, or others shall include a detailed accounting of how those funds have and will continue to be used and what additional projects, activities, and benefits will be supported with the proposed cost recovery mechanism. The Utilities shall describe, through detailed accounting and project delivery records, what projects and activities have been and will be supported by the existing and/or proposed cost recovery mechanisms. The Utilities will also demonstrate why the additional proposed funding included in the funding and financing section of their GRP is required to develop adequate resilience above and beyond what is supported by the existing rate mechanisms. Since each GRP will have specifically identified projects, the Commission's expectation is that only the expenditures attributable to those projects would be supported by the proposed resilience cost recovery mechanism, otherwise it would default to existing rates and cost recovery mechanisms.

In the Utilities' regular reporting and annual review process, Utilities shall provide a detailed accounting of the expenditures of these existing rate mechanisms in addition to the progress reports and expenditures of any additional revenue, regardless of the source, but especially including any revenue collected through a cost recovery mechanism proposed for authorization by the Commission and intended to support its proposed resilience investments.

E.2 Alignment with Related System or Operational Improvements

Each Utility must describe any system operational expansion or improvement which is planned or pending and its alignment with, and benefits to, the proposed investments in its GRP. Types of system or operational improvements which may be related and relevant include but are not limited to: advanced metering infrastructure projects, SCADA system implementations or upgrades, new generation investments, distributed generation resources, additions (added capacity) to the transmission and/or distribution systems, and demand-response programs or initiatives. In each case, the Utility must describe the planned or pending improvement and how it might relate to and benefit, or complement, the proposed resilience investments.

E.3 Alignment with Federal Funding

Every effort must be made, both now and in the future, to identify non-ratepayer funds to offset the costs associated with implementing the GRPs required herein. Specifically, it is incumbent on each Utility to continuously review their GRP for alignment with and potential leveraging of existing and future federal or state funding opportunities, particularly those included in the Infrastructure Investment and Jobs Act (IIJA).

The IIJA provides a competitive grant opportunity directly to utilities for the purpose of preventing Grid Interruptions and enhancing electric Grid Resilience in addition to grants to state, tribal, and local governments for similar activities. This program seeks to fund "activities that are supplemental to existing hardening efforts" or "reduce the likelihood of consequences of disruptive events."

Given the approach of GRPs established herein, the Commission expects that Utilities with GRPs will be competitive for IIJA funding. Therefore, the Commission directs Utilities to identify funding

opportunities as well as conditions thereto for consideration by the LPSC as part of project and spending proposals, and to seek all available funding that could offset the costs borne by ratepayers associated with the adoption of the GRPs. To further bolster the competitiveness of any such applications, the Commission encourages utilities to seek to develop their respective and forthcoming GRPs in alignment with the overarching objectives of the IIJA. This includes applying for all relevant funding for programs that may benefit emergency preparedness or resilience of state or local governments. For example, the Federal Emergency Management Agency (FEMA) has available competitive funding opportunities that provide resilience or emergency preparedness funding for state and local entities and includes backup energy and energy resilience. FEMA programs include the Building Resilient Infrastructure (BRIC), Flood Mitigation Assistance, and Hazard Mitigation Grant Programs, some of which have increased funding through the IIJA.

As part of the Funding and Financing section of its GRP, each Utility shall provide a report describing its funding progress to the Commission as part of its reporting. Such reports shall include at a minimum: (1) the date of application for each funding opportunity, the name of the funding program, and the amount of funding sought; (2) the number of applications pending approval/denial as of the date of the report; and (3) a list of all funding sources obtained by name of source and amount of funding.

Considering the uncertainty of the application success, as well as potential for conditions placed on such funding which will need to be considered by the Commission, BCAs should be presented with and without any targeted federal or state funding.

E.4 Additional Eligible & Required Expenses

The development of GRPs may be included in the Utility's proposed GRP budget. Eligible planning and assessment activities include reimbursing the Utilities' reasonable and prudently incurred expenses for the development of their GRPs and conducting feasibility studies or other investigations that may be required to assess the merits of resilience investments.

E.5 Foreseeable Implementation Risks

Each Utility must include a description of foreseeable implementation risks, meaning potential issues that could arise, and which are outside of the Utility's control, and which may affect the implementation schedule, financing, cost recovery, BCRs, or benefits of the proposed Grid Resilience investments.

F. Performance Metrics and Accountability Reporting

Building long-term Grid Resilience requires incremental progress over several years. To track this progress and measure improvement, the Commission will require regular reporting on plan implementation and performance metrics from Utilities to assess not only the implementation of the Grid Resilience solutions but also their impact on grid performance. It will be critical to use a standard set of indicators for resilience performance metrics. The Commission may issue specific reporting requirements and formats as part of the review and Acknowledgment of GRPs. However, no requirement established by this rule will change a Utility's obligation to report on reliability metrics as established under the General Order of 1998, Docket No. U-22389. In re: Ensuring Reliable Electric Service.

Several types of performance metrics will be considered. Output measures may be included to track the progress of the GRP implementation; tracking the progress on the installation of new equipment, project statuses, and similar reporting. Outcome metrics should be used to track actual system performance. Metrics that will be considered as part of the required reporting include reliability metrics that Utilities are already required to collect and report such as SAIDI and SAIFI. The Commission may require Utilities to report these metrics, wherever feasible, by customer type or class to understand the impact that the system improvements have on various geographies, communities, customer types.

Utilities shall submit in their GRPs proposed metrics for monitoring the progress of the implementation of their GRPs, proposed metrics for evaluating the long-term benefits of their proposed investments, and proposed metrics for measuring changes in Grid Resilience in their service area. Further, Utilities shall provide a proposed plan for collecting and analyzing this information and may partner with research institutions, consultants, or other partners in this plan. Lastly, Utilities shall include in their GRPs a proposed schedule and recurrence for reporting each of the proposed metrics to the Commission.

Appendix IV includes example Grid Resilience performance metrics for Utilities to consider in the development of their GRP performance metrics.

Appendix II

Grid Resilience Planning Resources

Risk, Vulnerability, and Consequence Assessment Resources

1. Federal Emergency Management Agency (FEMA)'s Lifelines toolkit: A reference for examining the various types of services and infrastructure that can be supported with Grid Resilience

    a. https://www.fema.gov/sites/default/files/2020-05/CommunityLifelinesToolkit2.0v2.pdf.

2. Many local governments throughout Louisiana maintain hazard mitigation plans, and the Governor's Office of Homeland Security & Emergency Preparedness maintains the state hazard mitigation plan. These plans, and the administrators who lead the development of these plans, are resources for identifying critical services, facilities, and infrastructure that can be considered for Grid Resilience investments.

3. For assessing the consequences to vulnerable communities and populations, various established data sets and associated mapping tools can be used in this analysis including the Center for Disease Control's Social Vulnerability Index, the federal government's Justice40 Initiative which identifies disadvantaged census tracts, and HUD's low-to-moderate income census data.

    a. CDC Social Vulnerability Index: https://www.atsdr.cdc.gov/placeandhealth/svi

    b. Justice40 Initiative: https://www.energy.gov/em/justice40-initiative

    c. US HUD Map Resources: https://hud.maps.arcgis.com/

Benefit Cost Analysis Resources

1. The Interruption Cost Estimate (ICE) Calculator is a tool designed for estimating Interruption costs and/or the benefits of avoided Interruptions. While it is designed for assessing reliability improvements, it can be used for Grid Resilience applications.

    a. https://icecalculator.com/home

2. FEMA's Benefit-Cost Analysis calculator is a source of established data for the monetized value of CMI, and includes pre-populated costs of CMI by customer type.

    a. FEMA BCA Toolkit: https://www.fema.gov/grants/tools/benefit-cost-analysis

3. See BCA methodology, illustrative benefits, and illustrative Grid Resilience investment types in Application of a Standard Approach to Benefit-Cost Analysis for Electric Grid Resilience Investments Sandia National Laboratories. (2021). (No. SAND2021-5627). United States Department of Energy.

    a. https://www.synapse-energy.com/sites/default/files/Standard_Approach_to_Benefit-Cost_Analysis_for__Electric_Grid_Resilience_Investments_19-007.pdf

    b. The following is excerpted from this report (pages 40, 41), explaining the calculation steps for a grid resilience BCA:

In this section, we also suggest a simple construct for calculating resilience benefits. In the table below, we include two types of metrics for each resilience benefit component: one for the scope of the impact and one for the value of each impact. The scope of the impact can be measured by the

number of or counts of items damaged, people or businesses affected, or lost opportunities. The value of each impact is represented in net present value dollars of the avoided cost per item damaged, person or business affected, or opportunity lost. The probability of occurrence of the event can also be accounted for, as discussed in Section 5.1.

The steps to calculate a resilience BCA using these inputs follows:

1. Multiply the scope of each benefit by the net present value of each benefit.

2. Calculate the net present value of each of the costs.

3. Sum all the benefits. Multiply the sum of all the benefits by the probability of event occurrence.

4. Sum all the costs.

5. Divide the total probability-adjusted benefits by the total costs.

The formula follows, where:

BS = benefit scope
BV = benefit value
TB = total benefits
CV = cost value
TC = total costs
POE = probability of event

First:

$$BS1\ x\ NPV(BV1) = TB1$$
$$BS2\ x\ NPV(BV2) = TB2$$
$$BS3\ x\ NPV(BV3) = TB3$$

Next:

$$NPV(CV1) = TC1$$
$$NPV(CV2) = TC2$$
$$NPV(CV3) = TC3$$

Then:

$$\frac{\sum(TB1, TB2, TB3, \dots)\ x\ POE}{\sum(TC1, TC2, TC3, \dots)}$$

Proposed Funding and Financing Resources

1. US DOE Grid Resilience and Innovation Partnerships (GRIP) Program: Grants to utilities and governmental entities to support activities that will modernize the electric grid to reduce impacts due to extreme weather and natural disasters.

    a. https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program

Performance Metrics and Accountability Reporting Resources

See illustrative Grid Resilience metrics and their explanation in Performance Metrics to Evaluate Utility Resilience Investments. Sandia National Laboratories. (No. SAND2021-5919). United States Department of Energy, 2021. Tables from appendix a. Energy Investments with Resilience Benefits: Performance Metrics Reporting Tool, excerpted in Appendix IV, below.

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Appendix III

Grid Resilience Project Types

The following information is excerpted from Application of a Standard Approach to Benefit-Cost Analysis for Electric Grid Resilience Investments Sandia National Laboratories. (2021). (No. SAND2021-5627). United States Department of Energy.

Utilities, customers, and third parties can make many types of investments[15] that improve grid resilience. The table below provides a list of these investments, grouped into four categories including: (1) transmission and distribution system, (2) generation, (3) automation and controls, and (4) cross cutting. The table also indicates whether each investment is on the utility-side of the meter, the customer-side of the meter, or both.[16]

Some investments, such as constructing a sea wall to block flooding from storm surge and sea level rise, are made primarily to improve resilience and all the costs and benefits are resilience-related. However, some of the technologies and solutions shown in the table below are not new or specific to resilience. In some cases, resilience may not be the only or primary reason for making the investment and there may also be costs and benefits that are not resilience-related. The resilience costs and benefits of these solutions can vary significantly. BCA is particularly well-suited for evaluating the costs and benefits of the wide range of solutions that exist to improve grid resilience, as well as address other important goals.

15 We use the term "investment" broadly to mean all types of costs.
16 The utility-side of the meter is often referred to as front-of-meter and the customer-side of the meter is often referred to as behind-the-meter.

Table: Electric Grid Investments with potential Resilience Benefits

Investments	Description	Utility-Side	Customer-Side
Transmission and Distribution System			
Grid Hardening	Pole, wire, transformer, circuit, feeder, and substation upgrades or replacements	X	
Physical Security	Fencing, locks, enclosures, platforms, building extensions, monitoring systems, and alarms, among other investments that protect transmission and distribution system assets	X	
Replacement Parts	Local store of replacement parts that are in high demand and/or difficult to procure on short notice	X	
Physical Spacing and Barriers	Undergrounding, relocation, elevation, and enclosures to prevent threats from jeopardizing critical equipment	X	
Vegetation Management	Tree and brush trimming, removal, and planting of utility-friendly varieties	X	
Generation			
Distributed Energy Resources	Energy efficiency, demand response, load curtailment, electric vehicles, distributed generation, and distributed storage that serve the critical load, reducing the utility resources required to restore that load immediately after a resilience event	X	X
Supplemental Heating and Hot Water Systems	Electric, fossil, solar, or biomass fueled supplemental water and heating systems that provide a secondary or alternate source of water and/or space heating during a resilience event		X
Backup Generation	Diesel and natural gas generators, fuel cells, or renewable energy paired with storage that provide a secondary or alternate source of power during a resilience event		X
Physical Security	Fencing, locks, platforms, building extensions, monitoring systems, and alarms, among other investments that protect generation assets		X
Replacement Parts	Local store of replacement parts that are in high demand and/or difficult to procure on short notice	X	X
Physical Spacing and Barriers	Relocation, elevation, and enclosures to prevent threats from jeopardizing critical equipment	X	X

Investments	Description	Utility-Side	Customer-Side
Automation & Controls			
Transmission and Distribution Grid Automation and Controls	Advanced distribution management systems (ADMS), flexible AC transmission system (FACTS) devices, geographic information systems (GIS), distribution system supervisory control and data acquisition (DSCADA), outage management systems (OMS), distributed energy resource management systems (DERMS), fault location, isolation and service restoration systems (FLISR), volt-var optimization (VVO), voltage stabilization (for example, SVC STATCOM), and network monitoring devices	X	
Meters	Customer electric meters that provide outage and restoration notification and/or on-demand data (e.g., advanced meter infrastructure (AMI))	X	
Metering Controls	Communication networks and data management systems	X	X
Cyber Protection System Controls	Communications between control centers, cyber system categorization, system security management and controls, electronic security perimeters, configuration change management, and information protection	X	X
Cross Cutting			
Microgrids	A group of interconnected electricity generators and users operating as part of the larger grid normally, but able to operate in islanded mode during resilience events	X	X
Threat and Vulnerability Assessments	Studies of risks and consequences to inform planning	X	X
Mapping of Hosting Capacity	Electric grid impact evaluation of changes to load	X	X
Critical load identification and prioritization	Definition, list, and restoration sequence for priority customers, load, and the substations and feeders that serve priority customers	X	X
Planning	Facility management planning, community emergency preparedness, cyber and physical system response, restoration, and recovery planning	X	X
Training	Classroom instruction for key staff and practice drills on threat response	X	X
Performance Measurement and Evaluation	Defining and reporting resilience performance metrics	X	X

APPENDIX IV.

Example Grid Resilience Performance Metrics

The following tables include example Grid Resilience performance metrics excerpted from Performance Metrics to Evaluate Utility Resilience Investments. Sandia National Laboratories. (No. SAND2021-5919). United States Department of Energy, 2021. Appendix A. Energy Investments with Resilience Benefits: Performance Metrics Reporting Tool. For a complete discussion of these metrics, please see the report section preceding Appendix A.

Annual Performance Metrics, Event Level Reporting

Event Level Reporting			
Metrics	**Calculations**	**Major Events**	**Resilience Events**
Event Characteristics			
Frequency of Events (number of events)	a		
Duration of Events (total minutes of all events)	b		
Average Event Duration (minutes per event)	b / a		
Probability of Event Occurrence			

Annual Performance Metrics, Customer Level Reporting

Customer Level Reporting												
Metrics	**Calculations**	**TOTAL CUSTOMERS**	**Tier I: Critical Community Services**				**Tier II: Critical Individual Services**	**Tier III: Non-Critical**				
			Customer Sub-Category 1	**Customer Sub-Category 2**	**Customer Sub-Category 3**	**Customer Sub-Category 4**	**Customer Sub-Category 5**	**Customer Sub-Category 1**	**Customer Sub-Category 2**	**Customer Sub-Category 3**	**Customer Sub-Category 4**	**Customer Sub-Category 5**
Customers and Load												
Total Customers	c											
Percent of Customers by Customer Subcategory												
Total Load (kWh)	d											
Percent of Load by Customer Subcategory												
Average Customer Size	d / c											
Critical Customers	e											
Percent of Critical Customers by Customer Subcategory												
Critical Customers as a Percent of Total Customers	e / c											
Critical Load (kWh)	f											
Percent of Critical Load by Customer Subcategory												
Critical Load as a Percent of Total Load	f / d											
Islandable Resources												
Number of customers with any islandable resources:												
Total	g											
FOM Supply source provided by the utility	h											
BTM solar PV + storage generator	i											
BTM battery storage system (no solar PV)	j											
BTM natural gas generation	k											
BTM diesel generation	l											
BTM propane generation	m											
Percent of customers with any islandable resources:												
Total	g / c											
FOM Supply source provided by the utility	h / c											
BTM solar PV + storage generator	i / c											
BTM battery storage system (no solar PV)	j / c											
BTM natural gas generation	k / c											
BTM diesel generation	l / c											
BTM propane generation	m / c											
Customer Resilience												
Normal Days - CAIDI (reporting period)												
Major Event Days - CAIDI (reporting period)												
Resilience Event Days - CAIDI (reporting period)												
All Days - CAIDI (reporting period)												
Normal Days - CAIDI (baseline period)												
Major Event Days - CAIDI (baseline period)												
Resilience Event Days - CAIDI (baseline period)												
All Days - CAIDI (baseline period)												
Normal Days - CAIFI (reporting period)												
Major Event Days - CAIFI (reporting period)												
Resilience Event Days - CAIFI (reporting period)												
All Days - CAIFI (reporting period)												
Normal Days - CAIFI (baseline period)												
Major Event Days - CAIFI (baseline period)												
Resilience Event Days - CAIFI (baseline period)												
All Days - CAIFI (baseline period)												

Annual Performance Metrics, System Level Reporting

System Level Reporting								
Metrics	**Calculations**	**TOTAL SYSTEM**	**Tier I: High Consequence Geographies**		**Tier II: Medium Consequence Geographies**		**Tier III: Low Consequence Geographies**	
			System Sub-Category 1	**System Sub-Category 2**	**System Sub-Category 3**	**System Sub-Category 4**	**System Sub-Category 5**	**System Sub-Category 6**
Equipment								
Total Substations	n							
Customers Served by Substations	o							
Average Number of Customers Served per Substation	o / n							
Critical Substations	p							
Customers Served by Critical Substations	q							
Percent of Customers Served by Critical Substations	q / c							
Average Number of Customers Served per Critical Substation	q / p							
Total Feeders	r							
Customers Served by Feeders	s							
Average Number of Customers Served per Feeder	s / r							
Critical Feeders	t							
Customers Served by Critical Feeders	u							
Percent of Customers Served by Critical Feeders	u / c							
Average Number of Customers Served per Critical Feeder	u / t							
System Resilience								
Normal Days - SAIDI (reporting period)								
Major Event Days - SAIDI (reporting period)								
Resilience Event Days - SAIDI (reporting period)								
All Days - SAIDI (reporting period)								
Normal Days - SAIDI (baseline period)								
Major Event Days - SAIDI (baseline period)								
Resilience Event Days - SAIDI (baseline period)								
All Days - SAIDI (baseline period)								
Normal Days - SAIFI (reporting period)								
Major Event Days - SAIFI (reporting period)								
Resilience Event Days - SAIFI (reporting period)								
All Days - SAIFI (reporting period)								
Normal Days - SAIFI (baseline period)								
Major Event Days - SAIFI (baseline period)								
Resilience Event Days - SAIFI (baseline period)								
All Days - SAIFI (baseline period)								

Resilience Events Metrics, Event Level Reporting

Event Level Reporting			
Metrics	**Calculations**	**Data**	**Sources**
Event Characteristics			
Threat Type(s)			
Location(s)			
Starting Date			
Ending Date			
Duration (days)			
Probability of Event Occurrence			
Utility Staff Impacts			
Affected Utility Staff	a		
Total Utility Staff	b		
Affected Utility Staff as a Percent of Total Utility Staff	a / b		
Staff Injuries	c		
Staff Deaths	d		
Staff Injuries as a Percent of Total Staff	c / b		
Staff Deaths as a Percent of Total Staff	d / b		
Utility Infrastructure Impacts			
Infrastructure Damages ($)			
Non-Utility Staff and Population Impacts			
Affected Municipal Staff	e		
Total Municipal Staff	f		
Affected Municipal Staff as a Percent of Total Municipal Staff	e / f		
Injuries	g		
Deaths	h		
Injuries as a Percent of Total Customers	g / m		
Deaths as a Percent of Total Customers	h / m		
Non-Utility Goods, Infrastructure and Economic Development Impacts			
Critical Goods and Infrastructure Damages ($)	i		
Total Goods and Infrastructure Damages ($)	j		
Critical Goods and Infrastructure Damages as a Percent of Total Damages	i / j		
Critical Goods Not Produced/Sold ($)	l		
Total Goods Not Produced/Sold ($)	m		
Critical Goods Not Produced/Sold as a Percent of Total Goods Not Produced/Sold	l / m		
Forgone Future Economic Development Opportunities ($)			

Resilience Events Metrics, Customer Level Reporting

Customer Level Reporting													
Metrics	**Calculations**	**TOTAL CUSTOMERS**	**Tier I: Critical Community Services**				**Tier II: Critical Individual Services**	**Tier III: Non-Critical Services**					
			Customer Sub-Category 1	**Customer Sub-Category 2**	**Customer Sub-Category 3**	**Customer Sub-Category 4**	**Customer Sub-Category 5**	**Customer Sub-Category 1**	**Customer Sub-Category 2**	**Customer Sub-Category 3**	**Customer Sub-Category 4**	**Customer Sub-Category 5**
Customers and Load													
Total Customers *(from Annual Metrics)*	m												
Maximum Affected Customers	n												
Maximum Affected Customers as a Percent of Total Customers	n / m												
Departed Customers													
Total Load (kWh) *(from Annual Metrics)*	o												
Maximum Affected Load (kWh)	p												
Maximum Affected Load as a Percent of Total Load	p / o												
Departed Load (kWh)													
Islandable Resources													
Number of customers with any islandable resources: *(from Annual Metrics)*													
Total	q												
FOM Supply source provided by the utility	r												
BTM solar PV + storage generator	s												
BTM battery storage system (no solar PV)	t												
BTM natural gas generation	u												
BTM diesel generation	v												
BTM propane generation	w												
Number of customers with any islandable resources that functioned during the event:													
Total	x												
FOM Supply source provided by the utility	y												
BTM solar PV + storage generator	z												
BTM battery storage system (no solar PV)	aa												
BTM natural gas generation	ab												
BTM diesel generation	ac												
BTM propane generation	ad												
Percent of islandable resources that functioned during the event:													
Total	x / q												
FOM Supply source provided by the utility	y / r												
BTM solar PV + storage generator	z / s												
BTM battery storage system (no solar PV)	aa / t												
BTM natural gas generation	ab / u												
BTM diesel generation	ac / v												
BTM propane generation	ad / w												
Customer Resilience													
Pre Resilience Event Days - CAIDI													
Resilience Event Days - CAIDI (reporting period) *(from Annual Metrics)*													
Post Resilience Event Days - CAIDI													
Pre Resilience Event Days - CAIDI w/ islandable resources													
Resilience Event Days - CAIDI w/ islandable resources													
Post Resilience Event Days - CAIDI w/ islandable resources													
Pre Resilience Event Days - CAIFI													
Resilience Event Days - CAIFI (reporting period) *(from Annual Metrics)*													
Post Resilience Event Days - CAIFI													
Pre Resilience Event Days - CAIFI w/ islandable resources													
Resilience Event Days - CAIFI w/ islandable resources													
Post Resilience Event Days - CAIFI w/ islandable resources													

Resilience Events Metrics, System Level Reporting

System Level Reporting								
Metrics	**Calculations**	**TOTAL SYSTEM**	**Tier I: High Consequence Geographies**		**Tier II: Medium Consequence Geographies**		**Tier III: Low Consequence Geographies**	
			System Sub-Category 1	**System Sub-Category 2**	**System Sub-Category 3**	**System Sub-Category 4**	**System Sub-Category 5**	**System Sub-Category 6**
Equipment								
Critical Substations *(from Annual Metrics)*	ae							
Maximum Affected Critical Substations	af							
Customers Served by Affected Critical Substations	ag							
Affected Critical Substations as a Percent of Critical Substations	af / ae							
Average Number of Customers Served per Affected Critical Substation	ag / af							
Critical Feeders *(from Annual Metrics)*	ah							
Maximum Affected Critical Feeders	ai							
Customers Served By Affected Critical Feeders	aj							
Affected Critical Feeders as a Percent of Critical Feeders	ai / ah							
Average Number of Customers Served per Affected Critical Feeder	aj / ai							
System Resilience								
Pre Resilience Event Days - SAIDI								
Resilience Event Days - SAIDI (reporting period) *(from Annual Metrics)*								
Post Resilience Event Days - SAIDI								
Pre Resilience Event Days - SAIDI w/ islandable resources								
Resilience Event Days - SAIDI w/ islandable resources								
Post Resilience Event Days - SAIDI w/ islandable resources								
Pre Resilience Event Days - SAIFI								
Resilience Event Days - SAIFI (reporting period) *(from Annual Metrics)*								
Post Resilience Event Days - SAIFI								
Pre Resilience Event Days - SAIFI w/ islandable resources								
Resilience Event Days - SAIFI w/ islandable resources								
Post Resilience Event Days - SAIFI w/ islandable resources								

Appendix V.

Grid Resilience Plan Checklist

Risk Assessment with Quantitative Risk Modeling			
Required Element	**YES**	**NO**	**N/A**
Lists the ten largest grid interruption events (measured in CMI) experienced in the service area over the five years preceding development of the GRP, including causes (A.1)	☐	☐	
Includes total number of customers impacted by each Grid Interruption Event (A.1)	☐	☐	
Includes total CMI for Grid Interruption Event (A.1)	☐	☐	
Describes how these events compare to the Utility's annual SAIDI statistical mean for the past five years (A.1)	☐	☐	
Lists all potential risks that could cause major Grid Interruption events and ranks them by relative importance from greatest threat to least threat (A.1)	☐	☐	
Identifies the risks on the list that are likely to change in the future due to environmental or human factors, and the causes for changes in risk (A.1)	☐	☐	
Selects risk(s) likely to have the greatest negative impact as measured by SAIDI scores (A.1)	☐	☐	
Acquires or generates data on event probability and impact (A.1)	☐	☐	
Required only for Utilities with 4 Million mWh or more in annual sales			
Includes rationale for selecting risks to be modeled (A.1)	☐	☐	☐
Uses a reasonable estimate for expected Grid Interruption reductions derived from a model or source of Utility's choosing, and provides all assumptions and inputs used to determine how Grid Interruption durations are expected to be reduced during various events (A.1)	☐	☐	☐
Models the risk(s) and their probabilities, using the latest science and data available, to project future grid interruption events and their likely impacts, demonstrating how the model includes projected risk increases due to climate change and/or environmental factors (A.1)	☐	☐	☐
Maps risks and their probabilities to the service area (A.1)	☐	☐	☐
If cyber security is not among the top risks listed, provides a description of the Utility's activities to detect and address cyber threats to the Utility's systems (A.1)	☐	☐	☐

Describes how increasing frequency and severity of extreme weather events is accounted for in Risk Assessment (A.1)	☐	☐	☐
Optional Element			
Provides visibility into the specific conditions for each distribution feeder or circuit, thus identifying specific upgrades/solutions relative to identified risks (A.1)	☐	☐	

Vulnerability Assessment			
Required Element	**YES**	**NO**	**N/A**
Using a GIS tool, maps all Utility assets across generation, transmission, and distribution against the risk types that have spatial components to identify areas of risk, and which assets have what level of exposure to these threats (B.1)	☐	☐	☐
Develops and lists a set of assumptions for the threshold of failure of each asset given its design, age, condition, or other relevant factors, and the intensity of the threat (B.1)	☐	☐	☐
Runs all assets through various risk scenarios included in the risk model and compares the results, showing which assets are projected to fail under which risk scenarios and event type (B.1)	☐	☐	☐
For Utilities not required to conduct quantitative risk modeling, identify and include in the GRP a list of assets most at risk of failure, the threats under which they are most vulnerable, and thresholds at which they are assumed to fail (B.1)	☐	☐	☐
Describes how increasing frequency and severity of extreme weather events is accounted for in Vulnerability Assessment (B.1)	☐	☐	☐
Optional Element			
Provides visibility into the specific conditions for each distribution feeder or circuit, thus identifying specific upgrades/solutions relative to vulnerabilities (B.1)	☐	☐	

Consequence Scenarios Assessment		
Required Element	**YES**	**NO**
Provides a map (using a GIS tool) showing critical infrastructure in the Utility's service area (C.1)	☐	☐
Assesses social vulnerability and the relative impacts of Grid Interruptions throughout the Utility's service area by mapping the risks and vulnerabilities onto a map of social vulnerability factors (C.1)	☐	☐
Overlays the maps of the Risk Assessment, the Vulnerability Analysis, and the Consequence Assessment, and identifies in a list and accompanying map(s), critical loads, critical infrastructure and/or facilities, and disadvantaged communities and their associated risks (C.1)	☐	☐

Describes how increasing frequency and severity of extreme weather events is accounted for in Consequence Assessment (C.1)	☐	☐
Optional Element		
Provides visibility into the specific conditions for each distribution feeder or circuit, thus identifying specific upgrades/solutions relative to consequence scenarios (C.1)	☐	☐

Grid Resilience Projects List & Map with Project Benefit-Cost Analyses			
Required Element	**YES**	**NO**	**N/A**
Provides Preliminary Grid Resilience Projects List (D.1)	☐	☐	
Considers non-wire alternatives including energy storage, microgrids, and other similar solutions as part of the Preliminary Grid Resilience Projects List (D.1)	☐	☐	
If non-wire alternatives are not included in Final Grid Resilience Projects List, provides an explanation of why these types of projects were not selected as proposed investments ((D.1)	☐	☐	☐
Includes Final Grid Resilience Projects List with proposed investments for implementation over a initial five-year period (D.3)	☐	☐	
Final Grid Resilience Projects List details the specific projects to be implemented, the method of implementation, the estimated timeline and sequence for implementation, and the detailed benefit-cost analysis information for each proposed project (if applicable) (D.3)	☐	☐	
Transparency of methodology for project selection, prioritization, and BCA calculations (D.3)	☐	☐	
Organizes proposed activities into discrete projects and evaluates for feasibility, costs, and benefits (D.3)	☐	☐	
Displays project information in a map format (D.3)	☐	☐	
Conforms to the following Final Grid Resilience Projects List format, providing responses as detailed in the Resilience Rule (25-26): Project name: Project number: Resilience challenge: Project/program description: Project location: Estimated project costs: Description & calculation of direct benefits: Description of co-benefits: (D.3)	☐	☐	
Optional Element			

Conducts an alternatives analysis to determine different ways to achieve similar outcomes and demonstrate why the proposed project is the best alternative to address the challenge (D.1)	☐	☐	
Conducts a dependency analysis to identify which, if any, of the projects should be done together to yield the most benefits or completed in a specific order to facilitate others (D.1)	☐	☐	
Considers the voluntary adoption of higher minimum standards to be used in all future restoration, upgrade, replacement activities (D.1)	☐	☐	
Solicits proposed for Non-Wires Alternatives and customer-based solutions through RFI process (D.2)	☐	☐	
Includes redundant power programs in Final Grid Resilience Projects List, and, if included, provides description of the proposed program and/or projects, what facility(ies) or types of facility(ies) it is intended to serve, and how the proposed program or project(s) will be funded (D.6)	☐	☐	☐

Benefit-Cost Analyses			
Required Element	**YES**	**NO**	**N/A**
Includes project BCAs, wherever feasible, and wherever a BCA is not included, explains why it cannot be feasibly calculated (D.5)	☐	☐	
Where BCA is required, calculates direct benefits including the following components: 1. Avoided restoration costs 2. Avoided customer interruption costs (D.5)	☐	☐	☐
Provides data sources, calculations, and assumptions that were used to calculate BCAs (discount rates, project lifespans, and similar variables typically used in BCA calculations) (D.5)	☐	☐	☐

Estimate of Proposed Funding & Financing			
Required Element	**YES**	**NO**	**N/A**
Includes funding and financing element that describes in detail the total proposed budget and the method and sources the Utility proposes to use to fund the implementation of the GRP (E)	☐	☐	
Utility demonstrates how the proposed funding and financing plan provides the best value to their customers and ratepayers and is equitable such that the cost burdens are distributed fairly, commensurate with the benefits (E)	☐	☐	
Indicates whether it proposes to request the approval of additional ratepayer funds (E)	☐	☐	
If Utility proposes the use of ratepayer funds, describes in detail the proposed cost recovery mechanism, whether it be rate based or a rider, the term of a proposed addition to rate base or rider, whether it is volume-based or a flat rate by customer class, and the approximate projected monthly costs to residential customers with monthly average consumption of 1,000	☐	☐	☐

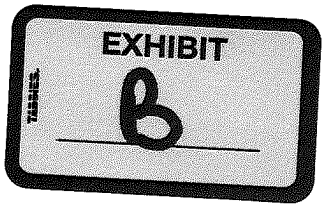
kWh, 1,500 kWh, and 2,000 kWh (E)			
If Utility proposes the use of ratepayer funds, projects the anticipated revenue from the cost recovery mechanism over the implementation timelines of the GRP (E.1)	☐	☐	☐
If Utility proposes the use of ratepayer funds, discloses its proposed rate of return for investments to be funded by the cost recovery mechanism (E.1)	☐	☐	☐
If Utility proposes the use of ratepayer funds to implement Grid Resilience investments which have existing rate mechanisms or proposed rate mechanisms pending before the Commission, includes a detailed accounting of how those funds have and will continue to be used and what additional projects, activities, and benefits will be supported with the proposed cost recovery mechanism (E.1)	☐	☐	☐
If Utility proposes the use of ratepayer funds, demonstrates why the additional proposed funding included in the funding and financing section of GRP is required to develop adequate resilience above and beyond what is supported by the existing rate mechanisms (E.1)	☐	☐	☐
Description of any system operational expansion or improvement which is planned or pending and its alignment with, and benefits to, the proposed investments in its GRP (E.2)	☐	☐	☐
Provides a report describing Utility's funding progress related to federal funding streams, including: 1. The date of application for each funding opportunity, the name of the funding program, and the amount of funding sought, 2. The number of applications pending approval/denial as of the date of the report, and 3. A list of all funding sources obtained by name of source and amount of funding (E.3)	☐	☐	☐
Includes a description of foreseeable implementation risks, meaning potential issues that could arise, and which are outside of the Utility's control, and which may affect the implementation schedule, financing, cost recovery, or benefits of the proposed Grid Resilience investments (E.5)	☐	☐	

Performance Metrics & Regular Reporting		
Required Element	**YES**	**NO**
Submits proposed metrics for monitoring the progress of the implementation of GRP (F)	☐	☐
Submits proposed metrics for evaluating the long-term benefits of GRP proposed investments (F)	☐	☐
Submits proposed metrics for measuring changes in Grid Resilience in Utility's service area (F)	☐	☐
Provides a proposed plan for collecting and analyzing this information, including any partnerships with research institutions, consultants, or other partners in this plan (f)	☐	☐
Includes a proposed schedule and recurrence for reporting each of the proposed metrics to the Commission (F)	☐	☐

ATTACHMENT A

RULES REGARDING ELECTRIC UTILITY

GRID RESILIENCE PLANS



LOUISIANA PUBLIC SERVICE COMMISSION

RULES REGARDING ELECTRIC UTILITY

GRID RESILIENCE PLANS AND RELATED REVIEW

PURPOSE

The Louisiana Public Service Commission ("Commission" or "LPSC") hereby promulgates the following rules (the "Rules") in an effort to establish formal procedures applicable to Electric Utilities subject to the jurisdiction of the Commission. These Rules are intended to set the guidelines and requirements for utilities to develop Grid Resilience Plans. ("GRP"s).

Consequently, the Commission finds it necessary to establish these Rules to require Electric Utilities to develop and provide the Commission with ~~Grid Resilience Plans~~GRPs to enhance the state's potential collective ability to withstand, adapt to, and recover from risks posed to the electrical generation, transmission, and distribution systems, thereby potentially reducing the negative impacts of Forced Interruptions to ratepayers, customers, critical facilities, and the general public by reducing restoration costs, economic impacts, and secondary consequences of Grid Interruptions, especially those caused by low-probability/high-consequence events.

Each Electric Utility shall have its own ~~Grid Resilience Plan~~GRP, which shall encompass the Electric Utility's Risk, Vulnerability, and Consequence Assessments, Grid Resilience Projects List, Proposed Funding Plan, and any other elements as determined by the Commission.

AUTHORITY

Article IV, Section 21 of the Louisiana Constitution of 1974 provides the Commission with the following authority:

> B. **Powers and Duties.** The Commission shall regulate all common carriers and public utilities and have such other regulatory authority as provided by Law. It shall adopt and enforce reasonable rules, regulations and procedures necessary for the discharge of its duties, and shall have other powers and perform other duties as provided by Law.

Consistent with the above authority, the Commission has adopted the following rules and regulations that apply to all Electric Utilities under its jurisdiction.

Rule-making Context and Background

Louisiana has experienced several extensive, multi-day electric Grid Interruption events in recent years, resulting in massive economic damages and loss of life. There is broad consensus that these events have been caused by a combination of factors, including Louisiana's risk profile as a place with a relatively higher likelihood of receiving the most intense and direct impacts of widespread disasters1 and an Electrical Grid which has not been designed, constructed, or upgraded to adequately mitigate these risks including the strength to withstand extreme winds, the elevation to avoid flood damages, and the winterization to minimize the impacts of extreme freeze events.

[1] NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2023).

As a result, Louisiana ratepayers are now experiencing the increasing costs of restoration from several major extreme weather events. In 2022 and 2023 alone, the Commission has approved over $4B in storm restoration costs, all of which are passed through to ratepayers through cost recovery riders in conjunction with the securitization process. It is generally acknowledged that there is potential that these costs could be reduced in future extreme weather events by proactively and reasonably investing in equipment replacements and upgrades, system modernization, enhanced vegetation management, and operational improvements. It is also ~~generally agreed~~possible that the impacts of outages could possibly be further mitigated with the addition of redundancy throughout the system in the form of distributed generation and/or energy storage to provide backup grid services. These investments, collectively, ~~would likely~~could potentially reduce restoration costs by decreasing the amount of damage the systems sustain, reducing the time and materials required to conduct this restoration, and reducing the price of materials and labor as improvements would be conducted proactively, rather than reactively. Further, these improvements would ~~likely~~potentially reduce the economic and social costs to households, businesses, and governments by reducing the extent and duration of major Grid Interruptions.

While the risks to infrastructure of all kinds from natural and human-made causes appear to be increasing, so too is the science and practice of resilience, or "the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents." 2 The Commission's effort in this rulemaking aligns with the trend around the United States wherein public ~~utility~~Utility commissions are increasingly requiring utilities to develop plans

[2] Presidential Policy Directive 21 (PPD-21): Critical Infrastructure Security and Resilience

to mitigate future risks. Further, the federal government is making substantial investments in Grid Resilience within the Infrastructure Investment and Jobs Act (IIJA) and this rule-making initiative can position Louisiana communities and utilities to better compete for those funds. The ultimate goal of this initiative is to mitigate the impacts of a broad range of risks to Louisiana's Electrical Grid and the associated economic and social consequences that can result from these impacts.

With this Rule, the Commission intends to set the guidelines and requirements for ~~Grid Resilience Plans~~GRPs and ~~for~~to ensure that Utilities ~~to~~ develop ~~Grid Resilience Plans~~GRPs that meet the Commission's requirements while customizing the strategies, investments, and activities to their organization, service area, and particular challenges and opportunities. Since Utilities are the entities with the most knowledge of and expertise in their systems and service areas, they are in the best position to assess the risks, vulnerabilities, and opportunities for improvement. This Rule provides the procedures for the Commission to receive and review the Utilities' GRP, allow for Stakeholder participation and input, and acknowledge whether or not the Utilities have completed the required GRP submission. The Rule further establishes certification procedures through which Utilities shall pursue Commission approval of GRP projects, project spending levels and any cost recovery plans, and to determine whether they are prudent and in the public interest. Nothing in this Rule predetermines whether GRP project spending by Utilities is prudent or in the public interest, or commits the Commission to grant certification approval of any GRP project, GRP spending, or cost recovery proposals. Further, the Commission does not intend for this rule to interrupt, displace, or replace any existing practices, systems, or strategies that Utilities use to carry out their regular operations but to augment the Utilities' practices to include Grid Resilience, especially as a distinct activity from Reliability.

Reliability, as defined herein, can generally be considered the ability of the power system to deliver Electrical Energy as demanded by users, under ~~normal~~circumstances other than extreme or extraordinary operating conditions. In other words, Reliability means that Energy is available when expected. Under extreme or extraordinary operating conditions, uninterrupted delivery of Electrical Energy cannot always reasonably be expected. ~~The increasing frequency and intensity~~The probability of extreme weather conditions requires that the Commission and Utilities look beyond the current standards, practices, and metrics required by Reliability standards and regulations to focus on low-probability/high-consequence events and what additional measures are needed to mitigate the impact of these events, recognizing that entirely eliminating Grid Interruptions under these extreme circumstances is not likely to be feasible. While some Reliability standards and metrics can be useful and applicable to Grid Resilience, they must be adapted to ~~adequately account for~~reasonably consider extraordinary circumstances. While Reliability metrics, standards, and regulations have been well-established and in effect for many years, the science and practice of Grid Resilience is relatively new and without equivalent national standards. By promulgating this Grid Resilience Rule, the Commission intends to start the process of defining how Utilities should undertake Grid Resilience planning and investment, recognizing that these requirements and practices will need to be refined over time as the state of Grid Resilience science and practice evolves.

SECTION 101. Definitions

1. Acknowledgment - A GRP will be deemed Acknowledged when the Commission determines that the submitted plan sufficiently adheres to the requirements set forth herein. Acknowledgment solely constitutes the Commission's Acknowledgement and recognition that the Utility's submission complies with the filing requirements set forth herein.

Acknowledgment does not constitute approval, authorization, or a determination of prudence or public interest of the assessments, plans, actions, budgets, or any other component of the GRP.

~~1.~~2. Advanced Metering Infrastructure (AMI) - Systems that use two-way communications to read ~~utility~~Utility meter data remotely and automatically, and perform other related functions.

3. Assets/Electrical Assets - Equipment used primarily for the generation, transmission, distribution, and delivery of electricity, including generation facilities, interconnection facilities, electrical substations, power lines, transmission towers, distribution poles, switches, meters, and other similar electrical infrastructure assets.

~~5.~~4. Benefit-Cost Analysis (BCA) - A systematic process for identifying, quantifying, and comparing expected benefits and costs of an investment, action, or initiative.

~~7.~~5. Benefit-Cost Ratio (BCR) - The ratio of the benefits of a project, expressed in monetary terms, relative to its costs, also expressed in monetary terms, typically expressed in discounted present values.

~~9.~~6. Catastrophe (CAT) modeling - A probabilistic tool used to estimate losses and simulate potential financial catastrophes using computer-assisted calculations. Insurance companies

often use CAT models to evaluate and manage devastating risks from natural disasters like hurricanes, earthquakes, floods, and wildfires.

~~11.~~7. Commission/LPSC - The Louisiana Public Service Commission.

~~13.~~8. Customer - A (i) natural person or (ii) a single juridical entity, including any of its affiliated companies which are affiliated through common ownership, who receive, and pay for, Service from an Electric Utility.

~~15.~~9. Interruption Duration - The period of time that begins when electrical service is lost to a customer and ends when service has been restored to that customer.

~~17.~~10. Customer Minutes Interrupted (CMI) - The number of minutes a customer loses electrical service.

~~19.~~11. Demand/Electricity Demand - The rate at which electrical energy is delivered to or by a system, part of a system, or piece of equipment, at a given instant or averaged over any designated period of time. Electricity Demand is usually measured in kilowatts (kW). Rate

Schedules and Rate Riders may utilize varying definitions of Demand as necessary for billing purposes.

~~21.~~12. Demand-side Management - Includes but is not limited to energy efficiency, demand response, distributed generation and storage, smart grid, water-energy measures, electric vehicle hardware, and innovative rate design.

~~23.~~13. Distributed Energy Resource (DER) - Geographically-distributed energy generation and storage, usually connected to a distribution grid.

~~25.~~14. Distributed Generation (DG) - Electricity generation that is not centralized and connected to transmission, but rather is decentralized and connected to distribution. DG individual units are typically much smaller in generation capacity than centralized generation plants.

~~27.~~15. Distribution System - That portion of an electrical system that delivers Electric Energy from transformation points on the transmission system to the customer. The distribution system is generally considered to be anything from the distribution substation fence to the customer meter.

~~29.~~16. Electrical Grid - The electrical power system network comprised of the generation, transmission, and distribution systems and all their component parts and integrated operating systems including software, switches, transformers, substations, meters, etc.

~~31.~~17. Energy/Electrical Energy - The amount of electricity used or consumed by a Customer for a specific period, usually measured in kilowatt hours (kWh) or megawatt hours (MWh).

~~33.~~18. Electric Utility/Utility - any person furnishing electrical service within this state, the parish of Orleans excepted, including any electric cooperative transacting business in this state, provided, however, that said term shall not be construed to apply to any person owning, leasing and/or operating an electricity generation facility provided such person is not primarily engaged in the generation, transmission, distribution, and/or sale of electricity, and provided that such person: (a) consumes all of the electric power and energy generated by such facility for its own use at the site of generation or at some other location if mutually acceptable agreements to transport such electric power and energy can be reached with each electric public ~~utility~~Utility whose transmission facilities would be electrically utilized therefor, provided, however, notwithstanding any provision contained herein, there shall be no obligation or duty, expressed or implied, to purchase, to sell, to transport, or to engage in any other type of transaction with respect to the electric power and energy that may be generated by such person, imposed upon any public ~~utility~~Utility by this Section except as shall be provided in the cogeneration rules and regulations adopted by the Louisiana Public

Service Commission pursuant to the Public Utility Regulatory Policies Act of 1978; or, (b) only consumes a portion thereof in such manner and sells the entire remaining portion of such electric power and energy generated to an electric public ~~utility~~Utility as herein defined; or, (c) sells the entire production of electric power and energy generated by such facility to an electric public ~~utility~~Utility as herein defined. Notwithstanding anything to the contrary, an Electric Utility shall not include any Municipal entity providing electric service to its citizens, unless it elected to be regulated by the Commission pursuant La. Constitution Art. 4 Section 21(C).

~~35.~~19. Forced Interruption/Grid Interruption - An Interruption that results from conditions or forces originating from outside of the Electrical Grid (wind, flooding, lightning, ice, vegetation, animals, cyber- or physical attacks, or unknown sources, etc.) or an interruption caused by improper operation of equipment or human error, or improper maintenance of equipment, or an intentional interruption required to relieve stress on a primary energy source or for safety purposes (load shed event).

~~37.~~20. Generation - The production or storage, or both, of Electrical Energy with the intent of enabling practical use or commercial sale of the available energy. This includes photovoltaic, wind-farm, hydroelectric, etc., as well as normal commercial and industrial thermal sources.

~~39.~~21. Grid Resilience - The ability of a physical Electrical Grid system and/or its operators to prepare for, adapt to, withstand, and recover from deliberate attacks, accidents, naturally occurring threats, or extreme weather events.

~~41.~~22. Grid Resilience Plan (GRP) - A filing before the Louisiana Public Service Commission, submitted by a ~~utility~~Utility, as required by the rules herein and associated order, intended to meet the standards and requirements detailed herein.

~~43.~~23. Intelligent Grid/Smart Grid - An electrical power system that utilizes information exchange and control technologies, distributed computing and associated sensors and actuators.

~~45.~~24. Interruption - The loss of electrical service to one or more customers.

~~47.~~25. Load/Electrical Load - An electrical component or portion of a circuit that consumes (active) Electrical Energy.

~~49.~~26. Microgrid - Electricity distribution systems containing Loads and Distributed Energy Resources (such as distributed generators, storage devices, or controllable loads) that can be

operated in a controlled, coordinated way either while connected to the main power network or while islanded.

~~51.~~27. Non-Wires Alternative (NWA) - an electrical grid investment that is intended to provide a substitute for or remove the need to construct or upgrade components of a distribution and/or transmission system.

~~53.~~28. Numerical Weather Model (NWM) - a quantitative tool that uses weather data to forecast different types of weather, including wind speeds, precipitation, temperature, barometric pressure, and other meteorological elements. NWMs can be customized to create visual representations depending on specific meteorological needs.

~~55.~~29. Quantitative Risk Modeling/Modeling - A method for risk analysis where numerical values are assigned to both impact and likelihood based on statistical probabilities and monetarized valuation of loss or gain.

~~57.~~30. Rate - Any compensation, charge, fare, toll, rental, or classification that is observed, charged, or collected by an Electric Utility for a Service, product or commodity it provides as allowed by law.

~~59.~~31. Rate Rider - An additional Rate or charge to be applied to a Customer bill that is separate and distinct from the basic Rates paid under the Customer's applicable Rate Schedule. Typically, Rate Riders are applied to more than one Rate Schedule, although that is not a requirement. Commonly used Rate Riders include, but are not limited to:

a. Formula Rate Plan Rider (FRP) - A Rate Rider that defines the procedure by which the Rates contained in Rate Schedules may be periodically adjusted.

b. Fuel Adjustment Clause (FAC) - A mechanism, the inputs to which are updated on a monthly basis, that provides for recovery of an Electric Utility's fuel costs.

~~61.~~32. Rate Schedule - A schedule included within an Electric Utility's Tariff, which provides the various Rates for particular classes for which the ~~utility~~Utility anticipates offering Services under. Each specific Rate Schedule shall include: 1) Type of electric Service provided under the Schedule; 2) Rates and charges associated with Service under the Schedule; 3) All classification(s) of Customers which could be included under the Schedule; and 4) All practices, rules or regulations which specifically apply to the Services under the Schedule.

~~63.~~33. Reliability - The probability that a system will perform its intended functions without loss of service, within design parameters, under specific operating conditions, and for a specific period of time. In the ~~utility~~Utility industry, reliability is often expressed as system reliability

indices, for example Customer Average Interruption Duration Index (CAIDI), Average Service Unavailability Index (ASUI), and many others.

~~65.~~34. Scheduled Interruption - An Interruption that results when a component of the Electric Grid is deliberately taken out of service at a selected time for purposes of construction, preventive maintenance, or repair.

~~67.~~35. Substation - An assemblage of equipment for purposes other than generation or consumption, through which electric energy in bulk is passed for the purpose of modifying its characteristics. Service equipment, distribution transformer installations, or other minor distribution or transmission equipment are not classified as substations. A substation is of such size or complexity that it incorporates one or more buses, a multiplicity of circuit breakers, and usually is either the sole receiving point of commonly more than one supply circuit, or it sectionalizes the transmission circuits passing through it by means of circuit breakers.

~~69.~~36. System Average Interruption Duration Index (SAIDI) - The average amount of time a customer's service is interrupted during the reporting year. SAIDI = Sum of all Customer Interruption Durations divided by Total Number of Customers.

~~71.~~37. System Average Interruption Frequency Index (SAIFI) - The average number of times that a customer's service is interrupted during the reporting year. SAIFI = Total Number of Customer Interruptions divided by Total Number of Customers.

~~73.~~38. Tariff - The all-encompassing document filed with and approved by the Commission, to which an Electric Utility provides Service. An Electric Utility's Tariff contains rules to address the responsibilities and authorities of the ~~utility~~Utility as it relates to its various Customer classes. Such rules shall address, but are not limited to: Rates, allocation of costs for line extensions, and allocation of costs for new Customer connections. The Tariff shall also include other issues which define the responsibilities and authorities of the Electric Utility. The Tariff shall include, but is not limited to: Rate Schedules, Rate Riders, and Terms of Service.

~~75.~~39. Terms of Service - Terms included within an Electric Utility's Tariff that are intended to facilitate the rendering of uniform, efficient and adequate Service to the various Customer classes of the ~~utility~~Utility. Specifically, the Terms of Service defines the responsibilities, obligation, and authorities the ~~utility~~Utility possesses in exchange for its provision of Service to Customers, as well as the responsibilities and obligations of Customers in exchange for receiving Service.

~~77.~~40. Service - The sale or distribution of Electric Energy by a public ~~utility~~Utility in the performance of the Electric Utility's responsibilities.

~~79.~~41. Transmission System - An interconnected group of electric transmission lines and associated equipment for the movement or transfer of electric energy in bulk between points of supply and points for delivery.

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SECTION 201. Requirement to File a Grid Resilience Plan

For reasons of the health, welfare, and safety of Louisiana citizens, each Electric Utility is hereby directed to develop and submit a Grid Resilience Plan (GRP) as soon as possible. Each ~~utility~~Utility required to submit a GRP shall file their initial plan no later than December 31, 2024. The Commission will establish a procedural schedule based on the initial filing date~~. Each utility shall file a GRP that is reasonable and practicable, as determined by the Commission. Each GRP will be treated as its own docket and proceed along its established procedural schedule for review, evaluation, revision, resubmission, and acceptance.~~ , which will include the Commission's review, evaluation, and possible modifications, working towards Commission Acknowledgment. Stakeholders shall also be allowed to participate in the docket through written comments, formal discovery, and technical conferences, when deemed appropriate. Collaborative provision of information by the Utilities on their analysis and plans is highly encouraged and expected. Utilities shall be allowed to present revisions and resubmissions of their GRP after receipt of comments from the Commission and stakeholders. After review by the Commission, including any revisions and resubmissions by the utility, the Commission shall acknowledge whether or not the utility has completed the GRP submission as required by this rule. Acknowledgement by the Commission shall not constitute approval of the GRP or any of the projects, project spending, or cost recovery proposed therein. The determination of whether utility proposals for individual projects within the GRP, project spending levels and cost recovery from ratepayers is prudent and in the public interest shall

be addressed by the Commission in subsequent certification proceedings to be conducted under the LPSC Rules of Practice and Procedure.

SECTION 301. Utility Scope of Responsibility

Unless otherwise determined by the Commission, each ~~utility~~Utility required to file a GRP must assess all assets and systems under its ownership and/or direct management or control within its designated service area. Utilities are not responsible for developing solutions for assets or systems outside of their designated service area but are expected to contemplate how any dependencies on partner companies for grid services such as generation and/or transmission may impact the resilience of the electrical grid in their service area, and conversely, how its proposed actions may benefit or negatively impact partner utilities operating outside of its service area.

SECTION 401. Minimum Standards

The standards and requirements included in this rule shall be considered the minimum level of responsibility required by each regulated Electric Utility. Utilities are invited and encouraged to develop and submit GRPs which exceed the standards referenced herein~~.~~; provided however, that any project and spending proposals by the Utility that exceed the minimum standards shall be identified and include cost/benefit justifications for consideration by the Commission.

SECTION 501. Review and Evaluation Procedure

Upon the filing of a ~~utility's~~Utility's GRP, the Commission will review and evaluate the filed plan and may involve in this review any additional outside counsel, engineers, and/or consultants, as determined at the Commission's sole discretion. The Commission reserves the right to ~~accept~~Acknowledge any plan, in sum or in part, and to require specific revisions, additions, and/or supplementary information~~.~~ in order to comply with the minimum requirements of this rule. The Commission may, at its sole discretion, require as many rounds of revision and re-submission as it deems necessary for a plan to meet ~~its~~the requirements ~~and for the plan to be deemed in the public interest.~~of this Rule. The Commission also reserves the right to not ~~accept~~Acknowledge a submitted GRP. The Commission will consider the completeness and quality of each GRP in this review and evaluation process. A checklist of required and optional GRP elements and sub-elements is included in Appendix V for the Utilities' convenience.

~~Once the Commission has reached a determination on a utility's submitted GRP, the Commission will establish the associated requirements of implementing the plan and reporting on plan implementation progress and associated metrics. These requirements shall commence with the Commission's determination and be established by a schedule and timeline associated with the determination date.~~

After the Commission has acknowledged that the Utility has completed the GRP submission as required by this rule, the Utility shall file an application with the Commission seeking certification of any GRP projects, project spending levels, and any cost recovery plans that pertain to the initial five year implementation plan set forth in the GRP, and such applications shall be docketed and considered under the Commission's Rules of Practice and Procedure. The Commission may involve

in this review any additional outside counsel, engineers, and/or consultants, as determined necessary by the Commission.

The Utility shall bear the burden-of-proof in such proceedings that its GRP projects, project spending levels, and any cost recovery plans, are prudent and in the public interest. Nothing in this Rule commits the Commission to determine that GRP project spending by utilities is prudent or in the public interest or to grant certification approval of any GRP project spending or cost recovery proposals.

SECTION 601. Reporting, Monitoring, & Accountability

~~Upon determination of a utility's GRP, the Commission will establish associated reporting requirements. The Commission will require, at minimum, annual reporting on the plan's implementation including procurement and construction of physical improvements, performance metrics, and revenue collection, and will likely require semi-annual (every six months) construction updates on the individual projects scheduled for that construction cycle.~~

To the extent the Commission grants certification of a Utility's projects and proposals submitted in its GRP application in whole or part, the Commission shall require reporting by the Utility on implementation progress and associated metrics. Implementation progress reports shall be filed with the Commission not less than semi-annually. Stakeholders participating in the certification proceedings shall receive copies thereof subject to appropriate confidentiality protections.

SECTION 701. Planning Cycle

Each ~~utility~~Utility shall use a 10-year outlook for the proposed resilience investments and activities in its GRP and shall include a five-year implementation plan detailing the proposed schedule of the

specific projects and activities to be completed in the first five years and the associated costs and benefits of each project, where applicable. Utilities shall provide an estimated implementation budget for both the ~~10~~ten-year outlook and five-year implementation plan.

SECTION 801. Confidentiality

~~The Commission will determine what information within each Electric Utility's~~Utilities may pursue confidentiality protections for portions of their GRP and certification application as may be ~~filed confidentially under seal~~appropriate pursuant to Rule 12.1 of the Commission's Rules of Practice and Procedure ~~of the Louisiana Public Service Commission.~~ .

SECTION 901. Required Elements of a Grid Resilience Plan (GRP)

Unless otherwise determined by the Commission, the following shall be required elements of a GRP:

1. Risk Assessment with Quantitative Risk Modeling
2. Vulnerability Assessment
3. Consequence Scenarios Assessment
4. Final Grid Resilience Projects List & Map with Project ~~Benefit-Cost Analyses, where applicable~~BCA and BCR
5. Estimate of Proposed Funding and Financing
6. Performance Metrics and Regular Reporting

The rigor of these requirements is tiered based on ~~utility~~Utility size. The table below describes the required and optional elements for utilities above and below this threshold.

	Required GRP Element	Annual ~~sales~~Sales > 4M MWh[3]	Annual ~~sales~~Sales < 4M MWh
1.	Risk Assessment with Quantitative Risk Modeling	Required	Quantitative Risk Modeling Optional
2.	Vulnerability Assessment	Required	Required
3.	Consequence Scenarios Assessment	Required	Required
4.	Grid Resilience Projects List & Map with Project Benefit-Cost Analyses, where feasible	Required	Required
5.	Estimate of Proposed Funding and Financing	Required	Required
6.	Performance Metrics and Regular Reporting	Required	Required

Each of the required elements of a GRP is detailed in Appendix I, accompanied by prescriptive steps for each ~~utility~~Utility to follow. Each ~~utility~~Utility is expected to follow these steps but customize the approaches, analysis, data, and solutions to the characteristics of its service area, assets, and systems in a manner that best serves their customers.

[3] ~~As of 2021 and as reported by the US Energy information Agency Data from forms EIA-861 schedules 4A & 4D and EIA-861S.~~

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APPENDIX I

Minimum Standards for the Required Elements of a Grid Resilience Plan

Risk, Vulnerability, and Consequence Assessments

This first component of a GRP assesses the risks to the grid, their potential impact on electrical assets and systems, and the consequence of these impacts on ratepayers and communities. These

components are composed of three distinct but related sections: a risk assessment, a vulnerability assessment, and a consequence assessment. Risks are threats that can cause damage to the grid or its components and/or interrupt electrical service and must be assessed for their potential severity and the probability that they will occur. Vulnerability is the amount of exposure various grid assets have to those risks and their susceptibility to being affected by those risks. Vulnerability can vary even if the risks are the same. For instance, two transmission towers in similar locations might face the same wind load risk but if one is built to newer, stronger standards and the other is older or not as strong, they have different levels of vulnerability to the same risk. Lastly, consequences, or the impacts of a Grid Interruption event can vary widely depending on who they affect and for how long.

Each of the three assessments described herein – risk, vulnerability, and consequence – should be conducted with sufficient granularity to provide a comprehensive assessment at the distribution feeder level. That is, the assessment should provide visibility into the specific conditions for each distribution circuit or feeder, thus identifying specific upgrades or solutions that are specific to the risks, vulnerabilities, and consequences at a granular level. Additionally, these assessments shall incorporate and describe how they have considered the increasing frequency and severity of extreme weather events.

Risk Assessment

The risk assessment component should be conducted as an all-hazards approach, meaning that any potential threat should be considered, even if only one or more –risks– is selected for mitigating activities. The assessment should not just focus only on the most recent or most severe risk experienced but should contemplate other types of risk that may have occurred less recently, less frequently, and even those that have never been experienced by the system but are potential risks

nonetheless. While ~~utilities~~Utilities are expected to consider a broad range of risks, they are only required to develop and submit a complete risk assessment for at least one risk type and are expected to focus on the risk, or risks, that are most likely to cause widespread and/or long-duration Grid Interruptions.

A.1 Risk Assessment Instructions:

Step 1. List the ten largest grid interruption events, as measured in CMI, experienced in the service area over the five years preceding the year in which the GRP is being developed and include their causes. Include the total number of customers impacted by the Grid Interruption event, total CMI for each event and how these events compare to the ~~utility's~~Utility's annual SAIDI statistical mean for the past five years.

Step 2. List all potential risks that could cause major Grid Interruption events and rank them by relative importance from greatest threat to least threat.

Step 3. Identify the risks on the list that are likely to change in the future due to environmental or human factors, and the causes for changes in risk.

Step 4. Select the risk (or risks) to be assessed using Quantitative Risk Modeling. The ~~utility~~Utility may choose to model more than one risk type (extreme heat, freeze events, high winds, floods, etc.) and should select the risks that are the most likely to create extended Grid Interruption and/or wide

scale Grid Interruptions, with the greatest negative impact as measured by SAIDI scores. To be modeled effectively, Utilities must acquire or generate data on event probability and impact. Each Utility must include their rationale for selecting the risks to be modeled. There is not yet a uniform modeling tool that can be mandated for assessing Grid Resilience. Utilities may use a reasonable estimate for expected Grid Interruption reductions derived from a model or source of ~~-~~their choosing; however, each ~~utility~~Utility must provide all assumptions and inputs used to determine how Grid Interruption durations are expected to be reduced during various events as part of its submission.

Step 5. Model the risks and their probabilities, endeavoring to use the latest science and data available, to project future grid interruption events and their likely impacts. Demonstrate how the model ~~includes~~accounts for projected risk increases due to ~~climate change and/or~~ environmental factors. Map these risks and their probabilities to the service area to visualize the spatial elements of the risk type. For instance, map floodplain areas or areas likely to be inundated in a 1% annual return interval for rainfall and/or storm surge events, and map areas with likelihood of experiencing tropical storm force winds. Where a risk type does not vary spatially across the service area or where this spatial analysis cannot be performed due to a lack of data or predictability, apply the risk uniformly across the entire service area. Types of models that Utilities may choose to use include but are not limited to are Numerical Weather Models and Catastrophe, or CAT, models. Utilities may use existing systems and platforms to conduct quantitative risk modeling provided these systems can adequately project the probability of future risk scenarios and thereby provide input to ~~benefit-cost analyses~~BCAs with reasonable rigor and accuracy.

NOTE: this step is required of Utilities with total annual sales of 4 million MWh but optional for those Utilities with less than 4 million MWh of annual sales.

Step 6. If cyber security is not among the top risks listed, provide a description of the Utility's activities to detect and address cyber threats to the Utility's systems. This description may be a summary drawn from other public reporting as required by the Commission and/or federal regulatory agencies or standards.

B. Vulnerability Assessment

In this step, each Utility evaluates the vulnerability of various assets under different risk types. This is done by applying the risk types to the current system and calculating the likely impacts. Current asset data on the various components of the system is critical for vulnerability assessment. Since factors such as vegetation levels, asset design, the age and condition of assets, elevation, soils, and many others affect the exposure and performance of an asset under threat, these factors must be known to assess vulnerability.

The Utility should apply the quantitative risk models to the Utility's current system to project the impacts of the risks on the system. Utilities that are not required to model the risks may estimate probabilities of occurrence and severity based on historical events and apply these risks uniformly across their service area. Utilities should apply this analysis across all elements of the system and all types of facilities and assets. Assumptions on the threshold for the failure of each asset, given its

design and condition, and intensity of the threat, should be calculated based on recent events and current ~~utility~~Utility asset data. The Utility can then determine what assets are expected to withstand certain conditions and where failure is expected.

Based on this analysis, several calculations can be made that will be necessary for developing ~~benefit-costs analyses~~BCAs, including the approximate time needed to restore power, the cost to repair or replace the asset to current or higher design standards, and the number and type of customers that will be affected. If assets must be replaced, upgrades should also be evaluated~~.~~ and BCAs presented for both base replacement and upgrade of equipment to demonstrate whether the upgrade is cost-justified to customers. These estimates will be critical in determining which solutions are the best for mitigating the negative impacts of Grid Interruptions.

B.1 Vulnerability Assessment Instructions~~:~~

Step 1. Using a geographic information systems (GIS) tool, map all Utility assets across generation, transmission, and distribution against the risk types that have spatial components to identify areas of risk, where applicable, and which assets have what level of exposure to these threats.

Step 2. Develop a set of assumptions for the threshold of failure of each asset given its design, age, condition, or other relevant factors, and the intensity of the threat. Include the assumptions used to establish the thresholds of failure.

Step 3. Run all assets through various risk scenarios included in the risk model and compare the

results, showing which assets are projected to fail under which risk scenarios and event types. For Utilities not required to conduct quantitative risk modeling, identify and include in the GRP a list of assets most at risk of failure, the threats under which they are most vulnerable, and thresholds at which they are assumed to fail.

C. Consequence Assessment

This assessment should describe the consequences of Grid Interruptions by their impacts on different geographies within the service area, different types of customers, and the cascading impacts on downstream infrastructure systems.

C.1 Consequence Assessment Instructions

Step 1. Provide a map (using a GIS tool) showing critical infrastructure in the Utility's service area. For more resources on identifying critical infrastructure types, see Appendix II.

Step 2. Assess social vulnerability and the relative impacts of Grid Interruptions throughout the Utility's service area by mapping the risks and vulnerabilities onto a map of social vulnerability factors. For more resources on identifying vulnerable communities and populations, see Appendix II.

Step 3. Overly the maps of the Risk Assessment, the Vulnerability Analysis, and the Consequence Assessment, and identify in a list and accompanying map(s), critical loads, critical infrastructure and/or facilities, and disadvantaged communities and their associated risks.

NOTE: As part of developing the Grid Resilience solutions, as described in the following section, each Utility will develop a method by which to prioritize Grid Resilience investments and demonstrate how the prioritized activities support critical loads that serve infrastructure or facilities that provide essential response and recovery services, disadvantaged communities and/or customers, and/or enable other resilience investments that support one or both efforts.

D. Grid Resilience Projects List

The Utility shall compile a list of projects and initiatives for the various types of investments and improvements that could mitigate the impacts of the assessed risks and vulnerabilities. The investments and activities shall be organized into discrete projects and activities and prioritized on their cost-effectiveness for delivering the most resilience benefit. Appendix III. Grid Resilience Project Types, contains a list of example projects types that Utilities can use in the development of their GRPs.

D.1 Preliminary Grid Resilience Projects List

Developing a more resilient Electrical Grid must be pursued across a range of scales, systems, equipment, and technology. Utilities are therefore encouraged to consider a range of strategies and project types and develop a comprehensive list of options, or a Preliminary Grid Resilience Projects List, before selecting a subset of investments to include in the Final Grid Resilience Projects List. The process of selecting, grouping, and assessing investments can be done iteratively with the

benefit-cost analysis, where feasible, since some projects may have greater or lesser impact depending on how they are implemented in relationship to other investments.

As part of this process, Utilities are encouraged, but not required, to conduct an alternatives analysis to determine different ways to achieve similar outcomes and demonstrate why the proposed project is the best alternative to address the challenge. Similarly, Utilities are encouraged, but not required, to conduct a dependency analysis to identify which, if any, of the projects should be done together to yield the most benefits or completed in a specific order to facilitate others. Lastly, Utilities are encouraged, but not required, to consider the voluntary adoption of higher minimum standards to be used in all future restoration, upgrade, or replacement activities. Utilities are required to consider Non-wires Alternatives that are likely to provide Grid Resilience services including energy storage, microgrids, and other similar solutions as part of the Preliminary Grid Resilience Projects List.

Utilities are not required to include Non-wires Alternatives projects in their Final Grid Resilience Projects List but must provide an explanation of why these types of projects were not selected as proposed investments if not included.

D.2 Non-Wires Alternatives & Customer-based Solutions Request for Information

As part of the development of the Preliminary Grid Resilience Projects List, Utilities are encouraged, but not required, to solicit proposals for Non-Wires Alternatives and customer-based solutions through a request for information process. In doing so, the Utility could identify the communities and feeders most vulnerable to Grid Interruptions based on the Risk, Vulnerability, and Consequence Assessments, and publicly solicit proposed solutions through a Request for Information (RFI) for

non-wires solutions to mitigate these risks and vulnerabilities and to increase customer and Grid Resilience. The Utility could also invite proposed solutions to mitigate risks at critical facilities beyond those identified as most vulnerable communities and feeders but which provide a localized resilience benefit.

The RFI could solicit proposals for mitigating the risks through third-party and customer-based solutions, including distributed energy resources (DERs), virtual power plants (VPPs), Microgrid, energy storage, and other solutions that can provide short-term and long-term Grid Resilience benefits to customers. The RFI could solicit from respondents the interconnection requirements in order to support the solution proposed. Based on these identified interconnection requirements, the Utility could identify any required infrastructure upgrades or improvements required to support the proposed non-wires solutions. The Utility could prepare a report summarizing the findings of the RFI to be included in GRP. The summary report would describe which, if any, of the proposed non-wires solutions the Utility considers feasible and describe the Utility's proposed strategy to incorporate these non-wires solutions into its GRP.

D.3 Final Grid Resilience Projects List

Having evaluated the potential Grid Resilience investments, their costs, benefits, and contribution to the state's goals, Utilities will then compile their capital plan for Grid Resilience. While many, or even most, projects will be capital projects, some Grid Resilience investments may include non-physical improvements such as software or SCADA systems, capacity building and training for Utility staff and partners, plans and studies, or similar activities. The Utility's GRP should propose, in detail, the specific projects to be implemented, the method of implementation (directly by the

Utility, via a 3rd party contractor, or partnership), the estimated timeline and sequence for implementation, and the detailed benefit-cost analysis information for each proposed project, if applicable. The Utility should be transparent in showing how it came to the calculations presented for each project and the method of project selection and prioritization used to develop the GRP.

Since adapting large infrastructure systems to future risks is a long-term process, GRPs should propose capital investments over 10 years. However, because costs, technology, regulations, and best practices are rapidly changing, the specific proposed investments for implementation should be proposed for a shorter period of five years. This will allow the Utility to update the GRP at least every five years, updating the methods and approaches and specific investment plans to adopt the best available science and technology.

D.~~3~~4 Grid Resilience Projects List Instructions~~:~~

Step 1. The Utility will organize proposed Grid Resilience activities into discrete projects to evaluate them for feasibility, costs, and benefits. Individual projects may be grouped into project packages by geography or by grid sub-components such as circuits, feeders, laterals, rights-of-way or similar, according to the Utility's rationale~~.~~, which shall be outlined and explained.

Step 2. ~~For those projects which require a benefit-cost analysis~~Where required, the Utility will then conduct ~~Benefit-Costs Analysis (~~BCA~~)~~ for each project~~, where feasible,~~ to estimate the projected costs and benefits. This BCA will then be used to inform the alternatives analysis and prioritization of projects for the final projects list.

Step 3. For each project, the Utility should conduct an alternatives analysis, comparing various Grid Resilience investments that could address the same challenge and then demonstrate why the proposed project in the Final Grid Resilience Projects List is the best solution to this particular problem.

Step 4. The Utility should then conduct a dependency analysis to identify which, if any, of the projects should be implemented at the same time to yield the most benefits or completed in a specific sequence to facilitate others.

Step 5. The Utility will compile this information into the Final Grid Resilience Projects List, laying out the details of each proposed Grid Resilience investment and project. In its GRP, the Utility must present its proposed Grid Resilience investments and projects in at least as much detail as is described below, for every proposed project, program, or investment.

Step 6. The Utility will also display project information in a map format within the plan, showing the spatial distribution of proposed projects across its service area.

~~D.4~~ Final Grid Resilience Projects List format~~:~~

Project name. A unique name for the initiative / investment / project.

Project number. A unique number associated with the project. This can be a sequential number of the projects in the list (1,2,3, etc.) or a unique identifier as defined by the Utility.

Resilience Challenge. A short description describing the risk(s) to be mitigated and the threat they pose to the grid and customers.

Project/Program Description. A synopsis describing what the proposed investment is and what it will do to build Grid Resilience.

Project Location. This can be in the form of an address if applicable, latitude-longitude coordinates if an address is not relevant and must, at a minimum include the Parish(es) and the LPSC region(s) in which the investment is located. System-wide investments such as a SCADA system upgrade or a demand-side management program offered throughout the service area can be listed as "System-wide" and do not require a specific geographic location.

Estimated Project Costs. The Utility's best available estimate of the project costs based on reasonable due diligence, presented in US dollars at their current value at the time the plan is developed, along with a short description of what efforts were made to estimate these costs and what variables may cause them to change in the next five years~~.~~, and the class level of accuracy of the estimate, e.g. +/- 100%, 50%, etc.

Description & Calculation of Direct Benefits. A qualitative description of the specific types of benefits expected from the project, the extent of these benefits, and to whom they accrue, with a particular focus on benefits that accrue to disadvantaged communities, low-income communities and/or ratepayers, and critical infrastructure facilities / critical loads. For every project with a quantitative benefit-cost analysis, a detailed description of the calculations, assumptions, term, discount rates, escalation rates, average service life of project, and other inputs and methods used to develop the benefit calculation is required, along with the amount of benefits expected over the lifecycle of the project, expressed in US Dollars. Any benefits that cannot be quantified and/or monetized can also be discussed in qualitative terms. Each project with a quantified benefit-cost must also list its ~~benefit-cost ratio.~~BCR. See the Benefit-Cost Analyses Resources section in Appendix II for additional information.

Note: Utilities are allowed to submit proposed projects with benefit-cost ratios of less than 1.0.

Description of Co-Benefits~~:~~

Beyond the cost reduction and cost avoidance included in the standard ~~benefit-cost analysis~~BCA calculation, the Utility is encouraged but not required to include a qualitative discussion of any additional indirect benefits, or co-benefits, whether or not they can be quantified. Examples of co-benefits that a project could facilitate include grid modernization, remote management, increased safety features, energy storage, decarbonization, electrification, renewable generation and/or transmission, distributed generation, demand-side management, energy efficiency, and electric vehicle charging infrastructure, among others. Projects could facilitate these co-benefits by providing enhanced capacity for generation, transmission, or distribution, by improving automation and

controls or remote management, or other pathways as detailed by the Utility. Projects that provide these co-benefits may be prioritized for implementation by the Utility due to these merits.

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D.5 Benefit-Cost Analyses

Conducting a BCA for individual projects and initiatives can be a critical step in the development of any resilience plan. Since resilience investments do not provide mitigation benefits in the form of reduced recovery costs, avoided losses, or the mitigation of other negative consequences unless and until the system is threatened, there is not a guarantee of the delivery of modeled benefits as there often is in an energy efficiency project where the projected benefits are more predictable. However, using the best available science on risks, the best available asset data on the system's design and

current condition, and the most current data on costing and the benefits of avoided consequences, a Utility can make robust estimates of the ~~probable~~potential benefit that a resilience investment can deliver. Utilities shall include project BCAs, wherever feasible, and wherever a BCA is not included, shall explain why a BCA cannot feasibly be calculated.

The goal of conducting a BCA is to demonstrate to those providing the investment, whether they be ratepayers, private investors, or government agencies, that the benefits of the project justify the costs. The additional goal for regulators is to be able to compare the relative benefits and cost-effectiveness of resilience investments across the Utilities under their jurisdiction. By having a common approach and methodology, regulators can be assured that they are authorizing commensurate investments across the various service areas, and that any cost recovery they may approve is defensible and beneficial.

Since many projects will not yet be scoped in detail at the time the Utility is first developing its GRP, the Commission expects planning-level BCAs using the best available costing and benefit data. ~~The Commission may request that utilities include final BCAs as part of the reporting that the utility will provide in the annual evaluation process.~~ Utilities are expected to develop their own BCA methods and disclose the methods and assumptions used to develop each project BCA, including discount rates, project lifespans, and similar variables typically used in BCA calculations.

There are various approaches and methods to develop a benefit-cost analysis. Some types of Grid Resilience projects require different methods because they offer additional benefits beyond reduced

damages and avoided Interruption costs such as increased generation or storage, which can provide benefits under 'blue sky' conditions. Furthermore, as some benefits are hard to quantify and impossible to monetize, this rule allows for the inclusion of such benefits in the overall evaluation of a project's merits.

Benefit ~~calculations~~Calculations for Projects with BCAs

Direct benefits that must be calculated for projects with BCAs include the following components:

1. Avoided restoration costs
2. Avoided customer interruption costs

Restoration costs consist of capital and operational costs related to restoring power to customers after Grid Interruption events. The second category, avoided customer interruption costs, includes the economic burden that customers (of all types) incur due to the loss of electrical service. The Commission recognizes the inherent variability and uncertainty when estimating both avoided restoration costs and, especially, avoided customer interruption costs. Therefore, it is incumbent upon the Utility to provide the data sources, calculations, and assumptions that were used to estimate these costs and to ensure that they are reasonable. Avoided Utility lost revenues from avoided lost customer load may not be included as a benefit in the BCA. See Appendix II for more resources on the Benefit Cost Analyses.

D.~~5~~6 Redundant Power Programs or Projects

Since it is impossible to eliminate the risk of Grid Interruptions, it is critical that backup energy, or redundant power, be developed wherever feasible. This is especially true for facilities that provide

essential services during an emergency and/or an extended Grid Interruption, and vulnerable communities. Utilities are therefore encouraged, but not required, to include redundant power programs or projects in their GRPs. Such programs or projects could offer the installation of on-site backup Electrical Energy generation and/or storage for the critical loads to be supported in the event of a Grid Interruption. Such programs should focus on providing backup power for facilities that provide critical services such as hospitals, nursing homes, pharmacies, grocery stores, fueling stations and electric vehicle charging stations, restaurants, and large retailers, and/or public and civic institutions which provide critical services during extended Interruptions such as police and fire stations, recreation centers used as temporary housing or recovery centers, transit centers, faith-based institutions, and other non-profit recovery centers. Any Utility including a redundant power program or project(s) in its Final Grid Resilience Project list must provide a description of the proposed program and/or projects, what facility(ies) or types of facility(ies) it is intended to serve, and how the proposed program or project(s) will be funded. -Redundant facilities that would provide benefits beyond their redundancy, i.e., benefits to other customers on the grid, should be identified and explained.

E. Proposed Funding and Financing

Each Utility's GRP will include a funding and financing element which describes in detail the total proposed budget and the method and sources the Utility proposes to use to fund the implementation of the GRP. All potential sources should be considered including ratepayer funds, federal funds, private debt and equity, and funding provided by the ~~utility~~Utility. The Utility shall demonstrate how

the proposed funding and financing plan provides the best value to their customers and ratepayers and is equitable such that the cost burdens are distributed fairly, commensurate with the benefits.

Utilities may propose new revenue sources and/or a cost recovery mechanism as part of their GRPs. For any proposed use of ratepayer funds, the Utility must detail the proposed cost recovery mechanism, whether it be rate based or a rider, the term of a proposed addition to rate base or rider, whether it is volume-based or a flat rate by customer class, whether it seeks recovery on an equal percentage base revenue basis or other basis, whether it distinguishes cost recovery as between utility distribution and transmission system investments and the customers which use each such part of the system, and the approximate projected monthly costs to residential customers with monthly average consumption of 1,000 kWh, 1,500 kWh, and 2,000 kWh. The Utility must project the anticipated revenue from the cost recovery mechanism over the implementation timelines of the GRP. Further, the Utility must disclose its proposed rate of return for investments to be funded by the cost recovery mechanism. Utilities are not required to propose the use of additional revenue but, if so, must demonstrate how they propose to fund the proposed Grid Resilience investments without the use of additional revenue.

~~The Commission's act of acceptance of any Utility's GRP shall not include approval, imply approval, or set precedent of approval of additional ratepayer funds for the implementation of the GRP. Rather, any request for the use of additional ratepayer funds by a Utility for the use of implementing its proposed Grid Resilience investments within its GRP, may be considered by the Commission as a secondary action, after acceptance of the final version of the GRP. The Commission also reserves the right to not consider the request for additional ratepayer funds. This two-step process is intended to allow for any proposed use of ratepayer funds to be revised in alignment with any substantive~~

~~revisions to the GRP during the Commission's review process. The procedural schedule established for the docketed proceeding used to review any Utility's GRP shall dictate if and when in the process any proposed use of additional ratepayer funds may be considered.~~

E.1 Existing Rate Mechanisms

Any Utility proposing the use of additional ratepayer funds to implement Grid Resilience investments which have existing rate mechanisms, or proposed rate mechanisms pending before the Commission, which provide funding for any activity, or similar activity, that is also proposed within the Utility's GRP, such as vegetation management, equipment upgrades, replacements to or hardening of the transmission and/or distribution systems, grid modernization, or others ~~must~~shall include a detailed accounting of how those funds have and will continue to be used and what additional projects, activities, and benefits will be supported with the proposed cost recovery mechanism. The Utilities shall describe, through detailed accounting and project delivery records, what projects and activities have been and will be supported by the existing and/or proposed cost recovery mechanisms. The Utilities will also demonstrate why the additional proposed funding included in the funding and financing section of their GRP is required to develop adequate resilience above and beyond what is supported by the existing rate mechanisms. Since each GRP will have specifically identified projects, the Commission's expectation is that only the expenditures attributable to those projects would be supported by the proposed resilience cost recovery mechanism, otherwise it would default to existing rates and cost recovery mechanisms.

In the Utilities' regular reporting and annual review process, Utilities shall provide a detailed accounting of the expenditures of these existing rate mechanisms in addition to the progress reports

and expenditures of any additional revenue, regardless of the source, but especially including any revenue collected through a cost recovery mechanism proposed for authorization —by the Commission and intended to support its proposed resilience investments.

E.2 Alignment with Related System or Operational Improvements

Each Utility must describe any system operational expansion or improvement which is planned or pending and its alignment with, and benefits to, the proposed investments in its GRP. Types of system or operational improvements which may be related and relevant include but are not limited to: advanced metering infrastructure projects, SCADA system implementations or upgrades, new generation investments, distributed generation resources, additions (added capacity) to the transmission and/or distribution systems, and demand-response programs or initiatives. In each case, the Utility must describe the planned or pending improvement and how it might relate to and benefit, or complement, the proposed resilience investments.

E.3 Alignment with Federal Funding

Every effort must be made, both now and in the future, to identify non-ratepayer funds to offset the costs associated with implementing the GRPs required herein. Specifically, it is incumbent on each Utility to continuously review their GRP for alignment with and potential leveraging of existing and future federal or state funding opportunities, particularly those included in the Infrastructure Investment and Jobs Act (IIJA).

The IIJA provides a competitive grant opportunity directly to utilities for the purpose of preventing Grid Interruptions and enhancing electric Grid Resilience in addition to grants to state, tribal, and local governments for similar activities. This program seeks to fund "activities that are supplemental to existing hardening efforts" or "reduce the likelihood of consequences of disruptive events."

Given the approach of GRPs established herein, the Commission expects that ~~utilities~~Utilities with GRPs will be competitive for IIJA funding. Therefore, the Commission directs Utilities to identify funding opportunities as well as conditions thereto for consideration by the ~~utilities~~LPSC as part of project and spending proposals, and to seek all available funding that could offset the costs borne by ratepayers associated with the adoption of the GRPs. To further bolster the competitiveness of any such applications, the Commission encourages utilities to seek to develop their respective and forthcoming GRPs in alignment with the overarching objectives of the IIJA. This includes applying for all relevant funding for programs that may benefit emergency preparedness or resilience of state or local governments. For example, the Federal Emergency Management Agency (FEMA) has available competitive funding opportunities that provide resilience or emergency preparedness funding for state and local entities and includes backup energy and energy resilience. FEMA programs include the Building Resilient Infrastructure (BRIC), Flood Mitigation Assistance, and Hazard Mitigation Grant Programs, some of which have increased funding through the IIJA.

As part of the Funding and Financing section of its GRP, each Utility shall provide a report describing its funding progress to the Commission as part of its reporting. Such reports shall include at a

minimum: (1) the date of application for each funding opportunity, the name of the funding program, and the amount of funding sought; (2) the number of applications pending approval/denial as of the date of the report; and (3) a list of all funding sources obtained by name of source and amount of funding.

Considering the uncertainty of the application success, as well as potential for conditions placed on such funding which will need to be considered by the Commission, BCAs should be presented with and without any targeted federal or state funding.

E.4 Additional Eligible & Required Expenses

The development of GRPs may be included in the Utility's proposed GRP budget. Eligible planning and assessment activities include reimbursing the Utilities' reasonable and prudently incurred expenses for the development of their GRPs and conducting feasibility studies or other investigations that may be required to assess the merits of resilience investments.

E.5 Foreseeable Implementation Risks

Each Utility must include a description of foreseeable implementation risks, meaning potential issues that could arise, and which are outside of the Utility's control, and which may affect the implementation schedule, financing, cost recovery, BCRs, or benefits of the proposed Grid Resilience investments.

F. Performance Metrics and Accountability Reporting

Building long-term Grid Resilience requires incremental progress over several years. To track this progress and measure improvement, the Commission will require regular reporting on plan implementation and performance metrics from Utilities to assess not only the implementation of the Grid Resilience solutions but also their impact on grid performance. It will be critical to use a standard set of indicators for resilience performance metrics. The Commission may issue specific reporting requirements and formats as part of the review and ~~acceptance~~Acknowledgment of GRPs. However, no requirement established by this rule will change a Utility's obligation to report on reliability metrics as established under the General Order of 1998, Docket No. U-22389. In re: Ensuring Reliable Electric Service.

Several types of performance metrics will be considered. Output measures may be included to track the progress of the GRP implementation; tracking the progress on the installation of new equipment, project statuses, and similar reporting. Outcome metrics should be used to track actual system performance. Metrics that will be considered as part of the required reporting include reliability metrics that Utilities are already required to collect and report such as SAIDI and SAIFI. The Commission may require Utilities to report these metrics, wherever feasible, by customer type or class to understand the impact that the system improvements have on various geographies, communities, customer types.

Utilities shall submit in their GRPs proposed metrics for monitoring the progress of the implementation of their GRPs, proposed metrics for evaluating the long-term benefits of their proposed investments, and proposed metrics for measuring changes in Grid Resilience in their

service area. Further, Utilities shall provide a proposed plan for collecting and analyzing this information and may partner with research institutions, consultants, or other partners in this plan. Lastly, Utilities shall include in their GRPs a proposed schedule and recurrence for reporting each of the proposed metrics to the Commission.

Appendix IV includes example Grid Resilience performance metrics for Utilities to consider in the development of their GRP performance metrics.

Appendix II

Grid Resilience Planning Resources

Risk, Vulnerability, and Consequence Assessment Resources

~~2.~~1. Federal Emergency Management Agency (FEMA)'s Lifelines toolkit: A reference for examining the various types of services and infrastructure that can be supported with Grid Resilience

~~a. https://www.fema.gov/sites/default/files/2020-05/CommunityLifelinesToolkit2.0v2.pdf.~~

a. https://www.fema.gov/sites/default/files/2020-05/CommunityLifelinesToolkit2.0v2.pdf.

~~3.~~2. Many local governments throughout Louisiana maintain hazard mitigation plans, and the Governor's Office of Homeland Security & Emergency Preparedness maintains the state hazard mitigation plan. These plans, and the administrators who lead the development of

these plans, are resources for identifying critical services, facilities, and infrastructure that can be considered for Grid Resilience investments.

~~4.~~3. For assessing the consequences to vulnerable communities and populations, various established data sets and associated mapping tools can be used in this analysis including the Center for Disease Control's Social Vulnerability Index, the federal government's Justice40 Initiative which identifies disadvantaged census tracts, and HUD's low-to-moderate income census data.

a. CDC Social Vulnerability Index: ~~https://www.atsdr.cdc.gov/placeandhealth/svi~~https://www.atsdr.cdc.gov/placeandhealth/svi

b. Justice40 Initiative: ~~https://www.energy.gov/em/justice40-initiative~~https://www.energy.gov/em/justice40-initiative

c. US HUD Map Resources: https://hud.maps.arcgis.com/

Benefit Cost Analysis Resources

~~2.~~1. The Interruption Cost Estimate (ICE) Calculator is a tool designed for estimating Interruption costs and/or the benefits~~.~~ of avoided Interruptions. While it is designed for assessing reliability improvements, it can be used for Grid Resilience applications.

~~a. https://icecalculator.com/home~~

a. https://icecalculator.com/home

~~3.~~2. FEMA's Benefit-Cost Analysis calculator is a source of established data for the monetized value of CMI, and includes pre-populated costs of CMI by customer type.

a. FEMA BCA Toolkit: https://www.fema.gov/grants/tools/benefit-cost-analysis

~~4.~~3. See BCA methodology, illustrative benefits, and illustrative Grid Resilience investment types in Application of a Standard Approach to Benefit-Cost Analysis for Electric Grid Resilience Investments Sandia National Laboratories. (2021). (No. SAND2021-5627). United States Department of Energy.

~~a. https://www.synapse-energy.com/sites/default/files/Standard_Approach_to_Benefit-Cost_Analysis_for__Electric_Grid_Resilience_Investments_19-007.pdf~~

a. https://www.synapse-energy.com/sites/default/files/Standard_Approach_to_Benefit-Cost_Analysis_for__Electric_Grid_Resilience_Investments_19-007.pdf

b. The following is excerpted from this report (pages 40, 41), explaining the calculation steps for a grid resilience BCA:

In this section, we also suggest a simple construct for calculating resilience benefits. In the table below, we include two types of metrics for each resilience benefit component: one for the scope of the impact and one for the value of each impact. The scope of the impact can be measured by the number of or counts of items damaged, people or businesses affected, or lost opportunities. The value of each impact is represented in net present value dollars of the avoided cost per item damaged,

person or business affected, or opportunity lost. The probability of occurrence of the event can also be accounted for, as discussed in Section 5.1.

The steps to calculate a resilience BCA using these inputs follows:

1. Multiply the scope of each benefit by the net present value of each benefit.
2. Calculate the net present value of each of the costs.
3. Sum all the benefits. Multiply the sum of all the benefits by the probability of event occurrence.
4. Sum all the costs.
5. Divide the total probability-adjusted benefits by the total costs.

The formula follows, where:

BS = benefit scope
BV = benefit value
TB = total benefits
CV = cost value
TC = total costs
POE = probability of event

First:

$$BS1\ x\ NPV(BV1) = TB1$$
$$BS2\ x\ NPV(BV2) = TB2$$
$$BS3\ x\ NPV(BV3) = TB3$$

Next:

$$NPV(CV1) = TC1$$
$$NPV(CV2) = TC2$$
$$NPV(CV3) = TC3$$

Then:

$$\frac{\sum(TB1, TB2, TB3, \dots)\ x\ POE}{\sum(TC1, TC2, TC3, \dots)}$$

Proposed Funding and Financing Resources

2.1. US DOE Grid Resilience and Innovation Partnerships (GRIP) Program: Grants to utilities and governmental entities to support activities that will modernize the electric grid to reduce impacts due to extreme weather and natural disasters.

a. https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program

Performance Metrics and Accountability Reporting Resources

See illustrative Grid Resilience metrics and their explanation in Performance Metrics to Evaluate Utility Resilience Investments. Sandia National Laboratories. (No. SAND2021-5919). United States Department of Energy, 2021. Tables from appendix a. Energy Investments with Resilience Benefits: Performance Metrics Reporting Tool, excerpted in Appendix IV, below.

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Grid Resilience Project Types

The following information is excerpted from Application of a Standard Approach to Benefit-Cost Analysis for Electric Grid Resilience Investments Sandia National Laboratories. (2021). (No. SAND2021-5627). United States Department of Energy.

Utilities, customers, and third parties can make many types of investments15 that improve grid resilience. The table below provides a list of these investments, grouped into four categories including: (1) transmission and distribution system, (2) generation, (3) automation and controls, and (4) cross cutting. The table also indicates whether each investment is on the utility-side of the meter, the customer-side of the meter, or both.16

Some investments, such as constructing a sea wall to block flooding from storm surge and sea level rise, are made primarily to improve resilience and all the costs and benefits are resilience-related. However, some of the technologies and solutions shown in the table below are not new or specific to resilience. In some cases, resilience may not be the only or primary reason for making the investment and there may also be costs and benefits that are not resilience-related. The resilience costs and benefits of these solutions can vary significantly. BCA is particularly well-suited for evaluating the costs and benefits of the wide range of solutions that exist to improve grid resilience, as well as address other important goals.

15 We use the term "investment" broadly to mean all types of costs.
16 The utility-side of the meter is often referred to as front-of-meter and the customer-side of the meter is often referred to as behind-the-meter.

Table: Electric Grid Investments with potential Resilience Benefits

Investments	Description	Utility-Side	Customer-Side
Transmission and Distribution System			
Grid Hardening	Pole, wire, transformer, circuit, feeder, and substation upgrades or replacements	X	
Physical Security	Fencing, locks, enclosures, platforms, building extensions, monitoring systems, and alarms, among other investments that protect transmission and distribution system assets	X	
Replacement Parts	Local store of replacement parts that are in high demand and/or difficult to procure on short notice	X	
Physical Spacing and Barriers	Undergrounding, relocation, elevation, and enclosures to prevent threats from jeopardizing critical equipment	X	
Vegetation Management	Tree and brush trimming, removal, and planting of utility-friendly varieties	X	
Generation			
Distributed Energy Resources	Energy efficiency, demand response, load curtailment, electric vehicles, distributed generation, and distributed storage that serve the critical load, reducing the utility resources required to restore that load immediately after a resilience event	X	X
Supplemental Heating and Hot Water Systems	Electric, fossil, solar, or biomass fueled supplemental water and heating systems that provide a secondary or alternate source of water and/or space heating during a resilience event		X
Backup Generation	Diesel and natural gas generators, fuel cells, or renewable energy paired with storage that provide a secondary or alternate source of power during a resilience event		X
Physical Security	Fencing, locks, platforms, building extensions, monitoring systems, and alarms, among other investments that protect generation assets		X
Replacement Parts	Local store of replacement parts that are in high demand and/or difficult to procure on short notice	X	X
Physical Spacing and Barriers	Relocation, elevation, and enclosures to prevent threats from jeopardizing critical equipment	X	X

Investments	Description	Utility-Side	Customer-Side
Automation & Controls			
Transmission and Distribution Grid Automation and Controls	Advanced distribution management systems (ADMS), flexible AC transmission system (FACTS) devices, geographic information systems (GIS), distribution system supervisory control and data acquisition (DSCADA), outage management systems (OMS), distributed energy resource management systems (DERMS), fault location, isolation and service restoration systems (FLISR), volt-var optimization (VVO), voltage stabilization (for example, SVC STATCOM), and network monitoring devices	X	
Meters	Customer electric meters that provide outage and restoration notification and/or on-demand data (e.g., advanced meter infrastructure (AMI))	X	
Metering Controls	Communication networks and data management systems	X	X
Cyber Protection System Controls	Communications between control centers, cyber system categorization, system security management and controls, electronic security perimeters, configuration change management, and information protection	X	X
Cross Cutting			
Microgrids	A group of interconnected electricity generators and users operating as part of the larger grid normally, but able to operate in islanded mode during resilience events	X	X
Threat and Vulnerability Assessments	Studies of risks and consequences to inform planning	X	X
Mapping of Hosting Capacity	Electric grid impact evaluation of changes to load	X	X
Critical load identification and prioritization	Definition, list, and restoration sequence for priority customers, load, and the substations and feeders that serve priority customers	X	X
Planning	Facility management planning, community emergency preparedness, cyber and physical system response, restoration, and recovery planning	X	X
Training	Classroom instruction for key staff and practice drills on threat response	X	X
Performance Measurement and Evaluation	Defining and reporting resilience performance metrics	X	X

APPENDIX IV.

Example Grid Resilience Performance Metrics

The following tables include example Grid Resilience performance metrics excerpted from Performance Metrics to Evaluate Utility Resilience Investments. Sandia National Laboratories. (No. SAND2021-5919). United States Department of Energy, 2021. Appendix A. Energy Investments with Resilience Benefits: Performance Metrics Reporting Tool. For a complete discussion of these metrics, please see the report section preceding Appendix A.

Annual Performance Metrics, Event Level Reporting

Event Level Reporting			
Metrics	**Calculations**	**Major Events**	**Resilience Events**
Event Characteristics			
Frequency of Events (number of events)	a		
Duration of Events (total minutes of all events)	b		
Average Event Duration (minutes per event)	b / a		
Probability of Event Occurrence			

Annual Performance Metrics, Customer Level Reporting

Customer Level Reporting													
Metrics	Calculations	TOTAL CUSTOMERS	Tier I: Critical Community Services				Tier II: Critical Individual Services	Tier III: Non-Critical				
			Customer Sub-Category 1	Customer Sub-Category 2	Customer Sub-Category 3	Customer Sub-Category 4	Customer Sub-Category 5	Customer Sub-Category 1	Customer Sub-Category 2	Customer Sub-Category 3	Customer Sub-Category 4	Customer Sub-Category 5
Customers and Load												
Total Customers	c											
Percent of Customers by Customer Subcategory												
Total Load (kWh)	d											
Percent of Load by Customer Subcategory												
Average Customer Size	d / c											
Critical Customers	e											
Percent of Critical Customers by Customer Subcategory												
Critical Customers as a Percent of Total Customers	e / c											
Critical Load (kWh)	f											
Percent of Critical Load by Customer Subcategory												
Critical Load as a Percent of Total Load	f / d											
Islandable Resources												
Number of customers with any islandable resources:												
Total	g											
FOM Supply source provided by the utility	h											
BTM solar PV + storage generator	i											
BTM battery storage system (no solar PV)	j											
BTM natural gas generation	k											
BTM diesel generation	l											
BTM propane generation	m											
Percent of customers with any islandable resources:												
Total	g / c											
FOM Supply source provided by the utility	h / c											
BTM solar PV + storage generator	i / c											
BTM battery storage system (no solar PV)	j / c											
BTM natural gas generation	k / c											
BTM diesel generation	l / c											
BTM propane generation	m / c											
Customer Resilience												
Normal Days - CAIDI (reporting period)												
Major Event Days - CAIDI (reporting period)												
Resilience Event Days - CAIDI (reporting period)												
All Days - CAIDI (reporting period)												
Normal Days - CAIDI (baseline period)												
Major Event Days - CAIDI (baseline period)												
Resilience Event Days - CAIDI (baseline period)												
All Days - CAIDI (baseline period)												
Normal Days - CAIFI (reporting period)												
Major Event Days - CAIFI (reporting period)												
Resilience Event Days - CAIFI (reporting period)												
All Days - CAIFI (reporting period)												
Normal Days - CAIFI (baseline period)												
Major Event Days - CAIFI (baseline period)												
Resilience Event Days - CAIFI (baseline period)												
All Days - CAIFI (baseline period)												

Annual Performance Metrics, System Level Reporting

System Level Reporting								
Metrics	Calculations	TOTAL SYSTEM	Tier I: High Consequence Geographies		Tier II: Medium Consequence Geographies		Tier III: Low Consequence Geographies	
			System Sub-Category 1	System Sub-Category 2	System Sub-Category 3	System Sub-Category 4	System Sub-Category 5	System Sub-Category 6
Equipment								
Total Substations	n							
Customers Served by Substations	o							
Average Number of Customers Served per Substation	o / n							
Critical Substations	p							
Customers Served by Critical Substations	q							
Percent of Customers Served by Critical Substations	q / c							
Average Number of Customers Served per Critical Substation	q / p							
Total Feeders	r							
Customers Served by Feeders	s							
Average Number of Customers Served per Feeder	s / r							
Critical Feeders	t							
Customers Served by Critical Feeders	u							
Percent of Customers Served by Critical Feeders	u / c							
Average Number of Customers Served per Critical Feeder	u / t							
System Resilience								
Normal Days - SAIDI (reporting period)								
Major Event Days - SAIDI (reporting period)								
Resilience Event Days - SAIDI (reporting period)								
All Days - SAIDI (reporting period)								
Normal Days - SAIDI (baseline period)								
Major Event Days - SAIDI (baseline period)								
Resilience Event Days - SAIDI (baseline period)								
All Days - SAIDI (baseline period)								
Normal Days - SAIFI (reporting period)								
Major Event Days - SAIFI (reporting period)								
Resilience Event Days - SAIFI (reporting period)								
All Days - SAIFI (reporting period)								
Normal Days - SAIFI (baseline period)								
Major Event Days - SAIFI (baseline period)								
Resilience Event Days - SAIFI (baseline period)								
All Days - SAIFI (baseline period)								

Resilience Events Metrics, Event Level Reporting

Event Level Reporting			
Metrics	**Calculations**	**Data**	**Sources**
Event Characteristics			
Threat Type(s)			
Location(s)			
Starting Date			
Ending Date			
Duration (days)			
Probability of Event Occurrence			
Utility Staff Impacts			
Affected Utility Staff	a		
Total Utility Staff	b		
Affected Utility Staff as a Percent of Total Utility Staff	a / b		
Staff Injuries	c		
Staff Deaths	d		
Staff Injuries as a Percent of Total Staff	c / b		
Staff Deaths as a Percent of Total Staff	d / b		
Utility Infrastructure Impacts			
Infrastructure Damages ($)			
Non-Utility Staff and Population Impacts			
Affected Municipal Staff	e		
Total Municipal Staff	f		
Affected Municipal Staff as a Percent of Total Municipal Staff	e / f		
Injuries	g		
Deaths	h		
Injuries as a Percent of Total Customers	g / m		
Deaths as a Percent of Total Customers	h / m		
Non-Utility Goods, Infrastructure and Economic Development Impacts			
Critical Goods and Infrastructure Damages ($)	i		
Total Goods and Infrastructure Damages ($)	j		
Critical Goods and Infrastructure Damages as a Percent of Total Damages	i / j		
Critical Goods Not Produced/Sold ($)	l		
Total Goods Not Produced/Sold ($)	m		
Critical Goods Not Produced/Sold as a Percent of Total Goods Not Produced/Sold	l / m		
Forgone Future Economic Development Opportunities ($)			

Resilience Events Metrics, Customer Level Reporting

Customer Level Reporting													
Metrics	Calculations	TOTAL CUSTOMERS	Tier I: Critical Community Services				Tier II: Critical Individual Services	Tier III: Non-Critical Services				
			Customer Sub-Category 1	Customer Sub-Category 2	Customer Sub-Category 3	Customer Sub-Category 4	Customer Sub-Category 5	Customer Sub-Category 1	Customer Sub-Category 2	Customer Sub-Category 3	Customer Sub-Category 4	Customer Sub-Category 5
Customers and Load												
Total Customers *(from Annual Metrics)*	m											
Maximum Affected Customers	n											
Maximum Affected Customers as a Percent of Total Customers	n / m											
Departed Customers												
Total Load (kWh) *(from Annual Metrics)*	o											
Maximum Affected Load (kWh)	p											
Maximum Affected Load as a Percent of Total Load	p / o											
Departed Load (kWh)												
Islandable Resources												
Number of customers with any islandable resources: *(from Annual Metrics)*												
Total	q											
FOM Supply source provided by the utility	r											
BTM solar PV + storage generator	s											
BTM battery storage system (no solar PV)	t											
BTM natural gas generation	u											
BTM diesel generation	v											
BTM propane generation	w											
Number of customers with any islandable resources that functioned during the event:												
Total	x											
FOM Supply source provided by the utility	y											
BTM solar PV + storage generator	z											
BTM battery storage system (no solar PV)	aa											
BTM natural gas generation	ab											
BTM diesel generation	ac											
BTM propane generation	ad											
Percent of islandable resources that functioned during the event:												
Total	x / q											
FOM Supply source provided by the utility	y / r											
BTM solar PV + storage generator	z / s											
BTM battery storage system (no solar PV)	aa / t											
BTM natural gas generation	ab / u											
BTM diesel generation	ac / v											
BTM propane generation	ad / w											
Customer Resilience												
Pre Resilience Event Days - CAIDI												
Resilience Event Days - CAIDI (reporting period) *(from Annual Metrics)*												
Post Resilience Event Days - CAIDI												
Pre Resilience Event Days - CAIDI w/ islandable resources												
Resilience Event Days - CAIDI w/ islandable resources												
Post Resilience Event Days - CAIDI w/ islandable resources												
Pre Resilience Event Days - CAIFI												
Resilience Event Days - CAIFI (reporting period) *(from Annual Metrics)*												
Post Resilience Event Days - CAIFI												
Pre Resilience Event Days - CAIFI w/ islandable resources												
Resilience Event Days - CAIFI w/ islandable resources												
Post Resilience Event Days - CAIFI w/ islandable resources												

Resilience Events Metrics, System Level Reporting

System Level Reporting								
Metrics	Calculations	TOTAL SYSTEM	Tier I: High Consequence Geographies		Tier II: Medium Consequence Geographies		Tier III: Low Consequence Geographies	
			System Sub-Category 1	System Sub-Category 2	System Sub-Category 3	System Sub-Category 4	System Sub-Category 5	System Sub-Category 6
Equipment								
Critical Substations *(from Annual Metrics)*	ae							
Maximum Affected Critical Substations	af							
Customers Served by Affected Critical Substations	ag							
Affected Critical Substations as a Percent of Critical Substations	af / ae							
Average Number of Customers Served per Affected Critical Substation	ag / af							
Critical Feeders *(from Annual Metrics)*	ah							
Maximum Affected Critical Feeders	ai							
Customers Served By Affected Critical Feeders	aj							
Affected Critical Feeders as a Percent of Critical Feeders	ai / ah							
Average Number of Customers Served per Affected Critical Feeder	aj / ai							
System Resilience								
Pre Resilience Event Days - SAIDI								
Resilience Event Days - SAIDI (reporting period) *(from Annual Metrics)*								
Post Resilience Event Days - SAIDI								
Pre Resilience Event Days - SAIDI w/ islandable resources								
Resilience Event Days - SAIDI w/ islandable resources								
Post Resilience Event Days - SAIDI w/ islandable resources								
Pre Resilience Event Days - SAIFI								
Resilience Event Days - SAIFI (reporting period) *(from Annual Metrics)*								
Post Resilience Event Days - SAIFI								
Pre Resilience Event Days - SAIFI w/ islandable resources								
Resilience Event Days - SAIFI w/ islandable resources								
Post Resilience Event Days - SAIFI w/ islandable resources								

Service List for R-36227
as of 8/30/2023

Commissioner(s)

Foster L. Campbell
Mike Francis
Eric Skrmetta
Craig Greene
Davante Lewis

LPSC Staff Counsel

W. Noah Hoggatt, LPSC Staff Attorney

LPSC Staff

Donnie Marks, LPSC Utilities Division
Robin Pendergrass, LPSC Auditing Division

LPSC Consultant

David Lessinger
935 Gravier Street, Suite 1650
New Orleans, LA 70112
Email: david.lessinger@csrsinc.com
Fax: ; Phone: (833)523-2526

David Williams
232 Lake Avenue
Metairie, LA 70005
Email: eepewill@gmail.com
Fax: ; Phone: (832)452-3239

Intervenor : **Alliance for Affordable Energy**

Logan Atkinson Burke
Alliance for Affordable Energy
4505 S. Claiborne Avenue
New Orleans, LA 70125
Email: Logan@all4energy.org
Fax: (504)313-3478; Phone: (504)208-9761

Jessica Hendricks
4505 S. Claiborne Ave
New Orleans, LA 70125
Email: jessica@all4energy.org
Fax: (504)313-3478; Phone: (504)208-9761

Sophie Zaken
Alliance for Affordable Energy
4505 S. Claiborne Avenue
New Orleans, LA 70125
Email: regulatory@all4energy.org
Fax: (504)313-3478; Phone: (504)208-9761

Susan Stevens Miller - Pro Hac Vice
Earthjustice
1001 G Street NW, Suite 1000
Washington, DC 20001
Email: smiller@earthjustice.org
Fax: ; Phone: (202)797-5246

Intervenor : **Association of Louisiana Electric Cooperatives, Inc.**

Kyle C. Marionneaux
Marionneaux Kantrow, LLC
10202 Jefferson Highway, Building C
Baton Rouge, LA 70809
Email: kyle@mklawla.com
Fax: (225)757-1709; Phone: (225)769-7473

Kara B. Kantrow
Marionneaux Kantrow, LLC
10202 Jefferson Highway, Bldg. C
Baton Rouge, LA 70809-3183
Email: kara@mklawla.com
Fax: (225)757-1709; Phone: (225)769-7473

J. H. "Hunter" Odom III
Marionneaux Kantrow, LLC
10202 Jefferson Highway, Building C
Baton Rouge, LA 70809
Email: hunter@mklawla.com
Fax: (225)757-1709; Phone: (225)769-4773

Intervenor : **Cleco Power LLC**

Paul F. Guarisco
Phelps Dunbar, LLP
400 Convention Street, Suite 1100
Baton Rouge, LA 70802
Email: paul.guarisco@phelps.com
Fax: (225)381-9197; Phone: (225)376-0241

John O. Shirley
Phelps Dunbar LLP
II City Plaza, 400 Convention Street, Suite 1100
Baton Rouge, LA 70821
Email: john.shirley@phelps.com
Fax: (225)376-9197; Phone: (225)376-0288

Taylor J. Boudreaux
Phelps Dunbar, LLP
II City Plaza, 400 Convention Street, Ste 1100
Baton Rouge, LA 70821
Email: taylor.boudreaux@phelps.com
Fax: (225)381-9197; Phone: (225)376-0241

Intervenor : **Entergy Louisiana, LLC**

Alison N. Palermo
Stanley, Reuter, Ross, Thornton & Alford
909 Poydras Street
Suite 2500
New Orleans, LA 70112
Email: anp@stanleyreuter.com
Fax: (504)524-0069; Phone: (504)523-1580

W. Raley Alford III
Stanley, Reuter, Ross, Thornton & Alford, LLC
909 Poydras Street
Suite 2500
New Orleans, LA 70112
Email: wra@stanleyreuter.com
Fax: (504)524-0069; Phone: (504)523-1580

Harry M. Barton
Entergy Services, Inc.
639 Loyola Avenue
Mail Unit L-ENT-26E
New Orleans, LA 70113
Email: hbarton@entergy.com
Fax: (504)576-5579; Phone: (504)576-2984

Elizabeth C. Ingram
Entergy Services, LLC
4809 Jefferson Highway
Mail Unit L-JEF-357
Jefferson, LA 70121
Email: eingram@entergy.com
Fax: (504)840-2681; Phone: (504)840-2528

D. Skylar Rosenbloom
Entergy Services, LLC
639 Loyola Avenue
Mail Unit L-ENT-26E
New Orleans, LA 70113
Email: drosenb@entergy.com
Fax: (504)579-5579; Phone: (504)576-2603

Lawrence J. Hand Jr.
Entergy Louisiana, LLC

4809 Jefferson Highway
Mail Unit L-JEF-357
Jefferson, LA 70121
Email: lhand@entergy.com
Fax: (504)840-2681; Phone: (504)840-2528

Stacy Castaing
4809 Jefferson Highway, Mail Unit L-JEF-357
Jefferson, LA 70121
Email: scastai@entergy.com
Fax: (504)840-2681; Phone: (504)840-2681

Intervenor : **Environmental Defense Fund**

Bria M. Calvin
Environmental Defense Fund
3801 Canal Street
New Orleans, LA 70119
Email: bcalvin@edf.org

Liz Russell
Environmental Defense Fund
3801 Canal Street
New Orleans, LA 70119
Email: lwrussell@edf.org

Michael Panfil
Environmental Defense Fund
3801 Canal Street
New Orleans, LA 70119
Email: mpanfil@edf.org

Intervenor : **Louisiana Energy Users Group**

Gordon D. Polozola
Kean Miller LLP
400 Convention Street, Suite 700 (70802)
P.O. Box 3513
Baton Rouge, LA 70821
Email: gordon.polozola@keanmiller.com
Fax: (225)388-9133; Phone: (225)387-0999

Randy Young
Kean Miller, LLP
400 Convention Street, Suite 700 (70802)
Post Office Box 3513
Baton Rouge, LA 70821-3513
Email: Randy.Young@keanmiller.com
Fax: (225)388-9133; Phone: (225)387-0999

Intervenor : **Northeast Louisiana Power Cooperative, Inc.**

Luke F. Piontek
Roedel, Parsons, Blache, Fontana, Piontek & Pisano
8440 Jefferson Highway, Suite 301
Baton Rouge , LA 70809
Email: lpiontek@roedelparsons.com
Fax: (225)928-4925; Phone: (225)929-7033

Daniel T. Price
Roedel, Parsons, Blache, Fontana, Piontek & Pisano
8440 Jefferson Highway, Suite 301
Baton Rouge, LA 70809
Email: dprice@roedelparsons.com
Fax: (225)928-4925; Phone: (225)929-7033

Raven A. Bourque
Roedel, Parsons, Blache, Fontana, Piontek & Pisano
8440 Jefferson Highway, Suite 301
Baton Rouge, LA 70809
Email: rbourque@roedelparsons.com
Fax: (225)928-4925; Phone: (225)929-7033

Intervenor : **Packaging Corporation of America and Louisiana Energy Users Group and Lafayette Utilities System and International Paper Company**

Carrie R. Tournillon
Kean Miller, LLP
909 Poydras Street, Suite 3600
New Orleans, LA 70112
Email: carrie.tournillon@keanmiller.com
Fax: (225)388-9133; Phone: (225)387-0999

Intervenor : **Pointe Coupee Electric Membership Corporation**

Jennifer J. Vosburg

Jennifer J. Vosburg, LLC

P. O. Box 956

New Roads, LA 70760

Email: jjv@jenniferjvosburg.com

Fax: (225)618-4370; Phone: (225)240-2282

Myron Lambert

P.O. Box 160

2506 False River Drive

New Roads, LA 70760-0160

Email: mlambert@pcemc.org

Fax: (225)638-8124; Phone: (225)328-3989

Intervenor : **Southwest Louisiana Electric Membership Corporation**

Theodore G. Edwards IV

Davidson, Meaux, Sonnier, McElligott, Fontenot, Gideon & Edwards

810 South Buchanan Street

P. O. Box 2908

Lafayette, LA 70501

Email: gedwards@davidsonmeaux.com

Fax: (337)237-3676; Phone: (337)237-1660

Elizabeth Bonnette

Davidson, Meaux, Sonnier, McElligott,Fontenot, Gideon & Edwards, LLP

810 South Buchanan Street (70501)

Post Office Drawer 2908

Lafayette, LA 70502-2908

Email: lleblanc@davidsonmeaux.com

Fax: (337)237-3676; Phone: (337)237-1660

Hoa Nguyen (Paralegal)

Davidson, Meaux, Sonnier, McElligott, Fontenot, Gideon & Edwards

810 South Buchannan

P. O. Box 2908

Lafayette, LA 70502

Email: hnguyen@davidsonmeaux.com

Fax: ; Phone: (337)237-1660

Wayne Phillips

P.O. Box 90866

Lafayette, LA 70509-0866

Email: wayne.phillips@slemco.com

Fax: (337)896-2542; Phone: (337)896-5384

Christopher J. Piasecki

Davidson, Meaux, Sonnier, McElligott, Fontenot, Gideon & Edwards

810 South Buchanan Street

P. O. Box 2908

Lafayette, LA 70502-2908

Email: cpiasecki@davidsonmeaux.com

Fax: ; Phone: (337)237-1660

Intervenor : **Southwestern Electric Power Company**

Jonathan P. McCartney
Wilkinson Carmody & Gilliam
400 Travis Street, Suite 1700,
Shreveport, LA 71101
Email: jmccartney@wcglawfirm.com
Fax: (318)221-3705; Phone: (318)221-4196

Bobby S. Gilliam
Wilkinson Carmody & Gilliam
400 Travis Street, Suite 1700
Shreveport, LA 71101
Email: bgilliam@wcglawfirm.com
Fax: (318)221-3705; Phone: (318)221-4196

Intervenor : **Together Louisiana (TLA)**

Broderick Bagert
2721 S. Broad St
New Orleans, LA 70125
Email: broderick@togetherla.org

Alaina DiLaura
2721 S. Broad St
New Orleans, LA 70125
Email: alaina@togetherla.org

Erin Hansen
2721 S. Broad St.
New Orleans, LA 70125
Email: erin@togetherla.org

Pierre Moses
2721 S. Broad St
New Orleans, LA 70125
Email: pmoses@127energy.com

Abel Thompson
2721 S. Broad St
New Orleans, LA 70125
Email: abel@togethernola.org

Cynthia Coleman
2721 S. Broad St
New Orleans, LA 70125
Email: cynthia@togetherla.org

Erik Hancock
2721 S. Broad St.
New Orleans, LA 70125
Email: erik@togetherla.org

Interested Party :

Andrew Tuozzolo
Council Utility Regulatory Office
City of New Orleans
1300 Perdido Street, Room 6E07
New Orleans, LA 70112
Email: avtuozzolo@nola.gov

Helena Moreno
New Orleans City Council
1300 Perdido Street, Room 6E07
New Orleans, LA 70112

Interested Party : LCTA

Robert L. Rieger Jr.
Adams and Reese, LLP
450 Laurel St
Suite 1900
Baton Rouge, LA 70801-1820
Email: Robert.Rieger@arlaw.com
Fax: (225)336-5220; Phone: (225)336-5200

Susan N. Eccles
Adams and Reese LLP
450 Laurel Street
Suite 1900
Baton Rouge, LA 70801
Email: susan.eccles@arlaw.com
Fax: ; Phone: (225)378-3226

Taylor M. LeDuff
Adams & Reese LLP
450 Laurel Street, Suite 1900
Baton Rouge, LA 70801
Email: Taylor.LeDuff@arlaw.com
Fax: (225)336-520_; Phone: (225)336-5200