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April 17, 2023

Via Electronic Delivery
Ms. Lora W. Johnson, CMC, LMMC
Clerk of Council
City Hall - Room 1E09
1300 Perdido Street
New Orleans, LA 70112

Re: IN RE: SYSTEM RESILIENCY AND STORM HARDENING
Council Docket No. UD-21-03

Dear Ms. Johnson:

In compliance with Council Resolution R-23-74, Entergy New Orleans, LLC ("ENO") attaches for filing its Application for Approval of Future Ready Resilience Plan (Phase I). This filing includes the Direct Testimony and Exhibits of Sean Meredith, Jason De Stigter, and Alyssa Maurice-Anderson. ENO submits this filing electronically and will submit the requisite original and number of hard copies once the Council resumes normal operations, or as you direct. ENO requests that you file this submission in accordance with Council regulations as modified for the present circumstances.

Please note that one exhibit in the filing (SM-2), which is attached to Mr. Meredith's testimony, contains Highly Sensitive Protected Material ("HSPM"). The HSPM exhibit is being provided via electronic means only to those appropriate reviewing representatives who have executed the Official Protective Order in this docket, and as further provided therein.

If you have any questions, please do not hesitate to call me. Thank you for your courtesy and assistance with this matter.

Sincerely,

Edward R. Wicker, Jr.

ERW/jlc

cc: Official Service List (UD-21-03)

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

IN RE: SYSTEM RESILIENCY AND STORM HARDENING	**))**	**DOCKET NO. UD-21-03**

APPLICATION OF ENTERGY NEW ORLEANS, LLC FOR APPROVAL OF FUTURE READY RESILIENCE PLAN (PHASE I)

Entergy New Orleans, LLC ("ENO" or "the Company"), in compliance with the requirements of Resolution R-23-74 issued by the Council of the City of New Orleans ("Council"), respectfully submits this Application for Approval of ENO's Future Ready Resilience Plan (Phase I) ("Application"). For the reasons described herein and in the accompanying testimony, the Council should approve the Application.

Given the extreme weather events impacting New Orleans and the entire Gulf Coast region with increased frequency and severity, and that ENO customers are more dependent than ever on the electric system, the Company understands the need to strengthen further the resilience of its electric system. In particular, with this Application, the Company requests that the Council approve its proposed resilience efforts as serving the public convenience and necessity, in the public interest, and therefore prudent. In addition, the Company requests that the Council approve, among other things, the Company's proposed cost recovery mechanism and monitoring plan, and issue all such approvals no later than December 31, 2023, such that the Company expeditiously can proceed to implement the proposed infrastructure hardening for the benefit of customers.[1] The relief sought in this Application, as supported by the accompanying witness testimony and exhibits

[1] As noted herein, considering the threat of future storms and need to construct incremental infrastructure hardening in New Orleans, ENO urges that the Council timely consider (and approve) the Application even if consideration of other resilience efforts (*e.g.*, microgrids) remains pending.

thereto, is necessary to foster a more hardened system that can better withstand extreme events, reduce restoration costs for customers, and mitigate customer outages from such events.

I. OVERVIEW

Following Hurricane Ida, and considering the recent years of historically severe weather annually affecting the areas served by the Company and the other Entergy Operating Companies ("EOCs"),[2] including both major hurricanes and severe winter storms, the Company began a process of studying what efforts it could take to build on and accelerate the hardening efforts previously approved by the Council. The result of those comprehensive and customer-focused efforts – which have been aimed at understanding the risks faced and identifying cost-effective and achievable hardening projects to build a more resilient electric system in New Orleans – is the Company's Future Ready Resilience Plan ("Resilience Plan").[3]

The Company recommends $1 billion in distribution and transmission hardening projects to be completed in two phases over the ten-year period from 2024 to 2033. In this Application, the Company seeks specific approval of Phase I, which includes approximately $559 million in hardening projects proposed to be implemented in the first five years (2024 to 2028) ("Phase I"). As discussed herein and in witness testimony, the Resilience Plan is reasonably expected to reduce the cost to customers of restoring the electric grid in New Orleans after major storms, as well as to reduce the number and duration of outages that customers experience following those events. These expected improvements are vital to both the Company and the communities served by the Company, as well as to the economy in New Orleans. Through the requested monitoring plan, the

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[2] The five EOCs include ENO; Entergy Arkansas, LLC; Entergy Louisiana, LLC; Entergy Mississippi, LLC; and Entergy Texas, Inc.

[3] Given that Resolution R-23-74, as noted herein, narrowed the scope of this docket, the Company's Resilience Plan solely focuses on hardening projects. Should the Council ultimately be inclined to consider additional measures as part of an overall resilience strategy for New Orleans, those measures (some of which the Company briefly mentions herein) can complement the Company's Resilience Plan.

Company proposes to provide the Council with semi-annual updates regarding its activities under the Resilience Plan.[4]

In addition, the Company is seeking approval of a new rider, the Resilience and Storm Hardening Cost Recovery Rider ("Resilience Rider"), to permit timely recovery of the Resilience Plan's revenue requirement. The Resilience Rider would help support ENO's ability to finance the projects in the Resilience Plan and ensure that they can be done timely and efficiently, including taking advantage of economies of scale and a qualified workforce because the work would be ongoing and not forced to start and stop as rate changes are sought and decided. Without timely and efficient cost recovery for the projects, ENO's financial health likely would be further compromised given the amount of the expenditures involved over an extended period. Moreover, in the event ENO receives federal funds for certain projects in the Resilience Plan, there is flexibility in the Resilience Rider to offset investment and reduce the rate timely pursuant to a methodology contained therein. The Resilience Rider contains true-up provisions under which the Company would provide the Council with an annual report regarding the actual costs of projects in the Resilience Plan.

In support of the relief requested in this Application, the Company has attached hereto the testimonies of the following witnesses:

- Sean Meredith – Vice President, System Resilience for Entergy Services, LLC ("ESL"). Mr. Meredith presents ENO's Resilience Plan and provides details regarding the proposed projects therein. He summarizes the estimated costs and benefits of implementing the Resilience Plan, provides support for the conclusion that the Resilience Plan is in the public interest and should be undertaken, and discusses the Company's

[4] The specific projects contained in the Resilience Plan are attached to the testimony of Company witness Sean Meredith as Highly Sensitive Protected Materials ("HSPM") Exhibit SM-2. Although the Company's Resilience Plan sets forth the Company's best efforts to identify the scope and timing of the projects, the precise work performed (as well as the exact timing of when that work will be performed) will be subject to continual refinement as the Company implements the Resilience Plan ultimately approved by the Council.

proposed monitoring plan. He also discusses certain modeling and a more frequent and intense storm future.

- Jason De Stigter – Director, 1898 & Co. Mr. De Stigter summarizes the results and methodology used for potential levels of infrastructure hardening investment for the Company, in particular for the Resilience Plan. He describes the major elements of the Storm Resilience Model ("SRM"), and the datasets used and model system impacts due to storm events, and explains how to understand the resilience benefit results. He also describes the calculations and results of the SRM.

- Alyssa Maurice-Anderson – Director, Regulatory Filings and Policy, for ESL. Ms. Maurice-Anderson supports the Company's requested approval of the Resilience Rider and associated ratemaking treatment for the projects in the Resilience Plan, as well as certain additional ratemaking treatment. She also discusses bill impacts to customers from Phase I of the Resilience Plan. In addition, she supports a finding from the Council that the Company's Resilience Plan is in the public interest and therefore prudent.

II. BACKGROUND

The Company takes seriously its responsibility to provide customers with safe and reliable service at the lowest reasonable cost. To that end, in collaboration with the Council, ENO historically has planned its electric system to withstand reasonably expected risks, and the Company has been modernizing its system over time. The Company and the Council have worked together on storm hardening, and the Company's prior storm hardening strategies were approved by the Council.[5] In addition, the Company has made significant investments in its electric system and worked to maintain its system – all of which have produced results.[6] The last few hurricane

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[5] For example, upon Council approval in July 2017, the Company executed an approximately $30 million storm hardening plan, which included pole treatment or replacement, targeted equipment for replacement or upgrade, grid sectionalization and automation, and circuit reconfiguration. *See* Council Resolution R-17-331.

[6] In May 2020, for example, the Company brought into service the New Orleans Power Station ("NOPS"), which added 128 megawatts ("MW") of needed local generation, facilitated the deployment of renewable resources, and played a vital role in New Orleans' recovery from Hurricane Ida. The 20 MW New Orleans Solar Station ("NOSS") followed later in 2020, and the Company also has deployed distributed commercial and residential rooftop solar facilities throughout New Orleans. The Company also has made significant investments in transmission lines and substations in New Orleans that have improved ENO's resilience and ability to reliably serve customers. Moreover, the Company has invested significantly in its distribution system to modernize and improve the reliability and resilience of the grid, as documented extensively in Council Docket No. UD-17-04 and elsewhere.

seasons have shown, however, that extreme weather events are impacting the New Orleans area and the entire Gulf Coast region with increased frequency and severity, with greater costs and disruptions to ENO, its customers, and New Orleans itself.[7] The Council correctly has observed that "this cycle of damage and repair is not sustainable for the Company or ratepayers."[8]

Given the increasing frequency and intensity of extreme weather events, and that higher demand is being placed on resilience than even the very recent past,[9] the Council opened this docket to "increase resiliency and storm hardening on ENO's system, with a particular focus on reducing weather-related power outages."[10] In July 2022, consistent with Council direction,[11] the Company presented, among other things, a preliminary set of infrastructure hardening projects, identified through comprehensive modeling and rigorous analysis, intended to accelerate the Company's efforts and be implemented over the next ten years.[12] In addition, Together New Orleans ("TNO") submitted a resilience proposal, which involves building "resiliency hubs" at various churches and community centers, to be powered by solar panels and batteries, where residents can gather during a storm outage.[13] Other stakeholders also submitted certain proposals with varying resilience objectives.[14]

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7 Over the last several years, major hurricanes have become more frequent and intense, and slower and wetter, further increasing the potential for devastation. Between 2005 and 2017, no hurricanes higher than a Category 2 struck the United States. Since 2017, however, eight major hurricanes have made landfall in the contiguous United States or Puerto Rico: Harvey (2017), Irma (2017), Maria (2017), Michael (2018), Laura (2020), Zeta (2020), Ida (2021), and Ian (2022). Moreover, coastal erosion caused by such severe storms, among other things, has increased the vulnerability of New Orleans by removing an important wetlands buffer.

8 Resolution R-21-401, p. 2.

9 Many people are now working from their homes and are more dependent than ever on constant connectivity for daily life and in storm events.

10 Resolution R-21-401, p. 2.

11 Resolution R-21-401, pp. 2-3.

12 ENO Resilience and Storm Hardening Filing, dated July 1, 2022.

13 TNO Proposal to Infrastructure Investment and Jobs Act ("IIJA") Joint Council and Legislative Committee, dated July 26, 2022.

14 For example, the City of New Orleans ("City") submitted a resilience proposal including potential opportunities for microgrids, rooftop solar, community solar, generator readiness projects, resilience programs with TNO, and clean energy programs. City Proposal, dated July 1, 2022.

After submitting those proposals, the parties and other stakeholders have worked collaboratively to consider resilience and related issues through participation in discovery, technical conferences, and several rounds of comments.[15] To provide further guidance in this docket, the Council recently issued Resolution R-23-74, which requires, among other things, that ENO submit:

> (a) a narrowed list of distribution and transmission projects based on those expected to result in the highest level of resiliency and storm hardening throughout the City over the next five (5) years, considering the system's current level of vulnerability, the costs and benefits of each of the proposed projects, including the prioritization of project implementation based on benefits vs. cost or other criteria, and the lowest reasonable impact on customers' rates that should be considered in the Master System Resiliency and Storm Hardening Plan; (b) a reasonably detailed annual budget for each project, the projected timeline for completion, and the total estimated cost of the projects; and (c) a proposed cost recovery mechanism, including a supportable basis for cost allocation by customer class.[16]

Consistent with Resolution R-23-74, the Company has filed this Application seeking approval of Phase I of its Resilience Plan, the Resilience Rider, and related requests for relief.

III. <u>THE MODEL AND INVESTMENT LEVELS</u>

As noted above, the Resilience Plan involves significant incremental spending in hardening the Company's distribution and transmission systems to address the potential impacts caused by increasingly severe weather events. In collaboration with 1898 & Co.,[17] the Company utilized a resilience-based planning approach to identify hardening projects[18] and prioritize investment in ENO's transmission and distribution assets through the SRM. Using a four-step process that

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15 Resolution R-22-411, pp. 2-5.

16 Resolution R-23-74, pp. 8-9.

17 1898 & Co. is the consulting division of Burns & McDonnell Engineering Company, Inc., and has experience in, among other things, risk and resilience analysis studies on a variety of electric power transmission and distribution assets, including developing complex and innovative risk and resilience analysis models.

18 With respect to the Resilience Plan, the term "project" refers to a set of assets for hardening.

Messrs. De Stigter and Meredith discuss in their testimonies, the SRM employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to evaluate the assets on ENO's system and calculate resilience costs and estimated benefits of hardening those assets in terms of avoided customer minutes interrupted and avoided future storm restoration costs.

The ultimate purpose of the SRM is to identify and prioritize projects that would have the highest benefits to customers. Because it would be infeasible, both logistically and financially, to address the risks arising from every single asset on the ENO electric system, the SRM serves to identify and prioritize hardening the sets of assets that would deliver the most benefits to customers in terms of avoided outage minutes and avoided future storm restoration costs for the money spent. In this way, the SRM facilitates the prudent and efficient use of finite resources to achieve the most significant reduction of risk that can be achieved through reasonable diligence. This methodology is described in more detail in the testimony and exhibits of Mr. De Stigter, who assisted the Company in developing the Resilience Plan.

As an initial matter, the SRM identified an overall set of hardening projects costing approximately $1.3 billion that could be executed by the Company over the next ten years. Thereafter, the Company worked with 1898 & Co. to evaluate two additional, alternative sets of hardening projects (or investment levels) that are subsets of the overall set – one portfolio of projects costing approximately $1 billion and another portfolio of projects costing approximately $750 million. Considering the three sets of projects, the Company compared their potential costs, annual spending levels, and potential benefits to customers, and also evaluated the potential bill impacts to customers. In so doing, the Company generally kept three over-arching principles in mind: (i) the need to mitigate the impact of major storms (*i.e.*, improving resilience following a major storm by reducing customer minutes interrupted and restoration costs); (ii) the goal of investing in projects where the customer benefits outweigh the costs; and (iii) the realities of establishing an executable and feasible portfolio of projects considering such factors as labor, materials, and other constraints. The Company and 1898 & Co. determined that each level of investment ($1.3 billion, $1 billion, and $750 million) met each of these principles. Messrs. Meredith and De Stigter discuss (and compare) the different portfolios in their testimonies and attached exhibits.

The Company selected the portfolio of hardening projects costing approximately $1 billion for its Resilience Plan. The Company chose this portfolio because it is achievable (in terms of project cost, timing, and execution), and will improve the resilience of the system by helping to significantly reduce the costs of future restorations and the duration of outages after severe weather events in the future. While additional projects within the $1.3 billion portfolio could be completed that would provide value to customers (and, as a result, potentially provide more overall benefits to customers), the Company has been and continues to be mindful of bill impacts to customers. The $1 billion portfolio reduces the overall projected costs of the $1.3 billion portfolio without sacrificing too much of the potential benefits that can be realized through these investments. The $750 million portfolio of projects generated by the SRM is the minimum level of accelerated hardening necessary to meaningfully improve the resilience of the Company's electric system to the extent called for by the Council and stakeholders in this docket.

The $1.3 billion and $750 million portfolios provide a ceiling and floor, respectively, for addressing resilience on an accelerated basis. The Company ultimately selected the $1 billion portfolio because it strikes an appropriate balance between costs to customers and the need for accelerated infrastructure hardening to address the frequency and intensity of storms that pose an increasing threat to the Company's electric system.

IV. RESILIENCE PLAN

Under the Resilience Plan, the Company proposes to complete nearly 650 identified distribution and transmission hardening projects, which will harden more than 26,600 structures over more than 500 line miles at a cost of approximately $1 billion over the course of the ten-year period from 2024 to 2033. The Company is proposing to implement the Resilience Plan in two five-year phases. In this Application, the Company seeks specific approval of Phase I of the Resilience Plan (2024 to 2028), which includes hardening projects estimated to cost approximately $559 million. Messrs. De Stigter and Meredith discuss the Resilience Plan more fully in their testimonies.

A. Proposed Projects and Costs

The SRM grouped hardening projects into four general programs: Distribution Feeder Hardening (Rebuild), Lateral Hardening (Rebuild), Lateral Undergrounding, and Transmission Rebuild.[19] The projects included in the Distribution Feeder Hardening (Rebuild), Lateral Hardening (Rebuild), and Transmission Rebuild programs involve hardening the assets contained in those projects (*e.g.,* bringing those assets up to the current design standards). The Lateral Undergrounding program involves the undergrounding of overhead lines.

1. Distribution Projects

The SRM identified 140 hardening projects in the Distribution Feeder Hardening (Rebuild) and Distribution Feeder Undergrounding programs that have positive benefit to cost ratios and fall within the $1 billion portfolio, at an estimated nominal cost of $647 million over ten years. For Phase I of the Resilience Plan, the Company proposes to complete 58 of these projects, at an estimated nominal cost of $262 million. Additionally, the SRM identified 493 projects in the

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[19] The SRM considered additional programs, such as Distribution Feeder Undergrounding, but the SRM did not select projects in those programs.

Lateral Hardening (Rebuild) program and thirteen (13) projects in the Lateral Undergrounding program that have positive benefit to cost ratios and fall within the $1 billion portfolio, at an estimated nominal cost of $292 million and $10 million, respectively. For Phase I of the Resilience Plan, the Company proposes to complete 259 Lateral Hardening (Rebuild) projects and twelve (12) Lateral Undergrounding projects, at an estimated nominal cost of $144 million and $10 million, respectively. These projects are contained in Exhibit SM-2 to Mr. Meredith's testimony.

By way of example, the Company proposes to perform one Distribution Feeder Hardening (Rebuild) and six Lateral Hardening (Rebuild) projects during Phase I along a circuit located in Council District E, hardening more than 480 structures across more than twelve (12) line miles. Together, these projects are estimated to cost approximately $18 million, and are expected to reduce future restoration costs following storms by approximately $12.9 million and reduce the total number of customer minutes interrupted following major events by 50 million minutes over the next fifty (50) years assuming an above average frequency of storms. Another example is a set of two Distribution Feeder Hardening (Rebuild) and seven Lateral Hardening (Rebuild) projects that the Company proposes to complete during Phase I along a circuit located in Council District B, hardening more than 430 structures along more than 5 line miles. Together, these projects are estimated to cost approximately $13 million, and are expected to reduce future restoration costs following storms by approximately $6.6 million and reduce the total number of customer minutes interrupted following major events by 93 million minutes over the next fifty years assuming an above average frequency of storms.

2. <u>Transmission Projects</u>

The SRM identified 2 Transmission Rebuild projects that have positive benefit to cost ratios and fall within the $1 billion portfolio, at an estimated nominal cost of $51 million. These transmission projects are contained in Exhibit SM-2 to Mr. Meredith's testimony. Specifically, one project is on the Front Street to Michoud 230 kV line, a 23-mile line that traverses Lake Pontchartrain from ENO's Michoud substation and connects with Cleco Power LLC's Front Street substation. This line provides an additional connection to the eastern interconnect from the eastern side of New Orleans that allows for additional flexibility to operate during and after a major event. This project would be completed in Phase I of the Resilience Plan. The other project, which would be completed in Phase II of the Resilience Plan, is on the Gulf Outlet to Air Products 69 kV line, which is approximately one (1) mile in length, and would involve the replacement of several structures on the transmission line. Together, these projects are expected to reduce future restoration costs following storms by approximately $2.4 million, and reduce the total number of customer minutes interrupted following major events by 596 million minutes over the next fifty years assuming an above average frequency of storms.

B. <u>Customer Benefits</u>

The Company expects that the Resilience Plan will produce significant customer benefits by, among other things, (1) lowering future post-storm restoration costs and (2) decreasing the number of customers impacted and the duration of outages after major weather events by creating distribution and transmission systems that are more resilient in the face of increasingly severe weather. While no amount of investment or hardening will completely eliminate outages or restoration costs caused by future storms, the identified projects in the Resilience Plan are expected to decrease storm restoration costs, the number of customers impacted by outages from future storms, and the overall duration of outages over the next fifty years.

Based on the SRM, assuming each hardening project in the Resilience Plan is performed, the SRM projects that the Company and customers will see future restoration costs following storms decreased by approximately $390 million and the total number of customer minutes interrupted following major events decreased by 7.1 billion minutes over the next fifty years assuming an above average frequency of storms. In other words, the identified projects are reasonably projected to produce a reduction in storm restoration costs of approximately 49 percent and a decrease in the projected customer minutes interrupted after a major storm by approximately 45 percent over the next 50 years assuming an above average storm future. For the projects completed during Phase I of the Resilience Plan, the Company estimates that those projects will decrease future restoration costs following major weather events by approximately $216 million and lead to a reduction in total customer minutes interrupted following major events of 3.76 billion minutes over the next fifty years assuming an above average frequency of storms.

Another anticipated benefit of implementing the Company's Resilience Plan is that "blue sky" resilience work can be more carefully planned, executed, and overseen as compared to reactive, post-storm restoration work where the Company is working as quickly and safely as possible to restore power, often in highly unattractive conditions and with tens of thousands of contract workers laboring simultaneously across a vast area impacted by a major storm. Further, although the focus of the Resilience Plan is on protection of the Company's systems against major storm events, taking an accelerated approach to hardening projects allows customers to enjoy the enhanced reliability benefits of the projects sooner than if the projects were delayed. While this benefit is incidental, it is not insignificant, particularly considering customers' ever-increasing reliance upon electricity.

V. <u>MONITORING PLAN</u>

To keep the Council informed on the progress of the Resilience Plan, the Company is proposing to file progress reports every six months beginning August 1, 2024. As discussed by Mr. Meredith in his testimony, the reports generally will provide information regarding the preceding two quarters and will address subjects such as project completion status, projects schedule, material business issues, and related matters. For example, the report filed on August 1, 2024, will discuss hardening projects completed and developments in the execution of the Resilience Plan for the period of January 1, 2024, through June 30, 2024. The report filed on February 15, 2025, will discuss projects completed and developments in the execution of the Resilience Plan for the period of July 1, 2024, through December 31, 2024. Near the end of Phase I, the Company will evaluate the impact of its efforts and make a recommendation about completing the portfolio of resilience projects in Phase II of the Resilience Plan (2029 to 2033).[20]

VI. RATE RECOVERY AND BILL IMPACTS

A. Resilience Rider

As Ms. Maurice-Anderson discusses in her testimony, ENO is entitled to a reasonable opportunity to recover its prudently incurred costs under the Resilience Plan.[21] Given the large capital investment involved in implementing the Resilience Plan and ENO's small size and risk profile, it is essential that ENO have assurance that it can recover its investment in a timely manner. ENO does not currently have a ratemaking mechanism that would permit timely cost recovery over the Resilience Plan's construction phase. Undertaking the proposed Resilience Plan without a ratemaking mechanism that provides contemporaneous cost recovery would compromise ENO's credit metrics and cash flow and thus expose ENO to further adverse action from credit rating agencies and expose its customers to higher costs, not only as to the Resilience Plan but across

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[20] Phase II of the Resilience Plan is projected to include approximately $441 million in additional infrastructure hardening projects.

[21] *South Cent. Bell Tel. Co. v. Louisiana Pub. Serv. Comm'n*, 594 So. 2d 357, 366 (La. 1992) ("Under that principle, South Central Bell is entitled to be compensated for all prudent investments at their actual cost when made (their 'historical' cost) irrespective of whether individual investments are deemed necessary or beneficial in hindsight; and the utility is entitled to the presumption that the investments were prudent, unless the contrary is shown."); *see also Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 605 (1944); *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm' of West Virginia*, 262 U.S. 679, 690 (1923).

ENO's entire business.[22] Therefore, ENO is proposing that the revenue requirement associated with the Resilience Plan be recovered through the Resilience Rider. In short, the Resilience Rider would allow ENO to recover from customers, on a timely basis, the cost of the Resilience Plan, and would provide a stable, long-term recovery mechanism that could be used for the duration of the construction phase.

The Resilience Rider would help support ENO's ability to finance the Resilience Plan projects on reasonable terms and ensure that they can be done timely and efficiently, including taking advantage of economies of scale and a qualified workforce because the work would be ongoing and not forced to start and stop as rate changes are sought and decided. Contemporaneous cost recovery also is appropriate because as ENO completes projects, customers receive the benefits. An additional benefit of the Resilience Rider is that, in the event ENO receives federal (or other public) funds for resilience projects, there is flexibility to offset investment and reduce the rate timely pursuant to a methodology contained therein. Further, as part of the true-up portion of the Resilience Rider, the Company will provide the Council with an annual report comparing the actual project costs with projected costs, along with variance explanations.[23] ENO patterned

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[22] As the Council knows, in 2021 after Hurricane Ida, credit rating agencies downgraded ENO several times, and they have warned that further downgrades are possible if financial pressures are not mitigated and system resilience is not enhanced. Credit ratings directly affect ENO's cost of capital investment and overall customer rates. Without timely and efficient cost recovery for the projects presented herein, ENO's financial health likely would be further compromised given the amount of the expenditures involved over an extended period.

[23] As discussed in Ms. Maurice-Anderson's testimony, the Company's revenue requirement calculations capitalize distribution conductor handling costs incurred with projects in the Resilience Plan, which are those costs associated with transferring existing conductors and fixtures to new poles during pole replacements. While the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts typically requires these costs to be recorded to Account 593 Maintenance of Overhead Lines, an operation and maintenance expense ("O&M") account, the Company intends to request a waiver from the FERC to allow ENO to capitalize these costs, which treatment would benefit customers by allowing recovery of the costs over time as projects are depreciated, and thereby lowering the Resilience Plan's immediate bill effects, instead of being recovered in their entirety in the year the cost is incurred. In so doing, ENO seeks to prevent an increase in O&M recorded to Account 593 solely due to those projects. Other utilities recently sought and were granted substantially similar authorizations from FERC. *See* Florida Power & Light Co., FERC Letter Order, Docket No, AC18-23 (Jan. 31, 2018); Gulf Power Co., FERC Letter Order, Docket No, AC20-131 (July 30, 2020); Duke Energy Florida, LLC, FERC Letter Order, Docket No, AC21-141 (July 29, 2021). All other distribution conductor handling costs would continue to be recorded as O&M in Account 593.

the Resilience Rider on cost recovery mechanisms previously approved by the Council,[24] and it is consistent with the regulatory treatment adopted in other jurisdictions.[25]

ENO proposes that the Resilience Rider rate be allocated as a percentage rate adjustment to customers' base rate charges and be applicable to the same rate schedules as the adjustments under its Electric Formula Rate Plan. The estimated revenue requirement would be allocated to each rate class based on its percentage contribution to per book base revenue in the previous calendar year. Thus, the rate under the Resilience Rider would be the same for each rate class. Moreover, using base revenue to allocate costs to be recovered through the Resilience Rider is consistent with the allocation used in the SSCR Rider, which contains a single rate for all rate classes and recovers storm restoration and financing costs based on projected base revenue. Given that the Council has allocated storm restoration costs and related financing costs using projected base revenue, it is reasonable to use base revenue as an allocator to recover the Resilience Plan, which largely is intended to mitigate storm restoration costs.

B. <u>Bill Impacts</u>

ENO's objective is to accelerate its resilience efforts to provide a more hardened system, while simultaneously maintaining affordable electric rates for customers. The Company understands that bill impacts are critically important in setting the appropriate pace of resilience investment. At the same time, however, New Orleans will experience hurricanes and other storm events in the future. Considering that inevitability and the consequences to customers, Mr. De Stigter discusses in his testimony that customers are expected to be better off with the Resilience

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24 The Purchased Power and Capacity Acquisition Cost Recovery Rider ("PPCACR Rider"), for example, allowed ENO to recover contemporaneously the revenue requirement associated with its investment in Union Power Block 1 prior to the implementation of new base rates from the 2018 Rate Case. Moreover, the Securitized Storm Cost Recovery Rider ("SSCR Rider") recovers the costs associated with Hurricane Isaac storm restoration and the 2015 replenishment of ENO's storm reserve.

25 For example, Section 366.96(7) of the Florida Statutes requires the Florida Public Service Commission to set rider rates to recover the cost of Florida utilities' resiliency projects.

Plan than without it. Indeed, the Resilience Plan is a tool that is expected to make customers' bills more affordable over the long run. As further discussed by Ms. Maurice-Anderson, the table below shows the estimated bill impacts associated with Phase I of the Resilience Plan.

Projected Rider Rate Impact of Proposed $1.0 Billion Resilience Plan Years 2024 through 2028			
Year	**Projected Total Cumulative Revenue Requirement ($ in Millions)**	**Projected Residential Cumulative Revenue Requirement ($ in Millions)**	**Projected Monthly Residential Bill Impact ($/month)**
2024	**$0.9**	**$0.4**	**$0.20**
2025	**$11.4**	**$5.5**	**$2.53**
2026	**$19.7**	**$9.6**	**$4.38**
2027	**$37.7**	**$18.3**	**$8.38**
2028	**$53.4**	**$25.9**	**$11.86**

C. Additional Ratemaking Treatment

As discussed by Ms. Maurice-Anderson in her testimony, ENO requests authorization to create a regulatory asset for the remaining net book value associated with assets that must be retired and replaced with new assets as part of the Resilience Plan. In future rate proceedings, ENO would include the regulatory asset in rate base and amortize such retired plant costs at a rate consistent with the associated depreciation expense currently reflected in rates. With this ratemaking treatment, customers would not see an incremental increase in rates while the Company recovers its prudently incurred costs, all else being equal. The net book value of these assets is already reflected in ENO's rate base and, therefore, its rates. Additionally, the prudent retirement of these assets to advance resilience objectives should not change ENO's right to recover a return on these assets.[26]

[26] For additional ratemaking treatment, see the earlier reference to distribution conductor handling costs incurred with projects in the Resilience Plan.

VII. PUBLIC INTEREST

The approvals sought in this Application are in the public interest. As Ms. Maurice-Anderson discusses in her testimony, the Company, along with 1898 & Co., has taken a comprehensive, thoughtful approach to developing the Resilience Plan and Resilience Rider, among other aspects of this Application, with the goal of reducing the effects of future storms on customers. The approach is customer-centric in that it quantifies benefits of the Resilience Plan directly in relation to the effects of those investments on customers, both on the storm restoration costs that customers will bear after future storms and the duration of the outages that customers will experience because of those storms. The Resilience Plan contains projects that produce overall customer benefits, and the Company's customers are expected to be better off paying for the proposed Resilience Plan in return for reduced storm restoration costs and reduced outage durations, rather than continuing on the current path without the Resilience Plan. Other factors discussed by the Company's witnesses also support finding that the proposed Resilience Plan and Resilience Rider, among other requests for relief, serve the public interest, are therefore prudent, and should be approved by the Council.[27]

VIII. REQUEST FOR TIMELY TREATMENT

As Mr. Meredith discusses in his testimony, considering the threat of future storms, ENO urges that the Council consider and approve the Application expeditiously, and no later than December 31, 2023. Council approval in this timeframe would allow the Company to timely commence Phase I of the Resilience Plan, with the intention to perform work on certain hardening projects before next hurricane season. Thereafter, the Company would file its first progress report

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[27] For all requests in this Application, as Ms. Maurice-Anderson states in her testimony, the Company has complied with, or is not in conflict with, the provisions of all applicable Council Resolutions and any other laws, regulations, or requirements that may be applicable.

with the Council on August 1, 2024, as proposed in the requested monitoring plan. Accordingly, for the Company to timely commence work and file the proposed report, the Company requests that the Council consider and approve the Application no later than December 31, 2023, even if consideration of additional resilience measures (*e.g.*, microgrids) remains pending.

IX. ADDITIONAL RESILIENCE MEASURES

Consistent with Resolution R-23-74, the Company has focused this Application on the hardening projects in the Resilience Plan. As the Council knows, however, the Company continues to consider additional resilience measures that potentially can complement the Resilience Plan to enhance local resilience. While consideration of additional measures remains under consideration and should not delay approval of the Resilience Plan, the Company briefly discusses certain measures below should the Council ultimately be inclined to consider and include them as part of a more comprehensive resilience strategy for New Orleans.

First, the Company continues to consider the potential costs and benefits of implementing new technology options in the form of microgrids to help prevent power disruptions to customers served on various feeders in the event of storm outages. While microgrids are not a substitute for hardening projects in the Resilience Plan, the projects complement each other. Indeed, the hardening projects in the Resilience Plan would establish a necessary, resilient foundation to implement and test the effectiveness of microgrids throughout New Orleans. In particular, the Company is evaluating the potential to deploy feeder-level microgrids, anchored by different sources of power, at locations based on the number of customers and criticality of loads served, the timing of certain feeder hardening projects in the Resilience Plan, as well as the presence of disadvantaged communities that are particularly affected by storm outages. By way of example, the Company is considering the following microgrids:

Derbigny Microgrid: This microgrid would serve all 1,300 customers on Feeder 1553 connected to the Derbigny 230 kV substation, including a drainage pumping station and the Odyssey House assisted living facility. This project would use the available local natural gas infrastructure to install a 6.5 MW natural gas fired generator to provide power to customers on the feeder.

Almonaster Microgrid: This microgrid would serve all 3,608 customers on Feeder 623 connected to the Almonaster 230 kV substation, including the Annunciation Inn assisted living facility. The project would use a 14.5 MW, 58 MWh battery to island the feeder and restore power to the load should the power source from the substation be disrupted.

Sherwood Forest Microgrid: This microgrid would couple the NOSS location with a 7.7 MW, 31 MWh battery, to serve all 1,300 customers on Feeder 1601 connected to the Sherwood Forest 115 kV substation, including Fire Engine #37 and Sewage and Water Board facilities.

The Company looks forward to further considering microgrids in the context of the Council's separate docket.[28]

Second, as the Council knows, trees and branches pose significant risks to the Company's electric utilities and public safety during storm events. The Company is considering whether an increase in the specifications for pruning/trimming City-owned trees, which currently allow for a 4-foot clearance from the Company's electric lines, may reduce those risks. An increase likely also would better align with the specifications in other EOC jurisdictions and current industry standards. In addition, the Company is considering whether to seek the ability to trim/prune City-owned trees around overhead secondary power lines, and proposing certain guidelines for trimming/pruning their limbs in relation to conductors, as well as the ability to skyline certain main trunk lines for City-owned trees, would further reduce those risks. While the Company continues

[28] The Council recently stated that microgrids would be considered in an "independent docket separate and apart from" this docket, "due to the need of a more comprehensive and focused analysis" of microgrids. Resolution R-23-74, p. 7.

to evaluate whether to propose such changes, among others, the Company expects they would have a favorable impact on resilience during storms.

Third, the Company understands that TNO intends to create "resilience hubs" at various churches and community centers in New Orleans, to be powered by rooftop solar panels and batteries in the event of an outage after a storm, where residents can seek to cool off and charge their phones, among other things. The Company has proactively engaged in discussions with TNO about its proposal, including how its proposed "resilience hubs" may complement the hardening projects in the Resilience Plan. While discussions are ongoing, and the Company looks forward to reviewing TNO's contemporaneous filing in this docket,[29] the Company believes there are opportunities to continue to work together on resilience.

Fourth, as the Council is aware, the Company has and will continue to seek federal funds that may provide resilience and cost benefits for ENO and its customers and align with the Company's resilience goals in the New Orleans area. ENO, for example, has submitted application(s) to the Department of Energy ("DOE") for federal funding for resilience through the Grid Resilience and Innovative Partnership ("GRIP") Program under the Infrastructure Investment and Jobs Act ("IIJA"). While the IIJA resilience programs are a high priority, ENO has and will continue to pursue other funding opportunities as they become available and align with the Company's resilience goals. ENO intends to keep informed the parties and other key stakeholders on its efforts to secure additional funding for resilience.

Finally, for New Orleans to be truly resilient, it will require more than just a strong electric grid and related enhancements. It will require consideration of additional measures such as building code standards, urban planning, elevation requirements, water management, and coastal

[29] Resolution R-23-74, pp. 4, 9-10. (TNO "shall make a filing no later than April 17, 2023….").

restoration. In each of these ways, New Orleans must become more resilient to protect its community and assets, generate economic activity, and preserve the economic competitiveness of the region. The Company has and continues to engage in discussions with local and state agencies and representatives, among others, regarding these issues. Should the Council wish to consider these issues in an overall resilience strategy for New Orleans, the Company is open to collaborating as part of wider efforts to develop and pursue a community approach to resilience.

X. PRAYER FOR RELIEF

For the foregoing reasons, Entergy New Orleans, LLC respectfully requests that its Application be approved. In particular, the Company requests that the Council:

1. Approve Phase I of the Resilience Plan as serving the public convenience and necessity, and in the public interest and therefore prudent, subject to an ongoing obligation of ENO to prudently manage the Resilience Plan;
2. Deem the prudently incurred costs under the Resilience Plan to be eligible for cost recovery via the rate mechanisms proposed by the Company;
3. Approve the Resilience and Storm Hardening Cost Recovery Rider to permit timely recovery of the Resilience Plan's revenue requirement and other procedures therein;
4. Approve a regulatory asset to be included in rate base for the remaining net book value associated with assets that must be retired and replaced with new assets as part of the Resilience Plan, with the amortization of the unrecovered balance occurring over the remaining useful life of the assets;
5. Approve the Company's proposed monitoring plan for the Resilience Plan;

6. Rule that, with respect to the Resilience Plan and associated requested relief, the Company has complied with, or is not in conflict with, the provisions of all applicable Council Resolutions and any other laws, regulations, or requirements that may be applicable;

7. Grant a waiver of any applicable Council requirement to the extent that such a waiver may be required to facilitate approval of the Resilience Plan and associated requested relief;

8. Issue a Council decision on the matters contained in this Application no later than December 31, 2023; and

9. Grant all other relief that the law and the nature of the case may permit or require.

Respectfully submitted,

By: ______________________________

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CERTIFICATE OF SERVICE
UD-21-03

I hereby certify that I have served the required number of copies of the foregoing pleading upon all other known parties of this proceeding individually and/or through their attorney of record or other duly designated individual.

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New Orleans, Louisiana, this 17th day of April, 2023

____

Edward R. Wicker, Jr.

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***IN RE*: SYSTEM RESILIENCY AND STORM HARDENING**	**))**	**DOCKET NO. UD-21-03**

DIRECT TESTIMONY

OF

SEAN MEREDITH

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

APRIL 2023

TABLE OF CONTENTS

EXHIBIT LIST

I. INTRODUCTION AND PURPOSE

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Sean Meredith. My business address is 2107 Research Forest Dr., Suite 300, The Woodlands, TX 77380. I am employed by Entergy Services, LLC ("ESL")[1] as Vice President, System Resilience.

Q2. ON WHOSE BEHALF ARE YOU SUBMITTING THIS DIRECT TESTIMONY?

A. I am submitting this Direct Testimony on behalf of Entergy New Orleans, LLC ("ENO" or the "Company").

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I have a Bachelor of Science degree in Systems Engineering from the United States Naval Academy, and I completed the Naval Nuclear Propulsion Program. I served in the United States Navy as a submarine officer aboard three fast attack submarines over a ten-year period. In my last assignment, aboard the USS Hartford, I served as the Engineer Officer responsible for the operation, maintenance, and repair of the nuclear reactor plant and all support systems, as well as training and qualifying all sailors in the engineering department.

In 2014, I joined Entergy's nuclear organization as a supervisor of the Instrumentation and Controls department at the James A. FitzPatrick Nuclear Power Plant

[1] ESL is a service company to the five Entergy Operating Companies ("EOCs"), which are Entergy Arkansas, LLC; Entergy Louisiana, LLC; Entergy Mississippi, LLC; Entergy New Orleans, LLC; and Entergy Texas, Inc.

in Scriba, New York, where I was responsible for the maintenance and repair of various systems in the plant. In 2016, I joined Entergy's transmission organization as a senior program manager and became the Training Manager for transmission in the spring of 2017. In that capacity, I led a team that established and executed a Journeyman Training Program for all craft journeymen and transitioned the apprenticeship training programs to utilize a new training facility. In 2018, I became the director of operations for the Transmission Control Center North with responsibilities for the EOCs' transmission operations that included bulk power operations, generation coordination with the Midcontinent Independent System Operator, Inc. ("MISO"), and outage management. From April 2020 to October 2021, I served as Vice President, Power Plant Operations, where I was responsible for the safe, compliant, and reliable operation of the EOCs' non-nuclear generation fleet, including the strategic planning for all generation assets across the EOCs' service areas. Finally, in October 2021, I assumed my current role as Vice President, System Resilience.

Q4. PLEASE DESCRIBE YOUR CURRENT JOB RESPONSIBILITIES.

A. As the Vice President, System Resilience, I am responsible for the strategic leadership and oversight of the EOCs' efforts related to resilience. I am responsible for leading the development of the Company's strategic initiatives and goals to achieve excellence in resilience project performance and drive continued project efficiency around the execution of resilience projects. As part of that effort, I help ensure that the Company's standards incorporate resilience aspects and are properly included in all new generation, transmission, and distribution projects. Moreover, I provide leadership, direction, and oversight to a geographically dispersed organization of technical professionals, field leadership, and contract personnel, ensuring that internal and external resources are available to meet the projected workload. I work collaboratively with senior leadership and key stakeholders to accomplish strategic imperatives and deliver on desired outcomes of the Company's resilience-based programs.

Q5. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE A REGULATORY COMMISSION?

A. Yes. A list of my prior testimony is attached as Exhibit SM-1.

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony presents ENO's Future Ready Resilience Plan ("Resilience Plan") and provides details regarding the proposed projects in the Resilience Plan. I also summarize the estimated costs and benefits of implementing the Resilience Plan, and I compare those estimated costs and benefits of implementing the Resilience Plan with two alternative portfolios of projects. I provide support for the conclusion that the Resilience Plan is in the public interest and should be approved and undertaken.

II. RESILIENCE PLAN

Q7. WHAT IS THE RESILIENCE PLAN?

A. The Resilience Plan is the Company's proposed course of action to improve overall electric system resilience through accelerated infrastructure hardening projects. The Company is proposing to implement the Resilience Plan at an approximate cost of $1 billion over the 10-year period from 2024 to 2033 in two 5-year phases. The Resilience Plan is the result of a holistic review of the Company's assets and vulnerabilities in the light of the changing circumstances illustrated by the extreme weather events of recent years. That comprehensive review was used to determine a broad set of transmission and distribution resources that should be targeted for hardening.

In this docket, the Company seeks specific approval of Phase I of the Resilience Plan, which includes hardening projects estimated to cost approximately $559 million over the 5-year period of 2024 to 2028.[2] For the projects completed during Phase I of the Resilience Plan, the Company estimates that those projects will decrease future restoration costs following major weather events by approximately $216 million and lead to a reduction in the total number of customer minutes interrupted ("CMI") following major events of 3.76 billion minutes over the next fifty years assuming an above average frequency of storms. If fully implemented over 10 years, the Resilience Plan is estimated to decrease future restoration costs following storms by approximately $390 million and to decrease the total number of customer minutes interrupted ("CMI") following major events by 7.1 billion minutes over the next fifty years assuming an above average frequency of storms. Put another way, the identified projects are reasonably projected to produce a reduction in storm restoration costs of approximately 49 percent over the next 50 years assuming an above average storm future. Moreover, the identified projects are reasonably projected to produce a decrease in the projected customer minutes interrupted after a major storm by approximately 45 percent over the next 50 years assuming an

[2] Phase II of the Resilience Plan is projected to include approximately $441 million in infrastructure resilience projects.

above average storm future. This decrease includes reducing the number of outages, reducing the number of customers interrupted, and decreasing the length of the outage time.

Q8. PLEASE DESCRIBE THE RESILIENCE PLAN.

A. Under the Resilience Plan, the Company proposes to complete nearly 650 identified distribution and transmission hardening projects, which will harden more than 26,600 structures over more than 500 line miles over the course of the 10-year period from 2024 to 2033, at an approximate cost of $1 billion.[3] Those projects are generally grouped into four programs: Distribution Feeder Hardening (Rebuild), Lateral Hardening (Rebuild), Lateral Undergrounding, and Transmission Rebuild. I discuss the scope of those programs later in my testimony. The specific projects contained in the Resilience Plan are attached to my testimony as Highly Sensitive Protected Materials ("HSPM") Exhibit SM-2. While the Company's Resilience Plan sets forth the Company's best efforts to identify the scope and timing of the proposed hardening projects, the precise work performed (as well as the timing of when that work will be performed) will be subject to continual refinement as the Company implements its Resilience Plan.

Q9. DOES THE RESILIENCE PLAN INCLUDE THE ONLY SET OF PROJECTS THAT THE COMPANY HAS IDENTIFIED TO ADDRESS SYSTEM RESILIENCE?

A. No. In addition to the Resilience Plan of approximately $1 billion, the Company has identified two alternative spending levels for infrastructure hardening projects. *First*, the

[3] With respect to the Resilience Plan, the term "project" refers to a set of assets for hardening.

Company has identified a set of projects costing approximately $1.3 billion over 10 years, which represents an optimized project list that is cost-beneficial and executable and provides a higher amount of potential benefits to customers. *Second*, the Company has identified a set of projects costing approximately $750 million over 10 years, which represents a minimum amount of investment necessary to make a meaningful difference with respect to improving the resilience of ENO's electric grid. While the Company believes that its proposed Resilience Plan of approximately $1 billion represents the appropriate level of accelerated hardening to improve electric system resilience in the New Orleans area, the $1.3 billion and $750 million portfolios provide a ceiling and floor, respectively, for addressing resilience on an accelerated basis.

Q10. IS THE COMPANY REQUESTING APPROVAL OF THE ENTIRE RESILIENCE PLAN AT THIS TIME?

A. No. As I mentioned earlier, at this time, the Company is currently requesting approval of Phase I of the Resilience Plan, which includes approximately $559 million in projects proposed to be implemented in the first five years (2024-2028).

Q11. DOES THE RESILIENCE PLAN CONTAIN THE ONLY RESILIENCE PROJECTS BEING CONSIDERED BY THE COMPANY?

A. No. Creating a resilient system involves a continual process of identifying opportunities and evaluating options to improve and adapt the ability of the Company's electric system to withstand and/or recover from major weather events. As part of those efforts to identify additional areas to improve system resilience, the Company is continuing to assess options that have not been included in the Resilience Plan at this time. Moreover, the Company limited the scope of this filing, and its Resilience Plan, to potential hardening projects consistent with the requirements of Resolution R-23-74.

III. IMPROVING SYSTEM RESILIENCE

Q12. WHAT DO YOU MEAN WHEN YOU SAY THAT THE RESILIENCE PLAN IS DESIGNED TO IMPROVE SYSTEM RESILIENCE?

A. In this context, resilience is the ability to prepare for, adapt to, and recover from non-normal events, such as hurricanes, floods, winter storms, and other major weather disruptions. By comparison, system reliability focuses on the availability of power to customers under normal operating conditions, which include day-to-day operational challenges such as thunderstorms.[4] Although resilience and reliability are complementary from the customers' perspective, the projects being proposed as part of the Resilience Plan were selected specifically to help improve the Company's resilience as compared to a focus on system reliability.

The projects that are being proposed as part of the Resilience Plan were selected and evaluated for their ability to aid the Company's efforts to avoid, mitigate, withstand, and/or recover from the effects of major disruptive weather events. For example, as discussed more fully below, the Company is proposing to harden certain distribution and transmission assets to standards designed to better withstand the extreme conditions caused by severe weather events. While such projects should be expected to have positive

[4] I note that this view of resilience is consistent with the explanation provided in the Resilience Investment and Benefit Report prepared by 1898 & Co. and attached as an exhibit to the direct testimony of Company witness Jason De Stigter.

impacts on the day-to-day operations of the Company's utility system under normal conditions by further protecting against and mitigating outages, they are focused more particularly on preparing the electric system to withstand and recover from severe, non-normal weather events.

Q13. WHY IS THE COMPANY PRESENTING ITS RESILIENCE PLAN AT THIS TIME?

A. Because the frequency and intensity of major storm events have increased, and because customers' dependence upon the electric grid has increased, which, in turn, has raised demands and expectations for a resilient system, it is critical that the Company's system be more resilient and reliable such that it can withstand conditions caused by severe weather events, avoiding and mitigating customer outages, and enabling faster, less costly restorations. Over the last six years, hurricanes have become more frequent and intense,[5] bringing greater costs and disruptions to ENO and its customers. As the Council has acknowledged, the frequency and intensity of severe weather events has increased dramatically.[6]

These major storms pose an increasing threat to the Company's electric system, which has reinforced the need to further invest, and to evaluate ways to accelerate that investment where appropriate, to address the increased frequency and intensity of storms. Indeed, as the Council further noted, "this cycle of damage and repair is not sustainable

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[5] Since 2017, eight major hurricanes (Category 3 or higher) have made landfall in the contiguous United States or Puerto Rico: Harvey (2017), Irma (2017), Maria (2017), Michael (2018), Laura (2020), Zeta (2020), Ida (2021), and Ian (2022).

[6] *See* Resolution R-21-401 at p. 1 ("[T]he frequency and intensity of severe weather events has increased dramatically.").

for the Company or ratepayers."[7] In compliance with Resolution R-21-401, in July 2022, the Company presented to the Council and other stakeholders a preliminary set of infrastructure resiliency and storm hardening projects. Now, after additional proceedings in this docket, and in compliance with the requirements of Resolution R-23-74, the Company is presenting the Resilience Plan to the Council and seeking approval of Phase I, among other requests for relief. The Resilience Plan is part of the Company's response to the threat of increased frequency and intensity of storms and its on-going collaborative efforts with the Council and other stakeholders in this docket. The Resilience Plan is expected to reduce the cost of restoring the electric grid after major storms as well as reduce the number and duration of outages associated with those events.

Q14. DOES FLORIDA'S RECENT EXPERIENCE WITH HURRICANE IAN HAVE ANY BEARING ON THE COMPANY'S APPROACH TO RESILIENCE?

A. Yes, I believe it does. As an initial matter, Hurricane Ian was the latest example of the increasingly frequent and intense storms affecting the Gulf Coast. Hurricane Ian made landfall on September 28, 2022, as a strong Category 4 Hurricane with maximum sustained winds of 155 mph, tying the record for the fifth-strongest hurricane on record to strike the United States and putting it on par with Hurricanes Laura (2020) and Ida (2021). And, as with Hurricanes Laura and Ida, Hurricane Ian caused widespread power outages.

Hurricane Ian underscored the potential value of undertaking the sort of Resilience Plan that the Company is proposing. After the 2004-2005 Atlantic hurricane

[7] *Id.* at p. 2.

seasons, the Florida Public Service Commission enacted rules requiring electric utilities to develop storm protection plans. In 2019, the Florida legislature codified the requirement for utilities to develop and implement storm protection plans with the objective of reducing restoration costs and outage times caused by extreme weather, and, under the statute, utilities are allowed to recover costs for approved plans through a charge separate and apart from base rates. Although the transmission and distribution systems of electric utilities in Florida suffered outages and sustained damage caused by Hurricane Ian, it appears that the storm protection investments of the affected utilities, in particular the type of comprehensive hardening projects proposed by the Company in the Resilience Plan, had a favorable impact on system resilience and the pace of restoration efforts.

Q15. HOW DID THE COMPANY DEVELOP THE RESILIENCE PLAN?

A. Following Hurricane Ida, and in the light of the back-to-back years of severe weather affecting the areas served by the EOCs in forms of both hurricanes and winter storms, the Company began a process of studying what efforts it could take to build on and accelerate the hardening efforts previously approved by the Council. The Resilience Plan is the result of the Company's effort, in conjunction with 1898 & Co., an outside industry consultant that provides strategic asset planning services and has experience in developing similar resilience plans, to understand the risks faced and to identify cost-effective and achievable hardening projects to build a more resilient electric system in New Orleans. Moreover, the collaborative process and work undertaken in this docket has helped inform and direct the development of the Resilience Plan presented with my testimony and the Company's filing.

Q16. WHY IS THE COMPANY PROPOSING TO UNDERTAKE THESE PROJECTS ON AN ACCELERATED BASIS RATHER THAN OVER TIME, AS EXISTING FACILITIES COMPLETE THEIR USEFUL LIVES?

A. The Company's customers have increased their reliance on electricity, and the 2020 and 2021 Atlantic hurricane seasons and lessons from the COVID-19 pandemic support accelerated resilience. Moreover, as I discuss herein, the frequency and intensity of major storm events have increased, and it is therefore critical that the Company's system be more resilient and reliable such that it can withstand conditions caused by severe weather events, avoiding and mitigating customer outages, and enabling faster, less costly restorations. The Company takes seriously its responsibility to provide customers with safe and reliable service at the lowest reasonable cost.

That said, the Company recognizes that the total cost of the proposed projects in the Resilience Plan is significant, and customers' bills will reflect the cost of those efforts. However, taking proactive steps to improve system resilience across the Company's distribution and transmission assets are expected to pay dividends in the long run with reduced customer outage time and restoration costs compared with the traditional approach of repairing assets after a major weather event.

Q17. WHAT BENEFITS DOES THE COMPANY EXPECT TO ACHIEVE BY IMPLEMENTING THE RESILIENCE PLAN?

A. There are generally three sets of benefits that can be achieved in undertaking a resilience effort like the Company is proposing. *First*, "blue-sky" work on the system can be more carefully and efficiently planned, executed, and overseen as compared to the reactive post-storm environment when the Company is working as quickly and safely as possible to restore power on a mass scale. *Second*, the "blue-sky" work can typically be executed at a reduced cost as compared to post-storm restoration work. *Third*, the Company believes that undertaking this work will result in fewer and shorter outages experienced by its customers during and following major weather events, and also reduce customer restoration costs after major storms. I discuss how these benefits were analyzed later in my testimony.

Q18. ARE THERE OTHER BENEFITS THAT THE PROPOSED PROJECTS IN THE RESILIENCE PLAN PROVIDE TO CUSTOMERS?

A. Yes. Although the focus of the Resilience Plan is protection against major storm events, an accelerated approach to resilience projects allows customers to enjoy the enhanced reliability benefits of these projects sooner than if the resilience projects were delayed.[8]

[8] The Company believes that the Resilience Plan, which includes projects focused on hardening large sections of the Company's distribution system with new equipment constructed to current standards, should improve system reliability (reflected in System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Data Index ("SAIDI") scores) over the long run. Nonetheless, a resilience effort of this size may at times increase the Company's SAIFI and SAIDI scores as a result of planned outages occurring while the Company completes the projects in a safe manner.

While this benefit is incidental, it is not insignificant, particularly considering customers' ever-increasing reliance upon electricity.

Q19. HOW IS THE COMPANY'S RESILIENCE PLAN DIFFERENT FROM THE COMPANY'S PAST AND PRESENT RELIABILITY EFFORTS?

A. Although resilience work and reliability work may often look the same and involve the same activities, such as replacing a utility pole, the analyses and drivers supporting that work are very different. For example, reliability may be diminished on a distribution circuit due to a poorly performing device such as a recloser (a device that temporarily turns off power to allow the system to return to normal and then restores power automatically). A poorly performing recloser may fail to open a circuit causing upstream devices to operate instead, interrupting more customers than necessary. It may also open inadvertently thus interrupting customers unnecessarily. A project born from a strategy to improve reliability would likely include replacing the recloser, and potentially the pole it was mounted on, if inspection of the pole determines that the pole is not up to standards. The new recloser would improve the reliability in that area. By comparison, a resilience-focused strategy would identify degraded poles, as well as otherwise-functioning poles that did not meet current standards and target them for replacement. If the poles include devices that need replacement, such as the faulty recloser in this example, they would be replaced when the poles were replaced. In instances where equipment has not reached the end of its life, but was not designed to meet the more stringent wind loading design standards that I discuss below, the Company likely will replace that equipment to meet the new standards if that equipment poses a material risk to the recovery after an event. In all, the approach the Company proposes in its Resilience Plan would result in improved reliability, but also in a more resilient system due to the pole upgrades, among other things. The reliability approach would result in nearly the same reliability performance during thunderstorms, or mild weather incidents, as the resilience approach, but not necessarily achieve the additional benefits of being more capable of withstanding extreme events that may be achieved under the resilience approach.

Q20. WILL ENO'S PROPOSED PLAN TO IMPROVE RESILIENCE DETRACT FROM ITS COMMITMENTS TO PROGRAMS DESIGNED TO IMPROVE RELIABILITY?

A. No. In fact, the Resilience Plan will co-exist with and complement ENO's programs targeted to improve reliability. For example, the Resilience Plan introduces a new facet into how ENO's transmission and distribution systems are planned, designed, and constructed. As I discuss below, projects that were and will be developed to improve reliability will be designed to withstand the Company's higher wind loading standards, thus improving resilience.

While there is certainly a need to enhance the resilience of ENO's electric system, continued reliability efforts are also needed. Thus, as the Company works to implement its Resilience Plan, reliability projects will continue to be developed and planned that provide the highest value to ENO's customers at the lowest reasonable cost. Moreover, the Company has and will continue to evaluate and compare its Resilience Plan and its ongoing reliability work to help avoid inefficiencies between these parallel efforts and to optimize the work done on its distribution and transmission systems. And, again, the

Resilience Plan will introduce projects that have resilience benefits that will complement the programs historically developed to improve reliability. Thus, the Resilience Plan will not detract from or replace the Company's ongoing reliability efforts.

Furthermore, to avoid any overlap between the Company's reliability programs and the proposed resilience projects, the Company will carefully coordinate resilience projects with its reliability programs to promote cost and operational efficiency and mitigate the costs and impact to customers of necessary planned outages that could be caused by duplicative efforts.

Q21. WILL THE RESILIENCE PLAN COMPLETELY ELIMINATE OR AVOID RESTORATION COSTS AND OUTAGES CAUSED BY EXTREME WEATHER EVENTS?

A. No. It is critical to understand that no amount of investment can make an electric system completely resistant to the impacts of extreme weather events. As such, the Resilience Plan will not completely eliminate power outages caused by severe storms or the need for future storm cost recovery or securitization proceedings following major storms. Moreover, the estimated reductions in restoration costs and outage times expected from the Resilience Plan are directly affected by how frequently ENO's service area is impacted by extreme weather events and where those impacts are felt. And no one can predict with absolute certainty how frequently such events will occur or where precisely they will strike.

Additionally, the success of the Resilience Plan and the benefits estimated to result from implementing the Resilience Plan are dependent to a certain extent on what other community stakeholders do. A truly resilient electric system requires more than just strengthening the electric grid. It must coincide with overall efforts to build more resilient communities, which involve considerations of the adequacy and enforcement of building code standards, urban planning, elevation requirements, water management, and coastal restoration, among other things.

Nonetheless, the expectation is that the proposed Resilience Plan will increase the resilience of ENO's electric system and, ultimately, will lower the costs and impacts of extreme weather events, in addition to helping further improve grid reliability and overall service quality for customers, resulting in fewer outages and disruptions for ENO's customers.

IV. DEVELOPING THE RESILIENCE PLAN

Q22. PLEASE GIVE AN OVERVIEW OF THE RESILIENCE PLAN.

A. As noted above, the Resilience Plan involves significant incremental spending in hardening the Company's distribution and transmission assets to address the potential impacts caused by increasingly severe weather events. In collaboration with its consultant 1898 & Co., the Company utilized a resilience-based planning approach to identify hardening projects and prioritize investment in ENO's transmission and distribution assets through the Storm Resilience Model ("SRM"), which Company witness Mr. De Stigter further discusses in his testimony. The proposed projects identified through that process will cost approximately $1 billion over the next 10 years.

Q23. PLEASE EXPLAIN THE METHODOLOGY USED TO IDENTIFY THE PROPOSED PROJECTS FOR INCLUSION IN THE RESILIENCE PLAN.

A. The SRM was the methodology used by the Company in collaboration with 1898 & Co. to assist in identifying the hardening projects for inclusion in the Resilience Plan. Using a four-step process, the SRM employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to evaluate the assets on ENO's system and calculate resilience costs and estimated benefits of hardening those assets in terms of CMI and avoided future storm restoration costs. The ultimate purpose of the SRM is to identify and prioritize projects that would have the highest benefits to customers. It would be infeasible, logistically and financially, to address the risk arising from every single asset on the ENO electric system. The SRM thus serves to identify and prioritize the set of assets to harden to deliver the most customer benefits in terms of avoided customer outage minutes and avoided future storm restoration costs for the money spent. In this way, the SRM facilitates the prudent and efficient use of finite resources to achieve the most significant reduction of risk that can be achieved through reasonable diligence. This methodology is described in more detail in the direct testimony and exhibits of Mr. De Stigter, a consultant with 1898 & Co. who helped in developing the Resilience Plan.

Q24. WHAT ASSETS DID THE SRM EVALUATE?

A. As discussed more fully by Mr. De Stigter in his direct testimony and the Resilience Investment and Benefits Report ("Report") prepared by 1898 & Co., the SRM is comprehensive and evaluated nearly all of ENO's transmission and distribution systems, including poles, circuits, transmission structures, and conductor.

Q25. HOW WERE THE HARDENING PROJECTS IN THE RESILIENCE PLAN IDENTIFIED?

A. As an initial matter, the Company (and 1898 & Co.) considered hardening projects for inclusion in the Resilience Plan based on a combination of data driven assessments, operational knowledge of the system, and historical performance of ENO's system during major storm events. As I mentioned earlier, a "project" refers to a collection of assets identified for hardening and evaluated by the SRM under a variety of different programs, which I discuss later. The approach to identifying hardening projects employs asset management principles utilizing a bottom-up approach starting with the system assets. The following describes the approach to identifying and grouping the Company's assets into hardening projects for consideration.

- **Distribution Projects:** For distribution projects, assets were grouped by their most immediate upstream protection device, which was either a breaker, recloser, sectionalizer, auto transfer switch, vacuum fault interrupter, or a fuse. This approach focuses on reducing customer outages. The objective is to harden each asset that could fail and result in a customer outage. Since only one asset needs to fail downstream of a protection device to cause a customer outage, failure to harden all the necessary assets still leaves vulnerable components that could potentially fail in a storm and result in an outage. Rolling assets into "projects" at the protection device level allows for hardening of all vulnerable components in the circuit and for capturing the full benefit for customers, including avoidance or mitigation of an outage.

When evaluating project types for distribution circuit projects – laterals (assets grouped by a fuse protection device) and feeders (assets grouped by a breaker or recloser protection device) – the Company considered both rebuilding to a storm resilient overhead design standard and undergrounding, where possible. Overhead hardening rebuilds are generally lower cost than undergrounding projects, but they may provide fewer resilience benefits than undergrounding. The SRM balances this tradeoff for every project across ENO's service area where both options are technically feasible (undergrounding in wetlands and in certain dense urban settings is typically not feasible). Assets identified for inclusion in these projects include older wood poles and those designed to a previous wind rating, as well as copper conductors.

Distribution assets were evaluated under multiple criteria to determine whether they are hardening candidates. Distribution structures were evaluated based on height, class, transformer count, and other attachments to calculate a percentage of maximum loading. For distribution conductor, the asset was included in a project as a hardening candidate if either of the conductor's adjacent poles was selected as a hardening candidate. Additionally, small conductor, such as copper, was included as a hardening candidate since it is at risk of failing in high wind events.

- **Transmission Projects:** At the transmission circuit level, poles identified for hardening will be replaced with higher wind rated structures and materials. Transmission structures were grouped at the transmission line or circuit level into projects.[9] A transmission asset was deemed to be a hardening candidate if the structure's wind rating did not meet or exceed a minimum wind hardening standard for that geographic region.[10]

- **Substation Projects:** Substation control houses can be another risk due if roofs are not designed to withstand winds that exceed certain speeds. If the roof is broken or ripped off during a storm, rainfall resulting in substantial water inside the control house will damage much of the substation protection equipment, rendering it out of service. The Company provided a list of control houses and known current wind ratings. In turn, control houses with non-hardened ratings were considered for hardening.

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[9] The SRM did not evaluate each transmission project for overhead to underground conversion. The construction of an underground transmission facility across the New Orleans footprint would pose particular challenges in terms of routing, conflicts with existing structures, trench construction in poor soils, excessive water, and/or trenchless installation techniques that require a large footprint for construction equipment, among other things.

[10] I note that the wind hardening standards used to identify transmission structures as potential hardening candidates are not identical to the Company's current standards for transmission assets. In completing its analysis, 1898 & Co. used a combined wind-loading map for both transmission and distribution assets that reflects a minimum required level of wind loading for both distribution and transmission assets. Although those minimum standards reflect the extreme wind loading requirements of National Electric Safety Code ("NESC") 250C, which I discuss more fully below, more stringent standards for the transmission system have been adopted. Accordingly, in some instances, 1898 & Co. evaluated the proposed transmission projects using a lower standard than is currently required under the Company's Extreme Wind Guidelines for transmission assets; however, in completing transmission rebuild projects, the Company will harden all transmission assets to its current standards (*e.g.*, a potential transmission project may have been evaluated under the assumption it would be hardened to 140 mph; however, if approved, that project will be hardened to 150 mph).

A detailed storm surge modeling using the Sea, Land, and Overland Surges from Hurricanes ("SLOSH") model was performed. Substations with any potential flooding risk were also considered. Those substations that are located behind a levee are not considered to be at risk of storm surge.

Q26. AFTER THE COMPANY'S ASSETS WERE GROUPED IN THAT WAY, DID THE SRM USE CERTAIN PROGRAMS TO CONSIDER HARDENING PROJECTS?

A. Yes. As part of the SRM, the Company further grouped the potential projects into seven different programs: Distribution Feeder Hardening (Rebuild), Distribution Feeder Undergrounding, Lateral Hardening (Rebuild), Lateral Undergrounding, Transmission Rebuild, Substation Control House Remediation, and Substation Storm Surge Mitigation. Table 1 shows the number of hardening projects considered in each program.

Table 1

Program	Project Count
Distribution Feeder Hardening (Rebuild)	476
Distribution Feeder Undergrounding	476
Lateral Hardening (Rebuild)	4,324
Lateral Undergrounding	4,324
Transmission Rebuild	36
Substation Control House Remediation	1
Substation Storm Surge Mitigation	1
Total	9,638

Q27. PLEASE EXPLAIN WHAT THE DIFFERENT PROGRAMS ENTAIL.

A. The projects considered in the Distribution Feeder Hardening (Rebuild), Lateral Hardening (Rebuild), and Transmission Rebuild programs involve the evaluation of the identified projects (*i.e.*, the set of grouped assets) to determine the level of work needed to harden the assets contained in those projects (*i.e.*, bring those assets up to the current design standards for distribution and transmission assets). As I discuss below, the Company's distribution and transmission design standards have recently been revised in the light of the severe weather conditions experienced in recent years. If the Resilience Plan is approved, the Company will thoroughly design and plan the work needed to bring each distribution or transmission asset in the selected projects up to the Company's updated standards and then perform the work as needed to rebuild or replace those assets. As I discuss below, the Company will keep the Council advised of any material changes between the projected and actual costs of a project.

As might be expected, the Distribution Feeder Undergrounding and the Lateral Undergrounding programs involve the undergrounding of overhead lines. It is worth noting that the cost of undergrounding overhead distribution and lateral segments can be higher than the cost of rebuilding or hardening those same segments. The relocation of long-established overhead electric facilities to underground can prove challenging, or in some cases infeasible, primarily due to the increased ground area required for underground equipment, which further increases the cost of such projects. While undergrounding the entirety of ENO's distribution or lateral segments would not be cost effective or technically feasible, selective undergrounding of certain lateral segments, as shown below, is expected to produce more benefits as compared to rebuilding or replacing those segments.

Finally, the Substation Control House Remediation program involves the hardening of identified substations by bringing the roofs of those facilities up to identified wind standards, and the Substation Storm Surge Mitigation program involves undertaking identified work such as constructing flood walls at specific substations to protect against storm surge caused by severe weather.

Q28. YOU MENTIONED THAT THE COMPANY'S TRANSMISSION AND DISTRIBUTION DESIGN STANDARDS ARE REFLECTED IN THESE PROGRAMS. PLEASE EXPLAIN.

A. As I mentioned, the hardening programs involve the evaluation and potential rebuilding or replacement of assets to bring those assets up to the Company's current distribution and transmission standards. It is important to again note that those standards were reevaluated recently as part of the Company's overall approach to addressing the resilience of the electric grid following back-to-back years with major hurricanes.

More specifically, the EOCs revised their wind design criteria for distribution and transmission structures. This revision recognizes that customers and communities are demanding a more resilient grid as they build back stronger, and the increased standards discussed further below reflect what researchers and New Orleans and other Gulf Coast residents have learned about the challenges that communities on or near the coast are facing and may face in the future. For example, hurricanes appear to be more frequently undergoing "rapid intensification," which refers generally to at least a 35 mph increase in intensity over a 24-hour period before landfall, as seen with Hurricanes Ian (2022), Ida (2021), Grace (2021), Laura (2020), Michael (2018), and Harvey (2017). In such instances, communities have less time to prepare for major weather and secure property, which, as a result, can lead to wind-blown objects interfering with the EOCs' distribution and transmission assets. Furthermore, as seen during Hurricane Ida, the "brown ocean effect," which refers to a storm's maintaining hurricane strength as it moves over swamps and marshland saturated with warm waters that fuel the storm, may explain why hurricanes are damaging property well inland. Thus, communities beyond the immediate coast have experienced, and must prepare for, hurricane-force conditions.

Q29. CAN YOU EXPLAIN HOW THE COMPANY REVISED ITS WIND LOADING CRITERIA?

A. Yes. Before addressing the process for the recent revisions, it is important to understand the foundation from which the EOCs were working. The distribution and transmissions systems have always been designed to meet or exceed the requirements of the NESC. Section 25 of the NESC provides the loading requirements to be applied to transmission and distribution facilities. Rule 250A provides the general loading requirements. Rules 250B, 250C, and 250D address, respectively, specific structure loading requirements for (i) combined ice and wind loading by geographical loading districts; (ii) extreme wind loading requirements; and (iii) extreme ice loading with concurrent winds. The extreme wind and extreme ice loading requirements of NESC 250C and 250D apply to structures or support facilities that exceed 18 meters (60 feet) above ground or water, in recognition that wind speed increases with increasing height above the ground.

It also is important to recognize the purpose of the NESC when considering the decision to exceed the NESC safety requirements within their design specifications. The purpose of the NESC, as defined in Rule 010, is "the practical safeguarding of persons and utility facilities during the installation, operation, and maintenance of electric supply and communication facilities, under specified conditions." It contains the basic provisions, under specified conditions, that are necessary for safeguarding of the public, utility workers, and utility facilities. "In essence, the rules of the NESC give the basic requirements of construction that are necessary for safety." *See* Comments to NESC 010-2017. However, the NESC does not prohibit or limit the EOCs' ability to consider other factors beyond safety and practicality and establish standards in excess of the requirements of the NESC. Accordingly, in addition to developing distribution design specifications that meet the NESC safety requirements, the EOCs have also considered many other factors in their design specifications, including customer and community requirements, costs of increased design specifications, as well as system reliability, repairability, and resilience.

After considering the experiences during the 2020 and 2021 Atlantic hurricane seasons, the balance of these factors supported revision to the wind loading guidelines that generally exceed the extreme wind loading requirements of Rule 250C. The assessment of design opportunities that may mitigate the effects of major hurricanes like Hurricanes Laura and Ida and make the grid more resilient included the following: (i) reviewing wind data from recent hurricanes;[11] (ii) exploring extreme wind guidelines similar to NESC 250C for distribution lines;[12] (iii) evaluating design specifications and

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[11] Hurricane Laura and Hurricane Ida both made landfall as strong Category 4 hurricanes with sustained winds speeds of 150 mph. During Hurricane Ida, an instantaneous peak wind gust of 172 mph was clocked by instruments on a ship in Port Fourchon, Louisiana, and a peak gust of 110 mph was recorded north of Lake Pontchartrain in Mandeville, Louisiana. Hurricane Ida did not downgrade to Category 3 (which has sustained winds up to 129 mph) until its eyewall was near Houma, Louisiana.

[12] Prior to the development of the EOCs' current extreme wind guidelines, the EOCs generally have designed distribution structures less than 18 meters (60 feet) above ground or water to meet or exceed the requirements of NESC 250B, which, again, provides the general combined ice and wind loading requirements to account for weather conditions in defined geographical loading districts. In the light of the EOCs' experience with Hurricanes Laura and

best practices from similarly-situated electric utilities; (iv) reviewing the technical impacts of increased wind guidelines on distribution structure design; (v) considering other actions that may reduce structure loading during extreme wind events; and (vi) evaluating other actions that may reduce exposure to wind damage.

Based on this assessment, it was technically feasible to improve the resilience of their structures using a stronger wind design to mitigate major storm impacts to the distribution system. Similar increases in the design standards were made for transmission assets. In evaluating design standards, the need for the transmission and distribution systems to withstand the extreme conditions increasingly experienced during major events was balanced with their duty to provide customers with safe and reliable service at the lowest reasonable cost. These considerations led to the adoption of wind loading standards for transmission assets that are higher in some areas than the standards in those same areas for distribution assets. These increased standards will benefit customers in the long run. Designing to these higher wind loading standards should result in stronger structures that are more capable of withstanding greater weather impacts, resulting in decreased restoration costs as well as fewer and shorter outages following major events.

Q30. PLEASE DESCRIBE THE NEW WIND LOADING STANDARDS FOR DISTRIBUTION.

A. Some brief additional background is helpful to describing the revised wind loading standards for distribution assets. As mentioned above, the distribution lines have always

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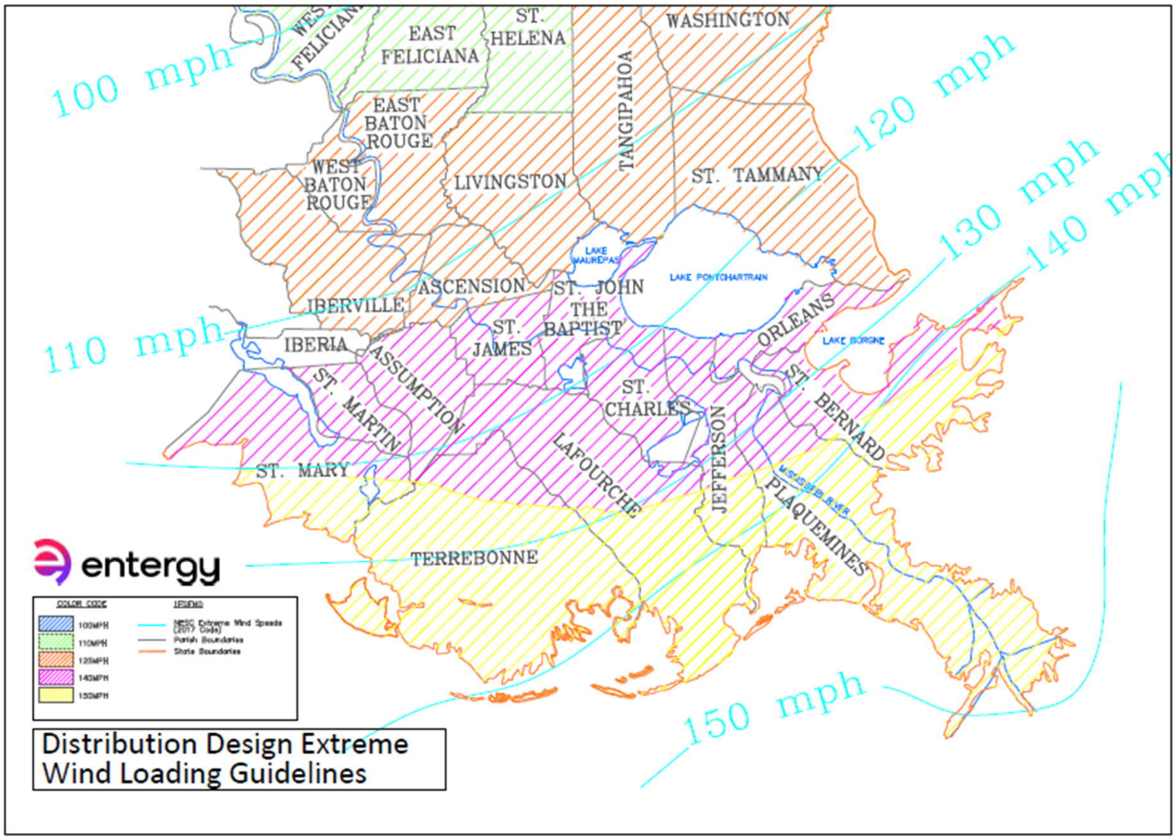
Ida, the EOCs have developed increased design standards for their distribution structures reflective of the extreme wind loading requirements of Rule 250C.

been designed to meet or exceed the applicable NESC standards. And, over the years, additional design practices have been adopted to harden distribution assets to prepare for severe weather. For example, the storm guying on distribution feeders have been installed in open marshy terrain immediately adjacent to the coast. After Hurricanes Katrina and Rita, several potential hardening strategies were considered with respect to distribution assets. Based on that analysis, additional practices were adopted, including using only Class 3 (or larger) poles for three-phase feeder construction for distribution lines located immediately adjacent to the coast and using steel distribution poles for new interstate crossings along major hurricane evacuation routes. Since 2018, after additional analysis, Class 1 poles for feeder poles south of Interstate 10 have been used, where feasible, and nothing smaller than Class 3 poles for all primary applications. At this time, as discussed above and shown in Figure 2 and in the attached Exhibit SM-3, new design standards have been issued that are based on the extreme wind loading requirements of NESC 250C, and further shows that those standards meet or exceed the NESC extreme wind loading requirements.

Figure 2
Wind Loading Guidelines for Distribution Lines



As indicated in Figure 2 and in the attached Exhibit SM-3, distribution assets and structures in Orleans Parish will be designed to the 140-mph extreme wind loading requirements, which exceeds the requirements of NESC 250C for Orleans Parish.

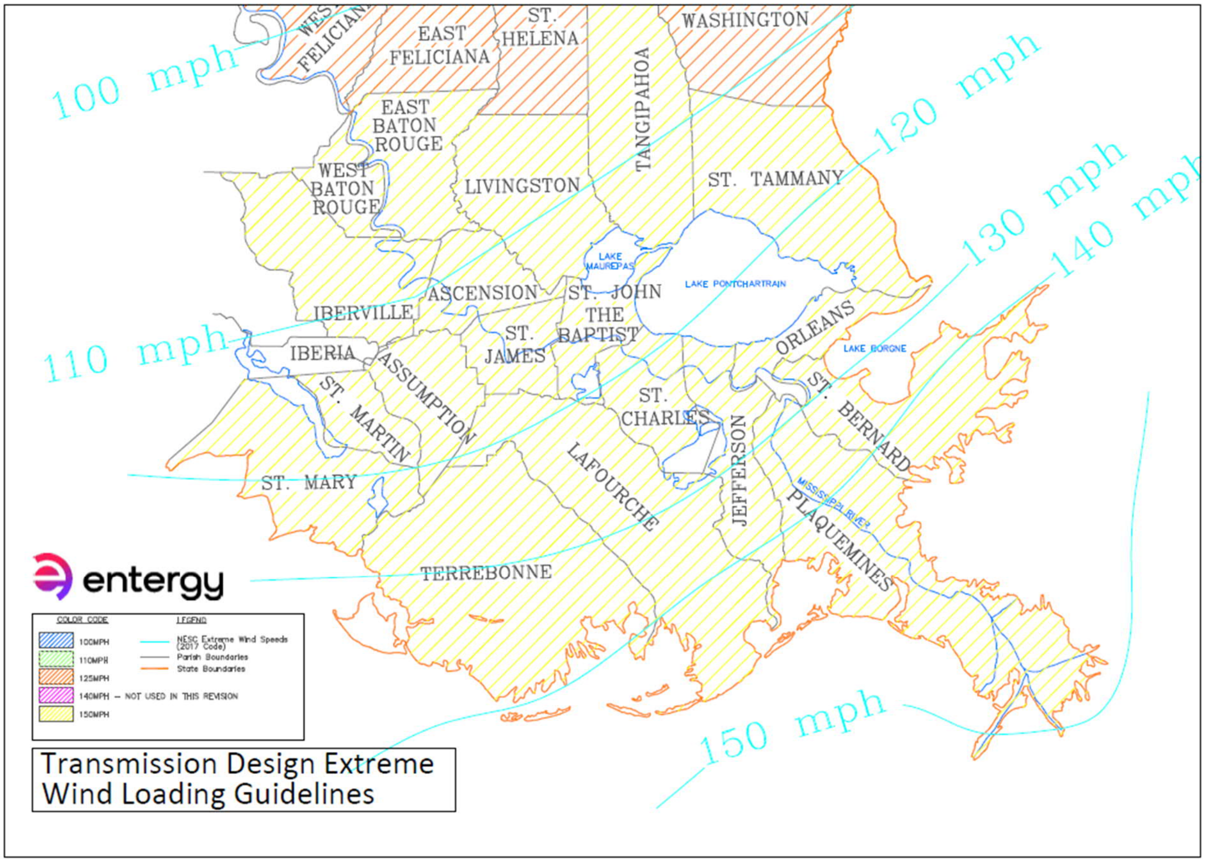
Q31. PLEASE DESCRIBE THE CURRENT WIND LOADING STANDARDS FOR TRANSMISSION AND HOW THEY COMPARE TO PRIOR STANDARDS.

A. As with the distribution standards, some additional background is helpful to understanding the current wind loading standards for transmission. In the mid-1990s, when the design standards were consolidated after Entergy Corporation's merger with Gulf States Utilities Company ("GSU"), the 140-mph wind loading requirements in the coastal zone (previously developed by Louisiana Power and Light in response to Hurricane Betsy and before the NESC introduced extreme wind loading requirements) were extended west to encompass coastal parishes and counties previously served by GSU. With increased extreme wind requirements in the 2002 NESC code, a 150-mph zone was created for the southern portions of the five most southeastern Louisiana parishes (Terrebonne, Lafourche, Jefferson, Plaquemines, and St. Bernard). The 140-mph zone was extended north to include the entirety of any county or parish that is crossed by Interstate 10. In the recent revision shown in Figure 3 below, the 140-mph coastal zone was raised to 150 mph, and existing 125-mph zones in Texas and Eastern Louisiana were connected by a new 125-mph zone through central Louisiana.

Specifically, all Parishes/Counties previously designed for 140 mph extreme wind loading, including Orleans Parish, will now be designed for 150 mph. Additionally, the eight parishes south of the Mississippi/Louisiana border that were previously designed for 110 mph will now be designed for 125 mph. Figure 3 below and the attached Exhibit SM-4 shows the revised minimum wind loading guidelines for transmission assets and further shows that those standards meet or exceed the NESC extreme wind loading requirements.

Figure 3

<u>Wind Loading Guidelines for Transmission Lines</u>



Q32. HOW WILL THE COMPANY IMPLEMENT THESE STANDARDS AS PART OF THE RESILIENCE PLAN?

A. As discussed above, as part of the Company's Resilience Plan, the Company proposes to evaluate and replace or rebuild the identified distribution and transmission assets as part of the "Hardening" and "Rebuild" programs. Going forward, and as part of the Resilience Plan, the Company will design and harden new structures using the revised wind zones to help determine the wind forces that are exerted on those structures. These designs account for the wind forces that may impact these structures as well as the wind forces that may impact the supported facilities or equipment attached to those structures, including the pole, transformers, conductors, and other components.

The Company will use multiple design and materials combinations to meet the applicable wind loading standards. The design of a structure is rooted in the loading requirements for that particular structure, which requirements drive the components and materials that are used. Accordingly, each distribution and transmission asset or structure is designed for the specific wind zone and its location using a number of design choices, including, but not limited to, the class of pole, the material used for the pole or other attachment (*e.g.*, composite or concrete poles or fiberglass cross arms), and the configuration of cross arms or insulators. Additionally, to help meet the wind loading requirements, other supporting applications such as storm guying may be used.

Q33. TURNING BACK TO THE METHODOLOGY USED TO DEVELOP THE RESILIENCE PLAN, YOU STATED THAT THE SRM USED A FOUR-STEP PROCESS. CAN YOU GIVE AN OVERVIEW OF THAT PROCESS?

A. Yes. *First*, the SRM starts with a universe of major storm events that could impact ENO's service area, called the "Major Storm Event Database," from which 49 unique storm types were identified. *Second*, a "Storm Impact Model" estimates the restoration costs and durations of outages following each of the 49 storm types under (i) the current condition of the Company's assets and (ii) the assumed conditions of those assets if hardened pursuant to the programs I discussed above. The Storm Impact Model compares the restoration costs and the duration of outages from both sets of circumstances to determine a "benefit" for completing each project in the programs.

Third, a "Resilience Benefit Module" employs stochastic modeling to determine a weighted benefit for each project in the programs over the next fifty years. And *fourth*, an investment optimization and project prioritization process is employed to determine an overall project list that is the most cost-beneficial for the Company and its customers. I discuss each step in more detail below, and this process is discussed more fully in Mr. De Stigter's direct testimony as well as in the Report prepared by 1898 & Co. that is attached as an exhibit to his testimony.

Q34. DID THE COMPANY FURTHER REFINE THE PROJECT LIST IDENTIFIED BY THE SRM?

A. Yes. As discussed in Mr. De Stigter's direct testimony as well as in the Report attached to his testimony, after the SRM identified an overall project list costing approximately $1.3 billion that could be executed by the Company over the next ten years, the Company worked with 1898 & Co. to evaluate two additional, alternative portfolios of projects (or investment levels) that are subsets of the overall list: a portfolio of projects costing approximately $1 billion and a portfolio of projects costing approximately $750 million. Looking at these three different portfolios of projects, the Company compared the potential costs, the annual spending levels, and the potential customer benefits that could be obtained by completing each set of projects. The Company also evaluated the potential bill impacts of completing each of the three different portfolios of projects. The Company ultimately determined to propose the $1 billion project list, *i.e.* the proposed Resilience Plan, because it provided the best "bang for the buck" for customers. I further discuss this later in my testimony.

A. Major Storm Event Database

Q35. PLEASE BRIEFLY EXPLAIN THE MAJOR STORM EVENT DATABASE AND HOW IT WAS USED IN THE SRM.

A. The Major Storm Event Database utilizes information drawn from the National Oceanic and Atmospheric Administration ("NOAA") database of major storm events, available information on the impact of major storms to other utilities, and the Company's experience with storms and storm recovery. The universe of information comprising the Major Storm Event Database included information regarding the major storms that have impacted ENO's service area over the last 170 years. This historical information was used to identify 49 unique storm types based on varying combinations of storm category, storm distance, and storm side (*i.e.*, weak side or strong side). Additionally, the future storm probabilities were developed for each of the different types of storms. Finally, for each storm type, the Major Storm Event Database also contained information regarding the potential impacts of the storm type, expressed in terms of the duration of outages, system percentage impacted, and storm costs.

Q36. DOES THE MAJOR STORM EVENT DATABASE INCORPORATE ANY ASSUMPTIONS ABOUT THE FREQUENCY OR INTENSITY OF FUTURE STORMS?

A. Yes, the SRM accounts for the increasing storm frequency and intensity seen in recent years in developing the future probabilities of each of the future storm types. The model uses the last thirty periods of 100 years (*i.e.*, 1922-2021, 1921-2020, 1920-2019, etc.) to predict the likelihood of future storms. If the thirty periods of 100 years were equally weighted, storms occurring during the middle years of the study period would more strongly influence future storm probabilities because they are captured in more of the individual 100-year periods the model uses. To correct for this effect and account for the increasing storm severity and restoration costs experienced in more recent storm seasons, the model weights the most recent years more heavily.

B. <u>Storm Impact Model</u>

Q37. PLEASE EXPLAIN THE STORM IMPACT MODEL FURTHER.

A. The Storm Impact Model identifies, from a weighted perspective, the particular laterals, feeders, transmission lines, access sites, and substations that may be damaged to the point of requiring repair and/or replacement for each type of storm in the Major Storm Event Database. The Storm Impact Model also estimates the restoration costs associated with the sub-system failures and calculates the impact to customers in terms of CMI. Finally, the Storm Impact Model models each storm event for both a "Status Quo" and "Hardened" scenario, which are more fully discussed by Mr. De Stigter and in the Report attached to his testimony. The Hardened scenario assumes that the assets that make up each project have been hardened in accordance with the programs I discussed above. The Storm Impact Model then calculates the resilience benefit of each hardening project from a reduced restoration cost, CMI, and monetized CMI perspective.

Q38. HOW DOES THE STORM IMPACT MODEL IDENTIFY THE ASSETS THAT ARE LIKELY TO FAIL DURING MAJOR STORM EVENTS?

A. The Storm Impact Model identifies the portions of the system that are likely to be damaged to the point of needing repair and/or replacement by modeling the elements that cause failures in the Company's assets. To do so, the "Likelihood of Failure," as modeled in the Storm Impact Model, assumes that a storm has impacted a project (*i.e.*, a set of assets) and caused an outage. The model does not choose specific structures or assets for failure, but rather assigns a weighted likelihood of failure in every storm for every project. The likelihood of that project failing, among all the possible projects, is based on the collective attributes of the assets (poles, structures, wires, control houses, etc.) inside that project. The calculation of the Likelihood of Failure score for a project is based on a vegetation rating, an age and condition rating, and a wind zone rating for each asset inside each project. The vegetation rating factor is based on the vegetation density around the conductor. The higher the vegetation density, the greater the probability of failure. The age and condition rating utilizes expected remaining life curves with the asset's "effective" age, determined using condition data. The wind zone rating is based on the actual wind rating of the asset as compared to the wind zone that the asset is located within; the larger the differential between the wind rating of the asset and the wind zone in which it sits, the greater the probability of failure.

Q39. HOW DOES THE STORM IMPACT MODEL DETERMINE THE COST OF RESTORATION FOLLOWING EACH STORM EVENT?

A. The Storm Impact Model calculates the restoration costs for every asset (including poles, overheard primary, transmission structures, transmission conductors, power transformers, and breakers) required to rebuild the system to provide service. The costs were based on estimated replacement costs plus storm restoration cost multipliers.

Furthermore, the Storm Impact Model uses this cost information and the Likelihood of Failure to determine which projects will incur costs, as well as the extent of those costs, as a result of a given type of storm. This produces a Status Quo restoration cost to represent a world without the project being hardened. The hardened restoration cost of a project is calculated by taking the Status Quo restoration cost and reducing it based on an improved strength and reduced likelihood of failure due to hardening. As mentioned, the restoration cost benefit is calculated as the difference between Status Quo restoration cost and Hardened restoration cost.

Q40. PLEASE EXPLAIN WHAT YOU MEAN WHEN YOU SAY THAT RESTORATION COSTS WERE BASED ON STORM RESTORATION COST MULTIPLIERS.

A. As I mentioned above, replacing assets following major weather events is much costlier than replacing assets during “blue-sky” hours through planned replacement. This is true for restoration work performed by the Company’s crews as well as restoration work performed by mutual assistance, non-Entergy crews. Accordingly, to approximate the additional cost it would take to repair or rebuild assets that were damaged during a major weather event, the Company and 1898 & Co. worked collaboratively to develop cost multipliers based on prior storm experiences, the expected inventory constraints, and the expected mix of Company and non-Company crews needed for the various asset types and storms.

Based on that collaborative analysis, the cost multipliers used to determine restoration costs were developed. With respect to the Company's crews, it was determined that the costs to restore infrastructure following storm events can be 1.5 to 2.0 times higher than infrastructure replacements during "blue-sky" rebuilds as a result of factors such as overtime fees, inefficiencies, and rework risks. For major weather events, the Company relies on mutual assistance to restore the system with non-Company crews from across the nation. Given costs and challenges associated with the per-diems, overtime rules, mobilization and demobilization, and managing outside resources, the costs of restoration work performed by those workers can be even higher.

Q41. HOW DOES THE MODEL ESTIMATE THE CUSTOMER MINUTES INTERRUPTED FOR EACH STORM EVENT?

A. The Storm Impact Model calculates the CMI by assets/project for each storm scenario. Since projects are organized by protection device, the customer counts and customer types are known for each asset in the Storm Impact Model. The time it will take to restore each protection device, or project, is calculated based on the expected storm duration and the hierarchy of restoration activities. This restoration time is then multiplied by the known customer count to calculate the total CMI.

Q42. YOU MENTIONED THAT A RESILIENCE BENEFIT WAS CALCULATED FOR EACH PROJECT BY MAJOR STORM EVENT. PLEASE EXPLAIN HOW THAT RESILIENCE BENEFIT WAS CALCULATED.

A. The resilience benefit for each project is determined by calculating the difference between the Status Quo and the Hardened Scenarios. Accordingly, the restoration cost benefit is calculated as the difference between Status Quo restoration cost and Hardened restoration cost. Similarly, the CMI benefit is calculated as the difference between the Status Quo CMI and Hardened CMI. These benefits are discussed more fully in the Report attached to Mr. De Stigter's testimony.

Q43. WERE BOTH RESTORATION COSTS AND CMI CONSIDERED?

A. Yes. Determining the value and potential benefits of any storm hardening effort is a complex task, and it requires more than a simple objective evaluation of the possibly avoided restoration costs. The communities served by the Company are increasingly dependent on electricity and expect a more resilient system. It follows, therefore, that the qualitative benefits of any resilience effort (*i.e.*, the benefits to customers that come from having an electric system that is better able to withstand and timely recover from major weather events) must also be considered.

Q44. WHY WERE CMI BENEFITS MONETIZED?

A. The CMI benefits were monetized for project prioritization purposes. The Storm Impact Model calculates each hardening project's CMI and restoration cost reduction for each storm scenario. In order to prioritize projects, a single prioritization metric is needed.

Since CMI is in minutes and restoration costs are in dollars, the SRM monetizes CMI. The monetized CMI benefit is combined with the calculated restoration cost benefit for each project to calculate a total resilience benefit in dollars.

Q45. HOW WERE CMI BENEFITS MONETIZED?

A. CMI benefits were monetized using the U.S. Department of Energy's ("DOE") Interruption Cost Estimate ("ICE") Calculator. This tool provides information that can be used to provide a rough approximation of the value placed on outages by electric customers, also known as the "Value of Service." The values in the tool are differentiated by customer type: residential, small commercial/industrial, and large commercial/industrial. For the SRM, 1898 & Co. used the DOE's ICE Calculator and extrapolated from it to account for the longer outage durations associated with storm outages. These estimates for outage cost for each customer are multiplied by the specific customer count and expected duration for each storm for each project to calculate the monetized CMI at the project level.

Q46. ARE THERE ANY LIMITATIONS ON USING THE DOE'S ICE CALCULATOR?

A. Yes. The DOE's ICE Calculator does not consider the all the factors that would be necessary to assess the causes and impacts of an outage to customers in specific circumstances. Again, for project prioritization purposes, the SRM uses an extrapolation of the DOE's ICE Calculator to evaluate the societal impacts to customers on a general basis. But there is no industry standard method for valuing the costs of outages to a particular customer, and the value of an outage to any particular customer would be based on many individualized factors. Moreover, outages for a particular customer could depend on factors beyond the control of a utility (*e.g.,* damage to a customer's home or business). Accordingly, the use of the DOE's ICE Calculator to help prioritize projects within the Resilience Plan is not an endorsement of the DOE's ICE Calculator's ability to calculate accurately or effectively the economic impact of a particular outage on any particular customer.

C. <u>Resilience Benefit Module</u>

Q47. PLEASE EXPLAIN THE RESILIENCE BENEFIT MODULE.

A. The Resilience Benefit Module uses the benefit calculated from the Storm Impact Model and the estimated project costs to estimate the net benefits for each project over the next fifty years. To be clear, the benefits of these storm hardening projects are highly dependent on the frequency, intensity, and location of future major storm events. For this reason, stochastic modeling, or a Monte Carlo Simulation, is used to randomly trigger the types of storm events from the Major Storm Event Database that may impact the Company's service area over the next 50 years at various levels of storm frequency. Each project's CMI, monetized CMI, and restoration costs were calculated for the 49 storm types for each event triggered in the Monte Carlo Simulation for both the Status Quo and Hardened Scenarios over the 50-year time horizon. As mentioned above, the difference between the Status Quo and Hardened Scenarios is the benefit for that project for that storm event. The sum of the benefits for all 49 storm types for each iteration of the simulation equals the total benefits for the project. The CMI, monetized CMI, and restoration benefits are then weighted by the probability of the 49 storm types to calculate the weighted benefit. To calculate the net benefits, the project costs are determined.

Q48. WHAT ECONOMIC ASSUMPTIONS ARE MADE IN THE RESILIENCE BENEFIT MODULE?

A. The resilience net benefit calculation performed as part of the Resilience Benefit Module includes the following economic assumptions:

- 50-year time horizon – most of the hardened infrastructure will have an average service life of 50 or more years;
- 2.5 percent escalation rate; and
- 7.5 percent discount rate.

Q49. HOW WERE PROJECT COSTS DETERMINED FOR EACH OF THE HARDENING PROJECTS CONSIDERED IN THE SRM?

A. Costs were estimated for the hardening projects considered in the SRM. Some of the estimated project costs were provided by the Company, while others were estimated using the data within the SRM to estimate the scope of the project, including asset counts and line miles, that was then multiplied by unit cost estimates developed collaboratively by the Company and 1898 & Co. to calculate the project costs. As discussed more fully above, the Distribution Feeder Hardening (Rebuild) and Lateral Hardening (Rebuild) projects consist of replacing or rebuilding structures within a protection zone that do not meet the Company’s current design standards, including replacing copper wire. The costs for Distribution Feeder Hardening (Rebuild) projects are the aggregate costs for all of the structures and wire under consideration for hardening. Project costs generally were developed using the following steps:

1. A base cost per structure was determined;
2. The base cost was increased to account for multi-phase conductor requirements or foundation needs for higher wind rating areas;
3. Next, a conductor cost was added for each span of wire that will need to be replaced in the project;
4. Additional costs were added based on the number and size of transformers in the project, including labor and materials costs; and
5. Cost estimates for projects are further adjusted based on factors such as: amount of nearby vegetation based on tree canopy density; ability to access the equipment from the road; known terrain based on U.S. Fish & Wildlife Service Seamless Wetland data (marsh land); and population density.

Additionally, Transmission Rebuild projects consist of replacing structures within a substation-to-substation segment that do not meet the current wind rating for the area. Generally, structure replacements on transmission will result in a steel mono-pole installation, and project costs are built to reflect this assumption. River crossing projects or other extenuating circumstances may result in adjusted project costs, but the transmission costs generally were developed using the following steps:

1. A base cost per mono-pole steel structure that includes insulators and attachments was determined;
2. The structure cost was increased to account for multi-circuit requirements or foundation needs for higher wind rating areas;
3. Next, a conductor cost per structure was added to account for reconductoring needs;
4. Cost estimates for projects are further adjusted based on factors such as: number of nearby trees based on tree canopy density; ability to access the equipment from the road (versus deep in the right-of-way); known terrain based on U.S. Fish & Wildlife Service Seamless Wetland data (marsh land); and population density.

With respect to the Distribution Feeder Undergrounding and Lateral Undergrounding projects, the Company's GIS data was used to determine the length of overhead conductor to be converted to underground for each project, and additional GIS analysis determined the population density. These factors were used to develop the cost per mile rate.

The costs for the Substation Control House Remediation and the Substation Storm Surge Mitigation programs are dependent on a number of different factors. For the remediation factors, the costs are influenced by the condition of the roof, vintage, and its size. For the storm surge mitigation projects, the costs to mitigate the effects of storm surge for each substation can vary widely depending on the mitigation method employed. The Company developed generally conservative base costs for these projects that it and 1898 & Co. used in the SRM.

Finally, to be clear, if the Resilience Plan is approved, the Company will continue to review and refine the hardening projects, and the final costs for any particular project may need to be adjusted. As I discuss more fully below, the Company will keep the Council informed regarding these adjustments.

D. <u>Investment Optimization and Project Prioritization</u>

Q50. PLEASE PROVIDE AN OVERVIEW OF THE PROJECT PRIORITIZATION AND INVESTMENT OPTIMIZATION PROCESS.

A. As part of the SRM, an optimized investment and project prioritization list is determined from consideration of the hardening projects in the programs I discussed above based on the highest ratio of resilience benefit to cost. Specifically, the model prioritizes each project using a benefit cost ratio based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This calculation is performed for the range of potential benefit values to create the overall resilience benefit cost ratio. Using the benefit cost ratio as a guide, the SRM performs an investment optimization simulation to identify the point of diminishing returns for hardening investments for the 10-year period. Prioritizing and optimizing projects in this way is intended to ensure that the overall investment level is appropriate, and customers get the most cost-effective solutions, *i.e*., "biggest bang for the buck."

Q51. HOW WERE THE HARDENING PROJECTS IN THE PROGRAMS PRIORITIZED IN THE SRM?

A. Because all projects in the SRM were evaluated on a consistent basis, they can all be ranked against each other and compared. The SRM ranks all the projects in the programs based on their benefit cost ratio using the life cycle 50-year present value gross benefit value. The ranking is performed for an average storm future, a high storm future, an extreme storm future, as well as an additional weighted value (based on the average, high, and extreme storm futures). Performing prioritization for the four benefit cost ratios (*i.e.*, the average, high, extreme, and weighted) is important since each project has a different slope in its benefits from an average storm future to an extreme storm future. For example, many of the Lateral Hardening (Rebuild) projects have the same benefit in an average storm future as they do in an extreme storm future. Alternatively, transmission asset hardening projects that are minorly beneficial in an average storm future may have significant benefits in a high storm future and even more in an extreme storm future. To account for these differences and an expectation of an above average storm future, the Company and 1898 & Co. settled on using the weighted value for the base prioritization metric.

E. <u>Further Evaluation</u>

Q52. IS THE COMPANY PROPOSING TO COMPLETE EVERY PROJECT WITH A POSITIVE BENEFIT COST RATIO?

A. No, the Company is not proposing to complete every project with a positive benefit cost ratio, much less proposing to harden every asset in the Company's distribution and transmission systems. While additional projects could be completed that would provide value to customers, the Company has considered other factors, including the potential bill impact to customers and supply chain limitations, to determine a proposed investment level (*i.e.*, the Resilience Plan) that the Company believes is achievable, will improve the resilience of the system, and will provide benefits to customers.

Q53. PLEASE EXPLAIN HOW THOSE OTHER FACTORS WERE EVALUATED.

A. Using the point of diminishing return identified by the project prioritization and investment optimization process of the SRM (*i.e.*, the point at which the incremental costs of each project outweighed the potential incremental benefits of completing more projects) as a starting point, the Company and 1898 & Co. further refined the total number of projects considering certain technical execution constraints such as supply chain limitations. This resulted in a portfolio of hardening projects costing approximately $1.3 billion. Based on the results of the analysis performed by the SRM, this set of transmission and distribution projects is the “maximum” of potential cost-beneficial hardening work that can be executed by the Company over the ten-year period, and the “maximum” potential benefits that can be obtained by completing the hardening projects.

From this optimized project list costing approximately $1.3 billion, the Company worked with 1898 & Co. to evaluate two additional, alternative portfolios of projects (or investment levels) that are subsets of the overall list: a portfolio of projects costing approximately $1 billion and a portfolio of projects costing approximately $750 million. The Company ultimately determined to propose the $1 billion project list, *i.e.* the proposed Resilience Plan, because it provided the best “bang for the buck” for customers.

Q54. WHY IS THE COMPANY PROPOSING THE $1 BILLION PORTFOLIO FOR ITS RESILIENCE PLAN?

A. The Company selected the $1 billion portfolio for its Resilience Plan because it is achievable and will improve the resilience of the system by helping to significantly reduce the costs of future restorations and the duration of outages after severe weather events in the future. While additional projects within the $1.3 billion portfolio could be completed that would provide value to customers (and, as a result, potentially provide more overall benefits to customers), the Company has been and continues to be mindful of bill impacts to customers. The $1 billion portfolio reduces the overall projected costs of the $1.3 billion portfolio without sacrificing too much of the potential benefits that can be realized through these investments. The Company ultimately selected the $1 billion portfolio because it strikes an appropriate balance between costs to customers and the need for accelerated infrastructure hardening to address the frequency and intensity of storms that pose an increasing threat to the Company's electric system.

Q55. CAN YOU ELABORATE ON THE $750 MILLION PORTFOLIO?

A. The project list costing approximately $750 million investment level represents a floor for addressing resilience on an accelerated basis. In considering the potential lists of projects to propose as part of the Resilience Plan, the Company generally kept three over-arching principles in mind: (i) the need to mitigate the impact of major storms (*i.e.*, improving resilience following a major storm by reducing CMI and restoration costs); (ii) the goal of investing in projects where the customer benefits outweigh the costs; and (iii) the realities of establishing an executable and feasible portfolio of projects considering such factors as labor, materials, and other constraints. The three sets of projects analyzed by the Company and 1898 & Co. ($1.3 billion, $1 billion, and $750 million) meet each of these principles.

Lower levels of investment, however, would not meet the first (and arguably the most important) principal, the need to meaningfully mitigate the impact of major storms. While lower levels of investment would be cost-beneficial and executable, completing smaller sets of projects contained in lower levels of investment would not achieve the necessary level of accelerated hardening needed to further strengthen the overall resilience of the Company's electric system to properly prepare it for future storms. As I discuss above, and as recognized by the Council, there is a real and pressing need to improve the resilience of the electric system in the New Orleans area in the light of the frequency and intensity of major storm events in recent years. The $750 million portfolio of projects generated by the SRM is the minimum level of accelerated hardening necessary to meaningfully improve the resilience of the Company's electric system to the extent called for by the Council and stakeholders in this docket.

Q56. DID THE COMPANY HAVE FINAL CONTROL OVER THE LIST OF HARDENING PROJECTS IN THE RESILIENCE PLAN?

A. Yes. While the analysis performed as part of the SRM and with 1898 & Co. served as a useful guide, the Company applied its own operational experience and judgment in determining which projects to propose as part of the Resilience Plan and how those projects ultimately should be scheduled.

F. <u>Overview of Proposed Projects and Estimated Benefits</u>

Q57. WHAT PROJECTS WERE IDENTIFIED FOR INCLUSION IN THE RESILIENCE PLAN AS A RESULT OF THE SRM AND ADDITIONAL EVALUATION?

A. Based on the results of the SRM and the additional evaluation, the Company has proposed in its Resilience Plan to undertake 648 hardening projects across its systems. The projects are listed in the attached HSPM Exhibit SM-2.[13] Furthermore, based on the project costs, which were determined as explained above, the Company estimates that the cost of performing the projects in the Resilience Plan over the next ten years will be approximately $1 billion.[14]

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[13] Notably, while the SRM identified transmission and distribution hardening projects for inclusion within the Resilience Plan, no substation projects were identified for inclusion.

[14] The projects proposed and the years in which costs are expected to be incurred are based on the results of the investment optimization and prioritization process discussed above. While the Company's proposed plan sets forth the Company's best efforts to identify the scope, cost, and timing of these projects, the precise work performed

Q58. CAN YOU PROVIDE AN OVERVIEW OF THE DISTRIBUTION HARDENING PROJECTS IN THE RESILIENCE PLAN?

A. Of the 476 projects considered for the Distribution Feeder Hardening (Rebuild) and Distribution Feeder Undergrounding programs, the SRM identified 140 hardening projects that provide benefits to customers and fall within the $1 billion portfolio, at an estimated cost of $647 million. For Phase I of the Resilience Plan, the Company proposes to complete 58 of these projects, at an estimated cost of $262 million.

Additionally, of the 4,324 projects considered for the Lateral Hardening (Rebuild) and the Lateral Undergrounding programs, the SRM identified 493 rebuild projects and 13 overhead to underground projects that provide benefits to customers and fall within the $1 billion portfolio, at an estimated nominal cost of $292 million and $10 million, respectively. For Phase I of the Resilience Plan, the Company proposes to complete 259 Lateral Hardening (Rebuild) projects and 12 Lateral Undergrounding projects, at an estimated cost of $144 million and $10 million, respectively.

Q59. CAN YOU PROVIDE AN EXAMPLE OF A DISTRIBUTION HARDENING PROJECT?

A. Yes. The Company, for example, proposes to perform one Distribution Feeder Hardening (Rebuild) and six Lateral Hardening (Rebuild) projects during Phase I along a circuit located in Council District E, which will harden more than 480 structures across more than 12 line miles. Together, these projects are estimated to cost approximately $18

will be subject to continual review and refinement as the Company implements the plan following approval. As I discuss below, the Company will keep the Council informed of material changes.

million, and these projects are expected to reduce future restoration costs following storms by approximately $12.9 million and reduce the total number of customer minutes interrupted following major events decreased by 50 million minutes over the next fifty years assuming an above average frequency of storms.

Another example is a set of two Distribution Feeder Hardening (Rebuild) and seven Lateral Hardening (Rebuild) projects that the Company proposes to complete during Phase I along a circuit located in Council District B, which will harden more than 430 structures along more than 5 line miles. Together, these projects are estimated to cost approximately $13 million, and these projects are expected to reduce future restoration costs following storms by approximately $6.6 million and reduce the total number of customer minutes interrupted following major events by 93 million minutes over the next fifty years assuming an above average frequency of storms.

Q60. CAN YOU PROVIDE AN OVERVIEW AND AN EXAMPLE OF THE TRANSMISSION HARDENING PROJECTS IN THE RESILIENCE PLAN?

A. Of the 36 projects considered for the Transmission Rebuild program, the SRM identified 2 projects that provide customer benefits and fall within the $1 billion portfolio, at an estimated cost of $51 million. Specifically, one project is on the Front Street to Michoud 230 kV line, a 23-mile line that traverses Lake Pontchartrain from ENO's Michoud substation and connects with Cleco Power LLC's Front Street substation. This line provides an additional connection to the eastern interconnect from the eastern side of New Orleans that allows for additional flexibility to operate during and after a major event. This project would be completed in Phase I of the Resilience Plan. The other project is on the Gulf Outlet to Air Products 69 kV line, which is approximately 1 mile in length, and would involve the replacement of several structures on the transmission line, which would be completed in Phase II of the Resilience Plan. Together, these projects are expected to reduce future restoration costs following storms by approximately $2.4 million and reduce the total number of customer minutes interrupted following major events decreased by 596 million minutes over the next fifty years assuming an above average frequency of storms.

Q61. DO YOU HAVE ANY OBSERVATIONS ON THE NUMBER OF UNDERGROUNDING PROJECTS SELECTED FOR INCLUSION IN THE RESILIENCE PLAN?

A. Yes. As I noted above, the cost of converting existing overhead distribution lines to underground is significant, and the potential resilience benefits considered by the SRM (*i.e.*, the potential reduction in restoration costs and avoided CMI following major events) did not justify the selection of many undergrounding projects. In other words, generally speaking, the increased cost of undergrounding existing overhead distribution lines was typically higher than the benefits that undergrounding those segments would provide. To be sure, the Company included in the Resilience Plan undergrounding projects where the resilience benefits as evaluated by the SRM support undertaking those costs.

I also note that prioritizing the undergrounding of existing distribution lines to a level above that indicated in the SRM could have limited the Resilience Plan's impact on overall system resilience. Given the increased costs of undergrounding, the amount of rebuild hardening projects that could be selected would decrease as more undergrounding projects are selected (barring a drastic budget increase). By selecting only those undergrounding projects that were supported by the resilience benefits, the Company was able to incorporate more rebuild hardening projects in the Resilience Plan, thereby hardening larger portions of the overall distribution system and providing the direct benefits of a resilient system to more customers.

Q62. WHAT ARE THE ESTIMATED BENEFITS OF COMPLETING THE PROJECTS IN THE RESILIENCE PLAN?

A. The completion of the hardening projects contained in the Resilience Plan is expected to benefit ENO's customers by creating distribution and transmission systems that are more resilient in the face of increasingly severe weather. While no amount of investment or hardening will completely eliminate outages or restoration costs caused by future storms, the identified projects are expected to decrease storm restoration costs, the number of customers impacted by outages from future storms, and the overall duration of outages over the next 50 years.

Based on the SRM, assuming each hardening project in the Resilience Plan is performed, which together total approximately $1 billion in costs, the SRM projects that the Company and customers will see future restoration costs following storms decreased by approximately $390 million and the total number of customer minutes interrupted following major events decreased by 7.1 billion minutes over the next fifty years assuming an above average frequency of storms. In other words, the identified projects are reasonably projected to produce a reduction in storm restoration costs of approximately 49 percent and a decrease in the projected customer minutes interrupted after a major storm by approximately 45 percent over the next 50 years assuming an above average storm future. These estimated benefits are discussed more fully in the direct testimony of Mr. De Stigter and in the Report attached to his testimony.

Q63. HOW DO THE PROJECTED BENEFITS OF THE PROJECTS IN THE RESILIENCE PLAN COMPARE WITH THE OTHER PROJECT PORTFOLIOS EVALUATED BY THE COMPANY?

A. As expected, the approximately $1.3 billion project portfolio generally has more total projected benefits than the Company's Resilience Plan, while the approximately $750 million project portfolio has less projected benefits than the Company's Resilience Plan. Table 4 and 5, below, shows a comparison of the projected avoided restoration costs and the projected reduced CMI benefits, respectively, of the three portfolios following major events over the next fifty years assuming an above average frequency of storms.

Table 4: Avoided Restoration Cost Benefits

	$1.3 Billion Portfolio	$1.0 Billion Portfolio	$750 Million Portfolio
Projected Restoration Cost Benefits	$473 M	$390 M	$297 M
Percent Reduction from Projected Benefits in $1.3 Billion Portfolio	-	17.5%	37.2%

Table 5: Reduced CMI Benefits

	$1.3 Billion Portfolio	$1.0 Billion Portfolio	$750 Million Portfolio
Projected Reduced CMI Benefits	8.4 billion	7.1 billion	5.8 billion
Percent Reduction from Projected Benefits in $1.3 Billion Portfolio	-	15.5%	31.0%

V. PROJECT MANAGEMENT AND CONTRACTING APPROACH

Q64. HOW WILL THE COMPANY MANAGE THE RESILIENCE PLAN?

A. Given the magnitude of the Resilience Plan and the Company's existing organizational framework for construction and project management in the Capital Projects organization, the Company plans to work with qualified contractors ("Alliance Partners") that will be retained in addition to the Company's management team. The Alliance Partners will be heavily relied upon for project execution and support; however, these Alliance Partners will not be utilized exclusively to execute the Resilience Plan, as the Company also plans to leverage existing contract partners and internal resources. Additionally, the Company will maintain appropriate project controls in the areas of project safety, cost, and schedule. The Company will also employ the necessary administrative and technical resources to ensure that project design, quality, and material deliverables are met in accordance with the Company's specifications.

The project management approach will follow the Company's Project Delivery System ("PDS") Policy, Standards and Guidelines in support of driving consistency and certainty in project delivery outcomes. The PDS provides a framework to ensure the Company's business units consistently and effectively develop and implement capital projects. The PDS establishes a Stage Gate Process ("SGP") approach as a single and comprehensive framework for project development, planning, and execution. The SGP provides a roadmap of key deliverables and decisions that need to be sequentially completed to promote consistent, reliable, and high-quality project outcomes. Additionally, the SGP prescribes a continuous systematic evaluation of the project organization, scope, and maturity of project management deliverables that helps ensure projects are executed successfully. This occurs through a series of independent Gate Reviews/Assessment and Approvals.

Q65. WHY IS THE COMPANY USING ALLIANCE PARTNERS?

A. The Company is using Alliance Partners because the Company has determined that this approach is the best method for controlling costs and to consistently and reliably execute the large portfolio of projects contained in the Resilience Plan. After considering a number of different contracting strategies, including an "EPC" model, baseload contractors, and strategic sourcing, the Alliance Partners model emerged as the preferred contracting strategy for the Resilience Plan for a number of reasons. Leveraging existing framework structures with existing Alliance Partners provides the Company with early contractor engagement, allows the Company to secure constrained resources earlier, and helps the Company realize economies of scale in implementing a major undertaking such as the Resilience Plan. The efficiencies that can be realized using Alliance Partners help to reduce overall project costs. Using an alliance model will also allow the Company to streamline governance and oversight of the Alliance Partners executing the Resilience Plan through aligned key performance indicators ("KPI"). Additionally, the Company expects that using this model will allow the Company to structure its agreements with

Alliance Partners to capture cost efficiencies realized through continued engagement and lessons learned. As the Company executes the Resilience Plan, the Company will continue to evaluate the best contracting structure with Alliance Partners to cost effectively execute the plan.

Moreover, the Company currently engages a number of key contracting partners to execute a number of transmission, distribution, and generation projects, and these partners have capabilities to execute work across all, or at least most, of these areas. As the Company works to identify Alliance Partners for the Resilience Plan through a competitive bidding process, the Company also will evaluate the capabilities of any possible partners across the broader portfolio of the Company's projects. The Company would then be able to structure the Alliance Partnerships with execution/contracting flexibility to ensure that the right contract structure is utilized to execute the projects with the most effective partner not only within the Resilience Plan, but also across the entire portfolio of Company projects and programs.

Q66. HOW WILL THE COMPANY SELECT ALLIANCE PARTNERS FOR THE RESILIENCE PLAN?

A. As I just mentioned, the Company plans to use a best value evaluation through a competitive bidding process among the identified Alliance Partners to perform the work, and, if needed, the Company will qualify additional partners to add capacity and execution capabilities. Let me explain. Using the list of hardening projects in the Resilience Plan generated through the Company's work with 1898 & Co., the Company will develop a bid package to take to market. The Company will then evaluate bids, considering such factors as capacity to support regional portfolios; ramp-up and execution plans; safety and oversight programs; engineering and construction capabilities; commercial rates; efficiency gains and continuous improvement programs; subcontracting plans; and sustainability considerations. Upon completion of the sourcing effort, the Company expects to make award recommendations that will allow the Company and its Alliance Partners to support executing regional portfolios of work through long-term alliance agreements.

VI. RISK MANAGEMENT, MITIGATION, AND OTHER CONSIDERATIONS

Q67. IS IT IMPORTANT TO HAVE PLANS IN PLACE TO MANAGE AND MITIGATE THE POTENTIAL RISKS ASSOCIATED WITH THE RESILIENCE PLAN?

A. Yes. The Resilience Plan represents a substantial investment, and it needs to be well managed. Good management includes proper consideration of the risks that can be reasonably foreseen and the development of a plan to reasonably manage and mitigate those risks. Good project management should not seek to eliminate all potential risks irrespective of the costs to do so, but instead should reasonably manage those risks considering the probability of occurrence, potential magnitude of impact, and cost to mitigate.

Q68. WHAT ARE SOME OF THE KEY RISKS TO IMPLEMENTING THE RESILIENCE PLAN AND HOW ARE THOSE RISKS BEING MANAGED?

A. There are a number of risks associated with an undertaking as large as the Resilience Plan. Key risks include, among other things, acquiring and managing adequate labor resources; ensuring an adequate supply of materials and managing lead time to acquire those materials; the potential for wage inflation to affect estimated costs; and potential delays to project scoping and execution. The Company will actively manage these key risks, as well as other risks that emerge, through its oversight of the work being completed by its Alliance Partners through its project management system and PDS, which I discuss above.

Q69. YOU MENTIONED THAT HAVING AN ADEQUATE SUPPLY OF MATERIALS IS A RISK TO IMPLEMENTING THE RESILIENCE PLAN. WHAT IS THE COMPANY'S STRATEGY FOR SOURCING MATERIALS TO USE TO COMPLETE THE RESILIENCE PLAN?

A. To address this risk, the Company is currently engaged in strategic discussions with an existing third-party material integrator who is deeply experienced in large-scale project materials acquisition and logistics in the utility industry. By using a third-party material integrator, the Company expects to operate more cost-effectively on a program of this scale and be able to: (a) isolate the project materials for directly-planned projects; (b) assure visibility into near- and long-term availability of materials; (c) isolate the project costs from ongoing operations; (d) allow for simpler ramp up and ramp down of infrastructure required for project activities; and (e) minimize potential disruptions. The Company will also continue to evaluate the materials markets through the life of the Resilience Plan to ensure that the risk is managed appropriately.

Q70. ARE THERE ANY OTHER AREAS THAT THE COMPANY IS EVALUATING AS IT DEVELOPS THE RESILIENCE PLAN?

A. Yes. A portion of the distribution hardening projects included in the Resilience Plan include poles that are owned by other entities, and the Company is evaluating options to manage the costs of hardening its assets on those joint-use poles.

Q71. WILL THE RESILIENCE PLAN NEED REVISION AND REFINEMENT AS IT IS IMPLEMENTED?

A. Yes. As I discussed above, although the Company's proposed Resilience Plan sets forth the Company's best efforts to identify the scope, cost, and timing of the hardening projects, the precise work performed (as well as the cost and timing of when that work will be performed) will be subject to continual review and refinement as the Company implements its Resilience Plan. And, as I discuss above, the Company also will work to coordinate and avoid overlap between the Resilience Plan and any ongoing reliability work.

VII. MONITORING AND COST CONTROL

Q72. IS THE COMPANY PROPOSING A MONITORING PLAN AS PART OF ITS RESILIENCE PLAN?

A. Yes. In working with its Alliance Partners to implement the Resilience Plan, the Company will track the progress of each proposed project and its costs as part of its project management. The Company will utilize its project management process-controls reporting that accompanies all project executions to track both assets installed and the costs of each project.

To keep the Council informed on the overall progress of the Resilience Plan, the Company is proposing to file progress reports every six months beginning August 1, 2024. The reports generally will provide information regarding the preceding two calendar quarters. For example, the report filed on August 1, 2024, will discuss projects completed, as well as developments in the execution of the plan for the period of January 1, 2024, through June 30, 2024; the report filed on February 15, 2025, will discuss projects completed, as well as developments in the execution of the plan for the period of July 1, 2024, through December 31, 2024. Those reports will address:

- <u>Project Completion Status</u> – identifying the projects completed during the reporting period;
- <u>Project Schedule</u> – providing general information about the projects scheduled for work during the next reporting period (e.g., program and region information) and an explanation for any material scheduling changes from previously-filed reports;
- <u>Business Issues</u> – identifying any material business issues as they relate to the Resilience Plan, including any material business disputes with Alliance Partners, force majeure issues, labor problems or disputes, and any issues associated with local governments or the local communities; and

- Additional Matters – providing a summary highlighting progress on the Resilience Plan, significant changes to the plan, and other notable developments, including, to the extent not provided elsewhere, information regarding any material variances to the schedule and/or scope of projects under the Resilience Plan.

Furthermore, cost monitoring will occur as part of the Resilience & Storm Hardening Cost Recovery Rider ("Resilience Rider") procedures. Under those procedures, which Ms. Maurice-Anderson discusses in her testimony, the Company would provide an annual report to the Council comparing the actual Resilience Plan Revenue Requirement to the projected Resilience Plan Revenue Requirement, along with explanations on material variance.

Q73. IS TIMELY COUNCIL APPROVAL OF THE RESILIENCE PLAN IMPORTANT?

A. Yes. Considering the threat of future storms, the Council should consider and approve the Application expeditiously, and no later than December 31, 2023. Council approval in this timeframe would allow the Company to timely commence Phase I of the Resilience Plan, in 2024 as planned, with the intention to perform work on certain hardening projects before next hurricane season. Thereafter, the Company would file its first progress report with the Council on August 1, 2024, as proposed in the requested monitoring plan. Accordingly, for the Company to timely commence work and file the proposed report, the Council should consider and approve the Application no later than

December 31, 2023, even if consideration of additional resilience measures (*e.g.*, microgrids) remains pending.

Q74. WHAT HAPPENS IF DISRUPTIVE EVENTS, SUCH AS ANOTHER PANDEMIC OR A SERIES OF STORMS, HAVE A MATERIAL EFFECT ON THE RESILIENCE PLAN'S COSTS OR PROGRESS?

A. Unanticipated delays and unforeseen circumstances are a part of any project, particularly with an undertaking as large as the proposed Resilience Plan. The Company will work to address any issues that might arise and, as I mentioned above, refine or revise the Resilience Plan as necessary given the realities of the situation. Furthermore, the Company will keep the Council advised of material changes to the Resilience Plan and its progress and the causes of any material changes.

VIII. CONCLUSION

Q75. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF TEXAS

COUNTY OF MONTGOMERY

NOW BEFORE ME, the undersigned authority, personally came and appeared, **SEAN MEREDITH**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

____
Sean Meredith

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 12th DAY OF APRIL, 2023

Carol Tompkins
NOTARY PUBLIC

My commission expires: 2/1/2025

NOTARY PUBLIC STATE OF TEXAS
CAROL TOMPKINS
My Notary ID # 130989368
Expires February 1, 2025

Listing of Previous Testimony Filed by Sean Meredith

DATE	TYPE	SUBJECT MATTER	REGULATORY BODY	DOCKET NO.
04/30/2021	Direct	ELL Storm Recovery Filing	LPSC	U-35991
07/23/2021	Supplemental	ELL Storm Recovery Filing	LPSC	U-35991
12/19/2022	Direct	ELL Resilience Plan	LPSC	U-36625

OpCo	Local Office	Council District	Sub-system ID	Program Name	Program Type	Project Start Year	Project End Year	Cost Estimate (Nominal)	BCR	50-yr CMI Benefits Weighted	50-yr PV Total Dollars Benefits Weighted	50-yr PV CMI Dollars Benefits Weighted	50-yr PV Restoration Dollars Benefits Weighted	Device Type	Circuit	Total Line Structures	Structures to be Hardened	Total Line Miles	OH Miles to be Convereted to UG
NO	Orleans	Council District A	[redacted]	Distribution Feeder Hardening	Rebuild	2024	2025	[redacted]	5.7308	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]	110	110	3.12	0
NO	Orleans	Council District A	[redacted]	Distribution Feeder Hardening	Rebuild	2024	2025	[redacted]	5.2223	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]	206	184	3.77	0
NO	Orleans	Council District A	[redacted]	Distribution Feeder Hardening	Rebuild	2024	2025	[redacted]	4.7880	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]	296	288	5.79	0
NO	Orleans	Council District B	[redacted]	Distribution Feeder Hardening	Rebuild	2024	2025	[redacted]	6.8598	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]	129	122	1.91	0
NO	Orleans	Council District B	[redacted]	Distribution Feeder Hardening	Rebuild	2024	2025	[redacted]	6.5521	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]	69	66	1.22	0
NO	Orleans	Council District B	[redacted]	Distribution Feeder Hardening	Rebuild	2024	2025	[redacted]	5.7773	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]	76	74	0.81	0
NO	Orleans	Council District B	[redacted]	Distribution Feeder Hardening	Rebuild	2024	2025	[redacted]	5.5057	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]	76	75	2.58	0
NO	Orleans	Council District B	[redacted]	Distribution Feeder Hardening	Rebuild	2024	2025	[redacted]	5.4182	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]	240	226	4.42	0
NO	Orleans	Council District B	[redacted]	Distribution Feeder Hardening	Rebuild	2024	2025	[redacted]	4.6569	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]	381	364	7.09	0
NO	Orleans	Council District B	[redacted]	Distribution Feeder Hardening	Rebuild	2024	2025	[redacted]	3.7088	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]	99	97	1.40	0
NO	Orleans	Council District B	[redacted]	Distribution Feeder Hardening	Rebuild	2024	2025	[redacted]	3.3859	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]	172	167	2.09	0
NO	Orleans	Council District B	[redacted]	Distribution Feeder Hardening	Rebuild	2024	2025	[redacted]	3.1635	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]	107	107	1.22	0
NO	Algiers	Council District C	[redacted]	Distribution Feeder Hardening	Rebuild	2024	2025	[redacted]	4.4732	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]	136	133	2.29	0
NO	Algiers	Council District C	[redacted]	Distribution Feeder Hardening	Rebuild	2024	2025	[redacted]	3.4488	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]	83	42	0.98	0
NO	Algiers	Council District C	[redacted]	Distribution Feeder Hardening	Rebuild	2024	2025	[redacted]	3.4485	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]	54	54	1.39	0
NO	Algiers	Council District C	[redacted]	Distribution Feeder Hardening	Rebuild	2024	2025	[redacted]	2.9128	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]	46	46	1.14	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	OH to UG	2024	2025	[redacted]	4.1112	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	56	56	0.48	0.484519094
NO	Algiers	Council District C	[redacted]	Lateral Hardening	OH to UG	2024	2024	[redacted]	5.4631	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	4	4	0.04	0.041628801
NO	Orleans	Council District C	[redacted]	Lateral Hardening	OH to UG	2024	2025	[redacted]	3.8926	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	40	40	0.32	0.324522831
NO	Orleans	Council District A	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	6.7880	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	23	23	0.42	0
NO	Orleans	Council District A	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	6.6245	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	5	4	0.14	0
NO	Orleans	Council District A	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	5.8863	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	27	27	0.40	0
NO	Orleans	Council District A	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	4.4825	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	41	19	0.30	0
NO	Orleans	Council District A	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	4.4416	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	5	5	0.09	0
NO	Orleans	Council District A	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	4.2897	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	35	29	0.38	0
NO	Orleans	Council District A	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	4.1314	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	22	19	0.27	0
NO	Orleans	Council District A	[redacted]	Lateral Hardening	Rebuild	2024	2025	[redacted]	3.7015	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	80	63	1.00	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	9.0893	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	7	7	0.08	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	6.1239	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	14	14	0.21	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	6.0238	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	4	3	0.04	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	5.8968	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	23	23	0.22	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	5.7474	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	27	27	0.27	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	5.1051	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	23	23	0.35	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2024	2025	[redacted]	4.1880	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	44	43	0.44	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	2.4055	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	1	1	0.02	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	2.1938	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	2	2	0.04	0
NO	Algiers	Council District C	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	10.0700	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	1	1	0.00	0
NO	Algiers	Council District C	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	8.8500	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	23	23	0.60	0
NO	Algiers	Council District C	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	6.9575	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	30	29	0.39	0
NO	Algiers	Council District C	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	5.7366	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	1	1	0.00	0
NO	Algiers	Council District C	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	5.7124	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	17	17	0.35	0
NO	Algiers	Council District C	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	4.8769	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	1	1	0.00	0
NO	Algiers	Council District C	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	4.8128	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	6	6	0.10	0
NO	Algiers	Council District C	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	4.1523	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	1	1	0.01	0
NO	East Orlea	Council District E	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	14.6391	[redacted]	[redacted]	[redacted]	[redacted]	Internal Vac Fault Interrupter	[redacted]	11	4	0.19	0
NO	East Orlea	Council District E	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	12.8768	[redacted]	[redacted]	[redacted]	[redacted]	Internal Vac Fault Interrupter	[redacted]	6	6	0.18	0
NO	East Orlea	Council District E	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	10.5253	[redacted]	[redacted]	[redacted]	[redacted]	Internal Vac Fault Interrupter	[redacted]	10	10	0.13	0
NO	East Orlea	Council District E	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	8.8089	[redacted]	[redacted]	[redacted]	[redacted]	Internal Vac Fault Interrupter	[redacted]	1	1	0.00	0
NO	East Orlea	Council District E	[redacted]	Lateral Hardening	Rebuild	2024	2024	[redacted]	5.1572	[redacted]	[redacted]	[redacted]	[redacted]	Internal Vac Fault Interrupter	[redacted]	2	2	0.00	0
NO	Orleans	Council District B	[redacted]	Distribution Feeder Hardening	Rebuild	2025	2026	[redacted]	4.9222	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]	134	132	2.55	0
NO	Orleans	Council District B	[redacted]	Distribution Feeder Hardening	Rebuild	2025	2026	[redacted]	4.4468	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]	264	253	4.17	0
NO	Orleans	Council District B	[redacted]	Distribution Feeder Hardening	Rebuild	2025	2026	[redacted]	3.6279	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]	203	202	3.39	0
NO	Orleans	Council District C	[redacted]	Distribution Feeder Hardening	Rebuild	2025	2026	[redacted]	3.8987	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]	181	172	3.04	0
NO	Orleans	Council District D	[redacted]	Distribution Feeder Hardening	Rebuild	2025	2026	[redacted]	4.1540	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]	117	116	3.32	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	OH to UG	2025	2025	[redacted]	2.7565	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	14	14	0.10	0.101524654
NO	Orleans	Council District A	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	3.9234	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	31	31	0.38	0
NO	Orleans	Council District A	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	3.7662	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	34	34	0.44	0
NO	Orleans	Council District A	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	3.4343	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	12	12	0.30	0
NO	Orleans	Council District A	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	3.4340	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	6	6	0.09	0
NO	Orleans	Council District A	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	3.3895	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	14	14	0.20	0
NO	Orleans	Council District A	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	3.3477	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	49	37	0.65	0
NO	Orleans	Council District A	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	3.2753	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	27	12	0.23	0
NO	Orleans	Council District A	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	3.1885	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	6	6	0.09	0
NO	Orleans	Council District A	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	2.5799	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	24	24	0.12	0
NO	Orleans	Council District A	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	2.5746	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	23	20	0.24	0
NO	Orleans	Council District A	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	2.3709	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	25	25	0.33	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	5.1217	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	31	31	0.50	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	3.6840	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	9	9	0.09	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	3.5842	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	1	1	0.00	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	3.3185	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	32	32	0.37	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	3.2819	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	13	13	0.15	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	3.2084	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	16	12	0.15	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	3.2044	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	29	29	0.43	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	3.1935	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	34	34	0.56	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	3.1610	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	24	24	0.29	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	2.8990	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	7	7	0.67	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	2.8836	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	13	13	0.13	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	2.7745	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	13	13	0.11	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	2.6984	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	13	13	0.09	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	2.6844	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	31	31	0.41	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	2.6575	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	6	6	0.05	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	2.6524	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	6	6	0.09	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	2.5933	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	15	15	0.21	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	2.5073	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	33	33	0.41	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	2.4929	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	39	39	0.37	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	2.4775	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	18	18	0.37	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	2.4732	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	18	18	0.25	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	2.4150	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	16	16	0.24	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	2.4007	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	10	10	0.12	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	2.3922	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	24	24	0.38	0
NO	Orleans	Council District B	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	2.2967	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	18	18	0.36	0
NO	Orleans	Council District C	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	5.6920	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	26	25	0.27	0
NO	Algiers	Council District C	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	4.7583	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	10	10	0.18	0
NO	Algiers	Council District C	[redacted]	Lateral Hardening	Rebuild	2025	2025	[redacted]	3.8266	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]	16	16	0.29	0

NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2025	2025	[redacted]	3.7177	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		1	1	0.00	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2025	2025	[redacted]	3.7055	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		33	33	0.53	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2025	2025	[redacted]	3.4003	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		1	1	0.01	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2025	2025	[redacted]	3.1380	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		15	15	0.25	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2025	2025	[redacted]	2.8486	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		1	1	0.01	0
NO	Orleans	Council District C	[redacted]		Lateral Hardening	Rebuild	2025	2025	[redacted]	2.6503	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		15	14	0.18	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2025	2025	[redacted]	2.4252	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		2	2	0.02	0
NO	Orleans	Council District C	[redacted]		Lateral Hardening	Rebuild	2025	2025	[redacted]	2.3983	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		9	9	0.12	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2025	2025	[redacted]	2.8213	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		15	11	0.19	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	4.6566	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		36	36	0.71	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	3.0165	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		41	40	1.02	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	2.8796	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		46	46	0.83	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	4.3292	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		190	174	3.74	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	3.4516	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		219	218	4.38	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	3.3600	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		91	91	1.54	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	3.0686	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		210	203	2.88	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	2.7991	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		136	129	2.65	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	2.5666	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		85	85	1.44	0
NO	Algiers	Council District C	[redacted]	[redacted]	Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	3.1516	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		154	151	5.17	0
NO	East Orlea	Council District C	[redacted]		Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	2.6470	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		177	176	4.04	0
NO	Algiers	Council District C	[redacted]	[redacted]	Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	2.6186	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		45	43	1.51	0
NO	Orleans	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	3.9649	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		120	117	3.42	0
NO	East Orlea	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	3.7866	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		103	99	2.13	0
NO	Orleans	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	2.8173	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		95	90	2.71	0
NO	Orleans	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	2.5896	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		105	105	1.70	0
NO	East Orlea	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	2.5778	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		74	66	1.77	0
NO	East Orlea	Council District E	[redacted]		Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	3.8920	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		111	105	2.96	0
NO	East Orlea	Council District E	[redacted]		Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	3.6676	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		48	47	0.99	0
NO	East Orlea	Council District E	[redacted]		Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	2.9776	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		40	39	0.95	0
NO	East Orlea	Council District E	[redacted]		Distribution Feeder Hardening	Rebuild	2026	2027	[redacted]	2.2800	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		320	314	8.13	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	OH to UG	2026	2027	[redacted]	2.0632	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		42	42	0.36	0.359530418
NO	Orleans	Council District C	[redacted]		Lateral Hardening	OH to UG	2026	2026	[redacted]	2.0885	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		21	21	0.16	0.164886416
NO	Orleans	Council District D	[redacted]		Lateral Hardening	OH to UG	2026	2027	[redacted]	2.7888	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		59	59	0.55	0.552183889
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	8.1817	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		12	12	0.19	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	6.4541	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		14	14	0.17	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	4.6718	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		30	30	0.56	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	5.2366	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		20	20	0.19	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	4.6854	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		1	1	0.03	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	4.0677	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		7	7	0.07	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2026	2027	[redacted]	4.0041	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		67	67	0.96	0
LA	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	3.5142	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		19	16	0.20	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	3.5033	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		28	28	0.26	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	3.4817	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		16	16	0.19	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	3.4043	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		24	23	0.26	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2026	2027	[redacted]	3.1614	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		52	49	0.66	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	2.8030	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		20	20	0.25	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	2.7587	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		10	10	0.10	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	2.7416	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		12	12	0.22	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	2.6661	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		4	4	0.04	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	2.6197	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		12	12	0.15	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	2.5669	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		11	11	0.15	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	2.3120	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		9	9	0.07	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	2.0828	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		20	20	0.21	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	2.0501	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		3	3	0.00	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	9.6547	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		16	16	0.28	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	5.4357	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		10	9	0.14	0
NO	East Orlea	Council District C	[redacted]	[redacted]	Lateral Hardening	Rebuild	2026	2027	[redacted]	5.4349	[redacted]	[redacted]	[redacted]	[redacted]	Auto Transfer Switch	[redacted]		86	86	2.27	0
NO	East Orlea	Council District C	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	5.0995	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		19	19	0.23	0
NO	Orleans	Council District C	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	3.9684	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		21	21	0.91	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	3.8797	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		10	10	0.12	0
NO	Orleans	Council District C	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	3.6645	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		27	27	0.40	0
NO	Orleans	Council District C	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	3.5563	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		2	2	0.05	0
NO	East Orlea	Council District C	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	3.5358	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		18	18	0.31	0
NO	East Orlea	Council District C	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	3.3905	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		35	31	0.40	0
NO	East Orlea	Council District C	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	3.1352	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		32	32	0.59	0
NO	Orleans	Council District C	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	3.0894	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		33	33	0.61	0
NO	Orleans	Council District C	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	2.9554	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		36	36	0.33	0
NO	Orleans	Council District C	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	2.6167	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		35	35	0.29	0
NO	Orleans	Council District C	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	2.4488	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		18	18	0.34	0
NO	Orleans	Council District C	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	2.2153	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		23	23	0.36	0
NO	Orleans	Council District C	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	2.2020	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		14	14	0.22	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	7.8163	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		22	22	0.44	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	7.2460	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		39	39	0.62	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	6.0396	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		21	21	0.27	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2026	2027	[redacted]	4.3890	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		83	83	1.13	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	4.3046	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		16	16	0.37	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	4.0658	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		17	17	0.33	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	3.6126	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		38	38	0.60	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	3.3599	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		10	10	0.11	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	3.1777	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		16	16	0.21	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	3.0864	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		15	14	0.29	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	3.0545	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		39	39	0.94	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	2.9433	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		34	32	0.59	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	2.6090	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		15	12	0.15	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	2.4985	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		36	30	0.31	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	2.2337	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		27	27	0.28	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	17.4795	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		7	7	0.06	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2026	2027	[redacted]	5.0474	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		130	127	3.77	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2026	2026	[redacted]	3.2538	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		5	5	0.10	0
NO			[redacted]	[redacted]	Transmission Rebuild	Rebuild	2026	2027	[redacted]	3.4014	[redacted]	[redacted]	[redacted]	[redacted]	Transmission	[redacted]	[redacted]	150	97	23.36	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2027	2028	[redacted]	3.8986	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		43	38	1.33	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2027	2028	[redacted]	3.8683	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		61	57	1.42	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2027	2028	[redacted]	3.3954	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		171	169	3.33	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2027	2028	[redacted]	2.4026	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		139	124	2.10	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2027	2028	[redacted]	1.9220	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		107	86	1.43	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2027	2028	[redacted]	4.4454	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		35	34	1.02	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2027	2028	[redacted]	3.6496	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		80	79	1.38	0

NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2027	2028	[redacted]	3.3794	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		181	170	2.87	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2027	2028	[redacted]	3.0187	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		98	96	2.04	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2027	2028	[redacted]	2.7375	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		121	111	2.38	0
NO	East Orlea	Council District C	[redacted]		Distribution Feeder Hardening	Rebuild	2027	2028	[redacted]	3.7278	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		137	136	2.28	0
NO	East Orlea	Council District C	[redacted]		Distribution Feeder Hardening	Rebuild	2027	2028	[redacted]	3.5349	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		105	103	1.43	0
NO	East Orlea	Council District C	[redacted]		Distribution Feeder Hardening	Rebuild	2027	2028	[redacted]	1.6842	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		108	104	1.59	0
NO	East Orlea	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2027	2028	[redacted]	3.1676	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		195	188	3.14	0
NO	Orleans	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2027	2028	[redacted]	3.0616	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		168	162	3.37	0
NO	Orleans	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2027	2028	[redacted]	2.9807	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		164	158	2.89	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	OH to UG	2027	2027	[redacted]	2.3963	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		2	2	0.00	0.004393941
NO	Orleans	Council District B	[redacted]		Lateral Hardening	OH to UG	2027	2027	[redacted]	1.5291	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		9	9	0.07	0.073075781
NO	Orleans	Council District B	[redacted]		Lateral Hardening	OH to UG	2027	2027	[redacted]	1.5226	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		2	2	0.01	0.005143941
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	4.2641	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		6	6	0.09	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	3.7756	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		40	39	0.55	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2027	2028	[redacted]	3.5269	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		87	87	0.77	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2027	2028	[redacted]	2.6957	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		60	60	0.82	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.5147	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		32	32	0.43	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.2586	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		25	25	0.34	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2027	2028	[redacted]	2.1965	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		49	49	0.52	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.1922	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		21	21	0.32	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	1.9839	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		23	23	0.34	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	1.7703	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		10	10	0.16	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	4.2525	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		15	15	0.16	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	3.5142	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		25	25	0.18	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.5653	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		23	23	0.28	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.4456	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		1	1	0.01	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.3331	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		13	13	0.21	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.1708	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		15	14	0.22	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	5.4211	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		1	1	0.01	0
NO	East Orlea	Council District C	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	3.1499	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		18	18	0.33	0
NO	East Orlea	Council District C	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	3.0551	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		34	32	0.44	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.9907	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		8	8	0.17	0
NO	East Orlea	Council District C	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.8458	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		14	14	0.18	0
NO	East Orlea	Council District C	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.7853	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		22	22	0.31	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.6684	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		38	10	0.26	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.5820	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		10	10	0.16	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.5786	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		1	1	0.00	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.4031	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		7	7	0.16	0
NO	East Orlea	Council District C	[redacted]		Lateral Hardening	Rebuild	2027	2028	[redacted]	2.1546	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		43	43	0.58	0
NO	East Orlea	Council District C	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.0732	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		17	17	0.18	0
NO	East Orlea	Council District C	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	1.9835	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		20	20	0.34	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	1.9814	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		22	22	0.64	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	3.4387	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		18	18	0.22	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.9638	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		16	16	0.20	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.8648	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		27	27	0.46	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.6123	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		12	12	0.18	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.4921	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		10	10	0.12	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.0966	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		23	23	0.28	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.0789	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		13	13	0.28	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	1.9937	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		6	6	0.12	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	1.9664	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		38	38	0.69	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	1.9607	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		26	26	0.52	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.9412	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		7	7	0.11	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.6438	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		6	6	0.10	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.6372	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		5	5	0.10	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.5913	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		19	19	0.41	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2027	2027	[redacted]	2.3134	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		14	14	0.26	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	2.3846	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		64	63	1.68	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	1.9995	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		97	97	1.57	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	1.9994	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		95	94	1.59	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	4.1338	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		40	40	1.28	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	3.0187	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		88	86	1.42	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	2.8731	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		119	116	2.31	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	2.8278	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		58	56	1.08	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	2.7307	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		148	143	3.08	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	2.6908	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		49	49	0.93	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	2.5758	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		89	81	1.88	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	2.3029	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		58	58	0.97	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	2.0858	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		63	63	0.77	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	1.8074	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		46	42	0.82	0
NO	Algiers	Council District C	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	3.0823	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		82	82	0.86	0
NO	Algiers	Council District C	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	2.8051	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		116	114	4.23	0
NO	Algiers	Council District C	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	2.7276	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		380	329	5.57	0
NO	Algiers	Council District C	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	2.5599	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		226	217	3.91	0
NO	Algiers	Council District C	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	2.5083	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		233	232	2.83	0
NO	Algiers	Council District C	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	1.9632	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		74	73	1.67	0
NO	Orleans	Council District C	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	1.8592	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		59	57	0.92	0
NO	Orleans	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	3.0893	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		112	106	2.92	0
NO	East Orlea	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	2.5073	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		182	161	3.66	0
NO	East Orlea	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	2.3078	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		67	65	1.64	0
NO	East Orlea	Council District E	[redacted]		Distribution Feeder Hardening	Rebuild	2028	2029	[redacted]	2.6234	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		132	130	3.07	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	OH to UG	2028	2028	[redacted]	1.8411	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		4	4	0.03	0.025662887
NO	Orleans	Council District B	[redacted]		Lateral Hardening	OH to UG	2028	2028	[redacted]	1.8635	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		5	5	0.04	0.036238648
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	4.5178	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		40	40	0.66	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	4.1252	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		12	12	0.15	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	4.0523	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		17	17	0.39	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	3.7967	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		7	7	0.15	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2028	2029	[redacted]	3.3997	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		44	44	0.51	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.7085	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		20	20	0.40	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.5650	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		38	38	0.62	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.5266	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		9	9	0.16	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.4703	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		9	9	0.16	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.4596	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		32	32	0.67	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.4166	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		4	4	0.07	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.2100	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		6	6	0.08	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.1700	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		8	8	0.09	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.1260	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		5	5	0.09	0

NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.0210	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		25	25	0.20	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	1.9299	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		28	28	0.48	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	1.9222	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		13	13	0.18	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	1.7946	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		16	16	0.22	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	4.6688	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		5	5	0.08	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	3.3930	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		24	24	0.38	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	3.3393	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		27	27	0.32	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	3.1279	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		10	10	0.12	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	3.0229	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		7	7	0.10	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	3.0221	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		30	30	0.36	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.9943	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		26	26	0.34	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.9784	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		19	19	0.27	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.9782	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		10	10	0.15	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.8675	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		44	32	0.63	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.8540	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		13	13	0.16	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.8442	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		36	35	0.61	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.8402	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		32	32	0.60	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.7834	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		28	28	0.29	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.7301	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		17	17	0.22	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.6775	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		10	10	0.12	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.4138	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		26	26	0.29	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.3309	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		23	23	0.33	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.3177	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		17	17	0.23	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.2900	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		20	20	0.19	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.2759	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		8	8	0.14	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.2444	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		27	27	0.34	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2029	[redacted]	2.2412	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		37	37	0.44	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.2159	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		28	28	0.36	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.0845	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		37	35	0.63	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	1.9425	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		23	22	0.18	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	1.9065	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		10	10	0.16	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	1.8865	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		27	27	0.38	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	1.8352	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		22	22	0.16	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	1.8000	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		26	26	0.42	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	1.7961	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		23	23	0.34	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	6.1309	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		3	3	0.11	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	4.9224	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		9	9	0.13	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	4.3975	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		12	10	0.18	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	4.3885	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		9	9	0.13	0
NO	East Orlea	Council District C	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	3.0421	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		40	39	0.56	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	3.0203	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		32	32	0.32	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.9603	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		14	14	0.11	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.7863	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		12	12	0.21	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.6522	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		34	34	1.11	0
NO	Orleans	Council District C	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.6410	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		38	38	0.43	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2028	2029	[redacted]	2.5878	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		63	63	0.64	0
NO	East Orlea	Council District C	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.4714	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		13	13	0.34	0
NO	East Orlea	Council District C	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.3278	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		11	11	0.11	0
NO	East Orlea	Council District C	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.2623	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		21	20	0.26	0
NO	East Orlea	Council District C	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.2250	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		39	39	0.67	0
NO	Orleans	Council District C	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.2129	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		11	11	0.20	0
NO	Orleans	Council District C	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.1574	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		38	38	0.58	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.0987	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		24	24	0.36	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.0757	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		2	1	0.00	0
NO	East Orlea	Council District C	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.0042	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		8	8	0.11	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	8.4200	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		9	8	0.17	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	3.3984	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		20	20	0.47	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	3.3758	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		22	21	0.32	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.8149	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		14	14	0.24	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.7985	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		15	15	0.20	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.7416	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		7	7	0.16	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.7280	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		25	25	0.34	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.6847	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		15	15	0.21	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.6329	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		20	20	0.41	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.4074	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		18	18	0.35	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.2854	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		22	22	0.23	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	2.1357	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		15	15	0.27	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	1.8551	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		16	16	0.31	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2028	2028	[redacted]	1.6789	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		9	9	0.18	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	2.2801	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		147	145	4.21	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	2.1875	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		68	68	1.72	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	2.8070	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		111	111	1.34	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	2.6596	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		152	150	3.18	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	2.5291	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		44	44	2.09	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	2.1817	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		128	117	2.58	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	2.1718	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		259	249	6.46	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	2.1624	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		207	202	4.01	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	1.9276	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		72	71	1.05	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	1.7797	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		95	95	1.64	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	1.6802	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		151	151	3.56	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	1.6215	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		49	49	0.84	0
NO	Algiers	Council District C	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	2.4117	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		145	144	2.10	0
NO	Algiers	Council District C	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	2.2986	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		162	162	2.65	0
NO	Algiers	Council District C	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	1.9029	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		155	155	2.23	0
NO	East Orlea	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	2.4547	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		117	111	2.92	0
NO	East Orlea	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	2.3814	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		119	104	2.77	0
NO	East Orlea	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	2.2252	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		115	114	2.22	0
NO	East Orlea	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	1.9880	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		80	80	2.04	0
NO	East Orlea	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	1.6354	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		61	59	1.93	0
NO	East Orlea	Council District E	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	2.6698	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		239	232	3.96	0
NO	East Orlea	Council District E	[redacted]		Distribution Feeder Hardening	Rebuild	2029	2030	[redacted]	1.7030	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		95	93	1.63	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	4.0361	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		9	9	0.10	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.8286	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		24	21	0.44	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.5771	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		17	17	0.31	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.4446	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		6	6	0.19	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.0917	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		17	17	0.34	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2029	2030	[redacted]	2.0868	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		77	71	1.22	0

NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.6339	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		22	22	0.35	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2029	2030	[redacted]	2.5938	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		53	53	0.67	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.5442	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		25	24	0.43	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.5204	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		14	14	0.33	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.4493	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		18	18	0.19	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.3947	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		27	27	0.38	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.3414	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		27	27	0.43	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2029	2030	[redacted]	2.1775	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		149	148	1.59	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.0572	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		18	18	0.24	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.0195	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		9	9	0.13	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	1.9976	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		26	26	0.29	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	1.9766	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		6	6	0.10	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	1.9408	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		27	27	0.39	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	1.9072	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		18	18	0.20	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	1.8545	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		22	22	0.38	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	1.8212	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		28	28	0.40	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	1.8148	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		19	19	0.27	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	1.7848	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		18	18	0.31	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	1.7519	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		13	13	0.14	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	4.2790	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		12	12	0.10	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.8749	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		35	35	0.49	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.8633	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		2	2	0.06	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.7078	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		24	24	0.39	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.4658	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		14	14	0.20	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.2592	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		6	6	0.11	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.0916	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		23	23	0.23	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.0380	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		10	10	0.24	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	1.9924	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		12	12	0.20	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	1.8480	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		16	16	0.17	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	1.8374	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		25	25	0.21	0
NO	Orleans	Council District C	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	1.7745	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		11	11	0.11	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	1.7149	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		13	13	0.32	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	1.7085	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		23	23	0.23	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	3.4848	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		9	9	0.15	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	3.3558	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		15	15	0.23	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.9322	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		11	11	0.17	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.6325	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		28	27	0.43	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.5717	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		31	30	0.38	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.3878	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		19	19	0.33	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.2878	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		3	2	0.01	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.0824	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		10	10	0.16	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	1.6656	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		24	24	0.41	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	3.2468	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		28	28	0.45	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.7391	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		10	10	0.19	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.4568	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		28	28	0.49	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.3883	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		19	19	0.36	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2029	2029	[redacted]	2.1156	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		21	21	0.48	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2030	2031	[redacted]	1.6336	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		222	222	3.25	0
NO	Orleans	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2030	2031	[redacted]	2.5202	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		79	78	1.87	0
NO	Orleans	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2030	2031	[redacted]	2.3961	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		121	121	2.10	0
NO	East Orlea	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2030	2031	[redacted]	2.2999	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		151	151	3.19	0
NO	Orleans	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2030	2031	[redacted]	1.7985	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		59	59	1.03	0
NO	East Orlea	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2030	2031	[redacted]	1.6922	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		53	53	0.99	0
NO	Orleans	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2030	2031	[redacted]	1.5539	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		56	54	1.58	0
NO	East Orlea	Council District E	[redacted]		Distribution Feeder Hardening	Rebuild	2030	2031	[redacted]	2.3101	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		160	139	3.12	0
NO	East Orlea	Council District E	[redacted]		Distribution Feeder Hardening	Rebuild	2030	2031	[redacted]	2.0389	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		65	65	1.41	0
NO	East Orlea	Council District E	[redacted]		Distribution Feeder Hardening	Rebuild	2030	2031	[redacted]	1.9408	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	[redacted]		91	89	1.70	0
NO	East Orlea	Council District E	[redacted]		Distribution Feeder Hardening	Rebuild	2030	2031	[redacted]	1.8356	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		273	256	4.18	0
NO	East Orlea	Council District E	[redacted]		Distribution Feeder Hardening	Rebuild	2030	2031	[redacted]	1.6721	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	[redacted]		184	146	3.73	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	OH to UG	2030	2030	[redacted]	1.5468	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		4	4	0.03	0.028439403
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	3.0119	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		29	29	0.41	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.0374	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		26	26	0.42	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.9677	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		24	23	0.46	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.9377	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		21	21	0.29	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.8167	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		33	32	0.56	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.7367	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		5	5	0.02	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.7208	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		16	16	0.20	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.6894	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		36	36	0.80	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.5724	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		17	17	0.23	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.1942	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		17	15	0.42	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.1536	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		33	33	0.32	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.8913	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		15	15	0.12	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.8405	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		7	7	0.06	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.8384	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		12	12	0.18	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.7967	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		34	34	0.57	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.7577	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		22	22	0.20	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.7181	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		11	11	0.19	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.6964	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		25	25	0.48	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.6961	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		8	8	0.12	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.6656	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		19	19	0.14	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.6327	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		9	9	0.17	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.6191	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		17	17	0.21	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.6000	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		7	7	0.13	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.5961	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		14	14	0.24	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.5822	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		7	7	0.16	0
NO	Orleans	Council District C	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.6660	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		30	30	0.43	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.1472	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		5	5	0.05	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.1199	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		16	15	0.27	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.0394	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		11	11	0.17	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.0105	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		17	17	0.14	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.9845	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		6	6	0.06	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.9778	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		5	5	0.11	0
NO	East Orlea	Council District C	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.8198	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		37	36	0.34	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.6313	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		28	28	0.35	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.8742	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		8	8	0.17	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.5549	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		8	8	0.12	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.4525	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		14	14	0.21	0

NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.2963	[redacted]	Fuse Switch	[redacted]		14	14	0.17	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.2204	[redacted]	Fuse Switch	[redacted]		9	7	0.21	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2031	[redacted]	2.2129	[redacted]	Fuse Switch	[redacted]		76	74	1.16	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.1988	[redacted]	Fuse Switch	[redacted]		7	7	0.18	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.1941	[redacted]	Fuse Switch	[redacted]		33	33	0.48	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.1717	[redacted]	Fuse Switch	[redacted]		27	27	0.50	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.1604	[redacted]	Fuse Switch	[redacted]		17	17	0.30	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.1377	[redacted]	Fuse Switch	[redacted]		11	11	0.15	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.1132	[redacted]	Fuse Switch	[redacted]		11	11	0.25	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.0811	[redacted]	Fuse Switch	[redacted]		6	6	0.08	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.0653	[redacted]	Fuse Switch	[redacted]		22	22	0.42	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.9885	[redacted]	Fuse Switch	[redacted]		28	27	0.61	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.9709	[redacted]	Fuse Switch	[redacted]		23	22	0.35	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.9239	[redacted]	Fuse Switch	[redacted]		6	6	0.14	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.8653	[redacted]	Fuse Switch	[redacted]		13	13	0.18	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.7844	[redacted]	Fuse Switch	[redacted]		12	11	0.18	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.7808	[redacted]	Fuse Switch	[redacted]		10	10	0.13	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.7759	[redacted]	Fuse Switch	[redacted]		42	42	0.42	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.7377	[redacted]	Fuse Switch	[redacted]		14	14	0.16	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.7356	[redacted]	Fuse Switch	[redacted]		17	16	0.26	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.6624	[redacted]	Fuse Switch	[redacted]		23	23	0.35	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.6568	[redacted]	Fuse Switch	[redacted]		11	11	0.23	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.6481	[redacted]	Fuse Switch	[redacted]		23	23	0.41	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.6457	[redacted]	Fuse Switch	[redacted]		9	9	0.17	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.5621	[redacted]	Fuse Switch	[redacted]		13	13	0.19	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.5611	[redacted]	Fuse Switch	[redacted]		40	40	0.74	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.4907	[redacted]	Fuse Switch	[redacted]		22	22	0.30	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2030	2031	[redacted]	2.2229	[redacted]	Fuse Switch	[redacted]		48	48	1.17	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.1688	[redacted]	Fuse Switch	[redacted]		12	12	0.21	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.1548	[redacted]	Fuse Switch	[redacted]		16	16	0.29	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.0469	[redacted]	Fuse Switch	[redacted]		20	20	0.40	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	2.0266	[redacted]	Fuse Switch	[redacted]		21	21	0.39	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2030	2031	[redacted]	2.0133	[redacted]	Fuse Switch	[redacted]		54	54	0.81	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.9599	[redacted]	Fuse Switch	[redacted]		20	20	0.54	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.8536	[redacted]	Fuse Switch	[redacted]		26	24	0.35	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.6798	[redacted]	Fuse Switch	[redacted]		41	41	0.63	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.6748	[redacted]	Fuse Switch	[redacted]		16	16	0.19	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.6588	[redacted]	Fuse Switch	[redacted]		21	21	0.36	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2030	2030	[redacted]	1.5809	[redacted]	Fuse Switch	[redacted]		32	32	0.32	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	2.2001	[redacted]	Breaker	[redacted]		81	74	1.96	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	2.0228	[redacted]	Recloser Bank	[redacted]		56	53	1.16	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.7916	[redacted]	Breaker	[redacted]		75	75	2.73	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.7345	[redacted]	Breaker	[redacted]		90	87	3.19	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.7174	[redacted]	Breaker	[redacted]		50	47	1.23	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.6854	[redacted]	Recloser Bank	[redacted]		263	253	4.59	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.5635	[redacted]	Breaker	[redacted]		102	100	1.49	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.5397	[redacted]	Recloser Bank	[redacted]		74	72	0.82	0
NO	Orleans	Council District A	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.5174	[redacted]	Recloser Bank	[redacted]		115	115	2.98	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.5861	[redacted]	Breaker	[redacted]		229	212	6.43	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.4933	[redacted]	Breaker	[redacted]		165	146	3.64	0
NO	Orleans	Council District B	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.4730	[redacted]	Breaker	[redacted]		124	121	2.67	0
NO	Algiers	Council District C	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.6042	[redacted]	Breaker	[redacted]		104	103	1.63	0
NO	Algiers	Council District C	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.5297	[redacted]	Breaker	[redacted]		75	70	1.12	0
NO	Algiers	Council District C	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.4961	[redacted]	Breaker	[redacted]		159	149	3.66	0
NO	Orleans	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.6193	[redacted]	Breaker	[redacted]		57	53	1.31	0
NO	Orleans	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.6117	[redacted]	Breaker	[redacted]		135	135	3.75	0
NO	East Orlea	Council District D	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.5300	[redacted]	Breaker	[redacted]		230	218	4.25	0
NO	East Orlea	Council District E	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2031	[redacted]	2.0044	[redacted]	Breaker	[redacted]		33	32	0.66	0
NO	East Orlea	Council District E	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.9959	[redacted]	Breaker	[redacted]		104	103	3.46	0
NO	East Orlea	Council District E	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.6499	[redacted]	Breaker	[redacted]		148	143	4.21	0
NO	East Orlea	Council District E	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.6429	[redacted]	Breaker	[redacted]		89	86	2.24	0
NO	East Orlea	Council District E	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.6239	[redacted]	Recloser Bank	[redacted]		136	136	2.80	0
NO	East Orlea	Council District E	[redacted]		Distribution Feeder Hardening	Rebuild	2031	2032	[redacted]	1.5298	[redacted]	Recloser Bank	[redacted]		127	115	1.53	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	2.4811	[redacted]	Fuse Switch	[redacted]		12	12	0.16	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	2.3326	[redacted]	Fuse Switch	[redacted]		39	38	0.60	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	2.2393	[redacted]	Fuse Switch	[redacted]		15	15	0.19	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	1.9465	[redacted]	Fuse Switch	[redacted]		23	22	0.49	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	1.5032	[redacted]	Fuse Switch	[redacted]		14	14	0.20	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	1.4470	[redacted]	Fuse Switch	[redacted]		19	19	0.28	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	2.4166	[redacted]	Fuse Switch	[redacted]		24	24	0.41	0
NO	Orleans	Council District B	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	2.3349	[redacted]	Fuse Switch	[redacted]		14	14	0.24	0
NO	Algiers	Council District C	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	4.3597	[redacted]	Fuse Switch	[redacted]		2	2	0.06	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	2.4636	[redacted]	Fuse Switch	[redacted]		19	19	0.62	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	2.4423	[redacted]	Fuse Switch	[redacted]		5	5	0.11	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	2.2442	[redacted]	Fuse Switch	[redacted]		40	40	0.56	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	2.1494	[redacted]	Fuse Switch	[redacted]		34	34	0.70	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	2.1185	[redacted]	Fuse Switch	[redacted]		14	14	0.28	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	2.0565	[redacted]	Fuse Switch	[redacted]		14	14	0.24	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	2.0553	[redacted]	Fuse Switch	[redacted]		15	15	0.31	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	2.0054	[redacted]	Fuse Switch	[redacted]		21	21	0.22	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	1.9723	[redacted]	Fuse Switch	[redacted]		41	41	0.74	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	1.7927	[redacted]	Fuse Switch	[redacted]		6	6	0.14	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	1.6562	[redacted]	Fuse Switch	[redacted]		13	13	0.19	0
NO	Orleans	Council District D	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	1.6478	[redacted]	Fuse Switch	[redacted]		11	11	0.15	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	1.5874	[redacted]	Fuse Switch	[redacted]		22	22	0.41	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	1.5830	[redacted]	Fuse Switch	[redacted]		12	12	0.26	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	1.4841	[redacted]	Fuse Switch	[redacted]		17	17	0.31	0
NO	East Orlea	Council District D	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	1.3903	[redacted]	Fuse Switch	[redacted]		11	11	0.22	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	2.7705	[redacted]	Fuse Switch	[redacted]		11	11	0.13	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	2.2741	[redacted]	Fuse Switch	[redacted]		24	24	0.46	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	2.2186	[redacted]	Fuse Switch	[redacted]		8	8	0.11	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	2.0918	[redacted]	Fuse Switch	[redacted]		34	34	0.57	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	2.0821	[redacted]	Fuse Switch	[redacted]		19	19	0.35	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	1.8599	[redacted]	Fuse Switch	[redacted]		17	17	0.35	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	1.8264	[redacted]	Fuse Switch	[redacted]		37	37	0.71	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2031	2032	[redacted]	1.7017	[redacted]	Fuse Switch	[redacted]		63	63	0.92	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	1.6412	[redacted]	Fuse Switch	[redacted]		13	13	0.21	0

NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	1.5485	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		6	6	0.06	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2031	2032	[redacted]	1.4564	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		42	42	0.70	0
NO	East Orlea	Council District E	[redacted]		Lateral Hardening	Rebuild	2031	2031	[redacted]	1.4509	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		10	10	0.17	0
NO			[redacted]	[redacted]	Transmission Rebuild	Rebuild	2031	2032	[redacted]	1.4531	[redacted]	[redacted]	[redacted]	[redacted]	Transmission	[redacted]	[redacted]	21	19	0.93	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2032	2032	[redacted]	1.8042	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		26	26	0.34	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2032	2032	[redacted]	1.7786	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		20	20	0.36	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2032	2032	[redacted]	1.7724	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		9	9	0.15	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2032	2032	[redacted]	1.7671	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		29	29	0.44	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2032	2032	[redacted]	1.7549	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		21	21	0.43	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2032	2032	[redacted]	1.6519	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		11	11	0.31	0
NO	Orleans	Council District A	[redacted]		Lateral Hardening	Rebuild	2032	2032	[redacted]	1.6436	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	[redacted]		8	8	0.17	0
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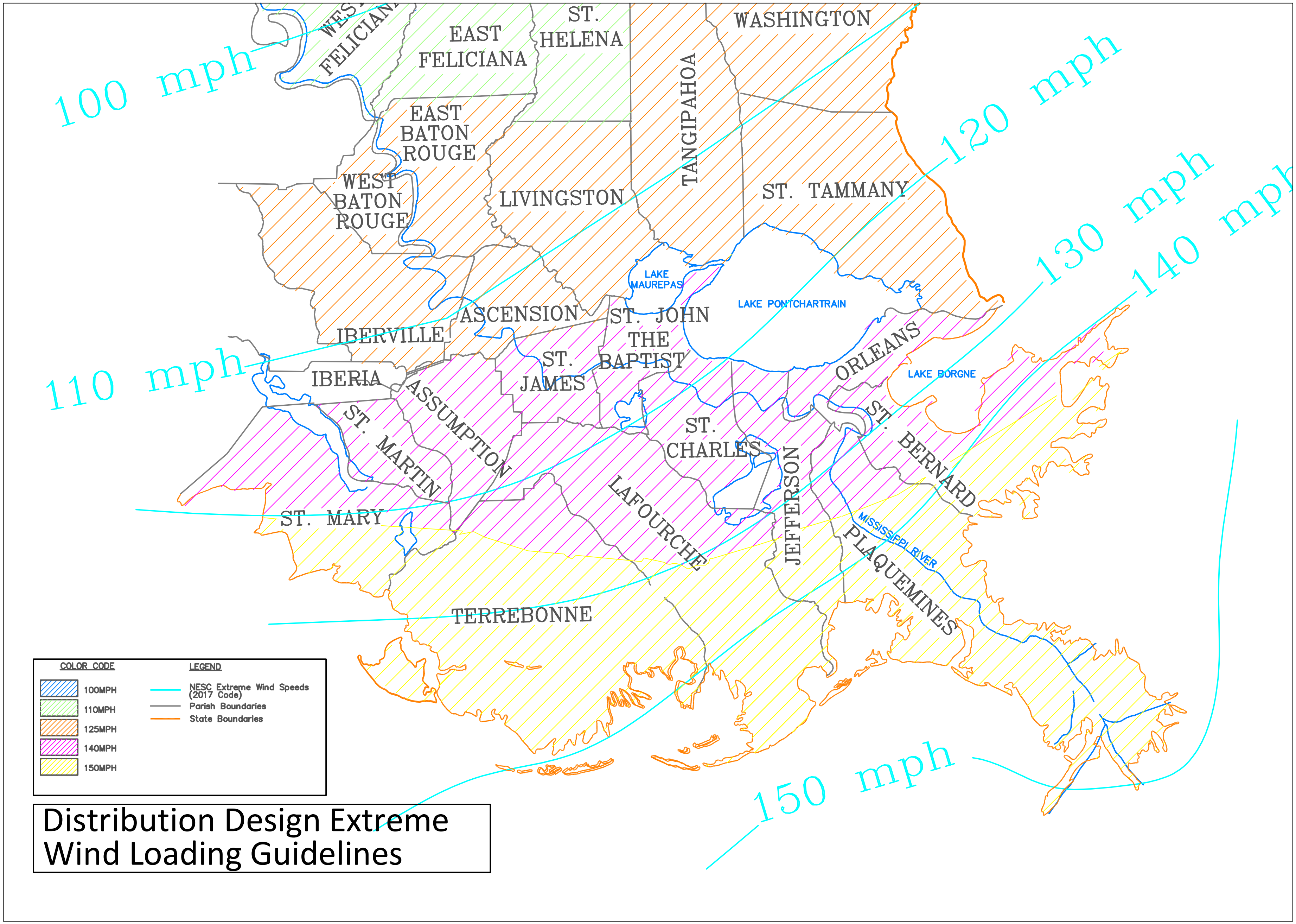
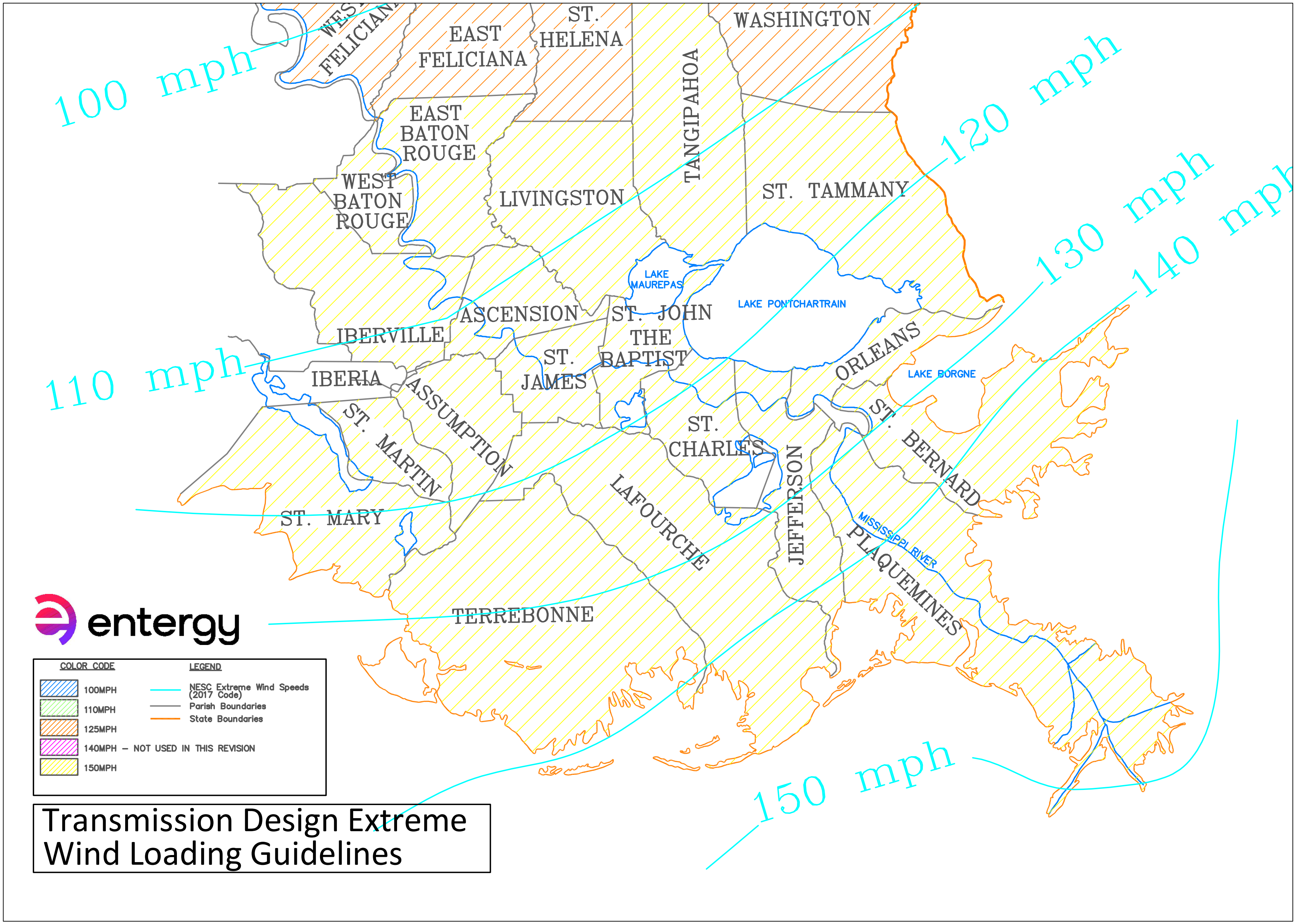


Distribution Design Extreme Wind Loading Guidelines



Transmission Design Extreme Wind Loading Guidelines

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***IN RE*: SYSTEM RESILIENCY AND STORM HARDENING**	**))**	**DOCKET NO. UD-21-03**

DIRECT TESTIMONY

OF

JASON D. DE STIGTER

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

APRIL 2023

TABLE OF CONTENTS

EXHIBITS

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jason De Stigter, and my business address is 9400 Ward Parkway, Kansas City, Missouri 64114.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by 1898 & Co. as a Director, and I lead the Utility Investment Planning team as part of our Utility Consulting Practice. 1898 & Co. was established as the consulting and technology consulting division of Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") in 2019. 1898 & Co. is a nationwide network of nearly 400 consulting professionals serving the Manufacturing & Industrial, Oil & Gas, Power Generation, Transmission & Distribution, Transportation, and Water industries.

Burns & McDonnell has been in business since 1898, serving multiple industries, including the electric power industry. Burns & McDonnell is a family of companies made up of more than 10,000 engineers, architects, construction professionals, scientists, consultants, and entrepreneurs with more than 40 offices across the country and throughout the world.

Q3. PLEASE DESCRIBE BRIEFLY YOUR EDUCATIONAL BACKGROUND AND CERTIFICATIONS.

A. I received a Bachelor of Science degree in Engineering and a Bachelor of Business Administration from Dordt College, now called Dordt University. I am a registered

Professional Engineer in the State of Kansas. My full resume is included as Exhibit JDD-1.

Q4. PLEASE DESCRIBE BRIEFLY YOUR PROFESSIONAL EXPERIENCE.

A. I am a professional engineer with 15 years of experience providing consulting services to electric utilities. Through my work at 1898 & Co. and Burns & McDonnell, I have extensive experience in asset management, capital planning and optimization, risk and resilience assessments and analysis, asset failure analysis, and business case development for utility clients. I have been involved in numerous studies modeling risk for utility industry clients, which have included risk and economic analysis engagements for several multi-billion-dollar capital projects and large utility systems. In my role as a Director, I have worked on and overseen risk and resilience analysis consulting studies on a variety of electric power transmission and distribution assets, including developing complex and innovative risk and resilience analysis models. My primary responsibilities are business development and project delivery within the Utility Consulting Practice, with a focus on developing risk and resilience-based business cases for large capital projects/programs.

Prior to joining 1898 & Co. and Burns & McDonnell, I served as a Principal Consultant at Black & Veatch inside its Asset Management Practice, where I also performed risk and resilience studies.

Q5. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE A REGULATORY BODY?

A. Yes. A list of my prior testimony is included in Exhibit JDD-1.

Q6. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. Entergy New Orleans, LLC ("ENO" or the "Company") engaged 1898 & Co. to assist with modeling, identifying, and prioritizing potential hardening projects to further improve and accelerate the Company's system resilience, and also estimating the costs and benefits of those projects. My testimony introduces, summarizes, and incorporates by reference the Resilience Investment and Benefits Report ("Report"), which is attached hereto as Exhibit JDD-2, that was developed as part of that effort.

Q7. WHAT WAS THE EXTENT OF YOUR INVOLVEMENT IN THE ACTIVITIES UNDERTAKEN FOR THE ENGAGEMENT WITH ENO?

A. I served as the 1898 & Co. project director and worked directly with personnel representing ENO involved in the resilience-based planning approach as part of the development of the Company's Future Ready Resilience Plan ("Resilience Plan"). For the Resilience Plan, I was directly involved in developing the methodology used to consider levels of investment and to identify and prioritize infrastructure hardening projects, along with calculating potential costs and benefits, for which the Storm Resilience Model ("SRM") was used. I also was involved in the assessment and results of the SRM. I further describe the SRM herein, as well as in the attached Report, for which I was the primary author.

Q8. BRIEFLY OUTLINE THE RESULTS OF THE SRM AND EVALUATION CONTAINED IN THE ATTACHED REPORT.

A. As shown in the attached Report, an overall investment level of approximately $1.3 billion over the 2024 to 2033 time horizon both has a positive business case and is technically achievable given current execution constraints, such as materials and labor supply. This investment level is considered a ceiling. The storm hardening projects identified in the Report that are part of this investment level are expected to: (1) decrease storm restoration costs after major weather events; and (2) decrease the number of customers impacted and the duration of the overall outage after major weather events *(i.e.*, reduce customer minutes interrupted ("CMI")).

First, the identified projects are reasonably projected to produce a reduction in storm restoration costs of approximately 50 percent. In relation to the $1.3 billion investment level, the amount of the restoration costs savings ranges from 37 to 55 percent of the investment level depending on future storm frequency and impacts. In other words, the avoided restoration cost benefits alone pay for approximately 37 to 55 percent of the $1.3 billion investment plan. Second, the identified projects are reasonably projected to produce a decrease in the projected customer minutes interrupted after a major storm by approximately 55 percent over the next 50 years. This decrease includes reducing the number of outages, reducing the number of customers interrupted, and decreasing the length of the outage time. In addition, the Company and 1898 & Co. used the SRM to help evaluate varying levels of hardening investment.

Q9. HOW DID THE COMPANY AND 1898 & CO. USE THE SRM TO HELP EVALUATE VARYING LEVELS OF HARDENING INVESTMENT?

A. The Company and 1898 & Co. used the SRM as part of a multi-stage process to develop for consideration three hardening investment levels over the next 10 years:

- Stage 1 – Find the appropriate investment level for the Company at which future incremental hardening investments yield benefits that are less than the incremental costs. The result is a set of projects that are cost beneficial.

- Stage 2 – Refine the investment portfolio to determine what is most likely feasible in the next 10 years with currently known labor and equipment constraints. The result is a set of projects costing approximately $1.3 billion (nominal) that could be performed in the next 10 years.
- Stage 3 – Use the set of projects identified in Stage 2 to develop two additional scenarios. The two other scenarios explore tradeoffs in benefits and cost for investments levels below the $1.3 billion set of projects. These scenarios provide proactive insight for the Company to further evaluate the next 10 years of resilience investment. The two additional scenarios have total 10-year investment levels of $1.0 billion and $750 million.

Table 1 shows the 50-year life-cycle benefits for each of the budget scenarios and the tradeoffs in benefits to move from the $1.3 billion scenario to the two alternative scenarios. Moving from the $1.3 billion scenario to the $1.0 billion scenario is equivalent to foregoing a set of projects with a benefit to cost ratio of 1.6; moving to the $750 million scenario is equivalent to foregoing a set of projects with a benefit to cost ratio of 1.8. And, decreasing the overall investment level even further would be foregoing sets of projects with increasingly higher benefit to cost ratios.

Table 1: Summary of Storm Resilience Investment Scenario Benefits

Metric	$1.3 Billion Scenario	$1.0 Billion Scenario		$750 Million Scenario	
		Scenario Results	Delta to $1.3B Scenario	Scenario Results	Delta to $1.3B Scenario
Weighted Avoided Storm Restoration Cost Benefits	$473 M	$390 M	-$83M	$297 M	-$176M
Weighted Avoided Storm Customer Benefits (CMI)	8.4B	7.1 B	-1.3B	5.8B	-2.6B
Benefit to Cost Ratio	2.55	2.78	1.62	3.06	1.78

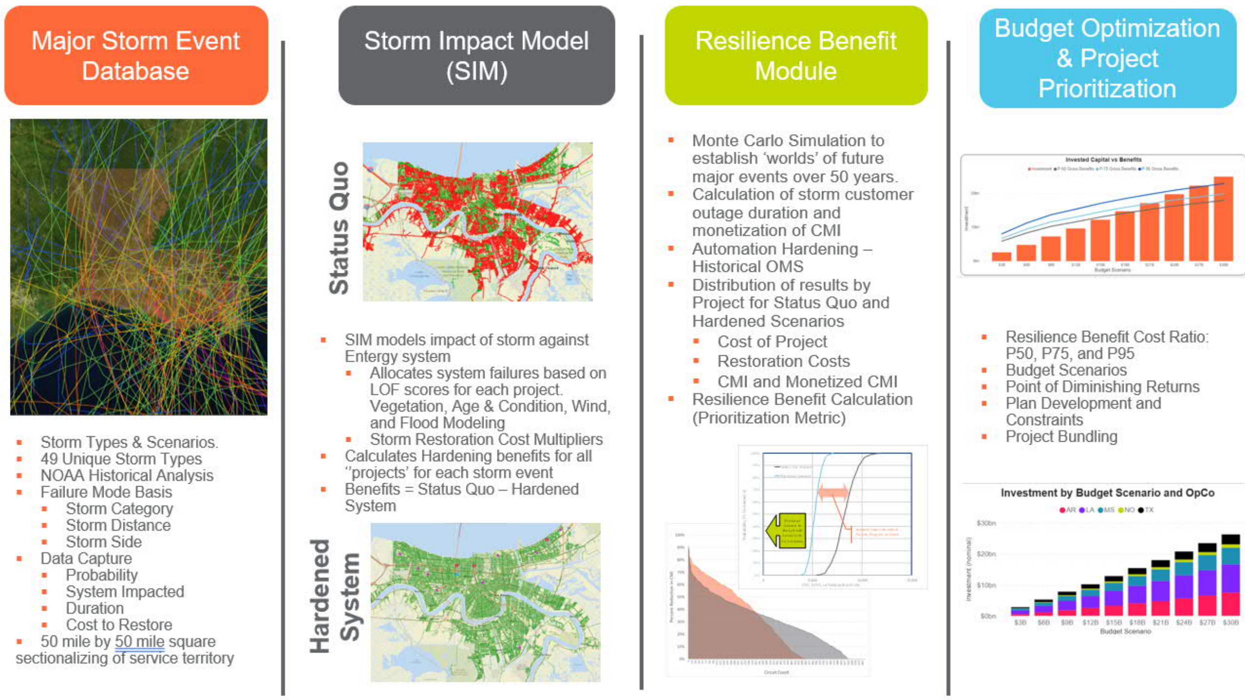
II. RESILIENCE-BASED PLANNING

Q10. PLEASE DESCRIBE THE ANALYSIS 1898 & CO. CONDUCTED FOR THE COMPANY.

A. 1898 & Co. utilized a resilience-based planning approach to identify hardening projects and to assist the Company in prioritizing investments in the Company's transmission and distribution systems utilizing the SRM. The SRM models the benefits of all potential hardening projects for an "apples to apples" comparison across the systems. The resilience-based planning approach calculates the benefit of storm hardening projects from a customer perspective (i.e., outage avoidance/duration and costs). This approach calculates the resilience benefit at the asset, project, and program level.

The SRM employs a data-driven, decision-making methodology utilizing robust and sophisticated algorithms to calculate resilience benefits, including decrease in storm restoration costs after major weather events and a reduction in customer minutes interrupted during outages. Figure 1 provides a high-level overview of the SRM (and its four modeling components) used to calculate project benefits and prioritize projects.

Figure 1: SRM Overview



Q11. CAN YOU EXPLAIN THE FOUR COMPONENTS OF THE SRM?

A. Yes. The Major Storm Events Database contains storm probability distributions (i.e., the range of likely outcomes across alternative scenarios), along with the range of sub-system impacts (i.e., transmission lines, substations, backbones, laterals) for 49 different storm types. The 49 different storm types are based on the range of storm categories, storm distance from the infrastructure, and the side of the storm impacting the infrastructure (i.e., the direction from which the storm approaches the asset). The database organizes the Company's service area into 4 different 50-mile by 50-mile system sections to provide the granularity of the impact of the 49 storm types against the infrastructure. The database includes probabilities and impacts for all 49 different storm types for each of the 4 system sections.

Each storm type for each system section is then modeled within the Storm Impact Model to identify which parts of the system are most likely to fail in the event of each type of storm. The Likelihood of Failure ("LOF") is based on the vegetation density around each conductor asset, the difference between the wind loading of the asset as compared to the Company's current wind loading standard, and the age and condition of the asset. The SRM is comprehensive in that it evaluates nearly all of the Company's transmission and distribution systems. The Storm Impact Model also estimates the restoration costs and CMI for each of the potential hardening projects for each storm type. For purposes of the Report, the term "project" refers to a collection of assets. Assets are typically organized from a customer impact perspective based on their upstream protection device. The Storm Impact Model calculates the benefit in decreased restoration costs and CMI if that project is hardened per ENO's hardening standards. The CMI benefit is monetized using the Department of Energy's ("DOE") Interruption Cost Estimator ("ICE") for project prioritization purposes.

The benefits of storm hardening projects are highly dependent on the frequency, intensity, duration and location of future major storm events over the next 50 years. Each storm type has a range of potential probabilities and consequences. For this reason, the Resilience Benefit Calculation utilizes stochastic modeling, also known as a Monte Carlo simulation, to randomly select a thousand future worlds of major storm events to calculate the range of both Status Quo and Hardened restoration costs and CMI for each project. The probability of each storm scenario is multiplied by the benefits calculated for each project (*i.e.*, the difference between the calculated values for the Status Quo and Hardened scenarios) from the Storm Impact Model to provide a resilience-weighted benefit for each project in dollars.

The Project Scheduling and Investment Optimization model prioritizes the projects based on the highest resilience benefit/cost ratio factoring in execution and investment-level constraints. It also performs the Investment Optimization over a range of budget levels to identify the point of diminishing returns. The model prioritizes each project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This is done for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporates technical and operational constraints in scheduling the projects applicable to ENO and its service area, such as contractor capacity, logistics, and limits on materials. Using the Resilience Benefit Calculation and Project Scheduling and Investment Optimization model, the SRM calculates the net benefit of the projects to customers in terms of reduced restoration costs and CMI for the 10-year investment profile.

This resilience-based prioritization facilitates the identification of the critical hardening projects that provide the most benefit to customers. Prioritizing and optimizing investments in the system helps provide confidence that the overall investment level is appropriate and that customers get the "biggest bang for the buck."

Q12. WHY IS THIS APPROACH TO HARDENING PROJECT IDENTIFICATION IMPORTANT?

A. This approach to hardening project identification is important for several reasons:

1. The approach is comprehensive in that it evaluates nearly all of the assets on the Company's transmission and distribution systems. By considering and evaluating

those systems on a consistent and uniform basis, the results of the Resilience Plan provide confidence that portions of the Company's transmission and distribution assets are not overlooked for potential resilience benefit.

2. By breaking down the entire distribution system by protection zone, the resilience-based planning approach is foundationally customer centric. Each protection zone has a known number of customers and type of customers such as residential, small or large commercial, and industrial, and priority customers (e.g., police, fire, schools, nursing homes, etc.). The objective is to harden each asset that has a higher risk of failing, which would result in a customer outage. Since only one asset needs to fail downstream of a protection device to cause a customer outage in that zone, failure to harden all the necessary assets still leaves vulnerable components that potentially could fail in a storm. Rolling assets into projects at the protection device level allows for hardening of all vulnerable components in the project zone and for capturing the full benefit for customers.

3. The granularity at the asset and project levels allows the Company to invest in portions of the system that provide the most value to customers from both a restoration cost reduction and avoided CMI perspective. For example, a circuit may have 10 laterals that come off a feeder, and the SRM may determine that only 3 out of the 10 should be hardened. Without this granularity, a suboptimal or inefficient level of investment could occur. The adopted approach provides confidence that the overall plan is investing in parts of the system that provide the most value for customers.

4. The approach balances the use of robust data sets along with the Company's experience with storm events to develop storm hardening projects. Data-only approaches may provide decisions that do not match reality, while experience-based solutions can reflect bias. The approach balances the two to better identify types of hardening projects.

Q13. WHY IS IT ADVANTAGEOUS TO MODEL STORM HARDENING PROJECT BENEFITS USING THIS RESILIENCE-BASED PLANNING APPROACH AND THE SRM?

A. The SRM was designed for the purpose of calculating storm hardening project benefits in terms of reduced restoration costs and CMI to build a plan with an appropriate level of investment that provides the most benefit for customers. It was appropriate to model storm hardening projects using the resilience-based planning approach and the SRM for the following reasons:

1. The benefits of hardening projects are wholly dependent on the number, type, and overall impact of future storms that impact the region served by the Company. Different storms have dramatically different impacts to ENO's transmission and distribution systems. For this reason, the resilience-based planning approach includes the "universe" of potential major events that could impact ENO over the next 50 years.

2. Major events cause assets to fail, and assets collectively serve customers. Moreover, it only takes one asset failure to cause customer outages. The cost to restore the failed assets is dependent on the extent of the damage and resources used to fix the system.

The duration to restore affected customers is dependent on the extent of the asset damage and the extent of the damage on the rest of the system. It may only take 4 hours to fix the failed equipment, but customers could be without service for 4 days if crews are busy fixing other parts of the system for 3 days and 20 hours. The pace of restoration is dependent on the type of storm to impact the system. Modeling this series of events for the entire system at the asset and project level for both Status Quo and Hardened scenarios is needed to accurately model hardening project benefits. Therefore, the resilience-based planning approach includes the Storm Impact Model to calculate the phases of asset and project resilience for each of the 49 storm events for both scenarios. The core data and calculations of the Storm Impact Model to develop the phases of resilience for every asset, project, program, and plan are discussed in further detail in the attached Report.

3. The output of the Storm Impact Model is the resilience benefit of each project for each of the 49 storm types. The life-cycle resilience benefit for each hardening project is dependent on the probability of each storm and the mix of storm events to occur over the life of the hardening projects. A project's resilience value comes from mitigating outages and associated restoration costs not just for one storm event, but from several over the life cycle of the assets. A future "world" of major storm events could include a higher frequency of Category 1 storms with average level impact and a low frequency of tropical storms with higher impacts. Alternatively, it could include a low frequency of Category 1 type storms with high impact and a high frequency of tropical storms with lower impacts. The number of storm combination scenarios is significant given that there are 49 unique types of storm events that could

impact grid infrastructure. To model this range of combinations, the SRM employs stochastic modeling, or Monte Carlo simulation, to randomly select from the 49 storm events for each of the 4 system sections to create a future "world" of the unique storm events that could hit ENO's service area. The Monte Carlo simulation creates a 1,000-future storm "world." From this, the life-cycle resilience benefit of each hardening project can be calculated. This is done in the Resilience Benefit Module, which is discussed in more detail in the attached Report.

4. To inform the questions of how much hardening investment is prudent and where that investment should be made, it was necessary to include an Investment Optimization and Scheduling Model within the SRM. The Investment Optimization algorithm develops the project plan and associated benefits over a range of investment levels to identify a point of diminishing returns (i.e., where additional investment provides very little return). The Project Scheduling component develops an executable plan by prioritizing projects that provide the most benefit while balancing ENO's technical constraints, such as contractor capacity, logistics, and materials limits.

Q14. CAN YOU SUMMARIZE THE KEY POINTS FROM HOW THE RESILIENCE-BASED PLANNING ASSESSMENT WAS PERFORMED IN THE SRM?

A. Yes. The following are the key points from how the resilience-based planning assessment was performed in the SRM:

- **Customer- and Asset-Centric**: The SRM is foundationally customer- and asset-centric in how it "thinks" with the alignment of assets to protection devices and protection devices to customer information (number, type, and priority). Further, the focus of investment to hardening all asset vulnerabilities that serve customers shows that the SRM identifies hardening projects that provide the most benefit to customers.

- **Comprehensive**: The comprehensive nature of the assessment is a best practice. By considering and evaluating nearly the entire transmission and distribution system, the results of the Resilience Plan provide confidence that portions of the ENO system are not overlooked for potential resilience benefit.
- **Consistency**: The SRM calculates benefits consistently for all projects. The model carefully normalizes for a more accurate comparison of potential benefits between asset types. For example, the model can compare a substation hardening project to a lateral undergrounding project. This is a significant achievement allowing the assessment to perform project prioritization across the entire asset base for a range of budget scenarios. Without this capability, the assessment would not have been able to identify a point of diminishing returns, balance restoration and CMI benefits, and calculate benefits on the same basis.
- **Rooted in Cause of Failure**: The SRM is rooted in the causes of asset and system failure from two perspectives. First, the Major Storms Event Database outlines the range of storm stressors and the high-level impact to the system. Second, the detailed data streams and algorithms within the Storm Impact Model are aligned with how assets fail – mainly vegetation density, asset age, wind design differential, and flood modeling. With this basis, hardening investment identification and prioritization provide a robust assessment to focus investment on the portions of the Company's system that are more likely to fail in a major storm.

- **Drives Prudency**: The assessment and modeling approach drives prudency for the Resilience Plan on two main levels. First, the granularity of potential hardening projects, nearly 9,600, allows the Company to invest in the portions of the system that provide the most value to customers. Without this granularity, there is risk that parts of the system "ride the coat-tails" of needed investment causing inefficient allocation of limited capital resources. Second, the Investment Optimization allows for the identification of the point of diminishing returns so that suboptimal or inefficient levels of investment in storm hardening are less likely.

Q15. WHAT ARE SOME OF THE CONCLUSIONS CAN BE MADE FROM THE RESULTS OF THE SRM AND EVALUATION CONTAINED IN THE ATTACHED REPORT?

A. The following contain the conclusions of the evaluation performed within the SRM:

- There is significant opportunity for additional resilience investment in the New Orleans system.
- An overall investment level of $1.3 billion over the next 10 years, as developed through the SRM, is technically achievable and has a positive business case. This investment level provides customers with optimal benefits given execution constraints. This investment level is reasonably expected to:
  - Decrease storm restoration cost by approximately 50 percent over the 50-year time horizon.
  - Decrease storm customer outages by approximately 55 percent over the 50-year time horizon.

- Additional, lower investment levels ($1 billion and $750 million) provide an opportunity for the Company to evaluate how to balance the near-term investment costs and impacts to customer bills. However, these lower investment levels come with tradeoffs in benefits. Moving from the $1.3 billion scenario to the $1.0 billion scenario is equivalent to foregoing a set of projects with a benefit to cost ratio of 1.6. Moving to the $750 million scenario is equivalent to foregoing a set of projects with a benefit to cost ratio of 1.8. And, decreasing the overall investment level even further would be foregoing sets of projects with increasingly higher benefit to cost ratios.
- If the resilience of the Company's system is meaningfully enhanced, customers will experience fewer storm outages from both direct and indirect factors. Direct benefits are realized by those customers whose infrastructure directly upstream was hardened. Indirect benefits are realized by all customers since storm restoration crews will be able to rebuild the system quicker because less infrastructure will fail.
- The hardening investment benefits are conservative. Firstly, the benefits outlined above are only direct benefits of investments to specific investments in the grid and do not factor in the indirect benefits from lower overall storm restoration durations. Secondly, the investments will also provide "blue sky" benefits from decreased outages that occur during non-major storm days. Both of these benefit streams are not factored into the evaluation performed by the SRM.

III. CONCLUSION

Q16. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time

AFFIDAVIT

STATE OF MISSOURI

COUNTY OF JACKSON

NOW BEFORE ME, the undersigned authority, personally came and appeared, **JASON D. DE STIGTER**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Jason D. De Stigter

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 11 DAY OF APRIL, 2023

Karen A. Landi

NOTARY PUBLIC

My commission expires: 8/30/26

Karen A. Landi
Notary Public Notary Seal
State of Missouri
Jackson County
My Commission Expires 8/30/2026
Commission # 22344133

Jason De Stigter, PE

Director - Utility Investment Planning

Jason leads the Utility Investment Planning business line at 1898 & Co., part of Burns & McDonnell. In this role, Jason is responsible for business development, marketing, staff training and development, solution and product development, and overall project delivery within the business line. The Utility Investment Planning business line supports electric utilities in developing long-term investment plans and portfolios to meet one or all of the following objectives: 1) aging infrastructure, 2) reliability, 3) resilience or system hardening, and 4) electrification and distributed energy resources (DERs). The business line owns solutions and tools around each of offerings to produce data-driven decisions. Jason is the main architect and solution developer of the data-driven analytic solutions for each of the four offerings inside 1898 & Co.'s AssetLens Analytics Engine.

Jason has 15 years of extensive experience in performing business case evaluation on a variety of project types helping utility clients with difficult investment decisions. Jason also has a deep financial and economic analysis background and specializes in business case evaluation and risk assessment and management for utility client. Jason has extensive experience modeling risk for utility industry clients. His modeling experience includes developing complex and innovative risk analysis models using industry leading risk analysis software tools employing Monte Carlo simulation, decision trees, and Optimization algorithms. His experience includes performing risk and economic analysis engagements for several multi-billion-dollar capital projects and large utility systems for aging infrastructure, system resilience, reliability and distribution automation, and electrification. Jason also serves as expert witness for many of these engagements supporting the full regulatory process.

Education

B.S. / Engineering

B.A. / Business Administration

Registrations

- Professional Engineer (KS)

6 years with 1898 & Co.

15 years of experience

Visit my LinkedIn profile.

TESTIMONY/REGULATORY FILING EXPERIENCE

Utility Company	Regulatory Agency	Docket No. | Year	Subject
Baltimore Gas & Electric	Maryland Public Service Commission	9692 | 2023 1898 Technical Report (137-276) *Testimony not provided, case is still pending	2024 – 2026 Mutli-Year Plan (MYP): Resilience Investment Plan
Entergy Louisiana	Louisiana Public Service Commission	U-36625 | 2022 Direct Testimony Filing/Sponsoring Report Case is still pending	2023-2033 Storm Resiliency Plan
Tampa Electric Company (TEC)	Florida Public Service Commission	20220048-EI | 2022 Direct Testimony (412-485) Filing/Sponsoring Report (141-222) Oral Testimony Provided	2022 – 2031 Storm Protection Plan (SPP)
Oklahoma Gas and Electric Company (OG&E)	Oklahoma Corporation Commission	202100164 | 2022 Direct Testimony (1-45) Filing/Sponsoring Report (46-181) Rebuttal Testimony Not in Public Domain	Grid Enhancement Business Case for 2020 & 2021 Investment
Tampa Electric Company (TEC)	Florida Public Service Commission	20200067-EI | 2020 Direct Testimony (549-623) Filing/Sponsoring Report (100-180) Rebuttal Testimony (72-105)	2020 – 2029 Storm Protection Plan (SPP)
Indianapolis Power & Light Company (now AES Indiana)	Indiana Utility Regulatory Commission	45264 | 2019 Direct Testimony Filing/Sponsoring Report Rebuttal Testimony Oral Testimony Provided	Indianapolis Power & Light Company Transmission Distribution Storage System Improvement Charge (TDSIC) Plan

Additionally, Jason testified in front of the State of Alaska Senate and House Resource committees on project economics and challenges of the AKLNG project.

PROJECT EXPERIENCE

10 Year Storm Resiliency Plan / Entergy Louisiana

Louisiana / 2022-Current

Project director for developing and providing justification for Entergy Louisiana's 2024-2033 10-year Storm Resiliency Plan for its transmission and distribution system to mitigate the impact of major events. The project utilized 1898 & Co.'s Storm Resilience Model to develop and prioritize projects on a cost benefit perspective. The model employed data-driven analyses and robust algorithms to calculate the resilience benefit of over 150,000 storm hardening projects in terms of the range of reduced restoration costs and customer minutes interrupted (CMI). The Storm Resilience Model organized the system into 50 mile by 50 mile system sections and models 49 storm events against each section and estimates which parts of the system will fail in each storm event. The model evaluates each project before and after hardening for both an overhead hardening and underground conversion. The model further utilizes Stochastic Model to simulate storm events and calculate resilience benefits. Finally, the model performs budget optimization to identify ideal investment levels and prioritize projects. The 1898 & Co. resilience benefit assessment report and Jason written testimony were included in the filing. Jason is supporting the regulatory process to include responding to data requests and interrogatories.

Resiliency Multi-Year Plan / Baltimore Gas & Electric

Maryland/ 2022-Current

Project director for developing distribution resiliency portfolio of overhead hardening and underground conversions for Baltimore Gas & Electric. Jason is leading the effort to identify and justify investments for the 2024 through 2026 time horizon. The project utilized 1898 & Co.'s Resilience Investment Model to develop and prioritize projects on a cost benefit perspective. The model employed data-driven analyses and robust algorithms to calculate the resilience benefit hardening projects and alternatives in terms of the range of reduced restoration costs and customer minutes interrupted (CMI). The output of the analysis included three years of specific distribution investments in overhead hardening and underground conversions and the benefits for those projects. 1898 & Co. provided a technical report that was included as an exhibit to BGE's witness. 1898 & Co. is currently supporting the discovery process, the case is still pending.

Distribution Automation Plan Development / Confidential Client

Midwest / 2022-Current

Project director for developing and providing justification for a distribution automation circuit configuration investment portfolio for a Midwest Investor-Owned Utility. The evaluation utilized 1898 & Co.'s reliability and distribution automation analytics model inside our AssetLens Analytics Engine, an asset investment planning tool to evaluate the life-cycle benefits of replacing Transmission and Distribution (T&D) infrastructure and deploying smart devices across the distribution system. The analytics model estimates the expected benefit of deploying distribution automation to every circuits factoring in scheme effectiveness due to tie-line constraints and conductor capacity. The business case monetized the outage improvement and estimated the project cost to include new reclosers, associated communications upgrades, new tie lines, and conductor upgrades. Jason will serve as the expert witness and sponsor the technical report. The case is expected to be filed in May 2023.

Long-term Portfolio Development / Confidential Client

Midwest / 2022-Current

Project director for developing the portfolio of investment projects for a Midwest Investor Owned Utility. Jason is leading the effort to identify and justify investments in transmission, substation, and distribution systems over the next 5 years. The evaluation leveraged 1898 & Co.'s AssetLens Analytics Engine, an asset investment planning tool to evaluate the life-cycle benefits of replacing Transmission and Distribution (T&D) infrastructure and deploying smart devices across the distribution system. The analysis leveraged utility datasets (GIS, OMS, distribution circuit models, asset management systems, condition records, customer counts and profiles) inside the engine's aging infrastructure and reliability analytics. The project included data cleansing, organizing, linking, and transformation and configuration of the holistic risk framework across poles, conductor spans, line transformers, breakers, power transformers, relays, and other assets classes. Jason will serve as the expert witness and sponsor the technical report.

Grid Investment Plan Benefits Assessment / Confidential IOU

Midwest / 2022 - Current

Project director for development of the benefits assessment for a $2.6 billion grid investment plan. The plan includes investments in distribution circuit upgrades, distribution automation, substation rebuilds, capacity rebuilds, and low voltage conversions to improve reliability and resilience, manage long-term costs, modernize for the future, and decrease risk. The engagement include mapping investments to the underlying asset infrastructure, calculating the benefits using the AssetLens Analytics Engine analytics models, and developing the business case for over 6,000 different investment activities across 6 programs. The analysis and results are formalized within a technical report that will be submitted within the public record.

Grid Enhancement Investment Plan Benefits Assessment / Oklahoma Gas & Electric

Oklahoma / 2021-2022

Project director for development of the benefits assessment for OG&E's 2020 and 2021 Grid Enhancement Plan. The plan includes investments in distribution circuit upgrades, distribution automation, and substation rebuilds totaling nearly $250 million. Jason organized the business case framework including the linkage of investments to benefits approaches and calculating the life-cycle benefits in terms of decreased customer outages and avoided restoration costs. Jason also served as the expert witness for the benefits assessment and has provided direct testimony sponsoring the technical report, supported interrogatories and data requests, and provided rebuttal testimony. OG&E settled the case in June 2022.

2022-2031 Storm Protection Plan Resilience Assessment / Tampa Electric Company

Florida / 2021-2022

Project director for supporting the development of TEC's 2022-2031 10-year Storm Protection Plans for its transmission and distribution system in accordance with Florida Statute 366.96. This project is an update to the original 2020-2029 10-Yr Storm Protection Plan. The project utilized 1898 & Co.'s Storm Resilience Model to develop and prioritize projects on a cost benefit perspective. The model employed data-driven analyses and robust algorithms to calculate the resilience benefit of over 20,000 storm hardening projects in terms of the range of reduced restoration costs and customer minutes interrupted (CMI). The Storm Resilience Model models nearly 100 storm events and estimates which parts of the system will fail in each storm event. The model evaluates each project before and after hardening. The model further utilizes Stochastic Model to simulate storm events and calculate resilience benefits. Finally, the model performs budget optimization to identify ideal investment levels and prioritize projects. The 1898 & Co. resilience benefit assessment report and Jason written testimony were included in the filing. Jason supported the regulatory process to include responding to data requests and interrogatories. Jason testified in hearings in Tallahassee in early August 2022. The commission approved nearly all of TEC investment plan.

Long-term Portfolio Development / Public Service New Mexico

New Mexico / 2021-Current

Project director for developing the portfolio of investment projects for Public Service New Mexico (PNM). Jason led the effort to identify and justify investments in PNM's transmission, substation, and distribution systems over the next 20 years. The evaluation leveraged 1898 & Co.'s AssetLens Analytics Engine, an asset investment planning tool to evaluate the life-cycle benefits of replacing Transmission and Distribution (T&D) infrastructure and deploying smart devices across the distribution system. The analysis leveraged PNM datasets (GIS, OMS, distribution circuit models, asset management systems, condition records, customer counts and profiles) inside the engine's aging infrastructure and reliability analytics. The project included data cleansing, organizing, linking, and transformation and configuration of the holistic risk framework across poles, conductor spans, line transformers, breakers, power transformers, relays, and other assets classes. The evaluation organized all PNM's assets into over 20,000 projects. The risk framework allowed for the calculation of benefit in financial terms across each of the 20,000 projects from, specifically the mitigated reactive and restoration costs and the monetization of customer outages. Finally, the project included budget optimization to identify the point of diminishing returns to provide valuable management insights into the level of needed investment in the system over the next 20 years. The overall investment level is confidential. PNM is currently executing the projects that resulted from the evaluation and moving their overall investment levels to manage system risk.

2020-2029 Storm Protection Plan Resilience Assessment / Tampa Electric Company

Florida / 2019-2020

Project director for supporting the development of TEC's 2020-2029 10-year Storm Protection Plans for its transmission and distribution system in accordance with Florida Statute 366.96. The projects utilized 1898 & Co.'s Storm Resilience Model to develop and prioritize projects on a cost benefit perspective. The model employed data-driven analyses and robust algorithms to calculate the resilience benefit of over 20,000 storm hardening projects in terms of the range of reduced restoration costs and customer minutes interrupted (CMI). The Storm Resilience Model models nearly 100 storm events and estimates which parts of the system will fail in each storm event. The model evaluates each project before and after hardening. The model further utilizes Stochastic Model to simulate storm events and calculate resilience benefits. Finally, the model performs budget optimization to identify ideal investment levels and prioritize projects. Tampa Electric Company $1.5 billion 10-year plan was approved in September 2020. The 1898 & Co. resilience benefit assessment report and Jason written testimony were included in the filing. Jason supported the regulatory process to include responding to data requests and interrogatories. He also provided rebuttal testimony. Tampa Electric settled with the interveners.

Grid Investment Business Case / Confidential IOU

Southeast / 2021

Project director for development of a business case for all grid investment planned projects over the next 10 years. Business case evaluated both mitigated life-cycle reactive and restoration costs and monetization of customer outages. Investments included traditional rebuilds for reliability and resilience purposes, distribution automation, communications, and deployment of new technologies. The business case was used for internal executive management approvals.

Distribution Investment Plan Development with AssetLens / Evergy

Missouri and Kansas / 2019-Current

Project director for configuration and implementation of AssetLens for Evergy's distribution system across multiple states and jurisdictions. AssetLens is an asset investment planning software developed by 1898 & Co. to 1) automate project identification in T&D systems using typical utility data set and 2) provide business justification for all projects in life-cycle NPV benefit terms. The software ingests a range of datasets to include GIS, OMS, distribution circuit models, asset management systems, condition records, customer counts and profiles and performs the necessary cleansing, transformation, and linking. Jason led the effort to configure the risk framework analytics that estimate the risk adjusted life-cycle costs and customer impact for all T&D asset classes including poles, pole tops, primary conductor spans, primary underground sections, secondary cable, line transformers, manholes, conduit, splices in manholes, network assets and more. The analytics employ a risk-based methodology across a range of failure types (various probabilities and consequences) to calculate the annual risk costs for a Status Quo and Investment scenario. Life-cycle risk costs include a range of reactive and restoration costs and the monetization of customer outages. The evaluation organized assets into over 100,000 potential projects and scheduled investments to maximize benefit given budget, schedule, and other technical constraints. The overall investment level is confidential. AssetLens visualizes the project plan geospatially providing specific assets for replacement with the business case results for each project. Evergy's distribution engineering teams has been using AssetLens to develop work orders and executive the project plan. It was also used to support their regulatory filing to the Missouri commission.

Distribution Automation Plan Development / Confidential IOU

Central Midwest / 2021-Current

Project director for development of a distribution automation investment plan for the next 5 years. The project involved using GIS and outage records to circuits that would provide the most benefit from the deployment of reclosers. The effort included estimating the number of devices for each circuit and placement of devices for the first few years of the plan. The business case results include the estimated decrease in customer outages and monetization of the outages for an investment business case. The utility is currently developing work orders for 2022 projects.

Overhead and Underground Business Case Development / Confidential IOU

Upper Midwest / 2021-Current

Project director for development of a business case comparing overhead rebuilds to a new modern standards or undergrounding. The business case was performed from a life-cycle cost perspective and impact to customers over a range of events to include extreme weather. The business case evaluated a range of areas of the system to include urban, rural, and suburban. The result of the evaluation may be used for responding to regulators requests.

Long-term Investment Plan Development / Confidential IOU

Midwest / 2021

Project director for identification and justification of distribution circuit and substation investments for a long-term investment plan. The evaluation utilized the AssetLens Analytics Engine to evaluate a range of investment options across the grid, establish 'ideal' investment levels, and provide direction to the 'ideal' split of investment across the system. The utility utilized the study to help develop their long-term investment plan for executive management approval and regulatory strategy.

Distribution Automation Business Case Pilot / Confidential IOU

Midwest / 2021

Project director for a pilot study on distribution automation project identification and justification. The evaluation performed 8760 modeling to understand system overloading constraints to performing automated load transfer schemes. The constraints analysis was utilized in the business case assessment to understand the percentage of time the scheme could operate and provide benefits to customers and if there was a business case to make other grid investments to unlock potential overloading constraints.

Distribution Reliability Investment Plan Development with AssetLens / Confidential IOU

Midwest / 2020-Current

Project director for development of a 10-year distribution investment plan focused on improving overall system reliability and delivery of AssetLens. The data and analytics-based planning approach included the cleansing, organizing, transformation, and linking of GIS, OMS, distribution circuit models, customer data, and condition information. The planning analytics included evaluation of the benefits and costs of rebuilding each protection zone, over 40,000, across they system. Benefit profiles included the mitigated reactive and restoration costs and decreased customer outages monetized using the DOE ICE Calculator. The project also included budget optimization to identify the long-term need for investment. The overall investment level is confidential. The client's distribution engineering team is currently utilizing the AssetLens solution to build work orders from the projects identified. The client is also moving toward the more 'ideal' long-term investment levels to manage system risk.

Long Term Electric Transmission and Distribution Capital Plan / Indianapolis Power & Light

Indiana / 2017-2019

Project manager for developing IPL's asset risk model. The asset risk model includes transmission circuit, substation, and distribution circuit assets. The asset risk model was used to identify and prioritize asset replacements for nearly $750 million of the $1.2 billion filing. Jason developed an innovative approach for modeling distribution circuit risk down to the span level. For the risk model, Jason developed an integrated and holistic probability and consequence of failure framework to evaluate any asset consistently. The approach has allowed IPL to prioritize investment across transmission and distribution and substations and circuits. The analysis included using Burns & McDonnell's proprietary capital optimization algorithm to group assets into projects and prioritize projects to maximize risk reduction benefit. Burns & McDonnell prepared two reports that are part of IPL's public record filing. Jason also provided written (direct and rebuttal) and oral testimony. The entire plan (100%) was approved in February of 2020.

Grid Modernization Engineering Study / Entergy

Louisiana/Mississippi/Arkansas/Texas / 2016–2019

Entergy is embarking on a new approach to electric distribution planning, design and engineering to meet the future needs of its customers. The new approach includes developing modernize electric distribution equipment, engineering and design, and construction standards to drive value throughout the supply chain from material purchasing, inventory, system design, and construction. Additionally, the grid modernization approach leverages a modern holistic distribution asset and capital planning process with associated tools (DNV GL's Synergy) to facilitate efficient and robust performance and risk assessment of Entergy's electric distribution system. The approach identifies the portfolio of issues facing a family or cluster of distribution feeders and then develops the ideal portfolio of projects to address to improve feeder performance, cost, and risk.

Project manager for the business case evaluation and capital project prioritization aspects of Grid Modernization Engineering Study for Entergy. For the portfolio of projects, Jason developed a robust business case methodology that calculates risk reduction benefits, reliability improvement, and operational efficiency (i.e. fewer truck rolls) to justify each capital investment.

Entergy intends to use the results of the engineering study to propose a list of grid modernization project to consider for regulatory approval and funding. Additionally, these projects and the holistic planning approach will be the first step in an evolutionary change to build Entergy's grid of the future, ready for the next generation of consumers and system performance.

69 kV Wood Pole Replacement Program Evaluation / Salt River Project (SRP)

Phoenix, Arizona / 2017–2018

Project manager for evaluation of the 'ideal' level of 69 kV wood pole replacement SRP should execute each year. The effort includes development of an asset risk model, including risk framework, and various replacement strategies that maximize risk reduction while also maintaining overall budget levels. The final outcome will include the risk mitigated for the whole portfolio over 30 years for a range of budget levels to identify an 'ideal' overall investment rate.

PRIOR EXPERIENCE

Capital and Operations & Maintenance (O&M) Budget Prioritization / Tulsa Metropolitan Utility Authority (TMUA) Utility Enterprise Initiative

Tulsa, Oklahoma / 2013-2016

Project manager for the Capital Prioritization and Optimization task of TMUA's Asset Management implementation initiative, Utility Enterprise Initiative. He used a 'Project Prioritization and Optimization' solution for several water and wastewater projects as part annual cycle phased approach (executed three of four phases). Jason was responsible for leading workshops with engineering and maintenance staff, developing business case approaches for each water/wastewater project, performing Monte Carlo and optimization simulations, and developing strategies for the Utility's capital improvement plan (CIP) during a period of tight budget constraints to minimize rate increases. TMUA was working toward codifying the process and tool into their own annual budget and rates process. As such, Jason was responsible for developing users guide documentation and holding training on the process and tool for TMUA.

2017 Executive Asset Management Plan Alternatives Evaluation / Washington Suburban Sanitation Commission (WSSC)

Laurel, Maryland / 2015

Project manager for alternatives evaluation to support WSSC in the development of their 2017 Enterprise Asset Management Plan Business Case. Effort included developing forecasted 30-year capital plans optimizing on level of service, risk and cost. WSSC utilized the results of the evaluation to develop long term forecasts of capital improvements for communication to decision make Capital Prioritization Pilot Project / Salt River Project (SRP)

Project Prioritization / Salt River Project

Arizona / 2013-2014

Subject matter expert for this pilot study for SRP to prioritize and optimize several electrical generation, transmission and distribution planned investments. Allowed SRP management the opportunity to further develop and improve upon their current budget processes and to consider adopting the solution enterprise-wide. Jason's responsibilities included developing business case approaches for several of the pilot study projects and supporting workshops.

Long Term Electric Transmission and Distribution Capital Plan / Duke Energy

Indiana / 2014-2015

Subject matter expert and manager for development of a risk-based electric T&D capital plan that included Duke's long-term electric transmission and distribution (T&D) investments. This work provided evidence of how Duke's investments in its system provided risk reduction benefits and focused spending on high risk assets. As a capital prioritization and risk subject matter expert, he also developed capital plan profiles and resulting risk reduction solutions which were key to showing the value of the 7-year capital plan.

Long Term Electric Transmission and Distribution Capital Plan / Northern Indiana Public Service Company (NIPSCO)

Indiana / 2013-2014

Subject matter expert for development of a long-term $1 billion plus capital plan for NIPSCO's electric T&D infrastructure. A system risk model was developed to analyze and score asset risk across the T&D system for NIPSCO. The model highlighted the risk reduction benefits achieved through NIPSCO's long-term asset replacement program, which is focused on addressing high-risk assets that are nearing the end of their useful life.

Capital Prioritization System Master Plan / Hetch Hetchy Water and Power

California / 2009, 2011, 2012

Primary consultant for this system master plan, developing the analysis and prioritization of recommended capital and O&M projects for the Hetch Hetchy power, transmission and civil asset system. The process utilized a risk-based approach to economically schedule investments to maximize risk reduction given a certain budget constraint. The Hetch Hetchy Reservoir system lies within the scenic Yosemite National Park and provides electricity and water storage for the San Francisco Public Utility Commission.

Capital Project Prioritization with Risk Assessment / Colorado Springs Utilities

Colorado Springs, Colorado / 2008

Primary analyst on an innovative capital project prioritization process for Colorado Springs Utilities' Raw Water System. The engagement applied the Strategic Value Creation process to quantify the physical and financial parameters of capital and O&M projects identified for the utility's raw water system. A wide variety of projects and risk were then prioritized to develop the system capital improvement plan while considering utility risk tolerance, budget constraints and other planning criteria. Monte Carlo simulations were used to quantify the physical and financial parameters of each individual project, and the projects are evaluated and ranked using a consistent and transparent approach.

Jason was responsible for performing the Monte Carlo analysis, understanding the risks of each CAPITAL and O&M project, and prioritizing the projects to reduce the overall risk to the client.

Alaska Liquefied Natural Gas (AKLNG) Economic and Risk Analysis / State of Alaska Departments of Natural Resources and Revenue

Alaska / 2013-2016

Project manager responsible for economic and risk analysis for the AKLNG project on behalf of the State. In this role, Jason developed analysis to explore various project questions and negotiating position to better understand the perspective of each project sponsor and the best position for the State. He routinely developed materials to present to the commissioners of the departments or Natural Resources and Revenue, the State of Alaska legislature, negotiating teams, and the governor's office. On a few occasions, Jason has testified to the state of Alaska legislature of the economics and risks associated with the AKLNG project.

Deep Tunnel Sewerage System (DTSS) Phase 2 Resiliency Assessment / Singapore Public Utilities Board (PUB)

Singapore / 2014-2015

Subject matter expert for an alternative's resiliency assessment of several deep tunnel sewerage systems alternatives for Singapore PUB. In his role for this engagement, Jason created an innovated approach to evaluating the resiliency of several tunneling alternatives including total risk weighted level of service and cost over the asset's life cycle. The assessment identified several key risks impacting each alternative then quantifying the likelihood and the level of service and cost impacts of each risk. Employing Monte Carlo simulation, the risk cost and discount to level of service scores were calculated to develop a range of potential benefit cost ratios for each alternative. Singapore PUB utilized the process and results to identify a preferred alternative and move forward with key design decisions.

Kirkwood Penstock Risk Evaluation / Hetch Hetchy Water and Power

California / 2014

Project manager for a risk assessment of HHWP's critical Kirkwood Penstock which over 80% of San Francisco Bay's water supply moves through. The risk assessment following guidelines set out by the United States Bureau of Reclamation including a failure modes and effects analysis applying a qualitative scoring-based approach to evaluate the likelihood and consequence of failure for each failure mode. HHWP utilized the results of the evaluation to prioritize investment needs to ensure reliability of this critical asset.

Business Case Evaluation and Risk Analysis / Hampton Roads Sanitation District (HRSD, Wastewater Utility)

Virginia / 2011-2012

Business case evaluation and lead risk consultant for this long-term evaluation of the business case and associated risk of alternative wastewater system master plans. Working with Hampton Roads' senior management team, Jason evaluated the economics and risk of alternative strategic long-term wastewater system expansion plans related to biosolids management, which involved hundreds of millions of dollars in capital and O&M expenditures. This developed a long-term strategy that is now being used to optimize short- and long-term implementation plans for HRSD's wastewater system.

Conveyance Alternative Risk Assessment / Metropolitan Water District

California / 2010

Primary consultant for this engagement which analyzed several water conveyance options for the California State Department of Water Resources. This analysis was focused on capital cost and schedule risk of different multi-billion-dollar canal and tunnel conveyance alternatives. Jason was the risk specialist for the Environmental team for the risk assessment workshop. Utility decision-makers utilized the results to more fully understand the risk inherent in each alternative to decide on a preferred alternative.

Integrated Water Power Plant Economic and Regulatory Assessment / Public Authority for Electricity and Water of Oman

Oman, Middle East / 2009-2010

Primary analyst for the economic and regulatory (tariff) modeling of a new, highly efficient integrated water & power plant. Jason's responsibilities included performing economic and tariff modeling of several different desalination and power plant alternatives and presenting final results to the Chairman of the Public Authority for Electricity and Water of Oman.

AGIA Economic and Risk Modeling / State of Alaska Department of Natural Resources (DNR)

Alaska / 2009-2010

Primary analyst for this economic and risk modeling assignment for the State of Alaska DNR. Analysis included modeling and evaluation of different natural gas pipeline project risk factors, as well as risk mitigation measures the state has within its control. The results of the analysis assisted the State of Alaska in negotiations with other pipeline stakeholders.

Black & Veatch's Energy Market Perspective Emissions Modeling

Overland Park, Kansas / 2012-2013

As part of Black & Veatch's annual release of its Energy Market Perspective, Jason developed a fundamental economic model to calculate emissions prices based on the EPA's Cross State Air Pollution Rule.

Commercial Modeling and Analysis / Alaska Gasline Development Corporation (AGDC)

Anchorage, Alaska / 2010-2011

Lead consultant for ongoing commercial and tariff modeling for AGDC's analysis of in-state pipeline alternatives. This modeling included sensitivity and scenario analysis, midstream tariff modeling, and stakeholder cash flow analysis.

Black & Veatch's Energy Market Perspective

Overland Park, Kansas / 2009-2011

The Energy Market Perspective developed by Black & Veatch uses an integrated market modeling approach to develop price forecasts for energy and natural gas prices. The modeling team, which included Jason, developed forecasts for CO2 taxes, energy demand and peak demand, generation retirements, generation expansion, renewables buildout and transmission expansion. Using these forecasts, the integrated market model used an interactive process of a production cost model for electric prices and a fundamental market model for natural gas prices.

Jason's principal responsibilities included developing forecasts, running and understanding the production cost model for a large region in the United States, and drawing conclusions for the region. The main forecasts Jason developed included energy and peak demand, generation retirements, generation expansion, and transmission expansion. Furthermore, Jason was responsible for developing the final report for the regional perspective.

Alaska Gasline Inducement Act (AGIA) Net Present Value (NPV) and Risk Analysis / State of Alaska Departments of Natural Resources and Revenue

Alaska / 2007-2008

In 2007, the state of Alaska passed the Alaska Gasline Inducement Act (AGIA). This act created a framework for the State to issue a license to build a 1,400 mile pipeline to transport natural gas from the North Slope of Alaska to either the North American market or elsewhere.

Uncertainty for a project of this size (over $30 billion) is understandably significant. In order to quantify this significant uncertainty, risk analysis was performed explicitly with the NPV model to evaluate the level of project risk to the various stakeholders due to various assumptions such as commodity prices, capital cost escalation, project schedule uncertainty, and reserve risk.

Jason performed economic, risk and financial analysis for several different stakeholders for the proposed projects and several sensitivities and alternative scenarios. Jason's main responsibilities included model development/creation, Monte Carlo risk modeling, and understanding risk for each stakeholder. He also performed financial analysis, data validation, and report and presentation support.

Socioeconomic Analysis, Riverbend Unit 3 and Fermi Unit 3 Nuclear Licensing Project / Entergy and Detroit Edison

Louisiana and Michigan / 2007-2008

Senior analyst served as an economist for a detailed socioeconomic analysis associated with the construction and operating license application (COLA) process for Entergy and Detroit Edison. He was responsible for developing population distributions; population projections; demographic characteristics to include age, sex, race and income; transient population distributions; and community characteristics for the surrounding area. Jason was also responsible for writing and reviewing significant portions of the COLA

Market and Economic Analysis / Termobarranquilla

Colombia, South America / 2007-2008

As a senior analyst, Jason provided market analysis, economic analysis and a discounted cash flow model to evaluate the worth of the Termobarranquilla power plant after an energy market restructuring in Colombia. He was responsible for developing an energy market model, economic dispatch model, discounted cash flow model and writing the report.

Taylor Energy Center Need for Power Application / Various Clients

Florida / 2006

Jason performed production costing, economic analysis and other support to facilitate the completion and filing of the Taylor Energy Center (TEC) Need for Power Application (NFP). The NFP provided a determination of the most cost-effective capacity addition to satisfy forecasted capacity requirements for the four separate utilities participating in the project while maintaining consistency with the Florida Public Service Commission statutory requirements. The analysis considered self-build and purchase-power alternatives.

Portfolio of Wind Farms and Coal Fired Plants / Sembcorp Industries Pte Ltd.

China / 2011

Lead consultant to Sembcorp Industries Pte (buy-side), in support of their potential acquisition of an equity position in a Chinese investment company (confidential). This engagement required due diligence site visits and technical and commercial review of a wind portfolio and coal fired generation plant in Shanxi Province, Hebei Province, and Inner Mongolia Autonomous.

Water and Wastewater Utility Independent Engineer's Report / Confidential Client

2011

Primary consultant assisted and prepared an independent engineer's report for a confidential client seeking to divest its portfolio of water and wastewater utilities. The report provided an overview of the systems, the major sources of supplies, rates, and environmental and regulatory issues. Major facilities were evaluated to document the condition of specific utilities. A final report was prepared and delivered to the client for use in its divestment proceedings.

Combined Cycle Due Diligence / Confidential Client

California / 2011

Jason was involved with the technical due diligence of 1,000 megawatt (MW) combined-cycle power plant in the state of California. Jason was responsible for reviewing maintenance and performance reports on plant equipment and safety along with O&M and energy management agreements. Jason also developed the corresponding report sections that summarized the results of the analysis.

Engineer's Report / Philadelphia Gas Works (PGW)

Philadelphia, Pennsylvania / 2010-2011

Lead consultant on the engineer's reports developed for PGW's last two revenue bond issues for $165 million and $150 million, respectively. Proceeds from the bond issues funded needed capital improvements to PGW's distribution system and LNG facilities. The engineer's report summarized the findings of a study of PGW's facilities, management, operations, gas supply, rates and marketing, and customer service, and assessed the financial feasibility of the bond issue.

E.ON US Portfolio Due Diligence, Various Coal, Gas and Hydroelectric Power Plants / E.ON

Kentucky, United States / 2010

Jason performed technical due diligence for the potential sales of approximately 9,500 MW coal, gas and hydroelectric generating assets in the state of Kentucky. Jason was responsible for reviewing maintenance and performance reports on plant equipment and safety along with O&M and energy management agreements. Jason also developed the corresponding report sections that summarized the results of the analysis.

Technical Due Diligence / Con Edison Development, Inc.

2007

Jason performed a technical due diligence assessment of certain power generation facilities in the northeast United States. He was responsible for developing power plant performance sections of the assessment and reviewing O&M, power purchase, maintenance, gas supply, oil supply, electrical interconnection and water supply agreements.

PUBLICATIONS AND PRESENTATIONS

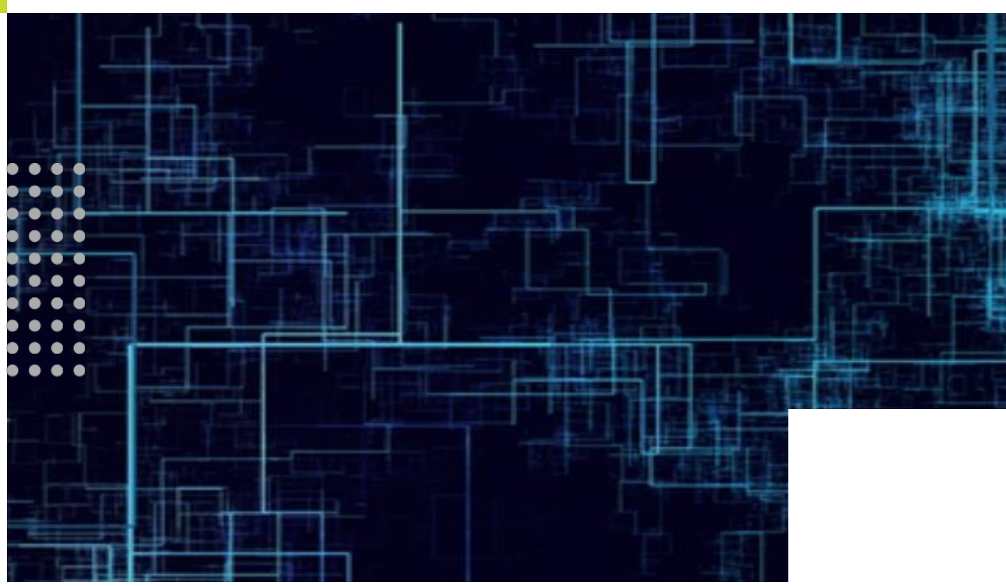
- *Asset Management: A Framework for Maximized Value*, published and featured in Burns & McDonnel's quarterly BenchMark article in 2020. (Video and quoted)
- How IPL Created an Optimized Capital Plan to manage risk across the entire T&D system, published and presented at the 2020 DistribuTECH conference. (Co-Author)
- How IPL solved the challenges of modeling linear assets in their asset risk model by leveraging GIS, published and presented at the 2020 DistribuTECH conference. (Co-Author)
- Capital Planning for Grid Modernization, Building the Grid of Tomorrow, 2018 EUCI course presenter. (Co-presenter)
- *Changing the Way the Grid's Future is Planned*, published Burns & McDonnell white paper in 2017. (Co-Author)
- Monetizing Risk Helps Tulsa Optimize Capital Investments, published in the July 2016 Journal American Water Works Associate (JAWWA). (Co-Author)
- Monte Carlo Simulations Take The Chance Out Of Investment Decisions, published in the April 2016 Breaking Energy. (Co-Author)
- Monetizing Risk – Capital Investment Prioritization and Optimization for Tulsa Metropolitan Utility Authority, published at the 2016 Utility Management Conference. (Co-Author)
- Priorities: Getting the Most From Your Capital Improvement Plan, published in the May 2015 Florida Water Resources Journal. (Author)
- Monetizing Risk – A Capital Investment Prioritization and Optimization Model, presented and published at the 2015 Texas Water Conference. (Co-Author/Presenter)
- How to Get More Reliability Bang from Your Capital Spending Buck, presented and published at the 2014 Florida Water Resources Conference. (Co-Author/Presenter)
- Triple Bottom Line and Monte Carlo Simulation: Business Case Evaluation Methodologies and Testing Sensitivities: Understanding Economic Models and Uncertainty in Results, presented at the 2013 WEFTEC conference workshop titled "WERF Barriers to Biogas Workshop: Learn to Use the Right Economic Methodologies to Evaluate Cost-Saving Projects". (Presenter)
- The Challenge of Regulatory Compliance and Multiple Facility Upgrades – A Progressive System Approach, presented and published at the 2012 WEFTEC conference proceedings. (Co-Author)
- Asset Management and Maintenance Strategies – Balancing Costs and Risk, poster presentation and published at Hydrovision 2011 conference. (Co-Author)

Resilience Investment and Benefits Report

Entergy New Orleans, LLC

Project No. 142412

Revision 1
4/17/2023



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LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
ANL	Argonne National Laboratory
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
C&I	Commercial & Industrial
CMI	Customer Minutes Interrupted
COF	Consequence of Failure
DOE	Department of Energy
GIS	Geographic Information System
ICE	Interruption Cost Estimator
IEEE	Institute of Electrical and Electronics Engineers
LOF	Likelihood of Failure
MED	Major Event Day
NIAC	National Infrastructure Advisory Council
NOAA	National Oceanic and Atmospheric Administration
OMS	Outage Management System
PNNL	Pacific Northwest National Laboratory
POF	Probability of Failure
PV	Present Value
ROW	Right-of-Way
SIM	Storm Impact Model
SLOSH	Sea, Land, and Overland Surges from Hurricanes
T&D	Transmission and Distribution

1.0 EXECUTIVE SUMMARY

1898 & Co., the advisory and technology consulting arm of Burns & McDonnell, was engaged on behalf of Entergy New Orleans, LLC (Entergy New Orleans or the Company) to assist with the development of a plan to strategically accelerate investment in storm resilience for the period 2024-2033 (Resilience Plan). In collaboration, Entergy New Orleans and 1898 & Co. utilized a resilience-based planning approach to identify hardening projects and to prioritize investments in the Company's transmission and distribution (T&D) system utilizing a Storm Resilience Model. The Storm Resilience Model evaluates each hardening project's ability to reduce the magnitude and/or duration of disruptive storm events. Key objectives for the Storm Resilience Model include:

1. Calculate the customer benefit of hardening projects through reduced utility restoration costs and impacts to customers;
2. Prioritize hardening projects with the highest resilience benefit per dollar invested into the system; and
3. Provide insights on various investment funding levels and execution constraints and their relationship to customer benefits.

The Storm Resilience Model employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to calculate the resilience benefit of hardening projects in terms of the range of reduced restoration costs and Customer Minutes Interrupted (CMI). The hardening projects provide resilience benefit from several perspectives. Some of the hardening projects help avoid storm-based outages, and others decrease the duration of storm-related outages. This report shows only the reduction in CMI, which accounts for both types of benefits. However, there is a strong relationship between reduction in CMI and reduction in Customers Interrupted (CI).

Resilience-based prioritization facilitates the identification of hardening projects that provide the most benefit to customers. Prioritizing and optimizing investments in the system helps provide confidence that the overall investment level is appropriate and that customers will get the most value for the level of investment.

This report outlines project prioritization and benefits calculations for the following storm hardening programs:

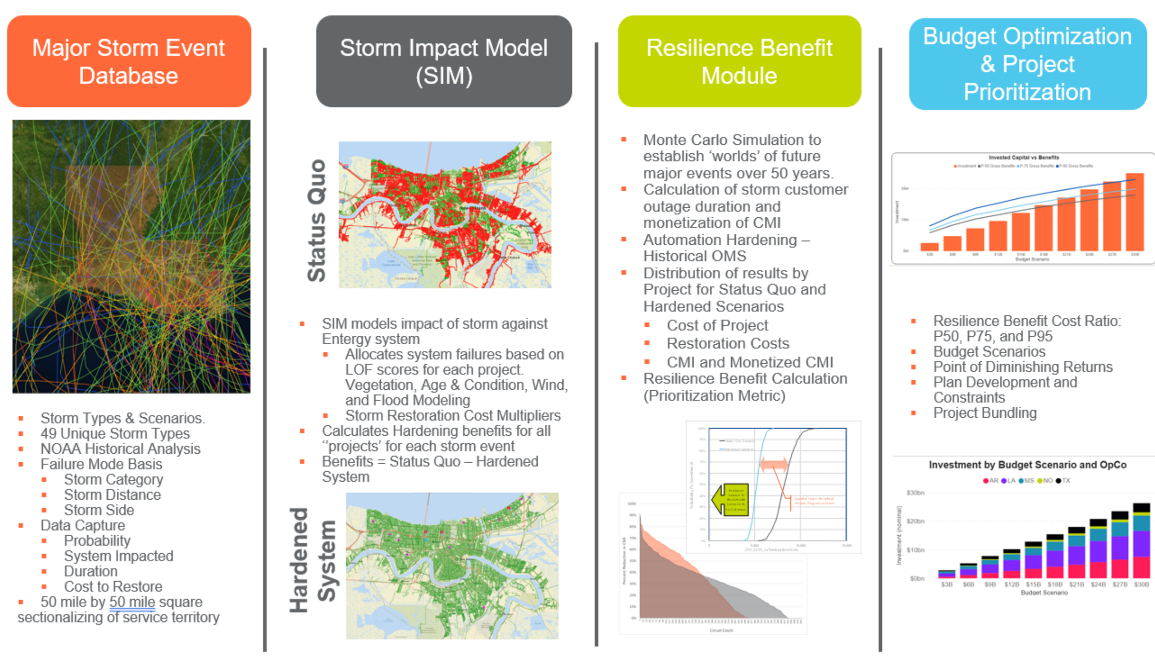
- Distribution Feeder Hardening (Rebuild)
- Distribution Feeder Undergrounding
- Lateral Hardening (Rebuild)
- Lateral Undergrounding
- Transmission Rebuild
- Substation Control House Remediation
- Substation Storm Surge Mitigation

1.1 Resilience Based Planning Approach

Figure 1-1 provides an overview of the Storm Resilience Model. The model employs a resilience-based planning approach to calculate the benefits of reducing storm restoration costs and CMI. Each of the different components are reviewed in further detail in Sections 2.0 through 7.0.

The Major Storm Events Database contains storm probability distributions, and the range of impacts for 49 different storm types. The 49 different storm types are based on the range of storm categories, storm distance from the infrastructure, and the side of the storm impacting the infrastructure. The database organizes the Entergy New Orleans service territory into 4 different 50-mile by 50-mile system sections to provide the granularity of the impact of the 49 storm types against the infrastructure. The database includes probabilities and impacts for all 49 different storm types for each of the 4 system sections.

Figure 1-1: Storm Resilience Model Overview



Each storm type for each system section is then modeled within the Storm Impact Model to identify which parts of the system are most likely to fail in the event of each type of storm. The Likelihood of Failure (LOF) is based on the vegetation density around each conductor asset, the gap in the current wind loading of the asset vs the applicable hardened wind loading standard, and the age of the asset base. The Resilience Model is comprehensive in that it evaluates nearly all of Entergy New Orleans' T&D system. Table 1-1 provides an overview of the potential project count for each of the programs.[1]

Table 1-1: Potential Hardening Projects Evaluated

Program	Project Count
Distribution Feeder Hardening (Rebuild)	**476**
Distribution Feeder Undergrounding	**476**
Lateral Hardening (Rebuild)	**4,324**
Lateral Undergrounding	**4,324**
Transmission Rebuild	**36**
Substation Control House Remediation	**1**
Substation Storm Surge Mitigation	**1**
Total	**9,638**

The Storm Impact Model also estimates the restoration costs and CMI for each of the projects in Table 1-1 above for each storm type. For the purposes of this report, the term "project" refers to a collection of assets. Assets are typically organized from a customer impact perspective (see Section 2.2). Finally, the Storm Impact Model calculates the benefit in decreased restoration costs and CMI if a project is hardened per Entergy New Orleans' hardening standards. The CMI benefit is monetized using the United States Department of Energy's (DOE) Interruption Cost Estimator (ICE) calculator for project prioritization purposes.

The Resilience Benefit Calculation utilizes stochastic modeling, also known as a Monte Carlo simulation, to select a storm probability for each of the 49 storm types for each of the system sections for 1,000 iterations. This produces 1,000 different future storm worlds and the expected range of benefit values depending on the different probabilities and impact ranges to the Entergy New Orleans system. The probability of each storm scenario is multiplied by the benefits calculated for each project from the Storm Impact Model to provide a resilience-weighted benefit for each project in dollars.

[1] As discussed in Section 8.1, for each alternative (e.g., hardened rebuild vs undergrounding), the model determined a benefit cost ratio, and the higher benefit cost ratio is preferred. The preferred potential hardening project is the overhead hardening or undergrounding alternative that provides the higher Resilience Benefit Cost Ratio, discussed below.

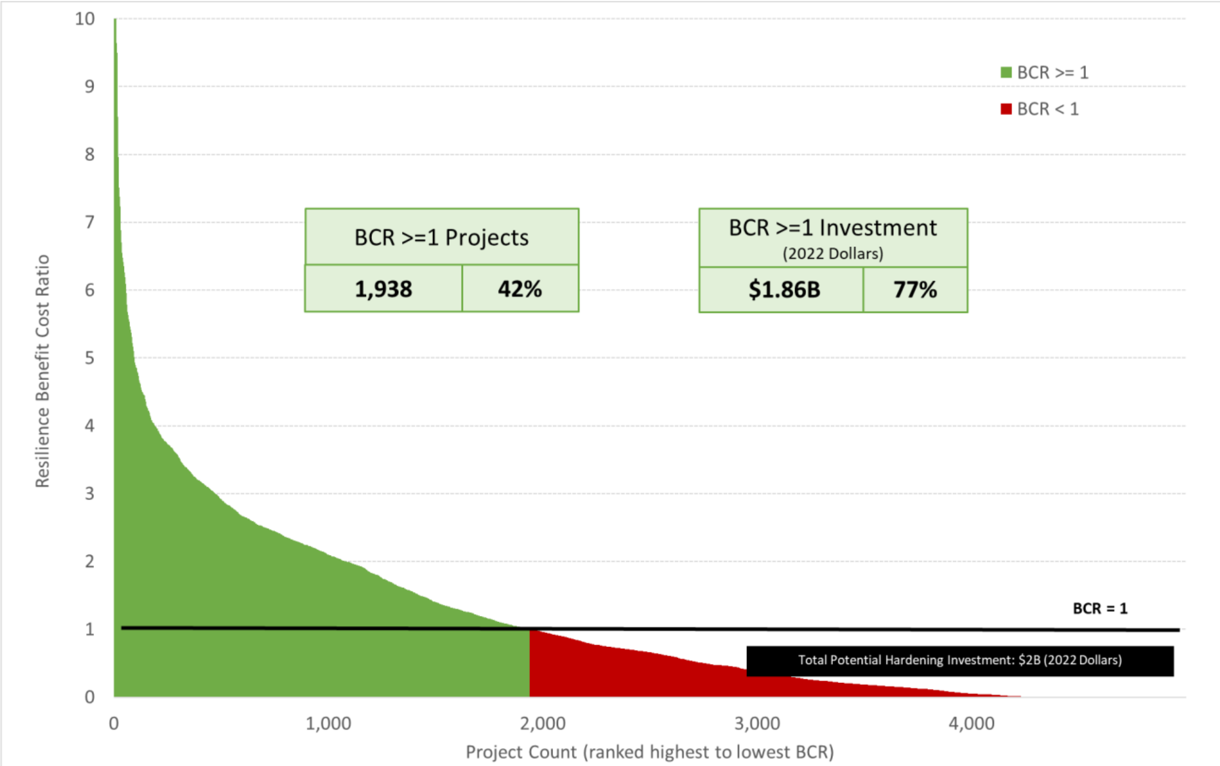
The Project Scheduling and Investment Optimization model prioritizes the projects based on the highest resilience benefit cost ratio factoring in execution constraints. It also performs investment optimization over a range of budget levels to identify the point of diminishing returns.

The model prioritizes each project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This is done for the range of potential benefit values to create the Resilience Benefit Cost Ratio. The model also incorporates technical and operational constraints in scheduling the projects applicable to Entergy New Orleans and its service area, such as contractor capacity, logistics, and materials limits. Using the Resilience Benefit Calculation and Project Scheduling and Investment Optimization model, the Storm Resilience Model calculates the net benefit in terms of reduced restoration costs and CMI for multiple investment profile scenarios.

1.2 Resilience Business Case Results

Figure 1-2 shows the results of the Resilience Benefit Cost Ratio for all potential hardening projects across the Entergy New Orleans service territory. The figure shows approximately 4,600 potential hardening projects were included in the evaluation. It should be noted that the evaluation considered both overhead hardening and underground conversion alternatives projects for most parts of the system for over 9,600 potential projects. The figure shows that approximately 42 percent of the potential hardening projects (by project count) have a Resilience Benefit Cost Ratio greater than 1. The figure also shows that approximately $1.86 billion of investment (over the next 10 years) has a Resilience Benefit Cost Ratio greater than 1. This is equivalent to 77 percent of the total hardening investments across all potential hardening projects. Most of the projects with a positive Resilience Benefit Cost Ratio are in the 1 to 10 range.

Figure 1-2: Project Resilience Benefit Cost Ratio Summary



1.3 Investment Scenarios

Entergy New Orleans and 1898 & Co. used a multi-stage process to arrive at three potential investment levels.

- Stage 1 – Find the appropriate investment level for Entergy New Orleans at which future incremental investments yield benefits that are less than the incremental costs. The result is a set of projects that is cost beneficial.
- Stage 2 – Refine the investment portfolio to determine what is most likely feasible in the next several years with currently known labor and equipment constraints. The result is $1.3 billion of investment that could be performed from 2024 through 2033.
- Stage 3 – Use the projects identified in Stage 2 (the $1.3 billion investment level) to develop two additional scenarios. The two other scenarios explore tradeoffs in benefits and cost for investment levels below the technical constraint scenario. These scenarios provide proactive insight for evaluating the next several years of resilience investment. The two additional scenarios have total investment levels $1.0 billion and $750 million over the next 10 years.

1.3.1 Stage 1 Results

The first stage utilized a resilience-based planning approach to understand the point of diminishing returns and identify and prioritize resilience investment in the T&D system. Given the total level of potential investment, the Investment Optimization analysis was performed in approximately $260 million increments ($260 million in 2022 dollars is approximately $290 million in nominal terms when escalated) up to $2 billion (in 2022 dollars). The Investment Optimization analysis, which compared the incremental costs to the incremental benefits at each budget level, determined that the point of diminishing returns occurs at an investment level of approximately $1.8 billion (in 2022 dollars) over the next 10 years. When that level of investment is exceeded, the incremental costs begin to exceed the incremental benefits.

1.3.2 Stage 2 Results

In the second stage of the investment evaluation process, Entergy New Orleans and 1898 & Co. refined the $1.8 billion scenario with technical execution constraints due to labor and materials availability. With these constraints included, the resulting investment profile scenario is $1.3 billion (nominal) over the next 10 years, which is $1.1 billion in 2022 dollars.

1.3.3 Stage 3 Results

In the third and final stage of the investment scenario analysis, Entergy New Orleans and 1898 & Co. created two alternative investment plans for additional analysis. The goals of the two investment plans are to explore tradeoffs in benefits and cost for investment levels below the $1.3 billion investment scenario (Stage 2). The investment scenarios are $1 billion and $750 million over the next 10 years.

Figure 1-3 below illustrates the annual investment levels for the $1.3 billion, $1 billion, and $750 million scenarios. Overall, these annual investment profiles accommodate the business processes and resources required to begin ramping up investment and construction of this magnitude.

Figure 1-3: Annual Investment by Scenario (Nominal $)

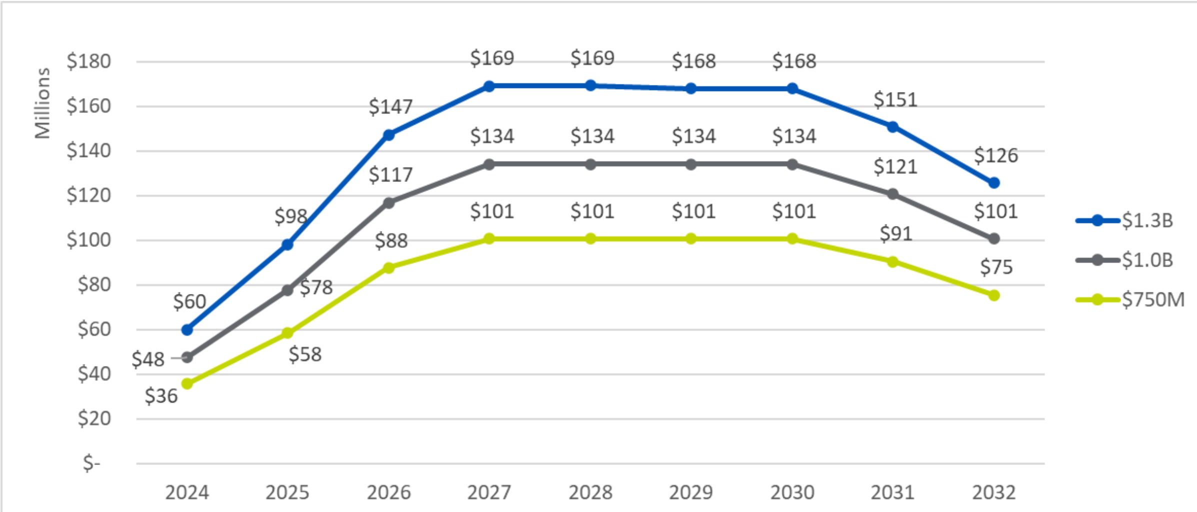


Table 1-2 shows the 50-year lifecycle benefits for each of the budget scenarios. The benefits of the three scenarios are summarized at the weighted prioritization metric level (see Section 7.0) that evaluates benefits at multiple storm future levels. As the table shows, each of the scenarios has a positive business case. The lowest level of investment, $750 million, has the highest benefit cost ratio (BCR) of 3.06, with declining ratios as the investment level increases to a BCR of 2.55 at the $1.3 billion scenario. This decline in overall benefit to cost ratios as investment increases is expected.

Table 1-2: Summary of Storm Resilience Benefits for Stage 3 Scenarios

Metric	$1.3 Billion Scenario	$1.0 Billion Scenario	$750 Million Scenario
Weighted Avoided Storm Restoration Cost Benefits	$473 M	$390 M	$297 M
Weighted Avoided Storm Customer Benefits (CMI)	8.4 billion	7.1 billion	5.8 billion
Weighted Avoided Storm Monetized Customer Benefits	$2.3 billion	$2.0 billion	$1.7 billion
Weighted Avoided Storm Monetized Total Benefits	$2.7 billion	$2.4 billion	$1.9 billion
Benefit to Cost Ratio	2.55	2.78	3.06

Table 1-3 summarizes the tradeoffs in benefits to move from the $1.3 billion scenario to the two other scenarios. The table shows a decrease in upfront investment costs of approximately $220 million with the $1.0 billion scenario compared to the $1.3 billion scenario, and $434 million savings with the $750 million scenario. From a benefits perspective, the $1.0 billion scenario has a decrease in 50-year lifecycle customer benefits of $356 million, and a $775 million decrease for the $750 million scenario. From an opportunity cost perspective, the $1.0 billion scenario is a decrease in net benefits of $136 million and $341 million for the $750 million scenario. In other words, moving from the $1.3 billion scenario to the $1.0 billion scenario is equivalent to foregoing a set of projects with a benefit to cost ratio of 1.6. Moving to the $750 million scenario is equivalent to foregoing a set of projects with a benefit to cost ratio of 1.8. Decreasing the overall investment level even further would be foregoing sets of projects with increasingly higher benefit to cost ratios.

Table 1-3: Incremental Benefit and Cost Summary Comparison to $1.3 Billion Scenario

Metric	$1.0 Billion Scenario	$750 Million Scenario
Plan Investment Level (2022$)	-$220M	-$434M
Weighted Avoided Storm Customer Benefits (CMI)	-1.3 billion	-2.6 billion
Weighted Avoided Storm Restoration Cost Benefits	-$83M	-$176M
Weighted Avoided Storm Monetized Customer Benefits	-$273M	-$599M
Weighted Avoided Storm Monetized Total Benefits	-$356M	-$775M
Weighted Avoided Storm Monetized Net Benefits	-$136M	-$341M
Opportunity Cost Benefit to Cost Ratio	1.62	1.78

1.4 Conclusions

The following include the conclusions of the investment scenarios evaluated within the Storm Resilience Model:

- There is significant opportunity for additional resilience investment in the New Orleans system. The resilience business case evaluated over 4,600 potential projects, and over 9,600 potential projects when including both overhead and underground alternatives, with approximately 42 percent having a positive business case. There is approximately $1.86 billion of positive BCR investment across the Company's system.
- An investment level of $1.8 billion is the "point of diminishing" returns. It is at this investment level that the impact of major events is optimally mitigated to maximize the decrease in the impact of major events while investing in the system to provide value to customers. While

additional investments could be made past this level to mitigate the impact of major events, they would not produce incremental benefits relative to their incremental costs. Due to technical constraints from material and labor, this scenario is currently not achievable.

- An overall investment level of $1.3 billion is technically achievable over the time horizon. This investment level provides significant benefits for customers, is reasonable, and provides customers with optimal benefits given execution constraints. This investment level is reasonably expected to:
  - Decrease storm restoration costs by approximately 50 percent over the 50-year time horizon. From a present value perspective, this decrease is approximately 37 to 55 percent of the overall $1.3 billion investment level.
  - Decrease storm customer outages by approximately 55 percent over the 50-year time horizon.
- Additional, lower investment levels provide an opportunity for Entergy New Orleans to continue to evaluate how to balance the near-term investment costs and impacts to customer bills. However, these lower investment levels come with tradeoffs in benefits. The $1.0 billion scenario has an opportunity cost of $136 million in net benefits, and $341 million in net benefits for the $750 million scenario. In other words, moving from the $1.3 billion scenario to the $1.0 billion scenario is equivalent to foregoing a set of projects with a benefit to cost ratio of 1.6. Moving to the $750 million scenario is equivalent to foregoing a set of projects with a benefit to cost ratio of 1.8. Decreasing the overall investment level even further would be foregoing sets of projects with increasingly higher benefit to cost ratios.
- If enough of the Entergy New Orleans system is made resilient, customers will experience fewer storm outages from both direct and indirect factors. Direct benefits are realized by those customers whose infrastructure directly upstream was hardened. Indirect benefits are realized by all customers since storm restoration crews will be able to rebuild the system quicker because less infrastructure will fail.
- The hardening investment benefits are conservative. Firstly, the benefits outlined above are only direct benefits of investments to specific investments in the grid and do not factor in the indirect benefits from lower overall storm restoration durations. Secondly, the investments will also provide ‘blue sky’ benefits from decreased outages that occur during non-major storm days. Both of these benefit streams are not factored into the evaluation within the Storm Resilience Model.

2.0 INTRODUCTION

Hurricanes have inflicted significant damage to New Orleans and the state of Louisiana in recent years, and parts of the state face years of recovery. One of the most important actions New Orleans can take to prepare for the next major storm is to make the electric grid more resilient. When the grid can better withstand the impacts of storms, everyone benefits. New Orleans businesses and families save money because they can get back on their “feet” quickly. Proactive investing in the grid also allows utilities to design integrated programs to address all phases of resilience (described below) which, in turn, will reduce storm-related restoration costs and outage times. This document outlines the approach to:

1. Calculate the benefit of the ‘universe’ of hardening projects through reduced utility restoration costs after major storms and the decrease (in both number and duration) in storm-related customer outages.
2. Prioritize hardening projects based on which projects deliver the highest resilience benefit per dollar invested into the system.
3. Provide insights on various investment funding levels and execution constraints and their relationship to customer benefits.

The resilience-based approach is an integrated data-driven, decision-making strategy comparing various storm resilience projects and alternatives on a normalized and consistent basis. This approach takes an integrated asset management perspective, that is, a bottom-up approach starting at the asset level. Each asset is evaluated for its likelihood of failure in a storm event as well as its consequence of failure in terms of restoration cost and customer minutes interrupted. Assets are rolled up to hardening projects, and hardening projects are then rolled up to programs. Where applicable, hardening alternatives are evaluated such as undergrounding a lateral as opposed to rebuilding it to a hardened overhead standard. Each project includes only the assets that do not meet the hardened design standards. This allows for the identification of project scopes that harden all vulnerable components to provide the most benefit to customers and that align with Entergy New Orleans’ design standards.

This report outlines project prioritization and benefit calculations for the following storm resilience programs:

- Distribution Feeder Hardening (Rebuild)
- Distribution Feeder Undergrounding
- Lateral Hardening (Rebuild)
- Lateral Undergrounding
- Transmission Rebuild
- Substation Control House Remediation
- Substation Storm Surge Mitigation

The following sections outline the foundation and background necessary to understand the rest of this report. These sections include a review of:

- Topic of resilience
- Resilience as the project assessment approach
- Entergy New Orleans asset base evaluated for resilience measures
- Resilience-based planning approach
- Resilience Investment Business Case Results

2.1 Resilience as the Benefits Assessment

In a 2013 paper, the National Association of Regulatory Utility Commissioners (NARUC) offered its own definition of resilience in a manner that is simple and easy to understand:

> *"it's the gear, the people and the way the people operate the gear immediately before, during and after a bad day that keeps everything going and minimizes the scale and duration of any interruptions."*

Before that, the National Infrastructure Advisory Council (NIAC) provided a definition that is often quoted, and which includes elements used in many other definitions. It states that resilience is:

> *"The ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event."*

The NIAC definition includes a system's ability to absorb and adapt. These important characteristics were also used by Argonne National Laboratory (ANL) in its work on state and social resilience and were incorporated into Pacific Northwest National Laboratory's (PNNL) work on the resilience impacts of transactive energy systems. The ANL approach can be used to break resilience into four phases that also align with NARUC's elegantly simple description – the difference being that ANL explicitly includes the ability of the system to recognize and mitigate potential failures before they happen. These four phases are described below.

- Prepare (Before)

  The grid is running normally, but the system is preparing for potential disruptions.
- Mitigate (Before)

  The grid resists and absorbs the event until, if unsuccessful, the event causes a disruption.
- Respond (During)

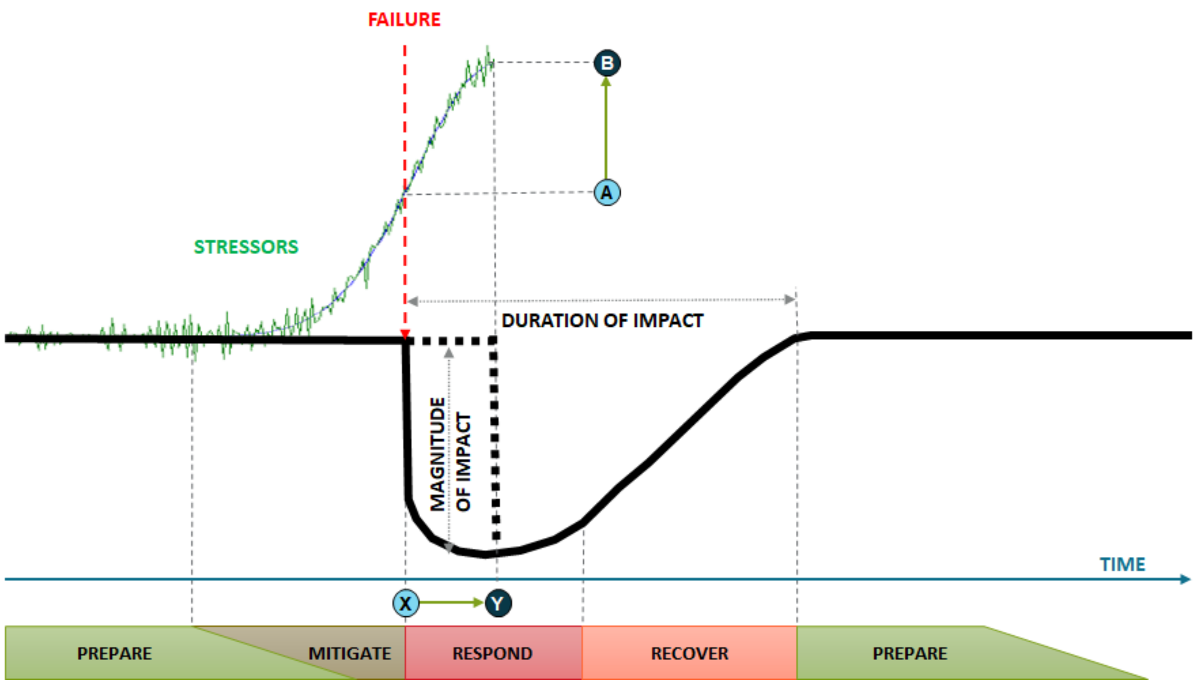
  The grid responds to the immediate and cascading impacts of the event. The system is in a state of flux, and fixes are being made while new impacts are felt. This stage is largely reactionary (even if using prepared actions).
- Recover (After)

  The state of flux is over, and the grid is stabilized at low functionality. Enough is known about the current and desired (normal) states to create and initiate a plan to restore normal operations.

This is depicted graphically in Figure 2-1 below. The green line represents an underlying issue that is stressing the grid, which increases in magnitude until it reaches a point where it impacts the operation of the grid and causes an outage. The origin of the stress may be electrical due to a failing component, or external due to storms or other events. The black line shows the status of the entire system or parts of the system (e.g., transmission circuits). The "pit" depicted after the event occurs represents the impact on a system in terms of the magnitude of impact (vertical) and the duration (horizontal). For utilities, this can be measured after the event and is used by the Institute of Electrical and Electronics Engineers (IEEE) 1366 to calculate reliability metrics. If Entergy New Orleans detects the strain on the grid caused by these stresses, then it increases the opportunity to act before a failure occurs, thus avoiding or reducing the impact of the subsequent event.

Figure 2-1 represents a conceptual view of resilience. It can be used to depict a specific transmission line or the whole transmission system or the entire grid. If the figure is used to represent a specific line, it represents the impact of the event on only that line. If the figure is used to represent the impact on the whole Entergy New Orleans system, it represents the aggregated impacts of the event (storm) and the multiple outages that may result from it. Note that whether this is a specific or overall depiction of resilience, there is no quantification of time. Time increases from left to right, but due to the nature of events that may occur, there are no timescales used.

Figure 2-1: Phases of Resilience



For example, hardening of the overhead transmission system is targeted at the "prepare" phase. Mitigation depends on the ability to detect developing issues and includes the capability to detect stresses on the grid by monitoring it. Effectively responding to an event as it is impacting the grid depends on the ability to make informed decisions, deploy crews rapidly to the right place at the right time, and for the grid to adapt to the stresses through reconfiguration. Recovery depends on coordinated activity and planning.

In Figure 2-1, the level of strain on the grid caused by the early effects of an event that could cause asset failure is represented by 'A'. As an example, this might be a wooden transmission pole, with failure occurring at time 'X'. In this example, suppose a steel monopole were used to replace the wood pole transmission structure. The monopole might succumb to failure at higher strain levels depicted by 'B' and would result in later failure at time 'Y'.

For the line where this occurred, this illustrates how hardening did not prevent failure but delayed it and shortened the outage duration. If it takes more work to erect a new monopole it might increase recovery time for a specific line, yet if fewer steel monopoles failed relative to the number of wood poles that would have failed, there would be fewer poles to replace, and the overall system outage time and recovery time would be reduced. Fewer asset failures means that more crews will be able to work on the assets that do fail, which can have a beneficial multiplying effect on outage reduction time.

The Storm Resilience Model evaluates the phases of resilience for storms on both the entire system and at the sub-system level (substations, transmission circuit, feeder, and lateral). Section 2.2 provides additional detail on this evaluation approach.

2.2 Evaluated System for Resilience Investment

The Storm Resilience Model (described in more detail in Section 2.3) is comprehensive in that it evaluates nearly all of Entergy New Orleans' T&D systems. Table 2-1 shows the asset types and counts included in the Storm Resilience Model.

Table 2-1: Entergy New Orleans Asset Base Modeled

Asset Type	Units	Number
Distribution Circuits	**[count]**	**145**
Feeder Poles	[count]	**29,619**
Lateral Poles	[count]	**37,314**
Feeder OH Primary	[miles]	**618**
Lateral OH Primary	[miles]	**593**
Transmission Circuits	**[count]**	**36**
Wood Poles	[count]	**211**
Steel / Concrete / Lattice Structures	[count]	**1,755**
Conductor	[miles]	**143**
Substations	**[count]**	**2**

All assets are strategically grouped into potential hardening projects, and only the assets that require hardening are included in the projects. The following sub-sections outline the approach to identifying hardening candidate assets and grouping them into projects.

2.2.1 Distribution Projects Identification

For distribution projects, assets were grouped by their most upstream protection device, which was either a breaker, recloser, sectionalizer, auto transfer switch, vacuum fault interrupter, or a fuse. This approach focuses on reducing customer outages. The objective is to harden each asset that could fail and result in a customer outage. Since only one asset needs to fail downstream of a protection device to cause a customer outage, failure to harden all the necessary assets still leaves vulnerable components that could potentially fail in a storm and result in an outage. Rolling assets into projects at the protection device level allows for hardening of all vulnerable components in the circuit and for capturing the full benefit for customers including avoidance or mitigation of an outage.

For distribution circuit projects (laterals and feeders), both rebuilding to a storm resilient overhead design standard and undergrounding, where possible, were considered when evaluating project types. Overhead hardening rebuilds are generally lower cost than undergrounding projects, but they provide less resilience benefits than undergrounding since the hardened overhead infrastructure is still exposed to wind, debris from vegetation, and other materials. The Storm Resilience Model balances this tradeoff for every project zone across the Energy New Orleans service territory. Assets in these projects include older wood poles and those designed to a previous wind rating, as well as copper conductor. Physical hardening addresses the weakened infrastructure storm failure component, while undergrounding greatly mitigates the storm exposure.

Distribution assets were evaluated under multiple criteria to determine whether they are hardening candidates. Distribution structures were evaluated based on height, class, transformer count, and other attachments to calculate a percentage of maximum loading. For distribution conductor, the asset was included in a project as a hardening candidate if either of the conductor’s adjacent poles are selected as hardening candidates. Additionally, small conductor, such as copper, was included as a hardening candidate since it is at risk of failing in high wind events.

2.2.2 Transmission Projects Identification

At the transmission circuit level, poles identified for hardening will be replaced with higher wind rated structures and materials. Transmission structures were grouped at the transmission line/ circuit level into projects. Transmission assets were deemed to be hardening candidates if the structures’ wind rating did not meet or exceed Entergy New Orleans’ wind hardening standard.

2.2.3 Substation Projects Identification

Entergy New Orleans’ control houses were identified as a particular risk due to some roofs not being designed to withstand winds that exceed certain speeds. If the roof gets broken or ripped off during a storm, rainfall results in substantial water inside the control house and will damage much of the substation protection equipment, rendering it out of service. Entergy New Orleans provided a list of control houses and known current wind ratings. In turn, control houses with non-hardened ratings were added as potential projects.

1898 & Co. used the Sea, Land, and Overland Surges from Hurricanes (SLOSH) model to evaluate the storm surge risk for substations. Substations with any potential storm surge risk were considered as candidate projects. Those substations that are behind a levee are not considered to be at risk of storm surge, as they already have a level of protection.

2.2.4 Potential Hardening Projects Evaluated

Table 2-2 contains a list of potential hardening projects based on the methodology outlined above. As seen below, there are a significant number of potential hardening projects, nearly 10,000. The following sections outline the approach to selecting the hardening projects that provide the most value to customers from a perspective of reducing both storm restoration costs and CMI.

Table 2-2: Potential Hardening Projects Evaluated

Program	Project Count
Distribution Feeder Hardening (Rebuild)	**476**
Distribution Feeder Undergrounding	**476**
Lateral Hardening (Rebuild)	**4,324**
Lateral Undergrounding	**4,324**
Transmission Rebuild	**36**
Substation Control House Remediation	**1**
Substation Storm Surge Mitigation	**1**
Total	**9,638**

2.3 Resilience Planning Approach Overview

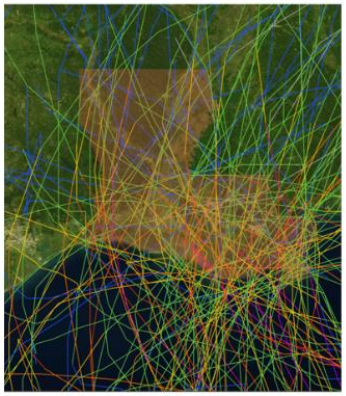
The resilience-based planning approach calculates the benefit of storm resilience projects from a customer perspective. This approach calculates the resilience benefit at the asset, project, and program level within the Storm Resilience Model. The results of the Storm Resilience Model are a:

1. Reduction in the Storm Restoration Costs
2. Reduction in the number of customers impacted and the duration of the overall outage, calculated as CMI

Figure 2-2 provides an overview of the resilience planning approach to calculate the restoration cost reduction and CMI reduction of hardening projects and the approach to prioritization those projects into an executable plan. It also includes the approach to establish an overall investment level for Entergy New Orleans.

Figure 2-2: Resilience Planning Approach Overview

Major Storm Event Database



- Storm Types & Scenarios.
- 49 Unique Storm Types
- NOAA Historical Analysis
- Failure Mode Basis
  - Storm Category
  - Storm Distance
  - Storm Side
- Data Capture
  - Probability
  - System Impacted
  - Duration
  - Cost to Restore
- 50 mile by 50 mile square sectionalizing of service territory

Storm Impact Model (SIM)

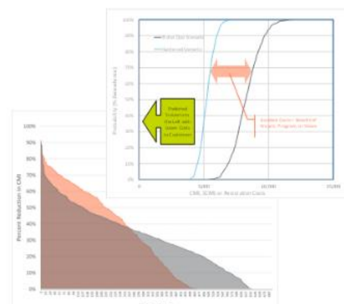
Status Quo

- SIM models impact of storm against Entergy system
  - Allocates system failures based on LOF scores for each project. Vegetation, Age & Condition, Wind, and Flood Modeling
  - Storm Restoration Cost Multipliers
- Calculates Hardening benefits for all ''projects' for each storm event
- Benefits = Status Quo – Hardened System

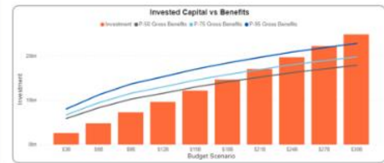
Hardened System

Resilience Benefit Module

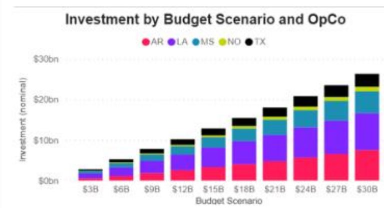
- Monte Carlo Simulation to establish 'worlds' of future major events over 50 years.
- Calculation of storm customer outage duration and monetization of CMI
- Automation Hardening – Historical OMS
- Distribution of results by Project for Status Quo and Hardened Scenarios
  - Cost of Project
  - Restoration Costs
  - CMI and Monetized CMI
- Resilience Benefit Calculation (Prioritization Metric)



Budget Optimization & Project Prioritization



- Resilience Benefit Cost Ratio: P50, P75, and P95
- Budget Scenarios
- Point of Diminishing Returns
- Plan Development and Constraints
- Project Bundling



2.3.1 Major Storms Event Database

Since the magnitude of the restoration cost decrease and CMI decrease is dependent on the frequency and magnitude of future major storm events that may impact the areas that Entergy New Orleans serves, the Storm Resilience Model starts with the 'universe' of major storm events that could impact the Entergy New Orleans service area, which is the Major Events Storms Database. The system was broken down into 4 50-mile by 50-mile square system sections to understand the frequency and magnitude of major events across the service area.

The Major Storms Event Database provides the high-level impact to the system of the storm stressor for each of the 50-mile by 50-mile system sections. The Major Storm Event Database includes the following for each of the 4 system sections:

- Storm Type
- Probability of a storm occurring
- Restoration Costs
- Percentage of the system impacted
- Duration of the storm

The Major Storm Events Database includes 49 unique storm types for each system section. The storm types include the various hurricane categories, system section distance from the storm, and side of the storm to impact the system section (the right side of a hurricane is typically more destructive than the left side). Each storm type has a range of probabilities and impacts that is based on historical evaluation of National Oceanic and Atmospheric Administration hurricane data, and the range of these impacts is based on expectations of system impacts from the 49 different storm types. These storm types include modifiers for vegetation density, asset age, structure 'right-of-way' access, and terrain including wetland and rocky areas. With these various combinations (high probability with lower consequence and low probability with high consequence, etc.), the Major Storms Event Database includes a vast range of different storm scenarios. Section 4.0 provides additional details on the Major Storms Event Database.

2.3.2 Storm Impact Model

Each storm scenario, up to 49 for each system section, is modeled within the Storm Impact Model to identify which parts of the system are most likely to fail given each type of storm. The Storm Impact Model calculates the restoration costs and customers impacted by system failures for both the Status

Quo and Hardened Scenarios. The Storm Impact Model identifies the damaged portions of the system by modeling the elements that cause failures in the Entergy New Orleans asset base.

The Storm Impact Model calculates a storm LOF score for each asset based on a combination of the vegetation density around the infrastructure, the current structure wind loading rating versus the desired wind loading, and the infrastructure age. The vegetation rating factor is based on the vegetation density around the conductor (see Section 3.4). The wind design gap rating is based on the delta between the desired wind loading capacity and the asset's current wind loading capacity (see Section 3.5). The age rating utilizes expected remaining life curves with the asset's age. The wind zone rating is based on the wind zone within which the asset is located. The Storm Impact Model includes a framework that normalizes the three ratings with each other to develop one overall storm LOF score for all circuit assets. The project level scores are equal to the sum of the asset scores normalized for length. The project level scores are then used to rank each project against each other to identify the likely lateral, backbone, or transmission circuit to fail for each storm type. The model estimates the weighted storm LOF based on the asset level scoring.

The model determines which substations are likely to flood during various storm types based on the flood modeling analysis. That analysis provides the flood level, i.e., feet of water above the site elevation, for various storm types (see Section 3.10).

The Storm Impact Model estimates which control houses are likely to fail during various storm types based on the current structure wind loading rating versus the desired wind loading.

Once the Storm Impact Model identifies the portions of the system that are damaged and caused an outage for a specific storm, it then calculates the restoration costs to rebuild the system to provide service. The restoration costs are based on the multipliers for storm replacement over the planned replacement costs using Entergy New Orleans labor and procured materials. The restoration cost multipliers are based on historical storm events and the expected outside labor and expedited material cost needed to restore the system.

Similarly, the Storm Impact Model calculates the CMI for each project. Since circuit projects are organized by protection device, the customer counts and customer types are known for each asset in the Storm Impact Model. Substation projects' customers have been calculated as a sum of the circuits at each substation, assuming that flooded substations and damaged control houses result in a complete outage of the substation and the feeders leaving those stations. For transmission projects, customers have been estimated as the customers in the project's system section and the eight surrounding system sections. This reflects the large, regional impacts that outages of transmission lines have on a system. The time it will take to restore each protection device, or project, is calculated based on the expected storm duration and the hierarchy of restoration activities. This restoration time is then multiplied by the known customer count to calculate the CMI. The CMI benefit is monetized using DOE's ICE Calculator for project prioritization purposes. It bears noting that the DOE's ICE Calculator does not consider the specific circumstances that would be necessary to assess the causes and impacts of an outage to customers in specific circumstances, particularly during longer outages. Again, the model uses the DOE's ICE Calculator to evaluate the societal impacts to customers generally for project prioritization purposes.

Finally, the Storm Impact Model calculates the reductions in project storm LOF, restoration costs, and CMI for each hardening project alternative. The output of the Storm Impact Model is the project LOF, CMI, monetized CMI, and restoration costs for each of the 49 storms for both the Status Quo and Hardened scenarios.

2.3.3 Resilience Benefit Calculation

The Resilience Benefit Calculation utilizes stochastic modeling, or Monte Carlo simulation, to select a 50-year storm probability scenario for each of the 49 storm types for 1,000 iterations. This produces 1,000 different future "storm worlds" and the expected range of benefit values depending on the different probabilities and impact ranges to the Entergy New Orleans system. The probability of each storm scenario is multiplied by the benefits calculated for each project from the Storm Impact Model to provide a resilience-weighted benefit for each project in dollars.

2.3.4 Project Scheduling and Investment Optimization

The Project Scheduling and Investment Optimization model prioritizes the projects based on the highest ratio of resilience benefit to cost. It also performs an Investment Optimization simulation to identify the point of diminishing returns for hardening investments for the period and portions of the system evaluated.

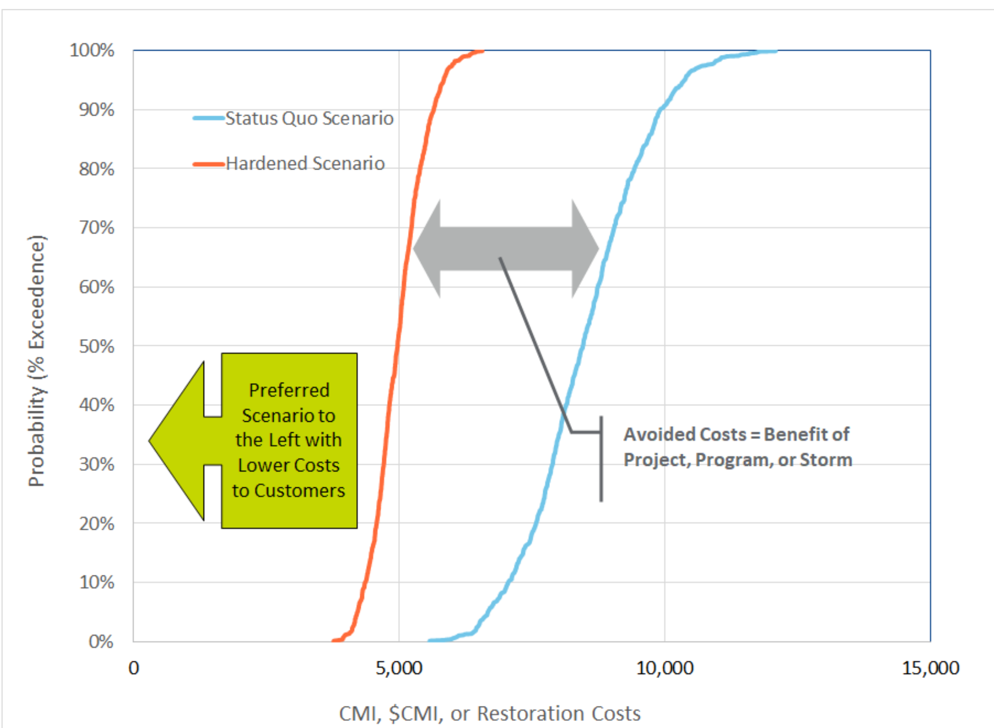
The model prioritizes each project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This calculation is performed for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporates technical and operational constraints in scheduling the projects applicable to Entergy New Orleans such as contractor capacity and material availability. Using the Resilience Benefit Calculation and project scheduling model, the Storm Resilience Model calculates the net benefit in terms of reduced restoration costs and CMI for an investment profile.

Investment Optimization is performed by running the model over a wide range of budget scenarios. Each budget scenario calculates the range in reduction of restoration costs and CMI. The Investment Optimization calculates the point where incremental hardening investments result in diminishing returns in customer benefit.

2.4 S-Curves and Resilience Benefit

The results of the 1,000 iterations are graphed in a cumulative density function, also known as an ‘S-Curve’. In layman’s terms, the thousand results are sorted from lowest to highest (cumulative ascending) and then charted. Figure 2-3 shows an illustrative example of the 1,000 iteration simulation results for the Status Quo and Hardened Scenarios.

Figure 2-3: Status Quo and Hardened Results Distribution Example



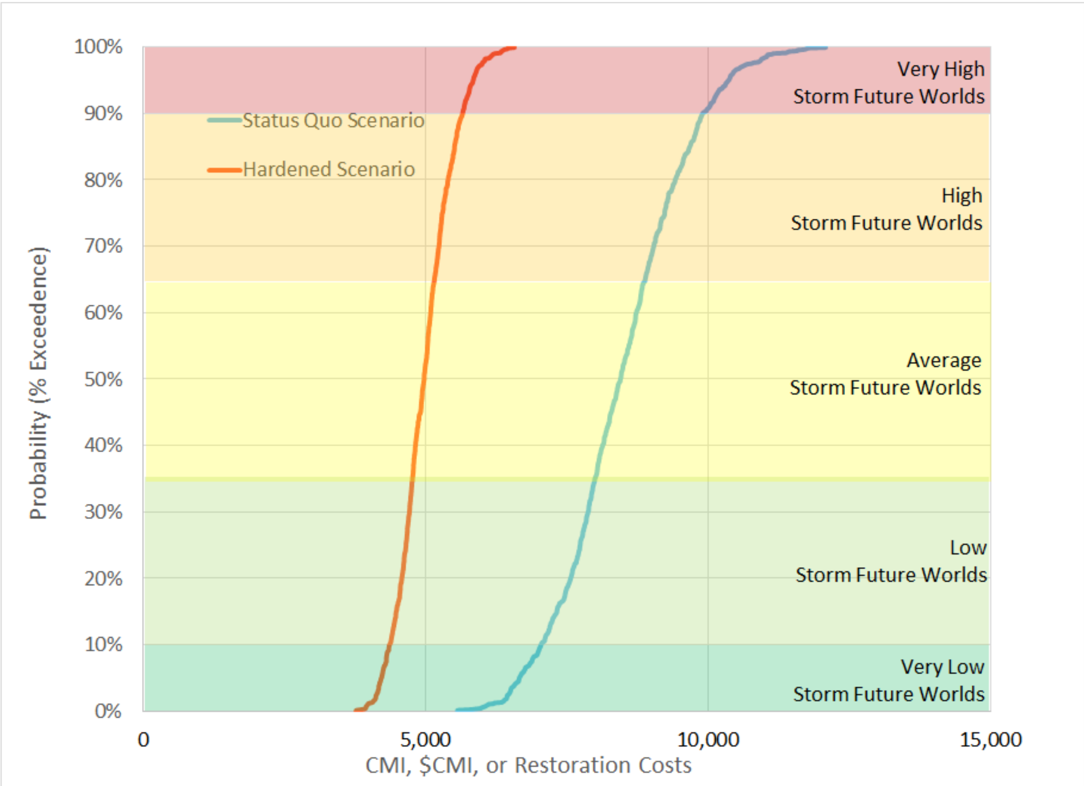
The horizontal axis shows the storm cost in terms of CMI, monetized CMI, or restoration costs. The values in the figure are illustrative. The vertical axis shows the percent exceedance values. For the

Hardened Scenario, the chart shows a value of 5,000 at the 40-percentile level. This means there is a 40 percent confidence that the Hardened Scenario will have a value of 5,000 or less. Each of the probability levels is often referred to as the P-value. In this case, the P40 (40 percentile) has a value of 5,000 for the Hardened Scenario.

Since the figure shows the overall cost (in minutes or dollars) to customers, the preferred scenario is the S-Curve further to the left. The gap or delta between the two curves is the overall benefit.

The S-Curves typically have a linear slope between the P10 and P90 values with 'tails' on either side. The tails show the extremes of the scenarios. The slope of the line shows the variability in results. The steeper the slope (i.e., vertical), the less range in the result. The more horizontal the slope, the wider the range and variability in the results. Figure 2-4 provides additional guidance on understanding the S-Curves and the kind of future storm worlds they represent.

Figure 2-4: S-Curves and Future Storms



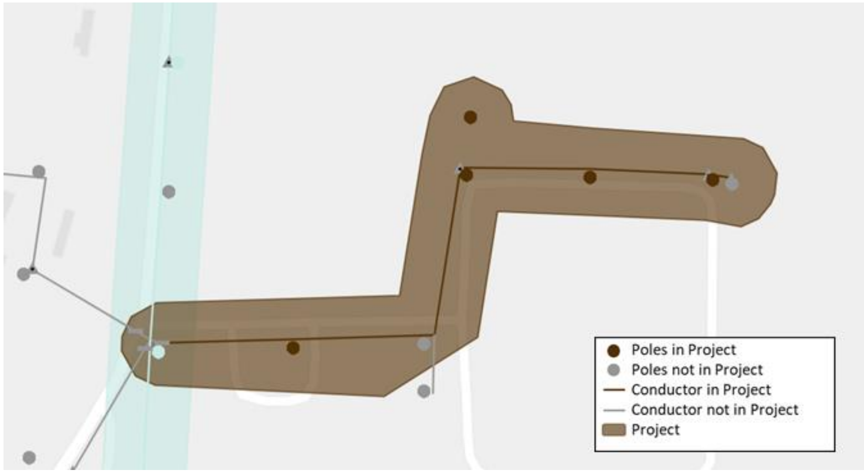
3.0 CORE DATA AND ANALTYICS

The resilience-based approach and methodology is data driven. This section outlines the core data sets and base algorithms employed within the Storm Resilience Model, while Sections 4.0 and 5.0 describe how these core data items are used within the Storm Resilience Model. This section includes both data from Entergy New Orleans' systems and external data sources.

3.1 Geographical Information System

The Geographic Information System (GIS) provides the list of assets in Entergy New Orleans' system and how they are connected to each other. Since the resilience-based approach is fundamentally an asset management, bottom-up based methodology, it starts with the asset data, then rolls all the assets up to projects, and all projects up to programs, and finally the programs up to an overall plan. The relationship between assets and projects is illustrated in the geospatial figure below.

Figure 3-1: Asset to Project Relationship



In alignment with this methodology, 1898 & Co. utilized the connectivity in the GIS and distribution circuit models to link each distribution voltage asset up to a lateral (fuse protection device) or feeder (breaker or recloser protection device). This provides a granular evaluation of the distribution system that allows projects to be created to target only portions of a circuit for resilience investment. Through this approach, Entergy New Orleans and 1898 & Co. were able to use the asset level information from Table 3-1 and convert it to the project level summaries in Table 3-2. It is important to note that each asset in Table 3-1 is tied to one of the projects listed in Table 3-2, which provides a bottom-up analysis.

Table 3-1: Entergy New Orleans Asset Base

Asset Type	Units	Value
Distribution Circuits	**[count]**	**145**
Feeder Poles	[count]	**29,619**
Lateral Poles	[count]	**37,314**
Feeder OH Primary	[miles]	**618**
Lateral OH Primary	[miles]	**593**
Transmission Circuits	**[count]**	**36**
Wood Poles	[count]	**211**
Steel / Concrete / Lattice Structures	[count]	**1,755**
Conductor	[miles]	**143**
Substations	[count]	**2**

Table 3-2: Projects Created from Entergy New Orleans Data Systems

Program	Project Count
Distribution Feeder Hardening (Rebuild)	**476**
Distribution Feeder Undergrounding	**476**
Lateral Hardening (Rebuild)	**4,324**
Lateral Undergrounding	**4,324**
Transmission Rebuild	**36**
Substation Control House Remediation	**1**
Substation Storm Surge Mitigation	**1**
Total	**9,638**

3.2 Outage Management System

The outage management system (OMS) includes detailed outage information by cause code for each protection device over the last 22 years. The Storm Resilience Model utilized this information to understand the historical storm related outages for the various distribution laterals and feeders on the system to include non-named tropical storm Major Event Days (MED) in the Major Storms Event Database.

3.3 Customer Type Data

Entergy New Orleans provided customer count and type information that featured connectivity to the GIS and OMS. This allowed the Storm Resilience Model to directly link the number and type of customers impacted to each project and the project's assets. For example, the Storm Resilience Model 'knows' that if pole 'Y' fails, fuse '1' will operate causing a set number of customers to be without service. The model also knows what type of customers are served by each asset: residential, small or large commercial, small or large industrial, and critical. This customer information is included for every distribution assets in the Entergy New Orleans system. The customer information is used within the Storm Impact Model to calculate the CMI (customers affected * outage duration) for each storm for each lateral or feeder project. Table 3-3 below shows the count of customers by class from Entergy New Orleans' service territory that have been linked to assets in the Storm Impact Model.

Table 3-3: Customer Counts by Type

Customer Type	Customer Count
Residential	166,878
Small Commercial and Industrial	14,956
Large Commercial and Industrial	1,707
Critical Customers	34
Total	183,575

3.4 Vegetation Density Algorithm

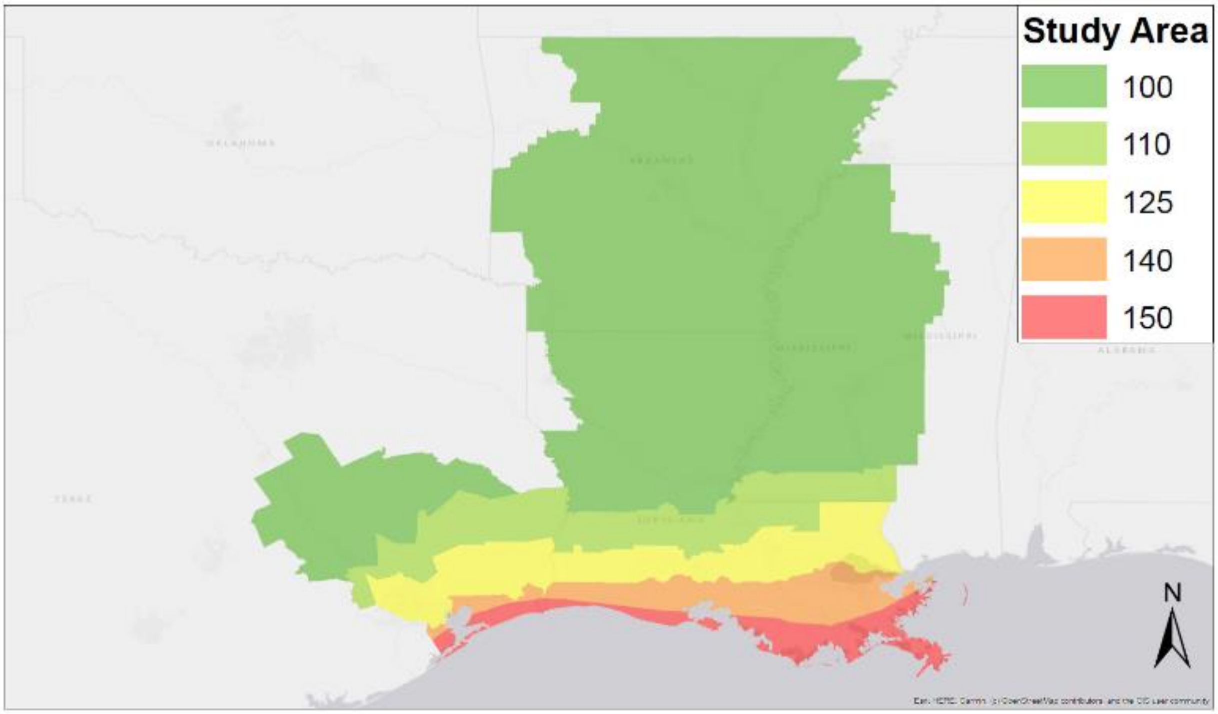
The vegetation density for each overhead conductor is a core data set for identifying and prioritizing resilience investment for the circuit assets because vegetation blowing into conductor is a primary failure mode for major storm events for Entergy New Orleans. The Storm Impact Model calculates the vegetation density around each transmission and distribution overhead conductor. The Storm Impact Model utilizes tree canopy data to calculate the percentage of vegetation for 100 feet by 100 feet areas across the entire Entergy New Orleans system. The 1,000 square foot area is indicative of the vegetation density on the system from a major storm perspective. For each span of conductor (approximately 75,000 spans), a vegetation density is assigned based on the square foot area the conductor goes through. This information is used within the LOF framework to identify the portions of the system mostly likely to have an outage for each type of storm.

3.5 Overhead Structure Wind Design Gap

Structures are designed to various loading standards. Over decades, standards change as the requirements of the infrastructure increase to meet customer needs. As the impact of grid outages to customers has increased over the last decade and the wind speeds across the service area have heightened, the wind loading standard of infrastructure across Entergy New Orleans' system has increased. While new infrastructure is built to the new standard, the delta between older infrastructure and current standards can grow. Infrastructure that has a wide gap between its actual wind loading rating and the newer hardened wind loading standard is at greater risk of failing given major storm events. The Storm Resilience Model uses the gap in wind loading to estimate the number of assets that would fail during a major event.

Entergy New Orleans provided extreme wind loading standards based on geographical areas. Figure 3-2 shows five wind zones and the hardening wind loading ratings for each zone. The zones show that wind speeds are typically higher closer to the coast and lower further inland.

Figure 3-2: Entergy Extreme Wind Zones



Using data from Entergy New Orleans and known attributes of transmission and distribution structures and control houses on the system, each asset's current wind rating was assessed. This rating is the wind speed the pole or control house is currently rated to withstand. 1898 & Co. performed a comprehensive analysis of the current actual wind rating vs the hardened wind rating standard for all distribution, transmission, and control house assets. Entergy New Orleans' transmission and distribution systems have approximately 78,000 structures with an actual wind speed rating below the current extreme wind hardened standard. These assets are at a much higher risk of failure during storms due to the information discussed above.

3.6 Age

As poles age, they lose some of their original design strength. Therefore, aged poles can fail at lower dynamic load levels than poles with their original design strength. The Storm Impact Model utilizes 1898 & Co.'s asset management solution, AssetLens Solutions, to estimate the age based LOF for each wood pole, metal structure, overhead primary conductor, and transmission conductor. 1898 & Co.'s AssetLens Solutions utilizes industry standard survivor curves with an asset class expected average service life and the asset's age to estimate the age based LOF over the next 10 years.

3.7 Accessibility

The accessibility of an asset has an impact on the duration of the outage and the cost to restore that part of the system. Rear lot structures take much longer to restore and cost more to restore than front lot structures. To take differences in accessibility into account, the Storm Resilience Model (within Storm Impact Model) performs a geospatial analysis of each structure against a data set of roads. Structures within a certain distance of the road were designated as having roadside access; others were designated as in the deep right-of-way (ROW). This designation was used to calculate restoration and hardening project costs in the Storm Impact Model.

3.8 Terrain

Like accessibility, the terrain where assets are located impacts both duration and cost to restore following a major storm event. Terrain such as marshes and swamps, defined as wetlands in the model, is much harder to navigate and access following these events, resulting in higher costs and longer outage times. To take these differences into account, the Storm Resilience Model performs a geospatial analysis of each structure against a data set from the U.S Department of Fish & Wildlife to determine if the structure is in wetlands or flat terrain. This information is used to estimate storm restoration costs by structure, outage duration, and higher hardening project costs.

3.9 DOE's ICE Calculator

To monetize the cost of a storm outage for the purpose of prioritizing projects and performing Investment Optimization, the Storm Impact Model and Resilience Benefit Calculation utilizes the DOE's ICE Calculator. The ICE Calculator is an electric reliability planning tool developed by Freeman, Sullivan & Co. and Lawrence Berkeley National Laboratory. This tool is designed for electric reliability planners at utilities, government organizations, or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States. The ICE Calculator was funded by the Office of Electricity Delivery and Energy Reliability at the DOE.

The Storm Impact Model includes the estimated storm interruption costs for residential, small commercial and industrial (C&I), and large C&I customers. The data from the calculator was extrapolated for the longer outage durations associated with major storms. The extrapolation includes diminishing costs as the storm duration extends. Additionally, multipliers of the ICE Calculator were used for critical customers and national critical infrastructure customers.

These rough indications of outage cost for each customer are multiplied by the specific customer count and expected duration for each storm for each project to calculate the monetized CMI at the project level.

3.10 Substation Flood Modeling

1898 & Co. utilized storm surge modeling from the Sea, Land, and Overland Surges from Hurricanes (SLOSH) model. The SLOSH models perform simulations to estimate surge heights above ground elevation for various storm types. The simulations are based on historical, hypothetical, and predicted hurricanes. The model uses a set of physics equations applied to the specific location shoreline, incorporating the unique bay and river configurations, water depths, bridges, roads, levees, and other physical features to establish surge height. These results are simulated several thousand times to develop the Maximum of the Maximum Envelope of Water, the worst-case scenario for each storm category. The SLOSH model results were overlaid with the location of Entergy New Orleans' substations to estimate the height above the ground elevation for storm surge. This data is then used in the Storm Impact Model to estimate the likelihood of substation failure for every storm scenario.

3.11 Transmission Outage Scenarios

Due to the complex interconnected nature of the transmission system, 1898 & Co. and Entergy New Orleans developed a transmission outage framework based off historical performance of the transmission system in major storm events and the known redundancies of the transmission system. This framework outlines the customer impact if a given line, or combination of lines, should fail. The impact of these outages is significant, resulting in regional, widespread customer outages. Additionally, these scenarios affect the ability to supply electricity to metropolitan areas like New Orleans, resulting in large blackouts involving large numbers of customers.

4.0 MAJOR STORMS EVENT DATABASE

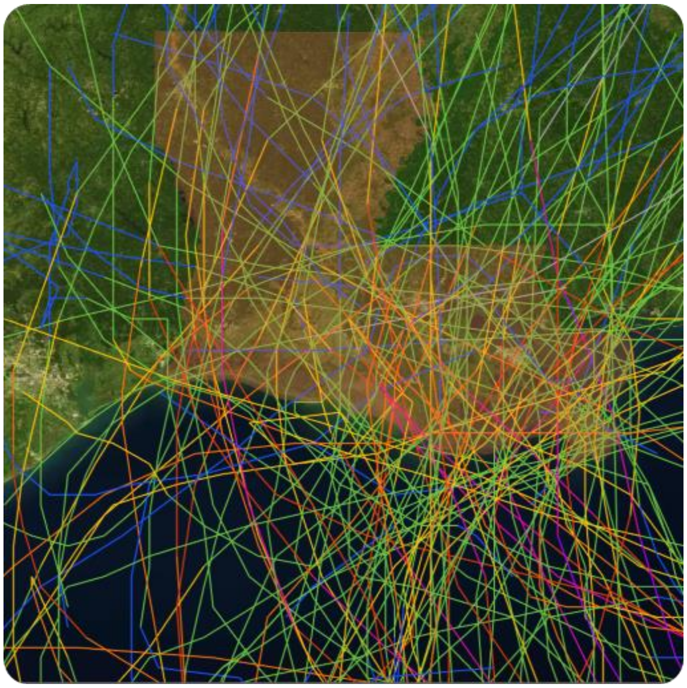
The first component of the Storm Resilience Model is the Major Storms Event Database. The database describes the phases of resilience (see Figure 2-1) for the range of storm events to impact the Entergy New Orleans service territory, It includes the probabilities for each of the events as well as range of impacts to the transmission system, substations, and distribution system while also outlining the duration and customers impacted and the restoration costs. This section describes the data sources and approach used to develop the database. Since the benefits of hardening projects are directly related to the frequency and impact of major storm events, the resilience-based planning approach starts with developing the range and frequency of storm types that could impact Entergy New Orleans' service area.

4.1 Historical Storm Overview

4.1.1 Storm Count and Type

The National Oceanic and Atmospheric Administration (NOAA) includes a database of major storm events over the past 170 years, beginning in 1852. This database was mined to evaluate the different types and frequency of major storms to impact Louisiana, including Entergy New Orleans' service area. Figure 4-1 provides an example screenshot from NOAA's storm database. It shows all the events, including path and category, to come within 150 miles of Entergy's service area. Review of the figure shows the changing category of the storm as it moves through Louisiana.

Figure 4-1: NOAA Example Output — Louisiana



Source: https://coast.noaa.gov/hurricanes/

The NOAA database was mined for all major event types up to 150 miles from Entergy New Orleans' service area boundary. The 150-mile radius was selected since hurricanes can have diameters of 300 miles, where some hurricane storm bands impact a significant portion of the Entergy New Orleans service area. Additionally, the database was mined for the storm category as it hit the Entergy New Orleans service area. Section 4.2 includes additional details on the mining process to understand the historical events as they moved through the Entergy New Orleans service area, including the range of permutations for storm side, storm distance, and storm category.

Figure **4-2** includes the summary results from the NOAA database of storms to hit or nearly hit the Entergy New Orleans service area since 1852. It categorizes each storm at its strongest point in the service area. If a storm directly hit the service area, its strength was recorded upon landfall. If a storm remained a peripheral hit, the strength was recorded at the closest point to the system. Only 1 category 5 storm has been recorded since 1852.

Figure 4-2: Summary of Storms in Entergy New Orleans' Territory since 1852[2]

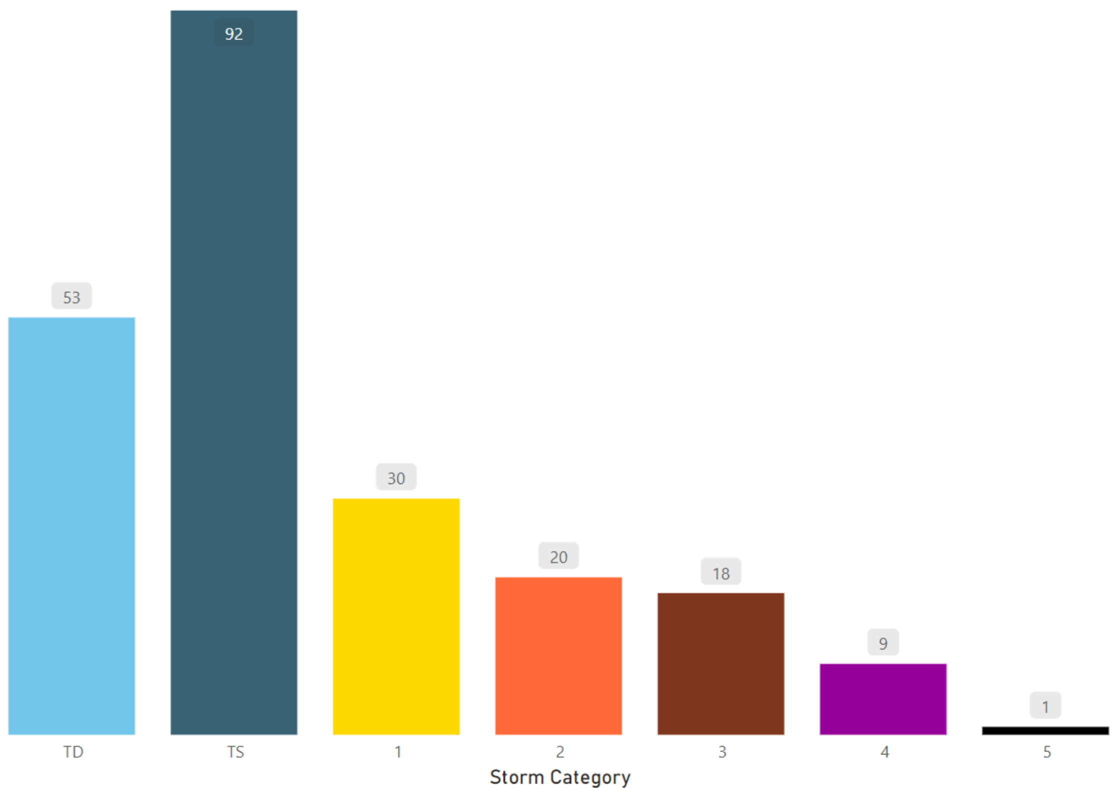
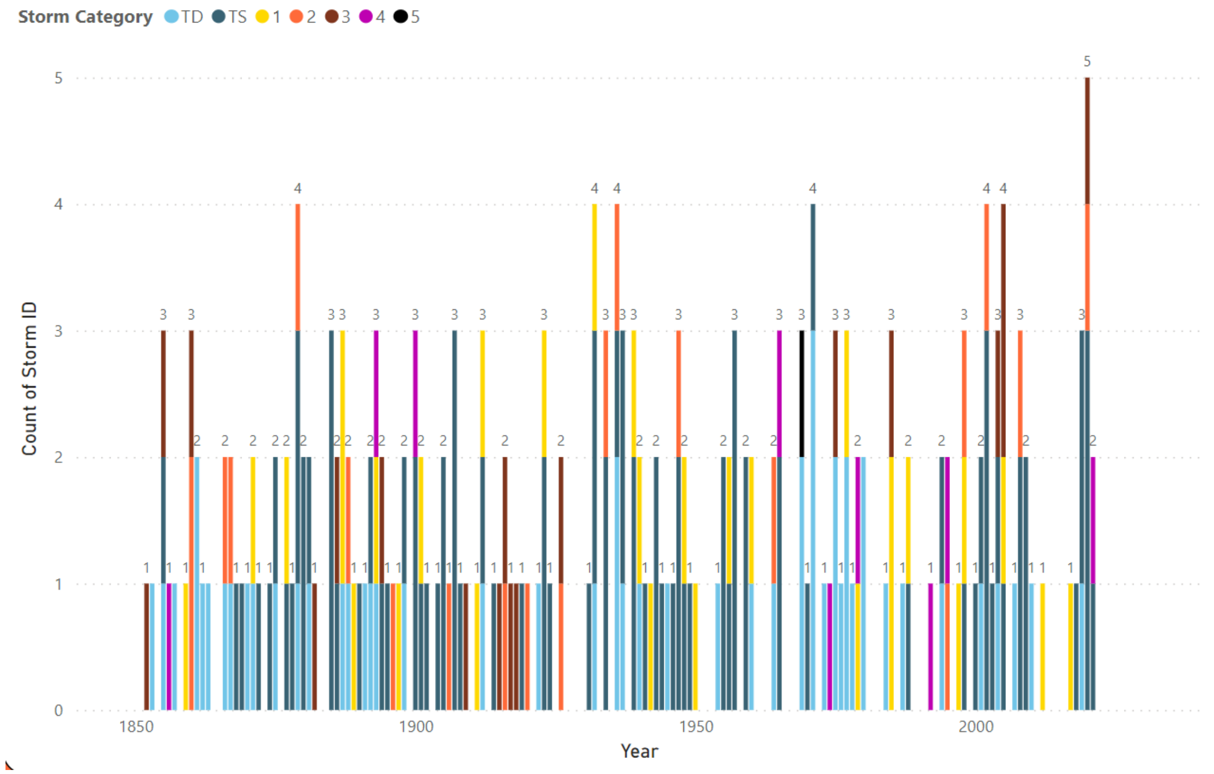


Figure **4-2** shows a total of 223 storm eyes came within 150 miles of Entergy New Orleans' service area since 1852. Of those, 48 storm eyes came directly through Entergy New Orleans' service area. Approximately 4.4 percent of storms were Category 4 or higher. 12 percent were Category 2 or 3 storms, and Category 1 storms make up 13.5 percent of the events. 65 percent of the events are Tropical Storms or Tropical Depressions.

Figure 4-3 shows storm count by category for all 223 major events for each year since 1852. The figure shows that storm activity over the past 170 years has been random and chaotic. Some years may see as low as 0 storms events with others as high as 5.

[2] Source: https://coast.noaa.gov/hurricanes/ with analysis by 1898 & Co.

Figure 4-3: Count of Storms for Entergy New Orleans System by Year[3]



Converting the data in Figure 4-3 into 10-year and 100-year rolling averages provides additional insights into storm activities to impact the Entergy New Orleans service area. Figure 4-4 and Figure 4-5 show the storm activity in Entergy New Orleans' service area over time using a 10-year and 100-year rolling average, respectively.

Figure 4-4 shows the sum of all the storms occurring in that year and the 9 years before, from 2012 through 2021. It is further broken down into storm categories. The 2021 column on the far right shows 13 storms hit Entergy New Orleans from 2012 to 2021. The rolling 10-year average profile from 1950 to 2021 shows wide swings in major storm counts and types. For instance, the period from 2009 to 2018 saw only 6 storms, with no category 2 or above storms, and the period 2012 to 2021 saw 13 storms, with three category 2 or higher storms. No Category 5 storms hit the system in the past 44 years. While it may be tempting to focus on the last 10 years of storm activity to start understanding storm frequency, Figure 4-4 shows that there have been worse periods and would exclude a Category 5 hurricane from the resilience modeling if only the most recent 10 years were considered.

[3] See footnote 2

Figure 4-4: 10-Year Rolling Count of Storms for Entergy New Orleans' System[4]

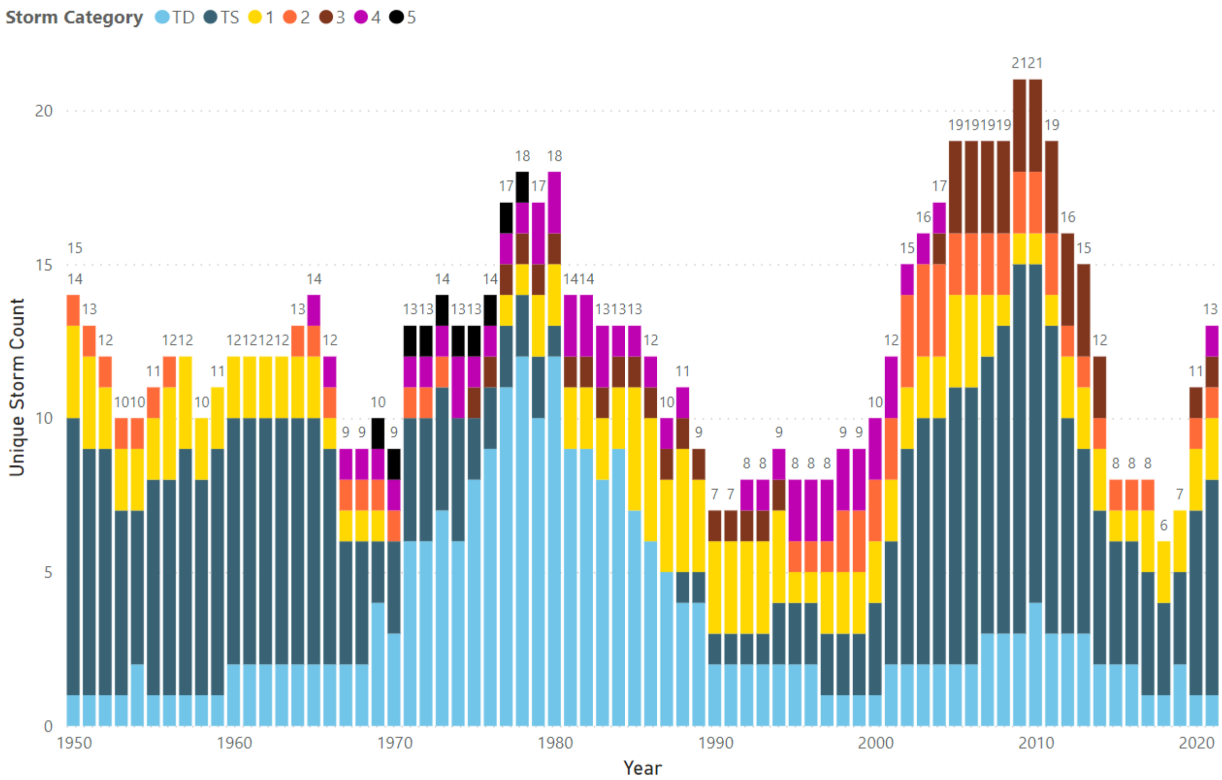


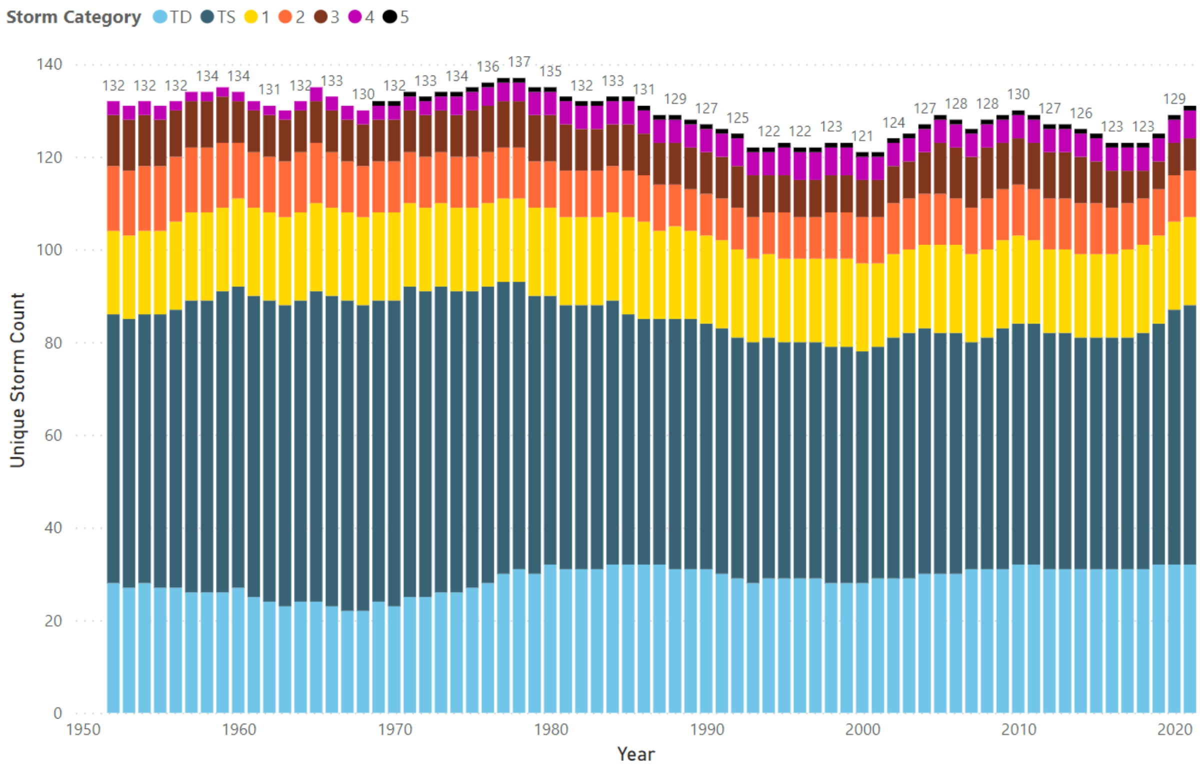
Figure 4-5 depicts the 100-year rolling count of storms. For a resilience-based assessment, this time horizon provides insights for those 'one in a 100-year' types of devasting events while also including 'one in twenty' and 'one in ten' and more regularly occurring events. As the figure shows, the variability between high and low storm activity periods is much lower, ranging from a low of approximately 166 storms to a high of 186. Analysis of the overall storm count activity from Figure 4-5 shows:

1. **Activity generally increasing from the 1852-1951 period (132 storms) to the 1879-1978 period (137 storms). That is an increase of 5 storms (137-132) over a 27-year period (1978-1951).**
2. **Activity generally decreasing from the 1879-1978 period (137 storms) to the 1902-2001 period (121 storms). That is a decrease of 16 storms (137-121) over a 23-year period (2000–1978).**
3. **Activity generally increasing from the 1902-2001 period (121 storms) to the 1922-2021 period (131 storms). That is an increase of 10 storms (131-121) over a 20-year period (2021-2000).**

[4] See footnote 2

The figure also shows the relative consistency of the mix of storm activity over the period. The rest of the report utilizes these 100-year rolling averages to understand storm frequency across Entergy New Orleans' service area.

Figure 4-5: 100-Year Rolling Count of Storms for Entergy New Orleans' System[5]



MED events such as thunderstorms are evaluated along with tropical cyclones. These were defined by IEEE 1366-2022 using the 2.5-beta method for MED definition.

[5] See footnote 2

4.2 Storm Activity and Service Area Merging

Section 4.1 provided the storm activity for New Orleans. The first step in developing the Major Storms Event Database was to understand the various storm activity types, their intensity, and how they mapped to Entergy New Orleans. It is important to note that hurricane events can be over 300 miles wide.

To better understand the historical frequency and intensity of various major events in the Entergy New Orleans service area, 1898 & Co. broke up the service area into 50-mile by 50-mile sections creating 4 system sections. Figure 4-6 shows the 4-system sections overlaid against the Entergy New Orleans service area.

Figure 4-6: 50x50 mile System sections

The system section-based storm assessment methodology allows analysis of major event intensity on a granular scale across the Entergy New Orleans service territory. The system section approach is necessary to understand storm intensity against the infrastructure (represented by the system section) for the following drivers:

- Storm category
- Storm distance
- Storm side (right / left)

4.2.1 Storm Intensity Factors

4.2.1.1 Storm Category

The category of the storm as it encounters the infrastructure is the first key driver of the expected consequence of an event. As the storm paths show from Figure 4-1, the storm category changes as it moves through the service area and loses energy. Table 4-2 shows each category and the associated sustained wind speeds.

Table 4-1: Storm Categories and their Wind Speeds

Category	Sustained Wind Speed (mph)
MED	N/A
Tropical Depression (TD)	< 38
Tropical Storm (TS)	39-73
Category 1	74-95
Category 2	96-110
Category 3	111-129
Category 4	130-156
Category 5	> 157

4.2.1.2 Storm Distance

The distance of the storm as it encounters the infrastructure is the second key driver of the expected consequence of an event. The closer the storm is to the infrastructure, the more expected the damage. However, hurricanes can be nearly 300 miles wide causing damage to infrastructure that is 150 miles away from the storm center as a few storm bands come across the service area. Because of this wide range, the Major Storms Event Database categorizes the second storm intensity factor into the following categories:

- **'Direct Hits'** are defined by when the eye of the storm comes within a 25-mile radius from the system section centroid in any direction. The max wind speed hits all or significant portions of system section twice, once from the front end and again on the back end of the storm. Additionally, the wind speeds cause the assets and vegetation to move in one direction as the storm comes in and in the opposite direction as it moves out. This double exposure to the system causes significant system failures.

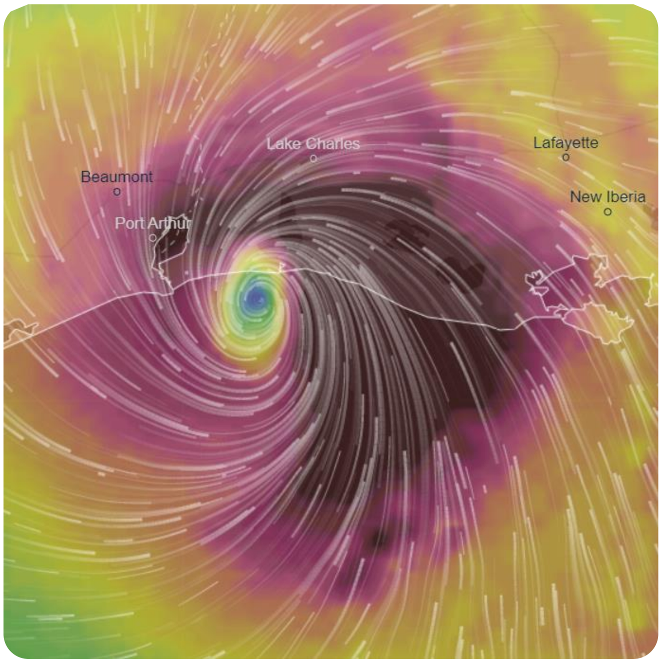
- **'Near Direct Hits'** are defined by when the eye of the storm comes within 26 to 50-mile radius form the system section centroid in any direction. In many cases, assets experience opposite directional wind as the storm moves through the area, exposing the system to significant potential damage.
- **'Partial Hits'** are defined by when the eye of the storm comes within 51 to 100-mile radius from the system section centroid in any direction. At this distance, the storm bands hit a significant portion of the assets in a system section. The storm passes through the territory once (compared to twice with direct hits), causing less damage relative to a 'direct hit' or a 'near-direct hit'. For large category storms, the 'Partial Hit' could still cause more damage than a 'Direct Hit' from a small storm.
- **'Peripheral Hits'** are defined by when the eye of the storm comes within 101 to 150-mile radius from the system section centroid in any direction. Since hurricanes can be 300 miles wide in diameter, some storm bands can hit a fairly large portion of the system, even if the main body of the storm misses the service area. Very strong winds still comprise these storm bands for large storms, but the damage is less than a 'Partial Hit' of the same strength and side.

4.2.1.3 Storm Side

The third intensity factor included within the Major Storms Event Database is the side of the storm that impacts the infrastructure. Due to the Coriolis effect, tropical storms and hurricanes have stronger east (right-side) winds than west (left-side) winds. These increased wind speeds on the right side of the storm cause more damage to assets on that side of the storm than those assets equally distant from the eye on the left side.

The figure below depicts this effect; the storm's eye is the blue dot in the middle of the red. The right side of the storm is a darker red than the left side, which shows the winds are faster there than on the pink/orange left side of the storm.

Figure 4-7: Storm Wind Strength Heat Map[6]



4.2.2 Storm Types

Combining all the permutations from the three storm activity intensity factors outlined above produces 49 different storm types included within the Major Storms Event Database. Table 4-2 shows the 49 different storm types. Direct hits are categorized under the right-side table. Tropical Depressions are not included within the 101–150-mile range since they are typically smaller events. Similarly, MEDs are only within the 'Direct Hit' distance.

[6] Sourced from Ventusky (https://www.ventusky.com/?p=29.43;-94.05;8&l=gust&t=20200827/0600)

Table 4-2: Storm Types

Right / Strong Side of the Storm				
	Distance (miles from system section centroid to storm eye)			
Category	25 (Direct)	50	100	150
5	1	10	24	38
4	2	11	25	39
3	3	12	26	40
2	4	13	27	41
1	5	14	28	42
TS	7	15	29	43
TD	8	16	30	
MED	9			

Left / Weak Side of the Storm				
	Distance (miles from system section centroid to storm eye)			
Category	25 (Direct)	50	100	150
5		17	31	44
4		18	32	45
3		19	33	46
2		20	34	47
1		21	35	48
TS		22	36	49
TD		23	37	
MED				

4.2.3 Capturing Storm Types Against System Sections

1898 & Co. utilized geospatial analytics to identify the historical count of the 49 different storm types against each system section based on storm path datasets available for download from NOAA's website. The basis for the analytics was to capture the storm's intensity factors as it is closest to a given system section. For each storm over the past 170 years, 1898 & Co. identified the storm's category, distance from the centroid of the system section, and side of the event. This was done for all 4 system sections. Figure 4-8 provides an illustration of the approach for one example system section.

Figure 4-8: Geospatial Analytics Approach Illustration

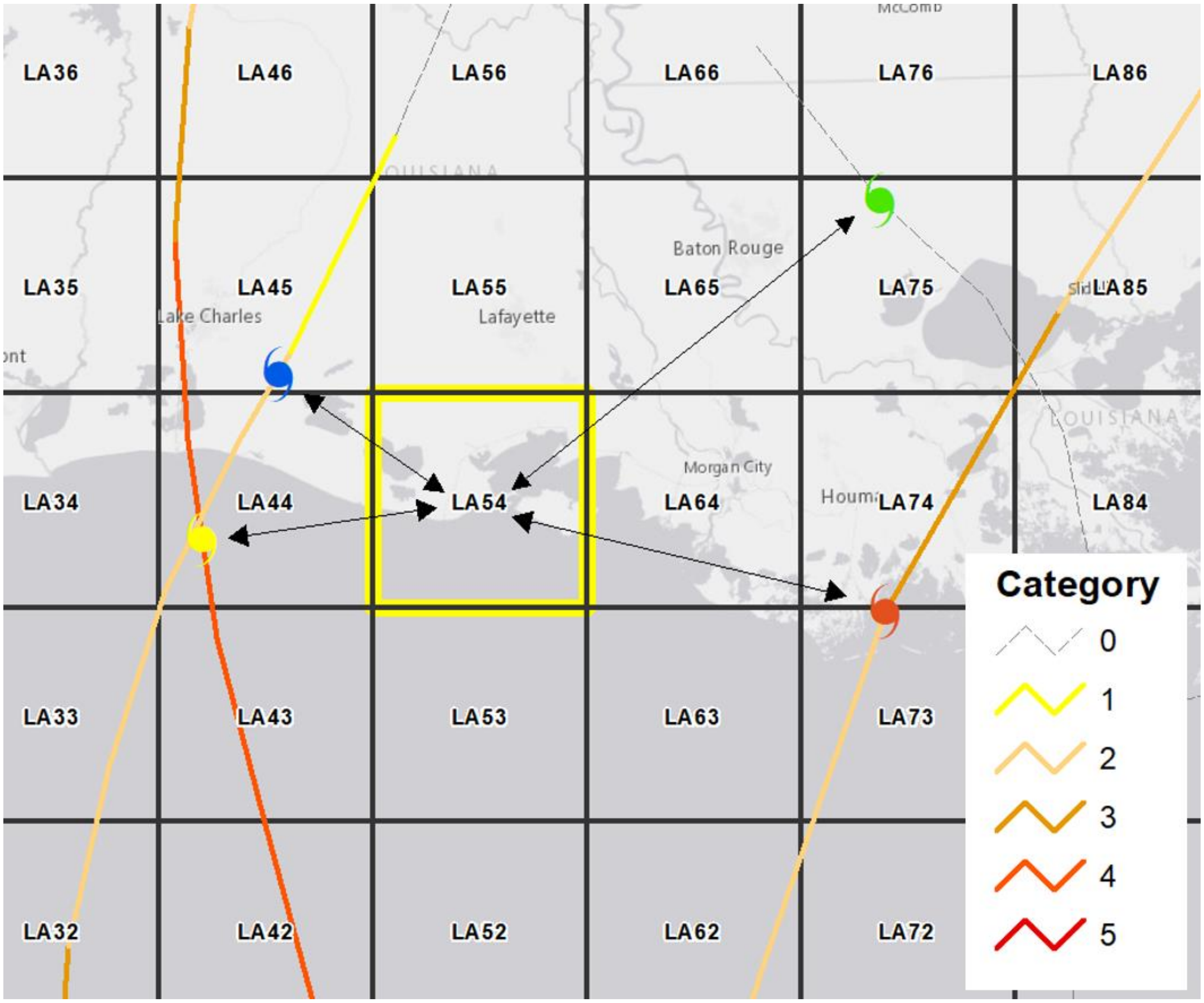


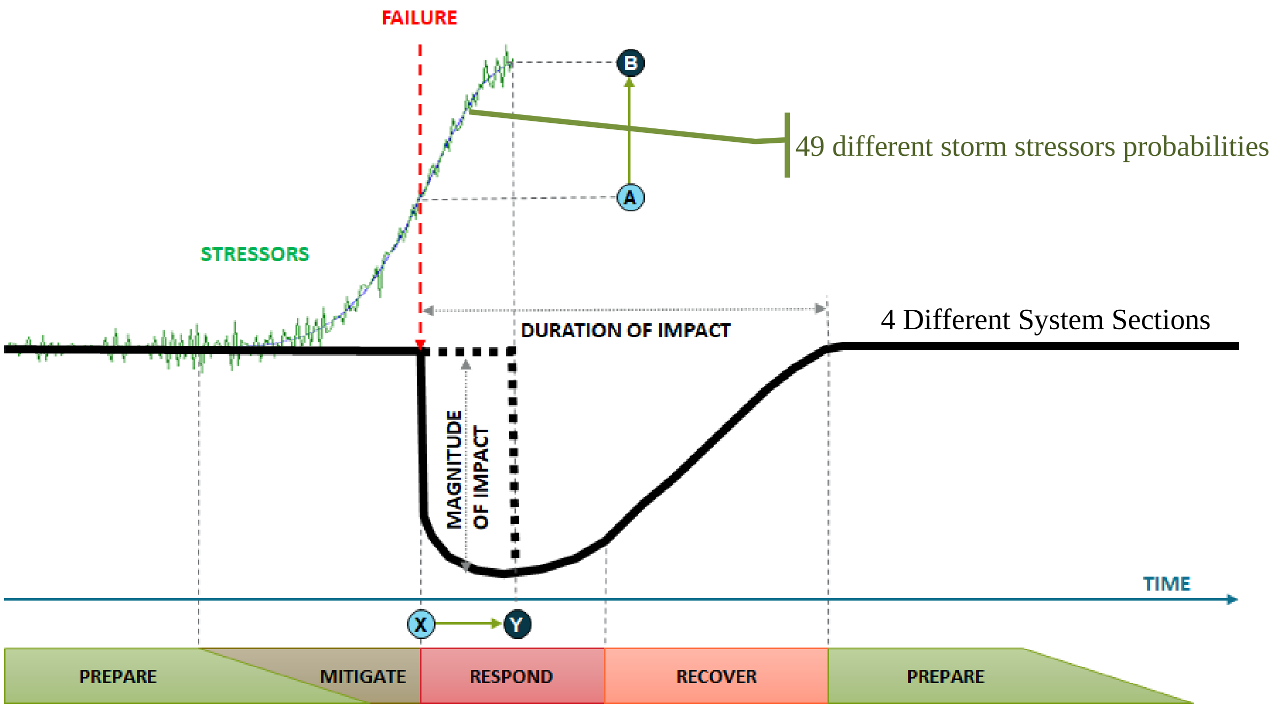
Table 4-3: Storm Statistics for Example System Section for 2020 Storms

Name	Time	Storm Location	Storm Side	Storm Category	Storm Distance (miles)	Storm Distance Bucket (miles)
Laura	8/27/2020 3:00	W	Right	4	65.5	100
Zeta	10/28/2020 18:00	ESE	Left	2	98.1	100
Delta	10/9/2020 23:00	NW	Right	2	55.5	100
Cristobal	6/8/2020 6:00	ENE	Left	TS	116.4	150

4.2.4 Major Storms Event Database and Resilience Framework

The Major Storms Event Database includes 49 different storm events against 4 different system sections. Figure 4-9 depicts how both factors map to the phases of resilience concept that serves as the theory behind the Storm Resilience Model approach to evaluating system vulnerability and benefits of hardening investments. The Major Storms Event Database includes 49 different 'stressors' and outlines the status of the 4 system sections. Section 4.3 shows the approach to forecast the frequency of each of the 49 storm stressors for each of the 4 system sections. Section 4.4 outlines the expected impacts to each system section for each of the 49 storm stressors.

Figure 4-9: Phases of Resilience Framework & Major Storms Event Database



4.3 Estimating Future Storm Probabilities

From a high-level perspective, the future storm probabilities (49 types) within the Major Storms Event Database for each of the 4 system sections are based on the historical 100-year rolling average of events for the last 30 100-year periods with some modifications explained below. Only the last 30 100-year periods were used because of concerns relative to recording bias and more recent climate factors.

The Major Storms Event Database includes a range of probabilities for each of the 49 storm types by the 4 system sections. As discussed in Section 6.3, the Storm Resilience Model employs Monte Carlo, or stochastic modeling, to select a future storm probability from a distribution. This is done for 1,000 iterations to create 1,000 storm futures for each system section.

4.3.1 100-Year Rolling Storm Probabilities

Figure 4-10 shows the rolling probability of a direct hit to an example system section for each 100-year window ending in the year shown. This figure shows all the hurricane events to directly come through the system section.

Figure 4-10: 'Direct Hit' Probabilities for Example System section[7]

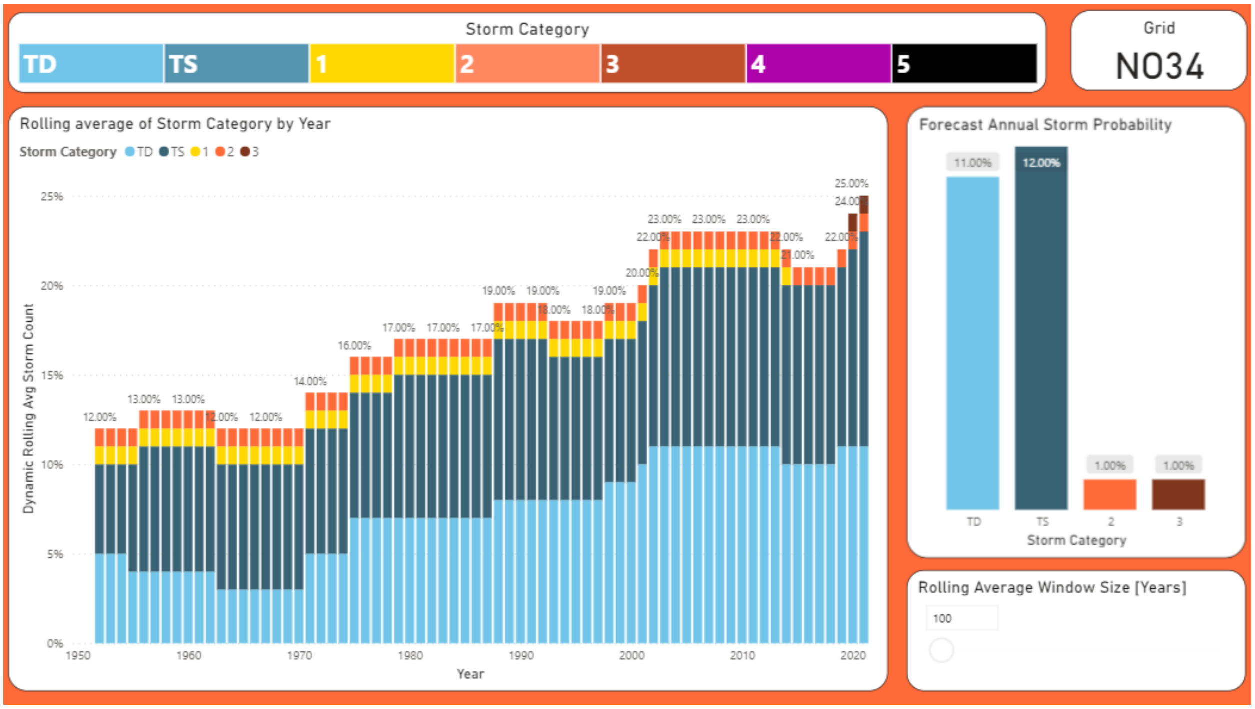


Figure 4-11, Figure 4-12, and Figure 4-13 show similar probabilities for the example system section for 'Near Direct Hits' (26 to 50 miles), 'Partial Hits' (51 to 100 miles), and 'Peripheral Hits' (101 – 150 miles), respectively. This same analysis was performed for all 4 system sections.

[7] See footnote 2

Figure 4-11: 'Near Direct Hit' Probabilities for Example System Section[8]

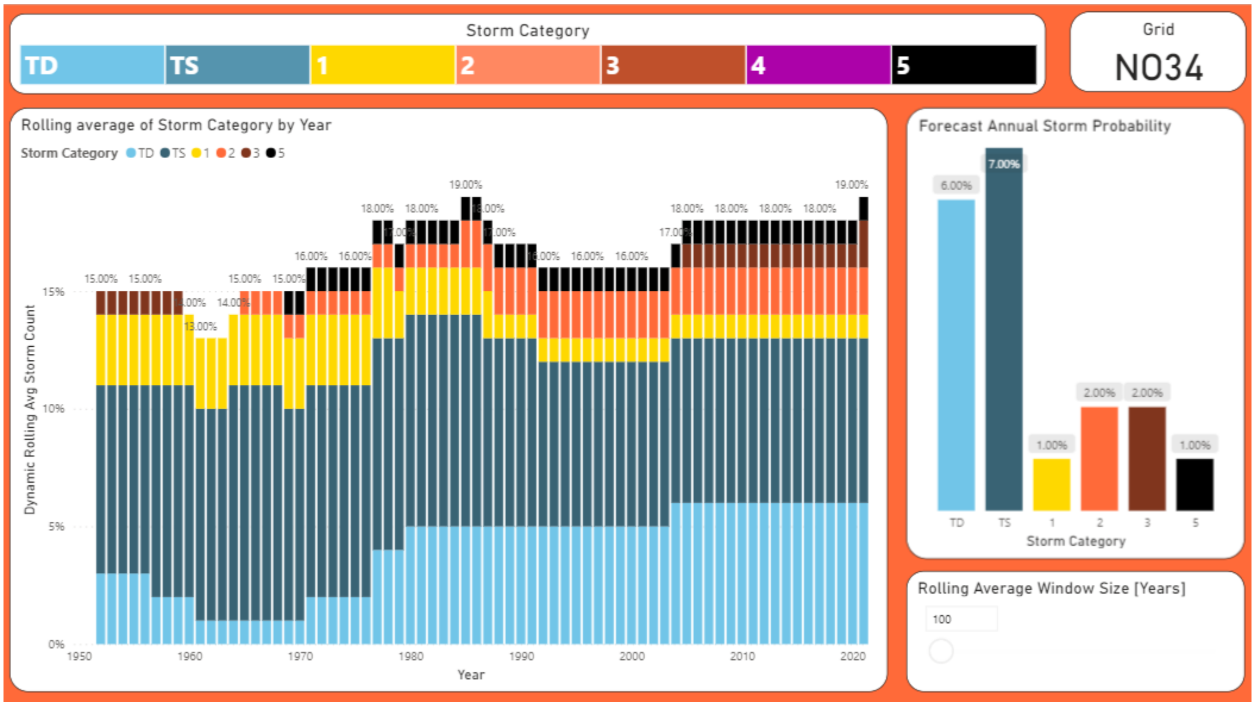
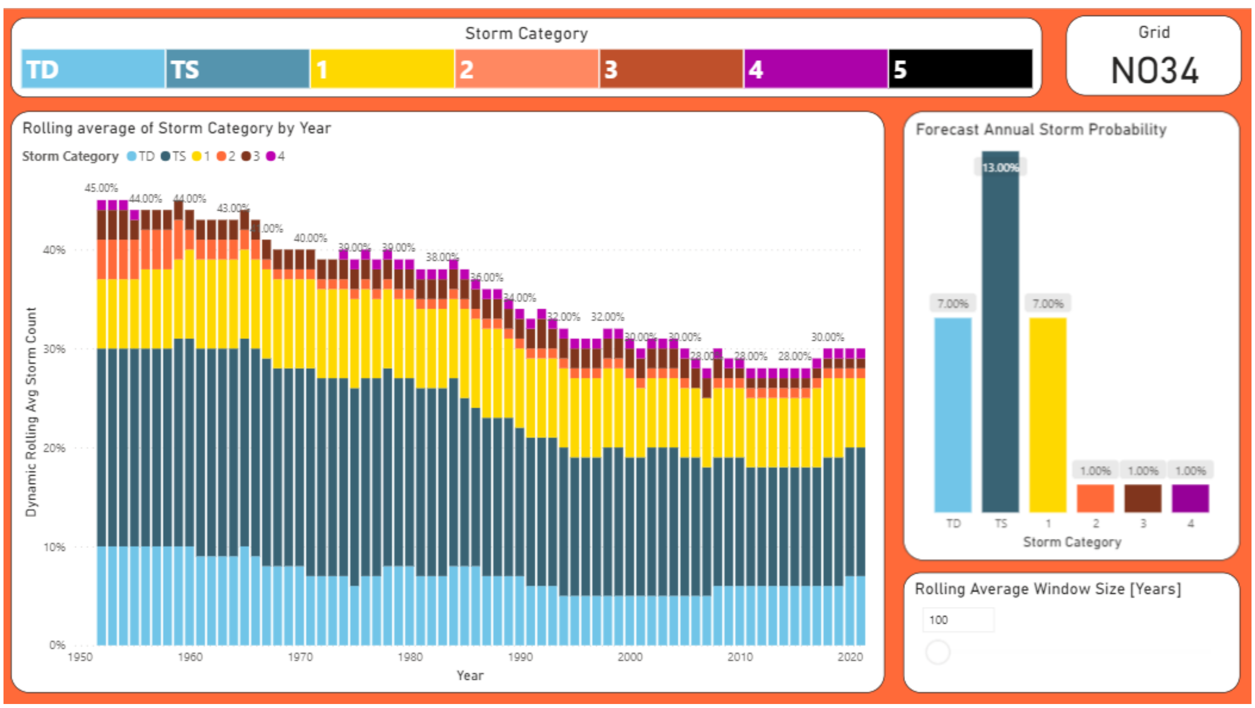
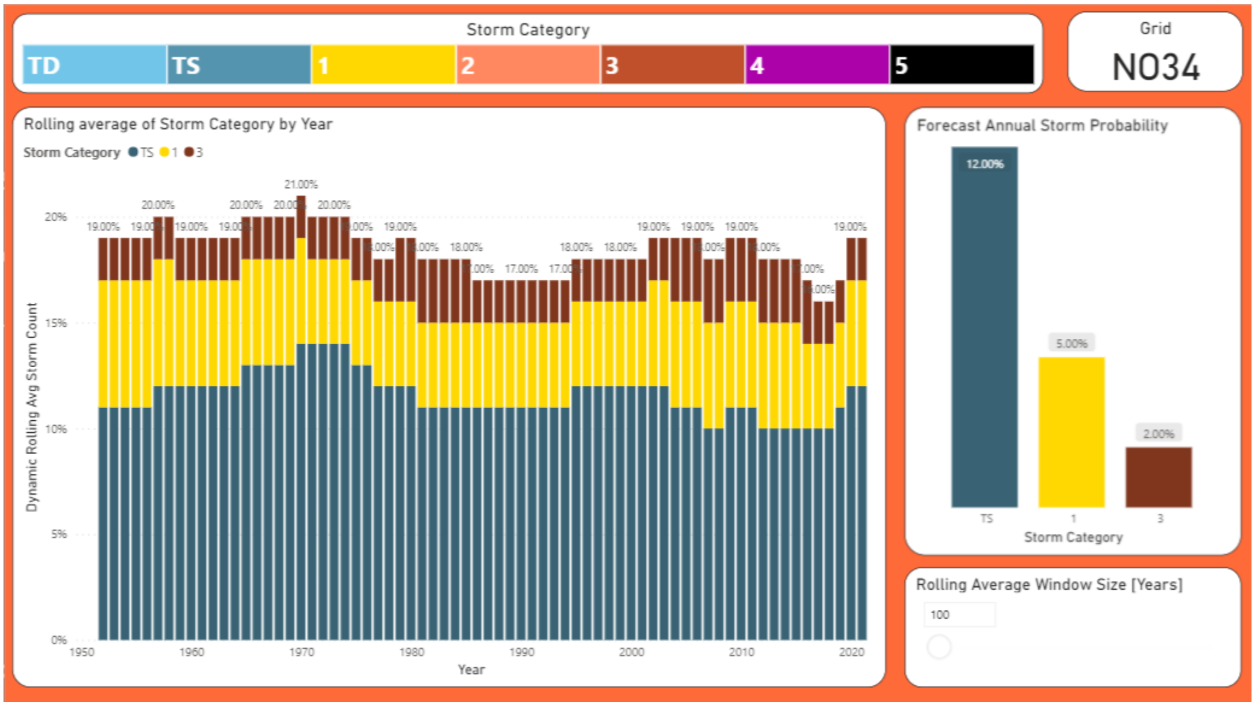


Figure 4-12: 'Partial Hit' Probabilities for Example System Section[9]



[8] See footnote 2.
[9] See footnote 2.

Figure 4-13: 'Peripheral Hit' Probabilities for Example System Section[10]



4.3.2 Recent Storm Activity Modifiers

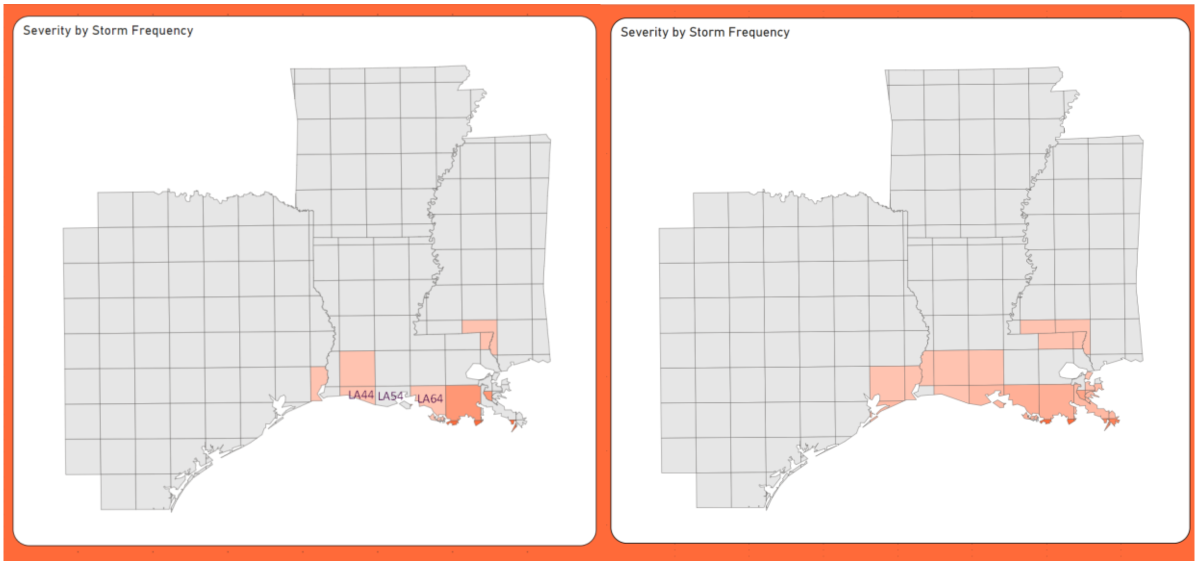
As discussed above, the model uses the last 30 100-year periods (1893-1992 through 1922-2021) to estimate the probabilities of future storms. If the 30 100-year periods are equally weighted, storms occurring during the middle years of the study period will more strongly influence future storm probabilities. The model weights the most recent years more heavily to incorporate the high frequencies of large category 4 storms over the past few years.

4.3.3 Averaging across East and West System sections

Due to the random nature of storm paths and the granularity of the 50x50 system sections, some system sections may see no strong storms over the entire 170 years of data. However, their neighbors may see multiple strong storms. The left image of Figure 4-14 offers an example for Category 4 Direct Hits to the example system section. Analysis of Figure 4-14 shows that system section LA54 has had no Category 3 or 4s over the past 170 years, although both system sections surrounding it have Category 4 direct hits. The Major Storms Event Database averages neighboring system sections to the east and west to adjust for this historical bias since those hurricanes could have easily moved east or west by 25 miles. The image on the right side of Figure 4-14 shows the resulting probabilities after the averaging.

[10] See footnote 2

Figure 4-14: Category 4 Direct Hits in the Past 100 Years Before and after East-West Averaging



4.4 Major Storms Impact

While the major storm frequency into the future is based on a direct link to historical major events, the consequence of the events is more challenging to estimate. Review of the historical record shows significant variation in the impacts from events that have similar characteristics, which leads to significant uncertainty in the modeling of such impacts from future storms. In some cases, lower category events have produced more damage and impact than higher category events due to a host of variables, including differences in the storm paths, speed, the infrastructure's design standards, customer density, and the vegetation density around the infrastructure.

Further complicating the evaluation of storm impacts is that the Entergy New Orleans service area is ever evolving with a changing customer base. While the historical record shows the potential for a Category 5 hurricane that occurred in 1969 (Camille), any impact data, if even available, would not be valuable in understanding the impact to Entergy New Orleans' system if it were to happen today because the customer base and system are completely different. For this reason, the Major Storms Event Database leverages more recent events from the past 10 to 15 years and linearly interpolates to fill in gaps for major events that have occurred in the historical past but not within the most recent past. The Major Storms Event Database includes impact assumptions around the following three categories for each of the 49 events to impact a system section:

- Percentage of sub-systems impacted
- Duration to restore each sub-system

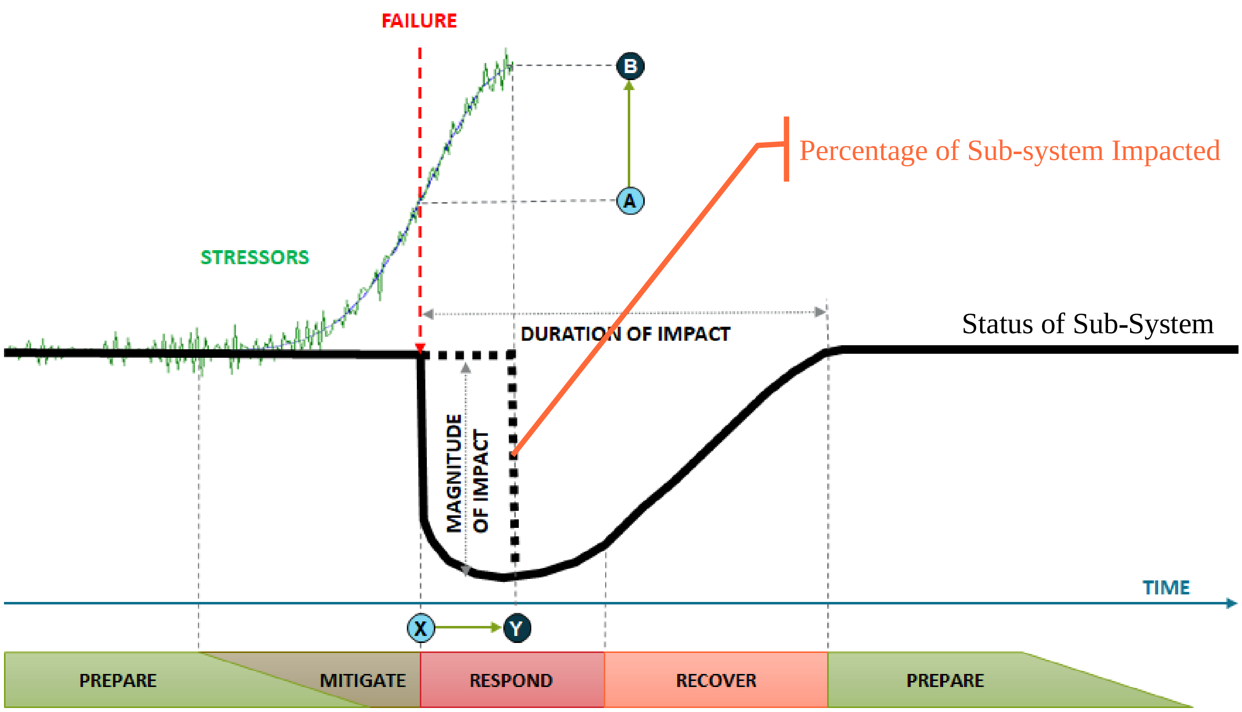
- Cost to restore each sub-system.

The next section outlines the historical major event impacts. This information was foundational in developing the three system section impacts outlined above. The following sections describe each of the three system section impacts that are part of the Major Storms Event Database.

4.4.1 Percentage of Sub-System Expected Impacts

The Major Storms Event Database outlines and describes the state of the system in terms of magnitude of impact in alignment with the resilience framework in Figure 2-1 and shown below in Figure 4-15.

Figure 4-15: Phases of Resilience Framework & Sub-System Impact



For each of the 49 storm events (stressors or the 'green' line from Figure 4-15), the database includes the expected range of impacts at the system section level for the following sub-systems:

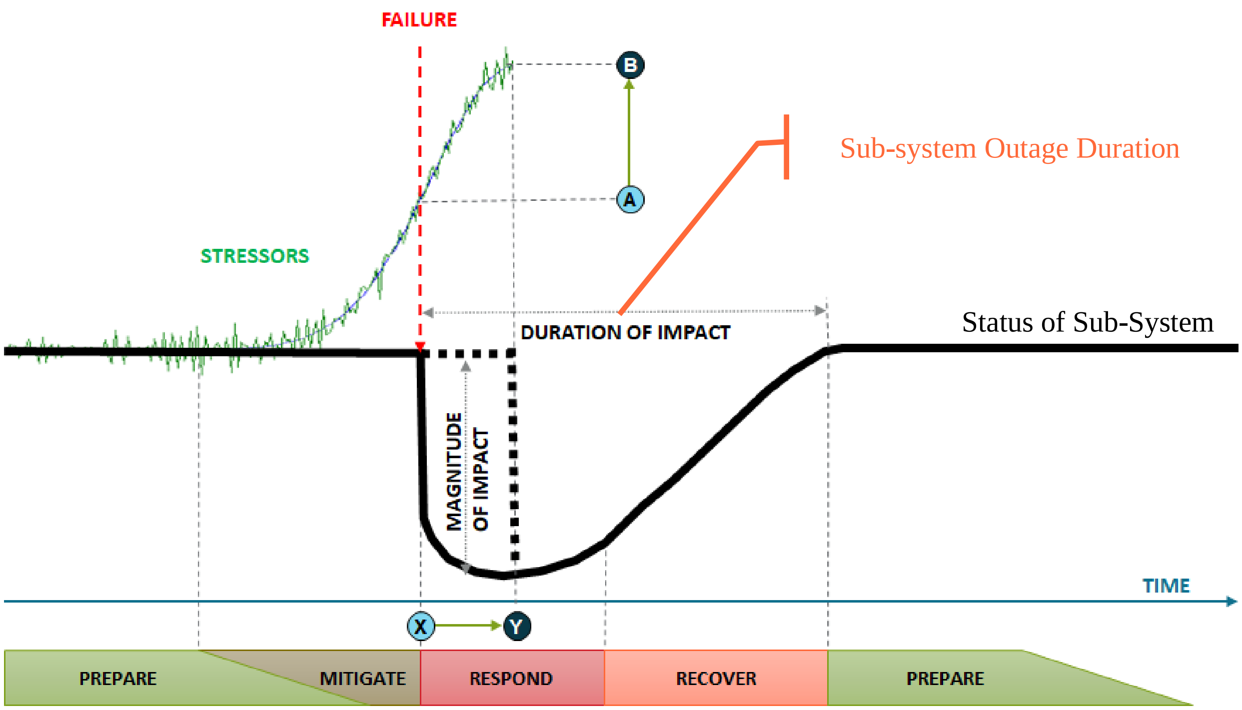
- Percentage of Transmission Circuits Down
- Percentage of sub-Transmission Circuits Down
- Percentage of at-risk Substation Flooded due to storm surge
- Percentage of at-risk Control Houses Damaged
- Percentage of Backbone (or Mainline) Protection Zones to Lock-out
- Percentage of Lateral Protection Zones to Lock-out

1898 & Co. and Entergy New Orleans developed the expected impact ranges for each of these sub-systems based on the historical storm reports adjusting for the system section modeling structure and the 49 storm events.

4.4.2 Major Event Duration

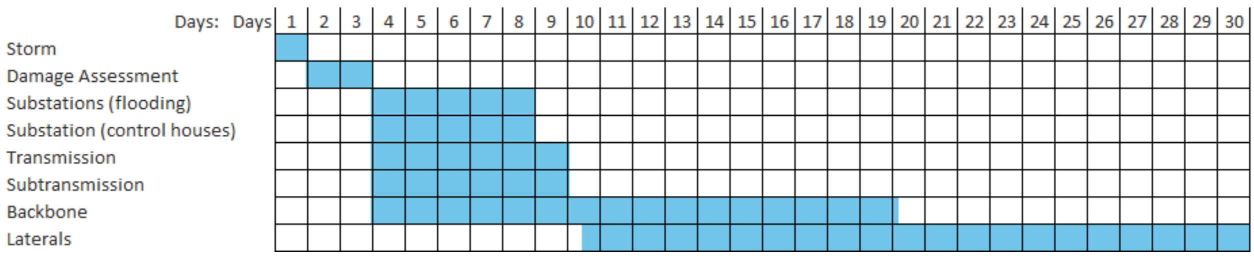
The Major Storms Event Database also includes the expected restoration profiles for each of the sub-systems for each of the 49 storm stressors ('green' line). While the previous section describes the impact to the system, this part of the database outlines the duration of restoration in alignment to the resilience framework in Figure 2-1 and shown below in Figure 4-16.

Figure 4-16: Phases of Resilience Framework & Sub-System Duration



1898 & Co. and Entergy New Orleans developed the expected total duration of each of the 49 storm events ('stressors') to impact each system section. The overall durations are in alignment to historical events from the last 15 years linearly interpolating for major events that have not occurred in the recent past. For the duration of restoration for each sub-section, the database includes historical experience from recent restoration efforts. Figure 4-17 shows an example of the sub-system restoration profile for a Category 4 hurricane direct hit. Similar restoration profiles were developed for all 49 storm event types. These restoration profiles by sub-system are critical for the calculation of customer outages completed within the Storm Impact Model. The Storm Impact Model considers the downstream customers of each protection device and where within the restoration profile that part of the system is likely to be restored.

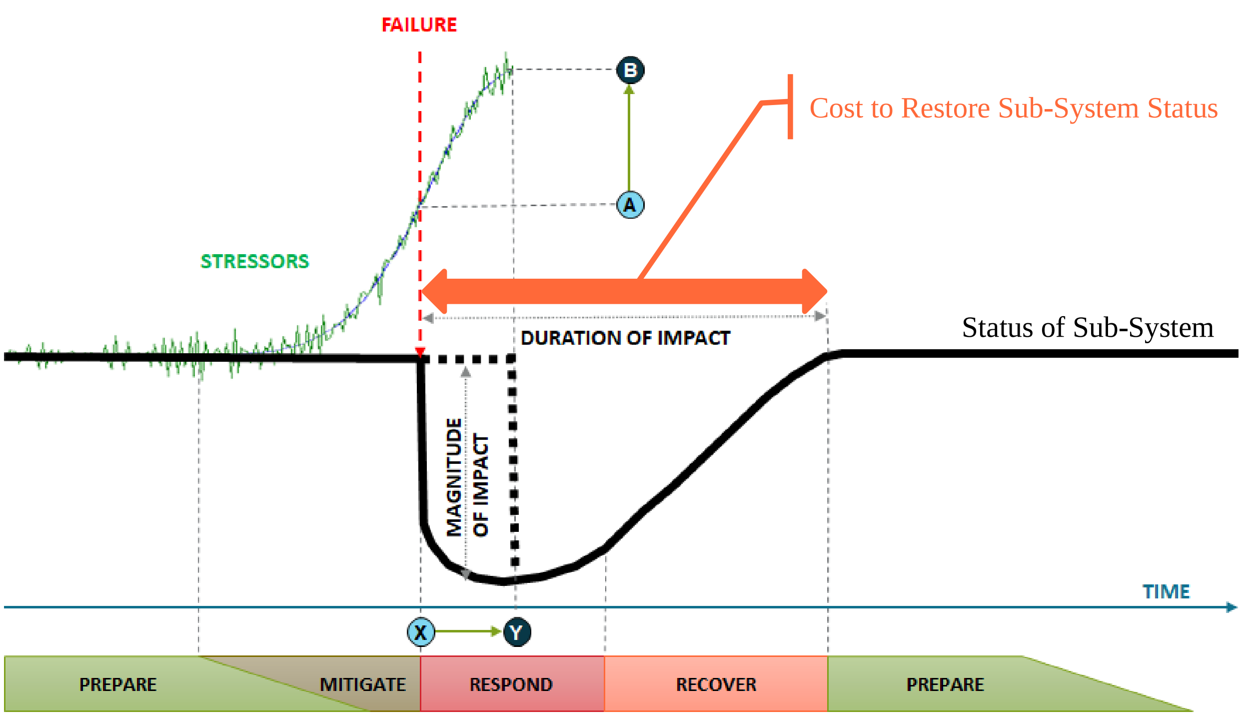
Figure 4-17: Sub-System Storm Restoration Profile for Cat 4 Direct Hit



4.4.3 Major Event Restoration Cost

The third impact category included in the Major Storms Event Database is the expected restoration costs for each of the 49 storm events ('stressors'). Figure 4-18 depicts the storm impact within the phase of resilience framework.

Figure 4-18: Phases of Resilience Framework & Sub-System Restoration Costs



The database includes the estimated restoration costs for each of the 49 major events to impact each of the 4 system sections. The database includes restoration costs for each system section and sub-system.

This is needed because there are several drivers of restoration costs. For instance, system sections with more assets, all else equal, would have more restoration costs than system sections with fewer assets.

For distribution circuits and transmission circuits, the database includes a similar approach to estimating the expected restoration costs for each of the events and system sections. The database factors in the following to estimate restoration costs for each of the 49 events and system sections:

- **Structure count and type** within the system section. System sections with high asset counts will have more failures and restoration costs. Additionally, some structures are more costly to restore like a lattice tower vs. a wood mono pole.
- **Entergy Crews vs. non-Entergy Crew mix**. Replacing assets during and immediately after major events is much costlier than replacing assets in a more methodical manner during 'blue-sky' hours. Overtime fees, unavoidable inefficiencies that arise from storm restoration, and logistical and other challenges are a few of the drivers for higher costs for storm restoration work. Because of these factors, the cost of replacing assets during storm events, even if only Entergy New Orleans crews perform the work to restore infrastructure, can be 1.5 to 2.0 higher than infrastructure replacements during 'blue-sky' rebuilds. For high category named events, Entergy New Orleans also relies on mutual assistance and contractors to restore the system, with non-Entergy New Orleans crews being brought in from across the nation to hasten restoration times and manage the massive scale of the restoration work that arises from such high category storm events. It should be noted that Entergy New Orleans often provides mutual assistance to other utilities as part of the reciprocal obligations between member utilities. Given the per-diems, overtime rules, mobilization and demobilization, and demands of managing outside resources, on top of the factors outlined above, the costs can be even higher. The estimation approach factors in the mix of Entergy New Orleans and non-Entergy New Orleans crews for each of the 49 storm events based on these multipliers.
- **Side of the storm** impacting the system section (right or left side). The right side of a storm causes more damage than the left side of the storm.
- **Structure current wind loading vs. hardening wind loading standards**. System sections with assets that meet more recent hardened wind loading standards will have fewer failures than system sections where the assets' current wind loading rating has a wide gap to the hardening standard. See Section 3.5 for additional details.

- **Vegetation density** around the infrastructure in the system section. The existence of more dense vegetation around infrastructure will drive more failures because wind blowing vegetation into circuits is a key driver of storm-based outages. See Section 3.4 for additional details.
- **Age** of the infrastructure in the system section. System sections with infrastructure that is older are more likely to have higher instances of asset failures than system sections with younger assets. See Section 3.6 for additional details.
- **Right-of-Way access** for the infrastructure in the system section. Assets with road access typically cost less to restore than assets in the deep ROW. See Section 3.7 for additional details.
- **Terrain.** Infrastructure in wetlands will be more costly to restore than infrastructure in flat terrain. See Section 3.8 for additional details.

The Major Storms Event Database includes a framework to incorporate these factors to estimate the expected range in restoration costs for each of the 49 storm events to impact each of the 4 system sections.

For Substation Storm Surge Mitigation, restoration costs are based on the number of assets in the substation and the expected cost multipliers to replace those assets during major events. Control house restoration costs employ a similar approach.

5.0 STORM IMPACT MODEL

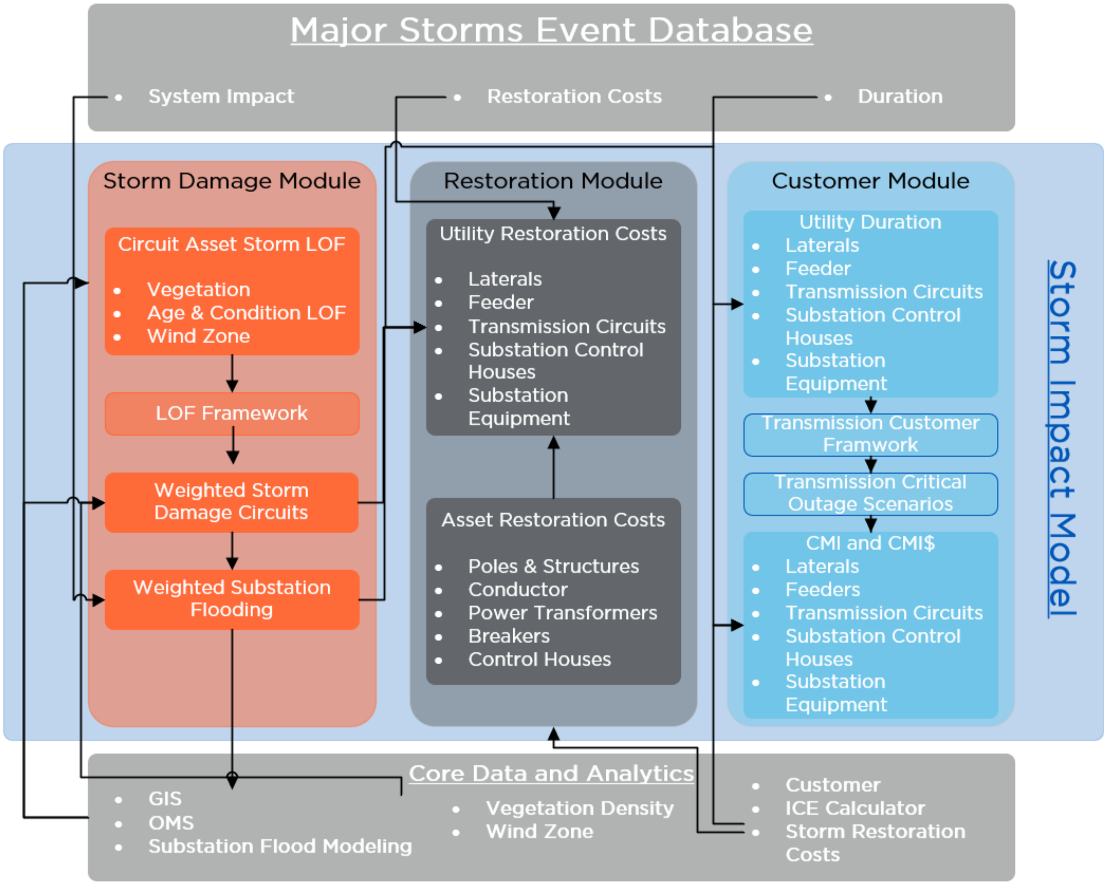
The second major component of the Storm Resilience Model is the Storm Impact Model. Whereas the Major Storms Event Database describes the phases of resilience at a high level for the Entergy New Orleans system, the Storm Impact Model goes a layer deeper and develops the phases of resilience for each potential hardening project on the Entergy New Orleans system for each storm scenario.

The Storm Impact Model models the impact to the system of any type of major storm event. Specifically, it identifies, from a weighted perspective, the particular laterals, feeders, transmission lines, and substations that are likely to fail for each type of storm in the Major Storms Event Database. The model also estimates the restoration costs associated with the specific sub-system failures and calculates the impact to customers in terms of CMI. Finally, the Storm Impact Model models each storm event for both a Status Quo and Hardened Scenario(s). The Hardened Scenario(s) assumes the assets that make up each project have been hardened. The Storm Impact Model then calculates the benefit of each hardening project from a reduced restoration cost and CMI perspective.

The Storm Impact Model utilizes a robust and sophisticated set of data and algorithms to model the benefits of each hardening project for each storm scenario. Section 3.0 outlines the core data, algorithms, and frameworks that are part of the Storm Impact Model, and also outlines a very granular level of analysis of the Entergy New Orleans system. This granular level of data and analysis allows for the Storm Resilience Model to reasonably project the ratio of resilience benefit to cost, resulting in more efficient hardening investment. This also provides confidence that investments are targeted to the portions of the system that provide the most value for customers.

Figure 5-1 provides an overview of the Storm Impact Model architecture. The following sections describe in more detail each of the core modules.

Figure 5-1: Storm Impact Model Overview



5.1 Core Data Sets and Algorithms

The core data sets and algorithms that feed into the Storm Impact Model are described in further detail in Section 3.0.

5.2 Weighted Storm Likelihood of Failure Module

The Weighted Storm LOF Module of the Storm Impact Model identifies the parts of the system that are likely to fail given the specific storm loaded from the Major Storms Event Database for each system section. The module is grounded in the primary failure mode of the asset base; storm surge for substations; wind and rain for control houses; and wind, structure design gaps, asset age, and vegetation for circuit assets.

5.2.1 Substation Storm Likelihood of Failure

A main driver of substation failures during major storm events is storm surge flooding and control house failures. The Major Storms Event Database designates the number of substations expected to experience flooding for each of the 49 storm scenarios and the number of control houses expected to have wind damage.

To identify which substations would be the most likely to experience flooding, the Storm Impact Model uses the substation flood modeling described in Section 3.10. This model provides the estimated feet of flooding above site elevation assuming the “maximum of maximum” approach; that is, a worst of the worst-case scenario. The flood modeling has flood height data for all 5 hurricane category types. The Storm Impact Model uses the flooding height values as likelihood scores to identify the substation probability of failure for each storm event in the Major Storms Event Database.

To evaluate which control houses are likely to experience wind damage, the Storm Impact model uses wind zone differential.

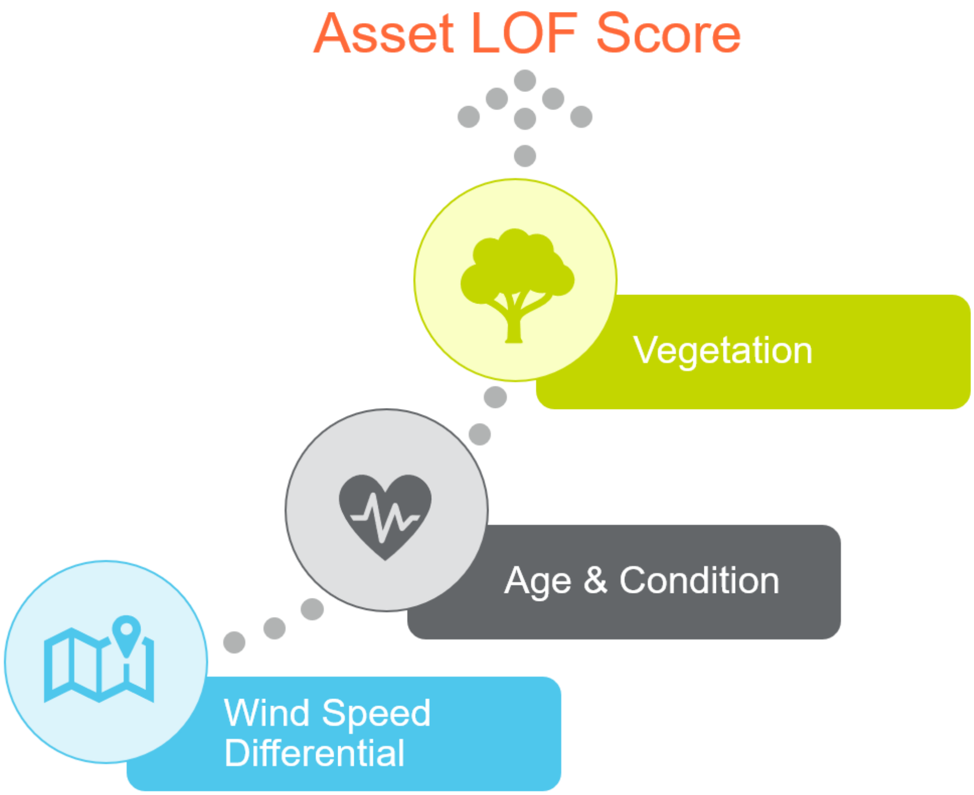
5.2.2 Circuits Storm Likelihood of Failure

A main driver of circuit failures during storms is wind blowing vegetation (and other debris) into the conductor, weighing it down. The additional weight, when combined with the wind loading, causes the structures holding up the conductor to fail. Typically, the vegetation touching the conductor triggers the protection device to operate; however, the enhanced loading on the poles causes asset failures that are costly to repair both in terms of restoration costs and in CMI. The storm LOF of an overhead distribution asset is a function of the vegetation around it, the age of the asset, and the applicable wind zone differential (coastal zones see higher wind speeds).

Figure 5-2 depicts the framework used to calculate the storm LOF score for each circuit asset on Entergy New Orleans’ T&D system. Assets included within the framework are wood poles, steel poles, concrete poles, lattice towers, overhead primary conductor, and overhead transmission conductor.

For the vegetation LOF scores, the Storm Impact Model uses the vegetation density of each overhead primary and transmission conductor normalized for length. Section 3.4 outlines the approach to estimate the vegetation density for approximately 1,400 primary and transmission conductors. Each primary and transmission conductor is one span from structure to structure. The vegetation density, normalized for length, is used in the LOF framework to calculate an LOF score for vegetation. Overall, the vegetation score contributes on average 11 percent of system LOF depending on the storm scenario.

Figure 5-2: Storm LOF Framework for Circuit Assets



For the age LOF, the Storm Impact Model utilizes 1898 & Co.'s asset management solution, AssetLens Solutions, to estimate the age based LOF for each wood pole, metal structure, overhead primary conductor, and transmission conductor. Section 3.6 includes additional details on the approach and LOF results. Overall, the age score contributes on average 5 percent of system LOF depending on the storm scenario.

The wind design gap criteria use the wind zone designation data from Section 3.5 inside the asset LOF framework to develop the LOF scores. Overall, the wind zone contributes on average 83 percent of system LOF depending on the storm scenario.

The Storm Impact Model uses the sum of the three criteria (vegetation, age, and wind design gap) to calculate the total storm LOF for each asset. The assets are then totaled up to the project level, providing a granular understanding of the LOF for each project. The Storm Impact Model uses the storm LOF scores to identify the circuit project LOF for each storm event in the Major Storms Event Database.

5.3 Project & Asset Reactive Storm Restoration

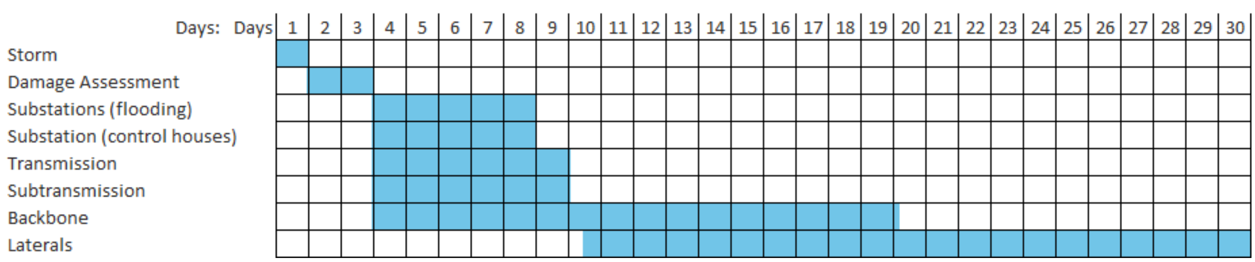
The Storm Impact Model estimates the cost to repair assets from a storm-based failure on a system section by system section basis. Storm restoration costs were calculated for every asset in the Storm Impact Model including wood poles, overhead primary conductor, transmission structures (steel, concrete, and lattice), transmission conductors, power transformers, relays, and breakers. The costs were based on storm restoration costs multipliers above planned replacement costs. These multipliers were developed by Entergy New Orleans and 1898 & Co. collaboratively. They are based on historical events, the expected inventory constraints, and expected mix of Entergy New Orleans and non-Entergy New Orleans crews needed for the various asset types and storms.

For each storm event, the restoration costs at the asset level are aggregated up to the project level and then weighted based on the project LOF (Section 5.2) and the overall restoration costs for the storm event outlined in the Major Event Storms Database.

5.4 Duration and Customer Impact

The Storm Impact Model calculates the duration to restore each project in the Status Quo Scenario. The assumptions for major asset class outage duration are outlined in the Major Event Storms Database. Figure 5-3 provides an example duration profile for the Category 4 and above storm event.

Figure 5-3: Example Storm Duration Profile



The project specific duration is based on percent complete vs percent time curves for each major asset class. The projects are ranked by metrics that are similar to those that Entergy New Orleans uses to prioritize storm restoration activity, such as priority/critical customers and customer count. Specific project durations are calculated based on completion vs time curves. For example, using the example from the figure above, a lateral project may have a relatively high priority (i.e., customer count is high with more critical customers). That lateral would be restored by day 10 of the profile above for a Category 4 event. However, the lowest ranked laterals will have project durations in the 30-day range for this category storm event.

The project duration is then multiplied by the number of affected customers for each project (see Section 3.3) to calculate the CMI for each project. Some of the storm scenarios include significant outages to the transmission system (see Section 3.11). The percentage of the system impacted is so high that the designed resilience and redundancy (looping) of the system are lost for a short period of time, which in turn causes large numbers of customer outages across the area from the transmission system. The Storm Impact Model allocates customer outages from these events to the various parts of the Entergy New Orleans transmission system based on transmission system operating capacity and the relevant assets' overall importance to the electric system.

Finally, the CMI for each project for each storm event is monetized using the DOE's ICE Calculator (see Section 3.9). The monetization is performed for each type of customer: residential, small commercial and industrial, large commercial and industrial, and the various priority customers. The monetization of CMI is calculated for project prioritization purposes as discussed below in Section 6.0.

5.5 Status Quo and Hardening Scenarios

The Storm Impact Model calculates the storm restoration costs and CMI for the Status Quo and Hardening Scenarios for each project for each of the 49 storm events. The delta between the two scenarios is the benefit for each project. This is calculated for each storm event based on the change to the core assumptions (vegetation density, age, wind zone, flood level, restoration costs, duration, and customers impacted) for each project.

The output from the Storm Impact Model is a project-by-project, probability-weighted estimate of annual storm restoration costs, annual CMI, and annual monetized CMI for both the Status Quo and Hardened Scenarios for all 49 major storm scenarios. The following section describes the methodology utilized to model all 49 major storms and calculate the resilience benefit of each project.

6.0 RESILIENCE NET BENEFIT CALCULATION MODULE

The Resilience Benefit Calculation Module of the Storm Resilience Model uses the annual benefit results of the Storm Impact Model and the estimated project costs to calculate the net benefits for each project. Since the benefits for each project are dependent on the type and frequency of major storm activity, the Resilience Benefit Module utilizes stochastic modeling, or Monte Carlo Simulation, to randomly select a thousand future worlds of major storm events to calculate the range of both Status Quo and Hardened restoration costs and CMI. The benefit calculation is performed for a 50-year time horizon, matching the expected life of hardening projects.

The following sections provide additional detail on the project costs, Monte Carlo Simulation, and feeder automation.

6.1 Economic Assumptions

The resilience net benefit calculation includes the following economic assumptions:

- Period: 50 years – most of the hardening infrastructure will have an average service life of 50 or more years
- Escalation Rate: 2.5 percent
- Discount Rate: 7.5 percent

6.2 Project Cost

Project costs were estimated for the approximately 10,000 projects in the Storm Resilience Model. Certain project costs were provided by Entergy New Orleans while others were estimated using the data within the Storm Resilience Model to estimate scope (asset counts and lengths) and then multiplying by unit cost estimates to calculate the project costs. The following sub-sections outline the approach to calculate project costs for each of the programs.

6.2.1 Distribution Feeder and Lateral Hardening

6.2.1.1 Rebuild

For each project, Entergy New Orleans' GIS data, GIS analysis for vegetation, underlying terrain, and road access were leveraged to estimate:

- Number of structures that need to be hardened to meet the desired wind standard;

- Length and phase count of conductor that would be replaced along with newly hardened structures; and
- Vegetation, distance to a road, and terrain type for the structures to be hardened.

Each of these values creates the scope for each of the projects. 1898 & Co. collaborated with Entergy New Orleans to develop unit costs estimates, which are multiplied by the scope activity (asset counts and lengths) and other cost drivers (vegetation, access, and terrain) to calculate the project cost.

6.2.1.2 Overhead to Underground Conversion

For each project, Entergy New Orleans' GIS data was used to determine the length of overhead conductor to be converted to underground, and additional GIS analysis determined the population density used for the cost per mile.

6.2.2 Transmission Rebuild

For each transmission project, Entergy New Orleans' GIS data, GIS analysis for vegetation, underlying terrain, and road access were leveraged to estimate:

- Number of structures that need to be hardened to meet the desired wind standard;
- Length of conductor that would be replaced along with newly hardened structures; and
- Vegetation, distance to a road, and terrain type for the structures to be hardened.

Each of these values creates the scope for each of the projects. 1898 & Co. collaborated with Entergy New Orleans to develop unit costs estimates, which are multiplied by the scope activity (asset counts and lengths) and other cost drivers (vegetation, access, and terrain) to calculate the project cost.

6.2.3 Substation Control House Roof Remediation

Control house roof remediation costs are dependent on several factors. The condition of the roof, its vintage, and its size all determine what type of remediation is needed to get the roof up to the current wind standard. Entergy New Orleans provided a base cost for substation storm surge mitigation projects that was intended to be generally conservative.

6.2.4 Substation Storm Surge Mitigation

Substations are a complex system of assets. Although the modeling done by 1898 & Co. identifies substations that are at risk of storm surge flooding, the mitigation measures required may differ widely from substation to substation. Therefore, the costs can vary widely as well. Entergy New Orleans provided a base cost for substation storm surge mitigation projects that was intended to be generally conservative.

6.3 Resilience-weighted Lifecycle Benefit

The benefits of storm resilience projects are driven by the frequency, intensity, and location of future major storm events over the next 50 years. Each storm type has a range of potential probabilities and consequences. For this reason, the Storm Resilience Model employs stochastic modeling, specifically Monte Carlo Simulation, which is a random sampling methodology.

In the context of the Storm Resilience Model, the Monte Carlo simulator selects the major storm events to impact the Entergy New Orleans service area over the next 50 years from the Major Storms Event Database (see Section 4.0). That database outlines the 'universe' of storm event types that could impact the Entergy New Orleans service area.

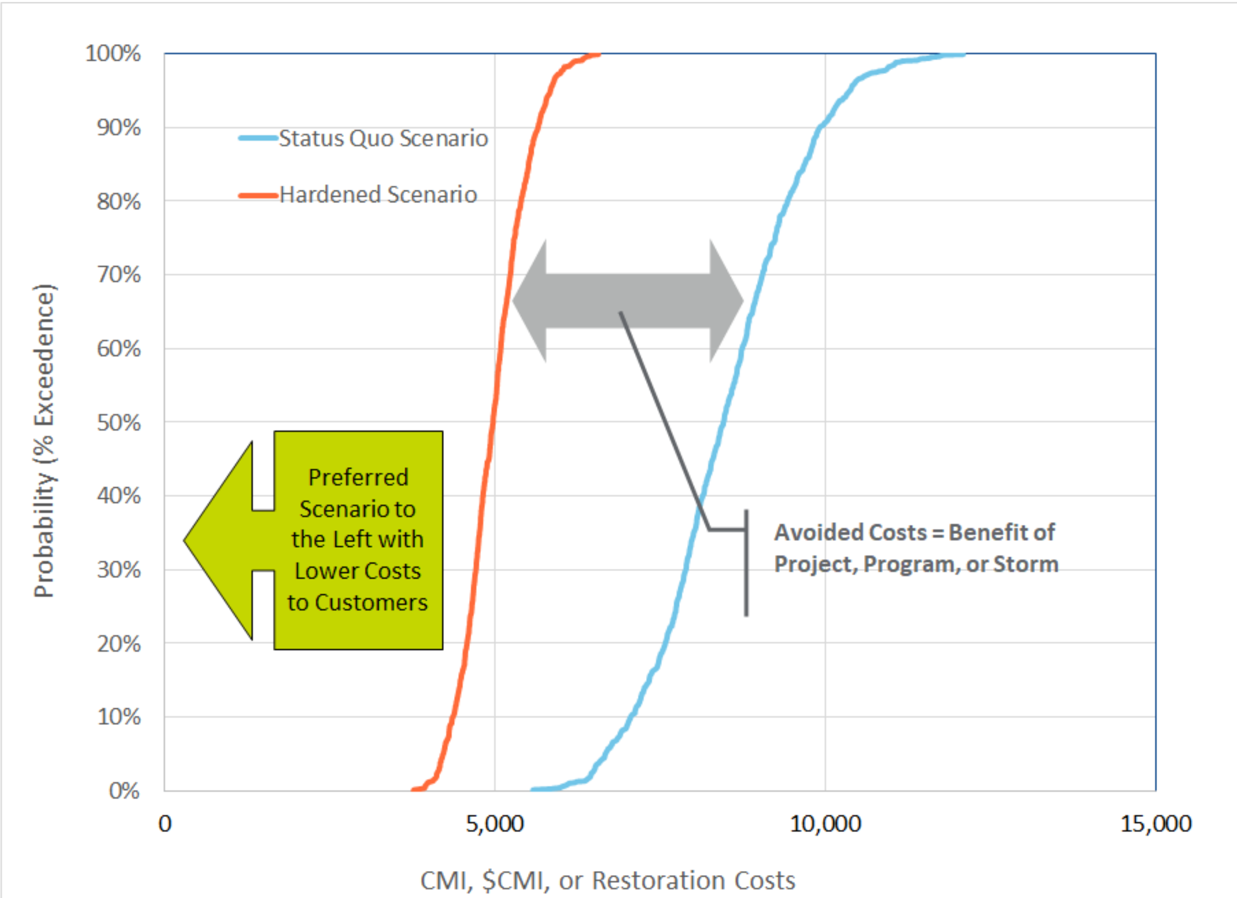
During the Monte Carlo simulation, each of the system sections are subjected to the range of 49 storm types and frequencies discussed in Section 4.0. For each iteration, storm types, and system section, the Monte Carlo simulator looks that the range of 50-year frequencies and selects the annual frequency for that iteration. For sections of the system where a storm type is not a valid choice, the Monte Carlo simulation chooses zero percent. Once the annual probability is selected for a system section, it is used in that iteration for each project developed from the Storm Impact Model.

Once an annual frequency is calculated for all storm types in a system section, the Monte Carlo simulator determines the benefits that each project provides annually under each iteration and its storm probability choices. Using information from the Storm Impact Model, the Monte Carlo simulator chooses a Status Quo value for each project and the benefits if that project were to be hardened, both under the same storm type. The Monte Carlo simulator performs these calculations for each project for 1,000 iterations.

The results of the 1,000 iterations are graphed in a cumulative density function, also known as an 'S-Curve'. The figure below shows an illustrative example of the 1,000 iteration simulation results for the

Status Quo and Hardened Scenarios. The resilience benefit of the project, program, or plan is the gap between the S-curves for the top part of the curve. Section 2.4 describes this in further detail.

Figure 6-1: Status Quo and Hardened Results Distribution Example



7.0 INVESTMENT OPTIMIZATION

The Storm Resilience Model models the benefits of all potential hardening projects for an 'apples to apples' comparison. Sections 3.0, 4.0, 5.0, and 6.0 described the approach and methodology to calculate the resilience benefit for the nearly 10,000 potential hardening projects. Resilience benefit values include:

- CMI 50-year Benefit
- Restoration Cost 50-year PV Benefit
- Lifecycle 50-year PV gross Benefit (monetized CMI benefit + restoration cost benefit)
- Lifecycle 50-year PV net Benefit (monetized CMI benefit + restoration cost benefit – project costs)

Each of these values includes a distribution of results from the 1,000 iterations. For ease of understanding and in alignment with the resilience base strategy, the approach focuses on the values for the average storm futures and above, specifically considering:

- P50 – Average Storm Future
- P75 – High Storm Future
- P95 – Extreme Storm Future

With all the projects being evaluated on a consistent basis, they can all be ranked against each other and compared. The Storm Resilience Model ranks all the projects based on their benefit cost ratio using the life cycle 50-year PV gross benefit value listed above. The ranking is performed for each of the following storm futures as well as a weighting of the three.

- Average Storm Future
- High Storm Future
- Extreme Storm Future

Performing prioritization for the four benefit cost ratios is important since each project has a different slope in its benefits from an average storm future to a very high storm future. Entergy New Orleans and 1898 & Co. settled on weighting the three values for the base prioritization metric.

8.0 RESULTS & CONCLUSIONS

Entergy New Orleans and 1898 & Co. utilized a resilience-based planning approach to identify and prioritize resilience investment in the T&D systems. This section presents the costs and benefits as determined by the foregoing analysis. Customer benefits are shown in terms of the:

1. Decrease in the Storm Restoration Costs
2. Decrease in the customers impacted and the duration of the overall outage, calculated as CMI

Additionally, the results are presented assuming monetization of the CMI using the DOE's ICE Calculator, modified for resilience. The DOE's ICE Calculator is discussed in Section 3.9. The monetization of the CMI allows for the calculation of a benefit cost ratio for each project. As discussed above, this was done for the purposes of prioritization of projects and establishing overall investment levels for consideration.

8.1 Resilience Benefit Cost Ratio

As discussed above in Section 6.3, the Storm Resilience Model calculates the Resilience Benefit Cost Ratio for project prioritization purposes. The Resilience Benefit Cost Ratio (BCR) is the sum of the avoided restoration cost and the monetized avoided customer outages divided by the project cost. A weighted value of the BCRs for different storm futures is used to calculate the final Resilience Benefit Cost Ratio for each hardening project.

Figure 8-1 shows the results of the Resilience Benefit Cost Ratio for all potential hardening projects across the Entergy New Orleans service territory. For each alternative (e.g. hardened rebuild vs undergrounding), the model determined a BCR, and the higher BCR is preferred. The preferred potential hardening project is the overhead hardening or undergrounding alternative that provides the higher Resilience Benefit Cost Ratio. The figure shows approximately 4,600 potential hardening projects were included in the evaluation. It should be noted that the evaluation considered both overhead hardening and underground conversion alternatives projects for most parts of the system for over 9,600 potential projects. The figure shows that approximately 42 percent of the potential hardening projects (by project count) have a Resilience Benefit Cost Ratio greater than 1. The figure also shows that approximately $1.86 billion of investment (over the next 10 years) has a Resilience Benefit Cost Ratio greater than 1. This is equivalent to 77 percent of the total hardening investments across all potential hardening projects. Most of the projects with a positive Resilience Benefit Cost Ratio are in the 1 to 10 range.

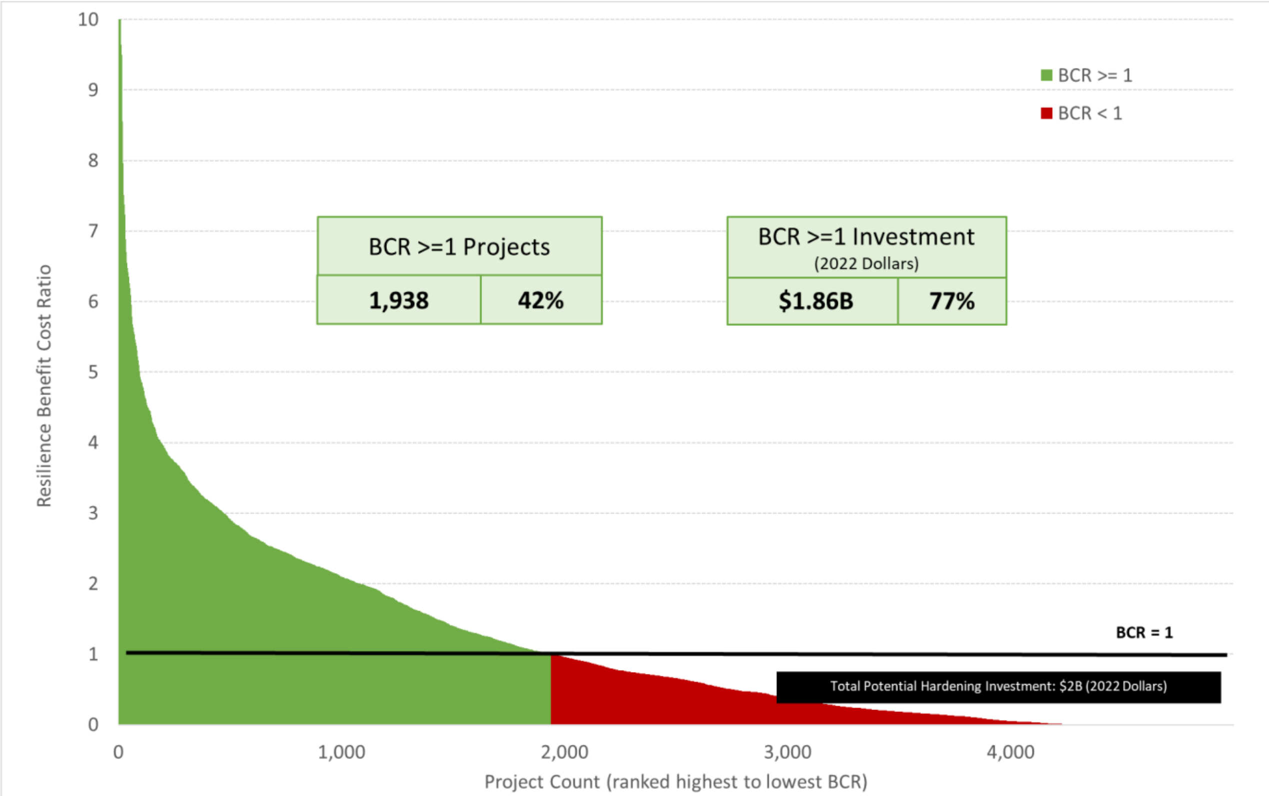


Figure 8-1: Project Resilience Benefit Cost Ratio Summary

8.2 Investment Scenarios

Entergy New Orleans and 1898 & Co. used a multi-stage process to arrive at three potential investment levels.

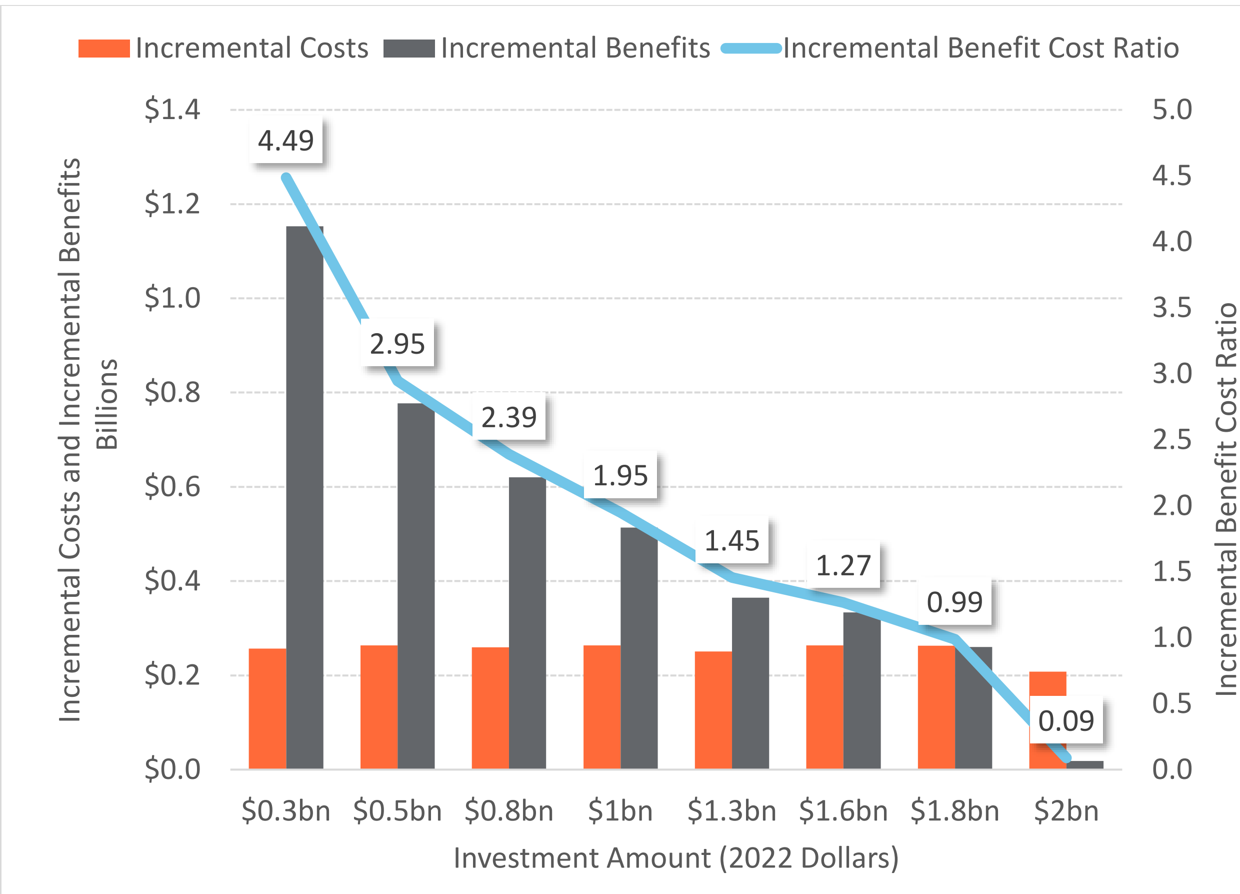
- Stage 1 – Find the appropriate investment level for Entergy New Orleans at which future incremental investments yield benefits that are less than the incremental costs. The result is $1.8 billion of investment in projects that are cost beneficial.
- Stage 2 – Refine the investment portfolio to determine what is most likely feasible in the next several years with currently known labor and equipment constraints. The result is $1.3 billion of investment that could be performed from 2024 through 2033. Detailed results are provided in this report for this scenario.
- Stage 3 – Use the projects identified in Stage 2 (the $1.3 billion investment level) to develop two additional scenarios. The two other scenarios explore tradeoffs in benefits and cost for investment levels below the technical constraint scenario. These scenarios provide proactive

insight for evaluating the next several years of resilience investment. The two additional scenarios have total investment levels $1.0 billion and $750 million over the next 10 years.

8.2.1 Stage 1 Results

The first stage utilized a resilience-based planning approach to understand the 'point of diminishing' returns and identify and prioritize resilience investment in the T&D system. Given the total level of potential investment, the Investment Optimization analysis was performed in approximately $260 million increments ($260 million in 2022 dollars is approximately $290 million in nominal terms when escalated) up to $2 billion (in 2022 dollars). Figure 8-2 shows the results of the Investment Optimization analysis comparing the incremental costs to the incremental benefits at each budget level.

Figure 8-2: Investment Optimization Results



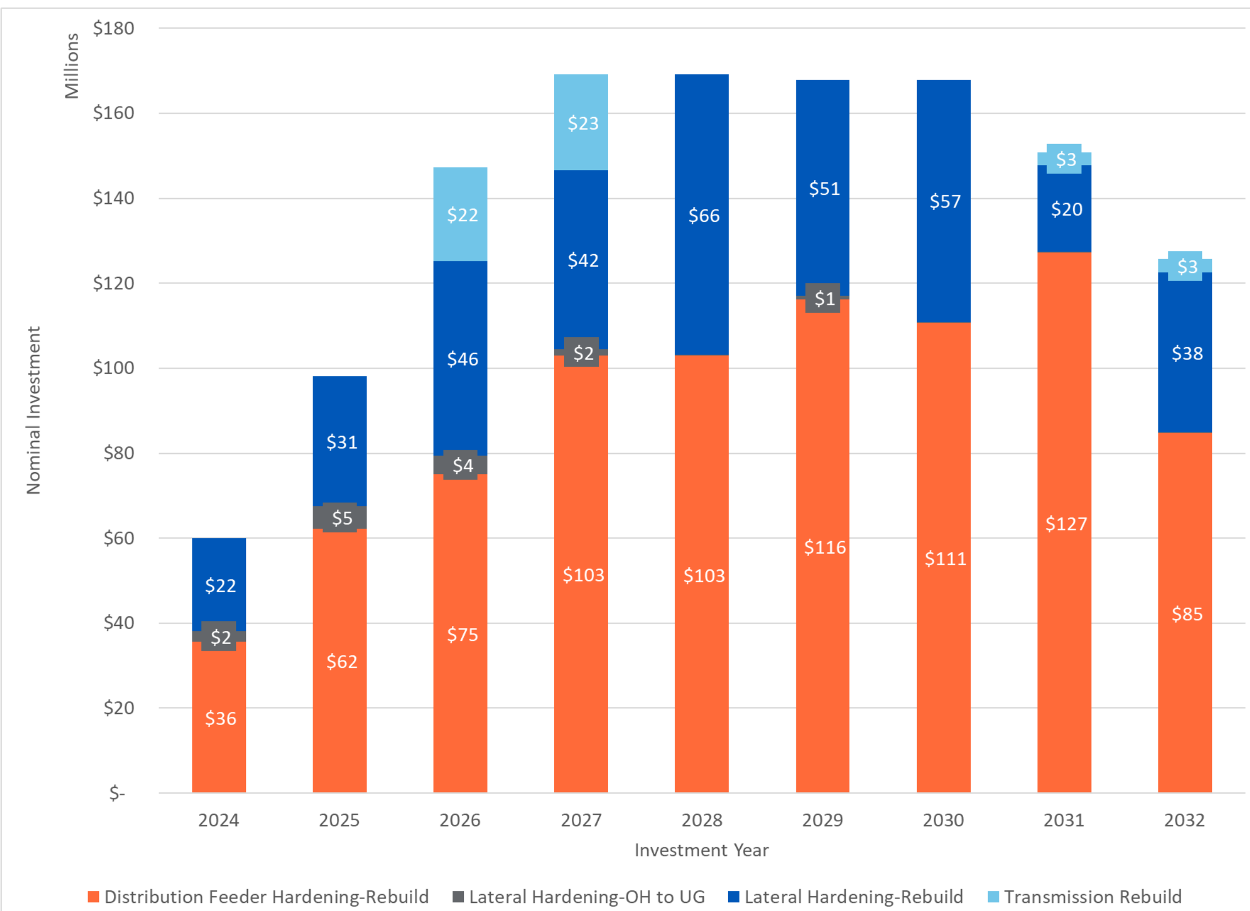
The figure shows that the point of diminishing returns occurs at an investment level of approximately $1.8 billion in 2022 dollars; when that level of investment is exceeded, the incremental costs begin to exceed the incremental benefit.

8.2.2 Stage 2 Results

In the second stage of the investment evaluation process, Entergy New Orleans and 1898 & Co. refined the $1.8 billion scenario with technical execution constraints due to labor and materials availability. With these constraints included, the resulting investment profile scenario is $1.3 billion (nominal) (or $1.1 billion in 2022 dollars).

Figure 8-3 shows annual spending for the $1.3 billion (nominal) scenario from the second stage. The figure includes the build-up by program to the total. The investment capital costs are in nominal dollars; that is, the dollars of that day. In this scenario, Distribution Feeder Hardening (Rebuild) projects make up the single largest portion of the total, accounting for 65 percent of the total investment. Lateral Hardening (Rebuild) projects are next, with 30 percent. Transmission (Rebuild) projects make up 4 percent, and Lateral Undergrounding projects make up approximately 1 percent.

Figure 8-3: Investment Profile ($1.3 Billion Scenario)

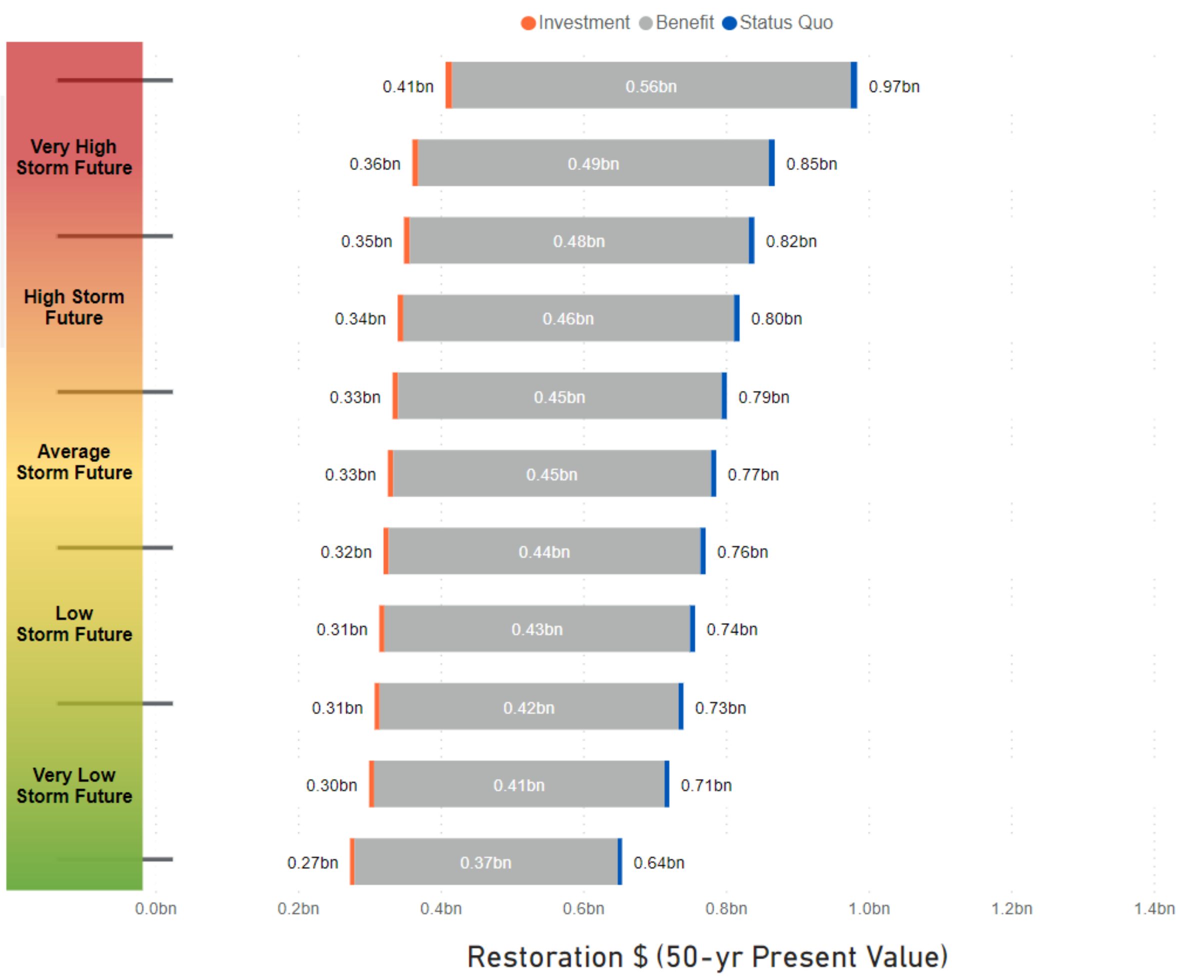


8.2.2.1 Avoided Restoration Cost Benefits

Figure 8-4 shows the range in restoration cost reduction at various storm futures for the $1.3 billion scenario. The values are shown in 50-year present value terms. It should be noted that the figure is based on the $1.3 billion investment scenario. The figure shows the benefits of this level of investment; the benefit values do not include the $1.3 billion of investment.

As a refresher, the very low storm future level represents a future world in which storm frequency and impact are less than average. The average storm future level represents a future world where storms frequency and impact are reflective of historical trends discussed in Section 4.3. The very high storm future levels represent a future world where storm frequency and impact are all high.

Figure 8-4: Restoration Cost Benefit ($1.3 Billion Scenario)

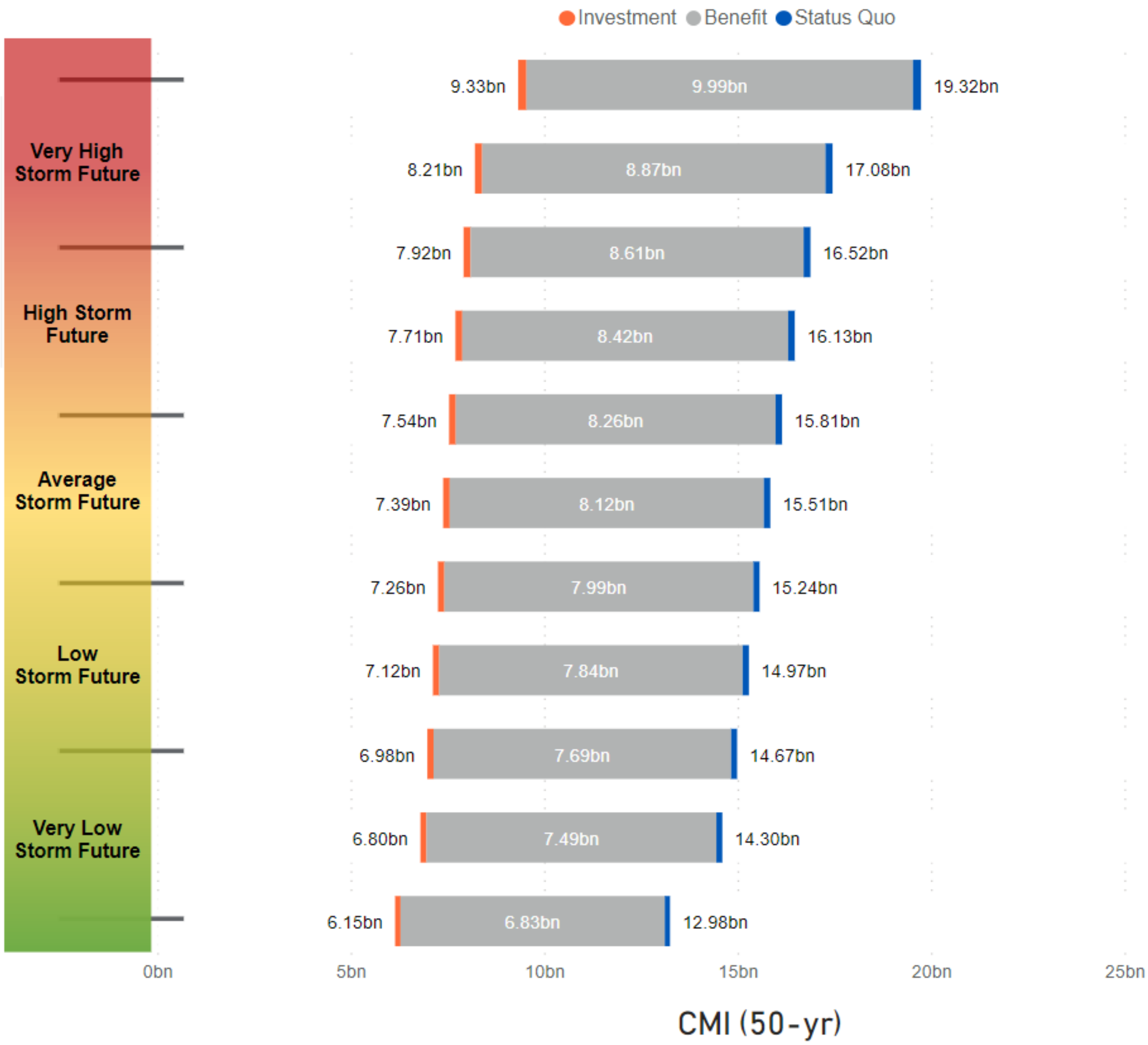


The figure shows that the 50-year PV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $640 million to $970 million. With the $1.3 billion investment level, the storm restoration costs are reasonably expected to decrease by approximately 50 percent. The decrease in expected restoration costs is approximately $370 million to $560 million. From a PV perspective, the expected restoration costs decrease benefit is approximately 37 to 55 percent of the costs in 2022 dollars. In other words, the avoided restoration cost benefits alone pay for approximately 37 to 55 percent of the investment plan in this scenario.

8.2.2.2 Avoided Customer Outage Benefit

Figure 8-5 shows the range in avoided storm customer minutes interrupted at various storm futures for the $1.3 billion scenario. The values are shown for a 50-year period. The figure shows that the 50-year total of future storm CMI in a Status Quo scenario from a resilience perspective is 12.98 billion to 19.32 billion. With this scenario, storm customer outages are reasonably expected to decrease by approximately 55 percent.

Figure 8-5: Customer Benefits ($1.3 Billion Scenario)



8.2.2.3 Resilience Benefit Cost Ratio

Section 8.1 shows the Resilience Benefit Cost Ratio results for all the individual projects within the $1.3 billion investment. This section shows the Resilience Benefit Cost Ratio for the $1.3 billion investment portfolio. It also includes the path from the two main benefit streams to calculating the Resilience Benefit Cost Ratio. It is important to note that the business case of the scenario is based upon the avoided restoration costs and avoided customer outages that reasonably can be expected to be achieved from the proposed investment. The Resilience Benefit Cost Ratio results for the $1.3 billion investment plan are only presented to show weighted average project prioritization for the portfolio.

A key piece of that path is the monetization of the storm CMI. Figure 8-6 shows the companion figure to Figure 8-5 based on the monetization of the storm CMI using the DOE ICE Calculator modified for resilience purposes. The values are shown in 50-year present value terms. Again, it should be noted that the figure is based on the $1.3 billion scenario. The figure shows the benefits of this level of investment; the benefit values do not include the $1.3 billion of investment.

Figure 8-6: Monetized Customer Benefit ($1.3 Billion Scenario)

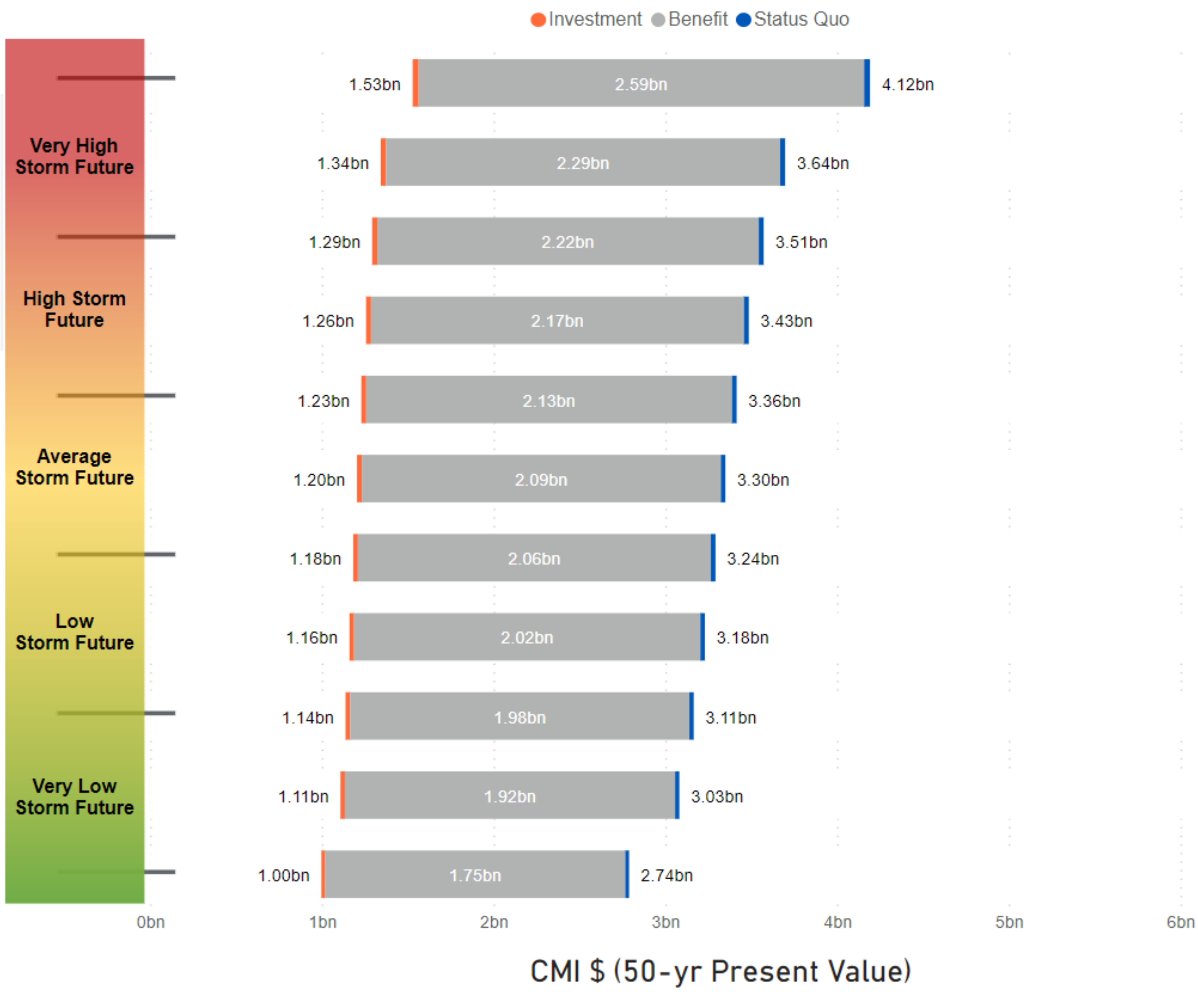


Figure 8-7 shows the sum of the restoration cost and monetized CMI for the Status Quo and Stage 2 investment plan scenario.

Figure 8-7: Total Monetized Benefit (Restoration + $CMI) ($1.3 Billion Scenario)

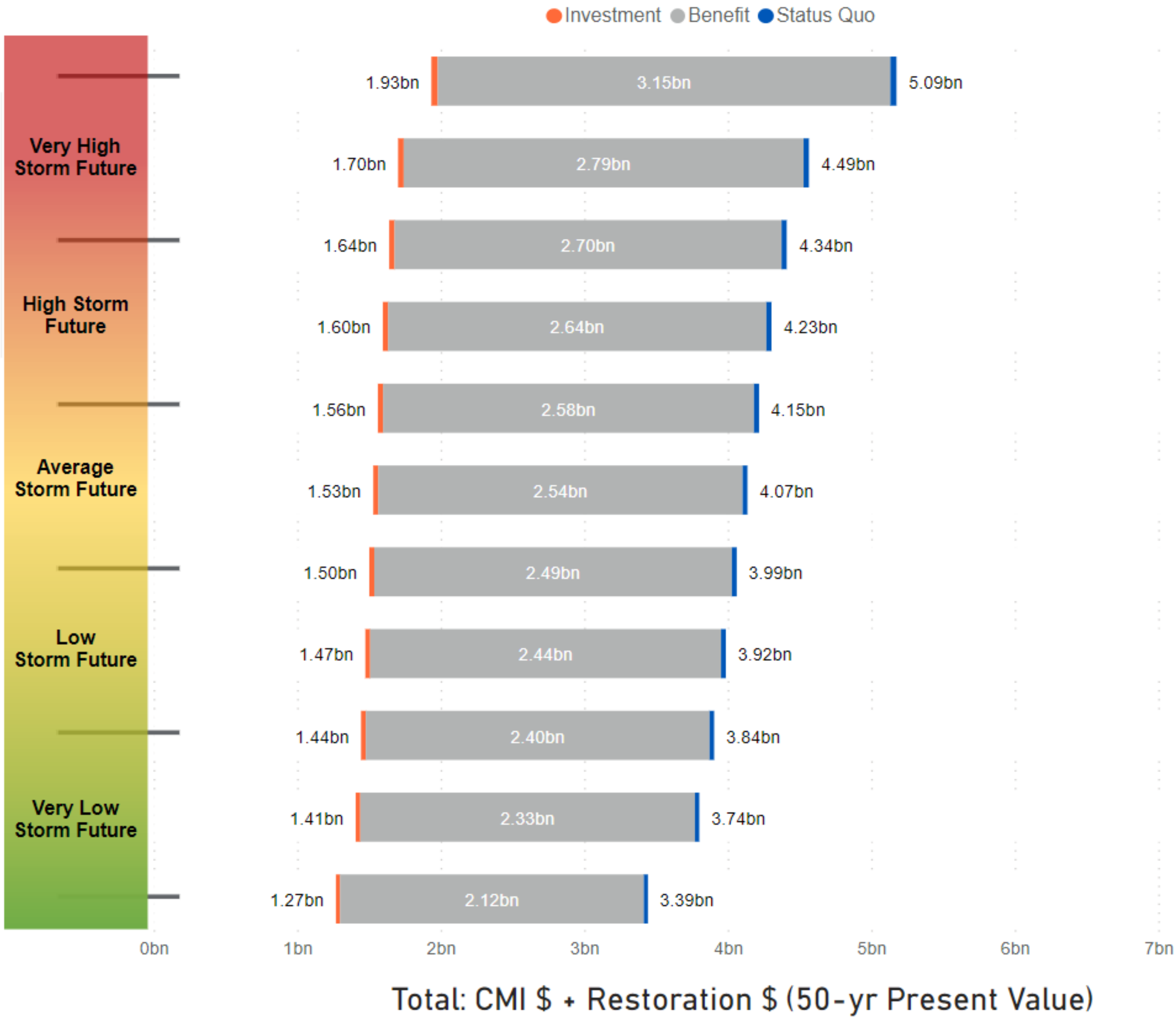


Figure 8-8 shows the portion of the total monetized benefit that comes from the avoided restoration costs and the portion from the monetized avoided customer outages. The figure also includes the total cost of the scenario in 2022 dollars, approximately $1.1 billion ($1.3 billion nominal).

Figure 8-8: Gross Benefit vs Costs ($1.3 Billion Scenario)

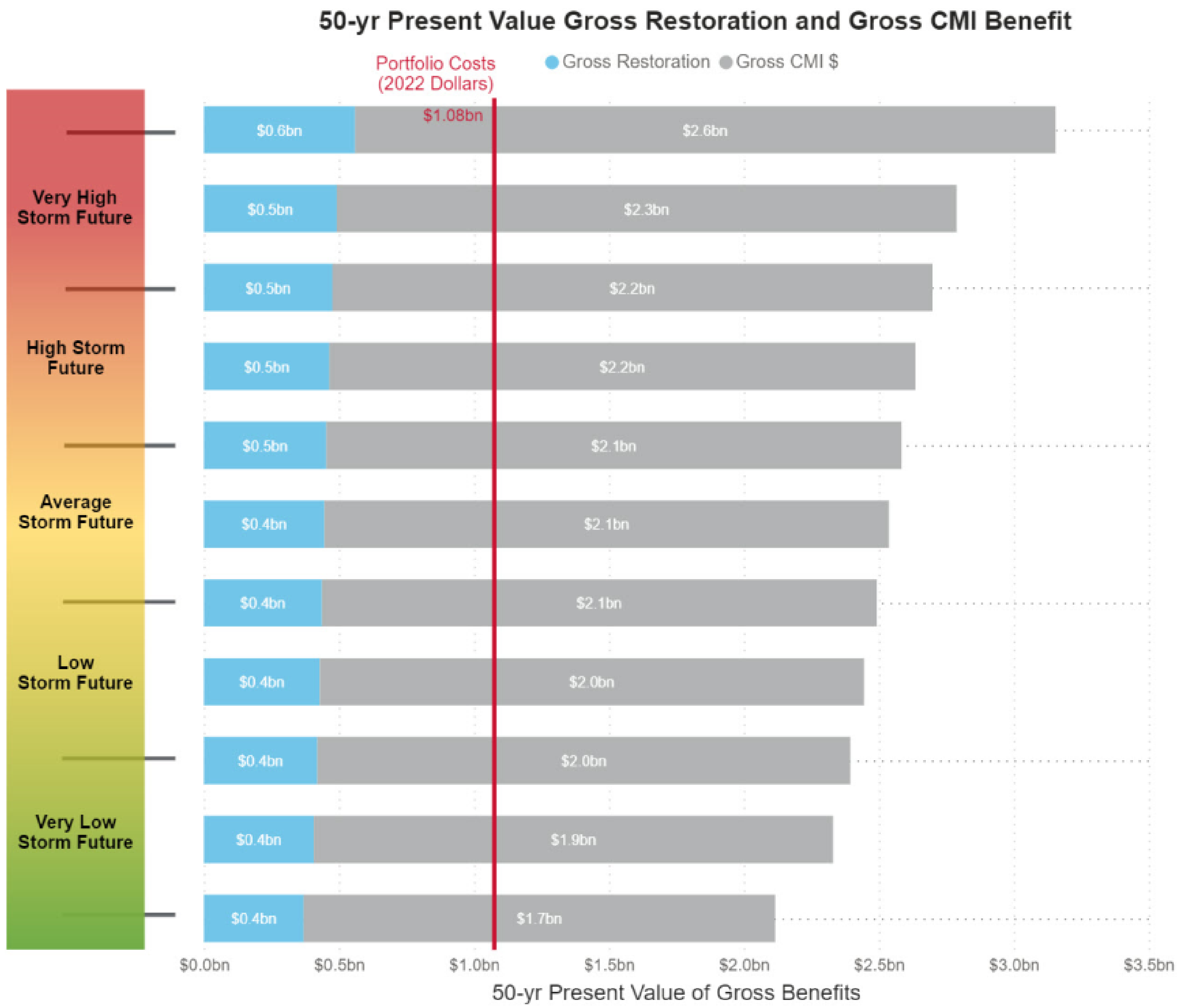
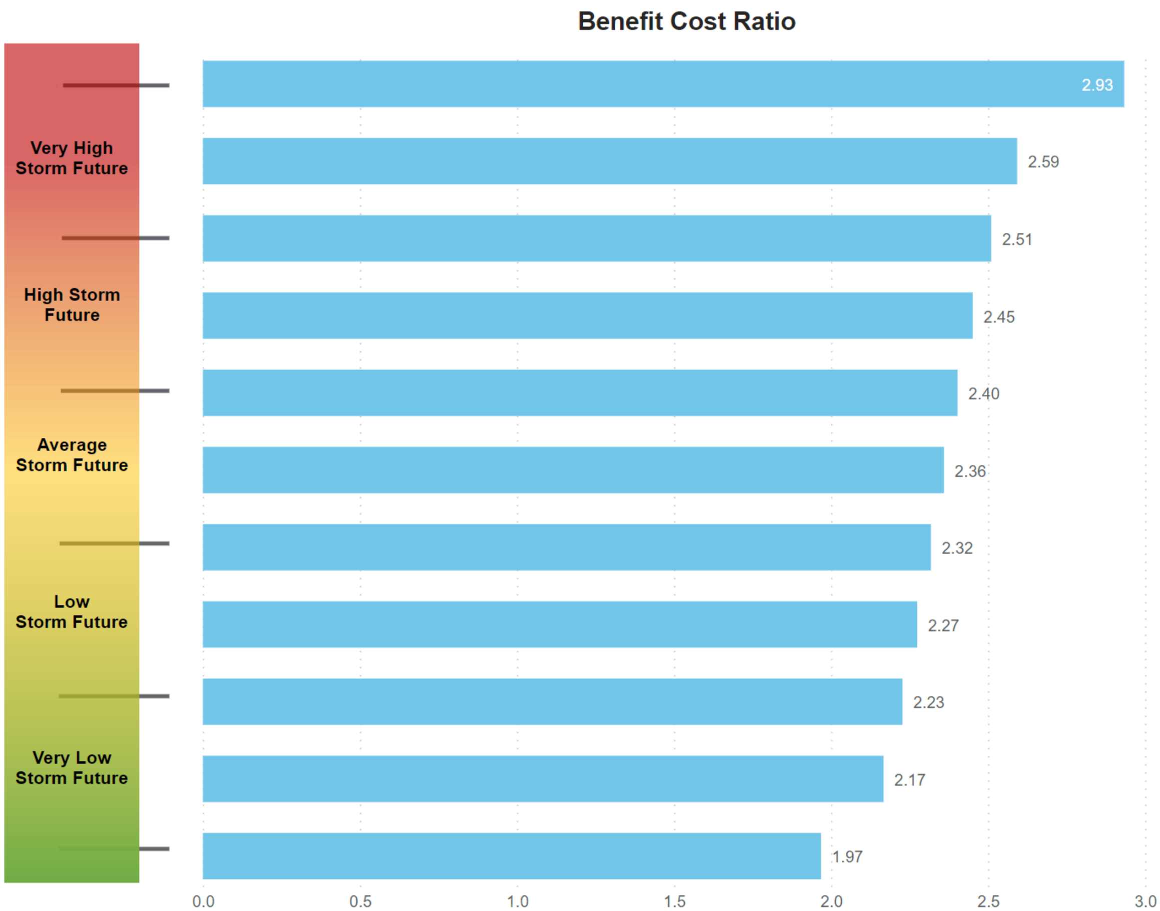


Figure 8-9 converts the gross benefits and costs from Figure 8-8 into the Resilience Benefit Cost Ratio for the $1.3 billion scenario. The figure shows that the overall $1.3 billion investment plan has a Resilience Benefit Cost Ratio as low as 2.0 in a very low storm future and as high as 3.0 in a very high storm future scenario. The average storm future scenario has a Resilience Benefit Cost Ratio of 2.4. This figure and the others above show that the projects included in the $1.3 billion scenario can reasonably be expected to provide significant benefits to customers in excess of cost.

Figure 8-9: Portfolio Resilience Benefit Cost Ratio ($1.3 Billion Scenario)



8.2.3 Stage 3 Results

In the third and final stage of the investment scenario analysis, Entergy New Orleans and 1898 & Co. created two investment plans for additional analysis. The goals of the three investment scenarios are to explore tradeoffs in benefits and cost for investment levels below the $1.3 billion investment scenario (Stage 2). The investment scenarios developed in stage two are:

- $1.0 billion (nominal dollars) – mid level investment scenario
- $750 million (nominal dollars) – low level investment scenario

Figure 8-10 below illustrates the annual investment levels for the $1.3 billion, $1 billion, and $750 million scenarios. Overall, these annual investment profiles accommodate the business processes and resources required to begin ramping up investment and construction of this magnitude.

Figure 8-10: Annual Investment by Scenario (Nominal $)

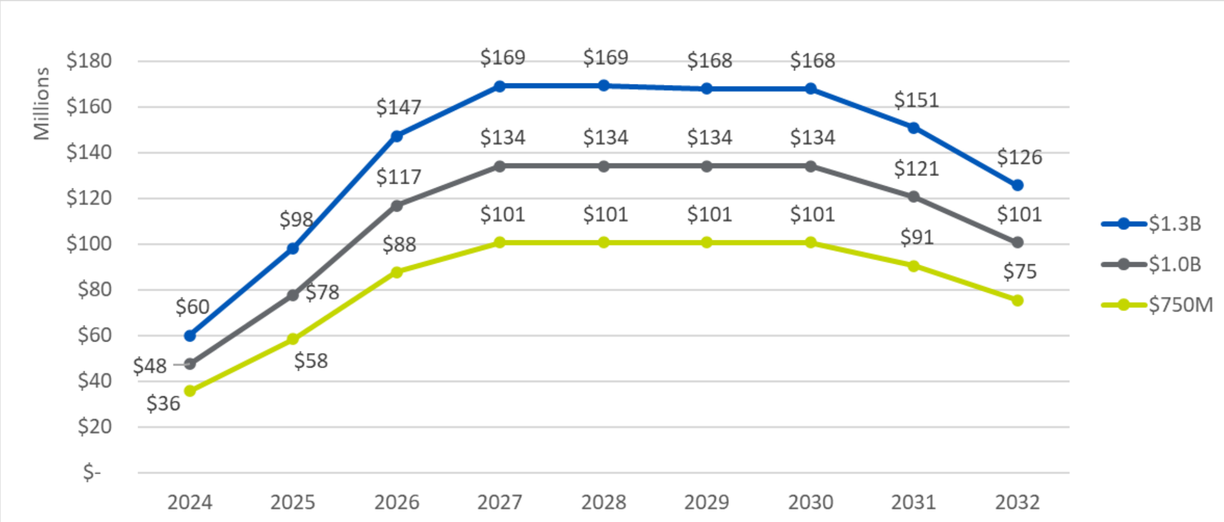


Table 8-1 shows the 50-year lifecycle benefits for each of the budget scenarios. The benefits are summarized at the weighted prioritization metric level (see Section 7.0) that evaluates benefits at multiple storm future levels. As the table shows, each of the scenarios has a positive business case. The lowest level of investment, $750 million, has the highest BCR of 3.06, with declining ratios as the investment level increases to a BCR of 2.55 at the $1.3 billion scenario. This decline in the overall benefit to cost ratios as investment increases is expected.

Table 8-1: Summary of Storm Resilience Benefits for Stage 3 Scenarios

Metric	$1.3 Billion Scenario	$1.0 Billion Scenario	$750 Million Scenario
Weighted Avoided Storm Restoration Cost Benefits	$473 M	$390 M	$297 M
Weighted Avoided Storm Customer Benefits (CMI)	8.4 billion	7.1 billion	5.8 billion
Weighted Avoided Storm Monetized Customer Benefits	$2.3 billion	$2.0 billion	$1.7 billion
Weighted Avoided Storm Monetized Total Benefits	$2.7 billion	$2.4 billion	$1.9 billion
Benefit to Cost Ratio	2.55	2.78	3.06

Table 8-2 summarizes the tradeoffs in benefits to move from the $1.3 billion scenario to the two alternative, stage 3-developed scenarios. The table shows a decrease in upfront investment costs of approximately $220 million with the $1.0 billion scenario compared to the $1.3 billion scenario and $434 million savings with the $750 million scenario. From a benefits perspective, the $1.0 billion scenario has a decrease in 50-year lifecycle customer benefits of $356 million and $775 million for the $750 million scenario. From an opportunity cost perspective, the $1.0 billion scenario is a decrease in net benefits of $136 million and $341 million for the $750 million scenario. In other words, moving from the $1.3 billion scenario to the $1.0 billion scenario is equivalent to foregoing a set of projects with a benefit to cost ratio of 1.6. Moving to the $750 million scenario is equivalent to foregoing a set of projects with a benefit to cost ratio of 1.8. Decreasing the overall investment level even further would be foregoing sets of projects with increasingly higher benefit to cost ratios.

Table 8-2: Incremental Benefit and Cost Summary to 1.3 Billion Scenario

Metric	$1.0 Billion Scenario	$750 Million Scenario
Plan Investment Level (2022$)	-$220M	-$434M
Weighted Avoided Storm Customer Benefits (CMI)	-1.3 billion	-2.6 billion
Weighted Avoided Storm Restoration Cost Benefits	-$83M	-$176M
Weighted Avoided Storm Monetized Customer Benefits	-$273M	-$599M
Weighted Avoided Storm Monetized Total Benefits	-$356M	-$775M
Weighted Avoided Storm Monetized Net Benefits	-$136M	-$341M
Opportunity Cost Benefit to Cost Ratio	1.62	1.78

8.3 Conclusions

The following include the conclusions of investment scenarios evaluated within the Storm Resilience Model:

- There is significant opportunity for additional resilience investment in the New Orleans system. The resilience business case evaluated over 4,600 potential projects, and over 9,600 potential projects when including both overhead and underground alternatives, with approximately 42 percent having a positive business case. There is approximately $1.86 billion of positive BCR investment across the Company's system.
- An investment level of $1.8 billion is the "point of diminishing" returns. It is at this investment level that the impact of major events is optimally mitigated to maximize the decrease in the impact of major events while investing in the system to provide value to customers. While

additional investments could be made past this level to mitigate the impact of major events, they would not produce incremental benefits relative to their incremental costs. Due to technical constraints from material and labor, this scenario is currently not achievable.

- An overall investment level of $1.3 billion is technically achievable over the time horizon. This investment plan level provides significant benefits for customers, is reasonable, and provides customers with optimal benefits given execution constraints. This investment level is reasonably expected to:
  - Decrease storm restoration cost by approximately 50 percent over the 50-year time horizon. From a present value perspective, this decrease is approximately 37 to 55 percent of the overall $1.3 billion investment level.
  - Decrease storm customer outages by approximately 55 percent over the 50-year time horizon.
- Additional, lower investment levels provide an opportunity for Entergy New Orleans to continue to evaluate how to balance the near-term investment costs and impacts to customer bills. However, these lower investment levels come with tradeoffs in benefits. The $1.0 billion scenario has an opportunity cost of $136 million in net benefits and $341 million in net benefits for the $750 million scenario. In other words, moving from the $1.3 billion scenario to the $1.0 billion scenario is equivalent to foregoing a set of projects with a benefit to cost ratio of 1.6. Moving to the $750 million scenario is equivalent to foregoing a set of projects with a benefit to cost ratio of 1.8. Decreasing the overall investment level even further would be foregoing sets of projects with increasingly higher benefit to cost ratios.
- If enough of the Entergy New Orleans system is made resilient, customers will experience fewer storm outages from both direct and indirect factors. Direct benefits are realized by those customers whose infrastructure directly upstream was hardened. Indirect benefits are realized by all customers since storm restoration crews will be able to rebuild the system quicker because less infrastructure will fail.
- The hardening investment benefits are conservative. Firstly, the benefits outlined above are only direct benefits of investments to specific investments in the grid and do not factor in the indirect benefits from lower overall storm restoration durations. Secondly, the investments will also provide ‘blue sky’ benefits from decreased outages that occur during non-major storm days. Both of these benefit streams are not factored into the evaluation within the Storm Resilience Model.

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BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

IN RE: **SYSTEM RESILIENCY AND STORM HARDENING**	**)))**	**DOCKET NO. UD-21-03**

DIRECT TESTIMONY

OF

ALYSSA MAURICE-ANDERSON

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

APRIL 2023

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EXHIBITS

I. INTRODUCTION AND BACKGROUND

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Alyssa Maurice-Anderson. I am employed by Entergy Services, LLC ("ESL")[1] as the Director, Regulatory Filings and Policy. My business address is 639 Loyola Avenue, New Orleans, Louisiana 70113.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying before the Council of the City of New Orleans ("Council") on behalf of Entergy New Orleans, LLC ("ENO" or the "Company").

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a Master of Business Administration (concentration in Finance) from Tulane University's Freeman School of Business (2011), a Juris Doctor from Loyola University New Orleans School of Law (2002), and a Bachelor of General Studies from the University of New Orleans (1998). I joined the ESL Legal Department in 2001, and until August 2020, I held varying levels of responsibility supporting regulatory litigation matters. Most notably, beginning in 2008, my practice focused on leading rate matters filed by regulated subsidiaries of Entergy Corporation -- first for ENO, then for Legacy Entergy Louisiana, LLC ("Legacy ELL") and Legacy Entergy Gulf States Louisiana, LLC ("Legacy EGSL")

[1] ESL is a service company to the five Entergy Operating Companies ("EOCs"), which are Entergy Arkansas, LLC ("EAL"), Entergy Louisiana, LLC, Entergy Mississippi, LLC ("EML"), Entergy Texas, Inc., and Entergy New Orleans, LLC.

and then for both ENO and Entergy Louisiana, LLC. My responsibilities included providing legal advice and developing legal strategies necessary to file applications/requests on behalf of the referenced operating companies; manage and obtain approval of ratemaking treatments that resulted in rates that were just and reasonable to customers and the investor-owned utility; as well as various related duties, such as issuing probability assessments, drafting and reviewing inserts to disclosure documents, *etc*. The ratemaking treatments for which the companies sought approvals (and which I supported) sometimes were made as stand-alone proceedings, *e.g.*, rate case or Formula Rate Plan ("FRP") proceedings or in connection with major strategic initiatives, such as joining the Midcontinent Independent System Operator, Inc. ("MISO"), business separations, resource additions, *etc*.

In 2020, I transitioned from the legal department to ENO as Director, Regulatory Operations (Affairs), reporting directly to the President and Chief Executive Officer of ENO. As Director, Regulatory Operations, I contributed to the development of regulatory strategy, appeared on behalf of ENO before the Council, and interfaced with customers at public meetings. Additionally, with the support of several analysts and ESL's Regulatory Services organization, I was responsible for the coordination and/or submission of retail regulatory filings on behalf of ENO. In May 2021, I returned to ESL and since then have worked as Director, Regulatory Filings and Policy.

In my current role, I oversee the department that assists in coordination and execution of activities necessary to meet certain regulatory filing requirements applicable to the EOCs as providers of utility service. Those activities include extracting per book data and/or preparing *pro formas* to that data for use in the various regulatory filings submitted by and on behalf of the EOCs and System Energy Resources, Inc., as well as providing financial analytics that support certain strategic initiatives that require regulatory approvals. The deliverables resulting from this technical support take the form of revenue requirement and cost of service studies, responses to internal and external data requests for financial information, and explanation of policies used in regulatory proceedings. I am also responsible for providing testimony on certain policy issues and/or ratemaking treatments, including the types that are the subject of this regulatory proceeding.

Q4. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY BODIES?

A. Yes. I have submitted pre-filed testimony to the Louisiana Public Service Commission ("LPSC") and the Public Utility Commission of Texas. A list of my previously filed testimony is attached hereto as Exhibit AMA-1. I have also appeared as regulatory counsel on behalf of ELL and ENO before the LPSC and the Council, respectively.

II. PURPOSE OF TESTIMONY

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my direct testimony is to address financial and ratemaking issues raised by the proposed Resilience Plan, as described in the Application and by Company witnesses Sean Meredith and Jason De Stigter. First, I explain why a new contemporaneous recovery mechanism, the proposed Resilience & Storm Hardening Cost Recovery Rider ("Resilience Rider" or "Rider"), is necessary for ENO to undertake the proposed Resilience Plan. The Resilience Rider is attached as Exhibit AMA-2. ENO currently does not have a ratemaking mechanism that would permit timely cost recovery for the proposed

Resilience Plan projects. Without such a mechanism, undertaking the proposed Resilience Plan would compromise ENO's cash flow and credit metrics.

The credit ratings agencies downgraded ENO in 2021 based on a number of factors, including its financial performance and vulnerability to weather-related risks combined with its small service area, and stated that further downgrades are possible if financial pressures are not mitigated, and system resilience is not enhanced. ENO needs to improve its financial condition and credit ratings to protect its customers from higher capital costs, not only as to the Resilience Plan, but across ENO's entire business. Undertaking the Resilience Plan without a mechanism that provides contemporaneous cost recovery would be deleterious to improving ENO's financial stability. Therefore, ENO respectfully urges the Council approve the recovery of the revenue requirement associated with the Resilience Plan through the Resilience Rider.

A stable, long-term recovery mechanism for the duration of the Resilience Plan would allow the projects to be executed efficiently, in a steady manner. This would enable ENO to leverage economies of scale and maintain a qualified workforce by avoiding the starts and stops that would occur as rate changes are sought and decided. Contemporaneous cost recovery also is appropriate because as ENO completes the Resilience Plan projects, benefits are available to customers. An additional benefit of the Resilience Rider is that, in the event ENO receives funds that could mitigate the cost of resilience projects (e.g., federal grants), there is flexibility to offset investment and reduce the rate timely pursuant to a methodology contained therein. Further, as part of the true-up portion of the Resilience Rider, the Company will provide the Council with an annual report comparing the actual project costs with projected costs, along with explanations for material variances.

My testimony also discusses the applicable public interest standard and explains why the Resilience Plan, among related requests for relief, is in the public interest. My testimony also recommends how the public interest standard should be applied in the context of an accelerated resilience program.

Further, my testimony supports the requested ratemaking treatment related to transmission and distribution assets that must be retired and replaced with new assets as part of the Resilience Plan. Specifically, ENO requests authorization to create a regulatory asset for the remaining net book value associated with assets that must be retired and replaced with new assets under the Resilience Plan. ENO would include the regulatory asset in rate base and amortize such retired plant costs at a rate consistent with the associated depreciation expense currently reflected in rates. With the approval of the proposed regulatory asset and associated ratemaking treatment, customers would not see an increase in rates associated with ENO's recovery of assets prudently retired in connection with the Resilience Plan. Moreover, my testimony discusses an accounting waiver that ENO intends to request at the Federal Energy Regulatory Commission ("FERC"), which would mitigate near-term bill effects of the Resilience Plan on the Company's customers.

III. OVERVIEW OF THE RESILIENCE RIDER

Q6. PLEASE PROVIDE AN OVERVIEW OF THE RESILIENCE RIDER.

A. The proposed Resilience Rider, which is attached to my testimony as Exhibit AMA-2, would accomplish contemporaneous recovery of the Resilience Plan costs through a forward-looking rate that would also include a true-up associated with completed projects after a prudence review. ENO would make two filings each year, and the Resilience Rider's procedures would provide the Council and its Advisors (a) sufficient time to review the projects to be placed in service in the following calendar year and (b) determine the prudence of project execution based on actual data from the previous calendar year. ENO would calculate the Resilience Rider rate based on a percentage of base revenue.

Q7. PLEASE EXPLAIN THE TIMING FOR THE TWO FILINGS UNDER THE RESILIENCE RIDER.

A. ENO would file the new proposed Resilience Rider rates on or before October 1 of each year, and such rates would become effective the following January. Each filing would include a calculation of the Resilience Revenue Requirement and supporting workpapers regarding ENO's costs under the Resilience Plan to be incurred in the upcoming calendar year. Beginning August 1, 2025, and each August 1 thereafter, ENO would file the true-up of the previous calendar year's Resilience Revenue Requirement and supporting workpapers. Therefore, the Resilience Revenue Requirement included in the annual redetermination filing would include estimated costs to be incurred after January 1, 2024 associated with the Resilience Plan projects closing in the upcoming calendar year, and the true-up filing would reflect actual amounts incurred for the same category of costs incurred in previous calendar years.

Q8. WHAT COSTS WOULD BE RECOVERED THROUGH THE RESILIENCE RIDER?

A. The Resilience Rider would recover depreciation expense and a return on the projects in the Resilience Plan described by Mr. Meredith in his testimony. Accordingly, ENO would include the costs of those projects as described above in its calculation of the Resilience Revenue Requirement filed each October. The calculation would reflect a forward-looking revenue requirement. As stated here earlier, the Company would subsequently true-up the Resilience Revenue Requirement with carrying costs at the prime bank lending rate as published in the Wall Street Journal on the last business day of each month. This true-up would ensure the level of costs actually incurred was reflected in rates billed to customers.

Q9. COULD THE RESILIENCE RIDER ACCOMMODATE OTHER TYPES OF COSTS IN THE FUTURE?

A. Yes. The Resilience Rider could accommodate the recovery of other types of resilience investments if the Council ultimately did so authorize. The Resilience Rider includes placeholders for such costs in the event they are authorized by the Council. This flexibility would be beneficial in that it will enable recovery of costs associated with additional projects that meet the Council's evolving policies regarding resilience, such as microgrids, in a manner that builds on the Council's prior decisions in this area.

Q10. HOW WOULD THE RESILIENCE REVENUE REQUIREMENT BE CALCULATED?

A. ENO would calculate the Resilience Revenue Requirement based on Resilience Plan projects (a) in service but not recovered through another method and (b) projected to enter service in the upcoming calendar year. The Resilience Revenue Requirement would include liberalized depreciation accumulated deferred income taxes ("ADIT") in the calculation of the rate base; however, the effect on net operating loss ADIT from such liberalized depreciation ADIT would be reflected in base rates and/or included in a future

FRP rate adjustment. The estimated Before Tax Rate of Return is based on the projected weighted average cost of capital ("WACC") using the most recently approved return on equity as of December 31 of the current calendar year unless another capital structure is approved for ratemaking purposes. The return on rate base would be based on the estimated Before Tax Rate of Return multiplied by the end-of-period investment for the upcoming calendar year.

Depreciation expense would be calculated based on a weighted average annual depreciation rate of 3.24% for distribution investments and a 2.33% annual depreciation rate for transmission investments, multiplied by the end-of-period resilience investment for the upcoming calendar year.[2] ENO would use these rates for purposes of the Resilience Rider. These rates are not intended to change current Council-approved depreciation rates, and any difference between what is assumed for Rider purposes and actual depreciation rates would be reflected in the true-up described in the Rider. The Resilience Revenue Requirement would also include property tax expense associated with the Resilience Plan projects. To support the revenue requirement, as I discuss further below, ENO would supply workpapers identifying each hardening project and its actual or expected in-service date.

[2] If the Council changes ENO's distribution and transmission depreciation rates in the future, ENO would update these average depreciation rates.

Q11. HOW WOULD THE RESILIENCE REVENUE REQUIREMENT BE ALLOCATED AMONG THE RATE CLASSES?

A. ENO proposes to allocate the Resilience Revenue Requirement based on each rate class's percentage contribution to per book base revenue in the previous calendar year. Thus, the rate under the Resilience Rider would be the same for each rate class.

Q12. WHY IS ENO PROPOSING A BASE REVENUE ALLOCATOR?

A. Base revenue should be the allocation basis because it is consistent with the allocation previously approved by the Council, *e.g.*, in the Securitized Storm Cost Recovery Rider ("SSCR Rider"), which contains a single rate for all rate classes. The SSCR Rider recovers storm restoration and financing costs based on projected base revenue. Given that the Council has allocated storm restoration costs and related financing costs using projected base revenue, it is reasonable to use base revenue as an allocator to recover resilience and storm hardening investments, which are intended in significant part to mitigate storm restoration costs.

Q13. DO YOU THINK IT WOULD BE REASONABLE TO SOLELY USE A DEMAND ALLOCATOR?

A. No. First, in general, the Council has tended not to rely solely on objectively calculated allocators, like a demand allocator, to allocate costs recovered through base rates. Second, customers' electric demand is not a principal driver of the Resilience Plan's costs. A principal driver is to make the City of New Orleans more resilient so that its businesses and residents can return to normal, more quickly and efficiently, after storm events. A major component of that community resilience is reducing future storm restoration costs, including the length of storm restoration, as soon as reasonably practical to do so.

Q14. HOW WOULD THE RESILIENCE RIDER RATES BE CALCULATED?

A. The Resilience Rider rates for each class would be calculated as a percentage of base revenue based on the most recently filed FRP or most recent calendar year's base revenue.

Q15. HOW MUCH TIME WOULD BE AVAILABLE TO REVIEW THE CALCULATION OF THE RESILIENCE REVENUE REQUIREMENT AND THE RESILIENCE RIDER RATES?

A. There would be thirty (30) days from the date of the annual redetermination filing on October 1 and ninety (90) days from the true-up filing (on August 1), until November 1, to review the calculation of the Resilience Revenue Requirement and the proposed Resilience Rider rates and for the parties to identify any corrections or other disputed issues to ENO. If there are any issues or disputed items, they are addressed in accordance with the Dispute Resolution Process provided for in the Resilience Rider and that I discuss later in my testimony. If there are no such issues or disputed resolutions, the Resilience Rider rate shall become effective in accordance with the terms of the Resilience Rider.

Q16. PLEASE DESCRIBE THE TRUE-UP OF THE RESILIENCE REVENUE REQUIREMENT AND PRUDENCE REVIEW.

A. Beginning August 1, 2025, and each August 1 thereafter, ENO would file a report including a true-up calculation of the estimated Resilience Revenue Requirement based on actual accounting data from the previous calendar year. To facilitate the review of true-up and the prudence of the hardening projects in the Resilience Plan, the Company would provide a document listing all projects included in the previous Resilience Revenue Requirement and all projects that entered service during the true-up period. The document would show the variances for each project and provide a brief description of the cause of any material variances. The Resilience Rider provides ninety (90) days, until November 1, to review the projects closed to plant in service in the previous calendar year and identify any disputed issues, including any expenditures challenged as being imprudently incurred.

Q17. PLEASE DESCRIBE THE DISPUTE RESOLUTION PROCEDURE THAT YOU MENTIONED EARLIER IN THIS TESTIMONY.

A. The proposed dispute resolution provisions of the Resilience Rider are substantially similar to those in the FRP. If ENO and other stakeholders resolve all or a portion of any disputed issues, then the Resilience Rider rate, including any necessary true-up and adjustments for any resolved items, would become effective January 1 of the following year. If disputed issues remain outstanding at the end of the review period, the rate would be implemented, subject to refund, until such time as the Council would resolve those disputed issues through a hearing process.

Q18. WHAT WOULD OCCUR IF ENO RECEIVED OTHER FUNDS TO OFFSET THE COST OF ANY RESILIENCE PLAN PROJECTS?

A. The Resilience Rider provides the Council a flexible mechanism to give customers, on a timely basis, the benefit of any funds (such as grants) that the Company may receive for hardening projects in the Resilience Plan. The Company has and continues to seek federal funds for resilience projects. Determining whether or when ENO would receive such funds to offset the cost of Resilience Plan projects is difficult. In the event the Company receives such funds for any hardening projects in the Resilience Plan, the Resilience Rider allows for an out-of-cycle change to the Resilience Rider rates to reflect the offset.

IV. NEED FOR THE RESILIENCE RIDER

Q19. WHY DOES ENO NEED THE RESILIENCE RIDER?

A. ENO needs the Resilience Rider so that the Company can execute the Resilience Plan on an accelerated basis to deliver benefits to customers as soon as practical and without compromising ENO's credit metrics and cash flow, while maintaining baseline operations. ENO needs to improve its financial condition and credit ratings to protect its customers from higher capital costs, not only as to the Resilience Plan but across ENO's entire business. As discussed by Mr. Meredith in his testimony, ENO is proposing to invest approximately $1 billion over ten years (2024 to 2033) to further accelerate infrastructure hardening of the Company's transmission and distribution systems. In the first five years, ENO expects to spend $559 million on these projects. Given the large capital investment and time horizon involved in implementing the Resilience Plan and ENO's small size and risk profile, it is essential that ENO have assurance that it has a reasonable opportunity to recover the costs of its resilience investment in a timely manner. The Resilience Rider provides that assurance and would serve as a constructive sign that the Council is willing to support ENO in the rehabilitation of its financial condition and, at a minimum, prevent any further degradation of ENO's credit ratings.

Q20. WOULD ENO'S EXISTING RATEMAKING MECHANISMS PERMIT TIMELY COST RECOVERY OF THE RESILIENCE PLAN?

A. No. ENO has a limited term FRP, and it is scheduled to expire this year. Additionally, the maximum term that ENO's FRPs have been initially approved has been only three years. Thus, the FRP alone has not historically presented the level of assurances needed to leverage the economies of scale that I mentioned above. Accordingly, the FRP is not a suitable cost recovery method for the ten-year period of hardening project deployment in the Resilience Plan. Also, a rate case would not provide suitable cost recovery considering the timeline for resolution of ENO's typical rate cases (i.e., 12 months). Multiple rate cases would be an expensive, inefficient, and unnecessary use of resources for periodically resetting rates. Thus, the proposed Resilience Rider is a workable solution because it provides a stable source of recovery that supports an efficient supply chain strategy over a ten-year cycle, synchronizes recovery with the availability of benefits to customers and provides a level of transparency that would enable efficient regulatory oversight.

Q21. SHOULD SINGLE-ISSUE RATEMAKING PRECLUDE THE USE OF A RIDER?

A. No. Despite any concerns about single-issue ratemaking, the Advisors have testified that riders may be used to recover significant costs incurred between base rate proceedings.[3] Indeed, when the Tax Cut and Jobs Act's reduction to the federal corporate income tax rate

[3] Direct Testimony of Joseph W. Rogers, UD-18-07, at 17-18 ("[R]iders may be used to provide for the recovery of significant costs incurred between full rate case proceedings that were not otherwise accounted for in base rates.").

became effective January 1, 2018, regulators embraced single-issue ratemaking.[4] The Resilience Plan involves significant costs that ENO will not have a reasonable opportunity to recover through typical ratemaking proceedings employed by the Council. Accordingly, single-issue ratemaking should not be an obstacle in this context.

Q22. IS ENO'S FINANCIAL CONDITION SOUND IN YOUR OPINION?

A. No. I would characterize ENO's financial condition as concerning. Since the decision in the 2018 Rate Case, in late 2019, S&P Global ("S&P") has downgraded ENO three times and four notches. S&P downgraded ENO in October 2020 from 'BBB+' to 'BBB' in October 2020; the basis of that downgrade was severe storm risks, a revised assessment of group support, and weaker forecasted credit metrics.[5]

In September 2021, S&P downgraded ENO's issuer rating twice, from 'BBB' to 'BB+'[6] and then from 'BB+' to 'BB.'[7] S&P further changed ENO's outlook to 'Developing.' S&P based its downgrades, in large part, on "ENO's small service territory, limited diversity, and ongoing exposure to severe storms and hurricanes" and weakened financial risk measures,[8] as ENO's credit metrics being on the lower end of the 'Significant Financial Risk' benchmark range.[9] Today, S&P's outlook on ENO continues to be 'Developing.'[10]

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4 *See* Resolution R-18-38 (ordering ENO to record regulatory assets and liabilities to preserve the Tax Cut and Jobs Act's effect on ENO's revenue requirement).

5 S&P, *Entergy New Orleans LLC*, October 8, 2020, at 1-2. Recent reports from S&P and Moody's cited in my testimony are included in Exhibit AMA-3, *in globo*.

6 S&P, *Entergy New Orleans LLC*, September 2, 2021.

7 S&P, *Entergy New Orleans LLC*, September 24, 2021.

8 S&P, *Entergy New Orleans LLC*, September 2, 2021, at 1.

9 S&P, *Entergy New Orleans LLC*, September 24, 2021, at 1.

10 S&P, *Entergy New Orleans LLC*, August 30, 2022, at 2.

In September 2021, Moody's Investor Service ("Moody's") changed ENO's outlook from 'Stable' to 'Negative.' Moody's based that change on "the added cost burden imposed by recent storm activity and the potential for impaired customer relations, increased political or regulatory challenges to full and timely cost recovery, and prolonged financial metric weakness."[11] Today, Moody's outlook continues to be 'Negative' based on its "weakened financial profile following 2021 storm activity, uncertainty regarding the current storm season, and outstanding regulatory approvals required to recover around $206 million of past storm costs."[12]

Q23. ARE ENO'S CURRENT CREDIT RATINGS ACCEPTABLE?

A. No. S&P's 'BB' issuer rating is unacceptable for balancing the interest of stakeholders in a way that is supportive of raising capital at the lowest reasonable cost for a company of ENO's size and risk profile (given its geography and relatively homogenous customer base). It is imperative that ENO and the Council work together to target an issuer rating and a financial condition that is beneficial to all stakeholders in the long-term. ENO cannot assume that its parent or sister companies will be willing or able to provide support in future instances of financial stress.

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[11] Moody's, *Entergy New Orleans LLC & Entergy New Orleans LLC,* September 23, 2021, at 1-2; Moody's, *Entergy New Orleans LLC,* September 29, 2021, at 2.

[12] Moody's, *Entergy New Orleans LLC,* October 4, 2022, at 2.

Q24. HOW IMPORTANT IS THE COUNCIL'S REGULATION OF ENO TO IMPROVEMENT IN ENO'S CREDIT RATINGS?

A. The Council's regulation is of the utmost importance. Credit ratings agencies examine both qualitative and quantitative factors in their analyses. Regulatory environment is the most important qualitative factor and substantially influences credit ratings analysis of a utility. The characterization of the regulatory environment, however, is manifested largely through rate actions. Rate actions are a primary driver of credit metrics, and the utility's credit metrics are part of the quantitative analysis. The connection between the health of the regulatory environment and the Company's ability to access capital on reasonable terms cannot be underestimated and has the potential to affect customer rates in a significant way.

Q25. WHAT EVIDENCE DO YOU HAVE TO SUPPORT YOUR OPINION THAT UNDERTAKING THE RESILIENCE PLAN WITHOUT THE RESILIENCE RIDER WOULD HARM ENO'S CREDIT METRICS AND CASH FLOW?

A. I sponsor the indicative financial model ("Financial Model") attached to my testimony as Exhibit AMA-4, which Financial Model uses simplifying assumptions to compare cash flow results assuming no contemporary cost recovery mechanism and assuming the proposed Resilience Rider is in place. The Financial Model shows that, assuming all else constant, ENO's most important credit metric, cash flow to debt, would experience significant increasing downward pressure over the first five years of the Resilience Plan (2024 to 2028), assuming no contemporary cost recovery mechanism is in place.

Q26. PLEASE FURTHER DESCRIBE THE FINANCIAL MODEL PRESENTED ON EXHIBIT AMA-4.

A. The Financial Model isolates the cash flows that would occur during the Resilience Plan. The Financial Model uses the cash flows to calculate the projected degradation of ENO's cash flow to debt ratio for the first five years of the Resilience Plan. For simplification purposes, the Financial Model does not include cash flow projections for the remainder of ENO's operations beyond the Resilience Plan because such projections are unnecessary to determine the effects associated with the Resilience Plan.

In addition to the Resilience Plan, ENO's baseline capital program requires significant amounts of cash. This baseline capital program will drive debt issuances just like the Resilience Plan and likewise will be a source of downward pressure on ENO's credit metrics if supporting ratemaking mechanisms are not in place to also recover the baseline capital spending.

Q27. WHY DOES THE FINANCIAL MODEL FOCUS ON THE CASH FLOW TO DEBT RATIO?

A. The funds from operations ("FFO") to debt ratio and the cash flow from operations before changes in working capital ("CFO pre-WC") to debt ratio are very important to utility credit analysts. These ratios measure the degree of financial risk (the lower the percentage, the higher the risk) experienced by a company by comparing its cash flow to the level of debt that such company requires to sustain its operating and capital investment activities. These ratios are often perceived as the most rigorous measure of creditworthiness since improvements in the measure require growing cash flow from operations at a faster pace than adding new debt and increasing risk.

Q28. WHAT ELEMENTS IN THE FINANCIAL MODEL ARE USED TO CALCULATE THE CASH FLOW TO DEBT RATIOS?

A. The Financial Model calculates cash flow using Interest Expense from the debt supporting the Resilience Plan projects. The Financial Model calculates debt by assuming that approximately 49% of the Resilience Plan's capital expenditures are funded with new debt issuances. The Resilience Plan's capital expenditures[13] for the first five years of the Resilience Plan are set forth in the table below.

Table 1
$1 Billion Resilience Plan
Projected 2024-2028
Capital Expenditures
($ millions)

Year	Total
2024	77.8*
2025	98.8
2026	124.4
2027	120.6
2028	137.3
Total	559.0

*$15.3 million of this amount incurred in 2023.

Q29. WHAT ARE THE ASSUMPTIONS ASSOCIATED WITH INTEREST PAYMENTS?

A. The Financial Model assumes that the interest paid on debt supporting the Resilience Plan projects is based on an assumed cost of debt of 6.1%, which is the assumed cost used in

[13] These expenditure amounts assume that conductor handling costs are capitalized as discussed *infra*.

ENO's financial planning processes. Debt issuances are assumed to occur mid-year for purposes of calculating interest paid in the year of issuance.

Q30. WHAT ARE THE ASSUMPTIONS REGARDING INCOME TAXES?

A. The Financial Model assumes that ENO continues to have a net operating loss ("NOL") through year-end 2028. Accordingly, in the Financial Model, it is assumed that ENO would not be making income tax payments. However, to the extent that ENO were making cash tax payments, such as the minimum tax under the Inflation Reduction Act, this factor would serve to further decrease ENO's cash flows.

Q31. WHAT ARE THE CASH-FLOW-TO-DEBT RATIOS FOR THE FIRST FIVE YEARS OF ENO'S PROPOSED RESILIENCE PLAN, ASSUMING THE RESILIENCE RIDER MECHANISM IS NOT IN PLACE FOR THE RECOVERY OF THE RESILIENCE PLAN'S ASSOCIATED COSTS?

A. As shown below, the cash flow to debt ratios are negative and trend downwards over time. These projections demonstrate that the Resilience Plan, without any cost recovery mechanism in place, would decrease ENO's overall cash flow to debt ratios.

Table 2
$1 Billion Resilience Plan
Cash Flow to Debt Ratio Assuming No Cost Recovery Mechanism
for the Years 2024 through 2028

	2024	2025	2026	2027	2028
CF to Debt – No Recovery	-3.6%	-4.5%	-5.7%	-6.1%	-6.7%

This type of degradation in ENO's credit metrics would be insufficient to support sustainable operations and the Resilience Plan. Thus, ENO needs to have a contemporaneous cost recovery mechanism to address the financial pressures of the Resilience Plan and place ENO in a position to increase system resilience in a meaningful way, while beginning to rehabilitate its financial condition. These actions both enhance the likelihood of positive outcomes for customers in the form of a more resilient system and lower rates over time.

Q32. WHAT EFFECT WOULD THE RESILIENCE RIDER HAVE ON ENO'S FINANCIAL CONDITION?

A. As shown in the table below, ENO's projected cash flow would improve relative to a situation where there is no Resilience Rider for the recovery of the costs associated with the Resilience Plan, and such improvement would put ENO in a better financial position to execute the Resilience Plan and meet the Council's and customers' expectations in the future.

Table 3
$1 Billion Resilience Plan
Cash Flow to Debt Ratio Comparing No Recovery Mechanism to Recovery Through the Proposed Resilience Rider for the Years 2024 through 2028

	2024	2025	2026	2027	2028
CF to Debt – No Recovery	-3.6%	-4.5%	-5.7%	-6.1%	-6.7%
CF to Debt – Rider Recovery	-1.3%	8.7%	7.7%	12.1%	12.8%

Q33. FOR PURPOSES OF THE COMPARISON REFLECTED IN TABLE 3, DID ENO CHANGE ANY ASSUMPTIONS IN THE FINANCIAL MODEL BECAUSE OF THE PROPOSED RESILIENCE RIDER?

A. The only change made to the Financial Model was to reflect the cash flow from the proposed Resilience Rider. The Financial Model assumes that ENO collects the estimated Resilience Revenue Requirement in the calendar year corresponding to the projects' placement in service.

Q34. CONSIDERING THE RESILIENCE RIDER, WHAT IS THE ESTIMATED EFFECT OF THE PROPOSED RESILIENCE PLAN ON THE BILL OF A TYPICAL RESIDENTIAL CUSTOMER?

A. Table 4 shows the estimated bill effect over the first five years of the Resilience Plan for a typical residential customer using of 1,000 kwh per month.

Table 4
$1 Billion Resilience Plan
Projected Rider Rate Impact
for a Typical Residential Customer using 1,000 kWh per Month
Years 2024 through 2028

Year	Projected Total Cumulative Resilience Plan Revenue Requirement ($ in Millions)	Projected Residential Cumulative Revenue Requirement ($ in Millions)	Projected Monthly Residential Bill Impact ($/month)
2024	$0.9	$0.4	$0.20
2025	$11.4	$5.5	$2.53
2026	$19.7	$9.6	$4.38
2027	$37.7	$18.3	$8.38
2028	$53.4	$25.9	$11.86

Q35. ARE THESE BILL EFFECTS JUSTIFIED BY THE EXPECTED CUSTOMER BENEFITS?

A. Yes. The 1898 & Co. analysis, and as discussed by Mr. Meredith and Mr. De Stigter, shows that ENO customers are better off paying for the Resilience Plan projects, paying reduced storm restoration costs, and experiencing shorter and fewer outages, as opposed to paying greater storm restoration costs and experiencing longer and more frequent storm outages without the Resilience Plan projects. Moreover, the preservation of ENO's financial integrity and related credit metrics mitigates exposure to downgrades that could result from insufficient cash flows. Thus, these bill effects are justified by the expected customer benefits.

V. PUBLIC INTEREST

Q36. IS THE PROPOSED RESILIENCE PLAN IN THE PUBLIC INTEREST?

A. Yes, the Resilience Plan is in the public interest. The related requests for relief in the Application, including the Resilience Rider and monitoring plan, are also in the public interest.

Q37. WHAT IS THE PUBLIC INTEREST?

A. The public interest is that which is thought to best serve everyone; it is the common good. If the net effect of a decision is believed to be positive or beneficial to society as a whole, it can be said that the decision serves the public interest.

Public utilities in general, and electric utilities in particular, affect nearly all elements of society. Public utilities have the ability to influence the cost of production of the businesses that are served by them, to affect the standard of living of their customers, to affect employment levels in the areas they serve, and to affect the interests of their investors. In sum, public utilities affect the general economic activity in the state.

In determining whether a particular decision or policy is in the public interest, there is no immutable law or principle that can be applied. While the public interest is often defined in terms of net benefits, such a test or standard merely substitutes one expression for another. The difficulty is in defining and, if possible, quantifying the net benefits.

It is recognized that net benefits cannot simply be defined as lower prices. For example, if lower prices are achieved through a reduction in the reliability or quality of service, it may very well be perceived that the lower prices have not produced net benefits. Similarly, higher prices might not produce negative net benefits or detriments. For example, if an existing price is low due to a cross-subsidy, removing that subsidy would raise that price, but doing so would not necessarily be detrimental. In a case previously relied upon by the Council,[14] the Louisiana Supreme Court reached just such a conclusion in *City of Plaquemine v. Louisiana Public Service Commission*, 282 So. 2d 440, 442-43 (1973), when it found that:

> The entire regulatory scheme, including increases as well as decreases in rates, is indeed in the public interest, designed to assure the furnishing of adequate service to all public utility patrons at the lowest reasonable rates consistent with the interest both of the public and of the utilities.
>
> Thus the public interest necessity in utility regulation is not offended, but rather served by reasonable and proper rate increases notwithstanding that an immediate and incidental effect of any increase is improvement in the economic condition of the regulated utility company.

[14] Resolution R-18-65, dated March 8, 2018, at 14 (relying on the quoted passage in describing the public interest standard).

Objective measurement of how a decision affects the public interest is problematic at best. For the past seventy or more years, regulatory decision-making has been tested in the courts by a balancing-of-interests standard. In these cases, beginning with *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 603 (1944), the courts have found that if the regulatory body's decision reflected a reasonable balancing of customer and investor interests, the decision was to be affirmed as just and reasonable.[15]

In sum, determining whether a decision is in the public interest requires a balancing of the various effects of a particular course of action measured subjectively over the longer run. Whether a course of action is in the public interest will depend upon relevant factors that are potentially quantifiable on an estimated basis, such as likely changes in costs, as well as upon other factors that are not quantifiable, such as the effect of that course of action on the robustness of a competitive market.[16] Finally, although witnesses can provide facts and opinions that bear on this issue, the decision-maker here – the Council – must ultimately weigh all of these factors and conclude whether the particular proposed course of action is in the public interest.

Q38. HAVE YOU REVIEWED THE REPORT THAT IS ATTACHED TO MR. DE STIGTER'S TESTIMONY, AND IF SO, WHAT ARE YOUR CONCLUSIONS?

A. I have reviewed that report, and I find the approach taken by 1898 & Co. to be reasonable and carefully planned in its assessment of (1) all storms that have affected ENO's service

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[15] *See also* Resolution R-18-65 at 107 (A public interest determination often requires "a subjective balancing of interests by the regulator . . . .").

[16] *See Permian Basin Area Rate Cases*, 390 U.S. 747, 815 (1968).

area over a long period of time and (2) virtually all of ENO's grid assets, to develop levels of investment and portfolios of hardening projects for the Company to consider, in particular the Resilience Plan.[17] As described in the direct testimony and report of Mr. DeStigter, the approach taken by 1898 & Co. also considers a multitude of other factors in its analysis, including the strength and location of storms as well as the age and condition of ENO's assets. Importantly, the approach is customer-centric in that it quantifies benefits of hardening projects directly in relation to the effects of those projects on customers, both on the storm restoration costs they will bear after future storms and the duration of the outages that customers will experience as a result of those future storms. This information was used to prioritize the hardening projects in the Resilience Plan that reflect overall customer benefits exceeding the costs of the related investments. Customers are projected to achieve net benefits from the investments proposed to be undertaken by ENO in this docket based on 1898 & Co.'s analysis. In short, if ENO does not go forward with the proposed Resilience Plan, customers would be worse off following severe weather events.

Q39. WHAT ARE THE REASONS THAT SUPPORT YOUR OPINION THAT THE RESILIENCE PLAN IS IN THE PUBLIC INTEREST?

A. Overall, I base this opinion on the following: the recent increasing frequency and intensity in storms; the effectiveness of Florida utilities' resilience investments during the recent Hurricane Ian (which Mr. Meredith discusses in his testimony); and on 1898 & Co.'s

[17] I also find reasonable and evidence of careful planning that the Company intends to carefully coordinate the Resilience Plan, as developed through the 1898 & Co. report, with the Company's reliability programs to promote efficiencies and best serve customers, as discussed by Mr. Meredith in his testimony.

analysis showing that customers are better off if ENO goes forward with its Resilience Plan.

Q40. PLEASE ELABORATE ON WHY THE INCREASING FREQUENCY AND INTENSITY IN STORMS SUPPORT A PUBLIC INTEREST FINDING IN FAVOR OF ENO'S PROPOSED RESILIENCE PLAN.

A. As discussed in detail by Messrs. Meredith and De Stigter in their testimonies, ENO's recent storm experience, and an expected storm future with increasingly frequent and intense storm activity, has made clear the need to further storm harden ENO's grid as soon as practical. Indeed, the Council has stated that "the current cycle of [storm] damage and repair is not sustainable."[18] Similarly, S&P in a recent opinion regarding Entergy Louisiana, LLC ("ELL") identified the importance of ELL taking steps to reduce storm restoration costs in order to mitigate relationship risk between ELL and its regulator and customers.[19] Although this report concerns ELL, ENO should manage and mitigate relationship risk in this area as well. And, both S&P[20] and Moody's have observed that ENO's size and its storm-prone location are credit negatives. For example, Moody's stated the following:

> ENOL's credit profile is challenged by its small, geographically concentrated service territory in a storm prone location. The coastal nature of the service territory is a material credit negative due to the rising risk of storm surges, more severe weather events and the impact this has on customer migration and local economic conditions. For these reasons,

[18] Resolution R-21-401, dated October 27, 2021, at 2.

[19] S&P, *Entergy Louisiana LLC*, August 25, 2022, at 1.

[20] S&P, *Entergy New Orleans LLC,* August 30, 2022, at 2.

> ENOL's credit rating is well below peer utilities with similar financial metrics.[21]

Q41. HOW DOES THE EFFECTIVENESS OF FLORIDA UTILITIES' RESILIENCE INVESTMENTS DURING HURRICANE IAN SUPPORT A FINDING THAT THE COMPANY'S PROPOSED HARDENING PLAN IS IN THE PUBLIC INTEREST?

A. As explained in the Direct Testimony of Mr. Meredith, the effectiveness of the Florida resilience investments indicates that ENO's proposed Resilience Plan projects should prove effective in mitigating storm restoration costs and the duration of customer interruptions as shown by the 1898 & Co. analysis. As also discussed by Mr. Meredith in his testimony, although Florida experienced wide-spread outages from Hurricane Ian in 2022, its more resilient system better withstood damage to the system and enabled more prompt restoration to those customers whose homes and businesses were in a condition that allowed them to take service. The Resilience Plan contains many of the same types of infrastructure hardening projects that were performed in Florida and appear to have been beneficial during Hurricane Ian, and the Company expects the same types of benefits from its proposed Resilience Plan, as discussed by Messrs. Meredith and De Stigter.

[21] Moody's, *Entergy New Orleans, LLC,* October 4, 2022, at 1.

Q42. THE 1898 & CO. ANALYSIS QUANTIFIES THE REDUCTION IN STORM RESTORATION COSTS AND IN CUSTOMER MINUTES INTERRUPTED AS BENEFITS FROM THE HARDENING PROJECTS IN THE RESILIENCE PLAN. DO THESE BENEFITS SERVE THE PUBLIC INTEREST?

A. Yes, they do. After Hurricane Ida, the Council opened this docket in large part because the cycle of storm restoration costs over the last few years in particular is not sustainable for customers or the Company itself. The expected reduction in future storm restoration costs from the Resilience Plan, as described by Mr. De Stigter in his testimony and the 1898 & Co. report, is a significant benefit to customers and serves the public interest. Indeed, being good stewards of customers' money, while maintaining reliable electric service, is fundamental to the public interest. With regard to the expected reduction in customer minutes interrupted, per Mr. De Stigter's testimony, a shortened period during which customers are without electricity from storm events is another significant benefit of the Resilience Plan.

Shorter outages allow customers to get back to normal quicker, whether those customers are residents or businesses, and that is certainly in the public interest. Moreover, I find 1898 & Co.'s use of the Interruption Cost Estimate ("ICE") Calculator from the U.S. Department of Energy ("DOE") to estimate, for project prioritization purposes, the societal benefit from reduced customer interruption minutes to be reasonable in the present circumstances.[22]

[22] As Mr. Meredith explains in his testimony, the DOE's ICE calculator does not consider the specific circumstances that would be necessary to assess the causes and impacts of an outage to customers in specific circumstances, and the use of the DOE's ICE calculator to help prioritize projects within the Resilience Plan is not an endorsement of any other use.

Q43. ARE THERE OTHER FACTORS THAT YOU CONSIDER RELEVANT TO A PUBLIC INTEREST DETERMINATION REGARDING THE RESILIENCE PLAN?

A. Yes. The other factors include the fact that the Company considered bill impacts to customers in selecting the $1 billion portfolio as the recommended Resilience Plan. It is in the public interest for the Company to balance costs to customers against expected benefits in making business decisions and selecting infrastructure projects. In addition, "blue sky" resilience work can be more carefully performed and cost-effective than reactive, post-storm restoration work, and customers will see the benefits of such "blue sky" work sooner than if the projects were delayed. These benefits are certainly in the public interest.

Further, as mentioned above, there are potentially positive credit implications associated with the Resilience Plan. S&P has stated that it views approval of substantial resilience investment as "credit supportive in the long run."[23] A more resilient system is expected to enable ENO to have more stable credit and reduce the chance of downgrades that would increase ENO's financing costs and thus increase customer bills, should downgrades occur.

[23] S&P, *Entergy New Orleans LLC*, August 30, 2022, at 4.

Q44. ARE THE RELATED REQUESTS FOR RELIEF IN THE APPLICATION, INCLUDING THE RESILIENCE RIDER AND MONITORING PLAN, ALSO IN THE PUBLIC INTEREST?

A. Yes. Earlier in my testimony, I explained why I recommend that the Council approve the Resilience Rider. Furthermore, the proposed monitoring plan will facilitate oversight of the Resilience Plan by the Council and its Advisors.

VI. ADDITIONAL RATEMAKING REGARDING THE RESILIENCE PLAN

Q45. PLEASE DESCRIBE THE COMPANY'S REQUEST CONCERNING UNRECOVERED PLANT COSTS.

A. ENO requests authorization to create a regulatory asset for the remaining net book value associated with assets that must be retired and replaced with new assets as part of the Resilience Plan.[24] ENO would include the regulatory asset in rate base and amortize such retired plant costs at a rate consistent with the associated depreciation expense currently reflected in rates. With this ratemaking treatment, customers would not see an incremental increase in rates while ENO recovers its prudently incurred costs, all else being equal.

Q46. WHY ARE YOU RECOMMENDING THAT THE COUNCIL ALLOW THE REGULATORY ASSET TO BE INCLUDED IN RATE BASE?

A. Allowing ENO to include the regulatory asset in rate base will not have any effect on customers' future rates relative to current rates. The net book value of these assets is

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[24] ENO also would seek authorization from the FERC through an accounting waiver to record such unrecovered plant costs in Account 182.2.

already reflected in ENO's rate base and, therefore, its rates. Additionally, the prudent retirement of these assets to advance resilience objectives should not change ENO's recovery of the cost of investment in these assets.

Q47. PLEASE DESCRIBE THE ACCOUNTING WAIVER THAT THE COMPANY INTENDS TO REQUEST FROM THE FERC.

A. The Company's revenue requirement calculations assume that ENO is able to capitalize distribution conductor handling costs incurred with projects in the Resilience Plan, which are those costs associated with transferring existing conductors and fixtures to new poles during pole replacements. ENO's conductor handling costs would increase as a result of the Resilience Plan. The FERC Uniform System of Accounts ("USOA") typically requires these costs to be recorded to Account 593, Maintenance of Overhead Lines, an operation and maintenance expense ("O&M") account. Thus, ENO must record these costs as expenses in the year in which the work was performed. ENO, however, intends to seek an accounting waiver from the FERC authorizing ENO to capitalize conductor handling costs incurred in conjunction with Resilience Plan capital projects, which treatment would benefit customers.

Q48. HOW WOULD CAPITALIZING CONDUCTOR HANDLING COSTS BENEFIT CUSTOMERS?

A. Capitalization benefits customers by recognizing these distribution conductor handling costs over time as projects are depreciated, and thereby lowering the Resilience Plan's immediate bill effects, instead of being recovered in their entirety in the year the cost is incurred. In so doing, ENO seeks to prevent an increase in O&M recorded to Account 593 solely due to those projects. By way of example, if ENO incurred $800,000 in conductor handling costs in 2025 and was authorized to capitalize those costs, ignoring income taxes and assuming an applicable depreciation rate of 3% and a 6.5% return on rate base, ENO would recover approximately $74,000 from customers in 2025. On the other hand, if ENO incurred $800,000 in conductor handling costs in 2025 but was not authorized to capitalize those costs, ENO would recover the full $800,000 from customers in 2025. All other distribution conductor handling costs incurred outside the Resilience Plan would continue to be recorded as O&M in Account 593.

Q49. HAVE OTHER ELECTRIC UTILITIES OBTAINED SIMILAR ACCOUNTING WAIVERS FOR CONDUCTOR HANDLING COSTS FOR THEIR RESILIENCE PLANS?

A. Yes. The FERC granted Florida Power & Light Company, Gulf Power Company, and Duke Energy Florida, LLC, limited duration authorizations allowing capitalization of conductor handling costs in connection with their resilience work.[25]

[25] *See Florida Power & Light Co.*, Letter Order, Docket No, AC18-23 (Jan. 31, 2018); *Gulf Power Co.*, Letter Order, Docket No, AC20-131 (July 30, 2020); *Duke Energy Florida, LLC,* Letter Order, Docket No, AC21-141 (July 29, 2021).

VII. COUNCIL RULES AND REGULATIONS

Q50. IN PREPARING YOUR TESTIMONY AND OFFERING YOUR OPINIONS, DID YOU CONSIDER APPLICABLE COUNCIL RULES AND REGULATIONS?

A. Yes. I considered Section 158 of the Code of the City of New Orleans and certain resolutions applicable to ENO.

Q51. DO YOU HAVE ANY OPINIONS REGARDING ENO'S REQUESTS IN THIS APPLICATION RELATIVE TO THOSE COUNCIL RULES AND REGULATIONS?

A. Yes. For all of the Company's requests in this Application, it is my understanding that the Company has complied with, or is not in conflict with, the provisions of all applicable Council resolutions and any other laws, regulations, or requirements that may be applicable. Moreover, to the extent that ENO has not complied with any such requirements of the City Code, the Council should allow ENO a reasonable time to cure any such deficiency or grant a waiver of any applicable Council requirement to the extent that such a waiver may be required to facilitate consideration and approval of the Resilience Plan and associated requested relief.

VIII. CONCLUSION

Q52. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, **ALYSSA MAURICE-ANDERSON**, who after being duly sworn by me, did depose and say:

That the above and foregoing is her sworn testimony in this proceeding and that she knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, she verily believes them to be true.

Alyssa Maurice-Anderson

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 12th DAY OF APRIL, 2023

NOTARY PUBLIC

My commission expires: Death

OFFICIAL SEAL
LACRESHA D. WILKINSON
BAR ROLL # [illegible]
STATE OF LOUISIANA
PARISH OF CATAHOULA
My Commission is for Life

List of Testimony Presented Before Utility Regulatory Bodies
by Alyssa Maurice-Anderson

No.	Date	Testimony	Docket No.	Jurisdiction	Type	Subject Matter
1	June 2022	Application of Entergy Louisiana, LLC, for Approval of the 2021 Solar Portfolio, the Geaux Green Option, Cost Recovery and Related Relief , Rebuttal Testimony	U-36190	Louisiana Public Service Commission	Rebuttal	Ratemaking
2	June 2022	In Re: Application of Entergy Louisiana, LLC for Recovery in Rates of Costs Related to Hurricane Ida and Related Relief, Direct Testimony Re Financing Application	U-36350	Louisiana Public Service Commission	Direct	Securitization, Ratemaking
3	June 2022	In Re: Application of Entergy Louisiana, LLC for Recovery in Rates of Costs Related to Hurricane Ida and Related Relief, Direct Testimony Re Ancillary Application	U-36350	Louisiana Public Service Commission	Direct	Securitization, Ratemaking
4	July 2022	Application of Entergy Texas, Inc. for Authority to Change Rates	53719	Public Utility Commission of Texas	Direct	Decomm Escalation Rate, Reg Services Affiliate Costs
5	Dec 2022	In Re: Application of Entergy Louisiana, LLC for Recovery in Rates of Costs Related to Hurricane Ida and Related Relief, Direct Testimony Re Financing Application	U-36350	Louisiana Public Service Commission	Settlement	Securitization, Ratemaking
6	Mar 2023	In Re: Application of Entergy Louisiana, LLC for Approval of the Entergy Future Ready Resilience Plan (Phase I)	U-36625	Louisiana Public Service Commission	Direct	Ratemaking

ENTERGY NEW ORLEANS, LLC ELECTRIC SERVICE RIDER SCHEDULE RSHCR	Effective: January 2024 Billing Filed: April 17, 2023 Supersedes: New Schedule Schedule Consists of: Two Pages plus Attachments A and B

RESILIENCE & STORM HARDENING COST RECOVERY RIDER

I. PURPOSE

The purpose of the Resilience & Storm Hardening Cost Recovery Rider ("Rider RSHCR") is to establish the Rider RSHCR Rates through which Entergy New Orleans, LLC ("ENO" or the "Company") will recover the revenue requirement associated with the Council-approved Resilience Plan capital additions ("RSHCR Revenue Requirement"). Capital additions associated with other transmission and distribution work shall not be eligible for recovery through this Rider RSHCR. The Rider RSHCR Rates are applied in conjunction with the currently applicable rates on file with the Council. To the extent that ENO receives government grant funding for such capital additions, such funding shall be accounted for as stated below.

II. DEFINITIONS

RSHCR Revenue Requirement shall include the cost associated with the Council-approved Resilience Plan capital additions determined in Council Docket No. UD-21-03 and any other costs that the Council finds appropriate to support the resilience of ENO's operations, including capital investments and expenses.

III. RIDER RSHCR RATES, REDETERMINATION, AND TRUE-UP

A. **Billing.** The Rider RSHCR Rates as set forth in Attachment A shall be derived by the formula ("RSHCR Rider Rate Formula") set out in Attachment B to this Rider RSHCR. The Rider RSHCR Rates shall be added to the rates set out in the monthly bills in accordance with the Company's Rate Schedules. The RSHCR Revenue Requirement will be allocated to the Rate Classes based on the previous calendar year's base revenue. The initial Rider RSHCR Rates effective the first billing cycle of January 2024 shall be based on the estimated annual RSHCR Revenue Requirement for calendar year 2024 determined in Council Docket No. UD-21-03.

B. **Redetermination.** For each calendar year after 2024, the Company shall update the RSHCR Rider Rates. On or before October 1, 2024, and each subsequent October 1 thereafter, the Company shall file a new estimated annual revenue requirement, which will be based on forecasted information for the following calendar year, and which will be used beginning with the first billing cycle of the following January. Such estimated annual revenue requirement shall include all costs associated with Resilience Plan capital additions for the following calendar year and Resilience Plan capital additions previously closed to plant in service.

C **True-Up and Prudence Review.** Beginning in 2025, on or before August 1, the Company shall file a report to support the prudence of the previous calendar year's actual RSHCR Revenue Requirement. Such report shall include a variance report comparing actual capital to projected capital additions plus any other material cost differences. Such report shall also include the computation to true-up the previous calendar year's actual RSHCR Revenue Requirement with the corresponding estimated annual RSHCR Revenue Requirement ("True-Up"). The difference plus interest shall be returned to or recovered from customers through the Rider RSHCR Rates over twelve months beginning in the first billing cycle of the following January, as shown in the RSHCR Rider Rate Formula. The interest rate to be utilized is the prime bank lending rate as published in the Wall Street Journal on the last business day of each month. Any grant funding from non-utility sources that ENO receives for Resilience Plan capital additions shall be treated as an offset to the capital additions included in the actual revenue requirement.

D. **Dispute Resolution.** The Council Advisors ("Advisors"), any intervenors allowed by the Council, and the Company (collectively, the "Parties") shall have until November 1 to file a report communicating any errors or disputes ("Correction/Error Report") with respect to the proposed Rider RSHCR Rates, the true-up, or the prudence of any capital addition or other cost. Each such indicated dispute shall include, if available, documentation to support the proposed correction or prudence dispute. The Company shall then have thirty (30) days to review any proposed corrections or disputes, to work to resolve any disputes, and to file revised RSHCR Rates reflecting all corrections and disputes upon which the Parties agree. The Company shall provide the Advisors with appropriate workpapers supporting any revisions.

In the event there are disputes regarding RSHCR Rates, the true-up, or the prudence of any capital addition or other cost, the Parties shall work together in good faith to resolve such disputes. If the Parties are unable to resolve the disputes or reasonably believe they will be unable to resolve the disputes by the end of the thirtieth (30) day after the filing of the Correction/Error Reports, revised RSHCR Rates reflecting all revisions to the initially filed RSHCR Rates on which the Parties agree shall be used in the Rider RSHCR Rates effective the first billing cycle of the following January.

Any remaining disputes shall be submitted to the Council for resolution. If the Council's final ruling on any disputes requires changes to the true-up initially used pursuant to the above provisions, within sixty (60) days after receipt of the Council's final ruling on any disputes, the Company shall file a revised true-up and shall determine the amount to be refunded or surcharged to customers, if any, together with interest based on the rate set forth in Paragraph C above. Such refund/surcharge amount shall be included in the next true-up computation.

IV. TERM

The Rider RSHCR shall remain in effect until the Council replaces the Rider RSHCR with a new contemporaneous cost recovery mechanism. After the completion of the Council-approved Resilience Plan, the Rider RSHCR Rates shall remain in effect unless and until the last day of the month prior to the implementation of base rates recovering the RSHCR Revenue Requirement previously recovered through the rider.

Within six months after termination of the Rider RSHCR, there will be a true-up of any periods not previously subject to a true-up as provided for above. Any over- or under- refund/recovery, including interest, will be included in Attachment A, Page 2, Line 12 of the then-effective Rider Schedule FAC as a Prior Period Adjustment to the Cumulative (Over)/Under Collection Account.

Entergy New Orleans, LLC
Resilience & Storm Hardening Cost Recovery Rider
Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement Formula
Rider RSHCR Rate Formula - XXXX (1) (2)

All Rate Classes	**0.0000%**

Notes:

(1) Excludes schedules: AFC, BRAR, IRAR-E, Contract Minimums, RES Customer Charges, DTK, EAC, EECR, EVCI, FAC, GPO, MES, MISO, PPCR, PPS, R-8, R-3, RPCEA, SMS, SSCR, SSCO, SSCRII, and SSCOII

(2) See Attachment B, Page 1, Col D

Entergy New Orleans, LLC
Resilience & Storm Hardening Cost Recovery Rider
Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement Formula
Rider RSHCR Rate Formula - XXXX

	Col A	Col B	Col C	Col D
Ln No.	Rate Class (1)	Applicable Base Rate Revenue ($) (2)	RSHCRRR ($) (3)	Rider RSHCR Rates (4)
1	All Rate Classes	$ -	$ -	**0.0000%**

Notes:
(1) Excludes schedules specifically identified on Attachment A, Page 1 of this Resilience & Storm Hardening Cost Recovery Rider.
(2) The billing determinants (Col B) shall be the ENO Base Rate Revenue applicable to Rider RSHCR based on the previous calendar year's base revenue per Section III.A of this Resilience & Storm Hardening Cost Recovery Rider.
(3) See Attachment B, Page 2, Line 17 for the RSHCRRR.
(4) Total Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement (RSHCRRR) (Col C) divided by Applicable Base Rate Revenue (Col B).

Entergy New Orleans, LLC
Resilience & Storm Hardening Cost Recovery Rider
Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement Formula (1)
For the Twelve Months ended December 31, XXXX

Ln No.	Description	Amount	Reference
	Rate Base:		
1	Plant in Service (2)	-	WP X
2	Accumulated Depreciation & Amortization (2)	-	WP X
3	**Net Utility Plant**	-	Line 1 + Line 2
4	Accumulated Deferred Income Taxes (3)	-	WP X
5	**Total Rate Base**	-	Line 3 + Line 4
6	Before-Tax Rate of Return on Rate Base (4)	0.00%	WP X
7	**Return on Rate Base**	-	Line 5 * Line 6
8	**Expenses:**		
9	Operation & Maintenance Expense (6)	-	WP X
10	Depreciation & Amortization Expense (5)	-	WP X
11	Taxes Other Than Income (5)	-	WP X
12	AFUDC Equity Tax Expense (7)	-	WP X
13	**Total Expenses**	-	Line 9 + Line 10 + Line 11 + Line 12
14	Revenue Related Expense Factor (8)	-	WP X
15	**Total Estimated Annual Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement**	-	(Line 7 + Line 13) * Line 14
16	True-up of Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement	-	Att B Pg 3, L24
17	**Total Annual Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement (RSHCRRR)**	$ -	Line 15 + Line 16

Notes:
(1) Pursuant to Section III.B of this Resilience & Storm Hardening Cost Recovery Rider
(2) Estimated Plant in Service and Accumulated Depreciation & Amortization balances at December 31 of the upcoming calendar year based on end of period. This amount also includes conductor handling costs, which the Council has authorized ENO to capitalize pursuant to Resolution R-2X-YYY.
(3) The amount is adjusted for the normalization limit per Regulation Section 1-167(l)-1(h)(6).
(4) The estimated Before Tax Rate of Return is based on the projected weighted average cost of capital using the most recently approved return on equity at December 31 of the current calendar year unless another capital structure is agreed upon for ratemaking purposes.
(5) Estimated Depreciation & Amortization Expense and Other Tax Expense for the upcoming calendar year.
(6) Operation & Maintenance Expense is associated with microgrids.
(7) This amount reflects the grossed-up federal and state income tax expense resulting from the recovery of book depreciation expense attributable to previous accruals of equity AFUDC, which is not deductible and is not included in tax depreciation expense. Recovery of this amount is consistent with Council ratemaking practice.
(8) Revenue Related Expense Factor = 1 / (1-Bad Debt Rate - Revenue Related Tax Rate). The ENO Bad Debt Rate and the Revenue Related Tax rate shall be developed consistent with the methodology used for calculating it in the most recent ENO rate filing and shall use the most recently available calendar year data at the time of filing.

Entergy New Orleans, LLC
Resilience & Storm Hardening Cost Recovery Rider
Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement Formula
True-up of Resilience & Storm Hardening Cost Recovery Revenue Requirement (1)
For the Period ended December 31, XXXX

Ln No.	Description	Amount	Reference
	Rate Base:		
1	Plant in Service (2)	-	WP X
2	Accumulated Depreciation & Amortization (2)	-	WP X
3	**Net Utility Plant**	-	Line 1 + Line 2
4	Accumulated Deferred Income Taxes (2)	-	WP X
5	**Total Rate Base**	-	Line 3 + Line 4
6	Before-Tax Rate of Return on Rate Base (3)	0.00%	WP X
7	**Return on Rate Base**	-	Line 5 * Line 6
8	**Expenses:**		
9	Operation & Maintenance Expense (4)		WP X
10	Depreciation & Amortization Expense (4)	-	WP X
11	Taxes Other Than Income (4)	-	WP X
12	AFUDC Equity Tax Expense (5)	-	WP X
13	**Total Expenses**	-	Line 9 + Line 10 + Line 11 + Line 12
14	Revenue Related Expense Factor	-	Att B, Pg 2, L12 PY Filing
15	**Actual Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement**	$ -	(Line 7 + Line 13) * Line 14
16	**Estimated Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement**	$ -	WP X
17	**Difference in Actual Annual Rider RSHCR Revenue Requirement and Estimated Rider RSHCR Revenue Requirement**	-	Line 15 - Line 16
18	**Interest:**		
19	Annual Prior Year True-up of Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement (6)	-	Att B Pg 3, L24 PY Filing
20	Prior Period Adjustments	-	
21	Total True-Up Adjustment Before Interest	-	Line 17 + Line 19 + Line 20
22	Interest Rate (7)	0.00%	
23	**Interest on Average Balance**	-	(Line 21/2) * Line 22
24	**Total True-Up of RSHCRRR with Interest**	$ -	Line 17 + Line 23

Notes:
(1) Pursuant to Section III.C of this Resilience & Storm Hardening Cost Recovery Rider
(2) Actual Plant in Service, Accumulated Depreciation & Amortization, and Accumulated Deferred Income Taxes balances at December 31 of the previous calendar year based on end of period. To the extent that ENO receives government funding for such capital additions, such funding shall be treated as an offset to the revenue requirement including interest calculated from the date that the funds were received.
(3) The Before Tax Rate of Return is based on the actual capital costs at December 31 of the previous calendar year.
(4) Actual Operation & Maintenance Expense, Depreciation & Amortization Expense, and Other Tax Expense for the previous calendar years balances as of December 31.
(5) This amount reflects the grossed-up federal and state income tax expense resulting from the recovery of book depreciation expense attributable to previous accruals of equity AFUDC, which is not deductible and is not included in tax depreciation expense. Recovery of this amount is consistent with Council ratemaking practice.
(6) Prior Period True-up of Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement (RSHCRRR) reflected on line 24 of Attachment B, Page 3 in the previous years Resilience & Storm Hardening Cost Recovery Rider filed August XXXX.
(7) Prime Rate on the last business day of the operations recovery period as stated in the Wall Street Journal was X.XX%.

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Ratings

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Research Update:

Entergy New Orleans LLC Downgraded To 'BBB' From 'BBB+' On Storm Risks, Outlook Negative

October 8, 2020

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Rating Action Overview

- Regulated utility Entergy New Orleans LLC's service territory is subject to the risk of severe storms and hurricanes.
- We our lowering our issuer credit rating on Entergy New Orleans LLC (ENO) to 'BBB' from 'BBB+'. The outlook is negative.
- We are revising our assessment of ENO's group support from parent company Entergy Corp. (Entergy) to moderately strategic from core given our view that group support has weakened because of the propensity and severity of storm activity along the Gulf Coast. Our stand-alone credit profile (SACP) for ENO remains 'bbb-'.
- At the same time, we are lowering our ratings on ENO's first-mortgage bonds to 'A-' from 'A'. The recovery rating remains '1+'.
- The negative outlook reflects our expectation of weaker financial measures including adjusted funds from operations (FFO) to debt in the 13%-15% range through 2022. In addition, our outlook reflects the potential that we could revise the designation of group support under our group rating methodology to nonstrategic within the next year. As such, we could lower the issuer credit rating on ENO to reflect view of a stand-alone credit profile (SACP) 'bbb-' and our assumption of no group support.

Rating Action Rationale

ENO's service territory creates severe storm and hurricane risks for the utility. Given ENO's exposure to severe storms including hurricanes, a low-lying service territory along the Gulf Coast, and relatively limited size and diversity to help absorb the impact of such storms, ENO's SACP remains 'bbb-'.

We revised our assessment of ENO's group status to parent Entergy, under our group rating methodology to moderately strategic from core. Our reassessment of ENO's group status incorporates its importance to the group's long-term strategy and being a reasonably successful utility. We have concluded that group support has weakened because of the propensity and severity of storm activity along the Gulf Coast, which is critical to a service territory that mostly encompasses a low-lying city that has been in the path of numerous hurricanes. We would however expect ENO to receive extraordinary group support in some circumstances. This could include in times of stress such as for storm repairs or large capital spending initiatives.

The outlook reflects our baseline forecast of weaker financial measures through 2022, the service territory's continued susceptibility to severe storms, and the lack of significant financial support from parent Entergy. Specifically, we expect ENO's service territory to have ongoing exposure to severe storms like the recent Hurricane Laura, and Hurricane Delta currently moving through the Gulf of Mexico, potentially leading to significant liabilities and damages to the infrastructure. Therefore our outlook reflects the potential that we could revise the designation of group support under our group rating methodology to nonstrategic within the next year. As such, we could downgrade ENO to reflect our view of ENO's SACP of 'bbb-' and our assumption of no group support. In addition, our negative outlook reflects our expectation of weaker financial measures including adjusted FFO to debt in the 13%-15% range through 2022

Environmental, social, and governance (ESG) credit factors for this credit rating change.

- Natural conditions

Outlook

The negative outlook on ENO reflects its small service territory, limited diversity, and ongoing exposure to severe storms and hurricanes and our expectation of weaker financial measures partly from higher capital spending and elevated leverage. Specifically, we forecast the company's adjusted consolidated FFO to debt to remain weak in the 13%-15% range in 2020 and 2021.

Downside scenario

We could lower our ratings on ENO if its business risk would materially weaken or financial measures decline, including adjusted FFO to debt consistently below 13%. The negative outlook reflects the weaker financial measures and the potential that we could revise the designation of group support under our group rating methodology to nonstrategic if we perceive limited to no group support for ENO during times of stress. As such, we could downgrade ENO to reflect our view of ENO's SACP of 'bbb-' and our assumption of no group support, particularly in times of stress such as for storm repairs or large capital spending initiatives. Although unlikely, we could lower our ratings on ENO if we lower our ratings on Entergy.

Upside scenario

We could revise the outlook to stable if financial measures materially strengthen and, although unlikely, we reassess and conclude that group support would be readily available to fund ENO if a severe storm resulted in material restoration costs to the utility.

Company Description

ENO is a vertically integrated electric and natural gas distribution utility operating largely in New Orleans.

Our Base-Case Scenario

- Expected EBITDA margin averaging about 22% per year;
- Annual capital spending of $160 million to $180 million through 2022;
- Dividends over $20 million after 2020;
- Negative discretionary cash flow indicating external funding needs;
- Generally constructive regulatory environments help provide prudent cost recovery; and
- All debt maturities are refinanced.

Based on our assumptions, we expect the following measures over the forecast period through 2022:

- Annual adjusted FFO to debt in the 13%-15% range;
- Annual adjusted debt to EBITDA in the 4.5x-5.5x range; and
- Annual adjusted FFO cash interest coverage in the 4x-4.5x range.

Liquidity

We assess ENO's stand-alone liquidity as adequate, because we believe its liquidity sources are likely to cover uses by more than 1.1x over the next 12 months and meet cash outflows even with a 10% decline in EBITDA. The assessment also reflects the company's generally prudent risk management, sound relationship with banks, and a generally satisfactory standing in credit markets.

Principal liquidity sources

- Cash and liquid investments of about $30 million;
- Estimated cash FFO of about $120 million; and
- Credit facility availability of about $25 million.

Principal liquidity uses

- Debt maturities of about $25 million;
- Capital spending of about $120 million; and
- Dividends of about $10 million.

Group Influence

We view ENO as a member of the Entergy group. We assess ENO as a moderately strategic subsidiary of Entergy because it is important to Entergy's long-term strategy and it is reasonably successful as a utility, and we expect extraordinary group support will remain limited to some circumstances. As a result, our rating on ENO is based on its SACP of 'bbb-' and one notch of group support.

Issue Ratings - Recovery Analysis

ENO's first-mortgage bonds benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating of two notches above the issuer credit rating.

Ratings Score Snapshot

Issuer Credit Rating: BBB/Negative/--

Business risk: Strong

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Satisfactory

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: bbb

Modifiers

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Satisfactory (no impact)
- Comparable rating analysis: Negative (-1 notch)

Stand-alone credit profile: bbb-

- Group credit profile: bbb+
- Entity status within group: Moderately Strategic (+1 notch above SACP)

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013

- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings List

Downgraded; Outlook

	To	**From**
Entergy New Orleans LLC		
Issuer Credit Rating	BBB/Negative/--	BBB+/Negative/--

Ratings Lowered; Recovery Rating Unchanged

	To	From
Entergy New Orleans LLC		
Senior Secured	A-	A
Recovery Rating	1+	1+

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

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Research Update:

Entergy New Orleans LLC Downgraded To 'BB+' On Weather-Related Weaker Credit Metrics; Outlook Stable; Bond Rating Lowered

September 2, 2021

Rating Action Overview

- Entergy New Orleans LLC (ENO), an operating subsidiary of Entergy Corp. (Entergy), will likely have weaker financial measures than we previously expected because of higher capital spending from severe storms and hurricanes, like Hurricane Ida. We forecast ENO's adjusted funds from operations (FFO) to debt to be in the 12%-13% range through 2023.
- We lowered our issuer credit rating on ENO to 'BB+' from 'BBB'. At the same time, we lowered our ratings on ENO's first-mortgage bonds (FMBs) to 'BBB+' from 'A-'. The '1+' recovery rating on the bonds remains unchanged.
- The lower issuer credit rating reflects a change in the business risk profile to satisfactory from strong due to ongoing risks related to ENO's exposure to coastal storms. In addition, we apply the negative comparable ratings analysis modifier due to weaker financial measures within the financial risk category.
- The stable outlook reflects our view that ENO will restore operations following hurricane Ida in an orderly manner and that any additional costs will be manageable within the current financial risk profile assumptions.

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Rating Action Rationale

The lower issuer credit rating reflects a weakening of ENO's business risk along with weakening financial measures. We changed the business risk profile to satisfactory from strong, reflecting ENO's small service territory, limited diversity, and ongoing exposure to severe storms and hurricanes. This revision reflects the smaller size of the utility, exposure to severe storms including hurricanes due to its low-lying service territory along the Gulf Coast, and expectation of more volatile profitability measures. Financial risk measures have weakened within the significant financial risk profile category to the lower end of the benchmark range. The weaker measures include adjusted FFO to debt in the 12%-13% range from severe storms such as Hurricane Ida that lead to higher capital spending, operating expenses from storm restoration, and revenue declines following power outages and load reduction.

The outlook reflects our baseline forecast of weaker financial measures through 2023, the service territory's ongoing susceptibility to severe storms, and limited financial support from parent Entergy. Specifically, we expect ENO's service territory to have ongoing exposure to severe storms like the recent Hurricane Ida, potentially leading to significant liabilities and damages to the infrastructure. The stable outlook incorporates the weaker financial measures including adjusted FFO to debt in the 12%-13% range through 2022. Our downside scenario, while not expected, includes the potential that we could revise the designation of group support under our group rating methodology to nonstrategic if we perceive limited to no group support for ENO during times of stress. As such, we could downgrade ENO to reflect our view of ENO's stand-alone credit profile (SACP) of 'bb' and our assumption of no group support, particularly in times of stress such as for storm repairs or large capital spending initiatives.

Environmental, social and governance (ESG) credit factors for this credit rating change.

- Natural conditions

Outlook

The stable outlook reflects our view that ENO will restore operations following hurricane Ida in an orderly manner and that any additional costs will be manageable within the current financial profile assumptions. The company's small service territory, limited diversity, and ongoing exposure to severe storms and hurricanes remains a risk as does the expectation of weaker financial measures partly from higher capital spending and elevated leverage. Specifically, we forecast the company's adjusted consolidated FFO to debt to remain in the 12%-13% range through 2023.

Downside scenario

We could lower the ratings on ENO if its financial measures decline, including sustained adjusted FFO to debt consistently below 11%. We could also lower the rating if we revise the designation of group support under our group rating methodology to nonstrategic if we perceive limited to no group support for ENO during times of stress. As such, we could downgrade ENO to reflect our view of ENO's SACP of 'bb' and our assumption of no group support, particularly in times of stress such as for storm repairs or large capital spending initiatives.

Upside scenario

We could upgrade ENO if financial measures remain consistently above 17% and we believe group support would be readily available to fund ENO if a severe storm resulted in material restoration costs to the utility.

Company Description

ENO is a vertically integrated electric and a natural gas distribution utility operating largely in New Orleans.

Our Base-Case Scenario

- Expected EBITDA margin averaging about 20% per year;
- Annual capital spending of $205 million through 2023;
- Dividends over $30 million through 2023;
- Negative discretionary cash flow indicating external funding needs;
- Generally constructive regulatory environments help provide prudent cost recovery; and
- All debt maturities are refinanced.

Based on our assumption, we expect the following measures over the forecast period through 2023:

- Annual adjusted FFO to debt in the 12%-13% range;
- Annual adjusted debt to EBITDA in the 5.5x-6.5x range; and
- Annual adjusted FFO cash interest coverage in the 3.5x-5x range.

Liquidity

We assess the company's stand-alone liquidity as adequate because we believe its liquidity sources are likely to cover uses by more than 1.1x over the next 12 months and meet cash outflows even with a 10% decline in EBITDA. The assessment also reflects the company's generally prudent risk management, sound relationship with banks, and a generally satisfactory standing in credit markets.

Principal liquidity sources:

- Cash and liquid investments of about $25 million;
- Estimated cash FFO of about $130 million;
- Expected ongoing group support of $110 million; and
- $40 million of the storm reserve.

Principal liquidity uses:

- Debt maturities of about $70 million;
- Capital spending of about $205 million.

Group Influence

We view ENO as a member of the Entergy group. We assess ENO as a moderately strategic subsidiary of Entergy because it is important to Entergy's long-term strategy and it is reasonably successful as a utility, and we expect extraordinary group support will remain limited to some circumstances. As a result, our rating on ENO is based on its SACP of 'bb' and one notch of group support.

Issue Ratings - Recovery Analysis

Key analytical factors

- ENO's debt structure consists of $35.6 million in securitized bonds, $525 million in FMBs secured by mortgages on its regulated utility assets, unsecured bank debt consisting of a $25 million revolving facility, and a $70 million term loan, and a long-term payable obligation owed to an associated company.
- Our '1+' recovery rating on ENO's senior secured FMBs reflect the substantial value of its regulated utility assets, which is sufficiently larger than its secured debt and the limited amount of priority claims, and other liabilities. For our recovery analysis, we treat the securitized bonds as a priority claim due to its senior claim to the company's cash flows and the structural protections of this financing structure.
- The recovery rating indicates our highest expectation for full recovery and results in an issue-level rating three notches above our long-term issuer credit rating. It also reflects collateral coverage in excess of 150%, which is consistent with our criteria for recovery ratings on debt issued by regulated utilities and secured by key utility assets.
- A default could stem from sudden liquidity pressure amid additional severe disruptions due to unpredictable weather events, costs, or other market events outside the company's control, which is consistent with the conditions of past utility defaults.
- We expect ENO would continue to operate and reorganize after a default given the essential nature of its services. We also assume the value of the utility's assets would be preserved. We use the net value of its regulated fixed assets as a proxy for its enterprise value. The company's regulated asset value is roughly $1.458 billion.

Simulated default assumptions

- Simulated year of default: 2026
- Gross enterprise value (discrete asset valuation approach): $1.458 billion.

Simplified waterfall

- Net recovery value after administrative costs (5%): $1.385 billion
- ENO value: $1.385 billion
- Priority claims at ENO (securitization bonds, unrated): $36.1 million

- Secured debt claims at ENO (FMBs): $536.1 million
- -- Recovery expectations: 100% (coverage in excess of 150%)
- Residual value available to other ENO claimants: $812.8 million
- Unsecured debt and other estimated claims: $107.7 million

Debt amounts include six months of accrued interest that we assume will be owed at default. We also assume cash flow revolvers are 85% drawn at default. We assume any debt maturing before default is refinanced on similar terms before maturity.

Ratings Score Snapshot

Issuer Credit Rating: BB+/Stable/--

Business risk: Satisfactory

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Fair

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: bb+

Modifiers

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Satisfactory (no impact)
- Comparable rating analysis: Negative (-1 notch)

Stand-alone credit profile: bb

Group credit profile: bb+

- Entity status within group: Moderately strategic (+1 notches above SACP)

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- General Criteria: Hybrid Capital: Methodology And Assumptions, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Recovery Rating Criteria For Speculative-Grade Corporate Issuers, Dec. 7, 2016
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings List

Downgraded; Outlook Action

	To	From
Entergy New Orleans LLC		
Issuer Credit Rating	BB+/Stable/--	BBB/Negative/--
Issue-Level Ratings Lowered; Recovery Ratings Unchanged		
Entergy New Orleans LLC		
Senior Secured	BBB+	A-
Recovery Rating	1+	1+

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

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Research Update:

Entergy New Orleans LLC Downgraded To 'BB' From 'BB+ On Group Status Revision; Outlook Developing

September 24, 2021

Rating Action Overview

- Entergy Corp. proposed multiple options regarding subsidiary Entergy New Orleans LLC (ENO) including a sale, spinoff, or municipalization of the utility following an announcement from the New Orleans City Council (NOCC) president regarding the future ownership of the utility.
- As a result, we revised our assessment of ENO's group status to nonstrategic from moderately strategic. Our stand-alone credit profile (SACP) remains 'bb'.
- With the change in group support, ENO will receive no uplift from its SACP of 'bb'. Therefore, we lowered the issuer credit rating on ENO to 'BB' from 'BB+'.
- At the same time, we lowered our ratings on ENO's first-mortgage bonds (FMB) to 'BBB' from 'BBB+'. The recovery rating on the bonds remains '1+' (150%).
- The outlook is developing to reflect the uncertainty surrounding the future ownership of ENO, which could result in our assessment of the utility's credit quality as stronger, weaker, or it may not affect credit quality at all.

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Rating Action Rationale

We revised our assessment of ENO's group status to the Entergy group, under our group rating methodology to nonstrategic from moderately strategic. In the aftermath of Hurricane Ida, the NOCC announced the intention to study the future ownership of ENO after which Entergy proposed the sale, spinoff, or municipalization of ENO along with merging into affiliate Entergy Louisiana LLC. In our view, this indicates there it is unlikely that ENO would receive extraordinary support from Entergy group--particularly in times of severe stress. Therefore, we revised ENO's group status to nonstrategic from moderately strategic regarding ENO's strategic importance to Entergy.

We continue to assess our SACP on ENO as 'bb'. Our assessment of ENO's business risk is satisfactory and its financial risk is significant. Financial risk measures remain within the significant financial risk profile category but at the lower end of the benchmark range. Specifically, we forecast ENO's adjusted funds from operation (FFO) to debt to remain in the 12%-14% range through 2023.

Our developing outlook reflects uncertainty regarding the future ownership of ENO pending the conclusion of the NOCC's investigation. The developing outlook reflects the uncertainty surrounding the future ownership of ENO, which could result in our assessment of the utility's credit quality as stronger, weaker, or it may not affect credit quality at all. After NOCC reaches a decision and there is greater certainty regarding the future ownership of the utility, we will be able complete further analysis on the credit quality of ENO and reflect this in our ratings and outlook.

Outlook

The developing outlook indicates that we could take a rating action on ENO following NOCC's decision on the future ownership of the utility.

Downside scenario

We could lower the ratings on ENO if:

- Its financial measures decline, including sustained adjusted FFO to debt consistently below 10%; or
- The NOCC's review and decision on ownership of ENO will lead to fundamental deterioration of the utility's credit quality or through a potential weakening of the regulatory relationship or financial profile deterioration from storm-related costs.

Upside scenario

We could take a positive rating action on ENO if:

- The utility's financial measures remain consistently above 17%; or
- The NOCC's review and decision on ENO's ownership will lead to fundamental improvement of the utility's credit quality. Such an event could occur, for example, if ENO was to be acquired by a stronger parent that we believed would be likely to support ENO in times of severe stress.

Company Description

ENO is a vertically integrated electric and a natural gas distribution utility operating largely in New Orleans.

Our Base-Case Scenario

Elevated capital spending averaging about $235 million in 2021 and 2022 due to restoration costs from Hurricane Ida, and about $175 million in 2023.

Dividends averaging about $30 million per year through 2023.

Negative discretionary cash flow indicating external funding needs;

Generally constructive regulatory environments help provide prudent cost recovery; and

All debt maturities are refinanced.

Liquidity

We assess the company's stand-alone liquidity as adequate because we believe its liquidity sources are likely to cover uses by more than 1.1x over the next 12 months and meet cash outflows even with a 10% decline in EBITDA. The assessment also reflects the company's generally prudent risk management, sound relationship with banks, and a generally satisfactory standing in credit markets.

Principal Liquidity Sources

- Cash and liquid investments of about $25 million;
- Estimated cash FFO of about $130 million;
- Expected access to the Entergy money pool of $110 million; and
- Storm reserves of about $40 million.

Principal Liquidity Uses

- Debt maturities of about $70 million; and
- Capital spending of about $195 million.

Group Influence

We view ENO as a member of the Entergy group. We assess ENO as nonstrategic to the Entergy group, reflecting our view that the company has very limited strategic importance to the parent. We believe that Entergy will no longer provide extraordinary support to ENO. As a result, we based our rating on ENO on the utility's SACP of 'bb'.

Issue Ratings - Recovery Analysis

Key analytical factors

- ENO's debt structure consists of $35.6 million in securitized bonds, $525 million in FMBs secured by mortgages on its regulated utility assets, unsecured bank debt consisting of a $25 million revolving facility, and a $70 million term loan, and a long-term payable obligation owed to an associated company.
- Our '1+' recovery rating on ENO's senior secured FMBs reflect the substantial value of its regulated utility assets, which is sufficiently larger than its secured debt and the limited amount of priority claims, and other liabilities. For our recovery analysis, we treat the securitized bonds as a priority claim due to its senior claim to the company's cash flows and the structural protections of this financing structure.
- The recovery rating indicates our highest expectation of full recovery and results in an

issue-level rating three notches above our long-term issuer credit rating. It also reflects collateral coverage in excess of 150%, which is consistent with our criteria for recovery ratings on debt issued by regulated utilities and secured by key utility assets.

- A default could stem from sudden liquidity pressure amid additional severe disruptions due to unpredictable weather events, costs, or other market events outside the company's control, which is consistent with the conditions of past utility defaults.
- We expect ENO would continue to operate and reorganize after a default given the essential nature of its services. We also assume the value of the utility's assets would be preserved. We use the net value of its regulated fixed assets as a proxy for its enterprise value. The company's regulated asset value is roughly $1.458 billion.

Simulated default assumptions

- Simulated year of default: 2026
- Gross enterprise value (discrete asset valuation approach): $1.458 billion.

Simplified waterfall

- Net recovery value after administrative costs (5%): $1.385 billion
- ENO value: $1.385 billion
- Priority claims at ENO (securitization bonds, unrated): $36.1 million
- Secured debt claims at ENO (FMBs): $536.1 million
- -- Recovery expectations: 100% (coverage in excess of 150%)
- Residual value available to other ENO claimants: $812.8 million
- Unsecured debt and other estimated claims: $107.7 million

Debt amounts include six months of accrued interest that we assume will be owed at default. We also assume cash flow revolvers are 85% drawn at default. We assume any debt maturing before default is refinanced on similar terms before maturity.

Ratings Score Snapshot

Issuer Credit Rating: BB/Developing/--

Business risk: Satisfactory

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Fair

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: bb+

Modifiers

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Satisfactory (no impact)
- Comparable rating analysis: Negative (-1 notch)

Stand-alone credit profile: bb

Group credit profile: bbb+

- Entity status within group: Nonstrategic (no impact)

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Recovery Rating Criteria For Speculative-Grade Corporate Issuers, Dec. 7, 2016
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate

Entities, Nov. 13, 2012

- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Related Research

Entergy New Orleans LLC Downgraded To 'BB+' On Weather-Related Weaker Credit Metrics; Outlook Stable; Bond Rating Lowered, Sept. 2, 2021

Ratings List

Downgraded; Outlook Action

	To	From
Entergy New Orleans LLC		
Issuer Credit Rating	BB/Developing/--	BB+/Stable/--
Issue-Level Ratings Lowered; Recovery Ratings Unchanged		
Entergy New Orleans LLC		
Senior Secured	BBB	BBB+
Recovery Rating	1+	1+

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

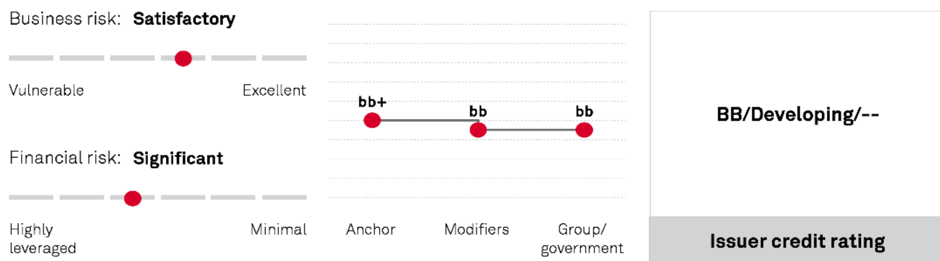
S&P Global
Ratings

RatingsDirect®

Entergy New Orleans LLC

August 30, 2022

Ratings Score Snapshot



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Credit Highlights

Overview

Key strengths	Key risks
Fully rate-regulated utility with a generally stable regulatory framework.	Small customer base with modest growth.
Residential and commercial customers contribute about 80% of operating revenues, providing stability to the revenue and cash flow.	Susceptible to weather-related disasters.
	Limited geographic, regulatory, and business diversity.
	Given the uncertainty of company’s future ownership, the issuer credit rating does not benefit from the parent's higher-rated group credit profile.

The New Orleans City Council (NOCC) announced its intention to study the future ownership of Entergy New Orleans LLC (ENO). Subsequently, Entergy Corporation proposed the sale, spin-off, or municipalization of ENO along with possibly merging it into affiliate Entergy Louisiana LLC. We view these developments as demonstrating significant uncertainty surrounding the future ownership of ENO, which could result in our assessing the utility's credit quality as stronger, weaker, or the same. Our developing outlook reflects this high degree of uncertainty, and we will monitor related developments. Also because of this uncertainty, we assess ENO as a nonstrategic subsidiary of Entergy Corp. and accordingly, our issuer credit rating on ENO does not benefit from Entergy's higher-rated group credit profile.

ENO's credit quality is materially affected by its small service territory, limited diversity, and ongoing exposure to severe storms and hurricanes. ENO operates in a low-lying service territory along the Gulf Coast, increasing its susceptibility to physical risks. We believe the company remains exposed to severe storms--such as Hurricane Ida in 2021--that can significantly damage its infrastructure. This could result in higher capital spending and operating expenses from storm restoration and revenue declines following power outages and load reduction. Overall, this credit risk also increases ENO's volatility of profitability measures, weakening credit quality.

We are monitoring ENO's securitization application. ENO filed for the recovery of about $133 million of storm costs, reduced by the storm escrow of about $46 million. We expect a decision by the NOCC in the first quarter of 2023. Additionally, in February 2022, ENO filed a securitization application with the NOCC requesting a review of ENO's storm reserve and to replenish the storm reserve funding level to $150 million, to be funded through securitization. We expect a decision on this in third quarter of 2022. In general, we view securitization as supportive of credit quality.

Outlook

The developing outlook indicates that we could take a rating action on ENO following NOCC's decision on the future ownership of the utility, which could result in our assessment of the utility's credit quality as stronger, weaker, or unchanged.

Downside scenario

We could lower the rating on ENO if:

- The utility's financial measures decline, including sustained adjusted funds from operations (FFO) to debt consistently below 10%;
- Credit quality weakens following the NOCC's review and decision on ownership of ENO;
- The regulatory relationship weakens; or
- The financial profile deteriorates as a result of storm-related costs.

Upside scenario

We could take a positive rating action on ENO if:

- The utility's FFO to debt consistently exceeds 17%; or
- The NOCC's review and decision on ENO's ownership improves the utility's credit quality. Such an event could occur, for example, if ENO were acquired by a stronger parent that we believed would likely support ENO in times of severe stress.

Our Base-Case Scenario

Assumptions

- Elevated capital spending averaging about $220 million through 2026;
- Negative discretionary cash flow, indicating external funding needs;
- Generally constructive regulatory environments help provide prudent cost recovery; and
- All debt maturities are refinanced.

Key metrics

Entergy New Orleans LLC--Key Metrics*

	2021a	2022e	2023f	2024f
FFO to debt (%)	14.1	13-14	14.5-15.5	14-15
Debt to EBITDA (x)	5.7	6.0-6.5	5.0-5.5	5.5-6.0
FFO cash interest coverage (x)	4.6	4.5-5.0	4.5-5.0	4.5-5.0

*All figures adjusted by S&P Global Ratings. a--Actual. e--Estimate. f--Forecast. FFO--Funds from operations.

Company Description

ENO is a vertically integrated electric and a natural gas distribution utility operating largely in New Orleans. It serves a small customer base of 209,000 electric and 110,000 natural gas customers, and it has a generation fleet of about 650 megawatts. About 95% of its generation portfolio is natural gas-fired generation, and the rest is solar generation.

Peer Comparison

Entergy New Orleans, LLC--Peer Comparisons

	Entergy New Orleans LLC	Cleco Power LLC	Tucson Electric Power Co.
Foreign currency issuer credit rating	BB/Developing/--	BBB+/Stable/NR	A-/Stable/NR
Local currency issuer credit rating	BB/Developing/--	BBB+/Stable/NR	A-/Stable/NR
Period	Annual	Annual	Annual
Period ending	2021-12-31	2021-12-31	2021-12-31
Mil.	$	$	$
Revenue	756	1,242	1,593
EBITDA	135	410	537
Funds from operations (FFO)	107	334	450
Interest	32	77	91
Cash interest paid	32	75	87
Operating cash flow (OCF)	71	99	418
Capital expenditure	221	298	548
Free operating cash flow (FOCF)	(149)	(199)	(130)
Discretionary cash flow (DCF)	(149)	(199)	(193)
Cash and short-term investments	43	86	10
Gross available cash	43	86	10

Entergy New Orleans, LLC--Peer Comparisons

Debt	845	2,008	2,354
Equity	639	1,949	2,531
EBITDA margin (%)	17.8	33.0	33.7
Return on capital (%)	4.9	5.9	6.4
EBITDA interest coverage (x)	4.2	5.3	5.9
FFO cash interest coverage (x)	4.3	5.4	6.1
Debt/EBITDA (x)	6.3	4.9	4.4
FFO/debt (%)	12.6	16.6	19.1
OCF/debt (%)	8.4	5.0	17.7
FOCF/debt (%)	(17.7)	(9.9)	(5.5)
DCF/debt (%)	(17.7)	(9.9)	(8.2)

Business Risk

Our assessment of ENO's business risk profile is negatively affected by its relatively small size (ENO only provides about 6% of Entergy's consolidated revenues), limited regulatory and business diversity, and its susceptibility to physical risks. The company's business risk is affected by the propensity and severity of storm activity within ENO's service territory along the Gulf Coast, as well as the utility's limited ability to protect against severe storms. Because of these risks, we assess the company at the lower half of the range of its business risk profile category, compared to peers. While we view securitization as a great backstop for storm restoration costs, securitization takes time to receive the ultimate funds, and it takes up headroom in rates for recovery of, and on, rate base investments. The company has requested the NOCC's approval for investment of $1.5 billion over 10 years toward grid resilience, hardening projects, and microgrid projects, which we view as credit supportive in the long run.

Supporting its business risk profile is the stability of cash flow. About 80% of ENO's customers are residential and commercial. Also, the company operates within a credit-supportive regulatory jurisdiction. ENO is regulated by the NOCC under a generally stable regulatory construct. The tariff setting is characterized by historical test years that can be updated for known and measurable changes, reducing regulatory lag and supporting operating cash flow and credit quality. In April 2022, ENO submitted its annual Formula Rate Plan (FRP) filing for the 2021 test year, requesting a rate increase of $42 million, including $4.7 million electric revenues previously approved by the New Orleans City Council. The request incorporates a rate base of $1.4 billion at a weighted-average cost of capital of 6.88% and earned return on equity of 5.43% for electric and 7.09% for gas.

Financial Risk

Our assessment of ENO's stand-alone financial risk profile incorporates a base-case scenario that includes adjusted FFO to debt of 13%-15% through 2024, which is at the lower end of the benchmark range of the significant financial risk profile category. In addition, we anticipate continued robust capital spending, which will result in negative discretionary cash flow through 2024. The utility will therefore require external financing or capital infusions from the Entergy group.

We assess ENO's financial risk under our medial volatility financial benchmarks, reflecting the company's lower-risk, regulated utility operations and effective management of regulatory risk. These benchmarks are more relaxed compared with those we use for a typical corporate issuer.

We assess the comparable rating analysis modifier as negative to account for our expectation that ENO's stand-alone financial measures will consistently reflect the lower end of the range for its financial risk profile category and our assessment of the company's business risk profile at the lower half of the range for its business risk profile category, compared to peers. The weak business risk profile also reflects the company's vulnerability to hurricanes, a risk that could stress credit measures.

Entergy New Orleans, LLC--Financial Summary

Period ending	Dec-31-2016	Dec-31-2017	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021
Reporting period	2016a	2017a	2018a	2019a	2020a	2021a
Display currency (mil.)	$	$	$	$	$	$
Revenues	652	703	705	674	621	756
EBITDA	144	142	128	119	125	135
Funds from operations (FFO)	208	127	140	95	89	107
Interest expense	24	24	27	27	32	32
Cash interest paid	22	23	27	29	32	32
Operating cash flow (OCF)	195	119	162	103	55	71
Capital expenditure	328	116	202	227	232	221
Free operating cash flow (FOCF)	(133)	3	(40)	(124)	(177)	(149)
Discretionary cash flow (DCF)	(152)	(93)	(64)	(124)	(177)	(149)
Cash and short-term investments	103	33	20	6	0	43
Gross available cash	103	33	20	6	0	43
Debt	340	390	509	604	731	845
Common equity	437	416	445	498	607	639
Adjusted ratios						
EBITDA margin (%)	22.2	20.1	18.1	17.7	20.1	17.8
Return on capital (%)	14.4	12.7	8.5	7.3	5.9	4.9
EBITDA interest coverage (x)	6.1	6.0	4.7	4.4	3.9	4.2
FFO cash interest coverage (x)	10.3	6.5	6.1	4.2	3.8	4.3
Debt/EBITDA (x)	2.3	2.8	4.0	5.1	5.8	6.3
FFO/debt (%)	61.3	32.6	27.5	15.8	12.2	12.6
OCF/debt (%)	57.5	30.4	31.8	17.1	7.5	8.4
FOCF/debt (%)	(39.2)	0.8	(7.8)	(20.5)	(24.2)	(17.7)
DCF/debt (%)	(44.8)	(23.8)	(12.5)	(20.5)	(24.2)	(17.7)

Reconciliation Of Entergy New Orleans, LLC Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

		Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2021										
Company reported amounts		788	639	769	138	65	28	135	79	-	218

Reconciliation Of Entergy New Orleans, LLC Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Cash taxes paid	-	-	-	-	-	-	4	-	-	-
Cash interest paid	-	-	-	-	-	-	(28)	-	-	-
Lease liabilities	10	-	-	-	-	-	-	-	-	-
Operating leases	-	-	-	2	0	0	(0)	2	-	-
Accessible cash and liquid investments	(43)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	1	(1)	(1)	-	(1)
Securitized stranded costs	(31)	-	(13)	(13)	(1)	(1)	1	(12)	-	-
Power purchase agreements	118	-	-	7	4	4	(4)	4	-	4
Asset-retirement obligations	3	-	-	0	0	0	-	-	-	-
Nonoperating income (expense)	-	-	-	-	1	-	-	-	-	-
Total adjustments	57	-	(13)	(3)	4	4	(28)	(8)	-	3
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	845	639	756	135	69	32	107	71	-	221

Liquidity

We assess the company's stand-alone liquidity as adequate because we believe its liquidity sources will likely cover uses by more than 1.1x over the next 12 months and meet cash outflows even if EBITDA declines 10%. The assessment also reflects the company's generally prudent risk management, sound relationship with banks, and a generally satisfactory standing in credit markets.

Principal liquidity sources

- Cash and liquid investments of about $30 million;
- Credit facility availability of about $25 million;
- Estimated cash FFO of about $140 million; and
- Working capital inflow of about $7 million.

Principal liquidity uses

- Capital spending of at least $160 million.

Environmental, Social, And Governance

ESG Credit Indicators

E-1	E-2	E-3	E-4	**E-5**	S-1	S-2	**S-3**	S-4	S-5	G-1	**G-2**	G-3	G-4	G-5

Environmental	Social	Governance
- Physical risks - Climate transition risks	- Social capital	- N/A

N/A--Not applicable. ESG credit indicators provide additional disclosure and transparency at the entity level and reflect S&P Global Ratings' opinion of the influence that environmental, social, and governance factors have on our credit rating analysis. They are not a sustainability rating or an S&P Global Ratings ESG Evaluation. The extent of the influence of these factors is reflected on an alphanumerical 1-5 scale where 1 = positive, 2 = neutral, 3 = moderately negative, 4 = negative, and 5 = very negative. For more information, see our commentary "ESG Credit Indicator Definitions And Applications," published Oct. 13, 2021.

Environmental factors are a very negative consideration in our credit rating analysis of ENO, namely because the utility's service territory has severe storm and hurricane risks. The company's exposure to severe storms including hurricanes, a low-lying service territory along the Gulf Coast, and relatively limited size and diversity to help absorb the effect of such storms are negative factors in our rating analysis. We expect the service territory to have ongoing exposure to severe storms that can lead to significant liabilities and damage to the infrastructure. Social factors are moderately negative because of reputational damage after severe storms and hurricanes, including Hurricane Katrina and Hurricane Ida.

Group Influence

We view ENO as a member of the Entergy group. We assess ENO as nonstrategic to the Entergy group, reflecting our view that the company has very limited strategic importance to the parent. We believe that Entergy will no longer provide extraordinary support to ENO. As a result, we base our rating on ENO on the utility's stand-alone credit profile (SACP) of 'bb'.

Issue Ratings--Recovery Analysis

Key analytical factors

- ENO's debt structure consists of $30.9 million in securitized bonds, $685 million in first-mortgage bonds (FMBs) secured by mortgages on its regulated utility assets, unsecured bank debt consisting of a $25 million revolving facility and a $70 million term loan, and a long-term payable obligation owed to an associated company.
- Our '1+' recovery rating on ENO's senior secured FMBs reflects the substantial value of its regulated utility assets, which is sufficiently larger than its secured debt, limited priority claims, and other liabilities. For our recovery analysis, we treat the securitized bonds as a priority claim due to its senior claim to the company's cash flow and the structural protections of this financing structure.
- The recovery rating indicates our highest expectation of full recovery and results in an issue-level rating three notches above our long-term issuer credit rating. It also reflects collateral coverage in excess of 150%, which is consistent with our criteria for recovery ratings on debt issued by regulated utilities and secured by key utility assets.
- A default could stem from sudden liquidity pressure amid additional severe disruptions due to unpredictable weather events, costs, or other market events outside the company's control, which is consistent with the conditions of past utility defaults.
- We expect ENO would continue to operate and reorganize after a default given the essential nature of its services. We also assume the value of the utility's assets would be preserved. We use the net value of its regulated fixed assets as a proxy for its enterprise value. The company's regulated asset value is about $1.458 billion.

Simulated default assumptions

- Simulated year of default: 2026
- Gross enterprise value (discrete asset valuation approach): $1.458 billion.

Simplified waterfall

- Net recovery value after administrative costs (5%): $1.385 billion
- ENO value: $1.385 billion
- Priority claims at ENO (securitization bonds, unrated): $36.1 million
- Secured debt claims at ENO (FMBs): $536.1 million
- -- Recovery expectations: 100% (coverage in excess of 150%)
- Residual value available to other ENO claimants: $812.8 million
- Unsecured debt and other estimated claims: $107.7 million

Rating Component Scores

Foreign currency issuer credit rating	**BB/Developing/--**
Local currency issuer credit rating	**BB/Developing/--**
Business risk	**Satisfactory**
Country risk	Very Low
Industry risk	Very Low
Competitive position	Fair
Financial risk	**Significant**
Cash flow/leverage	Significant
Anchor	**bb+**
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Satisfactory (no impact)
Comparable rating analysis	Negative (-1 notch)
Stand-alone credit profile	**bb**

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Recovery Rating Criteria For Speculative-Grade Corporate Issuers, Dec. 7, 2016
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- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings Detail (as of August 30, 2022)*

Entergy New Orleans LLC	
Issuer Credit Rating	BB/Developing/--
Senior Secured	BBB
Issuer Credit Ratings History	
24-Sep-2021	BB/Developing/--
02-Sep-2021	BB+/Stable/--
08-Oct-2020	BBB/Negative/--
02-Oct-2020	BBB+/Negative/--
03-May-2018	BBB+/Stable/--
Related Entities	
Entergy Arkansas LLC	
Issuer Credit Rating	A-/Stable/--
Senior Secured	A
Entergy Corp.	
Issuer Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Unsecured	BBB
Entergy Louisiana LLC	
Issuer Credit Rating	BBB+/Stable/--
Senior Secured	A
Entergy Mississippi LLC	
Issuer Credit Rating	A-/Stable/--
Senior Secured	A
Entergy Texas Inc.	
Issuer Credit Rating	BBB+/Stable/--
Preferred Stock	BBB-
Senior Secured	A
System Energy Resources Inc.	
Issuer Credit Rating	BBB+/Stable/--
Senior Secured	A

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings credit ratings on the global scale are comparable across countries. S&P Global Ratings credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's changes the outlooks of Entergy Corp. and its two Louisiana-based utilities to negative from stable

23 Sep 2021

Approximately $17 billion of debt securities affected

New York, September 23, 2021 -- Moody's Investors Service ("Moody's") today affirmed the ratings of Entergy Corporation (Entergy, including its Baa2 senior unsecured rating and P-2 short-term rating for commercial paper) and its two Louisiana-based utilities Entergy Louisiana, LLC (ELL, including its Baa1 Issuer rating) and Entergy New Orleans, LLC. (ENOL, including its Ba1 Issuer rating). The outlooks of all three entities were changed to negative from stable. See a complete list of affected debt toward the end of this press release.

The negative outlooks follow a 21 September 2021 8-K filing [1] which indicated that restoration costs for the repair and/or replacement of the electrical facilities damaged by Hurricane Ida are estimated to be in the range of $2.1 billion to $2.6 billion, higher than we had originally anticipated.

RATINGS RATIONALE

"The physical effects of climate change continue to cause significant damage to Entergy's Louisiana service territory, with over $4.5 billion of total storm costs for Entergy Louisiana and Entergy New Orleans combined over the past 13 months" said Ryan Wobbrock, Vice President - Senior Credit Officer. "These added costs will place incremental pressure on customer bills -- increasing risks related to customer relations and potential political intervention into rate making - and could keep Entergy's financial performance lower for longer" added Wobbrock.

While Entergy's current liquidity profile is adequate to address these costs over the near term and storm cost securitization has a proven track record for both of its Louisiana utilities, successive years with $2.0 billion storm events is unprecedented and could result in social and political push-back preventing full, timely and ongoing cost recovery.

The frequency and severity of storms could also cause Entergy's currently weakened financial profile (e.g., CFO pre-WC to debt of about 10% through LTM 2Q21) to persist, should securitization be delayed, political intervention surface for other incremental rate increases or additional storms cause further damage.

ELL has taken the brunt of these costs, with about $2.0 billion incurred in 2020 and preliminary estimates indicating that Hurricane Ida has caused another $2.0 - $2.4 billion. The roughly $4.0 billion of costs represent nearly 30% of ELL's approximately $14 billion total rate base.

ENOL's Ba1 Issuer rating already incorporates the utility's storm exposure to some degree and the likelihood of costly repairs that may be needed in any given year. However, a high degree of contentiousness and politicization has already begun in New Orleans, with various calls for an investigation into ENOL's performance during Hurricane Ida, a management audit, consideration of the potential sale or municipalization of the utility and market reforms introducing retail competition. These various and unique social pressures around stakeholder and customer relations have arisen largely as a result of customer outages experienced during the storm.

From a cost perspective, ENOL has been less affected by recent storms than ELL, with 2020 and 2021 combined storm costs expected to be under $200 million (i.e., about $40 million from Hurricane Zeta in 2020 and an estimated $120-$150 million for Hurricane Ida), which is about 20% of total electric and gas rate base.

The combination of these headwinds creates higher-risk political, regulatory and operating environments for both the utilities and Entergy. Should financial improvements not materialize over the next 12-18 months as a result of securitization or other measures, negative rating action could ensue.

Outlooks

The negative outlooks for Entergy, ELL and ENOL reflect the added cost burden imposed by recent storm activity and the potential for impaired customer relations, increased political or regulatory challenges to full and timely cost recovery, and prolonged financial metric weakness.

FACTORS THAT COULD LEAD TO AN UPGRADE OR DOWNGRADE OF THE RATINGS

Factors that could lead to a downgrade

Entergy could be downgraded if there are challenges affecting the company's ability to achieve a 14% cash flow to debt ratio by 2023, if one or more of its key subsidiaries are downgraded or if there is a decline in regulatory support for its utilities.

ELL and ENOL could be downgraded if storm costs are not recovered on a timely basis, if regulatory support declines or if the ratio of CFO pre-WC to debt declines (below 18% for ELL or below the mid-teens percent range for ENOL) for an extended period of time.

Additional material and destructive storms could also apply downward pressure the ratings of Entergy, ELL and ENOL.

Factors that could lead to an upgrade

Given the negative outlook for all three companies, it is unlikely that any of them will be upgraded over the next 12-18 months. However, the outlooks could stabilize if regulatory support remains consistent with recent historical practices, storm costs are recovered on a timely basis and if each company can recover to appropriate CFO pre-WC to debt levels by year-end 2023.

Affirmations:

..Issuer: Entergy Corporation

.... Issuer Rating, Affirmed Baa2

....Senior Unsecured Shelf, Affirmed (P)Baa2

....Senior Unsecured Commercial Paper, Affirmed P-2

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa2

..Issuer: Entergy Louisiana, LLC

.... Issuer Rating, Affirmed Baa1

....Senior Secured First Mortgage Bonds, Affirmed A2

....Senior Secured Shelf, Affirmed (P)A2

..Issuer: Entergy New Orleans, LLC.

.... Issuer Rating, Affirmed Ba1

....Senior Secured First Mortgage Bonds, Affirmed Baa2

..Issuer: Louisiana Loc. Govt. Env. Fac.& Comm.Dev.Auth

....Senior Secured Revenue Bonds, Affirmed A2

..Issuer: Louisiana Public Facilities Authority

....Senior Secured Revenue Bonds, Affirmed A2

Outlook Actions:

..Issuer: Entergy Corporation

....Outlook, Changed To Negative From Stable

..Issuer: Entergy Louisiana, LLC

....Outlook, Changed To Negative From Stable

..Issuer: Entergy New Orleans, LLC.

....Outlook, Changed To Negative From Stable

The principal methodology used in these ratings was Regulated Electric and Gas Utilities published in June 2017 and available at https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_1072530 . Alternatively, please see the Rating Methodologies page on www.moodys.com for a copy of this methodology.

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For further specification of Moody's key rating assumptions and sensitivity analysis, see the sections Methodology Assumptions and Sensitivity to Assumptions in the disclosure form. Moody's Rating Symbols and Definitions can be found at: https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_79004.

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At least one ESG consideration was material to the credit rating action(s) announced and described above.

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REFERENCES/CITATIONS

[1] https://entergycorporation.gcs-web.com/node/33331/html

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CREDIT OPINION
29 September 2021

Update

Rate this Research

Entergy New Orleans, LLC.

Update following outlook change to negative

Summary

Entergy New Orleans, LLC.'s (ENOL, Ba1 negative) credit profile is supported by its monopoly service territory as a vertically integrated utility company and predictable financial metrics derived from a formula rate plan (FRP).

ENOL's credit profile is challenged by its small, geographically concentrated service territory in a storm-prone location. The coastal nature of the service territory is a material credit negative due to the rising risk of storm surges, more severe weather events and the impact this has on customer migration or local economic conditions. For these reasons, ENOL's credit quality is well below peer utilities with similar financial metrics.

Recent storm events have also created a more contentious political and regulatory environment for ENOL, with various calls for an investigation into the utility's performance during Hurricane Ida (August 2021), a management audit, consideration of a potential sale or municipalization of the utility and market reforms introducing retail competition. These various and unique social pressures around stakeholder and customer relations could have negative financial implications for the company, if support for incremental rate increases wanes.

Recent Developments

On 23 September 2021, we changed the outlooks of ENOL, its parent company Entergy Corp. (Baa2 negative) and affiliate utility, Entergy Louisiana, LLC (ELL, Baa1 negative) to negative following a 21 September 2021 8-K filing which indicated that restoration costs for the repair and/or replacement of the electrical facilities damaged by Hurricane Ida are estimated to be in the range of $2.1 billion to $2.6 billion, enterprise-wide, which are higher than we had originally anticipated.

From a cost perspective, ENOL has been less affected by the most recent storms than ELL, with 2020 and 2021 combined storm costs expected to be under $200 million (i.e., about $40 million from Hurricane Zeta in 2020 and an estimated $120-$150 million for Hurricane Ida), which is about 20% of ENOL's total electric and gas rate base.

RATINGS

Entergy New Orleans, LLC.

Domicile	New Orleans, Louisiana, United States
Long Term Rating	Ba1
Type	LT Issuer Rating
Outlook	Negative

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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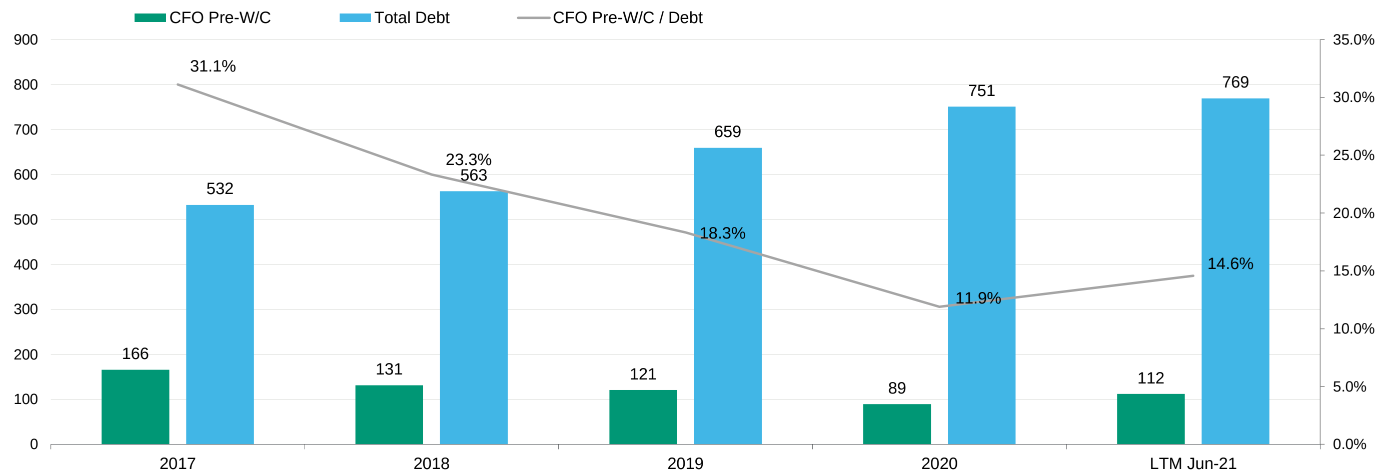
Exhibit 1
Historical CFO pre-WC, CFO pre-WC to Debt, Total Debt



Source: Moody's Financial Metrics

Credit strengths

» Adequate financial metrics should be sustainable given regulatory provisions and a rate base of around $900 million

» Storm cost recovery mechanisms are tested and important features given climate risks

Credit challenges

» Small and concentrated service territory in a low-lying coastal region exposed to storm surges and severe weather events

» Weaker than expected financial metrics due to recent storm activity

» Currently contentious political and regulatory environment following Hurricane Ida

Rating outlook

ENOL's negative outlook reflects a higher-risk political and regulatory environment following Hurricane Ida. Customer outages and the added cost burden caused by recent storm activity risks impaired customer relations, increased political or regulatory challenges to full and timely cost recovery, and prolonged financial metric weakness.

Factors that could lead to an upgrade

» It is unlikely that ENOL's issuer rating will be upgraded to Baa3, due to its concentrated service territory and vulnerability to storm activity.

» However, the maintenance of a financial profile that is much stronger than peer utilities and significantly improved regulatory and legislative support could lead to an upgrade

Factors that could lead to a downgrade

» A materially adverse regulatory decision

» Significant storm damage and delayed cost recovery for repairs

» A sustained decline in financial metrics, including cash flow to debt ratios remaining below the mid-teens

Key indicators

Entergy New Orleans, LLC.

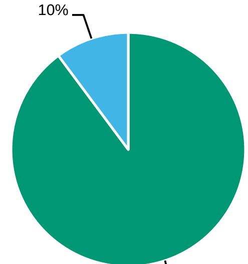
	Dec-17	Dec-18	Dec-19	Dec-20	LTM Jun-21
CFO Pre-W/C + Interest / Interest	8.1x	6.3x	5.5x	3.8x	4.4x
CFO Pre-W/C / Debt	31.1%	23.3%	18.3%	11.9%	14.6%
CFO Pre-W/C – Dividends / Debt	17.0%	19.1%	18.3%	11.9%	14.6%
Debt / Capitalization	43.5%	42.6%	44.0%	44.3%	44.6%

All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Profile

ENOL is an electric and gas utility serving the city of New Orleans, Louisiana. The company is the smallest of the Entergy Corporation (Entergy, Baa2 negative) family, which includes five utility subsidiaries and System Energy Resources, Inc. (SERI Baa3 negative, a 1,400 MW nuclear unit in Mississippi). ENOL represents well under 10% of Entergy's adjusted consolidated cash flow, debt and net PP&E. ENOL's rate base is currently split roughly 90:10 (i.e., roughly $800 million to about $100 million) between electric and gas assets.

Exhibit 3
Roughly 90% of ENOL's revenue is derived from electric operations, even amid COVID-19 challenges for electric sales
Revenue ($M) for the 3 months ended 30 June 2021



Source: Entergy Corp.

Detailed credit considerations

More contentious political and regulatory environment following Hurricane Ida

The magnitude of the damage ($120-$150 million) and customer outages (roughly 205,000 at the peak of the storm) caused by Hurricane Ida has resulted in a higher level of political and regulatory contentiousness for ENOL, with various calls for an investigation into the utility's performance during Hurricane Ida, a management audit, consideration of the potential sale or municipalization of the utility and market reforms introducing retail competition. While a negative political reaction to severe storms is not new for the utility industry, the nature and severity of the rhetoric in New Orleans is unusual, including Entergy's own press release (21 September 2021) that outlined four potential paths for the future operation and ownership of ENOL (i.e., a merger with ELL, sale of ENOL to a third party, spin off ENOL as a stand-alone company and ENOL municipalization).

Given the degree of political and stakeholder scrutiny at this time, it is possible that regulators will modify they typical nature of storm recovery, or limit other rate increases requested by the utility in annual FRP filings - a key consideration in ENOL's negative outlook. We will continue to monitor the progress with storm and FRP filings, as well as the future legal structure and ownership of the utility.

Notwithstanding the current relationship climate between Entergy and the City of New Orleans, there is a strong precedent for storm cost securitization in New Orleans and we expect that ENOL will be able to move forward on this mode of cost recovery. We view securitization to be a credit positive method of cost recovery, since it incorporates the lowest cost of financing to minimize the customer rate impact and is non-recourse to the utility, which acts as a pass through conduit of collections. We estimate that $150 million of storm cost securitization would translate to about a 1% increase to ENOL revenue, or about 3% of non-fuel related gross profit.

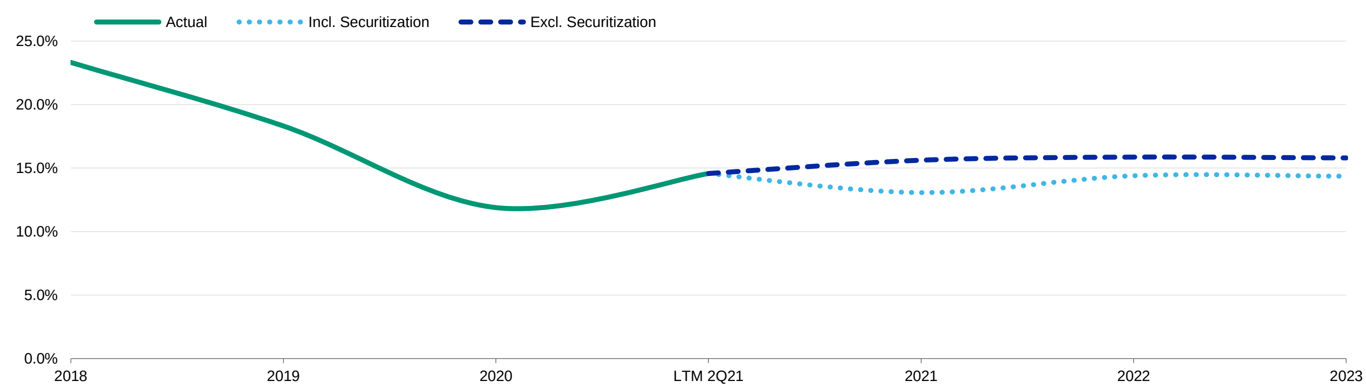
Ida occurred only 11 months after Hurricane Zeta, which also caused damage to the company's service territory in October 2020. However, the cost of Zeta was much less, at roughly $36 million, including approximately $28 million in capital costs and about $8 million in operating costs.

Financial metrics should remain steady around 16% CFO pre-WC to debt over the next two years

Based upon ENOL's regulatory rate framework, we expect the utility will generate CFO pre-WC to debt in the mid teen's percent range through 2023. Even without storm-related headwinds from lost revenue, higher costs and additional debt, this financial profile will remain below historical averages due to the ongoing impact of 2017's federal tax reform, a lower ROE and increasing debt used to fund capital expenditures.

In Exhibit 4, we show our base case financial projections (the “excluding securitization” line disregards securitized debt) for ENOL, based on its regulatory allowed rate base (approximately $900 million), capital structure (51%) and allowed ROE (9.35%). Our assumptions also include some growth attributable to around $480 million in capital expenditures made from 2021-2023 and including new generation assets in rates and a modest level of deferred tax benefits. Tax assumptions could differ materially from actual results since Entergy employs aggressive tax strategies at times, which has greatly benefitted ENOL and affiliate cash flow in the past. Exhibit 4 also shows the impact that securitizing $150 million of debt would have on ENOL's metrics (“Including securitization”).

Exhibit 4
ENOL's CFO pre-WC to debt should remain steady in the mid-teen's percent range through 2023



Source: Moody's Financial Metrics and Moody's projections

Aside from storm repair and equipment replacement, ENOL's capital expenditure program will include advanced metering infrastructure, additional solar power generation resources as well as the long-term repair and replacement of 844 miles of steel and cast iron pipes that were flooded with saltwater after hurricanes Katrina and Rita. The company has estimated that the effort will cost a total of $465 million over several years, an amount that has been certified by the New Orleans City Council.

Monopoly utility operating within a formulaic rate plan framework

ENOL's credit is underpinned by its business profile as a vertically integrated utility operating in a monopoly service territory with a regulatory allowed return on equity. The underlying framework of ENOL's regulated rates is supportive, since it includes a three-year formula rate plan (FRP) for both electric and gas operations and a pilot program for full revenue decoupling. The FRP also contains some forward-looking adjustments for known and measurable costs in subsequent FRP evaluation periods and new rate constructs for renewable power offerings and electric vehicle investments.

In July 2021, ENOL submitted its FRP 2020 test year filing, which reported a 6.26% earned ROE and seeks approval for about $65 million of rate increases. The case is still being reviewed, with resulting rates to be effective in November, unless the City Council sets a procedural schedule that would extend the process into 2022.

Previously, the City Council had approved certain parameters of the FRP, which allows ENOL to: 1) use a 51% equity structure, 2) increase the depreciation rate (and annual revenue recovery) of its New Orleans Power Station to 3% from 2%, 3) retain over-recovery of $2.2 million in rider revenues, 4) recover $1.4 million of certain rate case expenses outside of the earnings band and 5) recover the costs of the New Orleans Solar Station (NOSS, a 20 MW solar plant) upon its completion. NOSS has subsequently been completed and is now in-service and reflected in rates.

These features provide a line of sight into what ENOL's cost recovery and financial position should be - absent any regulatory penalties or changes to the framework - throughout the three-year plan period, a credit positive.

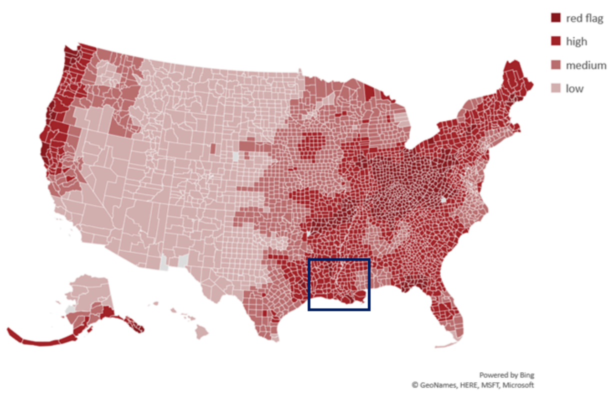
ESG considerations

Environmental - climate risks

ENOL has an ongoing vulnerability to weather events that constrains its credit profile. While New Orleans is better prepared for a major hurricane than it was pre-Katrina, the company still has a higher risk service territory because it is concentrated in a small geographic area and is located partially below sea level in a storm prone location. Therefore, potentially damaging storms, with increasing severity and higher storm surges, are the most persistent threat to the company's customers and assets.

Exhibit 5

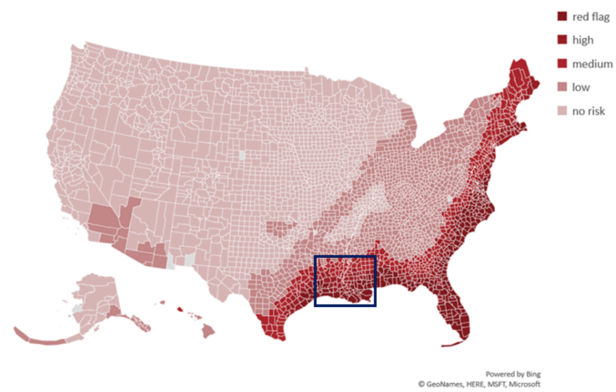
Relative projected extreme rainfall and flood stress



This metric is a combination of 3 projected components (wet days, very wet days, rainfall intensity) with annual changes from 2030-2040 vs. 1975-2005 + 2 historical components (flood frequency and flood severity, on return inundation basis).
Source: 427 (data sourced from CMIP5 models and Fathom)

Exhibit 6

Hurricane risk (historical data)



The indicator reflects the cumulative wind velocity from recorded cyclones over the period 1980-2016
Source: 427 (data sourced from IBTrACS version 3)

Historically, regulatory responses have been helpful in recovering costs of major storms - a credit positive. For example, the City Council allows ENOL to collect revenue for a storm reserve fund and has provided for the securitization of storm costs through a discrete charge to customers. We expect similar treatment to be applied following Hurricanes Zeta and Ida.

Environmental - carbon transition

ENOL's owned generation portfolio is comprised almost entirely of natural gas-fired units, which emit roughly half of the carbon, per unit of electricity generated, than coal-fueled generation. The company also acquires roughly 30% of its generation supply from an affiliate's nuclear plant, which has no carbon emissions. The company is actively pursuing the implementation of solar generation, a trend we expect to continue over the foreseeable future. Entergy as a whole exhibits strong positioning for the carbon transition with a business model that is not expected to be materially affected, as well as its plans in place to mitigate carbon transition exposure.

In May 2021, the City Council adopted a Renewable and Clean Portfolio Standard (RCPS) for the city, which requires that, by 2050, Entergy must entirely eliminate the use of fossil fuels. This legal mandate will help to improve ENOL's carbon profile, over time, and will be credit positive as long as the appropriate cost recovery provisions maintain the utility's financial profile throughout the transition.

Social

ENOL is facing significant social risk around customer, political and regulatory relationships as a result of significant customer outages due to Hurricane Ida. Given the degree of political and stakeholder scrutiny at this time, it's possible that regulators will modify the typical nature of storm recovery, or limit other rate increases requested by the utility in annual FRP filings - a key consideration in ENOL's negative outlook.

Governance

ENOL's governance is driven by that of Entergy Corp., its ultimate parent company.

Entergy's governance is broadly in-line with other utilities and does not pose particular risk. This is underpinned by our view that the company's financial strategy and risk management, management credibility and track record are generally supportive to credit, despite the above average use of aggressive tax policies that have caused some cash flow volatility and recent challenges by regulators.

Liquidity analysis

We expect ENOL to maintain adequate liquidity over the next 12-18 months, due to the availability of external borrowing sources, including external liquidity sources, and its ability to borrow from the Entergy money pool.

ENOL requires external funding since the company generates material amounts of negative free cash flow, like most utilities. For example, through LTM 30 June 2021, ENOL generated around $67 million of cash flow from operations, had $205 million in capital expenditures, but distributed no dividends due to these high capital needs. ENOL's negative free cash flow was $138 million through LTM Q2 2021 - a trend that we expect to continue.

To supplement internal liquidity needs, ENOL has a FERC authorized short-term borrowing limit of $150 million, corresponding to its ability to borrow from the Entergy money pool through July 2022. As of 30 June 2021, ENOL had a $38 million payable balance on the money pool. Additionally, ENOL has a stand-alone credit agreement in the amount of $25 million, maturing in June 2024, which was fully available at 30 June 2021. ENOL also has a $70 million unsecured term loan issued on 18 December 2019 that will mature in May 2022, which is fully outstanding. The company also has $1 million of letters of credit outstanding under an uncommitted credit facility to support its MISO obligations.

ENOL's next significant long-term debt maturity is $100 million of senior secured notes due in July 2023.

Appendix

Exhibit 7

Credit metrics and financial statistics

CF Metrics	Dec-17	Dec-18	Dec-19	Dec-20	LTM Jun-21
As Adjusted					
FFO	**164**	**133**	**127**	**116**	**115**
+/- Other	2	-2	-6	-26	-3
CFO Pre-WC	**166**	**131**	**121**	**89**	**112**
+/- ΔWC	-28	45	-6	-25	-45
CFO	**137**	**176**	**115**	**64**	**67**
- Div	75	24	0	0	0
- Capex	115	196	218	223	205
FCF	**-53**	**-44**	**-103**	**-159**	**-138**
(CFO Pre-W/C) / Debt	31.1%	23.3%	18.3%	11.9%	14.6%
(CFO Pre-W/C - Dividends) / Debt	17.0%	19.1%	18.3%	11.9%	14.6%
FFO / Debt	30.7%	23.7%	19.3%	15.4%	15.0%
RCF / Debt	16.6%	19.5%	19.3%	15.4%	15.0%
Revenue	716	717	686	634	685
Interest Expense	23	25	27	31	33
Net Income	51	58	67	48	42
Total Assets	1,508	1,584	1,731	1,936	1,906
Total Liabilities	1,101	1,149	1,245	1,331	1,295
Total Equity	407	435	486	605	611

All figures & ratios calculated using Moody's estimates & standard adjustments. Periods are Financial Year-End unless indicated. LTM=Last Twelve Months.
Source: Moody's Financial Metrics

Exhibit 8

Peer comparison

	Entergy New Orleans, LLC. Ba1 (Negative)			Mississippi Power Company Baa1 (Stable)			Duke Energy Kentucky, Inc. Baa1 (Stable)			Alaska Electric Light and Power Company(AELP) Baa3 (Stable)		
(In US millions)	FYE Dec-19	FYE Dec-20	LTM Jun-21	FYE Dec-19	FYE Dec-20	LTM Jun-21	FYE Dec-19	FYE Dec-20	LTM Jun-21	FYE Dec-20	FYE Dec-20	LTM Jun-21
Revenue	686	634	685	1,264	1,172	1,222	479	452	483	37	43	44
CFO Pre-W/C	121	89	112	419	341	345	134	125	132	15	17	17
Total Debt	659	751	769	1,614	1,506	1,995	823	885	834	133	127	124
CFO Pre-W/C + Interest / Interest	5.5x	3.8x	4.4x	6.9x	6.6x	6.9x	6.0x	5.5x	5.7x	5.1x	6.0x	5.7x
CFO Pre-W/C / Debt	18.3%	11.9%	14.6%	26.0%	22.6%	17.3%	16.3%	14.1%	15.8%	11.1%	13.8%	13.3%
CFO Pre-W/C – Dividends / Debt	18.3%	11.9%	14.6%	26.0%	17.7%	9.6%	16.3%	14.1%	15.8%	3.1%	9.4%	8.8%
Debt / Capitalization	44.0%	44.3%	44.6%	43.6%	40.8%	46.4%	48.6%	48.0%	44.3%	52.6%	51.1%	47.8%

All figures & ratios calculated using Moody's estimates & standard adjustments. Periods are Financial Year-End unless indicated. LTM=Last Twelve Months

Source: Moody's Financial Metrics

Rating methodology and scorecard factors

Entergy New Orleans, LLC

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 6/30/2021		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	B	B	B	B
b) Generation and Fuel Diversity	B	B	B	B
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.6x	A	5x - 5.5x	A
b) CFO pre-WC / Debt (3 Year Avg)	14.5%	Baa	16% - 19%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	14.0%	Baa	14% - 17%	Baa
d) Debt / Capitalization (3 Year Avg)	45.2%	Baa	49% - 50%	Baa
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		Baa1		Baa1
HoldCo Structural Subordination Notching	0	0	0	0
a) Scorecard-Indicated Outcome		Baa1		Baa1
b) Actual Rating Assigned		Ba1		Ba1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 6/30/2021(L).
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Investors Service

Ratings

Exhibit 10

Category	Moody's Rating
ENTERGY NEW ORLEANS, LLC.	
Outlook	Negative
Issuer Rating	Ba1
First Mortgage Bonds	Baa2
PARENT: ENTERGY CORPORATION	
Outlook	Negative
Issuer Rating	Baa2
Senior Unsecured	Baa2
Commercial Paper	P-2

Source: Moody's Investors Service

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EMEA	44-20-7772-5454

MOODY'S INVESTORS SERVICE

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INVESTORS SERVICE

CREDIT OPINION
4 October 2022

Update

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RATINGS

Entergy New Orleans, LLC.

Domicile	New Orleans, Louisiana, United States
Long Term Rating	Ba1
Type	LT Issuer Rating
Outlook	Negative

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Entergy New Orleans, LLC.

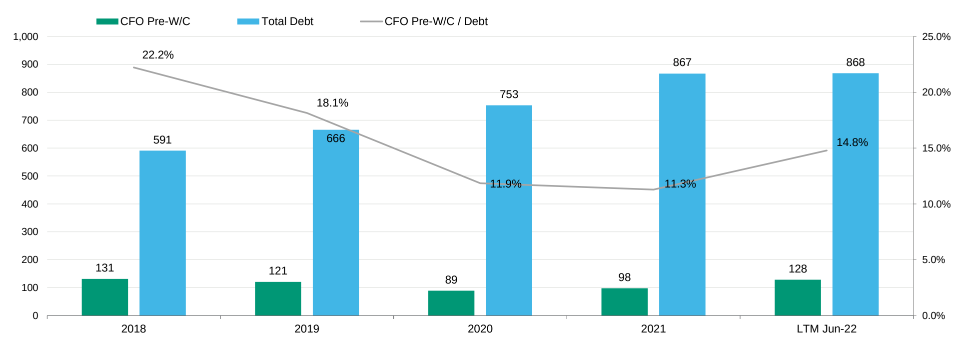
Update to credit analysis

Summary

Entergy New Orleans, LLC.'s (ENOL, Ba1 negative) credit profile is supported by its monopoly service territory as a vertically integrated utility company and its supportive regulatory construct underpinned by a formula rate plan (FRP). Management has also been able to quell negative political rhetoric that surfaced following the storm damage caused by Hurricane Ida in 2021. However, the company is still in the midst of the 2022 storm season and is awaiting cost recovery approvals for approximately $206 million of storm expenditures.

ENOL's credit profile is challenged by its small, geographically concentrated service territory in a storm prone location. The coastal nature of the service territory is a material credit negative due to the rising risk of storm surges, more severe weather events and the impact this has on customer migration and local economic conditions. For these reasons, ENOL's credit rating is well below peer utilities with similar financial metrics.

Exhibit 1
Historical CFO pre-WC, CFO pre-WC to Debt, Total Debt



Source: Moody's Financial Metrics

Credit strengths

» Adequate financial metrics should be sustainable given regulatory provisions and a rate base of around $1.3 billion

» Storm cost recovery mechanisms are tested and important features given climate risks

Credit challenges

» Small and concentrated service territory in a low-lying coastal region exposed to storm surges and severe weather events

» Financial metrics are currently weak, but expected to rebound once storm cost securitization is completed

Rating outlook

ENOL's negative outlook reflects a weakened financial profile following 2021 storm activity, uncertainty regarding the current storm season and the outstanding regulatory approvals required to recover around $206 million of past storm costs.

Factors that could lead to an upgrade

» It is unlikely that ENOL's issuer rating will be upgraded to Baa3, due to its concentrated service territory and vulnerability to storm activity

» However, the maintenance of a financial profile that is much stronger than peer utilities and significantly improved regulatory and legislative support could lead to an upgrade

Factors that could lead to a downgrade

» A materially adverse regulatory decision

» Significant storm damage and delayed cost recovery for repairs

» A sustained decline in financial metrics, including cash flow to debt ratios remaining below the mid-teens percent range

Key indicators

Exhibit 2

Entergy New Orleans, LLC.

	Dec-18	Dec-19	Dec-20	Dec-21	LTM Jun-22
CFO Pre-W/C + Interest / Interest	6.3x	5.5x	3.8x	4.3x	4.9x
CFO Pre-W/C / Debt	22.2%	18.1%	11.9%	11.3%	14.8%
CFO Pre-W/C – Dividends / Debt	18.2%	18.1%	11.9%	11.3%	14.8%
Debt / Capitalization	43.8%	44.2%	44.4%	46.3%	45.1%

All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Profile

ENOL is an electric and gas utility serving the city of New Orleans, Louisiana. The company is the smallest of the Entergy Corporation (Entergy, Baa2 negative) corporate family, which includes five utility subsidiaries and System Energy Resources, Inc. (SERI, Baa3 negative, a 1,400 MW nuclear unit in Mississippi). ENOL represents about 3% of Entergy's adjusted consolidated cash flow, debt and net PP&E. ENOL's rate base is currently split roughly 85%:15% between electric and gas assets (i.e., roughly $1.1 billion to about $200 million, respectively). The utility is regulated by the New Orleans City Council (NOCC).

Detailed credit considerations

Adverse political and regulatory rhetoric has subsided, but key cost recovery remains outstanding

The magnitude of the damage ($206 million based on a securitization filing currently before the NOCC) and customer outages (roughly 205,000 at the peak) caused by Hurricane Ida had resulted in a high level of political and regulatory contentiousness directed at ENOL toward the end of last year. However, the storm also occurred in the midst of an election period and little has been done since that time to adversely affect the utility (including ownership changes that had been threatened at the time). This tension was one of the key factors that lead to ENOL's negative outlook.

While the contentious rhetoric has subsided, the company is still seeking to replenish storm reserves with the use of securitization proceeds (i.e., $75 million of the $206 million filing amount). There is a strong precedent for storm cost securitization in New Orleans and we expect that ENOL will be able to move forward on this mode of cost recovery. We view securitization as a credit positive method of cost recovery, since it incorporates the lowest cost of financing to minimize the customer rate impact and is non-recourse to the utility, which acts as a pass through conduit for collections.

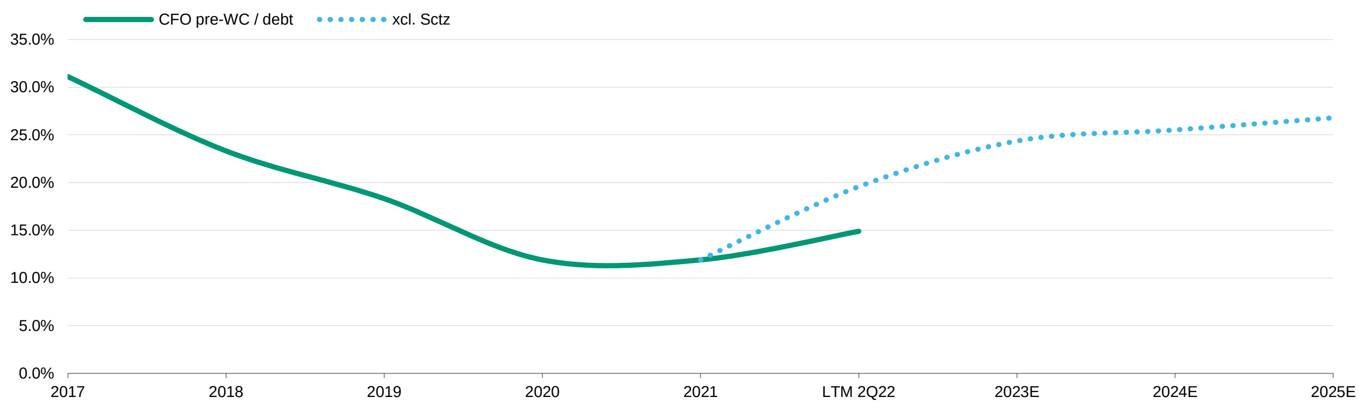
Financial metrics will be improved after storm cost recovery is complete

Based upon ENOL's regulatory rate framework, we expect the utility will generate CFO pre-WC to debt around 25% once storm securitization is complete and a normal regulator schedule and financial performance resumes.

In Exhibit 4, we show our base case financial projections, excluding the $206 million of costs to be secured and based on ENOL's regulatory allowed rate base (approximately $1.3 billion), capital structure (51%) and allowed ROE (9.35%). Our assumptions also include some growth attributable to around $700 million of capital expenditures we assume in 2023-2025 and a modest level of deferred tax benefits. Tax assumptions could differ materially from actual results since Entergy employs aggressive tax strategies at times, which has greatly benefitted ENOL and affiliate cash flow in the past.

Exhibit 3

ENOL's ratio of CFO pre-WC to debt should rebound to the mid-20% percentage range when storm cost securitization is complete



Source: Moody's Financial Metrics and Moody's financial projections

Monopoly utility operating within a formulaic rate plan framework

ENOL's credit is underpinned by its business profile as a vertically integrated utility operating in a monopoly service territory with a regulatory allowed return on equity. The underlying framework of ENOL's regulated rates is supportive, since it includes a three-year formula rate plan (FRP) for both electric and gas operations and a pilot program for full revenue decoupling. The FRP also contains some forward-looking adjustments for known and measurable costs in subsequent FRP evaluation periods and new rate constructs for renewable power offerings and electric vehicle investments.

In April 2022, ENOL submitted its FRP 2021 test year filing, which reported a 6.88% earned ROE and seeks approval for about $42 million of rate increases. The case is still being reviewed, with resulting rates to be effective in September, unless the NOCC sets a procedural schedule that would extend the process into 2023.

ESG considerations

ENOL's ESG Credit Impact Score is CIS-4 (Highly Negative)

Exhibit 4
ESG Credit Impact Score

CIS-4
Highly Negative

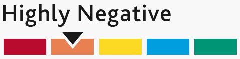
For an issuer scored CIS-4 (Highly Negative), its ESG attributes are overall considered as having a discernible negative impact on the current rating. The negative influence of the overall ESG attributes on the rating is more pronounced compared to an issuer scored CIS-3.

Source: Moody's Investors Service

ENOL's ESG Credit Impact Score is highly negative (**CIS-4**), reflecting highly negative environmental risks given the company's small size and concentrated service territory in a storm-prone location. For these reasons, ENOL's credit rating is well below peer utilities with similar financial metrics. The CIS also reflects moderately negative social risks and neutral-to-low exposure to governance risks.

Exhibit 5
ESG Issuer Profile Scores

ENVIRONMENTAL
E-4
Highly Negative



SOCIAL
S-3
Moderately Negative

GOVERNANCE
G-2
Neutral-to-Low

Source: Moody's Investors Service

Environmental

ENOL's highly negative exposure to environmental risks (**E-4** issuer profile score) is driven by the coastal nature of its service territory, which is a material credit negative due to the rising risk of storm surges, more severe weather events and the impact this has on customer migration and local economic conditions.

Social

Exposure to social risks is moderately negative (**S-3** issuer profile score) reflecting the fundamental utility risk that demographics and societal trends could include social pressures or public concern around affordability, utility reputational or environmental risks. In turn, these pressures could result in adverse political intervention into utility operations or regulatory changes.

Governance

ENOL's governance is driven by that of its parent. Entergy's governance is broadly in-line with other utilities and does not pose particular risk (**G-2** issuer profile score). This is supported by our neutral-to-low scores on financial strategy and risk management, management credibility and track record, despite the above average use of aggressive tax policies that have caused some cash flow volatility and challenges by regulators.

ESG Issuer Profile Scores and Credit Impact Scores for ENOL are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for ENOL on MDC and view the ESG Scores section.

Liquidity analysis

We expect ENOL to maintain adequate liquidity over the next 12-18 months, due to the availability of external borrowing sources, including external liquidity sources, and its ability to borrow from the Entergy money pool.

We expect ENOL's internal liquidity to consist of around $160 million of cash flow from operations, compared to a like amount of capital expenditures over the next 12 months. As a result, ENOL's free cash flow position will largely depend on its dividend policy. ENOL has not paid a dividend to Entergy for the past 4 years.

To supplement internal liquidity needs, ENOL has a FERC authorized short-term borrowing limit of $150 million, corresponding to its ability to borrow from the Entergy money pool through October 2023. Additionally, ENOL has a stand-alone credit agreement in the amount of $25 million, maturing in June 2024, which was fully available at 30 June 2022. The company also has $1 million of letters of credit outstanding under an uncommitted credit facility to support its MISO obligations.

ENOL's next significant long-term debt maturity is $100 million of senior secured notes due in July 2023.

Rating methodology and scorecard factors

Exhibit 6

Entergy New Orleans, LLC

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 6/30/2022		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	B	B	B	B
b) Generation and Fuel Diversity	B	B	B	B
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.6x	A	5x - 6x	A
b) CFO pre-WC / Debt (3 Year Avg)	14.0%	Baa	16% - 20%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	14.0%	Baa	16% - 20%	A
d) Debt / Capitalization (3 Year Avg)	45.6%	Baa	41% - 46%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		Baa1		A3
HoldCo Structural Subordination Notching	0	0	0	0
a) Scorecard-Indicated Outcome		Baa1		A3
b) Actual Rating Assigned		Ba1		Ba1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 6/30/2022(L).
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Investors Service

Appendix

Exhibit 7

Credit metrics and financial statistics

CF Metrics	Dec-18	Dec-19	Dec-20	Dec-21	LTM Jun-22
As Adjusted					
FFO	**133**	**127**	**116**	**119**	**161**
+/- Other	-2	-6	-26	-22	-32
CFO Pre-WC	**131**	**121**	**89**	**98**	**128**
+/- ΔWC	45	-6	-25	-15	-17
CFO	**176**	**115**	**64**	**83**	**111**
- Div	24	0	0	0	0
- Capex	196	218	223	220	242
FCF	**-44**	**-103**	**-159**	**-137**	**-131**
(CFO Pre-W/C) / Debt	22.2%	18.1%	11.9%	11.3%	14.8%
(CFO Pre-W/C - Dividends) / Debt	18.2%	18.1%	11.9%	11.3%	14.8%
FFO / Debt	22.6%	19.1%	15.3%	13.8%	18.5%
RCF / Debt	18.6%	19.1%	15.3%	13.8%	18.5%
Revenue	717	686	634	769	873
Interest Expense	25	27	31	30	33
Net Income	58	67	48	47	80
Total Assets	1,584	1,731	1,936	2,150	2,102
Total Liabilities	1,149	1,245	1,331	1,512	1,429
Total Equity	435	486	605	639	673

All figures & ratios calculated using Moody's estimates & standard adjustments. Periods are Financial Year-End unless indicated. LTM=Last Twelve Months.
Source: Moody's Financial Metrics

Exhibit 8

Peer comparison

(In US millions)	Entergy New Orleans, LLC. Ba1 (Negative)			Kentucky Power Company Baa3 (Stable)			Duke Energy Kentucky, Inc. Baa1 (Stable)			Alaska Electric Light and Power Company(AELP) Baa3 (Stable)		
	FYE Dec-20	FYE Dec-21	LTM Jun-22	FYE Dec-20	FYE Dec-21	LTM Jun-22	FYE Dec-20	FYE Dec-21	LTM Jun-22	FYE Dec-21	FYE Dec-21	LTM Jun-22
Revenue	634	769	873	550	646	702	452	520	580	43	45	45
CFO Pre-W/C	89	98	128	75	63	132	125	145	134	17	17	16
Total Debt	753	867	868	1,125	1,215	1,245	885	921	853	127	123	122
CFO Pre-W/C + Interest / Interest	3.8x	4.3x	4.9x	2.9x	2.7x	4.4x	5.5x	6.3x	5.8x	6.0x	5.9x	5.4x
CFO Pre-W/C / Debt	11.9%	11.3%	14.8%	6.7%	5.2%	10.6%	14.1%	15.7%	15.7%	13.8%	14.0%	12.9%
CFO Pre-W/C – Dividends / Debt	11.9%	11.3%	14.8%	6.7%	5.2%	10.6%	14.1%	15.7%	15.7%	9.4%	9.5%	8.3%
Debt / Capitalization	44.4%	46.3%	45.1%	47.0%	48.1%	47.7%	48.0%	45.8%	43.2%	51.1%	50.1%	47.3%

All figures & ratios calculated using Moody's estimates & standard adjustments. Periods are Financial Year-End unless indicated. LTM=Last Twelve Months
Source: Moody's Financial Metrics

Ratings

Exhibit 9

Category	Moody's Rating
ENTERGY NEW ORLEANS, LLC.	
Outlook	Negative
Issuer Rating	Ba1
First Mortgage Bonds	Baa2
PARENT: ENTERGY CORPORATION	
Outlook	Negative
Issuer Rating	Baa2
Senior Unsecured	Baa2
Commercial Paper	P-2

Source: Moody's Investors Service

REPORT NUMBER 1340173

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

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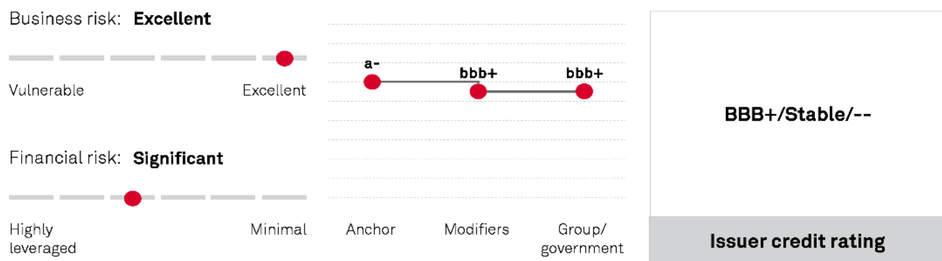
Entergy Louisiana LLC

August 25, 2022

Ratings Score Snapshot



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Credit Highlights

Overview

Key strengths	Key risks
Mid-sized rate-regulated vertically integrated electric utility operations.	Mid-sized rate-regulated vertically integrated electric utility operations.
Relatively supportive regulatory jurisdiction with formula rate plans (FRP), providing an element of cash flow stability and predictability. Additionally, Louisiana has a well-established procedure for allowing utilities to securitize their storm related costs, which we assess as credit supportive.	Exposure to severe hurricanes and storms within its service territory.
	Lack of sufficient system hardening limits the company's ability to protect against severe storms and increases its business risk relative to peers.
	High dependence on industrial customers that could increase cash flow volatility.

Exposure to hurricane activity. Entergy Louisiana (ELL) remains exposed to hurricanes as evidenced by the recent 2021 category 4 Hurricane Ida which was the most destructive hurricane in Louisiana since the 2005 Hurricane Katrina. Furthermore, the National Oceanic and Atmospheric Administration is predicting an above-average Atlantic hurricane season for 2022, potentially raising risk for the company. Although the state has a well-established law that enables utilities to seek securitization to recover such costs, increasing commodity prices, interest rates, inflationary pressures, and the company's robust capital spending could all pressure the customer bill, potentially weakening the company's consistent ability to effectively manage regulatory risk.

ELL raised its three-year capital spending program. ELL raised its three-year capital plan to about $4.7 billion from approximately $4.2 billion. The increase in capital spending is driven by the projected increase in industrial demand in the Gulf region and to address the resiliency of its transmission and distribution system due to the increased frequency and intensity of storms. Given the rising customer bill from rising commodity costs and other rising costs from inflation, ELL's ability to effectively manage regulatory risk could become increasingly challenging.

ELL filed a prudence review of Hurricane Ida restoration costs of $2.6 billion. In April 2022, ELL filed with the Louisiana Public Service Commission (LPSC) for determination on the prudence and to certify Hurricane Ida costs of about $2.6 billion, of which $1 billion of costs were already recovered through securitization in 2022. Following the LPSC's certification of Hurricane Ida costs, ELL will request the use of securitization for the unrecovered costs (about $1.6 billion), and we expect the securitization bonds to be issued in the first half of 2023.

Outlook

The stable outlook on ELL over the next 24 months reflects our stable outlook on parent Entergy and our expectations that ELL's standalone financial measures will consistently reflect the lower end of the range for its financial risk profile category. Specifically, we expect that ELL's standalone adjusted funds from operations (FFO) to debt will reflect the 14%-17% range through 2024.

Downside scenario

We could lower our ratings on ELL over the next 24 months if:

- We lower our ratings on its parent Entergy; and
- Stand-alone financial measures for the utility weaken such that its adjusted FFO to debt is consistently below 13%.

Upside scenario

We could raise our ratings on ELL over the next 24 months if:

- The utility's stand-alone adjusted FFO to debt is consistently above 18%; or
- We raise our rating on parent Energy.

Our Base-Case Scenario

Assumptions

- Gross profit increase averaging about 5% per year;
- Expected EBITDA margin averaging about 35% per year;
- Annual capital spending averaging about $1.6 billion through the forecast period;
- About $785 million in capital spending to restore hurricane damage from hurricane Ida in 2022;
- Negative discretionary cash flow indicating external funding needs;
- Securitization proceeds received in 2023; and
- All debt maturities are refinanced.

Key metrics

Entergy Louisiana, LLC--Key Metrics*

Mil. $	2021a	2022f	2023f	2024f
FFO to debt (%)	13.1	14-16	15-17	14-16
Debt to EBITDA (x)	6.2	5.0-6.0	5.0-6.0	5.0-6.0
FFO cash interest coverage (x)	5.2	5.0-6.0	9.0-10	8.0-9.0

*All figures adjusted by S&P Global Ratings. a--Actual. f--Forecast. FFO—Funds from operations.

Company Description

ELL is a mid-sized electric and gas utility in Louisiana and is a subsidiary of Entergy Corp. ELL serves about 1.2 million customers in Louisiana, consisting of about 1.1 million electric customers and about 100 thousand gas customers. The company has about 10,700 MW of operating capacity and its electric generation is highly dependent on natural gas-fired generation (about 75%) and nuclear power (about 20%), with only limited exposure to coal-fired generation (about 5%).

Peer Comparison

Entergy Louisiana, LLC--Peer Comparisons

	Entergy Louisiana LLC	Union Electric Co. d/b/a Ameren Missouri	Arizona Public Service Co.	Alabama Power Co.	MidAmerican Energy Co.
Foreign currency issuer credit rating	BBB+/Stable/--	BBB+/Stable/A-2	BBB+/Negative/A-2	A-/Stable/A-2	A/Stable/A-1
Local currency issuer credit rating	BBB+/Stable/--	BBB+/Stable/A-2	BBB+/Negative/A-2	A-/Stable/A-2	A/Stable/A-1
Period	Annual	Annual	Annual	Annual	Annual
Period ending	2021-12-31	2021-12-31	2021-12-31	2021-12-31	2021-12-31
Mil.	$	$	$	$	$
Revenue	5,058	3,353	3,804	6,413	3,547
EBITDA	1,829	1,355	1,719	3,025	1,361
Funds from operations (FFO)	1,495	1,115	1,447	2,509	1,815
Interest	431	180	295	519	333
Cash interest paid	352	222	252	331	292
Operating cash flow (OCF)	982	900	951	2,088	1,604
Capital expenditure	3,666	2,049	1,472	1,738	1,899
Free operating cash flow (FOCF)	(2,683)	(1,150)	(521)	350	(295)

Entergy Louisiana, LLC--Peer Comparisons

Discretionary cash flow (DCF)	(2,743)	(1,175)	(919)	(626)	(295)
Cash and short-term investments	19	0	9	1,060	232
Gross available cash	19	248	9	1,060	232
Debt	11,390	5,723	6,787	9,190	7,547
Equity	8,181	5,871	6,750	10,859	8,960
EBITDA margin (%)	36.2	40.4	45.2	47.2	38.4
Return on capital (%)	7.1	5.9	7.2	10.2	3.2
EBITDA interest coverage (x)	4.2	7.5	5.8	5.8	4.1
FFO cash interest coverage (x)	5.2	6.0	6.7	8.6	7.2
Debt/EBITDA (x)	6.2	4.2	3.9	3.0	5.5
FFO/debt (%)	13.1	19.5	21.3	27.3	24.1
OCF/debt (%)	8.6	15.7	14.0	22.7	21.3
FOCF/debt (%)	(23.6)	(20.1)	(7.7)	3.8	(3.9)
DCF/debt (%)	(24.1)	(20.5)	(13.5)	(6.8)	(3.9)

Business Risk

Our assessment of ELL’s business risk profile reflects its lower-risk, fully rate-regulated utility business that provides an essential service in its service territory. Given material barriers to entry, ELL and the regulated utility industry as a whole effectively operate insulated from competitive market challenges. This underlines our view of regulated utilities' very low industry risk compared to other industries.

ELL benefits from a constructive regulatory framework by the LPSC, where it operates under an FRP, providing stability to its cash flows and enabling it to generally earn close to its allowed return on equity. ELL’s business risk profile also benefits from various riders, including capacity, transmission, fuel, and gas infrastructure. Overall, we expect the ELL will continue to effectively manage regulatory risk, focusing on further reducing its regulatory lag.

However, we view ELL at the lower end of the excellent business risk profile category compared with peers, given the propensity and severity of storm activity within ELL's service territory along the Gulf Coast and the limited ability of the utility to protect against severe storms. While we view securitization as a good backstop for storm restoration costs, securitization takes time to receive the ultimate funds and takes up headroom in the customer bill, potentially increasing the risk of the company consistently managing regulatory risk. We believe that for ELL to reduce its credit risk exposure to severe storms, it is important for the company to have a more resilient infrastructure that withstands severe storms, reducing the rate of recovery of pass-through costs to customers. Parent, Entergy Corp, intends to spend about $4 billion in accelerated resiliency spending within the next five years and about $15 billion over the next ten years, which we assess as supportive of the company’s long-term credit quality.

ELL is a mid-sized utility serving roughly 1.2 million electric and gas customers in Louisiana, accounting for about 40% of parent Entergy’s total adjusted operating income. Most of ELL’s operations are the electric utility; its customer base comprises approximately 90% electric and 10% gas customers. About 50% of ELL’s operating revenues are from residential and commercial customers, providing a measure of cash flow stability, this is partially offset by about 50% of operating revenues coming from industrial customers, which could expose the company to cash flow volatility, especially in an economic downturn.

The company owns around 10,700 megawatts (MW) of generating capacity, only about 30% of which is from nuclear and coal generation. We believe nuclear generation has a higher operating risk than other forms of power generation, and we believe coal generation potentially has greater environmental risk.

Financial Risk

Over the next three years, we expect ELL's elevated capital spending to average roughly $1.6 billion through 2024, driving its financial performance. We expect that the company's regulatory construct will provide periodic annual rate increases as its rate base grows, and we forecast operating cash flow will fund about 50%-70% of total funding needs. We anticipate the shortfall will be funded with a combination of debt and capital contributions from parent Entergy. Furthermore, we expect ELL's financial measures will remain at the lower end of the range for its financial risk profile category, primarily reflecting the company's robust capital spending. We anticipate securitization proceeds to provide relief starting in 2023.

Our base case includes adjusted FFO to debt in the 14%-17% range through 2024 and is predicated on the company's robust capital spending program, 2023 securitization proceeds of about $1.6 billion, annual dividends of about $200 million, and annual FRP increases. In addition, we forecast the company's ability to cover annual cash interest payments based on FFO, bolstering our assessment of ELL's financial risk, with coverage averaging 5x-6x per year through 2024. Finally, we forecast leverage, as indicated by adjusted debt to EBITDA, to be elevated in the 5.5x-6x range through 2024.

We assess ELL's financial risk profile using our medial volatility financial benchmarks, reflecting the company's steady cash flow and rate-regulated utility operations. These benchmarks are more relaxed than the benchmarks we use for typical corporate issuers.

Debt maturities

- 2022 - $200 million
- 2023 - $1.445 billion
- 2024 - $1.782 billion
- 2025 - $300 million
- 2026 - $775 million
- Thereafter - $6.412 billion

Entergy Louisiana, LLC--Financial Summary

Period ending	Dec-31-2016	Dec-31-2017	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021
Reporting period	2016a	2017a	2018a	2019a	2020a	2021a
Display currency (mil.)	$	$	$	$	$	$
Revenues	4,154	4,277	4,273	4,262	4,047	5,058
EBITDA	1,518	1,752	1,410	1,646	1,723	1,829
Funds from operations (FFO)	1,008	1,677	1,191	1,294	1,396	1,495
Interest expense	343	349	364	383	411	431
Cash interest paid	354	309	324	337	341	352
Operating cash flow (OCF)	987	1,278	1,311	1,161	1,023	982
Capital expenditure	1,069	1,842	1,799	1,652	2,001	3,666
Free operating cash flow (FOCF)	(83)	(563)	(488)	(491)	(978)	(2,683)
Discretionary cash flow (DCF)	(368)	(655)	(616)	(699)	(999)	(2,743)
Cash and short-term investments	214	36	43	2	728	19
Gross available cash	214	36	43	2	728	19
Debt	6,290	6,927	7,425	7,971	8,998	11,390
Common equity	5,082	5,309	5,903	6,397	7,458	8,181

Entergy Louisiana, LLC--Financial Summary

Adjusted ratios

EBITDA margin (%)	36.6	40.9	33.0	38.6	42.6	36.2
Return on capital (%)	9.9	11.3	9.0	8.5	7.3	7.1
EBITDA interest coverage (x)	4.4	5.0	3.9	4.3	4.2	4.2
FFO cash interest coverage (x)	3.8	6.4	4.7	4.8	5.1	5.2
Debt/EBITDA (x)	4.1	4.0	5.3	4.8	5.2	6.2
FFO/debt (%)	16.0	24.2	16.0	16.2	15.5	13.1
OCF/debt (%)	15.7	18.5	17.7	14.6	11.4	8.6
FOCF/debt (%)	(1.3)	(8.1)	(6.6)	(6.2)	(10.9)	(23.6)
DCF/debt (%)	(5.9)	(9.5)	(8.3)	(8.8)	(11.1)	(24.1)

Reconciliation Of Entergy Louisiana, LLC Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2021									
Company reported amounts	10,914	8,181	5,068	1,651	927	337	1,829	1,053	60	3,679
Cash taxes paid	-	-	-	-	-	-	18	-	-	-
Cash interest paid	-	-	-	-	-	-	(338)	-	-	-
Lease liabilities	65	-	-	-	-	-	-	-	-	-
Operating leases	-	-	-	14	1	1	(1)	13	-	-
Postretirement benefit obligations/ deferred compensation	429	-	-	-	-	-	-	-	-	-
Accessible cash and liquid investments	(19)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	13	(13)	(13)	-	(13)
Securitized stranded costs	-	-	(10)	(10)	-	-	-	(10)	-	-
Asset-retirement obligations	-	-	-	80	80	80	-	-	-	-
Nonoperating income (expense)	-	-	-	-	263	-	-	-	-	-

Reconciliation Of Entergy Louisiana, LLC Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
U.S. decommissioning fund contributions	-	-	-	-	-	-	-	(60)	-	-
EBITDA: other income/ (expense)	-	-	-	94	94	-	-	-	-	-
D&A: other	-	-	-	-	(94)	-	-	-	-	-
Total adjustments	476	-	(10)	178	344	94	(334)	(70)	-	(13)
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	11,390	8,181	5,058	1,829	1,271	431	1,495	982	60	3,666

Liquidity

We assess the company's stand-alone liquidity as adequate because we believe its liquidity sources will likely cover uses by more than 1.1x over the next 12 months and meet cash outflows even if EBITDA declines 10%. The assessment also reflects the company's generally prudent risk management, sound relationship with banks, and a generally satisfactory standing in credit markets.

Principal liquidity sources

- Cash and liquid investments of about $150 million as of March 2022;
- Total availability under the revolving credit facility of $350 million as of March 2022;
- Estimated cash FFO of about $1.6 billion; and
- May 2022 securitization proceeds of about $3.1 billion.

Principal liquidity uses

- Debt maturities of about $200 million;
- Working capital outflows of about $200 million;
- Capital spending of about $2.25 billion; and
- Dividends of about $200 million.

Environmental, Social, And Governance

ESG Credit Indicators

Environmental	Social	Governance
E-1 E-2 E-3 **E-4** E-5	S-1 S-2 **S-3** S-4 S-5	G-1 **G-2** G-3 G-4 G-5
- Physical risks - Waste and pollution	- Health and safety	- N/A

N/A—Not applicable. ESG credit indicators provide additional disclosure and transparency at the entity level and reflect S&P Global Ratings' opinion of the influence that environmental, social, and governance factors have on our credit rating analysis. They are not a sustainability rating or an S&P Global Ratings ESG Evaluation. The extent of the influence of these factors is reflected on an alphanumerical 1-5 scale where 1 = positive, 2 = neutral, 3 = moderately negative, 4 = negative, and 5 = very negative. For more information, see our commentary "ESG Credit Indicator Definitions And Applications," published Oct. 13, 2021.

Environmental factors are a negative consideration in our credit rating analysis of ELL because the geographical position of the utility is exposed to extreme weather conditions. Consequently, hurricanes like Hurricane Ida negatively affect the company's transmission and distribution infrastructure and therefore impact the company's cash flow leverage via high restoration costs. Social factors are a moderately negative consideration in our credit rating analysis based on the nuclear generation's health and safety risks.

Group Influence

Under our group rating methodology, we assess ELL to be an insulated subsidiary of Entergy, reflecting our view that ELL is a stand-alone legal entity that functions independently, financially, and operationally, files its rate cases, and is independently regulated by its state commission. ELL has its own books and records, including financials. ELL also has its own funding arrangements, including issuing its own long-term debt and having separate committed credit facilities to cover short-term funding needs. The company does not commingle funds, assets, or cash flows, as demonstrated by parent Entergy's inability to borrow from the Entergy money pool; however, Entergy can lend to the pool. Based on the insulating measures in place, we could potentially rate ELL up to one notch higher than its group credit profile (GCP). Currently, we rate ELL's issuer credit rating the same as the 'bbb+' GCP because ELL's stand-alone credit profile is also at 'bbb+'.

We assess ELL as a core subsidiary of parent Entergy. This reflects our view that ELL represents a significant portion of Entergy's operating revenues, which are used to pay shareholder dividends, thus providing strong economic incentives to Entergy to preserve ELL's credit strength, and we do not expect a default by either Entergy or another entity within the group would lead to a default of the utility.

Issue Ratings--Recovery Analysis

Key analytical factors

ELL's first mortgage bonds benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating two notches above the issuer credit rating.

Rating Component Scores

Foreign currency issuer credit rating	**BBB+/Stable/--**
Local currency issuer credit rating	**BBB+/Stable/--**
Business risk	**Excellent**
Country risk	Very Low
Industry risk	Very Low
Competitive position	Strong
Financial risk	**Significant**
Cash flow/leverage	Significant
Anchor	**a-**
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Satisfactory (no impact)
Comparable rating analysis	Negative (-1 notch)
Stand-alone credit profile	**bbb+**
Group Credit Profile	bbb+
Entity status within the group	Insulated (no impact)

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- General Criteria: Hybrid Capital: Methodology And Assumptions, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Recovery Rating Criteria For Speculative-Grade Corporate Issuers, Dec. 7, 2016
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Related Research

Ratings Detail (as of August 25, 2022)*

Entergy Louisiana LLC	
Issuer Credit Rating	BBB+/Stable/--
Senior Secured	A
Issuer Credit Ratings History	
02-Sep-2021	BBB+/Stable/--
14-Aug-2019	A-/Stable/--
03-May-2018	BBB+/Stable/--
Related Entities	
Entergy Arkansas LLC	
Issuer Credit Rating	A-/Stable/--
Senior Secured	A
Entergy Corp.	
Issuer Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Unsecured	BBB
Entergy Mississippi LLC	
Issuer Credit Rating	A-/Stable/--
Senior Secured	A
Entergy New Orleans LLC	
Issuer Credit Rating	BB/Developing/--
Senior Secured	BBB
Entergy Texas Inc.	
Issuer Credit Rating	BBB+/Stable/--
Preferred Stock	BBB-
Senior Secured	A
System Energy Resources Inc.	
Issuer Credit Rating	BBB+/Stable/--
Senior Secured	A

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings credit ratings on the global scale are comparable across countries. S&P Global Ratings credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

Exhibit AMA-4

Entergy New Orleans, LLC
Transmission & Distribution Resiliency Investments
Estimated Revenue Requirement Calculations
Financial Model - simplified

		1	2	3	4	5	6
		2023	2024	2025	2026	2027	2028
Inputs							
OpCo	ENO						
Composite income tax rate	26.93%						
Property tax rate	1.17%						
BTWACC / Before tax RORB	8.64%						
WACC / RORB	6.88%						
Interest rate	6.10%						
Debt Ratio	49.00%						
Equity Ratio	51.00%						
Total T&D Rate base & revenue requirement calculations							
Rate Base							
Beginning rate base		$0	$0	$8,463,098	$107,200,727	$159,345,483	$318,043,476
Plant in service							
Beginning plant in service		$0	$0	$8,652,441	$109,979,567	$168,114,055	$337,582,361
Plant additions		$0	$8,652,441	$101,327,126	$58,134,489	$169,468,306	$122,512,597
End of year plant in service		$0	$8,652,441	$109,979,567	$168,114,055	$337,582,361	$460,094,958
Depreciation							
Book depreciation - single year		$0	$139,556	$1,913,419	$4,485,381	$7,955,362	$12,463,700
Book depreciation - cumulative		$0	$139,556	$2,052,975	$6,538,356	$14,493,718	$26,957,418
Deferred Income Tax - single year		$0	($49,787)	($676,078)	($1,504,351)	($2,814,950)	($4,312,879)
Accum. Deferred Income Tax (ADIT)		$0	($49,787)	($725,865)	($2,230,216)	($5,045,167)	($9,358,046)
End of Year Rate Base		$0	$8,463,098	$107,200,727	$159,345,483	$318,043,476	$423,779,494
Before tax return on Ending Rate Base		$0	$731,212	$9,262,143	$13,767,450	$27,478,956	$36,614,548
O&M Expenses		$0	$0	$0	$0	$0	$0
Property Taxes		$0	$0	$99,601	$1,262,741	$1,890,436	$3,780,137
Total revenue requirement		**$0**	**$870,767**	**$11,275,163**	**$19,515,572**	**$37,324,754**	**$52,858,385**
Revenue Expense Conversion Factor		1.01069	1.01069	1.01069	1.01069	1.01069	1.01069
Total revenue requirement		**$0**	**$880,079**	**$11,395,743**	**$19,724,278**	**$37,723,918**	**$53,423,671**
Cash flow simple model calculations (assume no recovery)							
Capital spending - Single year		15,292,181	62,554,112	98,845,574	124,395,539	120,558,473	137,314,710
Capital spending - Cumulative		15,292,181	77,846,293	176,691,866	301,087,406	421,645,879	558,960,588
Debt issuance (49% Debt/ 51% equity) - Single year		7,493,169	30,651,515	48,434,331	60,953,814	59,073,652	67,284,208
Debt issuance - Cumulative		7,493,169	38,144,683	86,579,014	147,532,829	206,606,480	273,890,688
Interest expense @ 6.1%		228,542	1,391,954	3,804,073	7,140,411	10,801,249	14,655,164
Revenue							
Expense		(228,542)	(1,531,510)	(5,817,093)	(12,888,533)	(20,647,047)	(30,899,001)
Incremental Pre-tax Income		(228,542)	(1,531,510)	(5,817,093)	(12,888,533)	(20,647,047)	(30,899,001)
Incremental Tax Expense (26.925%)		61,535	412,359	1,566,252	3,470,238	5,559,217	8,319,556
Incremental Earnings - Resilience		(167,007)	(1,119,151)	(4,250,841)	(9,418,296)	(15,087,829)	(22,579,445)
Net Cash impact							
Revenue							
Cash expense		(228,542)	(1,391,954)	(3,903,674)	(8,403,152)	(12,691,685)	(18,435,301)
Operating cash flow		(228,542)	(1,391,954)	(3,903,674)	(8,403,152)	(12,691,685)	(18,435,301)
Debt issuance		7,493,169	30,651,515	48,434,331	60,953,814	59,073,652	67,284,208
Capex		(15,292,181)	(62,554,112)	(98,845,574)	(124,395,539)	(120,558,473)	(137,314,710)
Net Cash flow		(8,027,554)	(33,294,552)	(54,314,916)	(71,844,877)	(74,176,506)	(88,465,803)
OCF:Debt							
Operating Cash Flow		(228,542)	(1,391,954)	(3,903,674)	(8,403,152)	(12,691,685)	(18,435,301)

Debt	7,493,169	38,144,683	86,579,014	147,532,829	206,606,480	273,890,688
OCF:Debt Ratio	-3.1%	-3.6%	-4.5%	-5.7%	-6.1%	-6.7%

Cash flow simple model calculations (assume resilience rider)

Capital spending - single year	15,292,181	62,554,112	98,845,574	124,395,539	120,558,473	137,314,710
Capital spending - Cumulative	15,292,181	77,846,293	176,691,866	301,087,406	421,645,879	558,960,588
Debt issuance (49% Debt/ 51% equity) - Single year	7,493,169	30,651,515	48,434,331	60,953,814	59,073,652	67,284,208
Debt issuance - Cumulative	7,493,169	38,144,683	86,579,014	147,532,829	206,606,480	273,890,688
Interest expense @ 6.1%	228,542	1,391,954	3,804,073	7,140,411	10,801,249	14,655,164
Revenue	$0	$880,079	$11,395,743	$19,724,278	$37,723,918	$53,423,671
Expense	(228,542)	(1,531,510)	(5,817,093)	(12,888,533)	(20,647,047)	(30,899,001)
Incremental Pre-tax Income	(228,542)	(651,431)	5,578,650	6,835,745	17,076,871	22,524,670
Incremental Tax Expense (26.925%)	61,535	175,398	(1,502,052)	(1,840,524)	(4,597,948)	(6,064,767)
Incremental Earnings - Resilience	(167,007)	(476,033)	4,076,599	4,995,220	12,478,923	16,459,903
Net Cash impact						
Revenue	$0	$880,079	$11,395,743	$19,724,278	$37,723,918	$53,423,671
Cash expense	(228,542)	(1,391,954)	(3,903,674)	(8,403,152)	(12,691,685)	(18,435,301)
Operating cash flow	(228,542)	(511,875)	7,492,070	11,321,126	25,032,233	34,988,370
Debt issuance	7,493,169	30,651,515	48,434,331	60,953,814	59,073,652	67,284,208
Capex	(15,292,181)	(62,554,112)	(98,845,574)	(124,395,539)	(120,558,473)	(137,314,710)
Net Cash flow	(8,027,554)	(32,414,472)	(42,919,173)	(52,120,599)	(36,452,588)	(35,042,132)
OCF:Debt						
Operating Cash Flow	(228,542)	(511,875)	7,492,070	11,321,126	25,032,233	34,988,370
Debt	7,493,169	38,144,683	86,579,014	147,532,829	206,606,480	273,890,688
OCF:Debt Ratio	-3.1%	-1.3%	8.7%	7.7%	12.1%	12.8%

Variance (no recovery vs resilience rider)

Revenue (no recovery)	0	0	0	0	0	0
Revenue (rider)	$0	$880,079	$11,395,743	$19,724,278	$37,723,918	$53,423,671
difference	$0	$880,079	$11,395,743	$19,724,278	$37,723,918	$53,423,671
Operating cash flow (no recovery)	(228,542)	(1,391,954)	(3,903,674)	(8,403,152)	(12,691,685)	(18,435,301)
Operating cash flow (rider)	(228,542)	(511,875)	7,492,070	11,321,126	25,032,233	34,988,370
difference	-	880,079	11,395,743	19,724,278	37,723,918	53,423,671
OCF: debt ratio (no recovery)	-3.1%	-3.6%	-4.5%	-5.7%	-6.1%	-6.7%
OCF: debt ratio (rider)	-3.1%	-1.3%	8.7%	7.7%	12.1%	12.8%
difference	0.0%	2.3%	13.2%	13.4%	18.3%	19.5%