July 5, 2017

Via Hand Delivery
Ms. Lora W. Johnson, CMC
Clerk of Council
Room 1E09, City Hall
1300 Perido Street
New Orleans, LA 70112

Re: Supplemental and Amending Application of Entergy New Orleans, Inc. for Approval to Construct New Orleans Power Station and Request for Cost Recovery and Timely Relief
CNO Docket NO.: UD-16-02

Dear Ms. Johnson:

Please find enclosed for your further handling an original and three copies of the Public Supplemental and Amending Application of Entergy New Orleans, Inc. ("ENO") for Approval to Construct New Orleans Power Station and Request for Cost Recovery and for Timely Relief. This filing includes the Supplemental and Amending Direct Testimony and Exhibits of Charles L. Rice, Jr., Seth E. Cureington, Jonathan E. Long, Charles W. Long, Bliss M. Higgins, Dr. George Losonsky, Orlando Todd, and Robert A. Breedlove. Please file an original and two copies into the record in the above referenced matter, and return a date stamped copy to our courier.

In connection with the Company’s filing, a Confidential Version of the above-described documents bearing the designation “Highly Sensitive Protected Materials” are being provided to the appropriate reviewing parties pursuant to the terms and conditions of the Official Protective Order adopted in Council Resolution R-07-432. Portions of the information included in the filing consist of Highly Sensitive Protected Materials pursuant to Council Resolution R-07-432, the disclosure of which could subject not only the Company, but also its customers, to a substantial risk of harm. As such, these confidential materials shall be exempt from public disclosure, subject to the provisions of Council Resolution R-07-432.
Thank you for your assistance with this matter.

Sincerely,

[Signature]

Brian L. Guillot

Enclosures

cc: UD-16-02 Official Service List (via electronic mail and UPS)
BEFORE THE
COUNCIL OF THE CITY OF NEW ORLEANS

SUPPLEMENTAL AND AMENDING
APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO
CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF

DOCKET NO. UD-16-02

SUPPLEMENTAL AND AMENDING APPLICATION
OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO
CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF

Entergy New Orleans, Inc. ("ENO" or the “Company”) respectfully submits this Supplemental and Amending Application\(^1\) ("Supplemental Application") to the Council of the City of New Orleans ("Council"), which seeks, among other requests, authorization to proceed with constructing the New Orleans Power Station ("NOPS" or the "Project"), which will consist of either a combustion turbine ("CT") resource with a summer capacity of 226 megawatts ("MW"), or alternatively, seven Wärtsilä 18V50SG Reciprocating Internal Combustion Engine ("RICE") Generator sets ("Alternative Peaker").\(^2\) Either facility would be located at ENO’s Michoud facility in New Orleans East. In addition to a finding that the construction of NOPS is in the public interest, the Company also requests approvals relating to appropriate cost recovery, a construction monitoring plan, and a procedural schedule to permit a Council decision on this

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\(^1\) The Company hereby files this Supplemental and Amending Application to propose a smaller resource as an alternative to its original CT application. To be clear, however, the original CT is still a prudent option for the Council’s consideration; and accordingly, the Company hereby incorporates herein its original Application by reference, including all Direct Testimony filed therewith and the November 2016 Supplemental Testimony filed in support of New Orleans Power Station.

\(^2\) The use of “NOPS” throughout this Supplemental Application and supporting testimony refers to either the original CT or the Alternative Peaker.
Application no later than October 2017. In support of these requests, the Company represents the following:

INTRODUCTION

I.

ENO is an electric and gas utility organized and operating under the laws of the State of Louisiana, with its general office and principal place of business at 1600 Perdido Street, Building 505, New Orleans, Louisiana 70112. The Company is engaged in the manufacturing, production, transmission, distribution, and sale of electricity to residential, commercial, industrial, and governmental consumers throughout Orleans Parish. ENO furnishes electric service to approximately 200,000 retail electric customers in Orleans Parish. ENO is also engaged in the provision of natural gas service throughout New Orleans and serves approximately 107,000 retail gas customers.

II.

In January 2017, as discussed more fully by Company witness Seth E. Cureington, the Company received an updated forecast of projected peak customer demand for the 20-year planning horizon. The updated load forecast was created by Entergy Services, Inc. (“ESI”)\(^3\) for the purpose of updating the Company’s financial plans, including its sales forecast and financial models. ESI periodically updates its forecast of future customer demand for these reasons, and the information is also used to update the EOCs’ long-term capacity needs and long-term transmission planning.

\(^3\) ESI is an affiliate of the Entergy Operating Companies (“EOCs”) and provides engineering, planning, accounting, technical, and regulatory-support services to each of the EOCs. The five current EOCs are Entergy Arkansas, Inc. (“EAI”), Entergy Louisiana, LLC (“ELL”), Entergy Mississippi, Inc. (“EMI”), ENO, and Entergy Texas, Inc. (“ETI”).
As Mr. Cureington discusses, according to the updated load forecast, the Company’s projections of customer demand have moderated by an average of 3.4% per year (average of 40 MW per year) compared to the forecast used in the original Application. Accordingly, on February 14, 2017, after the Intervenors in this docket filed their Direct Testimony but before the Council’s Advisors filed Direct Testimony, the Company filed a Motion to Suspend the procedural schedule in this docket in order to analyze the implications of the updated forecast and to ensure that the Company takes the best course of action for its customers.

III.

Following the referenced Motion to Suspend, ENO has analyzed the implications of the updated forecast and has concluded that the original unit proposed to the Council, a 226 MW CT, still has significant benefits for customers and should be constructed. The Company also found, however, that the construction of a smaller unit would also create significant benefits and should also be considered by the Council. Accordingly, the Company now files this Supplemental and Amending Application proposing that the Council either (1) approve the originally proposed CT, or (2), approve the alternative smaller resource, which will be discussed throughout this filing.

IV.

As discussed by Mr. Cureington, ENO still emphatically needs a new local resource. The recent deactivations of Michoud Units 2 and 3, which were economic decisions based on maintenance and other operational and economic issues, resulted in the loss of approximately 781 MW of local capacity and created a need. In fact, even based on the Company’s updated load forecast, the Company still projects a demand for overall capacity, specifically peaking capacity, over the next 20 years. As Mr. Cureington explains, the Company has an overall capacity need of approximately 100 MW for the first ten years of the planning horizon, which
grows to 248 MW in the second ten years of the planning horizon. The Company is also projected to have a peaking and reserve capacity deficit of approximately 342 MW on average throughout the 20 year planning horizon.

While the Company continues to seek opportunities to offset some of its capacity needs with energy efficiency and demand-side management (“DSM”) programs, as well as adding renewable resources to its generation portfolio, such resources are not alternatives to NOPS and cannot satisfy ENO’s long-term peaking/reserve capacity deficit. Neither is it feasible for the Company to rely on the Midcontinent Independent System Operator, Inc. (“MISO”) capacity market for its long-term capacity needs. Further, as discussed more fully below, the Company has a long-term planning need for a local resource that can support local reliability, reduce reliance on transmission and resources external to Orleans Parish, and facilitate storm restoration.

V.

The Company also requests that the Council issue the approvals requested herein no later than October 31, 2017. This procedural schedule will allow the Company to issue timely notice to proceed (“NTP”) to the engineering, procurement, and construction (“EPC”) services contractor selected for the Project.

VI.

The Council should also be aware that the current cost estimate for the original CT has increased by $16 million, as discussed by Company witness Jonathan E. Long, bringing the overall cost estimate to approximately $232 million. The new anticipated Commercial Operation Date (“COD”), provided regulatory approval is received by the end of October 2017 and NTP is granted to the EPC contractor by November 1, 2017, is approximately November 2020.
VII.

The current cost estimate for the Alternative Peaker is $210 million. The anticipated COD, provided regulatory approval is received by the end of October 2017 and NTP is granted to the EPC contractor by November 1, 2017, is expected in October 2019.

VIII.

With this Supplemental and Amending Application, the Company is submitting the Supplemental and Amending Direct Testimonies of Charles L. Rice, Jr., Seth E. Cureington, Jonathan E. Long, Charles W. Long, Bliss M. Higgins, George Losonsky, Ph.D., Orlando Todd, and Robert A. Breedlove. The purpose of the testimony of each witness is as follows:

- **Charles L. Rice, Jr.** – Mr. Rice, President and Chief Executive Officer of ENO, provides an overview of the Supplemental Application. He also introduces the testimony of the other witnesses supporting the Supplemental Application.

- **Seth E. Cureington** – Mr. Cureington is the Director, Resource Planning and Market Operations for ENO. Mr. Cureington discusses the circumstances surrounding the updated load forecast referenced in ENO’s February 14, 2017 Motion to Suspend, and how the Company is still in need of long-term capacity, and in particular peaking and reserve capacity. He explains why local generation is needed, and the results of modeling conducted on behalf of the Company and the Council’s Advisors.

- **Jonathan E. Long** – Mr. Jonathan Long is the Vice President, Capital Projects for ESI. He provides an overview of the updated cost estimate and timeline for the CT. He also provides an overview of the Alternative Technology. He also describes the management approach that the Company intends to employ and the EPC contractor selected for the Alternative Peaker.
• **Charles W. Long** – Mr. Charles Long is the Director of Transmission Planning for ESI. He describes, from the transmission perspective, the unique characteristics of the Downstream of Gypsy (“DSG”) region and how the construction of either the CT or Alternative Peaker will have the effect of avoiding/delaying projects that would otherwise be necessary to maintain reliability. Mr. Long also describes the transmission related reliability benefits associated with constructing the CT and Alternative Peaker.

• **Bliss M. Higgins** – As described above, Ms. Higgins is an expert in air emissions and permitting and has concluded that the CT and the Alternative Peaker will have allowable emissions significantly below those of the former Michoud Plant and that these facilities emissions will comply with the U.S. Environmental Protection Agency (“EPA”) National Ambient Air Quality Standards, which were established to be protective of human health, including sensitive populations, with an adequate margin of safety via a lengthy EPA process with extensive and scientific community public involvement.

• **George Losonsky, Ph.D.,** – As described above, Dr. Losonsky is an expert geologist and former Commissioner of the Southeast Louisiana Flood Protection Authority-East. Dr. Losonsky conducted various analyses and concluded that the groundwater withdrawal associated with the CT and Alternative Peaker will not cause incremental subsidence or damage to infrastructure in New Orleans East.

• **Orlando Todd** – Mr. Todd is the Finance Director for ENO. Mr. Todd provides the estimated first-year revenue requirement associated with both NOPS options. He also describes the proposal to recover the costs associated with the Alternative Peaker. In
addition, Mr. Todd explains the proposed Cost Recovery Plan and the importance of timely recovery.

- **Robert A. Breedlove** – Mr. Breedlove is the Director of Plant Support in Fossil Operations. Mr. Breedlove provides the estimated operation and maintenance costs for the Alternative Peaker.

This Supplemental Application, along with the Company’s original Application, and the supporting testimony, include the specific data that the Company relied upon in making the decision to construct NOPS, estimates of the costs to construct both NOPS options, the estimated first year, non-fuel revenue requirement associated with both NOPS options, the estimated in-service dates, and the construction schedules and milestones.

**OVERVIEW OF RESOURCES**

**IX.**

As described in more detail by Mr. Jonathan E. Long in his Direct Testimony, the Company proposes to construct NOPS, which will consist of either the originally proposed CT or the Alternative Peaker. The technical details regarding the original CT are contained in the Company’s original Application.

**X.**

The Alternative Peaker, as stated above, will consist of seven Wärtsilä RICE generator sets. As explained by Mr. Jonathan E. Long, RICE is a well-known technology used, for example, in automobiles, trucks, marine propulsion, and backup power applications. RICE technology uses the expansion of hot gases to push a piston within a cylinder, converting the linear movement of the piston into the rotating movement of a crankshaft to generate power. In a
power plant, multiple spark-ignited or diesel RICE engines are grouped into blocks of engines, called generating sets, to provide modular electric generating capacity in standardized sizes.

XI.

Based on a study conducted by a qualified engineering firm, WorleyParsons, as described by Mr. Jonathan Long, the RICE units had the lowest levelized cost of electricity on a $/MWh basis compared to alternative CTs in the same output range, as well as other benefits such as very low water usage, a low emissions profile, the ability to support renewable resources, and the inclusion of black-start capability.

XII.

As Mr. Jonathan E. Long also discusses in his Direct Testimony, the current estimated cost to construct the Alternative Peaker is $210 million, which reflects the use of a fixed-price, fixed-duration form of EPC contract, subject to certain defined possible adjustments. The EPC contract accounts for a significant portion of the overall estimated cost of the Project. Other components included in the overall cost estimate are an allowance for funds used during construction (“AFUDC”), transmission interconnection to the switchyard, project contingency, internal construction management, indirect loaders, insurance coverage, expenses related to seeking Council certification, and other non-EPC costs. Charles Long describes the MISO interconnection study process in his Direct Testimony, and provides an update in his Supplemental and Amending Direct Testimony. Interconnection costs are not expected, but MISO’s process could identify costs that have not been included in the estimates provided.

XIII.

The estimated costs of operating and maintaining the Alternative Peaker are detailed in the Direct Testimony of Breedlove, and these costs are reflected in the estimated first-year non-
fuel revenue requirement set forth in the Supplemental and Amending Direct Testimony of Mr. Todd.

XIV.

As discussed in the Supplemental and Amended Direct Testimony of Mr. Rice, the construction of the either NOPS project is expected to have a positive impact on the economies of the State of Louisiana and Orleans Parish. Loren C. Scott & Associates, Inc. conducted a study and concluded that the construction and operation of the CT will produce significant economic benefits – totaling hundreds of millions of dollars – in terms of new business sales, household earnings, and jobs in both the State and Parish economies. Benefits result not only from one-time capital expenditures, but also from ongoing operational expenditures that will continue to accrue to the benefit of residents in Orleans Parish as long as the CT is in operation. The Company has engaged Loren C. Scott & Associates, Inc. to perform an analysis of the impacts of the Alternative Peaker, and its economic impact is expected to be similar to the CT’s.

PROJECT EXECUTION AND MANAGEMENT

XV.

As explained in the Supplemental and Amending Direct Testimony of Mr. Jonathan Long, Chicago Bridge and Iron, Inc. (“CB&I”) would remain the EPC contractor to construct the CT, should the Council choose that option. Regarding the Alternative Peaker, the Company has chosen a different single-source EPC contractor, Burns and McDonnell (“B&M”).

XVI.

B&M was selected through a procurement process as a result of its competitive pricing and prior experience with constructing resources that utilize RICE technology. By 2015, B&M had installed a total of 72 RICE engines, with 60 of these being Wärtsilä engines. B&M
constructed a total of 16 power generation facilities utilizing RICE technology. These projects include a 12 engine Wärtsilä plant at the Denton Energy Center in Denton, Texas, which employs the same engines that will be installed at NOPS; and the Southwest Texas Electric Cooperative’s Pearsall plant, which is also similar to the Alternative Peaker.

XVII.

Under the fixed-price EPC contract structure, B&M will act as an independent contractor with respect to the engineering, procurement, and construction services defined in the contract’s scope of work. B&M also will procure the RICE engines and balance of plant equipment from the original equipment manufacturers (“OEMs”). B&M’s procurement of this equipment will allow it full coordination and scheduling of the OEMs in order to meet the fixed-schedule provided in the contract.

XVIII.

As discussed by Mr. Jonathan Long, the Company does not have the in-house capability to provide all of the required EPC services for the Project. The use of an EPC contractor like B&M, which can perform all of these functions under a single contract, is cost-effective and common within the industry for such projects. The Alternative Peaker project will be managed and monitored by the Company through a Project Team, led by a Project Director, with oversight from an Executive Steering Committee (“ESC”). The ESC will provide oversight and strategic direction for the Project and will monitor and provide direction relating to Project performance, key risks, and value drivers that may affect the Project risk profile.

XIX.

As a component of the EPC Agreement, ENO will require B&M to provide opportunities to small and disadvantaged businesses for participation in any subcontracts and purchase orders
let in the performance of its obligations as the EPC contractor. The Company will require B&M to develop and maintain a list of Diverse Subcontractors and Suppliers that will be supplied to ENO on a quarterly basis. Minority-owned businesses, women-owned businesses, veteran-owned businesses, and disabled-veteran-owned businesses, among others, are included within the meaning of “diverse subcontractors and suppliers.” B&M will be required to submit a plan for utilizing diverse subcontractors and suppliers to ensure such participation in the construction of the Alternative Peaker.

RESOURCE NEEDS

XX.

As discussed by Mr. Cureington, ENO is still in need of a new local resource in Orleans Parish. The recent deactivations of Michoud Units 2 and 3, which were economic decisions based on maintenance and other operational issues, resulted in the loss of approximately 781 MW of local capacity and created a need. In fact, even based on the Company’s updated load forecast, the Company still projects a demand for overall capacity, specifically peaking capacity, over the next 20 years, as discussed above and by Mr. Cureington.

Mr. Charles Long also explains that the City of New Orleans is located in the eastern half of the DSG and Amite South load pockets, and that it is therefore very sensitive to local reliability issues. The City is located in a geographical and electrical peninsula, bordered by water on the north, east, and south. Accordingly, its ability to import power into New Orleans over the transmission grid is limited, which makes the area highly dependent on local generation to meet customer demand. This problem is only amplified by the fact that a large portion of the local fleet that provides reliability in the New Orleans area is aging and deactivating.
XXI.

As discussed more fully by Mr. Cureington, many Amite South and DSG generators have recently been retired, or are nearing the end of their useful lives. Given the ages of many units still in operation, deactivation could happen sooner than planned. The deactivations of Michoud Units 2 and 3, which together made up nearly 800 MW of generating capacity, are perfect examples of this risk. Given the acute sensitivity to reliability issues that ENO’s service territory faces, it is prudent for the Company to begin planning for these retirements, which will be decisions made independently of any decision to add generation based on the condition of the particular units at issue. Moreover, Messrs. Cureington and Rice explain that adding a local generator in New Orleans would not only help to address this issue, but would also create a hedge against market and supply related risks in MISO caused by ENO’s generation being located outside of the New Orleans Load Zone.

XXII.

Mr. Charles Long also explains that the transmission analysis conducted by the Company indicates that if generation is not added, ENO’s system may not remain reliable throughout the planning horizon absent costly transmission upgrades. In fact, if incremental generation is not added, and costly transmission upgrades are not performed, the Company’s service territory will face the risk of cascading (or uncontrolled) outages under certain scenarios that would affect most of the New Orleans area. Figure 1 depicts the areas that would be affected by the referenced outages:
As noted by Mr. Charles Long, adding either the originally proposed CT or the Alternative Peaker would mitigate the potential for these cascading outages.

XXIII.

Messrs. Charles Long and Seth Cureington also explain that a local unit will assist in storm restoration in the event the City of New Orleans becomes islanded (where most of the transmission lines importing power into the city are severed), as it was after Hurricane Gustav. This important benefit of adding local generation cannot be overstated and is consistent with the Council’s stated objective to harden the system in preparation for major weather events.

\[See\ \text{Exhibit}\ \text{CWL-6, pg. 4.}\]
Mr. Charles Long also explains that when generating capacity is added to the electric grid, it produces the most transmission-related benefits when located in proximity to the load that it will serve. Locating either NOPS option at the Michoud site will produce the following benefits:

- Increased load-serving capability in the New Orleans area, which is supportive to economic growth;
- Improved ability to serve existing load reliably by reducing the region’s dependence on already strained transmission facilities;
- Increased operational flexibility such that necessary maintenance activities for generation and transmission facilities in the area could be planned more efficiently without incurring operational risk during planned outages;
- Increased reactive power, which would improve stability in the DSG region and would thus avoid potential voltage instability and increasing system efficiency by providing reactive power margins to existing customers and supporting future industrial growth; and
- Increased storm restoration benefits, which would help the Company to restore service to customers in a timely manner following a major storm event.

**ALTERNATIVE ONE: THE CT XXIV.**

In June 2016, the Company proposed a natural-gas-fueled CT generating facility with a nominal capacity of approximately 226 MW, at summer conditions. Simply put, that CT remains the best option for customers. The Company has an overall capacity need that grows to
approximately 248 MW, and a peaking need of 342 MW on average throughout the 20 year planning horizon. The CT would address a substantial portion of that long-term need.

Moreover, as Mr. Cureington also discusses, the modeling used to estimate the Total Relevant Supply Costs of various portfolios, including those requested by the Council’s Advisors at the behest of certain intervenors in this docket who have opposed the construction of NOPS, produced results that were consistent with ENO’s original Application in that the CT is the most cost-effective means of addressing the Company’s identified long-term planning needs when using the Company’s assumptions around capacity prices in MISO. Even under a sensitivity using highly discounted capacity price assumptions, as recommended by intervenors opposed to NOPS, the CT is virtually tied with other portfolios and should therefore prevail given its significant local benefits.

XXV.

It is also important to note that when comparing the CT to the Alternative Peaker, there are some benefits created by the addition of local generation that increase as the size of the local generator increases and which give the CT a slight advantage over the Alternative Peaker because of its 100 MW size advantage. These benefits include the following:

- For reliability purposes, the DSG load pocket is in need of generating capacity to fill the void that will be created by retirements in the aging fleet of local resources. This need favors the addition of more generating capacity, not less.

- The 226 MW CT would eliminate all North American Electric Reliability Corporation (“NERC”) reliability issues throughout the 10-year planning horizon, including the cascading outages discussed above and all other reliability issues identified for smaller units in the Company’s reliability
analysis.

- As discussed more fully by Mr. Cureington, the larger CT would create a more effective hedge against market and supply related risks in MISO caused by ENO’s generation being located outside of the New Orleans Load Zone.
- The larger CT would create larger reliability margins over and above the minimum amount of generation needed for grid stability.
- The larger CT would create more reactive power, more flexibility to take outages, and less dependence on the transmission system than would a smaller unit.

For these reasons, and for the additional reasons provided in testimony supporting this Supplemental and Amending Application, the 226 MW CT remains the best option for customers.

ALTERNATIVE TWO: RICE GENERATOR SETS

XXVI.

In light of the recently updated load forecast, the Alternative Peaker will also provide benefits for ENO customers and should be considered a viable alternative to the originally proposed CT. As discussed above, and more fully by Mr. Jonathan Long, the Alternative Peaker has a low heat rate, low water usage, a low emissions profile, the ability to support renewable resources, and the inclusion of black-start capability.

XXVII.

The Alternative Peaker will also provide many of the same benefits as the larger CT, albeit to a lesser degree because it is 100 MW smaller. To recap, the Alternative Peaker will still add generating in DSG to fill the void that will be created as units in the aging generation fleet
inevitably retire on their own merits, provide a hedge against market and supply related risks in MISO caused by ENO’s generation being located outside of the New Orleans Load Zone, add generation to increase the flexibility to take outages to maintain transmission lines and generators, add reactive power, and lessen dependence on the transmission system to meet customer demand. The Alternative Peaker will also provide valuable storm restoration support and would have the ability to aid in islanding the city in an emergency situation.

XXVIII.

Another benefit of the Alternative Peaker, as discussed by Mr. Charles W. Long, is that the unit would also address the cascading, uncontrolled outages under certain contingencies, as discussed above. In fact, if the Alternative Peaker is constructed, then there would only be very minor overloading on the transmission system in planning year 2027. Under this circumstance, the Company would propose to wait until a point-in-time that is closer to the needed upgrades to determine if they are still necessary. Thus, there is a possibility that the Alternative Peaker would also satisfy all NERC reliability criteria.

XXIX.

Also, the Total Relevant Supply Costs of the various portfolios modeled, including under sensitivities around lower than projected capacity prices in MISO, resulted in the Alternative Peaker being competitive with other portfolios that were modeled. Specifically, while the Alternative Peaker was not the lowest cost alternative, its total supply cost ranged from 0.04% lower to 3.99% higher than the “transmission-only” and “100 MW Solar” cases that were modeled (across the entire range of assumptions and sensitivities). Thus, as explained by Mr. Cureington, this result is a virtual tie; and based on ENO’s need for a local resource, the Alternative Peaker should be selected over the transmission-only and solar portfolios that were
evaluated given its ability to address local reliability concerns and satisfy a portion of ENO’s need for peaking generation.

**NON-ALTERNATIVES**

**XXX.**

As Mr. Cureington discusses, renewable resources such as wind and solar are intermittent, as they rely on the wind and sun to produce energy, thus limiting their ability to be counted on to meet peak demands. As a result, renewables must be supported by dispatchable resources such as CT or Alternative Peaker to ensure sufficient resources are available to ramp-up and produce replacement energy when the wind is either not blowing or blowing less than projected, and similarly when cloud cover or unexpected weather limit the output of solar. Finally, because wind and solar are intermittent, these resources would not eliminate the need for quick-start and fast-ramping dispatchable resources. It should also be noted that because they are intermittent, the Company cannot count a megawatt of renewable resource capacity toward meeting a megawatt of its long-term capacity needs. Thus, even if intermittent resources could meet ENO’s peaking and reserve needs (which they cannot), the Company would need to acquire/construct significantly more of these resources than its capacity need dictates due to their lower capacity factor.

**XXXI.**

It should be noted that intermittent resources have a place in ENO’s supply portfolio. Indeed, as discussed by Mr. Charles Rice, ENO undertook a Request for Proposals (“RFP”) to determine whether there are cost-effective renewable resources available, and has selected three
resources. The RFP was conducted under the supervision of an Independent Monitor. After receiving and reviewing several bids, in May 2017, ENO announced that it had selected three RFP proposals for negotiation of definitive agreements, totaling approximately 45 MW, over twice the original amount sought in the RFP. Of the proposals selected, one is for the acquisition of an approximately 20 MW solar resource to be located in Orleans Parish, the second is for an approximately 5 MW solar self-build rooftop project also to be located in Orleans Parish, and the third involves a 20 MW long-term power purchase agreement from a solar resource to be located near Lafayette, Louisiana. However, without cost-effective storage, which does not exist at this time, it is not possible to utilize intermittent resources to meet ENO’s capacity reserve needs and, in turn, ensure reliable service to customers.

XXXII.

The Company is in the process of negotiating contracts with the third-party bidders and firming up other arrangements necessary to allow ENO to prepare the necessary Application(s) with supporting testimony and exhibits to submit to the Council seeking approval to add these projects to ENO’s resource portfolio. The contract negotiation process can take several months and is subject to numerous variables that can affect the outcome and timing for completion of negotiations. At this early stage in the process, ENO is tentatively targeting submission of its approval filing(s) sometime in the first quarter of 2018.

XXXIII.

As Mr. Cureington also discusses, achievable DSM resources are not available to meet the Company’s peak capacity needs. Indeed, the present load forecast has taken into account all

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5 On May 6, 2016, ESI issued a draft request for proposals for renewable generation resources. The RFP will facilitate a market test of the extent, and cost of, renewable resources available to provide benefits in excess of cost to the Company’s customers. More information on the Draft RFP can be found on the ESI RFP Website located at: https://spofossil.entergy.com/ENTRFP/SEND/2016ENOHRenewableRFP/Index.htm.
existing energy efficiency and demand side management in ENO’s portfolio, and it does not obviate the need for NOPS. Moreover, additional DSM and energy efficiency (“EE”) programs are costly to administer and the results therefrom continue to be uncertain. In 2014, the Company engaged ICF International, Inc. (“ICF”) to conduct an analysis of the long-term DSM potential achievable in New Orleans. ICF concluded that the achievable amount of DSM in New Orleans is not enough to negate the need for a local resource.

XXXIV.

In order to provide yet another independent evaluation of the long-term DSM potential in New Orleans, the Company recently engaged a second independent consultant, Navigant Consulting, Inc. (“Navigant”), to perform an additional analysis to determine the maximum achievable amount of EE potential savings over a 20-year planning horizon. Using its own methodology and leveraging relevant measures from the stakeholder-informed Arkansas Energy Efficiency Potential Study prepared for the Arkansas Public Service Commission in 2015, Navigant concluded that, under a very aggressive yet maximum achievable scenario, ENO could potentially reduce forecast sales by approximately 0.85%/year over the next 20 years. This level of reduction would cost roughly $400 million, but will not obviate ENO’s long-term need for incremental, long-term, local capacity.

ENVIRONMENTAL FACTORS

XXXV.

The Company engaged Dr. George Losonsky, Ph.D., a geologist who formerly served as a Commissioner of the Southeast Louisiana Flood Protection Authority-East, to study the issue of groundwater usage for both plants. Dr. Losonsky conducted various analyses and concluded that the groundwater withdrawal associated with the CT and Alternative Peaker will not cause
incremental subsidence or damage to infrastructure in New Orleans East. Specifically, Dr. Losonsky conducted site-specific calculations to predict a maximum drawdown over a 10-year period, and concluded that the proposed groundwater withdrawal/drawdown rates for the plants in question will be too small to directly affect subsidence or cause damage to buildings and infrastructure at the Michoud site or in New Orleans East.

XXXVI.

The Company also engaged Bliss M. Higgins, who has had a distinguished career at the Louisiana Department of Environmental Quality (“LDEQ”), the agency responsible for implementing all state and federal air quality laws and regulations in Louisiana, a state which is home to a very large and diverse industrial base. Ms. Higgins played a lead role in developing and implementing the Louisiana air toxics standards and program, and was the author of the Louisiana air toxics regulation. She also served as Assistant Secretary of the LDEQ Office of Environmental Services, and was responsible for final permit decision making for all permit actions taken by the Department.

Ms. Higgins’ testimony in this proceeding indicates that the allowable emissions for both units in question will be far lower than those of the former Michoud Units. In addition, Ms. Higgins explains the EPA’s National Ambient Air Quality Standards (“NAAQS”) are designed to be protective of human health, including sensitive populations such as children and the elderly. She explains the lengthy process used by the EPA to establish those standards, and that this process included reviewing the current policy-relevant science, extensive public outreach, public comment, and a public review period. Ms. Higgins further explains that the EPA conducts a Risk/Exposure Assessment in connection with setting the standards, wherein it considers the known or likely effects and risks associated with exposure at recent or current air
quality conditions and at conditions meeting the current NAAQS and alternative NAAQS under considerations. She also states that the state implements the NAAQS through a State Implementation Plan, which is comprised of the state laws, regulations, policies, guidelines, and programs necessary to govern air quality and specifically as needed to achieve and maintain compliance with the NAAQS across the state. In Louisiana, the LDEQ performs this implementation role.

In this case, the LDEQ will ultimately determine whether the unit selected by the Council will be permitted, but based on Ms. Higgins’ review of the facts, she fully expects for both units to comply with the EPA’s standards, and that therefore human health will be protected with “an adequate margin of safety.”

**COMPLIANCE WITH APPLICABLE COUNCIL RULES AND ORDERS**

**XXXVII.**

For the reasons discussed previously and in detail in the accompanying testimony, both NOPS are in the public interest, and are therefore prudent, and one should be approved by the Council. As discussed above, either project will add capacity to the Company’s generating resource portfolio that can be used in either a reserve or peaking role as necessary or appropriate, and will contribute to meeting the Company’s long-term supply needs. Moreover, either unit would support system reliability by adding necessary capacity within the supply-constrained DSG region.

**REGULATORY APPROVALS**

**XXXVIII.**

As part of this decision, the Council would approve an In-Service Cost Recovery Plan, which is discussed by Mr. Orlando Todd. In the past, the Council has allowed timely recovery of
the costs associated with new resources obtained for the benefit of ENO’s customers, such as Union Power Station Power Block 1 and the purchase power agreement (“PPA”) with respect to Ninemile 6. Such rate treatment provides an incentive for ENO to continue to undertake large investments or obligations in order to secure benefits for its customers.

ENO expects to commence commercial operation in October 2019 for the Alternative Peaker; or in November 2020 if the CT is selected. At that time, the Company expects the 2018 Combined Rate Case described in Paragraph 8 of the Algiers Transaction Agreement in Principle approved in Council Resolution R-15-194, dated May 14, 2015, to be complete and all of ENO’s customers to be subject to a single set of Council-approved base rates and riders. As a result of that proceeding, the Company further expects that the recovery of the capacity costs associated with the Ninemile 6 Unit and associated with Union Power Station Power Block 1 will be realigned from the Purchased Power and Capacity Acquisition Cost Recovery Rider (“PPCACR Rider”) to base rates. Finally, the Company assumes that ENO will be subject to a formula rate plan (“FRP”) following the Combined Rate Case. These are the principal regulatory assumptions that are the context for ENO’s proposed cost recovery plan.

**XXXIX.**

ENO proposes that the non-fuel revenue requirement associated with either project initially be recovered contemporaneous with commercial operation of the project through the PPCACR Rider, which would be modified for such purpose, or an alternative exact cost recovery rider. This rider would use the Company’s weighted-average cost of capital, including its actual capital structure, at the time the selected project commences commercial operation to determine the return on the Company’s investment in the project, and the return on equity resulting from the Combined Base Rate Case. These costs would be recovered from all of the Company’s
customers, including Algiers customers, which today do not pay charges pursuant to the PPCACR Rider. Assuming that the Council adopts a 2018 FRP in the Combined Base Rate Case, in the next FRP proceeding, the selected project’s non-fuel revenue requirement would be realigned so as to be recovered through the FRP Rate Adjustment but outside the FRP bandwidth formula. In the FRP proceeding after that, the selected project’s associated revenues and non-fuel revenue requirement would be included in the FRP bandwidth formula and recovered through the FRP Rate Adjustment.

**XL.**

Once the selected project commences commercial operation, ENO will begin incurring expenses related to the selected project that are not expected to be reflected in ENO’s base rates at the time. If the Council takes no action to address recovery of these expenses, then those expenses will have an adverse effect on ENO’s financial condition. In the event that there is no FRP in place after the Combined Rate Case, ENO proposes that the selected project’s non-fuel revenue requirement be recovered through the PPCACR Rider or a similar exact cost recovery rider until such time that ENO’s base rates are reset.

**XLI.**

As part of its requests, the Company proposes a Monitoring Plan whereby the Company would make periodic progress reports to the Advisors and the Council during the construction phase. The Monitoring Plan will serve as an “early warning system,” and the Company commits to providing the Council in the quarterly reports an affirmation as to whether continuing the selected project is, in their opinion, in the public interest. The Company requests that the Council require the Advisors to acknowledge the report, in writing, and submit any questions regarding the report within 30 days. As explained in the Direct Testimony of Ms. Shauna
Lovorn-Marriage, in the original Application, if circumstances change significantly after Council approval such that the Company believes it to be in the public interest to cease construction and/or cancel the selected project, it will make a filing in this proceeding seeking Council approval of that recommendation. In this Application, the Company seeks approval of this procedure.

**REQUEST FOR TIMELY TREATMENT**

**XLII.**

The Company also requests that the Council issue the approvals requested herein no later than October 31, 2017. This procedural schedule will allow the Company to issue timely NTP to the EPC contractor selected for the Project. The Company proposes a timeline that leads to a COD date of October 2019 for the Alternative Peaker; and November 2020 for the CT. Failure to issue NTP on November 1, 2017 will result in a day-for-day slip of those expected CODs. In addition, the estimated cost to construct the Alternative Peaker assumes that the Company is able to issue NTP no later than [REDACTED] following receipt of acceptable approvals from the Council. The inability of the Company to issue NTP by [REDACTED] would cause price escalation under the EPC contract, as discussed in the Direct Testimony of Mr. Jonathan E. Long.
XLIII.

Thus, in order to facilitate an October 2017 decision, the Company proposes the following Procedural Schedule:

<table>
<thead>
<tr>
<th></th>
<th>Issue Date of Procedural Schedule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Discovery</td>
<td>Resolution to 15 days prior to hearing</td>
</tr>
<tr>
<td>Direct Testimony of Intervenors</td>
<td>August 31, 2017</td>
</tr>
<tr>
<td>Direct Testimony of Advisors</td>
<td>September 15, 2017</td>
</tr>
<tr>
<td>Rebuttal Testimony of ENO</td>
<td>September 29, 2017</td>
</tr>
<tr>
<td>Evidentiary Hearing</td>
<td>October 6, 2017</td>
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<tr>
<td>Hearing Officer to Certify Record</td>
<td>October 16, 2017</td>
</tr>
<tr>
<td>Council Decision</td>
<td>No later than October 31, 2017</td>
</tr>
</tbody>
</table>

SERVICE OF NOTICES AND PLEADINGS

XLIV.

The Company requests that notices, correspondence, and other communications concerning this Joint Application be directed to the following persons:

Gary E. Huntley
Vice President, Regulatory and Governmental Affairs
Entergy New Orleans, Inc.
1600 Perdido Street
New Orleans, Louisiana 70112

Timothy S. Cragin
Brian L. Guillot
Alyssa Maurice-Anderson
Harry M. Barton
Entergy Services, Inc.
639 Loyola Avenue
Mailing Unit: ENT-26E
New Orleans, Louisiana 70113
REQUEST FOR CONFIDENTIAL TREATMENT

XLV.

The confidential information and documents included with the Supplemental Application marked Highly Sensitive Protected Materials or Confidential may be reviewed by appropriate representatives of the Council and its Advisors pursuant to the provisions of the Official Protective Order adopted in Council Resolution R-07-432. As such, these confidential materials shall be exempt from public disclosure, subject to the provisions of Council Resolution R-07-432.

PRAYER FOR RELIEF

XLVI.

WHEREFORE, Entergy New Orleans, Inc. respectfully requests that the Council, subject to the fullest extent of its jurisdiction, grant relief and give its approval as follows:

1. Find that the Company’s construction of NOPS, either the originally proposed CT or the Alternative Peaker, serves the public convenience and necessity and is in the public interest, and is therefore prudent;

2. Confirm that the Company will have a full and fair opportunity to recover all prudently-incurred costs;

3. Find that the retail non-fuel revenue requirement associated with the selected NOPS (to be determined in a subsequent revenue requirement filing) project is deemed eligible for recovery in the first billing cycle of the month following commercial operation of the selected NOPS, dollar-for-dollar for at least the initial twelve-months of operation via applicable PPCACR Rider, which would be modified for such purpose, or an alternative exact cost recovery rider. Following the first twelve-months, the associated non-fuel revenue requirement shall be realigned to ENO’s FRP, if applicable, or otherwise remain in the approved exact recovery rider;

4. Approve recovery, though the applicable FAC, of the energy costs and expenses incurred under the selected NOPS’ LTSA, if applicable;

5. Approve the Monitoring Plan under which the Company will: (i) report to the Council Advisors on a quarterly basis the status of the selected NOPS, including
schedule, costs, and other critical associated activities, and (ii) receive written acknowledgment from the Council Advisors;

6. Rule that, with respect to the selected NOPS, the Company has complied with, or is not in conflict with, the provisions of all applicable Council Resolutions;

7. Grant a waiver of any applicable requirement to the extent that such a waiver may be required to facilitate approval of the transaction described in this Application;

8. Develop and implement appropriate procedures to facilitate a Council decision on the Application no later than October 31, 2017; and

9. Order such other general and equitable relief as to which the Company may show itself entitled.

Respectfully Submitted:

By: [Signature]

Timothy S. Cragin, Bar No. 22313
Brian L. Guillot, Bar No. 31759
Alyssa Maurice-Anderson, Bar No. 28388
Harry M. Barton, Bar No. 29751
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ATTORNEYS FOR ENTERGY NEW ORLEANS, INC.
CERTIFICATE OF SERVICE
CNO Docket No. UD-16-02

I, the undersigned counsel, hereby certify that a copy of the above and foregoing has been served on the persons listed below by facsimile, by hand delivery, by electronic mail, or by depositing a copy of same with the United States Postal Service, postage prepaid, addressed as follows:

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Council of the City of New Orleans
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Susan Stevens Miller  
Chinyere Osuala  
Colleen Fitzgerald  
Alliance for Affordable Energy  
1625 Massachusetts Ave., NW Ste 702  
Washington D.C. 20036

New Orleans, Louisiana, this 6th day of July, 2017.
BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

SUPPLEMENTAL AND AMENDING APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF

DOCKET NO. UD-16-02

SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY OF CHARLES L. RICE, JR. ON BEHALF OF ENTERGY NEW ORLEANS, INC.

JULY 2017
# TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE OF TESTIMONY .................................................... 1

II. ALTERNATIVE ONE: THE ORIGINALLY PROPOSED CT ................................. 4

III. ALTERNATIVE TWO: RICE GENERATOR SETS .............................................. 9

IV. ENVIRONMENTAL FACTORS .......................................................................... 17

V. ENO’S 100 MW RENEWABLE COMMITMENT ................................................. 20

VI. COUNCIL APPROVALS AND TIMELINE ...................................................... 22

VII. INTRODUCTION OF WITNESSES ................................................................. 23

VIII. CONCLUSION ................................................................................................. 25
I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q1. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.
A. My name is Charles L. Rice, Jr. I am President and Chief Executive Officer of Entergy New Orleans, Inc. (“ENO” or the “Company”). My business address is 1600 Perdido Street, Building 505, New Orleans, Louisiana 70112.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING?
A. I am testifying on behalf of ENO.

Q3. ARE YOU THE SAME CHARLES L. RICE WHO FILED DIRECT TESTIMONY IN THIS DOCKET ON BEHALF OF ENO?
A. Yes.

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?
A. My Supplemental and Amending Direct Testimony ("Supplemental Direct Testimony") supports the Supplemental and Amending Application ("Supplemental Application") in this proceeding, which seeks, among other things, approval to proceed with a project to construct New Orleans Power Station ("NOPS"), which will consist of either a combustion turbine ("CT") resource with a summer capacity of 226 megawatts ("MW"), or alternatively, seven Wärtsilä 18V50SG Reciprocating Internal Combustion Engine ("RICE") Generator sets ("Alternative Peaker").
Q5. WHY IS ENO FILING A SUPPLEMENTAL AND AMENDING APPLICATION?

A. In January 2017, as discussed more fully by Company witness Seth E. Cureington, the Company received an updated forecast of projected customer demand for the 20 year planning horizon. The updated load forecast was created by Entergy Services, Inc. (“ESI”)\(^1\) for the purpose of updating the Company’s financial plans, including its sales forecast and financial models. ESI periodically updates its forecast of future customer demand for these reasons, and the information is also used to update the EOCs’ long-term capacity needs and long-term transmission planning.

As Mr. Cureington discusses, according to the updated load forecast, the Company’s projections of customer demand has moderated by an average of 3.4% per year (average of 40 MWs per year) compared to the forecast used in the original Application. Accordingly, on February 14, 2017, after the Intervenors in this docket filed their direct testimony but before the Council’s Advisors filed direct testimony, the Company filed a Motion to Suspend the procedural schedule in this docket in order to analyze the implications of the updated forecast and to ensure that the Company takes the best course of action for its customers.

Following the referenced Motion to Suspend, ENO has analyzed the implications of the updated forecast and has concluded that the original unit proposed to the Council, a 226 MW CT, still has significant benefits for customers and should be constructed. The Company also found, however, that the construction of a smaller unit would also create

\(^1\) ESI is an affiliate of the Entergy Operating Companies (“EOCs”) and provides engineering, planning, accounting, technical, and regulatory-support services to each of the EOCs. The five current EOCs are Entergy Arkansas, Inc. (“EAI”), Entergy Louisiana, LLC (“ELL”), Entergy Mississippi, Inc. (“EMI”), ENO, and Entergy Texas, Inc. (“ETI”).
significant benefits and should also be considered by the Council. Accordingly, the
Company now files this Supplemental Application requesting that the Council either (1)
approve the originally proposed CT, or (2) approve an alternative smaller resource, which
will be discussed throughout this filing.

Q6. HAS ENO KEPT CUSTOMERS INFORMED OF THE DEVELOPMENTS
DESCRIBED ABOVE?
A. Yes. Since ENO filed its original Application regarding NOPS in June 2016, my staff
and I have endeavored to keep ENO’s customers well informed regarding the Company’s
plans to replace the Michoud units, located in New Orleans East, which were more than
50 years old. Throughout the course of this proceeding, I have personally attended 12
public community meetings throughout the City of New Orleans in an attempt to engage
the community about the proposed plant. Consistent with this effort, following the
Motion to Suspend, I sent an email to ENO customers explaining that the Company
requested to temporarily suspend the procedural schedule in this docket so that it could
evaluate the implications of the updated load forecast. In April 2017, I sent an additional
e-mail updating customers about ENO’s progress and its investigation into a smaller
alternative resource, which is now being proposed as an option for the Council’s
consideration. That email previewed some of the benefits for customers that the
Alternative Peaker will offer, which are described in more detail below, and in the
various testimonies supporting this Supplemental Application.
Q7. PLEASE PROVIDE AN OVERVIEW OF YOUR SUPPLEMENTAL DIRECT TESTIMONY AND THE RELIEF SOUGHT BY ENO.

A. My testimony begins by describing the two proposed power plant alternatives and the associated benefits created by each. I explain that while ENO recommends approval of the originally proposed CT, the selection of the smaller Alternative Peaker will also create significant benefits for customers. I also explain that the testimonies and exhibits included with this filing demonstrate that the Company has a current need for long-term peaking/reserve resources, that the Company has a reliability need for local generating capacity, that the project is the lowest reasonable cost alternative, considering relevant risk factors, to meet those needs, and that the Company’s construction of NOPS, either with the CT or the Alternative Peaker, would therefore serve the public convenience and necessity. I also introduce the witnesses supporting the Application and provide a requested timeline for Council approvals.

II. ALTERNATIVE ONE: THE ORIGINALLY PROPOSED CT

Q8. AT THE OUTSET, PLEASE DISCUSS WHETHER THE COMPANY STILL HAS A NEED FOR LOCAL GENERATION.

A. As discussed by Mr. Cureington, ENO still emphatically needs a new local resource. The recent deactivations of Michoud Units 2 and 3, which were economic decisions based on maintenance and other operational issues, resulted in the loss of approximately 781 MW of local capacity and created a need. In fact, even based on the Company’s updated load forecast, the Company still projects an overall need for capacity, and specifically peaking and reserve capacity, over the next 20 years. As Mr. Cureington explains, the Company
has an overall capacity need of approximately 100 MW for the first ten years of the planning horizon, which grows to 248 MW in the second ten years of the planning horizon. The Company is also projected to have a peaking and reserve capacity deficit of approximately 342 MW on average throughout the 20 year planning horizon.

Moreover, as Company witness Charles W. Long explains, the City of New Orleans is located in the eastern half of the Down Stream of Gypsy (“DSG”) and Amite South load pockets, and is therefore very sensitive to local reliability issues. The City is located in a geographical and electrical peninsula, bordered by water to the north, east, and south. Accordingly, the City’s ability to import power over the transmission grid is limited, which makes the area highly dependent on local generation to meet customer demand. This problem is amplified by the fact that a large portion of the local fleet that provides reliability in the New Orleans area is aging and deactivating. As discussed more fully by Mr. Cureington, many Amite South and DSG generators have recently been retired, or are nearing the end of their useful lives. Given the ages of many units still in operation, deactivation could happen sooner than planned. The deactivations of Michoud Units 2 and 3, which together made up nearly 800 MW of generating capacity, are perfect examples of this risk. Given the acute sensitivity to reliability issues that ENO’s service territory faces, it is prudent for the Company to begin planning for these retirements, which will be decisions based on the condition of the particular units at issue and made independently of any decision to add generation.

In addition, the Company has conducted a transmission analysis that indicates that if a plant is not built at the Michoud facility, ENO’s system may not remain reliable throughout the planning horizon absent costly transmission upgrades. In fact, if
incremental generation is not added, and costly transmission upgrades are not performed, the Company’s service territory will face the risk of cascading (or uncontrolled) outages under certain scenarios that would affect most of the New Orleans area. Figure 1 depicts the areas that would be affected by the referenced outages:

Figure 1

As noted by Mr. Charles Long, adding either the originally proposed CT or the Alternative Peaker, which will be discussed below, will mitigate the potential for these outages. A local unit will also assist in storm restoration and in the event the City of New Orleans becomes islanded, meaning that the transmission lines importing power into the city are severed, as they were in Hurricane Gustav. This important benefit of adding local generation cannot be overstated and is consistent with the Council’s stated objective to
harden the system in preparation for major weather events. In summary, a local unit (i.e., the CT or the Alternative Peaker) is still very much needed and the Company is committed to its construction in order to provide substantial benefits for customers.

Q9. DOES THE COMPANY STILL RECOMMEND APPROVAL OF THE ORIGINALLY PROPOSED CT?

A. Yes. In June 2016, the Company proposed a natural-gas-fueled CT generating facility with a nominal capacity of approximately 226 MW, at summer conditions. Simply put, that CT remains the best option for customers. As mentioned, the Company has an overall capacity need that grows to approximately 248 MW, and a peaking need of 342 MW on average throughout the 20 year planning horizon. The CT would substantially address these long-term needs.

Moreover, as Mr. Cureington also discusses, the modeling used to estimate the Total Relevant Supply Costs of various portfolios, including those requested by the Council’s Advisors, produced results that were consistent with ENO’s original Application in that the CT is the most cost-effective means of addressing the Company’s identified long-term planning needs when using the Company’s assumptions around capacity prices in Midcontinent Independent System Operator, Inc. (“MISO”). Even under a sensitivity using highly discounted capacity price assumptions, the CT is virtually tied with other portfolios and should therefore prevail given its significant local benefits.

It is also important to note that when comparing the CT to the Alternative Peaker, there are some benefits created by the addition of local generation that increase as the size of the local generator increases and which give the CT a slight advantage over
the Alternative Peaker because of its 100 MW size advantage. These benefits include the
following:

- For reliability purposes, the DSG load pocket is in need of generating capacity
to fill the void that will be created by retirements in the aging fleet of local
resources. This need favors the addition of more generating capacity, not less.

- The 226 MW CT would eliminate all North American Electric Reliability
Corporation (“NERC”) reliability issues throughout the 10-year planning
horizon, including the cascading outages discussed above and all other
reliability issues identified for smaller units in the Company’s reliability
analysis.

- As discussed more fully by Mr. Cureington, the larger CT would create a more
effective hedge against market and supply related risks in MISO caused by
ENO’s generation being located outside of the New Orleans Load Zone.

- The larger CT would create larger reliability margins over and above the
minimum amount of generation needed for grid stability.

- The larger CT would create more reactive power, more flexibility to take
outages, and less dependence on the transmission system than would a smaller
unit.

For these reasons, and for the additional reasons provided in this Supplemental and
Amending Application, the 226 MW CT remains the best option for customers. In light
of the recently updated load forecast, however, the Alternative Peaker, as discussed more
fully below, will also provide benefits for ENO customers and should be considered a
viable alternative to the originally proposed CT.
Q10. WHAT IS THE CURRENT COST ESTIMATE AND PROJECTED COMMERCIAL OPERATION DATE FOR THE CT?

A. The Council should be aware that the current cost estimate for the CT has increased by $16 million, as discussed by Mr. Jonathan Long, bringing the overall cost estimate to approximately $232 million. The new anticipated Commercial Operation Date (“COD”), provided regulatory approval is received by the end of October 2017 and Notice to Proceed (“NTP”) is granted to the engineering, procurement, and construction (“EPC”) contractor by November 1, 2017, is approximately November 2020.

III. ALTERNATIVE TWO: RICE GENERATOR SETS

Q11. PLEASE DESCRIBE THE ALTERNATIVE PEAKER BEING PROPOSED BY THE COMPANY.

A. As explained by Mr. Jonathan Long, the Company engaged WorleyParsons, a qualified engineering firm, to conduct a study regarding the Company’s potential options for a smaller resource. The analysis indicated that RICE technology was the best option to meet ENO’s needs. As Mr. Jonathan Long explains, RICE is a well-known technology used in automobiles, trucks, marine propulsion, and backup power applications. RICE technology uses the expansion of hot gases to push a piston within a cylinder, converting the linear movement of the piston into the rotating movement of a crankshaft to generate power. In a power plant, multiple spark-ignited or diesel RICE engines are grouped into blocks of engines, called generating sets, to provide modular electric generating capacity
in standardized sizes. Please see Figure 2 for an example of an engine hall consisting of RICE engines:

**Figure 2**

Based on the study conducted by WorleyParsons, as described by Mr. Jonathan Long, the RICE units had the lowest levelized cost of electricity on a $/MWh basis compared to the alternatives considered, as well as other benefits such as low water usage, a low emissions profile, the ability to support renewable resources, and the inclusion of black-start capability.
Q12. IS THE ALTERNATIVE PEAKER PROPOSED TO BE LOCATED AT THE SAME SITE AS THE ORIGINALLY PROPOSED CT?

A. Yes. The Alternative Peaker is proposed to be located at the Michoud facility in New Orleans, Louisiana. Figure 3 illustrates the exact location of the Alternative Peaker:

Figure 3
Q13. WHAT IS THE CURRENT COST ESTIMATE AND PROJECTED COMMERCIAL OPERATION DATE FOR THE ALTERNATIVE PEAKER?

A. The current cost estimate for the Alternative Peaker is $210 million. The anticipated COD, provided regulatory approval is received by the end of October 2017 and NTP is granted to the EPC contractor by November 1, 2017, is expected in October 2019.

Q14. PLEASE ELABORATE ON THE BENEFITS ASSOCIATED WITH THE ALTERNATIVE PEAKER.

A. As discussed more fully by Mr. Jonathan Long, the RICE units have a heat rate that is significantly lower than the retired Michoud units’ heat rates and also lower than the proposed CT’s. A unit’s heat rate refers to the fuel required to generate a unit of electricity. Thus, the lower a plant’s heat rate, the less fuel is required to generate electricity and the more efficient the unit. In general, this is a benefit to customers since fuel is a pass-through cost.

The Alternative Peaker also utilizes a very low amount of water. As discussed by Mr. Jonathan Long, the RICE engines will use water to cool the engines due to evaporation in the generation process and for other uses at the site. The RICE engines, however, will use much less ground water than the retired Michoud units and the originally proposed CT.

The technology is also a great choice to back-up renewable generation. As this Council is well aware, ENO has committed to adding up to 100 MW of renewable resources to its generation portfolio, and the details of ENO’s plans are provided below.
As discussed in the testimonies of Messrs. Seth E. Cureington and Charles Long, however, renewable resources cannot meet a peaking capacity need because they are intermittent and not dispatchable, meaning they cannot produce power when the sun isn’t shining or the wind isn’t blowing and the Company cannot ramp up production when needed to meet demand. In order to address this problem, many utilities around the country have added RICE units to their portfolios because these units are able to start and achieve full load in a very short period of time, start and stop multiple times in a single day, and maintain emissions profiles over a range of operating outputs.

In addition, the unit will also include black-start capability, which will enable the Company to start the unit even when there is no power on the electric grid. This will give the Company the ability to restore electric service, should a complete loss of service occur. This could be a tremendous benefit if New Orleans is electrically “islanded” from the rest of the interconnected transmission grid, as it was after Hurricane Gustav.

Q15. ARE THERE ADDITIONAL BENEFITS ASSOCIATED WITH THE ALTERNATIVE PEAKER?

A. Yes. As mentioned above, the Alternative Peaker will provide many of the same benefits as the larger CT, albeit to a lesser degree. To recap, the Alternative Peaker will add generation in DSG to fill the void that will be created as units in the aging generation fleet inevitably retire on their own merits, provide a hedge against market and supply related risks in MISO caused by ENO’s generation being located outside of the New Orleans Load Zone, add generation to increase the flexibility to take outages to maintain transmission lines and generators, add reactive power, and lessen dependence on the
transmission system to meet customer demand. The Alternative Peaker will also provide valuable storm restoration support and would have the ability to serve load in the city in an emergency situation.

Another benefit of the Alternative Peaker, as discussed by Mr. Charles Long, is that the unit would also address the possibility of cascading, uncontrolled outages under certain contingencies, as discussed above. In fact, if the Alternative Peaker is constructed, there would only be very minor overloading on the transmission system in planning year 2027. Under this circumstance, the Company would propose to wait until a point-in-time that is closer to the needed upgrades to determine if they are still necessary. Thus, the Alternative Peaker could potentially also satisfy all NERC reliability criteria.

Also, as Mr. Cureington discusses, the Company modeled the Total Relevant Supply Costs of various portfolios, including those requested by the Council’s Advisors. Under every scenario, including under sensitivities around lower than projected capacity prices in MISO, the Alternative Peaker was competitive with other portfolios that were modeled. Specifically, while the Alternative Peaker was not the lowest cost alternative, its total supply cost ranged from .04% lower to 3.99% higher than the “transmission-only” and “100 MW Solar” cases that were modeled (this result was across the entire range of assumptions and sensitivities). Thus, as explained by Mr. Cureington, this result is a virtual tie, and based on ENO’s need for a local resource, the Alternative Peaker should prevail over the transmission only and solar portfolios given its ability to address local reliability concerns and satisfy a portion of ENO’s need for peaking generation.
Q16. WILL THE COMPANY USE A THIRD-PARTY EPC CONTRACTOR FOR THE
PROJECT?
A. Yes. The Company has selected Burns and McDonnell (“B&M”) to provide EPC
services for the Alternative Peaker as a result of a procurement process discussed by Mr.
Jonathan Long. B&M was selected through this process because of competitive pricing
and prior experience with constructing units using RICE technology. By 2015, B&M had
installed a total of 72 RICE engines, with 60 of these being Wärtsilä engines. B&M has
constructed a total of 16 power generation facilities utilizing RICE technology. One of
these projects is a 12 engine Wärtsilä plant at the Denton Energy Center in Denton,
Texas, which employs the same engines that will be installed at NOPS. The Southwest
Texas Electric Cooperative’s Pearsall plant is yet another plant constructed by B&M that
is similar to the Alternative Peaker.

Q17. IS THE PROJECT EXPECTED TO PROVIDE BENEFITS IN ADDITION TO THE
PLANNING BENEFITS DISCUSSED IN THE TESTIMONIES OF MESSRS.
CUREINGTON AND CHARLES LONG?
A. Yes. In June 2016, Loren C. Scott & Associates, Inc. studied the effect that construction
of the CT is expected to have on the economies of the State of Louisiana and Orleans
Parish. That study concluded that the construction and operation of the CT will produce
significant economic benefits – totaling hundreds of millions of dollars – in terms of new
business sales, household earnings, and jobs in both the State and regional economies.
Benefits result not only from one-time capital expenditures, but also from ongoing
operational expenditures that will continue to accrue to the benefit of residents in the region and State as long as the CT is in operation. The Company has engaged Loren C. Scott & Associates, Inc. to perform an analysis of the impacts of the Alternative Peaker, but its economic impact is expected to be similar to the CT’s.

Q18. WHY IS THE COST ESTIMATE OF THE ALTERNATIVE PEAKER SIMILAR TO THE ESTIMATE PROVIDED FOR THE CT?

A. As previously stated, the larger CT comes with economies of scale given its larger size, and the relationship that the Company has maintained with its manufacturer (Mitsubishi Hitachi Power Systems America, Inc. (“MHPSA”)) and EPC contractor (Chicago Bridge & Iron, Inc. (“CB&I”)). It should be noted that the EOCs have selected the same CT, the G-Frame, for use in multiple power plants across the Entergy fleet, including NOPS and three additional 2x1 combined-cycle gas turbine (“CCGTs”) being proposed in other service territories. Moreover, CB&I has been selected to construct these CCGTs. Accordingly, the relatively similar pricing between the CT and the smaller Alternative Peaker reflects more on the economies of scale that the Company has leveraged by proposing to purchase seven G-Frame turbines and using the same EPC contractor to construct each unit, than it does on the cost of the RICE units, which will employ a different technology and use a different EPC contractor. It should also be noted however, that although the Alternative Peaker costs more than the CT on a $/kW basis, as discussed more fully above, the Alternative Peaker has valuable benefits such as black-start capability, a lower heat-rate, and lower water usage.
IV. ENVIRONMENTAL FACTORS

Q19. HAS ENO STUDIED THE POTENTIAL ENVIRONMENTAL IMPACTS OF THE CT AND THE ALTERNATIVE PEAKER?

A. Yes. I would like to first take this opportunity to state that the Company has operated power plants at its Michoud Facility for over 50 years and the recent deactivations of Michoud Units 2 and 3 resulted in the loss of approximately 781 MW of local generation. Put simply, it was never a long-term solution to not fill the void left by the retirement of those units, as some Intervenors in this docket have suggested. Following the prudent decision to deactivate Michoud Units 2 and 3 based on their conditions, the Company has worked to execute on its plan to replace that generation with a newer, more efficient unit, since one is absolutely needed for long-term reliability. The Company originally proposed the CT, which had lower emissions and much lower groundwater usage than the retired Michoud Units. To further support its application, the Company has hired well-respected experts in the fields of air emissions and geology who have concluded that the emissions from the proposed CT are reasonable, based on standards developed by the Environmental Protection Agency (“EPA”), and that groundwater usage will be minimal and not cause subsidence and/or property damage.

In selecting the Alternative Peaker, the Company considered the fact that it will also have emissions that meet EPA standards and will use a negligible amount of groundwater that also, like the CT, will not cause subsidence or property damage. The Company has done its best to communicate these findings to the community at large throughout the pendency of its Application in this docket, and will continue to do so throughout this supplemental phase.
Q20. HAS ENO STUDIED THE POTENTIAL IMPACT OF GROUNDWATER USAGE FOR BOTH THE CT AND THE ALTERNATIVE PEAKER?

A. Yes. The Company engaged Dr. George Losonsky, Ph.D., P.G., a geologist who formerly served as a Commissioner of the Southeast Louisiana Flood Protection Authority-East, to study the issue of groundwater usage for both plants. Dr. Losonsky conducted various analyses and concluded that the groundwater withdrawal associated with the CT and Alternative Peaker will not cause incremental subsidence or cause damage to infrastructure in New Orleans East. Dr. Losonsky conducted site-specific calculations to predict a maximum drawdown over a 10-year period, and concluded that the proposed groundwater withdrawal/drawdown rates for the plants in question will be too small to directly affect subsidence or cause damage to buildings and infrastructure at the Michoud site or in New Orleans East.

Q21. HAS ENO STUDIED THE EMISSIONS IMPACT OF THE PROPOSED UNITS?

A. Yes. The Company engaged Bliss M. Higgins, who has had a distinguished career at the Louisiana Department of Environmental Quality (“LDEQ”), the agency responsible for implementing all state and federal air quality laws and regulations in Louisiana, a state which is home to a very large and diverse industrial base. Ms. Higgins played a lead role in developing and implementing the Louisiana air toxics standards and program and was the author of the Louisiana air toxics regulation. She also served as Assistant Secretary of the LDEQ Office of Environmental Services, and was responsible for final permit decision making for all permit actions taken by the Department.
Ms. Higgins’ testimony in this proceeding indicates that the allowable emissions for both units in question will be far lower than those for the retired Michoud Units. In addition, Ms. Higgins explains that the EPA’s National Ambient Air Quality Standards ("NAAQS") standards are designed to be protective of human health including sensitive populations, such as children and the elderly. She explains the lengthy process used by the EPA to establish those standards, and that this process included a review of the current policy-relevant science, extensive public outreach, public comment, and a public review period. Ms. Higgins further explains that the EPA conducts a Risk/Exposure Assessment in connection with setting the standards, wherein it considers the known or likely effects and risks associated with exposure at recent or current air quality conditions and at conditions meeting the current NAAQS and alternative NAAQS under considerations. She also states that the state implements the NAAQS through a State Implementation Plan ("SIP"), which is composed of the state laws, regulations, policies, guidelines, and programs necessary to govern air quality and achieve and maintain compliance with the NAAQS across the state. In Louisiana, the LDEQ performs this implementation role.

In this case, the LDEQ will ultimately determine whether the unit selected by the Council will be permitted, but based on Ms. Higgins’s review of the facts, she fully expects both units to comply with the EPA’s standards, and that therefore human health will be protected with “an adequate margin of safety.”
V. Eno’s 100 MW Renewable Commitment

Q22. Eno’s supplemental application and supporting testimony indicate that council approval of NOPS will help support the addition of renewables to Eno’s resource portfolio. Does Eno have any plans to add renewables to its resource portfolio?

A. Yes. Eno has committed to adding renewable resources to its portfolio and believes that doing so will benefit customers, including but not limited to adding environmentally clean resources that also provide fuel diversity and a hedge against natural gas exposure. I have previously committed on behalf of Eno to pursue up to 100 MW of renewable resources and I renew that commitment here.

Q23. Has Eno taken any concrete action towards fulfilling that commitment?

A. Yes. Eno recently conducted and concluded a formal Request for Proposals (“RFP”) seeking proposals for up to 20 MW of renewable resources. The RFP was conducted under the supervision of an independent monitor. After receiving and reviewing several bids, in May 2017, Eno announced that it had selected three RFP proposals for negotiation of definitive agreements, totaling approximately 45 MW, over twice the original amount sought in the RFP. Of the proposals selected, one is for the acquisition of an approximately 20 MW solar resource to be located in Orleans Parish, the second is for an approximately 5 MW solar self-build rooftop project also to be located in Orleans Parish.
Parish, and the third involves a 20 MW long-term power purchase agreement from a solar resource to be located near Lafayette, Louisiana.

Q24. WHAT IS THE CURRENT STATUS OF THE PROJECTS SELECTED FROM THE RFP?

A. The Company is in the process of negotiating contracts with the third-party bidders and firming up other arrangements necessary to allow ENO to prepare an Application (or Applications, if the projects are to be considered separately) with supporting testimony and exhibits to submit to the Council seeking approval to add these projects to ENO’s resource portfolio. The contract negotiation process can take several months and is subject to numerous variables that can affect the outcome and timing for completion of negotiations. At this early stage in the process, ENO is tentatively targeting submission of its approval filing (or filings) sometime in the first quarter of 2018.

Q25. YOU MENTIONED A COMMITMENT TO SEEK UP TO 100 MW OF RENEWABLE RESOURCES. DOES THE COMPANY HAVE ANY PLANS WITH REGARDS TO FULFILLING THE REMAINDER OF THAT COMMITMENT?

A. The Company is currently exploring available avenues for fulfilling the remainder of its 100 MW commitment.
Q26. FROM TIME TO TIME, SOME REPRESENTATIVES OF INTERVENORS HAVE SUGGESTED THAT ENO IS OPPOSED TO RENEWABLES. ARE YOU OR ENO OPPOSED TO ADDING RENEWABLES?

A. Absolutely not. The Company would like to add renewables to its portfolio and it is taking the actions necessary to do just that. The Company prefers to add renewables to its portfolio in a responsible manner for customers and all stakeholders ensuring grid reliability and considering risks.

VI. COUNCIL APPROVALS AND TIMELINE

Q27. WHEN DOES ENO REQUEST THE COUNCIL GRANT THE NECESSARY REGULATORY APPROVALS?

A. ENO asks that the Council take the steps needed to establish a Procedural Schedule such that the Council would issue a decision no later than October 31, 2017. This time table will provide adequate time for the Council, its Advisors and any stakeholders to review and provide comment on the Supplemental Application, while also permitting ENO to commence construction in time to achieve its target substantial completion date. In order to facilitate a October 2017 decision, the Company proposes the following Procedural Schedule:

<table>
<thead>
<tr>
<th>Discovery</th>
<th>Issue Date of Procedural Schedule Resolution to 15 days prior to hearing</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct Testimony of Intervenors</td>
<td>August 31, 2017</td>
</tr>
<tr>
<td>Direct Testimony of Advisors</td>
<td>September 15, 2017</td>
</tr>
<tr>
<td>Rebuttal Testimony of ENO</td>
<td>September 29, 2017</td>
</tr>
<tr>
<td>Evidentiary Hearing</td>
<td>October 6, 2017</td>
</tr>
<tr>
<td>Hearing Officer to Certify Record</td>
<td>October 16, 2017</td>
</tr>
<tr>
<td>Council Decision</td>
<td>No later than October 31, 2017</td>
</tr>
</tbody>
</table>
VII. INTRODUCTION OF WITNESSES

Q28. PLEASE INTRODUCE THE WITNESSES WHO HAVE FILED SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY ON BEHALF OF ENO AND IDENTIFY THE SUBJECTS THAT EACH ADDRESSES.

A. In addition to my testimony, ENO’s Supplemental Application is supported by the testimony of the following witnesses:

- **Seth E. Cureington** – Mr. Cureington is the Director, Resource Planning and Market Operations for ENO. Mr. Cureington discusses the circumstances surrounding the updated load forecast referenced in ENO’s February 14, 2017 Motion to Suspend, and how the Company is still in need of long-term capacity, and in particular peaking and reserve capacity. He explains why local generation is needed, and the results of modeling conducted on behalf of the Company and the Council’s Advisors.

- **Jonathan E. Long** – Mr. Jonathan Long is the Vice President, Capital Projects for ESI. He provides an overview of the updated cost estimate and timeline for the CT. He also provides an overview of the Alternative Peaker, the management approach that the Company intends to employ, and the EPC contractor selected for the Alternative Peaker.

- **Charles W. Long** – Mr. Charles Long is the Director of Transmission Planning for ESI. He describes, from the transmission perspective, the unique characteristics of the DSG region and how the construction of either the CT or Alternative Peaker will have the effect of avoiding/delaying projects that would otherwise be necessary to maintain reliability. Mr. Long also describes the
transmission related reliability benefits associated with constructing the CT and Alternate Peaker.

- **Bliss M. Higgins** – As described above, Ms. Higgins is an expert in air emissions and permitting and has concluded that the CT and the Alternative Peaker will have allowable emissions significantly below those of the former Michoud Plant and that these facilities emissions will comply with the U.S. Environmental Protection Agency (“EPA”) National Ambient Air Quality Standards, which were established to be protective of human health, including sensitive populations, with an adequate margin of safety via a lengthy EPA process with extensive and scientific community public involvement.

- **Dr. George Losonsky, Ph.D., P.G.,** – As described above Dr. Losonsky is an expert geologist and former Commissioner of the Southeast Louisiana Flood Protection Authority-East. Dr. Losonsky conducted various analyses and concluded that the groundwater withdrawal associated with the CT and Alternative Peaker will not cause incremental subsidence or cause damage to infrastructure in New Orleans East.

- **Orlando Todd** – Mr. Todd is the Finance Director for ENO. Mr. Todd provides the estimated first-year revenue requirement associated with the Project. He also describes the proposal to recover the costs associated with the Alternative Peaker and the importance of timely recovery.

- **Robert A. Breedlove** – Mr. Breedlove is the Director of Plant Support in Fossil Operations. Mr. Breedlove provides the estimated operation and maintenance
costs for the Alternative Peaker.

VIII. CONCLUSION

Q29. PLEASE SUMMARIZE YOUR SUPPLEMENTAL DIRECT TESTIMONY.

A. ENO is requesting the Council’s timely consideration of its Supplemental Application for approval to construct NOPS, which will consist of either a CT resource with a summer capacity of 226 MW, or alternatively, the Alternative Peaker with a capacity rating of approximately 128 MW. Both the CT and the Alternative Peaker have significant benefits, as described in this Supplemental Application and supporting testimonies. Either plant will improve supply conditions in the Company’s service area by providing a long-term resource capable of supporting reliable service to New Orleans during periods of peak demand and unplanned events, and either will mitigate market- and supply-related risks. As stated above, either plant will have the effect of eliminating the risk of cascading outages in New Orleans and the ability to provide reliability benefits such as support for restoration efforts following major weather events. The environmental allegations that have been levied against the proposed units are not accurate, as discussed by the Company’s technical reports and expert testimony in this proceeding. In short, the testimonies and exhibits included with this filing support the approval of either the CT or the Alternative Peaker by this Council.

Q30. DOES THIS CONCLUDE YOUR SUPPLEMENTAL DIRECT TESTIMONY?

A. Yes.
AFFIDAVIT

STATE OF LOUISIANA
PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, CHARLES L. RICE, JR., 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.

[Signature]
Charles L. Rice, Jr.

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 29TH DAY OF JUNE, 2017

[Signature]
NOTARY PUBLIC

My commission expires: at death

TIMOTHY S. CRAGIN
NOTARY PUBLIC (La. Bar No. 22313)
Parish of Orleans, State of Louisiana
My Commission is issued for Life
BEFORE THE
COUNCIL FOR THE CITY OF NEW ORLEANS

SUPPLEMENTAL AND AMENDING APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF DOCKET NO. UD-16-02

SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY OF SETH E. CUREINGTON

ON BEHALF OF ENTERGY NEW ORLEANS, INC.

PUBLIC VERSION HIGHLY SENSITIVE PROTECTED MATERIALS PURSUANT TO COUNCIL RESOLUTION R-07-432 HAVE BEEN REDACTED
JULY 2017

TABLE OF CONTENTS

I. INTRODUCTION ...............................................................................................................1
II. PURPOSE OF TESTIMONY ..............................................................................................1
III. UPDATED LOAD FORECAST AND IMPLICATIONS ..................................................6
IV. THE IMPORTANCE OF LOCAL PEAKING CAPACITY .............................................17
V. SUPPLEMENTAL TOTAL SUPPLY COST ANALYSES .............................................26
   A. The Company’s Reference Cases ..........................................................................27
   B. The Requested Portfolios .....................................................................................31
   C. Evaluation of the Modeling Results .....................................................................44
VI. CONCLUSION ..................................................................................................................48

EXHIBIT LIST

Exhibit SEC-10 Business Plan 17 Update Load Forecast (HSPM)
Exhibit SEC-11 Updated Load and Capability (HSPM)
Exhibit SEC-12 Inputs to AURORA Model Runs (HSPM)
Exhibit SEC-13 Total Relevant Supply Cost Analysis Results (HSPM)
Exhibit SEC-14 Navigant Report on EE Potential
I. INTRODUCTION

1 Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Seth E. Cureington. My business address is 1600 Perdido Street, New Orleans, Louisiana 70112.

2 Q2. ARE YOU THE SAME SETH E. CUREINGTON WHO FILED DIRECT TESTIMONY (JUNE 2016) AND SUPPLEMENTAL DIRECT TESTIMONY (NOVEMBER 2016) IN THIS DOCKET?

A. Yes.

3 Q3. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying before the Council of the City of New Orleans (“CNO” or the “Council”) on behalf of Entergy New Orleans, Inc. (“ENO” or the “Company”).

II. PURPOSE OF TESTIMONY

4 Q4. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY?

A. My Supplemental and Amending Direct Testimony (“Supplemental Direct Testimony”) supports the Supplemental and Amending Application (“Supplemental Application”) in this proceeding, which seeks, among other things, approval to construct the New Orleans Power Station (“NOPS”), which will consist of either a combustion turbine (“CT”) resource with a summer capacity of 226 megawatts (“MW”), or alternatively, seven
Wärtsilä 18V50SG Reciprocating Internal Combustion Engine (‘RICE”) Generator sets
(“Alternative Peaker”). My testimony proceeds as follows:

• I first explain the circumstances surrounding the updated load forecast referenced
in ENO’s February 14, 2017 Motion to Suspend, and I explain how the Company
is still in need of long-term capacity, and in particular peaking and reserve
capacity. I also explain that renewable resources, demand-side management
(“DSM”) programs, and/or reliance on the short-term Midcontinent Independent
System Operator, Inc. (“MISO”) capacity market are not viable alternatives to the
construction of either the original CT or the Alternative Peaker.

• Second, I explain how having a generating resource in the Company’s service
area (i.e., Orleans Parish) can help to mitigate market and supply related risks,
which would benefit customers.

• Next, I describe the results of the Company’s updated AURORAxmp Electric
Market Model (‘AURORA”) modeling, which takes into account the updated
load forecast mentioned above, to model the CT, the Alternative Peaker, and a
“transmission only” approach (which ENO does not consider a viable option for
meeting the identified needs).

• I then summarize the Council Advisors’ Recommendations,¹ which at the behest
of certain Intervenors who are opposed to NOPS, requested ENO to perform

¹ Advisors’ Recommendations with Respect to ENO’s New Orleans Power Station Supplemental Filing, Docket
No. UD-16-02 (“Advisors’ Recommendations”) (March 23, 2017).
AURORA modeling and analyses using different assumptions (the “Requested Portfolios”). I also provide the results of these analyses.

- Finally, I explain why the assumptions referenced above in the Requested Portfolios are not reasonable, citing to a new, independent examination of the achievable Energy Efficiency (“EE”) potential in ENO’s service territory, explaining why modeling capacity prices in the manner proposed by Intervenors opposed to NOPS is arbitrary, and explaining why renewable resources are not reasonable alternatives to dispatchable resources for meeting the Company’s peaking and reserve needs.

Q5. PLEASE SUMMARIZE THE CONCLUSIONS REACHED IN YOUR TESTIMONY.

A. As mentioned above, and as discussed more fully below, my testimony explains that ENO’s most recent load forecast (Highly Sensitive Protected Materials (“HSPM”) Exhibit SEC-10) has moderated by an average of 3.4% per year (average of 40 MW per year) compared to the forecast used in the original Application. Accordingly, I include an updated Load and Capability (“L&C”) analysis based on the revised forecast as HSPM Exhibit SEC-11, which indicates that the Company continues to have an overall need for long-term capacity, including a substantial need for peaking and reserve capacity.

My testimony also discusses the modeling used to estimate the Total Relevant Supply Cost for three Reference Cases (sometimes referred to as “Reference Portfolios”).

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2 The details regarding how DSM programs and customer-owned distributed energy resources are incorporated into the forecast are included in my workpapers.
Specifically, ENO modeled a portfolio that included the originally proposed CT (since that option is still before the Council), another with the Alternative Peaker, and a third that included incremental transmission upgrades necessary to mitigate North American Electric Reliability Corporation (“NERC”) violations but no long-term peaking resource addition. In addition, based on requests by certain Intervenors opposed to NOPS, the Council’s Advisors requested that ENO model certain other portfolios incorporating different assumptions, including what is likely an unrealistic assumption of DSM program implementation. Specifically, the Recommendations requested that ENO determine a least-cost portfolio using AURORA based on an assumed implementation of the Council’s DSM goal,3 and to the extent the least-cost portfolio included the Alternative Peaker, to develop a second least-cost portfolio without the Alternative Peaker. To comply with that request, the Company modeled four portfolios with the following incremental resource additions: (1) the Alternative Peaker, (2) the 226 MW CT, (3) 100 MW of additional solar (for a total of 200 MW of solar), and (4) 300 MW of wind resources.

Table 1 provides a summary of the Total Relevant Supply Cost results for both the Reference Cases and Requested Portfolios using ENO’s projected MISO capacity prices and a reference gas price forecast.

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3 See Advisors’ Recommendations at p. 1, n.2.
The results shown in Table 1 are consistent with ENO’s original Application in that the CT is the most cost-effective means of addressing the Company’s identified long-term planning needs while considering risk. Moreover, as explained below, although the portfolios that include the Alternative Peaker are ranked below the CT portfolios, the Alternative Peaker is a reasonable alternative to the CT. It should be noted at the outset, however, that portfolios that involve building transmission alone and/or adding renewable capacity are not viable planning alternatives to building a local, dispatchable peaking resource.
III. UPDATED LOAD FORECAST AND IMPLICATIONS

Q6. PLEASE DESCRIBE THE CIRCUMSTANCES THAT PROMPTED ENO TO FILE A REQUEST TO SUSPEND THE PROCEDURAL SCHEDULE IN THIS CASE.

A. On February 14, 2017, after the Intervenors filed their Direct Testimony, but before the Council’s Advisors filed their Direct Testimony, the Company filed a Motion to Suspend the procedural schedule in order to analyze the implications of an updated load forecast developed by Entergy Services, Inc. (“ESI”), a service company to the EOCs, for purposes of updating the Company’s financial plans, including the sales forecast and financial models. ESI periodically updates its forecast of future customer demand for these reasons, and the information is also used to update the EOCs’ long-term capacity needs and long-term transmission planning. As discussed more fully by Company witness Charles Rice, once ENO reviewed the results of the updated load forecast and determined that there could be implications to this proceeding (i.e., that the Company’s forecast of peak demand had moderated), it requested to suspend the proceeding in order to evaluate the best course of action for its customers.

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4 It should be noted that while the Company disagrees with most of the arguments put forward by the Intervenors in their Direct Testimony, the Company will reserve its right to address each argument advanced by the Intervenors in rebuttal. To the extent that the Advisors’ Recommendations, referenced above, are based on recommendations made by the Intervenors’ Direct Testimony, however, I will, in some cases, point out why those suggested assumptions are unreasonable and should not be relied upon for prudent long-term resource planning.

5 ESI is an affiliate of the Entergy Operating Companies (“EOCs”) and provides engineering, planning, accounting, technical, and regulatory-support services to each of the EOCs. The five current EOCs are Entergy Arkansas, Inc. (“EAI”), Entergy Louisiana, LLC (“ELL”), Entergy Mississippi, Inc. (“EMI”), Entergy New Orleans, Inc., and Entergy Texas, Inc. (“ETI”).
Q7. WHAT IS THE EFFECT OF THE FORECASTED CHANGE IN PEAK LOAD?

A. The Company’s original Application was based on the then-current peak load forecast, which was included in my HSPM Exhibit SEC-4. Based on that load forecast, and the Company’s existing long-term supply and demand-side resources, the Company projected an overall need for approximately 134 MW of capacity by 2020, and up to 205 MW by 2030. That forecast projected a peaking and reserve deficit of 377 MW in 2020, growing to 383 MW in 2030.

Under the updated load forecast, the Company continues to have an overall need for additional long-term capacity, including a substantial need for peaking and reserve capacity. As shown in Table 2, the Company now projects an overall need for approximately 99 MW of capacity by 2026, growing to 248 MW by 2036. The Company also has a persistent peaking and reserve deficit of approximately 342 MW on average in each year of the 20-year planning horizon. Table 2 provides an updated summary of the Company’s projected capacity position:
Table 2

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<th>2026</th>
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<tr>
<td></td>
<td>Need</td>
<td>Resources</td>
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<tr>
<td><strong>Base Load</strong></td>
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<tr>
<td><strong>Load Following</strong></td>
<td>308</td>
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<td><strong>Peaking &amp; Reserve</strong></td>
<td>426</td>
<td>88</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,270</td>
<td>1,171</td>
</tr>
</tbody>
</table>

Q8. AS A GENERAL MATTER, IS IT NORMAL TO EXPECT CHANGES IN LOAD FORECASTS OVER TIME?

A. Yes. Forecasts are subject to uncertainty; however, the Company relies on industry-standard tools and techniques to reduce that uncertainty to the extent possible. The Company estimates peak demand, but ultimately must be prepared to serve whatever level of load materializes, when it materializes.

Q9. WHAT CAUSED THE CHANGES FROM ENO’S PRIOR LOAD FORECAST TO THE UPDATED FORECAST DESCRIBED HEREIN?

A. The decline in the Company’s projected peak load was driven primarily by a decline in projected sales among the residential and commercial customer classes. Actual weather normalized sales in 2016 were approximately 2.1% lower than 2015 due primarily to a decline in residential and commercial usage per customer (“UPC”). While the Company continues to experience growth in the total number of customers served, the decline in

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6 Figures may not foot as compared to Exhibit SEC-11 due to rounding.
UPC more than offset that growth in 2016. Despite a small reduction in sales versus the
prior load forecast, projected Industrial class peaks increased slightly due to the projected
shift forward in the Company’s peak load when compared to the prior forecast. Projected
Governmental class sales and peak load is forecasted to be lower when compared to the
prior forecast primarily due to delays and modifications associated with the new Veterans
Affairs hospital project. The impact of the decline in UPC in 2016 among the residential
and commercial classes explains approximately 90% of the change in the Company’s
current forecast of peak load when compared to the prior forecast.

Q10. DUE TO THE INHERENT UNCERTAINTY IN ANY FORECAST, IS IT POSSIBLE
THAT THE UPDATED LOAD FORECAST COULD BE UNDERSTATED?
A. Yes. The load forecast is based on a “confidence interval” that captures 95% of the
potential load outcomes. While this means that there is a statistical possibility that actual
load could be lower than forecast, there is an equal statistical risk that actual load could
be higher than forecast, which would subject customers to the price risks of the short-
term capacity market and reliability risks if ENO has planned only for the forecasted load
and, as a result, lacks sufficient long-term resources to serve the actual load.

Q11. ARE THERE OTHER CIRCUMSTANCES THAT COULD INCREASE ENO’S NEED
FOR GENERATING CAPACITY?
A. Yes. I explained in my Direct Testimony that several of the existing legacy units
included in the Company’s portfolio are approaching the end of their useful lives and are
subject to deactivation earlier than expected.\(^7\) Table 3 below identifies the approximately 60 MW of allocated capacity associated with legacy units scheduled for deactivation within the planning horizon. If even a portion of this capacity is deactivated sooner than scheduled, the Company’s resource needs would increase sooner than forecasted, further exposing ENO’s customers to market and supply-related risks, including short-term capacity market prices that are expected to increase as equilibrium approaches.

<table>
<thead>
<tr>
<th>Algiers PPA Unit</th>
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<th>Age In 2017</th>
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Q12. IS THERE SIMILAR RISK WITH THE COMPANY’S COAL RESOURCES?

A. Yes. The Company’s portfolio currently includes approximately 33 MW of coal-fired generating capacity originating from long-term power purchase agreements with EAI for the White Bluff and Independence generating facilities. The planning assumptions reflected in HSPM Exhibit SEC-11 include that Independence Unit 1 remains active through the planning horizon. White Bluff Units 1 and 2 are assumed to deactivate by

\(^7\) See Cureington Direct at 22.
if not sooner, based on EAI’s current assumption that the White Bluff units will be allowed to continue operating without having to add expensive emissions control technology. However, if such control technology is required for continued operations, operation of the White Bluff units may no longer be economic and could be deactivated sooner than assumed. Similar to the risk I describe above regarding the aging legacy gas-fired fleet, if the White Bluff units deactivate sooner than planned, the Company’s resource needs would grow more quickly than forecasted, further exposing ENO’s customers to market and supply-related risks.

Q13. WHAT HAS THE COMPANY CONCLUDED WITH RESPECT TO ITS LONG-TERM RESOURCE NEEDS IN LIGHT OF THE UPDATED LOAD FORECAST?

A. Even based on the Company’s updated load forecast, it still has a need that would support the construction of the CT proposed in this docket. The Company’s planning principles outlined in my Direct Testimony support a balanced approach to resource planning that considers both cost and risk to customers in the provision of safe and reliable electric service. To that end, ENO’s analysis is based on a forecast of demand for the next 20 years, and while ENO is projected to have an overall capacity need of approximately 100 MW for the first ten years of the planning horizon, that need is projected to more than double in the second ten years of the planning horizon. As stated, ENO is projected to
have an overall capacity need of approximately 248 MW, the majority of which could be addressed by the CT. \(^8\)

Although ENO prefers to add long-term resources that would most cost-effectively meet the resource needs identified over the planning horizon, the Council could alternatively approve construction of a smaller resource now and defer the projected need to obtain additional long-term capacity until a later date. Accordingly, the Company has proposed a smaller Alternative Peaker that would meet a portion of ENO’s long-term capacity needs and mitigate exposure to market and supply related risks, while still adding generation in a strategic location of the electric grid that would produce reliability benefits and avoid the costly transmission upgrades discussed more fully by Company witness Charles W. Long. Thus, should the Council approve the Alternative Peaker, it would address the overall capacity need identified in the first half of the planning horizon, in which case ENO would continue to evaluate alternatives to fill the unmet resource needs projected for the second half of the planning horizon.

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\(^8\) The identified need assumes replacement capacity upon the assumed deactivation of Union Power Station Power Block 1 in 2033. I make the simplifying assumption in HSPM Exhibit SEC-11 to include the capacity associated with Union Power Station Power Block 1 through the remainder of the planning horizon.
Q14. TABLE 1 SHOWS A SUBSTANTIAL NEED FOR PEAKING AND RESERVE CAPACITY DESPITE THE MODERATION IN LOAD SHOWN IN THE UPDATED FORECAST. WILL THE TECHNOLOGY SELECTED FOR THE ALTERNATIVE PEAKER HELP TO ADDRESS THAT NEED EVEN THOUGH IT DOES NOT EMPLOY CT TECHNOLOGY?

A. Yes. HSPM Exhibit SEC-11 indicates that ENO will have a peaking and reserve capacity deficit in 2017 of approximately 332 MW, which deficit is expected to persist throughout the twenty-year planning horizon. As more fully discussed by Company witness Jonathan E. Long, the units that would comprise the Alternative Peaker are able to start and achieve full load in a very short period of time, and start and stop multiple times in a single day. Both of these characteristics are critical during periods of peak demand and unplanned events like generation or transmission outages because the proposed units can supply electricity almost simultaneously with customer demand. Thus, the Alternative Peaker would improve supply conditions in the Company’s service area by providing a long-term resource capable of supporting reliable service to New Orleans during periods of peak demand and unplanned events, and it would mitigate market and supply related risks.
Q15. ENO HAS CONTINUOUSLY EMPHASIZED THE IMPORTANCE OF MEETING ITS NEED FOR PEAKING CAPACITY. IS IT COMMON PRACTICE FOR UTILITIES TO DEPLOY PEAKING RESOURCES?

A. Yes. Prudent resource planning considers not only overall capacity needs, but also the need for capacity to serve specific supply roles, such as base load, load following, peaking, and reserve. Having an appropriate amount of capacity suitable to serve each of these supply roles allows the Company to reliably and cost-effectively serve the time-varying level of customer load. Supply role requirements are considered as general guidelines for portfolio planning purposes and do not necessarily address other planning criteria (e.g., locational considerations). The Company’s peaking requirement is defined as the level of load that is served in the highest 15% of the hours of the year. Finally, a planning reserve target also helps to maintain reliable service over a range of planned and unplanned circumstances.

Each supply resource has its own unique cost and performance characteristics that allow it to be functionally and economically suited to serve a given supply role. This is generally true for all load-serving entities. In order to reliably meet customers’ needs at the lowest reasonable cost, the Company must maintain a portfolio of long-term resources that includes the appropriate amounts and types of capacity. At this time, the Company has a need for long-term resources, including resources capable of operating in a peaking and reserve role. Table 4 provides a non-exhaustive, illustrative list of the amount of peaking resources owned by several major utilities.

Table 4
Q16. DOES THE COMPANY CONTINUE TO BELIEVE THAT DSM, RENEWABLE RESOURCES, AND THE MISO CAPACITY MARKET ARE NOT REASONABLE ALTERNATIVES FOR ADDRESSING THE IDENTIFIED LONG-TERM PEAKING AND RESERVE CAPACITY NEEDS?

A. Yes. Although there are benefits associated with renewable resource alternatives, such as hedging exposure to volatility in the price of natural gas, the intermittent nature of renewable resources limits the Company’s ability to rely on them to meet peak demand. Thus, should the Company need to call on such resources to ramp up production when customer demand peaks or an unplanned event occurs, those resources would not provide that dispatch capability.

Moreover, because renewable resources receive a lower capacity credit in MISO, the Company cannot count a megawatt of renewable resource capacity equal to a megawatt of gas-fired generation in planning to meet its long-term capacity needs. So even if those intermittent resources could meet the Company’s long-term need for peaking and reserve capacity (which they cannot), the Company would need to acquire significantly more capacity than its need dictates due to the lower capacity credit. This means that while renewable resources have significant benefits (ENO is currently taking
measures to add up to 100 MW of solar to its portfolio), many utilities, as discussed by Mr. Jonathan Long, have found that intermittent resources need to be backed up by traditional resources, and the Alternative Peaker is an ideal resource to function in such a role.

Regarding DSM resources, insufficient cost-effective incremental DSM programs are available beyond the Company’s currently-approved Energy Smart programs to meet the entirety of the Company’s long-term needs. During the 2015 IRP process, the Company engaged ICF International (“ICF”) to conduct an analysis of the long-term DSM potential achievable in New Orleans. Based on the results of ICF’s study, the achievable amount of DSM in New Orleans constitutes only approximately 14% of ENO’s projected need for long-term peaking and reserve capacity by 2019 (leaving a remaining deficit of 290 MW). As discussed more fully below, the Company recently engaged a second independent consultant, Navigant Consulting, Inc. (“Navigant”), to perform an additional analysis to determine the maximum achievable amount of EE potential savings over a 20-year planning horizon. Using its own methodology and leveraging relevant measures from the stakeholder-informed Arkansas Energy Efficiency Potential Study that it prepared for the Arkansas Public Service Commission in 2015, Navigant concluded that, under an aggressive scenario, ENO could potentially reduce forecast sales by roughly 17% over the next 20 years, which averages to 0.85%/year.9

As discussed more fully in my Direct Testimony, reliance on the MISO capacity market to meet long-term resource needs is also not a viable nor prudent alternative.

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9 The Navigant Report is attached as Exhibit SEC-14. The year by year incremental savings are shown in Table 1.
ENO’s planning assumption is that market equilibrium (where supply, including third party resources, and demand balance) in MISO South will occur around 2022. As market equilibrium approaches, capacity prices will reflect new build prices, which are significantly higher than today’s capacity prices. Deferring construction of a new resource comes with considerable risk given the long lead time necessary to gain regulatory approvals, obtain necessary permits, and plan and construct new resources. There is also risk around both the potential cost premiums for parts and equipment as other utilities seek to build modern, gas-fired resources, and the sharply higher and more volatile capacity prices expected as the capacity market approaches equilibrium. Moreover, as discussed more fully below, reliance on the MISO capacity market will not mitigate the local reliability considerations that are addressed by adding local generation in Orleans Parish. Accordingly, continued reliance on MISO’s capacity market constitutes a risky gamble, and as discussed more fully below, would expose ENO’s customers to congestion risk in the energy market as well.

IV. THE IMPORTANCE OF LOCAL PEAKING CAPACITY

Q17. PLEASE BRIEFLY SUMMARIZE THE COMPANY’S NEED FOR LOCAL GENERATION.

A. As discussed in detail in my original Direct Testimony, and in the Direct Testimony of Charles W. Long, ENO’s service area is located inside the Down Stream of Gypsy (“DSG”) and Amite South load pockets. These regions are heavily dependent on a limited amount of local generators to ensure reliability and to meet customer demand
because of geographic limitations on transmission import capability. As a result, the Company must now take steps to add new resources as the existing generation fleet that maintains reliability in DSG and Amite South ages and units continue to deactivate. This point is illustrated by the recent retirements of ENO’s Michoud Units 2 and 3, which together made up nearly 800 MW of generating capacity. Moreover, ELL’s recent decision to retire Little Gypsy Unit 1 and Ninemile Unit 3 is also instructive. These decisions, like all deactivation decisions, were made independently (i.e., not tied to any other investment decisions) based on unit condition and the economics of each respective unit, but it is simply a reality that as legacy units grow older and continue to deactivate, a void will be created that needs to be proactively addressed.

For example, some of the remaining legacy units located in Amite South and DSG are currently committed during a significant number of hours throughout the year in order to meet MISO’s commitment rules in these load pockets. The legacy units, however, are all over 40 years old, nearing the end of their useful lives, and are less efficient than either the CT or the Alternative Peaker. The planned deactivations of those units are also assumed to occur during the planning horizon and could occur sooner than expected given the age of these units.\(^{10}\)

The point here is that legacy generation in the Amite South and DSG load pockets will not operate in perpetuity and should not be over-relied upon in maintaining reliable and economic service. This means that to meet the reliability needs of New Orleans, which has a concentrated load squarely within the DSG load pocket and no

corresponding generation within the Company’s service area, incremental generation needs to be added.

Failure to add incremental generation inside the Company’s service area will exacerbate reliance on an already heavily-loaded transmission system to import electricity to serve load, which will increase risks to customers associated with, among other things, maintaining reliable service at the lowest reasonable cost, storm restoration, transmission upgrade costs, increased transmission and generation maintenance cost, outage frequency, and the flexibility to schedule transmission and generation outages.

The need to balance the reliance on transmission with in-region generation in developing long-term resource plans was illustrated when transmission lines used to serve Amite South and DSG load were severed by Hurricane Gustav, leaving the City of New Orleans “islanded” from the rest of the interconnected transmission grid and, thus, completely reliant on aging in-region generation at a critical time to customers.

Q18. HAS ELL TAKEN STEPS TO ADDRESS THE AGING LEGACY GENERATION IN THE DSG AND AMITE SOUTH REGIONS?

A. Yes. ELL, a utility that also serves load in these regions, has begun the process of building new generation to ensure reliability for its customers. This is evidenced by ELL’s plan to build a 980 MW combined-cycle gas turbine (“CCGT”) in Montz, Louisiana, which will be called the St. Charles Power Station (“SCPS”). The current cost estimate for that facility is approximately $870 million. In fact, my understanding is that in the Louisiana Public Service Commission (“LPSC”) docket related to SCPS, several
intervenors in that case advanced the argument that LPSC-jurisdictional customers should not be obligated to pay the full costs of the plant because it will have reliability benefits for ENO, which currently has a limited amount of local generation, and accordingly does not ensure its own reliability. But contrary to those intervenors’ statements, ENO and the Council are committed to doing their part to add local generation to address reliability.

As previously discussed in ENO’s original Application, the Council has already ordered ENO in Resolution R-15-524, to “use reasonable diligent efforts to pursue the development of at least 120 MW of new-build peaking generation capacity within the City of New Orleans.”11 That Resolution also emphasizes a commitment for ENO “to use diligent efforts to have at least one future generation facility located in the City of New Orleans.”12 NOPS, if approved, would comply with each of these directives from the Council. R-15-524 also directed ENO to “fully evaluate Michoud or Paterson, along with any other appropriate sites in the City of New Orleans, as the potential site for a CT or other peaking unit to be owned by ENO.”13 The construction of NOPS at the Michoud site, as discussed in my Direct Testimony, complies with that portion of the directive as well and adds incremental generating capacity in the City of New Orleans, as directed by the Council.

11 See R-15-524 at 12.
12 Id.
13 Id.
Q19. WILL AN IN-REGION RESOURCE LIKE NOPS MITIGATE MARKET AND SUPPLY RELATED RISKS?

A. Yes. The Company no longer has a source of generating capacity inside its service area that can respond to planned and unplanned events, which increases customers’ exposure to Locational Marginal Prices ("LMP") in the MISO wholesale energy market. In MISO, load serving entities purchase all of the energy necessary to serve their load from the MISO market at the LMP for the zone within which the load is situated ("Load Zone LMP"). Generators are paid the LMP at their location for any energy produced ("Generator LMP"). Because the New Orleans Load Zone is situated squarely within the DSG load pocket, the New Orleans Load Zone LMP tends to be higher than Load Zone LMPs that are not located in a load pocket due to congestion on the transmission system relied upon to serve load in DSG. This situation can be exacerbated during unplanned outages of a transmission line or a generator that can lead to significant increases in congestion, which puts upward pressure on the New Orleans Load Zone LMP.

In ENO’s case, because all of its generation is located outside of the New Orleans Load Zone, its customers’ exposure to increases in the New Orleans Load Zone LMP is only partially mitigated by the revenues received for its remote generation, which are generally lower than ENO’s payment obligations. While Auction Revenue Rights and Financial Transmission Rights ("ARR" and "FTR") can provide an effective hedge against congestion between the Company’s remote generation resources and the New Orleans Load Zone LMP, a local source of generation inside the load zone is necessary to help mitigate congestion risk during unplanned events such as the forced outage of an
existing source of generation. For example, if an event (planned or unplanned) occurred that caused New Orleans Load Zone LMPs to sharply increase, a local source of generation inside the load zone that MISO could dispatch would provide a source of revenues ($/MWh) that would be priced substantially the same as the New Orleans Load Zone LMP.

Q20. IS THERE EVIDENCE FROM THE COMPANY’S REAL-TIME OPERATIONS THAT INDICATES THAT AN ADDITIONAL PEAKING AND RESERVE CAPACITY RESOURCE IS NEEDED UNDER NORMAL OPERATING CONDITIONS?

A. Yes. Looking at the Company’s real-time generation compared to load for the Summer months of June 1 – August 31, 2016, ENO was short the necessary generation at various times throughout that period, leading to unhedged market purchases of energy approximately of the time. Moreover, the Company’s largest hourly purchase of energy was over MW. Having NOPS in the Company’s portfolio would provide a hedge against real-time shortages in generation that expose customers to the Load Zone LMP. Figure 1 below illustrates the timing and duration of the Company’s real-time short position last summer.
Q21. COULD LOCAL GENERATION MITIGATE RISK ASSOCIATED WITH MEETING THE LOCAL CLEARING REQUIREMENT FOR LOCAL RESOURCE ZONE 9?

A. Yes. The MISO capacity market includes ten Local Resource Zones (“LRZs”). For each LRZ, there is a minimum and maximum amount of capacity located in the zone that may clear the capacity auction. These zonal constraints can lead to different prices in different LRZs. For example, generally if there is a surplus of capacity in a zone, then the price in that zone may be lower than in neighboring zones, and if there is a scarcity of capacity in a zone, then the price there may be higher than the price in neighboring zones. The import and export limits for each zone are also important factors in the determination of zonal constraints that can lead to price separation between LRZs.
Capacity market settlements are zonal – loads are charged the auction clearing price for the LRZ in which they are located, and generators are paid the auction clearing price for the LRZ in which they are located. This creates the potential for price separation, which is a risk for load serving entities (“LSEs”) that do not own or contract for enough generating capacity located in the same zone as their load. With approximately □% of its capacity located outside of LRZ 9, ENO is such an LSE, and in the event of price separation, ENO’s capacity resources outside of LRZ 9 may be paid less than ENO’s load is charged. Price separation between LRZ 9 and LRZ 8 and 10 has not occurred in the first four capacity auctions that included MISO South. However, because the capacity import limit for LRZ 9 is significantly less than the planning reserve margin requirement set by MISO, there exists a risk of price separation between LRZ 9 and LRZ 8 and 10 that could be triggered by changes in the amount of capacity resources located in LRZ 9 and a corresponding increase in the need to import capacity. The addition of NOPS would mitigate customers’ exposure to the risk of price separation by providing an additional source of capacity in LRZ 9.

Q22. WHAT OTHER BENEFITS ARE ASSOCIATED WITH THE ADDITION OF A NEW AND MODERN SOURCE OF GENERATION IN THE LOAD POCKET?

A. Historically, the legacy generating units located in the Amite South and DSG load pockets have been dispatched throughout the year to maintain reliability of the bulk electric grid in the region. Within DSG, the units at ELL’s Ninemile generating facility provide the only source of local generation to serve in this role. Throughout the year,
MISO commits the units at Ninemile to maintain reliability in DSG, and while the new Ninemile Unit 6 is a highly efficient combined-cycle generating unit, the legacy Ninemile 4 and 5 units are approximately 45 years old and are less efficient than the CT or Alternative Peaker. When the Ninemile units are committed by MISO for reliability (referred to by MISO as “Voltage and Local Reliability” or “VLR”), ENO’s customers share in the variable cost to operate those units. Once NOPS is in service, it will provide an additional, more efficient source of generation to support reliability in DSG and is expected to displace some amount of generation currently provided by Ninemile 4 and 5, lowering costs for ENO’s customers.

Q23. DOES A LOCAL RESOURCE PROVIDE BENEFITS DURING STORM RESTORATION OR IN RESPONSE TO SIGNIFICANT UNPLANNED OUTAGES?

A. Yes. Having additional local generation will reduce the Company’s reliance on transmission assets that are likely to be out of service immediately following a significant unplanned outage or weather event (e.g., hurricanes). For example, as mentioned above, Hurricane Gustav severed all of the transmission lines serving the region, including the Company’s service area, which left the area “islanded,” or separated from the rest of the interconnected transmission grid. In an islanded situation, the Company is completely reliant on local generation, which currently means generation outside of Orleans Parish. If the generators located outside of Orleans Parish or the transmission lines that import power to New Orleans are in a forced outage, then the City would be completely without power. Having a local unit in New Orleans mitigates that risk. Moreover, as discussed
by Mr. Charles Long, the Alternative Peaker has black-start capability, meaning that it can start and operate without transmission support and could be critical to supplying power within the City as well as assisting in restoring the electric grid.

V. SUPPLEMENTAL TOTAL SUPPLY COST ANALYSES

Q24. PLEASE DESCRIBE THE ROLE OF PRODUCTION COST MODELING IN RESOURCE PLANNING AND EVALUATING SPECIFIC RESOURCE ALTERNATIVES.

A. Once a resource need is established, as it has been for ENO, and one or more resources are identified as potential alternatives capable of meeting that resource need, production cost modeling and simulations are used to assess the variable supply cost effects of adding a particular resource or set of resources to a utility’s resource portfolio. These variable supply cost effects can then be used as inputs into a broader economic analysis, in which spreadsheet models are used to layer on projected capacity costs, non-fuel operating costs, and revenues in order to determine the Total Relevant Supply Cost associated with the addition of a specific resource or set of resources to the utility’s portfolio.
A. The Company’s Reference Cases

Q25. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY’S UPDATED AURORA MODELING RUNS.

A. The Company conducted AURORA\textsuperscript{14} production cost modeling on each of three Reference Cases across sensitivities for natural gas and MISO capacity prices. As shown in HSPM Exhibit SEC-12, the first Reference Case (labeled “ENO Case 1” in the tables and exhibits) evaluates the addition of the Alternative Peaker. The second Reference Case (labeled “ENO Case 1G” in the tables and exhibits) evaluates the addition of the originally proposed 226 MW G-frame CT. The third Reference Case (labeled “ENO Case 2” in the tables and exhibits) evaluates the scenario in which no peaking resource is added, \textit{i.e.}, a “transmission-only” scenario. The scenarios requested by the Council’s Advisors at the behest of Intervenors opposed to NOPS will be discussed below.

Q26. WHAT COMMON ASSUMPTIONS WERE UTILIZED IN THE COMPANY’S REFERENCE CASES?

A. Uniform assumptions adopted in each of the ENO Reference Cases are presented in HSPM Exhibit SEC-12 and include the Business Plan 17 Update (“BP17U”) forecast of load and commodity prices including reference CO\textsubscript{2}, the planned addition by ENO of up to 100 MW of solar resources, the continuation of the Energy Smart program, and full deployment of Advanced Metering Infrastructure. Sensitivity analyses were conducted

\textsuperscript{14}See Cureington November 2016 Supplemental Direct at 4-5 for further explanation of the AURORA production cost model.
for each portfolio using low and high case natural gas price forecasts as well as a sensitivity using 60% of the Company’s MISO capacity price forecast.  

Q27. WHAT WERE THE RESULTING TOTAL RELEVANT SUPPLY COSTS OF THE COMPANY’S REFERENCE CASES?

A. The resulting model outputs for each portfolio were incorporated into the Total Relevant Supply Cost analysis, which is attached as HSPM Exhibit SEC-13. The results based on the reference, low and high gas price forecasts are summarized in Figure 2 below:

Figure 2

| ENO Reference Case – Total Relevant Supply Cost Results (PV 2017$; $MM)1,2,3 |
|---------------------------------|-----------------|-----------------|-----------------|
|                                  | REFERENCE GAS   | LOW GAS         | HIGH GAS        |
| Case 1                          | $1,826          | $1,524          | $2,197          |
| Case 1G                         | $1,735          | $1,408          | $2,122          |
| Case 2                          | $1,798          | $1,505          | $2,181          |

Notes:
1. The Fixed Cost component is the sum of DSM costs, Incremental Resource costs, Transmission costs and Capacity Purchases/(Sales).
2. The Capacity Purchases/(Sales) are based on the MISO South Capacity Price Curve as of May 2016.
3. The 20 year evaluation period of this analysis is (2017 – 2036).

See Advisors’ Recommendations at 3.
Q28. WHAT WERE THE RESULTS OF THE COMPANY’S REFERENCE CASES UNDER THE REQUESTED CAPACITY PRICE SENSITIVITY?

A. Figure 3 below summarizes the results of the Company’s Reference Cases using both high and low gas prices as well as projected MISO capacity prices that are 60% of the Company’s Reference Case MISO capacity price assumptions.

Figure 3

ENO Reference Case – Total Relevant Supply Cost Results (PV 2017$; $MM)$1,2,3

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Notes:
1. The Fixed Cost component is the sum of DSM costs, Incremental Resource costs, Transmission costs and Capacity Purchases/(Sales).
2. The Capacity Purchases/(Sales) are based on the MISO South Capacity Price Curve as of May 2016 at 60% of CONE.
3. The 20 year evaluation period of this analysis is (2017 – 2036).

Q29. DO YOU HAVE ANY COMMENTS ON THE TRANSMISSION-ONLY SCENARIO?

A. Yes. I believe that this scenario (ENO Case 2) understates the Total Relevant Supply Costs because it is essentially a “do-nothing” approach in which transmission upgrades are made solely to maintain NERC reliability requirements. It does not address the additional resources required to meet the identified needs of ENO’s customers, and it
does not address the market and supply related risks I discuss above. It also does not address the risk to customers associated with undue exposure to the short-term market price for capacity in MISO, which is expected to approach equilibrium. Thus, Case 2 is not a viable alternative for meeting ENO’s long-term resources needs but rather reflects a gamble that equilibrium is not on the horizon, capacity prices will remain low, market and supply related risks will not materialize, and none of the aging in-region generation necessary to support reliability in New Orleans or the coal-fired generation in ENO’s portfolio will deactivate early. Such a chain of assumptions is contrary to the Company’s reasoned expectations. Moreover, even if transmission projects were undertaken to facilitate additional import capability into Amite South and DSG, as the market approaches equilibrium there may not be excess capacity to purchase. Effectively, the transmission-only scenario would leave ENO’s customers exposed to significant risks.

Importantly, New Orleans is already totally dependent on transmission to serve the needs of its customers. The goal of a prudent local resource plan should be to ensure some amount of local generation is available to make the region less dependent on transmission, not more dependent. This is particularly true in the case of the Amite South and DSG load pockets. Adding more transmission in lieu of in-region generation makes the city more vulnerable to planned and unplanned events such as major storms, while a local generator would reduce that vulnerability. A dispatchable generator increases flexibility to take outages necessary to maintain vital transmission lines. Adding more transmission also does not add reactive power; a generator does.\textsuperscript{16}

\textsuperscript{16} Mr. Charles Long describes the need for and benefits of reactive power.
Accordingly, although the transmission-only approach appears economically competitive under the reduced capacity price sensitivity, which as discussed more fully below, is not a reasonable scenario; and it simply does not make sense to proceed with that option in lieu of building a local generator. New Orleans is already over-reliant on transmission to serve load. Moreover, as discussed by Mr. Charles Long, the terrain in an urban environment with swampy soil conditions like New Orleans makes transmission very difficult and costly to construct. As Mr. Charles Long discusses, the Company has not included detailed design-level transmission estimates because the Company has always planned to mitigate potential NERC violations with a local source of generation located at the Michoud site. If design-level estimates become necessary, it is very likely that projects to mitigate NERC violations will be more costly and will take a considerable amount of time to develop, seek approval, and then construct. Accordingly, for all of these reasons, Case 2 will not meet the Company’s objective to deploy resources necessary to meet long-term resource needs in the provision of safe and reliable service at the lowest reasonable cost.

B. The Requested Portfolios

Q30. PLEASE DESCRIBE THE REQUESTED PORTFOLIOS.

A. On March 23, 2017, as aforementioned, the Council’s Advisors filed Recommendations with Respect to ENO’s New Orleans Power Station Supplemental Filing, which requested that the Company model certain assumptions advanced by Intervenors opposed to NOPS. While legal counsel has advised me that ENO is under no legal obligation to
conduct analyses using assumptions advanced by intervenors opposed to the resource at
issue, the Company has performed the requested analyses to the best of its ability in
order to facilitate a more timely review of this proceeding.

It should be noted that it was requested that the Company utilize AURORA’s
capacity expansion feature in one of the Requested Portfolios, but the scope of the
modeling did not allow that feature to be used. Instead, the Company attempted to
simulate the results of the capacity expansion feature. Accordingly, the Company
conducted AURORA modeling on four portfolios using inputs and assumptions requested
in the Advisors’ Recommendations at the request of Intervenors. The Company also
performed the same sensitivities for natural gas and MISO capacity prices as was done
for the ENO Reference Cases described above.

The first Requested Portfolio (labeled “Case 3” in the tables and exhibits)
evaluates the addition of the Alternative Peaker. The second Requested Portfolio
(labeled “Case 3G” in the tables and exhibits) evaluates the addition of the originally
proposed 226 MW G-frame CT. The third Requested Portfolio (labeled “Case 4A” in the
tables and exhibits) evaluates the addition of an incremental 100 MW of solar. The
fourth Requested Portfolio (labeled “Case-4B” in the tables and exhibits) evaluates the
addition of 300 MW of wind resources.

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17 The capacity expansion algorithm component of the AURORA model would not perform the necessary
iterations through the entire 20-year planning horizon in order to converge on a solution for a particular resource.

18 The “incremental” 100 MW of solar in Case 4A is in addition to the 100 MW of solar resources that are
assumed in all of the supplemental AURORA modeling, for a total of 200 MW of solar in Case 4A.
Q31. WHAT COMMON ASSUMPTIONS WERE UTILIZED IN THE REQUESTED PORTFOLIOS?

A. Uniform assumptions adopted in each of the Requested Portfolios include the BP17U forecast of load adjusted for the estimated impact of the Council’s 2% DSM Goal, BP17U commodity prices including reference case CO2, the planned addition by ENO of up to 100 MW of solar resources, and full deployment of Advanced Metering Infrastructure. Sensitivity analyses were conducted for each portfolio using low and high case natural gas price forecasts as well as a sensitivity using sixty percent of the Company’s MISO capacity price forecast, which accommodates certain Intervenors’ arguments that “updated MISO capacity price forecast of net CONE” should be modeled. 19

Q32. WHAT WERE THE RESULTING TOTAL RELEVANT SUPPLY COSTS OF THE REQUESTED PORTFOLIOS?

A. Figure 4 below summarizes the results of the Requested Portfolios across reference, low and high gas prices.

19 See Advisors’ Recommendations at 3.
Figure 4

### Table: Requested Portfolios—Total Relevant Supply Cost Results (PV 2017$; $MM)$^{1,2,3}$

<table>
<thead>
<tr>
<th></th>
<th>REFERENCE GAS</th>
<th>LOW GAS</th>
<th>HIGH GAS</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Variable Costs</strong></td>
<td>$2,606</td>
<td>$2,338</td>
<td>$2,930</td>
</tr>
<tr>
<td><strong>Fixed Costs</strong></td>
<td>$2,541</td>
<td>$2,246</td>
<td>$2,882</td>
</tr>
</tbody>
</table>

**Notes:**
1. The Fixed Cost component is the sum of DSM costs, Incremental Resource costs, Transmission costs and Capacity Purchases/(Sales).
2. The Capacity Purchases/(Sales) are based on the MISO South Capacity Price Curve as of May 2016.
3. The 20 year evaluation period of this analysis is (2017 – 2036).

### Q33. WHAT WERE THE RESULTS OF THE REQUESTED PORTFOLIOS UNDER THE SENSITIVITY ANALYSES?

A. Figure 5 below summarizes the results of the Requested Portfolios using both high and low gas prices as well as projected MISO capacity prices that are 60% of the Company’s Reference Case MISO capacity price assumptions.
Q34. DO YOU HAVE CONCERNS WITH THE ASSUMPTIONS ASSOCIATED WITH THE REQUESTED PORTFOLIOS THAT AFFECT HOW THOSE RESULTS SHOULD BE CONSIDERED IN EVALUATING THE COMPANY’S APPLICATION TO CONSTRUCT NOPS?

A. Yes. As mentioned, the Requested Portfolios include several assumptions that were recommended by certain Intervenors in their direct testimony filed in January 2017. First, the Requested Portfolios include the Council’s DSM Goal referenced in Council Resolution R-15-599, which describes a goal of “increasing the projected savings from the Energy Smart program by 0.2% per year, until such time as the program generates...
kWh savings at a rate equal to 2% of annual kWh sales." Accordingly, for the Requested Portfolios, the Company adjusted the BP17U load forecast by reducing sales each year by 0.2% until a 2.0% incremental reduction, as measured over the prior three-year average sales, was achieved. After that, it reduced sales each year by 2.0% of the prior three-year average sales. In this manner, ENO’s forecasted load was significantly reduced during the planning period.

Q35. IS THE COUNCIL’S DSM GOAL ACHIEVABLE?

A. Not likely, and in any event it would not be cost-effective. The Company retained Navigant to assess the upper bounds of EE potential that could be achieved by ENO in a cost-effective manner. In the event that the upper bound of annual incremental cost-effective achievable savings potential was something less than 2.0%, Navigant was also asked to evaluate whether it would be theoretically possible, regardless of cost, to achieve 2.0% per year annual incremental savings. Finally, Navigant was asked to estimate the costs associated with achieving a 2.0% annual incremental savings level and sustaining it at that level over the study period. Those costs were incorporated into the Total Relevant Supply Cost analyses for the Requested Portfolios. Navigant’s report is attached as Exhibit SEC-14.

---

Q36. WHAT DID NAVIGANT CONCLUDE?

A. Navigant concluded that “with a comprehensive portfolio of efficiency measures, aggressive marketing and incentives, and realistic assumptions, ENO could cost-effectively reduce forecast load by roughly 17% over the next 20 years, an average of 0.85%/year.”²¹ Navigant further concluded that, while it achieved 2.0% in one year using unrealistic assumptions and including measures that are not cost-effective, even then it is not sustainable and declines after 2023 due to market saturation of the measures.²² Navigant further added that “the high ramp rate of this scenario is likely unrealistic and would be difficult to achieve under real-world conditions.”²³

Based on Navigant’s assessment, I believe that the results of the Requested Portfolios are skewed because they assume a level of load reduction that is over twice the level that could be achieved using aggressive assumptions and cost-effective measures. The aggressive savings potential level itself (an average of 0.85% per year) is more than double what ENO is actually achieving currently (approximately 0.4% per year), which further indicates that a 2.0% savings goal in not realistically or cost-effectively achievable. Finally, the benchmarking survey included in Navigant’s Report in Figure 9 show that 2.0% is nowhere near the average annual achievable “potential savings” of

²¹ See SEC-14 at 3.
²² Id. at 3, 13, and 21.
²³ Id. at 3.
other utilities in the South, which ranges from 0.53% to 1.07%. And actual savings for utilities in the South in 2015 tended not to achieve their potential savings.

Q37. PLEASE ELABORATE ON NAVIGANT’S CONCLUSIONS REGARDING THE ENERGY EFFICIENCY POTENTIAL FOR ACHIEVING 2.0% ANNUAL INCREMENTAL SAVINGS.

A. Navigant concluded that achieving 2.0% annual incremental savings is theoretically possible, but only for one year, and in order to achieve that result they had to assume that 100% of participant costs are covered by incentives, include program marketing effectiveness values that are “higher than realistic,” and use a total resource cost (“TRC”) screening level that was greater than or equal to 0.3, which means that many of the measures included in the portfolio are not cost effective. Further, the 2.0% savings potential level was only achieved in 2023, and then it tailed off significantly as the potential savings available from the measures were exhausted. Moreover, the estimated costs of that scenario exceed $1.4 billion over the 20-year period. In contrast, the estimated costs of the very aggressive, yet maximum achievable scenario were approximately $400 million. While the Company supports developing and pursuing...

24 See Exhibit SEC-14 at Figure 9, p. 28.
25 See Exhibit SEC-14 at Figure 10, p. 29.
26 See Exhibit SEC-14 at 13.
27 See Exhibit SEC-14 at 21-22.
28 See Exhibit SEC-14 at 5. The estimated costs to theoretically sustain potential savings at the 2.0% level over the 20-year period were $2.3 billion. Id.
29 See Exhibit SEC-14 at 5.
cost-effective DSM, based on Navigant’s conclusions, the Council’s DSM goal requires theoretical assumptions about unknown measures that have not yet been proven in actual market conditions, and thus lead me to conclude that the goal is simply not achievable at this time.\(^{30}\) Accordingly, the results of the Requested Portfolios do not constitute a reasonable basis for evaluating the resource options available to meet ENO’s resource needs because they utilize an unrealistically low load forecast.

Q38. IS THE REQUESTED RECOMMENDATION TO ASSUME A CAPACITY PRICE FORECAST THAT IS “NET CONE” REASONABLE FOR PURPOSES OF ENO’S MODELING?

A. No. The Company’s forecast assumes that as equilibrium approaches (where supply and demand are in balance) and the market tightens, capacity prices in MISO will trend towards, and eventually equal the cost of new entry (“CONE”). Apparently in response to the position taken by certain Intervenors who have opposed the construction of NOPS, the Advisors requested that the Company use a different methodology to project capacity prices called “Net CONE,” or the cost of new entry reduced by “potential energy market revenues.”\(^{31}\) Simply put, this is not the methodology used by MISO to calculate capacity prices, which is conceded by Mr. Luckow, the Intervenors’ witness who advanced this theory in his testimony, admitting that assuming capacity prices trend towards CONE is

\(^{30}\) As I explained in my November 2016 Supplemental Direct Testimony at page 9, the 2015 ICF International DSM Potential Study also supports the conclusion that achieving 2.0% annual incremental savings is not achievable in a cost-effective manner.

\(^{31}\) Luckow Direct at 17.
“logical in theory—and this is why such markets use CONE as a basis for setting price rules.”32 The testimony goes on to state, however, that in “other capacity markets,” net CONE is used.33

The first problem with this assumption is that it appears to be completely arbitrary. In fact, in order to reduce ENO’s assumption around capacity prices to align with his theory, Mr. Luckow randomly picked a value within the range of historic capacity prices in PJM, a completely different regional transmission organization (“RTO”), with different market dynamics.34 To the extent it has any analytical basis, in so far as the Intervenors have described Net CONE, at best it is a theoretical argument that relies on academic conjecture about bidding behavior and auction outcomes. In contrast, the Company’s projection is based on a reasonable trajectory toward CONE, which represents a “logical” assumption that prices will approach CONE as the market tightens.

Assuming that the prices that ENO will have to pay for future capacity are something less than CONE assumes that either the market will not approach equilibrium, and/or that there is a completely efficient capacity market. Yet in the 2015 State of the Market Report for the MISO Electricity Markets (published June 2016), MISO’s independent market monitor noted that the “PRA continues to reflect a poor representation of the demand for capacity, which undermines its ability to provide

32 Id.
33 Id.
34 Id. at 18-19.
efficient economic signals.”35 The Report went on to say that “MISO’s capacity market is not designed to provide efficient prices and incentives to govern investment and retirement decisions.”36 Mr. Luckow’s theory rests on the existence of an “efficient capacity market,” which MISO is not; and on the belief that significant merchant generation investment is likely in MISO South, which is not likely given the capacity market structure. In short, the Company modeled sensitivities around reduced capacity prices, as requested by the Advisors, but the Company does not endorse these reduced capacity prices because based on its analysis, equilibrium is expected to occur sometime around 2022 and there is no reasonable basis to assume future capacity prices at net CONE.

Q39. ARE ADDITIONAL RENEWABLE RESOURCES APPROPRIATE FOR MEETING ENO’S PEAKING AND RESERVE CAPACITY NEEDS?

A. No. During periods of peak demand, generating resources must be able to respond quickly to changing conditions on the electric system in order to maintain reliability by starting on short notice and responding to dispatch signals to quickly ramp up or down (i.e., “dispatchable”). Fossil-fueled resources like the CT and Alternative Peaker are technologically suited for peaking and reserve roles precisely because they are dispatchable. That capability supports local area reliability and, as Mr. Jonathan Long


36 Id. at 20.
describes, facilitates the integration of renewable resources in or near the Company’s service area by providing a quick start resource capable of coming online and ramping quickly to address the intermittency associated with renewables.

Q40. PLEASE ELABORATE ON THE ISSUES ASSOCIATED WITH RENEWABLES SUCH AS WIND AND SOLAR AND WHY THEY ARE NOT VIABLE ALTERNATIVES TO MEET PEAKING AND RESERVE NEEDS.

A. Renewable resources such as wind and solar are intermittent because they rely on the wind and sun to produce energy, thus limiting the Company’s ability to rely on them to meet customer demand. In other words, the generating capacity of renewables such as wind and solar are not dispatchable because the available capacity is solely a function of the amount of wind and sunlight available at a given time and thus cannot be counted on for meeting peak demand. As a result, renewables must be supported by dispatchable resources that can ramp up and produce replacement energy when the wind is either not blowing or blowing less than projected. Dispatchable resources are similarly required when the sun sets (which is typically when the Company’s load approaches its summer peak) or cloud cover and unexpected weather limits the output of solar throughout the day. Based on my own experience, I can state that thunderstorms and severe weather in summer afternoons and evenings, which coincides with the Company’s peak demand, are common occurrences in New Orleans.

In the case of wind resources, the greatest potential lies in areas remote from the Company’s service area requiring significant transmission upgrades to deliver those
resources to New Orleans. Moreover, wind resources typically peak during late evening and early morning hours when the Company’s load is typically the lowest, which could complicate the dispatch of vital baseload resources that typically operate 24 hours a day, 7 days a week. Another important consideration for wind and solar resources is the land intensity of those resources. Based on the Company’s own experience, solar resources can require approximately 7-10 acres of land per MW, as evidenced by the Company’s 1 MW solar pilot project in New Orleans East. Wind resources can require over 60 acres of land per MW, making it a practical impediment to develop wind resources in or around the Company’s service area. Accordingly, even if wind and solar resources were capable of serving in a peaking or reserve supply-role (which they are not), the practical impediments to development prevent them from meeting the Company’s need for a local peaking and reserve capacity resource.

Q41. DOES THIS MEAN THAT INTERMITTENT RESOURCES SUCH AS SOLAR AND WIND HAVE NO PLACE IN ENO’S SUPPLY PORTFOLIO?

A. Not at all. To the extent there are cost-effective sources of renewable energy available to the Company, they could provide benefits to customers in the form of increased diversity of supply, a hedge against exposure to volatility in commodity prices (e.g., natural gas), and other environmental attributes. Moreover, the Company has committed to pursuing up to 100 MW of renewable resources, and it has included that planned capacity in each of the AURORA simulations described above.
C. Evaluation of the Modeling Results

Q42. CONSIDERING THE ISSUES YOU DESCRIBED WITH RESPECT TO THE REQUESTED PORTFOLIOS, DO THE TOTAL RELEVANT SUPPLY COST ANALYSES CONTINUE TO SUPPORT THE COMPANY’S APPLICATION TO CONSTRUCT NOPS?

A. Yes. As I explained above, the 226 MW CT (Case 1G) is the most cost-effective resource alternative under low, reference and high gas price projections and using the Company’s MISO capacity price forecast. While the Reference Case with the Alternative Peaker (Case 1) is projected to result in a higher Total Relevant Supply Cost when compared to Case 1G, the increase is comparable to the transmission-only case (Case 2). Even under the discounted capacity price assumption, which I explained above is arbitrary, Case 1G is the most cost-effective alternative in the low gas sensitivity case and is virtually tied with Case 2 in the reference and high gas scenarios. While Case 1 is projected to result in a higher cost when compared to Case 1G in the reference and high gas scenarios, the increase is comparable to that of Case 2 in the low gas scenario. As I have explained, deploying a dispatchable unit in New Orleans mitigates market and supply related risks, especially as the market reaches equilibrium. Further, Mr. Charles Long explains the additional local reliability benefits, which will not be not realized under a transmission-only scenario. Accordingly, for these reasons, and for all of the additional reasons described above in my testimony, when confronted with comparatively equal Total Relevant Supply Costs for these two portfolios, the additional benefits of a
local, dispatchable resource clearly favors NOPS over the non-viable, transmission-only option.

Furthermore, the Requested Portfolios results favor Case 1G in all of the gas price scenarios when using the Company’s forecasted capacity prices. Those results change slightly when using a discounted capacity price forecast that is 60% of the reference case, but even in that scenario Case 1G is the most cost-effective alternative in the low gas case. Case 1G and Case 1 have a slightly higher cost when compared to Case 4A in the reference and high gas cases; however, the increase is comparable to that of Case 4A in the low gas scenario. Thus, given the identified planning needs, even in the Requested Portfolios, the benefits of adding local, dispatchable generation prevail.

Q43. IF THE 226 MW CT, THE ALTERNATIVE PEAKER, AND THE INCREMENTAL 100 MW SOLAR PORTFOLIOS ARE ROUGHLY EQUAL IN TERMS OF TOTAL RELEVANT SUPPLY COSTS, AS IN THE REQUESTED PORTFOLIOS, ARE THERE ADDITIONAL CONSIDERATIONS THAT FAVOR ONE OVER THE OTHER?

A. Yes. Traditional gas-fired generating units like the CT and Alternative Peaker are preferred to meet current and projected long-term peaking and reserve capacity needs due to their lower installed cost and operational flexibility when compared to other dispatchable resource alternatives. As stated, renewable resources like solar and wind are intermittent and must be backed up with dispatchable resources to ensure sufficient resources are available to ramp up and produce replacement energy when it is cloudy,
late in the day, or the wind is not blowing. Furthermore, the Company’s summer peaks occur late in the day when customers are returning home from work and turning on lights and appliances and lowering thermostat settings. Given that profile, solar is not an ideal peaking resource as it is often unavailable or declining (i.e., the sun is setting) right when it is needed most. Moreover, as I described above, having a local, dispatchable resource actually supports the addition of future renewable resources.

I also described in my Direct Testimony how MISO grants solar resources less capacity credit in its Resource Adequacy (“RA”) process, which means that it takes more MW of solar generation than an equivalent MW of CT generation for the same RA credit. Thus, the additional capacity provided by a 226 MW CT at a Total Relevant Supply Costs comparable to the 100 MW of solar should not be overlooked in its contribution to meeting ENO’s RA requirements in MISO and the Company’s long-term resource needs.

For all these reasons, given that the 100 MW solar portfolio and the 226 MW CT are virtually tied in terms of Total Relevant Supply Costs, the 226 MW CT is the better resource for meeting ENO’s identified long-term planning needs while considering risk.

Q44. IS THE COMPANY RECOMMENDING THE ALTERNATIVE PEAKER AS A REASONABLE ALTERNATIVE TO THE 226 MW CT?

A. The Company has included the Alternative Peaker as a reasonable alternative to the originally proposed 226 MW CT, recognizing that it represents a higher installed cost per kW and higher projected operating cost. Mr. Jonathan Long explains that the Alternative Peaker has lower water usage, a low emissions profile, an enhanced ability to support
renewable resources (because of its ability to start and achieve full load in a very short period of time, and its ability to start and stop multiple times in a single day), a lower heat rate, and the inclusion of black-start capability.\textsuperscript{37} Further, this option is only 2.3% more expensive on average than the transmission-only alternative in the Company’s Reference Cases, and a mere 1.3% more expensive on average than the Requested 100 MW solar portfolio, but it will add a local source of dispatchable generation capable of providing real and reactive power and mitigating market and supply-related risks when compared to the transmission-only and solar portfolios (albeit to a lesser degree than the CT), which makes the Alternative Peaker a reasonable alternative to the 226 MW CT and a better option than transmission-only and solar alternatives.

\textsuperscript{37} See Jonathan Long Supplemental at 6, 7.
horizon, and more than double that amount over the second ten years, and both the 226
MW CT and the Alternative Peaker reasonably address ENO’s capacity deficit, with the
Alternative Peaker projected to leave the Company slightly short at the end of the
planning period and the CT leaving the Company a bit long. Neither of those results are
unusual or unreasonable. Further, neither alternative completely addresses ENO’s short-
term or long-term peaking and reserve deficit.

Q46. SHOULD THE COUNCIL CONSIDER THE RESULTS OF THE ANALYSES
CONDUCTED IN THE COMPANY’S NOVEMBER 2016 SUPPLEMENTAL FILING
AS WELL?

A. The results of the November 2016 analyses are consistent with ENO’s position that the
226 MW CT is a cost-effective resource alternative for addressing the Company’s
identified long-term resource planning needs while considering risk. The more recent
analyses included with this Supplemental Testimony are based on different assumptions,
which are described above, but continue to support that NOPS is cost-effective for
addressing the Company’s identified long-term resource planning needs while
considering risk.

VI. CONCLUSION

Q47. DOES THIS CONCLUDE YOUR SUPPLEMENTAL DIRECT TESTIMONY?

A. Yes, at this time.
AFFIDAVIT

STATE OF LOUISIANA
PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, SETH CUREINGTON, 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.

Seth Cureington

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 27TH DAY OF JUNE, 2017

NOTARY PUBLIC

My commission expires: at death

TIMOTHY S. CRAGIN
NOTARY PUBLIC (La. Bar No. 22313)
Parish of Orleans, State of Louisiana
My Commission is issued for Life
BEFORE THE
COUNCIL OF THE CITY OF NEW ORLEANS

SUPPLEMENTAL AND AMENDING )
APPLICATION OF ENTERGY NEW )
ORLEANS, INC. FOR APPROVAL TO ) DOCKET NO. UD-16-02
CONSTRUCT NEW ORLEANS POWER )
STATION AND REQUEST FOR COST )
RECOVERY AND TIMELY RELIEF )

EXHIBIT SEC-10
through
EXHIBIT SEC-13

PUBLIC VERSION
HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

JULY 2017
Entergy New Orleans – Energy Efficiency Potential Study

Prepared for:

Entergy New Orleans

Submitted by:

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Reference No.: 195598
June 26, 2017
# TABLE OF CONTENTS

1. Executive Summary .................................................................................................. 1
   - Introduction and Background ............................................................................. 1
   - Approach to Estimating Market Potential
     - Market Characterization ................................................................................. 2
     - Measure Characterization ............................................................................... 2
     - Financial Inputs ............................................................................................... 2
     - Estimating Achievable Potential ...................................................................... 2
   - Key Findings ....................................................................................................... 3

2. Introduction ............................................................................................................... 6
   - Background .......................................................................................................... 6
   - Organization of Report ....................................................................................... 6
   - Caveats and Limitations
     - Forecasting Limitations .................................................................................. 6
     - Program Design ................................................................................................. 7
     - Measure Characterization ............................................................................... 7
     - Net Savings Study ............................................................................................. 7

3. Approach to Estimating Achievable Potential ........................................................ 9
   - Estimating Achievable Potential
     - Market Characterization ............................................................................... 10
     - Measure Characterization ............................................................................... 11
     - Approach to Achievable Potential Scenarios .................................................. 12

4. Results ..................................................................................................................... 15
   - Scenario 1: High Case Achievable Forecast ...................................................... 15
   - Scenario 2: High Case Theoretical – Known Measures ..................................... 21
   - Scenario 3: High Case Theoretical – Known and Unknown Measures ............. 24

5. Benchmarking the Results ..................................................................................... 26
   - Review of Entergy New Orleans EE Accomplishments .................................... 27
   - Market Potential Savings Benchmark at the State-Level .................................. 27
   - Actual Savings Benchmark at the State-Level .................................................... 28
   - Actual Savings and Cost of Savings Benchmark at the Utility-Level ............... 29

Appendix A. Model Global Assumptions .................................................................. 32
   - Stock Forecast .................................................................................................... 32
   - Katrina Effect ..................................................................................................... 33
LIST OF FIGURES AND TABLES

Figure 1. Energy Efficiency Potential Study Approach for ENO ............................................................ 1
Figure 2. Technical, Economic, and Achievable Potential........................................................................ 9
Figure 3. 2017 Electricity Consumption by Sector (Total = 5,586 GWh) .............................................. 10
Figure 4. 2017-2036 ENO Electricity Consumption Forecast by Sector .............................................. 11
Figure 5. Electric Incremental Potential as Percentage of Forecasted Electric Sales 2017 – 2036 ...... 15
Figure 6. Cumulative Achievable Potential by Sector as a Percentage of Forecasted Sales .......... 17
Figure 7. Incremental Achievable Potential as a Percentage of Forecasted Sales .............................. 19
Figure 8. Cumulative Achievable Potential 2017 – 2036 – Top 20 Measures (GWh) ...................... 20
Figure 9. Average Achievable Potential Savings Per Year as a Percentage of Sales in the South ....... 28
Figure 10. 2015 Actual Accomplished Net Savings by State ................................................................. 29
Figure 11. 2015 Actual Spending and Savings by Utility ................................................................. 30

Table 1. Incremental Potential by Scenario As a Percentage of Forecasted Sales ............................. 4
Table 2. Estimated Total Budget by Scenario ......................................................................................... 5
Table 3. 2017-2036 ENO Electricity Consumption Forecast by Sector (GWh) .................................. 11
Table 4. Cumulative & Incremental Achievable Potential (GWh/Year) ............................................... 16
Table 5. Incremental Achievable Potential as a Percentage of Forecasted Sales ............................ 18
Table 6. Estimated Budget for High Case Achievable Potential ......................................................... 21
Table 7. Incremental Theoretical Known Measures Potential as a Percentage of Forecasted Sales ...... 22
Table 8. Estimated Budget for Theoretical Known Measures Potential ............................................. 23
Table 9. Incremental Theoretical Known & Unknown Measures Potential as a Percentage of Forecasted Sales ........................................................................................................................................... 24
Table 10. Estimated Budget for Theoretical Known & Unknown Measures Potential .......... 25
Table 11. ENO EE Benchmarking Analysis Sources ........................................................................... 26
Table 12. Global Assumptions ............................................................................................................ 32
Table 13. Stock Forecast – Residential and C&I ............................................................................... 33
Table 14. Calculation of Katrina Effect ............................................................................................... 34
DISCLAIMER

This report was prepared by Navigant Consulting, Inc. (Navigant) for Entergy New Orleans (ENO). The work presented in this report represents Navigant’s professional judgment based on the information available at the time this report was prepared. Navigant is not responsible for the reader’s use of, or reliance upon, the report, nor any decisions based on the report. NAVIGANT MAKES NO REPRESENTATIONS OR WARRANTIES, EXPRESSED OR IMPLIED. Readers of the report are advised that they assume all liabilities incurred by them, or third parties, as a result of their reliance on the report, or the data, information, findings and opinions contained in the report.
1. EXECUTIVE SUMMARY

Introduction and Background

The New Orleans City Council (Council) recently issued a resolution that stated: “the Council believes it would be reasonable in the development of subsequent Energy Smart Program Years (Program Year 7 and beyond) for the Company to incorporate in its Energy Smart and IRP filings for evaluation by the Advisors, Intervenors, and the Council the goal of increasing the projected savings from the Energy Smart program by 0.2% per year, until such time as the program generates kWh savings at a rate equal to 2% annual kWh sales.”1 The purpose of this report is to provide an independent assessment of the EE savings potential for the ENO territory and to assess whether it is possible to achieve the 2% reduction goal in the ENO territory in a cost-effective manner.

Approach to Estimating Market Potential

Using Navigant’s Demand Side Management Simulator (DSMSim™) model, Navigant calculated achievable energy efficiency potential across ENO’s territory. As outlined in Figure 1, the central inputs to the model include characterizing the ENO territory market, characterizing the energy efficiency measures for inclusion in the analysis and solidifying financial model assumptions.

---

Market Characterization

Navigant worked with ENO to understand the breakdown of total electricity consumption by customer sector, based on ENO’s forecast. Total electricity demand is projected to increase from 5,586 GWh in 2017 to 6,628 GWh in 2036, with almost proportional increases in residential and commercial and industrial (C&I) consumption. This electric consumption forecast serves as the basis of the energy efficiency market potential analysis. Details are provided in Appendix A.

Measure Characterization

This potential study leveraged the database of electric measures characterized as part of the 2015 Arkansas Energy Efficiency Potential study, which was conducted by Navigant. The 2015 study used the Arkansas Technical Reference Manual (TRM) to specify the effective useful life (EUL) and how to calculate energy savings for each measure listed in the TRM. Because there is not a New Orleans or Louisiana TRM, using the Arkansas TRM was deemed appropriate by the Navigant team. Navigant developed estimates of implementation costs, estimates of measure density, baseline density and technical applicability in addition to calculating per unit savings based on the TRM. Electric-only impacts are captured as part this ENO analysis, and gas savings do not impact the cost-benefit evaluation of measures (i.e. if implementation of an electric measure increases or decreases gas use).

The Arkansas measure assumptions serve as a basis for this study given the relatively few changes in technology performance or measure costs since the 2015 study. In cases where material changes to measures have occurred, Navigant updated the underlying measures’ assumptions to reflect more recent inputs.

Financial Inputs

Appendix A. Model Global Assumptions key global assumptions used in the analysis for all three scenarios. The significance of these global assumptions is that they serve as key financial and valuation parameters (e.g., inflation and discount rates, avoided costs, etc.) used in the calculation of the achievable potential.

Estimating Achievable Potential

Navigant evaluated three potential scenarios as part of this study which included the following:

- **Scenario 1: High Case Achievable**: Represents Navigant’s best estimate regarding a level of EE potential that could be achievable by ENO with an aggressive roll-out of EE programs.

- **Scenario 2: High Case Theoretical – Known Measures**: Represents a theoretical level of potential under a set of conditions that may not be realistic. This theoretical scenario yields a
2.0% per year annual incremental savings potential as a percentage of utility sales in at least one year of the simulation horizon.

- **Scenario 3: High Case Theoretical – Known and Unknown Measures:** Identical to Scenario 2 with the exception that the incremental savings as a percentage of sales is assumed to be held at 2.0% per year after 2024, the year in which Scenario 2 reaches 2.0%.

Additional information about these scenarios is provided in Chapter 3.

**Key Findings**

Key study findings include the following:

- The High Case Achievable Scenario illustrates that with a comprehensive portfolio of efficiency measures, aggressive marketing and incentives, and realistic assumptions, ENO could cost-effectively reduce forecast load by roughly 17% over the next 20 years, an average of 0.85%/year. The cost of these savings is roughly $16 million/year in 2017 and $25 million/year in 2024. Costs decline thereafter as the market for known measures saturates. This portfolio is cost effective with a Total Resource Cost (TRC) ranging from 1.7-2.0 over the simulation horizon.

- The High Case Theoretical – Known Measures Scenario calculates the potential savings and program cost for a scenario where a peak incremental savings as a percentage of forecast sales equals 2.0%, which occurs in 2023 and declines thereafter due to market saturation of known measures. In this scenario, forecast load could be reduced by 23.4% over the 20-year simulation horizon, an average of 1.17%/year. Costs for this scenario are considerably higher than in the High Case Achievable Scenario due to higher incentive levels and increases in marketing expenditures. Annual expenditures to achieve this ramp up are roughly $59 million in 2017, rising to about $112 million in 2023 and declining thereafter due to market saturation. However, the high ramp rate of this scenario is likely unrealistic and would be difficult to achieve under real-world conditions.

- The High Case Theoretical – Known and Unknown Measures Scenario calculates the potential savings and costs for a portfolio that ramps up to 2.0%/year of incremental savings by 2023, and holds that level of incremental savings through 2036. This scenario requires the assumption that emerging efficiency measures, not currently known, will enter the market at a cost roughly equivalent to the modeled costs in 2023, escalated for inflation. This scenario is therefore the most theoretical and costly of all three scenarios, and requires assumptions that are highly theoretical and have not been proven in actual market conditions.

The incremental potential savings as a percentage of sales, and the calculated budgets required, for each of the three scenarios analyzed are provided below in Table 1 and Table 2.

---

3 Navigant used a fixed forecast which does not change with each increment of efficiency achieved year over year.
Table 1. Incremental Potential by Scenario As a Percentage of Forecasted Sales

<table>
<thead>
<tr>
<th>Year</th>
<th>Achievable</th>
<th>Theoretical Known Measures</th>
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2. INTRODUCTION

Background

The New Orleans City Council (Council) recently issued a resolution that stated: “the Council believes it would be reasonable in the development of subsequent Energy Smart Program Years (Program Year 7 and beyond) for the Company to incorporate in its Energy Smart and IRP filings for evaluation by the Advisors, Intervenors, and the Council the goal of increasing the projected savings from the Energy Smart program by 0.2% per year, until such time as the program generates kWh savings at a rate equal to 2% annual kWh sales.” The purpose of this report is to provide an independent assessment of the EE savings potential for the ENO territory and to assess whether it is possible to achieve the 2% reduction goal in the ENO territory in a cost-effective manner.

Organization of Report

This report is organized as follows:

- Section 3 describes the approach to estimating achievable potential and the scenarios evaluated.
- Section 4 describes the results of the high case achievable, high case theoretical known measures, and high case theoretical known and unknown measures scenarios.
- Section 5 benchmarks this study’s achievable potential results against neighboring states and utilities.
- Section 6 provides program recommendations for immediate and future implementation.
- Appendix A provides additional modeling assumptions.

Caveats and Limitations

The caveats and limitations associated with the results of this study are detailed in this section.

Forecasting Limitations

Navigant obtained future energy sales forecast from ENO. This forecast contains assumptions, methodologies, and exclusions. Navigant has leveraged the assumptions underlying these forecasts, as much as possible, as inputs into the development of the Reference Case stock and energy demand projections. Where sufficient and detailed information could not be extracted, Navigant developed independent projections of commercial building stock. These independent projections were developed based on secondary data resources and in collaboration with ENO. These secondary resources and any underlying assumptions are referenced throughout this report.

Program Design

The results of this study provide a big picture view of future savings potential in ENO’s service territory. However, this study is not considered a detailed program design tool. The nature of potential studies is for long-term planning and hence estimates should not be applied to short-term DSM planning activities.

Measure Characterization

Efficiency potential studies may employ a variety of primary data collection techniques (e.g., customer surveys, on-site equipment saturation studies, and telephone interviews), which can enhance the accuracy of the results, though not without associated cost and time requirements. Due to the limited timeline for the development of this potential study for the ENO territory, Navigant utilized the measure characterization from a 2015 EE potential study conducted by Navigant for Entergy Arkansas and six other investor-owned utilities in that state. Additional reasons for leveraging this study include similar energy efficiency measure mixes, comparable climate, and the existence of an established Technical Reference Manual (TRM), (which Louisiana and New Orleans currently do not have). To ensure the analysis accounted for differences in ENO’s territory in 2017, Navigant made several key adjustments to the Arkansas-based EE measures to reflect 2017 markets and ENO’s unique conditions.

Furthermore, the team considers the measure list used in this study to appropriately focus on those EE measures likely to have the highest impact on savings potential over the potential study time horizon. However, there is always the possibility that emerging technologies may arise that could increase savings opportunities over the forecast horizon, and broader societal changes may affect levels of energy use in ways not anticipated in the study.

Net Savings Study

Navigant and ENO agreed to show savings from this study at the net level, rather than gross, consistent with the existing reporting requirements and savings goals established as net of free-ridership. This means all savings reported in this study account for the effect of possible free ridership.

Unknown Measures

The High Case Theoretical – Known and Unknown Measures scenario assumes a hypothetical suite of currently unknown measures will become available in the future at an assumed aggregate cost ($/kWh basis) that is extrapolated from the modeled output. These specific measures (e.g., possible future emerging technologies not currently on the market) have not been identified as part of this study and would potentially permit maintaining the modeled level of savings.

Study Uncertainty

The forecasting nature of potential studies have inherent uncertainty. Potential studies include thousands of data points and assumptions, including utility forecasting, measure parameters, existing saturation levels, avoided costs, program assumptions, measure costs, and other inputs. Eliminating uncertainty is impossible, but the use of best available data minimizes the impact of these uncertainties.
3. APPROACH TO ESTIMATING ACHIEVABLE POTENTIAL

This section describes the methodology Navigant employed for estimating energy savings across the ENO service territory, including measure characterization, reference case forecast, and the definition of technical, economic, and achievable potential.

Estimating Achievable Potential

Figure 2 shows a graphical representation of technical, economic, and achievable potential. Navigant follows methodologies for conducting energy efficiency potential studies that have been developed and refined over the years through industry experience and guidebooks.6 This study defines technical potential as the total energy savings available, assuming all installed measures can immediately be replaced with the “efficient” measure/technology—wherever technically feasible—regardless of the cost, and market acceptance. Economic potential is a subset of technical potential, using the same assumptions as technical potential, but including only those measures that have passed the benefit-cost test chosen for measure screening. Achievable potential is a subset of economic potential that considers the likely rate of DSM acquisition, given factors like the rate of equipment turnover, simulated incentive levels, consumer willingness to adopt efficient technologies, and the likely rate at which marketing activities can facilitate technology adoption. The goal of this study is to calculate the electric achievable potential in ENO service territory.

Figure 2. Technical, Economic, and Achievable Potential

Market Characterization

Figure 3 shows the breakdown of total electricity consumption by customer sector forecasted for 2017, based on ENO’s load forecast. Approximately, 40% of electricity consumption comes from the residential sector – equivalent to 2,346 GWh – while 60% comes from the commercial and industrial (C&I) sector – equivalent to 3,510 GWh.

Figure 3. 2017 Electricity Consumption by Sector (Total = 5,586 GWh)

Source: ENO Load Forecast

Figure 4 shows the forecast of residential and C&I electricity consumption through 2036. Total electricity demand is projected to increase from 5,586 GWh in 2017 to 6,628 GWh in 2036, with almost proportional increases in residential and C&I consumption. Residential consumption increases 6% to 2,476 GWh in 2036, while C&I consumption increases 7% to 3,752 GWh in 2036. Table 3. 2017-2036 ENO Electricity Consumption Forecast by Sector (GWh) shows the ENO’s tabular load forecast. Figure 4 shows ENO’s load forecast in tabular form.
Measure Characterization

This potential study leveraged the database of electric measures characterized as part of the 2015 Arkansas Energy Efficiency Potential study. In 2015, Navigant conducted an Arkansas-wide study of energy efficiency potential for the seven investor-owned electric and gas utilities in Arkansas, including Entergy Arkansas, Inc. The 2015 study used the Arkansas Technical Reference Manual (TRM) to specify the effective useful life (EUL) and calculations for energy savings for each measure listed in the TRM. Navigant developed estimates of implementation costs, measure density, baseline density and technical applicability in addition to calculating per unit savings based on the TRM. This ENO analysis differs from the 2015 study in that it captures electric-only impacts. This study also assumes that gas savings do not impact the cost-benefit evaluation of measures (i.e. if implementation of an electric measure increases or decreases gas use).

Information regarding the allocation of end use energy, energy intensities, the existing saturation of energy-efficient devices, etc. required to estimate the EE potential for each measure was derived from a variety of sources. The Arkansas measure-assumptions serve as a basis for this study given the relatively
few changes in technology performance or measure costs since the 2015 study. In cases where changes to measure inputs have occurred, Navigant updated the underlying measure assumptions to reflect those changes. Similarly, where ENO-specific information was available, such as penetration of electric space heating, heat pumps, and space cooling, Navigant used these specific ENO inputs. The following list details specific adjustments made to the modeled measures to reflect 2017 data and ENO territory characteristics:

- All costs assumptions for LED measures were updated to reflect declines in technology costs.
- LED baseline technologies through 2020 are assumed to be EISA compliant. 2020 and beyond, baseline wattages are at CFL levels.
- All CFL and standard T8 fluorescent retrofits have been removed.
- All high bay lighting retrofits are LED.
- LED lamp and fixture retrofit options have been added.
- Home energy reports have a higher technical applicability than the Arkansas study.
- Duct sealing savings have been updated based on the Evaluation of PY5 Energy Efficiency Programs Portfolio, July 2016 report submitted by ADM Associates, Inc.
- Smart thermostat saturation levels have been reduced, indicating higher technical potential for this measure than the Arkansas study.
- Baseline saturation levels have been modified (percent of eligible stock that are at baseline conditions – i.e. are not retrofitted) for ceiling insulation, wall insulation, and central air conditioners by 20% to adjust for higher efficiency conditions because of re-construction post-Katrina. See Appendix A for more details.

The measure characterization consisted of estimating and defining key parameters across the various residential and C&I customer segments and inputting them into the DSMSim™ model to calculate the various potential scenarios. Navigant defined the parameters as follows:

1. Measure Description: Qualitatively indicates the EE action that is being performed by this measure.
2. Baseline Assumption: The baseline technology (base) characterized per the Arkansas TRM or Navigant’s engineering assumptions. The base represents existing technology.
3. End-Use, Sector and Segment Mapping: These parameters facilitate the mapping of each measure to the appropriate end uses, sectors, and customer segments.
4. Measure Lifetime: The lifetime in years for the base and EE technologies. The base and EE lifetime only vary in instances where the two cases represent inherently different technologies, such as LED or CFL bulbs compared to a baseline incandescent.
5. Measure Costs: The base (existing or code-based) and EE material and labor costs are used as inputs for the incremental measure costs.
6. Annual Energy Consumption: The annual energy consumption in kilowatt-hours (kWh) for each of the base and EE technologies.

Approach to Achievable Potential Scenarios

This section describes the three achievable potential scenarios included in this study.
Scenario 1: High Case Achievable Potential

The High Case Achievable Potential scenario represents Navigant’s best judgment regarding a level of EE potential that would be achievable with an aggressive roll-out of EE programs. The modeled measures cover a broad array of efficiency measures in existence today, adjusting for some known technology cost and efficiency advancements across the residential, commercial, and industrial sectors. It assumes aggressive, yet realistic, levels of program marketing of both hardware and behavioral measures, in addition to a comparatively high level of incentives. It further assumes that all measures are screened for cost effectiveness using a total resource cost (TRC) test. A summary of key modeling assumptions is provided below.

- TRC >= 1.0 at the measure level. Overall portfolio is also cost effective.
- Incentives cover ~60% of a measure’s total incremental cost.
- High, yet realistic, assumed program marketing effectiveness.
- Administrative costs on a $/kWh basis are roughly in line with historic levels.
- Includes known measures in existence today.

Scenario 2: High Case Theoretical – Known Measures

The High Case Theoretical – Known Measures scenario represents a theoretical level of potential under a set of conditions that may not be realistic. This theoretical scenario yields a 2.0%/year annual incremental savings potential as a percentage of utility sales in at least one year of the simulation horizon. To model the potential of this scenario, the requirement for measure-level cost effectiveness was reduced to a TRC >=0.3. To generate a fast adoption profile over time, the program marketing effectiveness values are higher than realistic. Further, this scenario assumes all incentives cover 100% of incremental measure cost, which is also higher than realistic. Similar to the High Case Achievable Potential scenario, this scenario only includes measures known to be in existence today. A summary of key modeling assumptions is provided below.

- TRC >= 0.3 at the measure level.
- Incentives cover 100% of a measure’s total incremental cost.
- Very high program marketing effectiveness.
- Administrative costs are ~50% higher than historic administrative costs, due to the increased marketing requirements.

7 The total resource cost test, TRC, is a benefit to cost ratio that includes the benefits and costs from the perspective of all customers in a utility service territory. The benefits are typically the avoided energy and capacity costs (sometimes other benefits are included) and the costs are the program costs (not including incentives) plus the incremental measure costs.

Scenario 3: High Case Theoretical – Known and Unknown Measures

The High Case Theoretical – Known and Unknown Measures scenario is identical to Scenario 2 with the exception that the incremental savings as a percentage of sales is assumed to be held at 2.0%/year after 2024, the year in which Scenario 2 reaches 2.0%. In Scenario 2, the simulated model output shows a marked decline in incremental annual potential due to saturation of the market for efficiency technologies. Scenario 3 holds the incremental savings level constant. This analysis does not postulate specific measures that would account for the difference between Scenario 2 and Scenario 3; as such, it is assumed that some set of measures unknown now would be introduced at the same incremental cost as simulated in 2023, escalated only for inflation.

A summary of key modeling assumptions is provided below.

- TRC >= 0.3 at the measure level.
- Incentives cover 100% of a measure’s total incremental cost.
- Very high program marketing effectiveness.
- Administrative costs are ~50% higher than historic administrative costs, due to the increased marketing requirements.
- Includes known measures in existence today and unknown measures not currently on the market but presumed to be potentially available in the future. The unknown measure costs equal the costs seen in 2023, the year in which incremental annual potential peaked in Scenario 2, and are escalated for inflation.
4. RESULTS

The following section outlines the results of the efficiency potential analysis. The following section include results for the three separate scenarios, as described in Chapter 3:

- Scenario 1: High Case Achievable
- Scenario 2: High Case Theoretical – Known Measures
- Scenario 3: High Case Theoretical – Known and Unknown Measures

Figure 5 provides an estimate of the incremental annual potential as a percentage of unadjusted forecast sales in the absence of efficiency programs from 2017 – 2036 for each scenario, which are described in detail in the subsequent sections.

![Figure 5. Electric Incremental Potential as Percentage of Forecasted Electric Sales 2017 – 2036](image)

**Scenario 1: High Case Achievable Forecast**

The High Case Achievable Potential Forecast represents Navigant’s best judgment regarding a level of EE potential that would be achievable with an aggressive roll-out of EE programs.

Table 4 shows the high case achievable results by sector, cumulatively and incrementally by year. In this scenario, we estimate that ENO has the potential to achieve a cumulative savings of 1,057 GWh by 2036,

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9 Navigant used a fixed forecast which does not change with each increment of efficiency achieved year over year.
or an average annual savings of 53 GWh per year, on a net basis (i.e., accounting for estimate free ridership).

### Table 4. Cumulative & Incremental Achievable Potential (GWh/Year)

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*Note: C&I and Res refer to Commercial, Industrial, and Residential Sectors, respectively.*

Values defined as “cumulative potential” represent the accumulation of each year’s annual achievable potential. For example, an annual achievable potential of 20 GWh per year results in a cumulative achievable potential of 100 GWh over a 5-year period. The same concept applies to achievable potential results represented as a percentage of sales; an annual achievable potential of 0.9% per year, for ten years, would result in a cumulative achievable potential of 9 percent of forecasted sales. Figure 6 below show the cumulative achievable potential as a percentage of forecasted electric sales for this study. We see below that ENO can reduce forecast sales in 2036 by 17% with a comprehensive set of efficiency programs that are aggressively marketed and incentivized.
As illustrated above, although C&I has the greater potential in absolute terms, measuring by GWh/year, the residential sector has the greatest cumulative potential savings as a percentage of forecast sales, with an opportunity to reduce forecast sales by ~20% over the study horizon. The high potential for duct sealing, insulation, and air conditioning tune-ups drives this forecasted savings.

Potential savings can also be represented on a yearly basis as “incremental” annual achievable potential. Table 5 and Figure 7 show ENO’s incremental achievable savings per year from 2017 – 2036 as a percentage of sales. As seen below, savings potential quickly ramps up to ~1%/year after 2019 and stays slightly above this value for roughly a decade. After ~10 years, incremental annual potential as a percentage of sales tails off due to known measure saturation of the market. In other words, the bucket of potential savings begins to empty, and therefore the rate at which the bucket of savings can be implemented diminishes over time. Given sufficient time, the incremental annual potential would be reduced to zero once all savings were completely harvested, unless replenished by new savings opportunities due to the emergence of new technologies, or introduction of new building stock through new construction.
### Table 5. Incremental Achievable Potential as a Percentage of Forecasted Sales

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<td>0.76%</td>
<td>1.35%</td>
<td>0.99%</td>
</tr>
<tr>
<td>2019</td>
<td>0.83%</td>
<td>1.50%</td>
<td>1.09%</td>
</tr>
<tr>
<td>2020</td>
<td>0.76%</td>
<td>1.69%</td>
<td>1.13%</td>
</tr>
<tr>
<td>2021</td>
<td>0.81%</td>
<td>1.59%</td>
<td>1.11%</td>
</tr>
<tr>
<td>2022</td>
<td>0.88%</td>
<td>1.45%</td>
<td>1.10%</td>
</tr>
<tr>
<td>2023</td>
<td>0.90%</td>
<td>1.44%</td>
<td>1.11%</td>
</tr>
<tr>
<td>2024</td>
<td>0.92%</td>
<td>1.37%</td>
<td>1.10%</td>
</tr>
<tr>
<td>2025</td>
<td>0.94%</td>
<td>1.37%</td>
<td>1.10%</td>
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<tr>
<td>2026</td>
<td>0.92%</td>
<td>1.21%</td>
<td>1.04%</td>
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<tr>
<td>2027</td>
<td>0.90%</td>
<td>1.07%</td>
<td>0.96%</td>
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<td>2028</td>
<td>0.87%</td>
<td>0.89%</td>
<td>0.89%</td>
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<tr>
<td>2029</td>
<td>0.82%</td>
<td>0.84%</td>
<td>0.83%</td>
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<td>2030</td>
<td>0.77%</td>
<td>0.71%</td>
<td>0.74%</td>
</tr>
<tr>
<td>2031</td>
<td>0.70%</td>
<td>0.58%</td>
<td>0.65%</td>
</tr>
<tr>
<td>2032</td>
<td>0.64%</td>
<td>0.44%</td>
<td>0.57%</td>
</tr>
<tr>
<td>2033</td>
<td>0.59%</td>
<td>0.39%</td>
<td>0.51%</td>
</tr>
<tr>
<td>2034</td>
<td>0.54%</td>
<td>0.27%</td>
<td>0.44%</td>
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<tr>
<td>2035</td>
<td>0.49%</td>
<td>0.19%</td>
<td>0.38%</td>
</tr>
<tr>
<td>2036</td>
<td>0.44%</td>
<td>0.09%</td>
<td>0.31%</td>
</tr>
</tbody>
</table>

*Note: C&I and Res refer to Commercial, Industrial, and Residential Sectors, respectively.*
In addition to overall results by sector, the analysis yielded results by measure. The measure with the highest potential was duct sealing in the residential sector, followed by high efficiency new construction and interior 4-ft LED lights, both in the commercial and industrial sector. These measure results are based on the measure characterizations described in Chapter 3, which are consistent with industry standards and benchmarked to ENO program performance in previous years. Figure 8 shows the top 20 achievable potential measures by average annual GWh, a key input into the incremental and cumulative achievable potential results outlined above.
The budget estimate for the high case achievable scenario is presented below in Table 6, which includes an estimate of administration cost as well as incentive costs. Administration costs of $0.135/kWh are slightly higher than historical administrative costs in ENO’s service territory due to adjustments for inflation. Incentive costs were calculated based on forecast measure adoption, incremental measure costs, and assumed incentive levels as described in the Chapter 3 scenario sections. Total cost of first year savings in 2017 is ~$0.28/first-year kWh compares favorably (i.e., on the low end) of program costs presented in the Chapter 5. Costs of first-year savings rise to ~$0.45/kWh over the simulation horizon due to inflation and a changing measure mix over time. As noted in Chapter 3, all measures in this scenario are cost effective with a TRC >=1.0. Inclusive of administrative costs, the portfolio is cost effective with a portfolio TRC ranging from ~1.7 to ~2.0 over the simulation horizon.
Table 6. Estimated Budget for High Case Achievable Potential

<table>
<thead>
<tr>
<th>Year</th>
<th>Administration</th>
<th>Incentives</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>$7,921,933</td>
<td>$8,415,905</td>
<td>$16,337,839</td>
</tr>
<tr>
<td>2018</td>
<td>$8,994,417</td>
<td>$9,502,727</td>
<td>$18,497,144</td>
</tr>
<tr>
<td>2019</td>
<td>$10,117,456</td>
<td>$10,575,742</td>
<td>$20,693,198</td>
</tr>
<tr>
<td>2020</td>
<td>$10,549,450</td>
<td>$11,693,058</td>
<td>$22,242,507</td>
</tr>
<tr>
<td>2021</td>
<td>$10,595,340</td>
<td>$12,009,587</td>
<td>$22,604,926</td>
</tr>
<tr>
<td>2022</td>
<td>$10,661,628</td>
<td>$12,608,018</td>
<td>$23,269,646</td>
</tr>
<tr>
<td>2023</td>
<td>$11,135,036</td>
<td>$13,405,238</td>
<td>$24,540,273</td>
</tr>
<tr>
<td>2024</td>
<td>$11,308,934</td>
<td>$13,546,160</td>
<td>$24,855,094</td>
</tr>
<tr>
<td>2025</td>
<td>$11,240,073</td>
<td>$13,337,032</td>
<td>$24,577,105</td>
</tr>
<tr>
<td>2026</td>
<td>$10,954,917</td>
<td>$12,914,864</td>
<td>$23,869,782</td>
</tr>
<tr>
<td>2027</td>
<td>$10,489,144</td>
<td>$12,226,714</td>
<td>$22,715,858</td>
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<tr>
<td>2028</td>
<td>$10,174,767</td>
<td>$12,317,023</td>
<td>$22,491,790</td>
</tr>
<tr>
<td>2029</td>
<td>$9,529,195</td>
<td>$11,733,497</td>
<td>$21,262,691</td>
</tr>
<tr>
<td>2030</td>
<td>$8,751,218</td>
<td>$10,818,053</td>
<td>$19,569,272</td>
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<td>$9,940,386</td>
<td>$17,918,234</td>
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<tr>
<td>2032</td>
<td>$7,235,021</td>
<td>$9,071,583</td>
<td>$16,306,604</td>
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<td>2033</td>
<td>$6,540,929</td>
<td>$8,279,731</td>
<td>$14,820,661</td>
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<td>2034</td>
<td>$5,913,374</td>
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<td>$13,493,010</td>
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<td>$5,370,357</td>
<td>$6,957,019</td>
<td>$12,327,376</td>
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<tr>
<td>2036</td>
<td>$4,929,933</td>
<td>$6,461,779</td>
<td>$11,391,712</td>
</tr>
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</table>

**Scenario 2: High Case Theoretical – Known Measures**

The High Case Theoretical – Known Measures scenario represents a theoretical level of potential assuming 100% of incremental costs are covered by incentives, and assuming a program ramp rate that would permit achieving a target of 2.0%/year in at least one year of the simulation horizon (See Chapter 3 for more detailed scenario assumptions). This ramp rate as well as the estimated incremental costs covered by the utility are not considered realistic, though savings and costs estimates are provided in this Chapter as a point of reference. Additionally, this scenario models a lower cost-effectiveness screening level threshold than Scenario 1. As seen in Table 7, incremental annual potential as a percentage of sales tails off after about 2023 due to market saturation of known measures. This rise and subsequent fall of incremental savings is consistent with expectations and is characteristic of typical technology adoption patterns.
Table 7. Incremental Theoretical Known Measures Potential as a Percentage of Forecasted Sales

<table>
<thead>
<tr>
<th>Year</th>
<th>C&amp;I</th>
<th>Res</th>
<th>All</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>0.98%</td>
<td>1.62%</td>
<td>1.23%</td>
</tr>
<tr>
<td>2018</td>
<td>1.01%</td>
<td>1.75%</td>
<td>1.30%</td>
</tr>
<tr>
<td>2019</td>
<td>1.24%</td>
<td>2.10%</td>
<td>1.58%</td>
</tr>
<tr>
<td>2020</td>
<td>1.28%</td>
<td>2.33%</td>
<td>1.69%</td>
</tr>
<tr>
<td>2021</td>
<td>1.41%</td>
<td>2.46%</td>
<td>1.81%</td>
</tr>
<tr>
<td>2022</td>
<td>1.56%</td>
<td>2.31%</td>
<td>1.85%</td>
</tr>
<tr>
<td>2023</td>
<td>1.67%</td>
<td>2.54%</td>
<td>2.01%</td>
</tr>
<tr>
<td>2024</td>
<td>1.57%</td>
<td>2.40%</td>
<td>1.90%</td>
</tr>
<tr>
<td>2025</td>
<td>1.44%</td>
<td>2.32%</td>
<td>1.77%</td>
</tr>
<tr>
<td>2026</td>
<td>1.27%</td>
<td>2.00%</td>
<td>1.55%</td>
</tr>
<tr>
<td>2027</td>
<td>1.10%</td>
<td>1.69%</td>
<td>1.33%</td>
</tr>
<tr>
<td>2028</td>
<td>0.93%</td>
<td>1.31%</td>
<td>1.09%</td>
</tr>
<tr>
<td>2029</td>
<td>0.79%</td>
<td>1.17%</td>
<td>0.94%</td>
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<tr>
<td>2030</td>
<td>0.67%</td>
<td>0.93%</td>
<td>0.77%</td>
</tr>
<tr>
<td>2031</td>
<td>0.57%</td>
<td>0.73%</td>
<td>0.63%</td>
</tr>
<tr>
<td>2032</td>
<td>0.49%</td>
<td>0.53%</td>
<td>0.52%</td>
</tr>
<tr>
<td>2033</td>
<td>0.45%</td>
<td>0.46%</td>
<td>0.46%</td>
</tr>
<tr>
<td>2034</td>
<td>0.40%</td>
<td>0.31%</td>
<td>0.38%</td>
</tr>
<tr>
<td>2035</td>
<td>0.38%</td>
<td>0.21%</td>
<td>0.32%</td>
</tr>
<tr>
<td>2036</td>
<td>0.34%</td>
<td>0.07%</td>
<td>0.25%</td>
</tr>
</tbody>
</table>

Note: C&I and Res refer to Commercial, Industrial, and Residential Sectors, respectively.

Budget

In addition to forecasting potential savings, Navigant estimated the associated administration and incentive costs. The estimated budget reflects the potential savings forecast for this scenario in that costs and savings increase until reaching peak potential and then decrease every year thereafter. Table 8 illustrates these costs and the total budget for each forecast year.
### Table 8. Estimated Budget for Theoretical Known Measures Potential

<table>
<thead>
<tr>
<th>Year</th>
<th>Administration</th>
<th>Incentives</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>$15,888,700</td>
<td>$43,289,308</td>
<td>$59,178,008</td>
</tr>
<tr>
<td>2018</td>
<td>$17,667,699</td>
<td>$47,000,703</td>
<td>$64,668,401</td>
</tr>
<tr>
<td>2019</td>
<td>$21,796,146</td>
<td>$56,107,967</td>
<td>$77,904,113</td>
</tr>
<tr>
<td>2020</td>
<td>$23,494,153</td>
<td>$61,704,384</td>
<td>$85,198,537</td>
</tr>
<tr>
<td>2021</td>
<td>$25,700,886</td>
<td>$69,262,968</td>
<td>$94,963,854</td>
</tr>
<tr>
<td>2022</td>
<td>$26,621,758</td>
<td>$73,327,177</td>
<td>$99,948,935</td>
</tr>
<tr>
<td>2023</td>
<td>$29,922,060</td>
<td>$81,854,462</td>
<td>$111,776,522</td>
</tr>
<tr>
<td>2024</td>
<td>$29,025,058</td>
<td>$81,090,358</td>
<td>$110,115,415</td>
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<tr>
<td>2025</td>
<td>$27,181,798</td>
<td>$76,588,307</td>
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<td>2026</td>
<td>$24,745,803</td>
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<td>$95,241,648</td>
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<td>2027</td>
<td>$21,951,653</td>
<td>$63,340,558</td>
<td>$85,292,210</td>
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<tr>
<td>2028</td>
<td>$19,367,559</td>
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<td>$76,982,709</td>
</tr>
<tr>
<td>2029</td>
<td>$16,649,166</td>
<td>$50,152,355</td>
<td>$66,801,521</td>
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<td>2030</td>
<td>$14,247,172</td>
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<td>$12,286,922</td>
<td>$38,231,201</td>
<td>$50,518,123</td>
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<tr>
<td>2032</td>
<td>$10,669,987</td>
<td>$33,711,185</td>
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<td>2033</td>
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<td>$29,967,885</td>
<td>$39,347,486</td>
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<td>2034</td>
<td>$8,372,842</td>
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<td>$35,351,082</td>
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<td>2035</td>
<td>$7,604,282</td>
<td>$24,595,475</td>
<td>$32,199,756</td>
</tr>
<tr>
<td>2036</td>
<td>$7,119,074</td>
<td>$23,244,385</td>
<td>$30,363,460</td>
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</table>
Scenario 3: High Case Theoretical – Known and Unknown Measures

This scenario is similar to Scenario 2 with the exception that the forecast assumes that ENO can maintain its annual percent savings from 2023 onwards through the emergence of unknown technologies at an assumed cost, rather than achieving a declining rate of savings due to market saturation, as described in Chapter 3. Table 9 shows projected savings per year, as a percentage of forecast sales, based on these assumptions.

Table 9. Incremental Theoretical Known & Unknown Measures Potential as a Percentage of Forecasted Sales

<table>
<thead>
<tr>
<th>Year</th>
<th>C&amp;I</th>
<th>Res</th>
<th>All</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>0.98%</td>
<td>1.62%</td>
<td>1.23%</td>
</tr>
<tr>
<td>2018</td>
<td>1.01%</td>
<td>1.75%</td>
<td>1.30%</td>
</tr>
<tr>
<td>2019</td>
<td>1.24%</td>
<td>2.10%</td>
<td>1.58%</td>
</tr>
<tr>
<td>2020</td>
<td>1.28%</td>
<td>2.33%</td>
<td>1.69%</td>
</tr>
<tr>
<td>2021</td>
<td>1.41%</td>
<td>2.46%</td>
<td>1.81%</td>
</tr>
<tr>
<td>2022</td>
<td>1.56%</td>
<td>2.31%</td>
<td>1.85%</td>
</tr>
<tr>
<td>2023</td>
<td>1.67%</td>
<td>2.54%</td>
<td>2.01%</td>
</tr>
<tr>
<td>2024</td>
<td>1.66%</td>
<td>2.53%</td>
<td>2.00%</td>
</tr>
<tr>
<td>2025</td>
<td>1.66%</td>
<td>2.54%</td>
<td>2.00%</td>
</tr>
<tr>
<td>2026</td>
<td>1.66%</td>
<td>2.54%</td>
<td>2.00%</td>
</tr>
<tr>
<td>2027</td>
<td>1.66%</td>
<td>2.54%</td>
<td>2.00%</td>
</tr>
<tr>
<td>2028</td>
<td>1.66%</td>
<td>2.53%</td>
<td>2.00%</td>
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<tr>
<td>2029</td>
<td>1.66%</td>
<td>2.53%</td>
<td>2.00%</td>
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<tr>
<td>2030</td>
<td>1.66%</td>
<td>2.53%</td>
<td>2.00%</td>
</tr>
<tr>
<td>2031</td>
<td>1.66%</td>
<td>2.53%</td>
<td>2.00%</td>
</tr>
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<td>2032</td>
<td>1.66%</td>
<td>2.52%</td>
<td>2.00%</td>
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<td>1.66%</td>
<td>2.52%</td>
<td>2.00%</td>
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<td>1.67%</td>
<td>2.51%</td>
<td>2.00%</td>
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<tr>
<td>2035</td>
<td>1.67%</td>
<td>2.50%</td>
<td>2.00%</td>
</tr>
<tr>
<td>2036</td>
<td>1.67%</td>
<td>2.49%</td>
<td>2.00%</td>
</tr>
</tbody>
</table>

Note: C&I and Res refer to Commercial, Industrial, and Residential Sectors, respectively.

Budget

Based on the measures and assumptions in this scenario, Navigant modeled potential costs. Similar to the potential savings for this forecast, costs do not decrease after the utility has reached its peak potential. Instead, costs continue to increase to account for new, unknown measures, which we assume cost the same as the suite of measures modeled in 2023 (the year of peak modeled savings), escalated
for inflation. Table 10 shows the administrative, incentive, and total costs per year for the High Case Theoretical – Known and Unknown Measures scenario.

Table 10. Estimated Budget for Theoretical Known & Unknown Measures Potential

<table>
<thead>
<tr>
<th>Year</th>
<th>Administration</th>
<th>Incentives</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>$15,888,700</td>
<td>$43,289,308</td>
<td>$59,178,008</td>
</tr>
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<td>$47,000,703</td>
<td>$64,668,401</td>
</tr>
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<td>2019</td>
<td>$21,796,146</td>
<td>$56,107,967</td>
<td>$77,904,113</td>
</tr>
<tr>
<td>2020</td>
<td>$23,494,153</td>
<td>$61,704,384</td>
<td>$85,198,537</td>
</tr>
<tr>
<td>2021</td>
<td>$25,700,886</td>
<td>$69,262,968</td>
<td>$94,963,854</td>
</tr>
<tr>
<td>2022</td>
<td>$26,621,758</td>
<td>$73,327,177</td>
<td>$99,948,935</td>
</tr>
<tr>
<td>2023</td>
<td>$29,922,060</td>
<td>$81,854,462</td>
<td>$111,776,522</td>
</tr>
<tr>
<td>2024</td>
<td>$30,048,385</td>
<td>$82,200,035</td>
<td>$112,248,420</td>
</tr>
<tr>
<td>2025</td>
<td>$30,641,147</td>
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<td>$114,462,735</td>
</tr>
<tr>
<td>2026</td>
<td>$31,302,153</td>
<td>$85,629,828</td>
<td>$116,931,982</td>
</tr>
<tr>
<td>2027</td>
<td>$31,999,000</td>
<td>$87,536,115</td>
<td>$119,535,115</td>
</tr>
<tr>
<td>2028</td>
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<td>$122,477,648</td>
</tr>
<tr>
<td>2029</td>
<td>$33,525,264</td>
<td>$91,711,347</td>
<td>$125,236,611</td>
</tr>
<tr>
<td>2030</td>
<td>$34,281,641</td>
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<td>$128,062,123</td>
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<tr>
<td>2031</td>
<td>$35,072,083</td>
<td>$95,942,807</td>
<td>$131,014,890</td>
</tr>
<tr>
<td>2032</td>
<td>$35,898,596</td>
<td>$98,203,807</td>
<td>$134,102,404</td>
</tr>
<tr>
<td>2033</td>
<td>$36,702,269</td>
<td>$100,402,326</td>
<td>$137,104,595</td>
</tr>
<tr>
<td>2034</td>
<td>$37,548,643</td>
<td>$102,717,657</td>
<td>$140,266,300</td>
</tr>
<tr>
<td>2035</td>
<td>$38,422,994</td>
<td>$105,109,524</td>
<td>$143,532,518</td>
</tr>
<tr>
<td>2036</td>
<td>$39,378,923</td>
<td>$107,724,552</td>
<td>$147,103,475</td>
</tr>
</tbody>
</table>
5. BENCHMARKING THE RESULTS

As part of this study, Navigant benchmarked the achievable energy efficiency potential results relative to regionwide achievable potential, actual savings, and actual savings costs. Navigant also benchmarked these figures against leading regions, states, and utilities for a comprehensive comparison. The analysis leveraged recent potential studies as well as data from two leading energy institutions, the American Council for an Energy-Efficient Economy (ACEEE), a non-profit advocacy group, and the US Department of Energy’s Energy Information Administration (EIA). In doing so, Navigant sought to contextualize the study’s results within the region, determining broader trends in the regional area and across the country. For comparison purposes, all savings figures are presented as a percent of electric sales. Table 11 shows the data and studies used in this benchmarking analysis.

Table 11. ENO EE Benchmarking Analysis Sources

<table>
<thead>
<tr>
<th>Information Type</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Achievable Potential Studies</td>
<td>• 2015 Navigant Study – Arkansas Energy Efficiency Potential Study</td>
</tr>
<tr>
<td></td>
<td>• 2015 ICF International Study – Long-Term Demand Side Management Potential in the Entergy New Orleans Service Area</td>
</tr>
<tr>
<td></td>
<td>• 2013 ACEEE Study – A Guide to Growing an Energy-Efficient Economy in Mississippi</td>
</tr>
<tr>
<td></td>
<td>• 2013 ACEEE Study – Louisiana’s 2030 Energy Efficiency Roadmap</td>
</tr>
<tr>
<td></td>
<td>• 2011 Global Energy Partners Study – Tennessee Valley Authority Potential Study</td>
</tr>
<tr>
<td></td>
<td>• 2007 ACEEE Study – Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas’s Growing Electricity Needs</td>
</tr>
<tr>
<td>Actual Savings Data</td>
<td>• 2015 ACEEE Spending and Savings Table</td>
</tr>
<tr>
<td></td>
<td>• 2010 ACEEE Spending and Savings Table</td>
</tr>
</tbody>
</table>
Review of Entergy New Orleans EE Accomplishments

In 2015, ICF International completed a demand side management (DSM) potential study, spanning 2015 – 2034 for ENO territory. The study estimated that ENO had a cumulative achievable potential of 3.9% - 10% savings over the study horizon, depending on incentive levels. This equates to an average annual savings of 0.3% - 0.5%. The ICF study came to this conclusion using a bottom-up approach, aggregating baseline data, measure data, and program data. The low case achievable potential defined by ICF aligns closely to ENO’s actual savings in 2015. In ENO’s most recent Energy Efficiency Programs Portfolio Evaluation from project year five, the utility realized 0.4% in actual savings.

Market Potential Savings Benchmark at the State-Level

Navigant compared this study’s results against other recent potential studies. The team conducted a comprehensive review of potential studies, specifically focusing on achievable potential from surrounding states for a regionwide comparison. The studies researched provided data on cumulative savings throughout the next decade. Since the Navigant ENO study defines achievable potential on an annual basis, the research team determined the average savings per year for comparison. Figure 9 shows average annual future savings potential over a 15-year timeframe for the 6-state region surrounding the ENO territory. The figure also illustrates that Navigant’s achievable potential estimate aligns to regionwide expectations. It is important to note that the achievable savings reported below (Figure 9) reflect an average of cumulative savings over the study period.

---

12 To determine annual percent savings, we divided the total percent savings by the study period.
Actual Savings Benchmark at the State-Level

In addition to evaluating the future potential for energy efficiency, Navigant also researched actual accomplished energy efficiency savings at the state-level to determine regionwide trends. The research team examined states surrounding ENO as well as high-performing states in other regions. The differences in actual savings across the country likely relates to differing program maturities, policies, retail rates, energy efficiency costs, energy efficiency spending, and other factors. This specific portion of the benchmarking aimed to verify how closely actual savings reflected achievable potential. Navigant used the most recent data from the EIA and ACEEE to derive this information. Figure 10 shows actual savings by state and region, including the 2015 median actual savings across the US of 0.61%.
Figure 10 illustrates that utilities do not necessarily achieve their achievable potential; achievable potential only loosely predicts actual savings. For example, Arkansas and Missouri accomplished savings of .61%, which is below the lowest achievable potential averages of 0.73% for the region. Additionally, Texas accomplished 0.18% in actual savings, compared to its achievable potential of 0.73% (Figure 9).

Additionally, one year of savings data does not guarantee that utilities will have consistent yearly savings at this level. For instance, Vermont achieved 2.32% savings in 2010 and 2.01% in 2015, demonstrating that savings may fluctuate. Also, California achieved 1.79% savings in 2010 and 1.95% savings in 2015, showing that achieving a stable 2% savings solely through EE measures can be challenging even in states with leading energy efficiency programs for the past 30 years.

**Actual Savings and Cost of Savings Benchmark at the Utility-Level**

Navigant also benchmarked actual savings and EE program expenditures at the utility-level to further examine the accuracy of achievable potential, determine key trends, and identify potential savings constraints. This process involved aggregating key data from local investor-owned utilities and nationwide peers with industry-leading energy efficiency programs. Figure 11 shows actual spending and saving from different utilities across the country.
As illustrated by the figure above, utility level energy efficiency savings tend to reflect statewide achievable potential and actual savings. More specifically, utilities in the South generally achieved less than 1% savings in 2015. The exception to this group is Entergy Arkansas which achieved a savings of 1.1%, more than the expected achievable potential and the actual savings of Arkansas. Those in leading energy efficiency states follow similar trends with utilities achieving roughly 1.5 – 3% savings in 2015, similar to statewide actual savings (Figure 11).

In terms of costs, the figure demonstrates that utilities with higher energy efficiency savings tend to spend more on a $/kWh basis than utilities with lower savings. The correlation indicates that percent kWh savings partially depends on the $/kWh a utility is willing to spend, and therefore, costs may be partially dependent on actual kWh savings. A recent 2014 study by the South-central Partnership for Energy Efficiency as a Resource (SPEER) came to a similar conclusion after comparing per capita (rather than $/kWh) energy efficiency spending by state. The study also noted that budget may limit incentives and advertising for energy efficiency programs, which in turn limits savings. Another 2010 study by Georgia Tech and Duke University, specifically cited legislation as a limitation to achieving high energy efficiency savings in the South. Additionally, electricity rates vary across regions and therefore, may also affect spending, potential achievable savings, and actual savings, since certain measures may not be as cost effective in some locations. Many other factors, including regional labor rates, specific regional infrastructure (e.g. nonprofit and community leader support) and an existing contractor network.

---

supporting EE installations, impact EE savings and costs. These studies and the figures above illustrate the myriad factors that can influence energy efficiency savings.
APPENDIX A. MODEL GLOBAL ASSUMPTIONS

Table 12 shows a selection of key global assumptions used in the analysis of energy efficiency for ENO. The significance of these global assumptions is that they serve as key financial and valuation parameters (e.g., inflation and discount rates, avoided costs, etc.) used in the calculation of economic and achievable potential.

<table>
<thead>
<tr>
<th>Assumption</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inflation Rate (%/year)</td>
<td>2%</td>
</tr>
<tr>
<td>Discount Rate (%/year)</td>
<td>7.427% nominal, for all Cost Tests</td>
</tr>
<tr>
<td>Avoided Costs</td>
<td>Electric energy: $37/MWh (2017 $)</td>
</tr>
<tr>
<td></td>
<td>Generation capacity: $75/kW-yr (2017 $)</td>
</tr>
<tr>
<td>Line Losses</td>
<td>Total Retail Average: 6.24%</td>
</tr>
</tbody>
</table>

Source: ENO

Stock Forecast

One of the key global inputs used in Navigant’s DSMSim is a forecast of residential and C&I stock. Residential stock is measured in residential accounts while C&I stock is measured through floor space (e.g., 1000 square feet of floor area).

Residential Stock Forecast

Navigant developed the residential stock forecast based on ENO’s forecast of residential accounts from 2017 through 2036. The table below shows the residential stock in 2017 and 2036. Residential stock increases from 180,129 accounts in 2017 to 197,926 accounts in 2036.

Commercial Stock Forecast

Navigant developed the commercial floor space stock based on ENO’s C&I electricity consumption and electricity-intensity estimates (kWh/sq. ft.) from the Commercial Building Energy Consumption Survey (CBECS). Navigant divided ENO’s C&I consumption (3,510 GWh) by the CBECS electricity intensity (18.6 kWh/sq. ft.), to determine a 2017 floor space stock of 189 million sq. ft. To project the forecast of C&I stock through 2036, Navigant analyzed historical employment levels in New Orleans using data from the New Orleans Regional Council for Business Economics (NORCBE). Historical employment levels indicate commercial and industrial economic activity, as well as electricity and natural gas demand. Navigant used the five-year historical employment levels from 2012 to 2016 to determine an average annual growth rate of 1.1% per year, applying the rate to the 2017 stock to forecast C&I stock through 2036.

Table 13 shows the C&I stock in 2017 and 2036, with stock increasing from 189 million sq. ft. in 2017 to 232 million sq. ft. in 2036.

### Table 13. Stock Forecast – Residential and C&I

<table>
<thead>
<tr>
<th>Sector</th>
<th>Units</th>
<th>2017</th>
<th>2036</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td># of accounts</td>
<td>180,129</td>
<td>197,926</td>
</tr>
<tr>
<td>C&amp;I</td>
<td>million sq. ft.</td>
<td>189</td>
<td>232</td>
</tr>
</tbody>
</table>

*Source: ENO data, and Navigant analysis*

**Katrina Effect**

The report refers to the "Katrina effect" as the impact of Hurricane Katrina on the mix of customer end-use equipment; specifically, the increased adoption of high efficiency equipment in the post-Katrina period due to the significant proportion of stock that sustained severe damage during the storm.

Navigant quantified the Katrina effect based on data obtained from three different reports and presentations by the U.S. Department of Housing and Urban Development (HUD).\(^\text{16}\), \(^\text{17}\), \(^\text{18}\) Quantifying the impact of Katrina on the mix of end-use equipment is difficult for several reasons.

- Different studies report various estimates of destroyed, damaged, and/or repaired stock due to differing methodologies, study areas, and dates of reference. The date of reference is also important because some studies may be based on data recorded following other non-Katrina storms (e.g., the compounded impact of Katrina, Rita, etc.).
- Property damage is measured based on a qualitative scale of damage, which introduces a certain degree of bias (e.g., "minor", "major", and "severe" damage).
- Each energy efficiency measure is unique and the likelihood that a given measure – for example, a refrigerator, roof insulation, or a central AC system – might be upgraded is subject to the likelihood that a home experienced flooding and/or wind damage.

Given these challenges in quantifying the Katrina effect, Navigant estimated the fraction of existing stock with high efficiency equipment based on two criteria (1) stock that experienced severe or major damage, and (2) stock that experienced both flooding and wind-damage. Navigant also calculated the fraction of existing stock was destroyed and later rebuilt. Navigant added these two estimates (damaged & repaired stock, and destroyed & rebuilt stock) and applied it to the measure-penetration assumptions used in the

---

\(^\text{16}\) HUD. December 2010. Housing Recovery in the Gulf Coast Phase I: Results of Windshield Observations in Louisiana, Mississippi, and Texas. Available at: [https://www.huduser.gov/Publications/pdf/Housing_Recovery_in_the_Gulf_Coast_PhaseI_v2.pdf](https://www.huduser.gov/Publications/pdf/Housing_Recovery_in_the_Gulf_Coast_PhaseI_v2.pdf)


study. For example, if the Katrina effect was estimated as 20% of existing stock, the new penetration of the base efficiency AC system was decreased by 20%, and the penetration of energy efficient AC systems was increased by 20%.

Table 14 shows the calculations used to estimate the Katrina effect. Navigant determined the Katrina effect to represent 20% of existing stock. This estimate is based on the calculation that 18.5% of existing stock was damaged and later repaired, and that 1.7% of existing stock was destroyed and later rebuilt.

Table 14. Calculation of Katrina Effect

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Stock (# properties)</th>
<th>Calculation/Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1) Properties with Major or Severe Damage</td>
<td>79,925</td>
<td>-</td>
</tr>
<tr>
<td>(2a) Properties with Flood and Wind Damage</td>
<td>82%</td>
<td>-</td>
</tr>
<tr>
<td>(2b) Properties with inferred repairs/rebuilding</td>
<td>64%</td>
<td>-</td>
</tr>
<tr>
<td>(3) Total Damaged Stock</td>
<td>41,748</td>
<td>(1) x (2a) x (2b)</td>
</tr>
<tr>
<td>(4) Estimate of Katrina-Only Impact (excl. other storms)</td>
<td>80%</td>
<td>-</td>
</tr>
<tr>
<td>(5) Damaged/Repaired Stock (Katrina-driven estimate)</td>
<td>33,398</td>
<td>(3) x (4)</td>
</tr>
<tr>
<td>(6) 2017 Stock</td>
<td>180,129</td>
<td>-</td>
</tr>
<tr>
<td>(A) Percent of Damaged/Repaired Stock</td>
<td>18.5%</td>
<td>(5) / (6)</td>
</tr>
<tr>
<td>(7) Percent of Stock Destroyed and Rebuilt (Estimate #1)</td>
<td>1.9%</td>
<td>HUD, Sep 2010</td>
</tr>
<tr>
<td>(8) Percent of Stock Destroyed and Rebuilt (Estimate #2)</td>
<td>1.5%</td>
<td>HUD, July 2011</td>
</tr>
<tr>
<td>(B) Percent of Destroyed/Rebuilt Stock</td>
<td>1.7%</td>
<td>[(7) + (8)] / 2</td>
</tr>
<tr>
<td>Katrina Effect (% of 2017 Stock)</td>
<td>20.2%</td>
<td>(A) + (B)</td>
</tr>
</tbody>
</table>

Source: Navigant analysis of HUD data
BEFORE THE
COUNCIL OF THE CITY OF NEW ORLEANS

SUPPLEMENTAL AND AMENDING
APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF)

DOCKET NO. UD-16-02

SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY

OF

JONATHAN E. LONG

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS PURSUANT TO COUNCIL RESOLUTION R-07-432 HAVE BEEN REDACTED

JULY 2017
TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE .................................................................1
II. PROJECT OVERVIEW ...............................................................................2
II. UPDATE TO ORIGINAL CT COST ESTIMATE AND TIMELINE ..................3
III. SITE CONFIGURATION AND TECHNOLOGY SELECTION .....................6
IV. ESTIMATED PROJECT COST AND SCHEDULE .....................................15
V. PROJECT MANAGEMENT AND CONTRACTING APPROACH ...................20
VI. CONSTRUCTION RISK MANAGEMENT AND MITIGATION ..................22

EXHIBITS

Exhibit JEL-10 Summary of EPC Contract Terms (HSPM)
Exhibit JEL-11 Construction Risks (HSPM)
Exhibit JEL-12 Updated C-K Technical Report
I. INTRODUCTION AND PURPOSE

Q1. PLEASE STATE YOUR NAME AND CURRENT BUSINESS ADDRESS.
A. My name is Jonathan E. Long. My business address is 639 Loyola Avenue, New Orleans, Louisiana 70113.

Q2. ARE YOU THE SAME JONATHAN LONG THAT FILED DIRECT TESTIMONY IN THIS DOCKET?
A. Yes.

Q3. ON WHOSE BEHALF ARE YOU FILING THIS DIRECT TESTIMONY?
A. I am testifying before the Council of the City of New Orleans ("CNO" or the “Council”) on behalf of Entergy New Orleans, Inc. ("ENO" or the “Company”).

Q4. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?
A. My Supplemental and Amending Direct Testimony ("Supplemental Testimony") supports the Supplemental and Amending Application in this proceeding, which seeks, among other things, approval to proceed with a project to construct New Orleans Power Station ("NOPS"), which will consist of either a combustion turbine ("CT") resource with a summer capacity of 226 MW, or alternatively, seven Wärtsilä 18V50SG reciprocating internal combustion engines ("RICE") (the “Alternative Peaker”).
My Supplemental Direct Testimony will largely focus on the Alternative Peaker option,¹ as many of the details regarding the original CT that are discussed in my original Direct Testimony (e.g., technology, engineering, procurement and construction (“EPC”) contractor, EPC Agreement terms, etc.) remain the same. There are, however, several changes to the original CT’s cost estimate and timeline that will be addressed herein, such as escalation and increased transmission costs related to the project.

Regarding the Alternative Peaker, I provide an overview of the alternative project, explain how it was selected, and how its cost estimate was developed. I then present the current cost estimate and schedule. Next, I provide an overview of the project management approach that the Company intends to employ.

II. PROJECT OVERVIEW

Q5. PLEASE PROVIDE A BRIEF OVERVIEW OF THE NOPS PROJECT.

A. In its June 2016 Application, the Company proposed to construct a 226 MW (nominal) CT using one Mitsubishi Hitachi Power Systems America 501 GAC CT, which is still an alternative for the Council’s consideration. The Company is now also proposing an Alternative Peaker, which as mentioned above, would include seven Wärtsilä RICE generator sets. The Alternative Peaker, if approved by the Council, would be located in New Orleans, Louisiana, within the site boundaries of

¹ It should be noted that to the extent possible, I have attempted to streamline my Supplemental Direct by not addressing concepts that were addressed in my original Direct Testimony (i.e., insurance, definition of EPC contractor, the Company’s management approach to construction, etc.).
the deactivated Michoud facility. The base elevation of the unit will be 3.5 feet above sea level, which includes an allowance for a flooding event similar to Hurricane Katrina in the design of the power block elevation. Moreover, as more fully stated below, the unit will be protected by the levees along the Intracoastal Waterway and the Lake Borgne surge barrier constructed/improved after Hurricane Katrina.²

The Alternative Peaker would be constructed by Burns and McDonnell (“B&M”) under a fixed price, fixed schedule form of EPC contract at an estimated cost of $210 million, or roughly $1,640 per kW, including the costs to interconnect to the switchyard. If there are no unanticipated project delays due to the inability to obtain necessary regulatory approvals and permits, or procure materials and equipment, the Alternative Peaker would be expected to enter service in October 2019.

II. UPDATE TO ORIGINAL CT COST ESTIMATE AND TIMELINE

Q6. IS THE COMPANY STILL PROPOSING THE ORIGINAL UNIT, A 226 MW CT?
A. Yes. The Company is proposing that the Council select the originally proposed CT based on benefits discussed by Company witnesses Seth E. Cureington and Charles W. Long. To be clear, if the Council selects this option, Chicago Bridge and Iron, Inc. (“CB&I”) would still be the EPC contractor that constructs that unit. Please refer

² For a full discussion of the risk mitigation measures put in place following Hurricane Katrina by the Army Corps of Engineers (“Corps”) designed to protect New Orleans East from 100-year storm events, please see 11/18/16 Supplemental Direct Testimony of Jonathan E. Long, at 16-22.
to my direct testimony for details related to the Company’s EPC agreement with CB&I.

Q7. HAVE THE PROJECT TIMELINE AND COST ESTIMATE RELATED TO THE CT BEEN AFFECTED BY NOTICE TO PROCEED NOT BEING ISSUED AS ANTICIPATED?

A. Yes. As explained in my original testimony, a construction project like NOPS represents a substantial undertaking, and the Company lacks the in-house capability necessary to execute the engineering, procurement and construction for such a project. Engaging an EPC contractor who can perform all of these functions under a single contract is cost effective and common within the power industry for such projects. EPC Contractors like CB&I, however, experience normal market pressures just like any other company, and cannot hold a contract open for an indeterminate amount of time at a locked-in price given the demand for its resources and inflationary pressures in the market. As such, EPC Agreements routinely employ escalation provisions to account for inflationary pressures should construction not begin on a specified date. This practice is reasonable and standard.

In this instance, the EPC Agreement with CB&I agreement provided a fixed price and fixed schedule duration, provided that Notice to Proceed (“NTP”) was issued on or before [redacted]. The Company noted in its original Application that if NTP was not issued by that date, the EPC contract price was subject to escalation. The costs associated with escalation will be $3.1 million,
assuming NTP is given by January 2018. The Company also noted that if NTP is not issued by [REDACTED], the EPC contract price is open to renegotiation.

Q8. ARE THERE ANY ADDITIONAL INCREASES COMPARED TO THE CT’S ORIGINAL ESTIMATE?

A. Yes. There are additional costs of approximately $2.9 million associated with Entergy payroll, expenses, indirect loaders and non-EPC engineering services. There is an estimated $3.1 million for Allowance of Funds Used During Construction ("AFUDC") costs associated with the delay and there is approximately $6.9 million of increased cost for transmission interconnection. It should be noted, however, that while the increase in transmission includes some escalation, it also includes an increase in scope. The original estimate assumed a similar breaker configuration that was used for the recently retired Michoud units. New transmission standards require a different breaker configuration to allow for a greater level of reliability. There is also a need to replace existing structures and build out the existing switchyard on the plant site to support the new interconnection lines.

Q9. WHAT IS THE TOTAL INCREASE IN COSTS FOR THE CT PROJECT?

A. The total increase in the overall cost estimate for the CT is $16 million, bringing the overall cost estimate of the CT to approximately $232 million.
Q10. HOW HAS THE ORIGINAL CT’S TIMELINE BEEN AFFECTED BY NOTICE TO PROCEED NOT BEING ISSUED AS ANTICIPATED?

A. As noted in my Direct Testimony, the inability to issue NTP by February 2017 resulted in a day-for-day slip in the project’s expected date of commercial operation.

The original anticipated Commercial Operation Date (“COD”) was December 2019. Based on delays to-date, the new anticipated COD assuming the EPC contractor would be given a NTP on or before November 1, 2017 is approximately November 2020.

III. SITE CONFIGURATION AND TECHNOLOGY SELECTION

Q11. PLEASE EXPLAIN WHY THE COMPANY HAS PROPOSED SEVEN WÄRTSILÄ RICE ENGINES AS ITS PREFERRED ALTERNATIVE TECHNOLOGY.

A. As discussed by Mr. Cureington, ENO is in need of a peaking resource to meet its capacity, supply role, and reliability needs. Following a recently updated load forecast, my team began to consider a technology with a lower output. The Company engaged WorleyParsons, a qualified engineering firm, to conduct a study regarding the Company’s potential options for a smaller resource. As described more fully below, the analysis indicated that the RICE units had the lowest levelized cost of electricity on a $/MWh basis, as well as other benefits such as low water usage, a low emissions profile, the ability to support renewable resources, and the inclusion of black-start capability. Based on these factors, the Company recommends moving
forward with proposing the Alternative Peaker as an alternative technology to the Council.

Q12. WHAT IS RICE TECHNOLOGY?

A. RICE is a well-known technology used in automobiles, trucks, marine propulsion, and backup power applications. Reciprocating engines use the expansion of hot gases to push a piston within a cylinder, converting the linear movement of the piston into the rotating movement of a crankshaft to generate power. While the steam engines that powered the industrial revolution were driven by externally-produced steam, modern reciprocating engines used for electric power generation are internal combustion engines in which an air-fuel mixture is compressed by a piston and ignited within a cylinder. RICE sizes for power generation range from 4 to 20 MW. In a power plant, multiple spark-ignited or diesel engines are grouped into blocks of engines, called generating sets, to provide modular electric generating capacity in standardized sizes. Please see Figure 1 for an example of an Engine Hall consisting of RICE engines:
Q13. IS THE ALTERNATIVE PEAKER PROPOSED TO BE LOCATED ON THE SAME SITE AS THE ORIGINALLY PROPOSED CT?

A. Yes. The Alternative Peaker is proposed to be located at the Michoud facility in New Orleans, Louisiana. Figure 2 illustrates the exact location of the Alternative Peaker:
Figure 2

[Image: An aerial view of a rice processing location.]
Q14. PLEASE DESCRIBE THE ANALYSIS PERFORMED BY WORLEY PARSONS, WHICH FACTORED INTO THE DECISION TO RECOMMEND THE ALTERNATIVE PEAKER.

A. The Company considered the following analysis when selecting the Alternative Peaker:

Table 1

<table>
<thead>
<tr>
<th>Equipment Configuration</th>
<th>Net Summer Output (MW)</th>
<th>Heat Rate</th>
<th>Installed Cost- ($M)</th>
<th>$/kW</th>
<th>LTSA ($/MWh)</th>
<th>Demin H2O + Aux Cooling (gpm)</th>
<th>Emissions4, Nox &amp; CO (ppm)</th>
<th>Levelized Cost of Electricity (LCOE)5 ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wärtsilä x7 unit</td>
<td>127.6</td>
<td>8.464</td>
<td>120.3</td>
<td>942</td>
<td>5.88</td>
<td>Very Low</td>
<td></td>
<td>5/15</td>
</tr>
<tr>
<td>GE LM6000 PG Sprint x2 units +</td>
<td>106.0</td>
<td>10.425</td>
<td>99.0</td>
<td>1019</td>
<td>3.60</td>
<td>143 + 159 = 302</td>
<td></td>
<td>5/15</td>
</tr>
<tr>
<td>chiller</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>GE LM6000 PF Sprint 25 x3 units</td>
<td>121.8</td>
<td>9.732</td>
<td>114.7</td>
<td>1045</td>
<td>4.71</td>
<td>57 + 0</td>
<td></td>
<td>5/15</td>
</tr>
<tr>
<td>+ evap cooler</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pratt &amp; Whitney FT-4000 (MHPSA)</td>
<td>108.5</td>
<td>10.013</td>
<td>87.9</td>
<td>903</td>
<td>3.11</td>
<td>105 + 0</td>
<td></td>
<td>5/15</td>
</tr>
<tr>
<td>M501F3 (MHPSA)</td>
<td>130</td>
<td>11.726</td>
<td>105</td>
<td>805</td>
<td>3.90</td>
<td>Very Low</td>
<td></td>
<td>5/9</td>
</tr>
</tbody>
</table>

3 These costs are based upon the EPRI PEACE model and are not site specific. It should also be noted that these costs are estimates of non-site specific EPC costs only and are not fully loaded. This analysis was without site specific cost estimates.

4 Emissions controls were added to all of the units to achieve the same NOx emissions. The cost of the controls and the aux loads were also included in each configuration which affected the net output and heat rate.

5 Based upon 4000 hours per year dispatch and $3.50/MMBtu gas.
Q15. WHAT IS THE EXPECTED OUTPUT OF THE ALTERNATIVE PEAKER?
A. As stated, the Alternative Peaker will be designed to reach a nominal output of approximately 128 MW and a heat rate of roughly [redacted].

Q16. WHY IS THE INSTALLED COST FOR THE UNIT IN TABLE 1 LOWER THAN THE COMPANY’S COST ESTIMATE OF $210 MILLION?
A. As stated above, the installed cost used in the analysis conducted by WorleyParsons to help the Company select the Alternative Peaker was not site specific, and represented only EPC costs. Therefore, it can reasonably be expected that all options evaluated would have had higher installed costs once non-EPC costs and site-specific engineering needs were added to the figures listed above.

Q17. WHAT DOES A UNIT’S HEAT RATE INDICATE?
A. Heat rate pertains to the fuel required to generate a unit of electricity. The lower a plant’s heat rate, the less fuel is required to generate the electricity needed to supply customers. In general, since fuel is a pass-through cost to ENO customers, the lower heat rate of the Alternative Peaker more positively impacts customers than a higher heat rate option.

Q18. WHY IS THE ALTERNATIVE PEAKER EXPECTED TO USE LESS GROUND WATER?
A. The Alternative Peaker will require water for multiple uses in the generation process.
These include cooling water makeup to the engines due to evaporation in the generation process, engine turbowashing, water for general plant washdown, and potable water for plant restrooms and faucet use. This technology uses significantly less groundwater than the recently retired Michoud units. The primary water usage for the retired units was associated with steam generation required to power the steam turbine, which was the prime mover for generating electricity. A great deal more water was required to generate this steam than would be necessary for either the RICE or CT technology.

Additionally, the retired Michoud units relied on large storage tanks to provide makeup water to address water loss associated with steam generation and other plant needs. The RICE technology also uses less water than the CT technology, which uses most of its water for evaporative cooling purposes during summer months when the air intake to the CT requires cooling prior to that air being presented into the compressor section of the machine.

Q19. WHY IS THE ALTERNATIVE PEAKER TECHNOLOGY WELL-SUITED FOR SUPPORTING INTERMITTENT RENEWABLE RESOURCES LIKE SOLAR?

A. The RICE units are able to start and achieve full load in a very short period of time, and they are able to start and stop multiple times in a single day. Both of these characteristics are critical to supplying generation when renewable resources are not available (e.g., on cloudy or rainy days or after sunset). The fast start capability is a great option in a peaking or emergency situation. These engines can supply
electricity on demand when renewable resources may not be available. This alternative also allows for partial load operation in the event there is not enough renewable energy available.

Q20. WHAT IS BLACK-START CAPABILITY AND HOW IS THIS UNIT MORE BLACK-START CAPABLE THAN ALTERNATIVES?

A. Black-start capability is the ability of the plant to start up under its own power without a backfeed of power from the electric grid. Typically there is an auxiliary load supplied to the unit from a local switchyard. In the event of a complete loss of power, the Alternative Peaker will have the ability to supply its own power to start-up and be able to supply power to the grid when needed. The low auxiliary load requirement for this unit makes the ability to black-start this machine more attractive than other options evaluated because a smaller self-starting generator is required, which has a much lower cost.

For example, CT options require higher gas pressure that requires a high auxiliary load. In the event of an emergency, the gas compressor would have to be started first in order to be able to supply the required gas pressure to the CT. A typical generator required to black-start a gas compressor would be in the range of 15 to 20 MWs, which will require a more costly generator.
Q21. **IS THE ALTERNATIVE PEAKER’S CONSTRUCTION COST FIXED AT $210 MILLION?**

A. No. As discussed more fully below, project costs consist of EPC Costs and Non-EPC Costs. The Non-EPC Costs are not fixed. Moreover, while the EPC contract price is fixed assuming the defined scope of work and a timely issuance of full NTP, other factors such as changes in scope due to discovery of new facts, force majeure events, delay in issuing notice to proceed, or changes in law could affect EPC Costs. Those subsequent evaluations could result in change orders that increase or decrease EPC Costs. Also, development projects spanning several years are exposed to a number of risks, both known and unknown, and despite diligent mitigation plans and efforts, scope changes may be required. For example, it would not be unusual that over the long history of the Michoud power plant, a cable for temporary power supply was buried. If that cable is uncovered during excavation, work must stop until it is investigated and ensured to be safe. Any work that the Contractor has to perform related to that discovered cable would be added to the scope of the Project through a change order.

Q22. **WHAT IS THE ASSUMED LIFE OF THE ALTERNATIVE PEAKER?**

A. The assumed life for the Alternative Peaker is 30 years.
IV. ESTIMATED PROJECT COST AND SCHEDULE

Q23. WHAT IS THE CURRENT ESTIMATE OF THE COSTS TO COMPLETE THE ALTERNATIVE PEAKER?

A. A summary of the components of the current cost estimate is shown below:

Q24. HOW WERE THESE COST ESTIMATES PREPARED?

A. These estimates are largely derived from the largest single cost component, the EPC agreement with B&M. Following the suspension in the procedural schedule in this docket, the project team, which I lead, was asked to (1) select an alternative technology; and (2) to select an EPC contractor to construct the alternative unit. The Company initiated a competitive process whereby two bidders were asked to submit proposals to perform the EPC work for the Alternative Peaker. B&M was selected through this process because of competitive pricing and prior experience constructing units using RICE technology. B&M is the industry leader in RICE projects over 25 MWs. By 2015, the company had installed a total of 72 RICE engines, with 60 of these being Wärtsilä engines. B&M has constructed a total of 16 power generation facilities utilizing RICE technology. One of these projects includes the 12 engine
Wärtsilä plant at the Denton Energy Center in Denton, Texas, which employs the same engines that will be installed at NOPS. It can achieve full load operation in 5 minutes and has black-start capabilities, which are both similar attributes to the proposed Alternative Peaker. The Southwest Texas Electric Cooperative’s Pearsall plant is another plant constructed by B&M that is similar to the Alternative Peaker.

The Company worked with B&M to derive a cost estimate for the Alternative Peaker that includes a reasonable amount of engineering design. As briefly mentioned above, Non-EPC Costs were estimated by ESI and include project management and oversight (both internal and external services), inspections and testing, environmental permitting, pursuing regulatory approvals, temporary facilities and supplies, and AFUDC.

Q25. DOES THE COST ESTIMATE REFLECT COST ESCALATION ADJUSTMENTS AND PROJECT CONTINGENCIES?

A. As is the case with the EPC Agreement underlying the originally proposed CT, the EPC agreement for the Alternative Peaker provides a fixed price and fixed schedule duration, provided that NTP is issued on or before a certain date. The NTP is not expected to be issued prior to receipt of acceptable approval from the Council. If NTP is not issued by that date, the EPC contract price is subject to escalation. If NTP is delayed beyond [redacted] per month with a yearly cap at [redacted] for equipment (excluding RICE), materials and indirect costs. Labor and RICE equipment are also subject to escalation. At this time, labor
escalation is a true-up based on actual sub-contractor costs that will be handled utilizing an open book process. The RICE equipment is based on an exchange rate factor and European producer price index at the time the equipment order is placed.

If NTP is not issued by ☐☐☐☐☐☐☐ the EPC contract price is open to renegotiation. Further, the Company included a contingency estimate that addresses the fact that construction projects of the cost magnitude and time duration have cost elements that are beyond the reasonable control of the Company and its management.

Even with a fixed-price EPC agreement and well-defined scope, experience demonstrates that unpredictable events, such as discovery of unknown site conditions or changes in laws or regulations, can require change orders that will affect project costs. Thus, contingency must be included in the estimate in order to provide a realistic estimate of the ultimate cost to complete the Project. The current Project estimate contains a contingency line item of approximately six percent of the total project costs, which is reasonable for a project of this nature. I describe risks to the Project and mitigation plans later in my testimony.

Q26. WHAT ARE SOME OF THE KEY MILESTONES IN THE ESTIMATED PROJECT SCHEDULE?

A. Substantial Completion is expected in October 2019, but no later than the end of 2019 provided regulatory approval is received by the end of October 2017 and NTP is granted to the EPC contractor by November 1, 2017. B&M would receive incentives for early completion and be required to pay liquidated damages for delayed
completion. Some of the key milestones in the schedule (assuming certification by November 1, 2017) are:

<table>
<thead>
<tr>
<th>Milestone</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulatory approval – w/ New Orleans City Council</td>
<td>Nov 2017</td>
</tr>
<tr>
<td>Notice to Proceed</td>
<td>Nov 2017</td>
</tr>
<tr>
<td>Engine Purchase Order (critical milestone to achieve on time Commercial Operations date)</td>
<td>Nov 2017</td>
</tr>
<tr>
<td>Air Permit issued</td>
<td>Jan 2018</td>
</tr>
<tr>
<td>Coastal Use Permit issued</td>
<td>Jan 2018</td>
</tr>
<tr>
<td>Engine delivery</td>
<td>Dec 2018</td>
</tr>
</tbody>
</table>
Q27. WHAT IS THE EXPECTED TIMING OF THE SPENDING AND FINANCIAL COMMITMENTS ASSOCIATED WITH THE ALTERNATIVE PEAKER?

A. The following HSPM graph depicts the Project’s projected cash flow and cancellation commitments:

Q28. WHAT DOES THE COMPANY CONSIDER TIMELY REGULATORY APPROVAL?

A. The current schedule is based on the expectation that the Company will have received acceptable approval from the Council by November 1, 2017. Substantial completion is expected to occur approximately 24 months following NTP.
Q29. ARE THERE BENEFITS TO ISSUANCE OF NTP PRIOR TO NOVEMBER 2017 IF EARLIER APPROVAL IS OBTAINED?

A. Yes. An earlier NTP would potentially allow the unit to be brought on-line prior to October 2019 and potentially allow customers to begin receiving the benefits from this Alternative Peaker earlier. This would also shorten the period over which the costs associated with AFUDC, Entergy internal costs and indirect costs would accumulate.

V. PROJECT MANAGEMENT AND CONTRACTING APPROACH

Q30. HAS THE COMPANY’S PLAN TO MANAGE THE EPC CONTRACT CHANGED SINCE ITS INITIAL FILING?

A. No, the Company will follow the same structure outlined in my original Direct Testimony.

Q31. HOW DOES THIS FORM OF EPC CONTRACT COMPARE TO THE EPC CONTRACT UTILIZED BY ELL FOR THE CONSTRUCTION OF NINEMILE 6, ST. CHARLES POWER STATION, AND THE ORIGINAL CT PROPOSED IN THIS CASE?

A. The EPC contract for the Alternative Peaker is expected to contain very similar Terms and Conditions as the EPC contract for Ninemile 6, SCPS, and the NOPS CT. These contracts are fixed-price, date-certain form of contracts. Schedule duration is
driven by the issuance of NTP and with escalation provisions if the NTP is delayed and subject to renegotiation if NTP not issued by a certain date.

The Alternative Peaker contract has schedule incentives and liquidated damages capped at % of the EPC contract value; and an overall aggregate monetary liability capped at % of the total EPC contract value. The Alternative Peaker contract is expected to include a craft labor escalation provision that will be fixed, which is a difference from the referenced contracts. A summary of how the EPC terms for the Alternative Peaker compare to other EPC contracts is provided in Table 2:

Table 2
Q32. HAS THE COMPANY AND B&M AGREED UPON THE TERMS OF AN EPC AGREEMENT?

A. No. The parties are in the final stages of negotiating the EPC agreement. A summary of the expected terms, however, has been attached as HSPM Exhibit JEL-10.

VI. CONSTRUCTION RISK MANAGEMENT AND MITIGATION

Q33. HOW DO THE KEY RISKS AFFECT THE PROJECT’S SCHEDULE AND PROJECTED COSTS?

A. The fixed-price structure and well-defined scope of work are expected to minimize the effect these key risks may have on project costs. The Company developed mitigation plans and included a contingency in the project cost estimate that is thought to be reasonably sufficient to mitigate identified risks. Delays in receiving regulatory approvals or the required permits beyond the dates assumed in the project schedule will increase total costs and result in a delayed in-service date. The project schedule has been developed by optimizing the sequence of activities to produce the shortest practical schedule at the lowest reasonable cost. The schedule has a built-in contingency for critical path activities that will help mitigate short delays.

Q34. IS THE CONTINGENCY REFLECTED IN THE PROJECT COST ESTIMATE ADEQUATE TO COVER ALL RISKS THAT COULD INCREASE COST?

A. No, and that is not the purpose of contingency funds in project management. Contingency is used to reasonably mitigate unplanned increases in project cost,
whether caused by known risks or unforeseen risks. It recognizes that large
construction projects that span several years can be adversely affected by events
beyond the utility’s control. ESI used a Monte Carlo simulation to determine the
level of contingency that would provide a reasonable level of mitigation of known
and unknown risks, but it is possible that some of these risks, if realized, could cause
cost increases beyond the contingency included in the cost estimate. It should be
noted that the Company does not retain any unused project contingency.

Q35. CAN YOU DISCUSS SOME OF THE KEY RISKS UNDER THE EPC
CONTRACT?

A. Yes. While the EPC contract with B&M provides for a fixed price and fixed
schedule, any fixed-price contract presents a risk of price increases through change
orders and extra work claims. This risk has been mitigated to the extent possible by
broadly defining the scope of work assigned to B&M as including everything
necessary to complete the Project that meets the specification and performance
requirements, except for items expressly stated in the scope document to be the
Company’s responsibility. The EPC contract also contains favorable change order
provisions that will enable the Company to direct B&M to proceed with a change
order as to which there is a good faith dispute between the parties, with the dispute
over price impact to be resolved in arrears.

This will protect the Company and its customers from the possibility that the
EPC contractor would threaten to delay work until change order disputes are resolved.
to its satisfaction. Further, B&M must notify the Company before making any changes required by force majeure events or changes in laws, and must document such changes and the resulting impacts before being entitled to any schedule relief, increase in the fixed price, or additional reimbursement. A discussion of other construction risks, mitigation, and allocation for the Alternative Peaker is contained on HSPM Exhibit JEL-11.

Finally, potential wage rate escalation on craft labor and per diem is expected to be a significant risk as a result of the anticipated labor shortage in the Gulf Coast region due to ongoing and proposed industrial capital investments over the next decade. Should the project proceed as planned with NTP being given on November 1, 2017, B&M carries the risk as it relates to craft labor wage and per diem. If the project is delayed for a year, the contract has an escalation provision as outlined above.

Q36. PLEASE ELABORATE ON THE CRAFT LABOR PROVISIONS CONTAINED IN THE EPC AGREEMENT.

A. Under the terms of the agreement, B&M has agreed to assume productivity risk associated with craft labor (i.e., man-hour estimates). B&M has also agreed to assume subcontractors’ craft labor wage escalation risk, as well as that of engineering and project management labor.

The EPC agreement pricing includes a total of [REDACTED] total escalation in the EPC’s fixed price cost. The total escalation includes [REDACTED] per annum for
Q37. DOES THE EPC AGREEMENT HAVE PROVISIONS THAT MITIGATE RISK RELATING TO B&M’s PERFORMANCE?

A. Yes. As I discussed earlier, the fixed-price, fixed-duration form of contract, coupled with liquidated damages for late delivery, heat rate, and output provide a measure of protection for customers. Additionally, the EPC agreement requires that B&M deliver a finished product that meets minimum requirements for performance and to warranty that work for 12 months following substantial completion. The contractor is also required to indemnify owner against claims for bodily injury and third-party property damage.

The EPC agreement establishes a milestone payment structure whereby the contractor will only be paid for the work that has been completed, as verified by the Company. The milestone payments are subject to a cumulative cap with monthly values stated in the contract that protects the Company’s cash flow. Additionally, payment retention will be accomplished in two ways:
Q38. WHAT TYPE OF INSURANCE IS INCLUDED IN THE COMPANY’S COST ESTIMATE FOR THE NOPS PROJECT?

A. As with units constructed by other EOCs, such as the Ninemile 6 CCGT, the Company intends to procure insurance prior to the issuance of NTP. The expected coverage will include Builders All Risk and Delay in Startup. Please see my Direct Testimony for more information regarding these insurances.

Q39. WHAT IS THE COMPANY’S POLICY REGARDING DIVERSE SUBCONTRACTOR PARTICIPATION IN THE CONSTRUCTION OF NOPS?

A. As a part of the EPC Agreement, ENO will require B&M to provide opportunities to small and disadvantaged businesses for participation in any subcontracts and purchase orders let in the performance of its obligations as the EPC contractor. The Company requires B&M to develop and maintain a list of Diverse Subcontractors and Suppliers that will be supplied to ENO on a quarterly basis. Minority-owned businesses, women-owned businesses, veteran-owned businesses, and disabled-veteran-owned businesses, among others, are included within the meaning of “diverse subcontractors and suppliers.” B&M will be required to submit a plan for utilizing diverse subcontractors and suppliers to ensure such participation in the construction of NOPS.
Q40. FINALLY, YOUR (NOVEMBER 2016) SUPPLEMENTAL DIRECT TESTIMONY REFERENCED A TECHNICAL REPORT PREPARED BY C-K ASSOCIATES (“CK”), LLC AND LOSONSKY AND ASSOCIATES, INC. HAS THAT REPORT BEEN UPDATED TO EVALUATE THE ALTERNATIVE PEAKER?

A. Yes. In his Supplemental Direct Testimony, one of the authors of the C-K Technical Report, Dr. George Losonsky, discusses the analyses he performed for the Addendum to the C-K Technical Report that is attached to his Testimony as Exhibit GL-2. As Dr. Losonsky’s Testimony addresses in detail, he performed additional evaluations of possible impacts from groundwater withdrawal associated with the operation of the Alternative Peaker. Specifically, he performed calculations to determine the range of possible drawdown levels, and any resulting consolidation settlement, that might occur due to the operation of the Alternative Peaker. He also supplemented his evaluation of groundwater usage issues related to the CT Unit by performing the same calculations to determine the possible impacts of the expected groundwater usage required for the CT. Dr. Losonsky concluded, based on the calculations set forth in Exhibit GL-2, that neither the Alternative Peaker nor the CT would “exacerbate subsidence or cause damage to infrastructure in New Orleans East.”

Moreover, CK conducted an air screening model evaluation using AERSCREEN software to understand how the proposed Alternative Peaker project might affect air quality in New Orleans East. (An air screening model evaluation was previously performed for the CT project and a report of that evaluation was attached to my Supplemental Direct Testimony filed in December 2016.) Based on the
AERSCREEN model evaluation, the CK report concludes that in no case will the emissions cause ambient air concentration to exceed regulatory standards, which are protective of human health and the environment. The CK report also concludes that the proposed Alternative Peaker will represent a significant reduction in allowable emissions compared to the emissions of the former Michoud plant and that emissions from the RICE project are dissipated before they reach the fence line to concentrations much below the National Ambient Air Quality Standards. The updated C-K Technical Report regarding emissions for the Alternative Peaker is attached hereto as Exhibit JEL-12.

Q41. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, at this time.
AFFIDAVIT

STATE OF LOUISIANA
PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, JONATHAN E. LONG, 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.

[Signature]
Jonathan E. Long

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 10th DAY OF JUNE, 2017

[Signature]
NOTARY PUBLIC

My commission expires: [Signature]

Harry M. Barton
Notary Public
Notary ID# 90845
Parish of Orleans, State of Louisiana
My Commission is for Life
BEFORE THE
COUNCIL OF THE CITY OF NEW ORLEANS

SUPPLEMENTAL AND AMENDING )
APPLICATION OF ENTERGY NEW )
ORLEANS, INC. FOR APPROVAL TO ) DOCKET NO. UD-16-02
CONSTRUCT NEW ORLEANS POWER )
STATION AND REQUEST FOR COST )
RECOVERY AND TIMELY RELIEF )

EXHIBIT JEL-10

and

EXHIBIT JEL-11

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

JULY 2017
TECHNICAL REPORT
RECIPIROCATING INTERNAL
COMBUSTION ENGINES ("RICE")
AIR QUALITY EVALUATION

New Orleans Power Station
Entergy New Orleans, Inc.
3601 Paris Road
New Orleans, Louisiana 70129

July 6, 2017

Prepared by:

CK Associates
Environmental Consultants

17170 Perkins Road
Baton Rouge, LA 70810
225-755-1000
CK Project Number: 14005
EXECUTIVE SUMMARY

Entergy New Orleans, Inc. (ENO) has proposed to construct either a combustion gas turbine (CT) electric generation facility or a 128 MW natural-gas-fired reciprocating internal combustion engines (“RICE”) facility. The RICE option is composed of seven 18 MW natural gas-fired reciprocating internal combustion engines with associated ancillary equipment. The new facility is referred to as New Orleans Power Station (NOPS), and will be located at the site of the deactivated Michoud Electric Generating Plant (Michoud plant). Some members of the community have raised concerns regarding air quality impacts of the proposed NOPS alternatives. However, both proposed NOPS alternatives will be permitted for less allowable emissions than the previously active Michoud plant at the same site.

CK Associates, LLC (CK Associates) conducted an air screening model evaluation using AERSCREEN to address community concerns and to understand how the proposed RICE alternative might impact air quality in New Orleans East. The CT alternative has previously been the subject of an air screening model evaluation (CK Associates, 2016. Technical Report - Evaluation of Groundwater Withdrawal and Air Quality).

Based on the air screening model evaluation, it was concluded that the emissions from the proposed RICE alternative will in no case result in ambient air concentrations above air quality regulatory standards, which are protective of human health and the environment.

This report was prepared by scientists familiar with local, regional, and statewide environmental conditions, air dispersion modeling, and air quality regulations, who are qualified to discuss the subject matter.
TABLE OF CONTENTS

1.0 INTRODUCTION .................................................................................................................... 1
2.0 AIR EMISSIONS EVALUATION ............................................................................................. 2
   2.1 Proposed Air Emissions .................................................................................................... 2
   2.2 Screening Level Air Modeling ........................................................................................... 2
3.0 CONCLUSIONS AND SUMMARY ........................................................................................... 3

LIST OF TABLES

Table 1  Air Emissions Summary
Table 2  Screening Model Inputs Summary
Table 3  Screening Model Results
1.0 INTRODUCTION

Entergy New Orleans, Inc. (ENO) has proposed to construct either a combustion gas turbine (CT) electric generation facility or a 128 MW natural-gas-fired reciprocating internal combustion engines (“RICE”) facility. The RICE option is composed of seven 18 MW natural gas-fired reciprocating internal combustion engines with associated ancillary equipment. The new facility is referred to as New Orleans Power Station (NOPS), and will be located at the site of the deactivated Michoud Electric Generating Plant (Michoud plant). Some members of the community have raised concerns regarding air quality impacts of the proposed NOPS alternatives. However, both proposed NOPS alternatives will be permitted for less allowable emissions than the previously active Michoud plant at the same site.

C-K Associates, LLC (CK Associates) conducted an air screening model evaluation using AERSCREEN to address community concerns and to understand how the proposed RICE alternative might impact air quality in New Orleans East. The CT NOPS alternative has previously been the subject of an air screening model evaluation (CK Associates, November, 2016). This report presents the analysis and calculations that support the following conclusion:

The emissions from the proposed RICE alternative will result from combustion of clean burning natural gas. In no case, will emissions result in ambient air concentrations above air quality regulatory standards, which are protective of human health and the environment.

The report was prepared by environmental scientists at CK Associates, an environmental and engineering consulting firm licensed in the state of Louisiana. The scientists who prepared this report are familiar with environmental regulations and relevant air quality subjects and are qualified to prepare this report.

2.0 AIR EMISSIONS EVALUATION

Under the Clean Air Act, the Environmental Protection Agency (EPA) is required to regulate emission of pollutants to protect public health and welfare. State and local governments also monitor and enforce Clean Air Act regulations, with oversight by the EPA. The Clean Air Act, which was last amended in 1990, requires EPA to set National Ambient Air Quality Standards (NAAQS) for pollutants considered harmful to public health and the environment. The EPA has set NAAQS (limits) for six principal pollutants, which are called "criteria" air pollutants. They are particle pollution (often referred to as particulate matter, PM_{10} and PM_{2.5}), photochemical oxidants and ground-level ozone, carbon monoxide, sulfur dioxide, nitrogen dioxide, and lead.

The RICE facility will include seven (7) natural gas-powered engines and supporting equipment (e.g. an emergency generator and a firewater pump). The RICE facility will require a permit issued by the Louisiana Department of Environmental Quality (LDEQ). The air permit will set emission limit controls and requirements for testing.
2.1 Proposed Air Emissions

The RICE facility will use newer, more efficient technology that must comply with emission limitations that are stricter than those that existed during the time when the deactivated units were installed at the former Michoud Plant. The allowable air emissions for the RICE facility will be lower for all criteria air pollutants than the permitted emissions for the former Michoud Plant. **Table 1** compares the allowable air emissions of the previous plant versus the RICE facility for all criteria pollutants. This table shows that the reduction in air emissions range from 49% for Volatile Organic Compounds (VOC) to 99% for Nitrogen Oxides (NOx).

2.2 Screening Level Air Modeling

Air dispersion modeling is the mathematical simulation of how air pollutants disperse in the ambient atmosphere. The LDEQ has emission thresholds that, if exceeded, require permit applicants to perform air dispersion modeling during the permitting process. Because the net emissions from the RICE NOPS alternative are below the air emissions thresholds, the regulations do not require that air dispersion modeling be performed. Nevertheless, at ENO’s request CK conducted voluntary screening level air dispersion modeling using conservative assumptions to understand ground-level concentration exposure to the public. The air dispersion model can effectively estimate the downwind ambient concentrations of constituents emitted from the RICE facility equipment sources.

Air dispersion modeling is performed with computer programs that solve the mathematical equations and algorithms which simulate the dispersion of emissions to air. EPA preferred models include AERSCREEN for screening analysis and AERMOD for refined model simulations. AERSCREEN is the recommended screening model that will produce conservative impact estimates without the need for actual hourly meteorological or detailed terrain data. If air quality evaluated using AERSCREEN passes the appropriate standards (e.g. NAAQS) there is no need for additional modeling (e.g. Refined AERMOD). AERSCREEN model will produce estimates of "worst-case" 1-hour concentrations for a single source, based on a matrix of meteorological conditions, and includes conversion factors to estimate "worst-case" 3-hour, 8-hour, 24-hour, and annual concentrations. AERSCREEN is intended to produce concentration estimates that are equal to or greater than the estimates produced by AERMOD with a fully developed set of actual meteorological and terrain data, but the degree of conservatism will vary depending on the application.

The AERSCREEN model was developed to provide an easy-to-use method of obtaining pollutant concentration estimates. To perform a modeling study using AERSCREEN, data for the following input requirements must be supplied:
• Source Type (Point, Flare, Area or Volume);
• Physical Source and Emissions Characteristics (emission rate, stack height, stack diameter, stack gas exit velocity and temperature, and receptor height above ground);
• Meteorology (surface characteristics, ambient temperatures, minimum wind speed, and anemometer height);
• Building downwash; and,
• Terrain (flat, elevated and complex terrain).

The stack parameters and emission rates employed in the RICE facility modeling analysis are included in Table 2. Also, the parameters used for the development of the meteorological data set are included in Table 2.

Table 3 shows the AERSCREEN modeling outputs of the RICE facility maximum ground-level concentrations compared to the NAAQS. Several averaging periods are considered based on the form of the NAAQS standard. The modeling included conservative assumptions, and demonstrates that personal ground-level exposure due to the NOPS emissions will be well below the applicable NAAQS.

3.0 CONCLUSIONS AND SUMMARY

The following conclusions were made based on the analysis presented herein:

• No new chemicals will be released due to NOPS when compared to the historical operations of the Michoud plant;
• Chemicals emitted are consistent with natural gas combustion;
• The proposed RICE facility will represent a significant reduction in allowable emissions compared to the allowable emissions of the former Michoud plant; and,
• Emissions are dissipated before they reach the fence line to concentrations much below the limits for public breathing level air (NAAQS).

In summary, the emissions from the proposed RICE NOPS alternative will result from combustion of clean burning natural gas. The proposed RICE allowable emissions are less than the permitted emissions from the former Michoud plant. In no case, will the emissions cause ambient air concentrations to exceed regulatory standards, which are protective of human health and the environment.
Table 1
RICE Air Emissions Summary
New Orleans Power Station

<table>
<thead>
<tr>
<th>Constituent</th>
<th>Constituent Identifier</th>
<th>Emissions Allowed Under Current Permit (Ton/Year)</th>
<th>Proposed RICE Permit Limits¹ (Ton/Year)</th>
<th>Difference Between Existing Permit and Proposed RICE Limits (Tons/Year)</th>
<th>Percent Reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td>Particulate Matter Less than 10 microns</td>
<td>PM&lt;sub&gt;10&lt;/sub&gt;</td>
<td>283.55</td>
<td>97.61</td>
<td>-185.94</td>
<td>66%</td>
</tr>
<tr>
<td>Particulate Matter Less than 2.5 microns</td>
<td>PM&lt;sub&gt;2.5&lt;/sub&gt;</td>
<td>283.55</td>
<td>97.61</td>
<td>-185.94</td>
<td>66%</td>
</tr>
<tr>
<td>Sulfur Dioxide</td>
<td>SO&lt;sub&gt;2&lt;/sub&gt;</td>
<td>22.55</td>
<td>2.87</td>
<td>-19.68</td>
<td>87%</td>
</tr>
<tr>
<td>Nitrogen Oxides</td>
<td>NO&lt;sub&gt;x&lt;/sub&gt;</td>
<td>8596.89</td>
<td>50.39</td>
<td>-8546.50</td>
<td>99%</td>
</tr>
<tr>
<td>Carbon Monoxide</td>
<td>CO</td>
<td>3132.22</td>
<td>89.31</td>
<td>-3042.91</td>
<td>97%</td>
</tr>
<tr>
<td>Volatile Organic Compounds</td>
<td>VOC</td>
<td>205.35</td>
<td>105.38</td>
<td>-99.97</td>
<td>49%</td>
</tr>
</tbody>
</table>

¹ Proposed permit limits based on information received from CB&I
### Table 2
RICE Screening Model Inputs Summary
New Orleans Power Station

<table>
<thead>
<tr>
<th>Source ID</th>
<th>Stack Height (ft)</th>
<th>Exit Temperature (°F)</th>
<th>Exit Velocity (fps)</th>
<th>Stack Diameter (ft)</th>
<th>NOx (lb/hr max)</th>
<th>NOx (lb/hr avg)</th>
<th>CO (lb/hr max)</th>
<th>PM$_{10/2.5}$ (lb/hr max)</th>
<th>PM$_{10/2.5}$ (lb/hr avg)</th>
<th>SO$_2$ (lb/hr max)</th>
<th>SO$_2$ (lb/hr avg)</th>
<th>Benzene (lb/hr avg)</th>
<th>Formaldehyde (lb/hr avg)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Per Engine</td>
<td>60</td>
<td>697</td>
<td>87.5</td>
<td>5.32</td>
<td>2.49</td>
<td>1.61</td>
<td>4.97</td>
<td>4.23</td>
<td>3.18</td>
<td>0.13</td>
<td>0.094</td>
<td>0.037</td>
<td>1.23</td>
</tr>
<tr>
<td>Firewater Pump</td>
<td>9</td>
<td>1056</td>
<td>51</td>
<td>0.67</td>
<td>NA</td>
<td>0.02</td>
<td>1.65</td>
<td>0.10</td>
<td>0.002</td>
<td>0.003</td>
<td>0.002</td>
<td>0.002</td>
<td>0.002</td>
</tr>
<tr>
<td>Emergency Generator</td>
<td>13</td>
<td>1015</td>
<td>293.7</td>
<td>0.83</td>
<td>NA</td>
<td>0.203</td>
<td>11.53</td>
<td>0.67</td>
<td>0.007</td>
<td>0.02</td>
<td>0.002</td>
<td>0.011</td>
<td>0.001</td>
</tr>
</tbody>
</table>

124-Hour averaging period for PM$_{2.5}$ modeled using the total emitted from the emergency units for testing in a 24-hour period.

<table>
<thead>
<tr>
<th>Minimum Wind Speed (m/s)</th>
<th>Anemometer Height (m)</th>
<th>Surface Albedo</th>
<th>Bowen Ratio</th>
<th>Surface Roughness Length (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.5</td>
<td>10</td>
<td>0.15</td>
<td>0.21</td>
<td>0.088</td>
</tr>
</tbody>
</table>
TABLE 3
<table>
<thead>
<tr>
<th>Constituent</th>
<th>Constituent Identifier</th>
<th>Averaging Period</th>
<th>RICE (7 Engines) Model Predicted Concentration (ug/m³)</th>
<th>NAAQS (ug/m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Particulate Matter Less than 10 microns</td>
<td>PM$_{10}$</td>
<td>24-Hour</td>
<td>21.82</td>
<td>150</td>
</tr>
<tr>
<td>Particulate Matter Less than 2.5 microns</td>
<td>PM$_{2.5}$</td>
<td>24-Hour</td>
<td>21.82</td>
<td>35</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Annual</td>
<td>2.7</td>
<td>12</td>
</tr>
<tr>
<td>Sulfur Dioxide</td>
<td>SO$_2$</td>
<td>1-Hour</td>
<td>1.18</td>
<td>196</td>
</tr>
<tr>
<td></td>
<td></td>
<td>3-Hour</td>
<td>1.36</td>
<td>1,300</td>
</tr>
<tr>
<td></td>
<td></td>
<td>24-Hour</td>
<td>0.82</td>
<td>365</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Annual</td>
<td>0.12</td>
<td>80</td>
</tr>
<tr>
<td>Nitrogen Dioxide</td>
<td>NO$_2$</td>
<td>1-Hour</td>
<td>18.56</td>
<td>188</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Annual</td>
<td>1.18</td>
<td>100</td>
</tr>
<tr>
<td>Carbon Monoxide</td>
<td>CO</td>
<td>1-Hour</td>
<td>180</td>
<td>40,000</td>
</tr>
<tr>
<td></td>
<td></td>
<td>8-Hour</td>
<td>162</td>
<td>10,000</td>
</tr>
<tr>
<td>Benzene</td>
<td></td>
<td>Annual</td>
<td>0.046</td>
<td>12</td>
</tr>
<tr>
<td>Formaldehyde</td>
<td></td>
<td>Annual</td>
<td>1.04</td>
<td>7.69</td>
</tr>
</tbody>
</table>

**NOTES:**
NAAQS = National Ambient Air Quality Standard
BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

SUPPLEMENTAL AND AMENDING )
APPLICATION OF ENTERGY NEW )
ORLEANS, INC. FOR APPROVAL TO )
CONSTRUCT NEW ORLEANS POWER )
STATION AND REQUEST FOR COST )
RECOVERY AND TIMELY RELIEF )

DOCKET NO. UD-16-02

SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY

OF

CHARLES W. LONG

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

JULY 2017
TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE ................................................................................................. 1
II. OVERVIEW OF RELIABILITY RISKS IN NEW ORLEANS .................................................. 3
III. RELIABILITY ANALYSIS RESULTS ..................................................................................... 8
IV. BENEFITS OF LOCAL GENERATION ................................................................................... 25

EXHIBITS

Exhibit CWL-6 Summary of Updated Reliability Analyses
I. INTRODUCTION AND PURPOSE

Q1. PLEASE STATE YOUR NAME AND CURRENT BUSINESS ADDRESS.
A. My name is Charles W. Long. I am employed by Entergy Services, Inc. (“ESI”),1 a service company to the EOCs, as Director, Transmission Planning. My business address is 6540 Watkins Drive, Jackson, Mississippi, 39213.

Q2. ARE YOU THE SAME CHARLES W. LONG WHO FILED DIRECT TESTIMONY IN THE ABOVE CAPTIONED DOCKET?
A. Yes.

Q3. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?
A. I am testifying on behalf of Entergy New Orleans, Inc. (“ENO” or the “Company”).

Q4. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL DIRECT TESTIMONY?
A. My Supplemental and Amending Direct Testimony (“Supplemental Direct Testimony”) supports the Application in this proceeding, which seeks, among other things, approval to proceed with a project to construct New Orleans Power Station (“NOPS”), which will consist of either a combustion turbine (“CT”) resource with a summer capacity of 226 megawatts (“MW”), or alternatively, seven Wärtsilä

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1 ESI is an affiliate of the Entergy Operating Companies (“EOCs”) and provides engineering, planning, accounting, technical, and regulatory-support services to each of the EOCs. The five current EOCs are Entergy Arkansas, Inc. (“EAI”), Entergy Louisiana, LLC (“ELL”), Entergy Mississippi, Inc. (“EMI”), Entergy New Orleans, Inc., and Entergy Texas, Inc. (“ETI”).
18V50SG Reciprocating Internal Combustion Engine (“RICE”) Generator sets
(“Alternative Peaker”).

Q5. PLEASE PROVIDE AN OVERVIEW OF YOUR SUPPLEMENTAL DIRECT TESTIMONY.

A. My Supplemental Direct Testimony first reemphasizes the unique operational
reliability-related characteristics of the Downstream of Gypsy (“DSG”) region of the
power system that serves the electric load in the City of New Orleans. It next
describes ENO’s transmission reliability analysis, which concludes that the original
unit proposed, the CT, would eliminate all reliability concerns throughout the
planning horizon and help create an increased reliability margin, which is a level of
reliability that exceeds the minimum level required to maintain a reliable grid but
allows room for growth and provides some operational margin.

The analysis also shows that the Alternative Peaker would mitigate the most
serious reliability concerns, namely the potential cascading outages in ENO’s service
territory, but would not eliminate all projected reliability risks associated with all
categories of contingencies required for North American Electric Reliability
Corporation (“NERC”) compliance. Thus, some transmission investment could still
be needed at some point to comply with NERC standards if the Alternative Peaker is
constructed; but as discussed more fully below, the Company would recommend a
wait-and-see approach with respect to those upgrades given the timing and level of
overloading involved. My testimony also discusses the transmission-related benefits
that local generation is expected to produce, and it provides an update regarding

II. OVERVIEW OF RELIABILITY RISKS IN NEW ORLEANS

Q6. PLEASE DEFINE THE TERM “LOCAL RELIABILITY CRITERIA.”

A. The term “local reliability criteria,” as it is used in the context of transmission planning and operations, is a very broad concept that commonly refers to more stringent criteria or operating practices defined for a “local area,” or a portion of the transmission system which usually has transmission topological considerations that differ from the remainder of the electric grid such that such local reliability criteria are warranted for the local area given those geographical constraints.

Q7. PLEASE ALSO DEFINE THE TERM “LOAD POCKET.”

A. A load pocket generally refers to a region of high load concentration, which is dependent upon local generation capability within its borders to reliably serve load due to a limit on the ability to import power into the region. Often, as is the case with DSG, simply expanding the transmission system to import more power is not the most cost-effective method to increase a utility’s local reliability in the load pocket due to geographical and constructability constraints that hinder the expansion of the transmission system in a cost-efficient manner. Moreover, an expansion of the transmission system to facilitate greater amounts of power imports into a local pocket provides limited reliability improvements, as I shall discuss below.
Furthermore, in the case of the Amite South and DSG load pockets, several of the local generators located within the load pockets are supercritical steam-turbine generators with very long start-up times. The long start-up times further constrain the operating flexibility of the system, especially for operating conditions that require the commitment of a generator for the mitigation of transmission constraints. Hence, load pockets are often operated to more stringent reliability criteria due to these unique operating characteristics. The load pockets at issue in this proceeding, Amite South and DSG, have been described in detail in my original Direct Testimony on pages 3-5.

Q8. HOW DO THESE RELIABILITY CONCEPTS OPERATIONALLY AFFECT NEW ORLEANS FROM A TRANSMISSION PERSPECTIVE?

A. New Orleans is located in the eastern half of the DSG load pocket and is very sensitive to local reliability issues. The City is located in a geographical and electrical peninsula bordered by water on the north, east and south. Almost all electrical energy is imported into the City from the west, primarily through East Jefferson Parish via the transmission grid, while a small amount of electric energy is transported through the very limited transmission capability from the Slidell area over the open waters of Lake Pontchartrain. Thus, the flow of energy into the City is heavily biased towards a west to east flow pattern.

The existing transmission facilities serving the City traverse a limited set of viable transmission corridors across wetlands and generally poor soil conditions through an area heavily congested with industrial, commercial, and residential
structures. In other words, without a local source of energy, such as the proposed NOPS, the City in general, and New Orleans East in particular, is entirely dependent on the set of existing transmission lines situated in a relatively small geographical area. Because of this lack of geographic diversity, it can reasonably be expected that all lines, save perhaps the single line from Slidell, would be vulnerable to similar outages and operational challenges.

In fact, without a local resource, the loss of even a portion of these transmission facilities delivering energy from the west into the City would likely prevent the Company from serving its entire load. Moreover, it should be noted that the loss of even one line for an extended period of time could result in significant separations\(^2\) of market energy prices in MISO, which is not uncommon since the retirement of the Michoud resources. These price separations are often precursors to reliability issues,\(^3\) but all of these concerns can be significantly reduced with the addition of a local resource. By way of analogy, in order to ensure a reliable supply of water, ancient cities preferred to have a local source of fresh water as opposed to relying on aqueducts or other methods to transport water into the city because it was

\(^2\) These price separations are the result of congestion on the transmission system. Congestion occurs when the flow of large amounts of power on the electric system result in transmission constraints, which in turn create higher Locational Marginal Prices (“LMPs”) on the downstream side of the constraint and lower LMPs on the upstream-side of the constraints. This price separation in the energy market is designed to incentivize generators on the downstream side of the constraint to dispatch up (in order to take advantage of the higher LMP) and generators in the upstream side to dispatch down (with the lower LMP inducing these resources to generate less) in a self-correcting action to mitigate the constraint.

\(^3\) These reliability constraints can be observed operationally when there are not sufficient resources to re-dispatch to mitigate the constraints in the system, no matter how large the price separation in the energy market. Typically, there is a corresponding NERC TPL reliability violation that can be observed in the long-term transmission planning process as well.
within their control and thus reduced their vulnerability to events beyond their control.

Moreover, within a load pocket, over-reliance on transmission to meet demand also diminishes operational flexibility. For example, if the Company needs to take a planned outage of a transmission element, scheduling such an outage would be extremely difficult in an environment where nearly all transmission elements are loaded near capacity. This creates an inflexible operational environment where there are no operational margins to perform necessary maintenance on the transmission grid or the generating resources interconnected to the transmission network. A generator sited locally will have the effect of creating operational flexibility by easing the loading on transmission elements and making it easier to keep the grid reliable during both planned and unplanned outages of transmission elements and generating resources.

Q9. PLEASE PROVIDE SOME SPECIFIC OPERATIONAL EXAMPLES OF RELIABILITY ISSUES THAT WOULD HAVE BEEN MITIGATED BY THE PRESENCE OF A GAS-FIRED GENERATOR AT THE MICHOUD FACILITY.

A. As mentioned above, one example of the consequences of ENO not having a local generator is that the DSG load pocket is more dependent on the transmission network to serve the Company’s electric load. The large flows of power on the transmission system often lead to stressed operational conditions, resulting in the rejection of outage requests needed for maintenance and construction. In the first half of this year alone, outages involving a 115 kV transmission segment, a 230/115 kV auto-
transformer, five 230 kV transmission lines and two 500 kV transmission lines were denied because of reliability constraints that could not be mitigated without risking electric service to the Company’s customers. Simply put, having a local generator will reduce the stress on heavily loaded transmission lines when necessary, which could mitigate the cancellations of maintenance and construction outages, without which critical equipment may be put at risk, potentially increasing cost to customers.

Another example of severe operational constraints that result from a scarcity of generation capacity is the occurrence of load-at-risk alerts and maximum generation events. Local generation shortfalls that occur operationally are monitored using the Entergy Load Risk Alert Levels (“ELRAL”) protocol of four alert levels.\(^4\)

Since the retirements of the Michoud resources, the operational generation shortages have resulted in six ELRAL Level 1 issuances for DSG, six ELRAL Level 1 issuances for Amite South (two of these ELRAL declarations being for both Amite South and DSG), fourteen ELRAL Level 1 issuances for the MISO-wide system, and one ELRAL Level 2 event for the MISO region. Each of the ELRAL level 1 notices implies that a scarcity of generation has resulted in the possibility that there may be loss of load in the DSG and/or Amite South load pocket. The ELRAL Level 2 did

\(^4\) ELRAL Level 0: Normal operation with no current risk to customer load.

ELRAL Level 1: Entergy foresees or is experiencing conditions where in the event of multiple contingencies, customer load in the affected area(s) may be at risk. All available resources are being utilized to meet customer load in the affected area(s).

ELRAL Level 2: Entergy foresees or is experiencing conditions where in the event of a single contingency, customer load in the affected area(s) may be at risk. Entergy foresees or has implemented interruption of Non-Firm Load in the affected area(s).

ELRAL Level 3: Entergy foresees or has implemented interruption of Firm Load in the affected area(s).
result in the curtailment of non-firm load in south Louisiana, including in New Orleans.

Local generation in the New Orleans area would certainly reduce the stresses to the transmission system that result in the types of operational issues mentioned above. Moreover, it should also be noted that many of the existing generators in the region are older, less efficient units that face the risk of deactivation, as described by Company witness Seth E. Cureington in his Supplemental Direct Testimony. Over time, as aging resources in Amite South, DSG, and elsewhere in the system deactivate, such operational issues and load-at-risk alerts will likely increase in frequency and severity. The certainty of power generated from a resource such as the NOPS will help minimize operational constraints such as the ones listed above, will help avoid long-term NERC TPL reliability standard violations, and would help support future load growth in the New Orleans area.

III. RELIABILITY ANALYSIS RESULTS

Q10. HAS THE COMPANY UPDATED ITS LONG-TERM RELIABILITY ANALYSIS TO ACCOUNT FOR THE UPDATED LOAD FORECAST?

A. Yes. Using the most recent load forecast available, the Company has performed a reliability assessment to determine the long-term reliability of the transmission network under various scenarios. The results of this analysis are as follows:

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5 Please see Exhibit CWL-6, attached hereto, for a summary of ENO’s Reliability Analyses.
“No NOPS” Scenario

By 2019, if NOPS is not constructed, several 230 kV and 115 kV lines in DSG would overload without additional transmission investment. In addition, a Category P6\(^6\) contingency event would result in severe overloads of several 115 kV lines in the DSG area, leading to uncontrollable cascading outages of up to six 115 kV transmission branches. Consequently, a voltage collapse and load shed event in the ENO transmission network would result from the severe reactive power deficit due to the loss of the transmission branches and reactive power support in the ENO transmission grid. Also in 2019, a breaker failure contingency at the Ninemile 230 kV substation was observed to result in three 230 kV transmission line overloads and one 115 kV transmission line overload.

In the 2022 study year, a breaker failure at the Ninemile 230 kV substation was observed to result in two 230 kV transmission line overloads. In addition, a category P6 contingency in the ENO transmission grid results in the cascading outages of five 115 kV transmission branches in the ENO transmission network resulting in a voltage collapse and wide-spread load shedding in the New Orleans area.

---

\(^6\) A P6 event is the loss of a transmission facility followed by system adjustments, followed by the loss of an additional transmission facility. P6 simulates operational conditions that would occur during a planned (maintenance outage) or unplanned outage to a transmission facility followed by an unplanned outage to an additional transmission element.
In the 2024 study year, the breaker failure at the Ninemile 230 kV substation results in two 230 kV transmission line overloads. The category P6 contingency results in the cascading outages of five 115 kV transmission branches in the ENO transmission network resulting in a voltage collapse and wide-spread load shedding in the New Orleans area.

In the 2027 study year, besides the two 230 kV overloads resulting from the 230 kV breaker failure at the Ninemile substation that were observed in the 2024 study year, an additional 230 kV transmission line is loaded to its rated capacity as a result of the same contingency. Additionally, the category P6 contingency results in the cascading outages of seven 115 kV branches in the ENO transmission system, resulting in widespread load loss and a voltage collapse. In order to mitigate the constraints observed in the system in the 2019, 2022, 2024, and 2027 study years in the absence of any incremental generation, the following transmission upgrades would have to be constructed:

---

7 Transmission upgrades in the Company’s current long-term transmission plan, in particular, due to the planned transmission upgrades associated with the Target Appendix A MTEP17 Jefferson Parish Area Reliability Plan project allow for fewer overloads resulting from the failure of the 230 kV breaker at Ninemile in the 2022 study year, compared to the 2019 study year.
Table 1: “No NOPS” Transmission Upgrades

<table>
<thead>
<tr>
<th>Project</th>
<th>Voltage</th>
<th>Total Project Cost</th>
<th>Need-by Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avenue C to Pauger Line Upgrade</td>
<td>115kV</td>
<td>$21,050,000</td>
<td>Summer 2021</td>
</tr>
<tr>
<td>Chalmette to Patterson Line Upgrade</td>
<td>115kV</td>
<td>$12,979,000</td>
<td>Summer 2021</td>
</tr>
<tr>
<td>Michoud to Curran Line Upgrade</td>
<td>230kV</td>
<td>$100,000</td>
<td>Summer 2027</td>
</tr>
<tr>
<td>Almonaster to Curran Line Upgrade</td>
<td>230kV</td>
<td>$18,050,000</td>
<td>Summer 2021</td>
</tr>
<tr>
<td>Southport to Joliet Line Upgrade</td>
<td>230kV</td>
<td>$5,125,000</td>
<td>Summer 2021</td>
</tr>
</tbody>
</table>

“110 MW generator” Scenario

The results of the reliability analysis of the transmission system assuming a 110 MW generator at Michoud, which is a good proxy for the Alternative Peaker, indicated that no transmission constraints would be expected in the system in the 2022 and 2024 study years. On the other hand, in the 2027 study year, a 230 kV breaker failure at Ninemile would result in two 230 kV transmission lines overloading. Notably, the 110 MW resource would be effective in mitigating the transmission constraints resulting from the category P6 contingency mentioned above, thus preventing the cascading outages and potential loss of load for ENO customers. Moreover, because the overloading in 2027 is relatively marginal and occurs approximately ten years in the future, the Company would propose to wait to determine if any transmission upgrades are necessary once NOPS is constructed. However, if it is decided that a transmission project should be constructed in order to
mitigate the constraints observed in the system in the 2027 study year, the following transmission upgrades are currently estimated to be required:

**Table 2: “110 MW Scenario” Transmission Upgrades**

<table>
<thead>
<tr>
<th>Project</th>
<th>Voltage</th>
<th>Total Project Cost</th>
<th>Need-by Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Almonaster to Curran Line Upgrade</td>
<td>230kV</td>
<td>$18,050,000</td>
<td>Summer 2027</td>
</tr>
<tr>
<td>Southport to Joliet Line Upgrade</td>
<td>230kV</td>
<td>$5,125,000</td>
<td>Summer 2027</td>
</tr>
</tbody>
</table>

**“226 MW” Scenario**

The results of the reliability assessment conducted with the assumption that the 226 MW NOPS resource will be interconnected to the grid in June 2019 and at the proposed capacity show that none of the constraints mentioned above in the 2019, 2022, 2024, or the 2027 study years were observed. Therefore, no upgrades would be required if NOPS were to interconnect to the transmission grid at Michoud as scheduled and at a capacity of 226 MW. The 226 MW NOPS resource is also effective in mitigating the transmission constraints resulting from the category P6 contingency that was observed in the “No NOPS” scenario mentioned above, thus preventing the cascading outages and potential loss of load for ENO customers.

---

8 Transmission upgrades, planning level cost estimates for these upgrades, and the required in-service dates for the mitigation of reliability constraints resulting from a 110 MW generator interconnected at Michoud.
Q11. PLEASE SUMMARIZE THE RESULTS AND TAKEAWAYS FROM ENO’S RELIABILITY ANALYSES.

A. The analyses show that if the Company does not add any locally-sited generation in the ENO area in the near future, the Company will be required to plan, fund, and construct transmission upgrades to comply with NERC reliability standards in order to maintain the reliability of the grid and to mitigate the potential risk of cascading outages. Adding a unit with an output of 226 MW will eliminate all grid reliability issues within the current 10-year planning horizon. It should also be noted that the Company’s analysis showed that a 170 MW generator would also eliminate all reliability issues within the planning horizon.

On the other hand, constructing the 110 MW, which is an adequate proxy for the Alternative Peaker, will eliminate the cascading outages, but not address all constraints in all years, thus indicating that additional transmission investment may be needed. However, because the overloads under the 110 MW Alternative Peaker scenario do not occur until 2027 and are relatively minor, the Company will wait to see whether it should move forward with the construction of the identified transmission upgrades.

Q12. WAS THE LATEST UPDATED LOAD FORECAST USED IN ENO’S RELIABILITY ANALYSIS?

A. Yes. The load forecast used to create ENO’s reliability analysis described herein is ENO’s current load forecast.
Q13. DID THE 2016 OR 2017 MISO TRANSMISSION EXPANSION PLAN ("MTEP") REPORTS IDENTIFY THE PROJECTS LISTED ABOVE THAT WOULD BE NECESSARY ABSENT NOPS?

A. MISO’s reliability transmission planning process calls for transmission solutions to be identified for category P6 contingencies only if the consequent load-shed is greater than 1,000 MW. In this case, MISO’s 1,000 MW trigger point would not result in a MISO identified project until approximately 90% of ENO’s load was at risk. While this level of risk may be acceptable to larger utilities in the MISO footprint, the Company believes that this level of risk is unacceptably high for our customers in New Orleans. Thus, while MISO’s transmission planning criteria do not result in the identification of these projects, the Company will enter these projects into a future MTEP process and submit them to MISO for their consideration, should NOPS not be constructed.

Moreover, it should also be noted that MISO identified the failure of the circuit breaker at the Ninemile 230 kV switchyard (mentioned in the results of the reliability assessment in the response to Q 10) as a critical contingency during the generator retirement Attachment Y reliability assessment for Michoud Unit 3. The Company worked with ELL and MISO to develop an operating procedure that ensured that this circuit breaker could be operated open whenever the breaker failure event could be expected to produce reliability constraints on the system. Operating

---

9 The Company implemented the breaker failure logic in the real-time state estimator such that the logic instructs system operators to open the circuit breaker if the simulated circuit breaker failure contingency results in overloads in the system.
the circuit breaker in the open position ensures that the circuit breaker cannot fail
while responding to a short-circuit in the system, thus preventing additional circuit
breakers electrically adjacent to the failed circuit breaker from having to operate to
isolate the fault. This in turn prevents the disconnection of more transmission lines
and more system overloads. However, such procedures to operate circuit breakers in
the open position are always a temporary mode of operation until a long-term remedy
can be put into place (in this case, NOPS and the additional transmission upgrades
already included in the Company’s long-term transmission plan). The
implementation of this operating procedure allowed the Company to deactivate the
Michoud 3 resource while also safeguarding the security of the transmission grid until
a long-term mitigating measure (ideally, the construction of the originally proposed
226 MW CT in New Orleans) can be placed into service..

Since the implementation of the operating procedure to operate the circuit
breaker at Ninemile in the open position, MISO has considered this breaker to be
open in the reliability assessments that are part of the MTEP process. Therefore,
MISO has not identified the constraints resulting from the breaker failure at Ninemile
mentioned in my response above. On the other hand, the Company considers this
operating procedure to be temporary in nature, to be used only until the
implementation of the long-term solution.
Q14. ARE THE TRANSMISSION UPGRADES IDENTIFIED ABOVE AN EFFECTIVE ALTERNATIVE TO LOCAL GENERATION?

A. No. A key function of the transmission grid is to enable the transportation of large amounts of power from resources to load and/or between different regions of the electric grid. While the transmission system is instrumental in facilitating the movement of electric power, it cannot produce electrical energy, capacity, or much needed dynamic reactive power in the DSG load pocket.

Thus, additional transmission upgrades aimed at increasing the import capability may not have that effect unless there is also excess long-term generating capacity outside of DSG. As discussed more fully in the Direct Testimony of Mr. Cureington, System Planning and Operations (“SPO”) forecasts that market equilibrium in the MISO South region (the point at which supply, including third-party resources, and demand, including appropriate planning reserves, are in balance) will occur around 2022. This means that even if the Company were to invest in constructing transmission with the intention of importing power into the ENO footprint, it is possible there would be no excess capacity available to import on a long-term basis. Therefore, relying on transmission investment could lead the Company into a position of lacking required capacity at a time when the market has no meaningful excess supply elsewhere in MISO.

Secondly, as stated in my Direct Testimony, there are significant constructability issues in the New Orleans area with respect to transmission. I have considerable experience with planning and constructing transmission in the New Orleans area, including assisting in the restoration of the storm-damaged transmission
system in the greater New Orleans area. In my experience, the soil conditions, obstructions, and environmental challenges tend to increase the cost of construction substantially and necessitate expensive wetlands damage mitigation following the construction of a transmission line. There are also rights-of-way issues, as well as many above-ground obstructions and below-ground infrastructure (such as pipelines) which make it very difficult to construct transmission facilities. NOPS, on the other hand, can be constructed on a small footprint and on land the Company already owns.

The Company has not conducted detailed planning-level cost estimates for the transmission upgrades identified above because these upgrades will not be necessary if the 226 MW NOPS option is constructed, and because the Company would propose to defer the decision on possible upgrades if the Alternative Peaker is selected.

However, if the Company were ordered to build transmission in lieu of NOPS, it is quite possible that those estimates would increase due to the complications mentioned above, and in my Direct Testimony.

Moreover, transmission upgrades will not add local generation to an area in need of such generation (i.e., transmission upgrades will not replace aging local generation, provide reactive power benefits, black-start capability, or storm support).
Q15. WILL THE SOUTHEAST LOUISIANA TRANSMISSION PROJECT\textsuperscript{10} ADDRESS THE RELIABILITY ISSUES IDENTIFIED?

A. This project was included in the study models utilized in the Company’s transmission analysis, which led to the identification of the projects needed for the mitigation of NERC reliability standard violations absent the NOPS. Thus, all reliability benefits for that project are captured in the analyses. This project is designed to eliminate constraints in western DSG and allow for more power to be imported into DSG. It will not solve reliability issues in the eastern end of DSG, including the critical category P6 contingency, which will be mitigated by NOPS. By way of analogy, adding additional traffic lanes on Interstate 10 between LaPlace and Kenner will not ease traffic concerns in downtown New Orleans.

Q16. HAS THE COMPANY CONDUCTED A RELIABILITY ANALYSIS USING THE ASSUMPTIONS REQUESTED BY THE COUNCIL’S ADVISORS?

A. Yes. The Company conducted a reliability analysis using the following assumptions based on recommendations sent to ENO by the Council’s Advisors:

- **Requested Case A**: load flow study assuming no generation additions at the Michoud site (see above in Q10, the “No NOPS” Scenario);

- **Requested Case B1**: load flow study assuming Resource Portfolio A includes the updated load forecast, 100 MW solar facility (assumed to be able to output at 35% of the maximum capacity at the summer peak hour),

\textsuperscript{10} The Southeast Louisiana Economic Transmission project was recommended for approval by the MISO Planning staff during the MTEP 16 economic transmission planning study process and was approved by the MISO Board of Directors as an Appendix A MTEP16 project on December 6, 2016. Details of the project can be found on slide 9 of this August 25, 2016, Economic Planning Users Group presentation: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2016/20160825/20160825%20EPUG%20Item%2003%20Project%20Recommendation.pdf
accounting for the Council’s 2% DSM goal\(^\text{11}\), and the Resource Portfolio, composed of a 226 MW G-Frame combustion turbine;

- **Requested Case B2**: load flow study assuming Resource Portfolio A includes the updated load forecast, 200 MW solar facility (assumed to be able to output at 35% of the maximum capacity at the summer peak hour), accounting for the Council’s 2% DSM goal;

- **Requested Case C**: load flow study assuming Resource Portfolio B includes the updated load forecast, 100 MW solar facility (assumed to be able to output at 35% of the maximum capacity at the summer peak hour), 2% DSM, and a ~128 MW generator consisting of seven peaking units; and

- **Requested Case D**: load flow study assuming ENO’s original proposal, a 226 MW CT (See above in Q10, “226 MW” Scenario).

At the outset, it should be stated that with respect to Advisor Cases B and C, the NERC standards do not address the modeling of solar or DSM resources in the context of long-term reliability planning. The Company notes that DSM load reductions are speculative in nature (i.e., capital expenditures on DSM do not guarantee load reductions) and therefore the inclusion of such load reductions in a reliability analysis does not ensure that the Company will remain compliant with NERC Reliability Standards if the reductions do not actually materialize. Inclusion of speculative load reductions is not consistent with the conservative approach that has been preferred for long-term reliability planning related to the ENO transmission system.

Similarly, the Company has included solar resources (discounted to 35% in the analysis, which represents an assumption regarding its on-peak output) in

\(^{11}\) The Council’s 2% DSM goal involves the development of Energy Smart Program years for Year 7 and beyond with a goal of increasing the projected savings from the Energy Smart program by 0.2% per year, until such time as the program generates energy savings at a rate equal to 2% of annual energy sales of the Company.
Requested Cases B and C, but solar generation is an intermittent resource and its output cannot be called upon to mitigate reliability constraints with any degree of certainty. Moreover, the Company assumed in its analyses of the Requested scenarios that the solar generation will all be interconnected strategically at the most favorable location for the mitigation of reliability constraints on the transmission system in and around DSG (i.e., the New Orleans East area). For example, the Company selected a portfolio of three resources in its recent Renewables RFP, totaling 45 MW. The first resource selected is a 20 MW solar facility located in New Orleans East; the second is a 5 MW project that will be spread across the New Orleans area; and the third is a 20 MW PPA with a resource that is remote from DSG and Amite South. This evidences the fact that it is unlikely that a significant portion of ENO’s solar portfolio will be located in New Orleans East due to cost and space issues, as explained by Mr. Cureington, and this uncertainty further complicates the issue of how to treat solar resources in NERC reliability planning. Thus the reliability benefits of solar resources are likely significantly overstated in the analysis.

While the inclusion of intermittent resources and speculative DSM may be informative from an economic perspective, reliability planning should be predicated on what can reasonably be counted on to reliably serve ENO system loads. Since the Company cannot know with a reasonable degree of certainty when these resources will be available and where they will be located, reliance on these uncertain resources for the purposes of meeting reliability criteria creates risks for customers. Notwithstanding these concerns the Company has included the assumptions in
Requested Cases B1, B2, and C, and the results are as follows (See Q10 for Requested Cases A and D):

**Requested Case B1**

The results of the reliability assessment conducted for the Requested Case B1 indicates that while several reliability constraints are observed in the early study years of the assessments, planned transmission projects that are expected to be in-service by 2020 mitigate these constraints. \(^{12}\) As a result of these transmission projects and the resources contemplated in Case B1, the latter study years of the Company’s assessment of Requested Case B1 showed no constraints on the system. In the 2019\(^{13}\) study year, a breaker failure at the Ninemile 230 kV substation was observed to result in two 230 kV transmission line overloads. In addition, a category P6 contingency in the ENO transmission grid results in no risk of cascading outages or a voltage collapse. In the 2024 and 2027 study years, no constraints were observed in the system that resulted from either the breaker failure or the category P6 contingency.

**Requested Case B2**

The results of the reliability assessment conducted for the Requested Case B2 indicate that several 230 kV and 115 kV lines in DSG would overload in the near-

---

\(^{12}\) Transmission upgrades in the Company’s current long-term transmission plan, in particular, the Target Appendix A MTEP17 Jefferson Parish Area Reliability Plan project, allow for the mitigation of the overloads resulting from the failure of the 230 kV breaker at Ninemile in the 2024 study year.

\(^{13}\) It should be noted that neither the CT nor the Alternative Peaker would be in service by the summer peak in 2019.
term planning horizon without additional transmission investment. Transmission upgrades currently in the Company’s long-term transmission plan then help to mitigate these constraints, but a subset of these constraints re-appears towards the end of the 10-year planning horizon under the assumptions incorporated into Requested Case B2.

In the 2019 study year, a breaker failure at the Ninemile 230 kV substation was observed to result in three 230 kV transmission line overloads and one 115 kV transmission line overload. In addition, a category P6 contingency in the ENO transmission grid results in the cascading outages of six 115 kV transmission branches in the ENO transmission network resulting in a voltage collapse and widespread load shedding in the New Orleans area.

In the 2024 study year, planned transmission upgrades result in no overloads in the transmission system resulting from the breaker failure event; similarly, the category P6 double contingency is not expected to result in cascading outages or severe voltage constraints in New Orleans, but could require some load shedding to mitigate violations.

In the 2027 study year, the 230 kV breaker failure contingency at Ninemile would result in two 230 kV transmission lines to overload. However, the Requested Case B2 scenario is not expected to result in severe transmission constraints following the category P6 contingency mentioned above, thus avoiding the cascading outages and voltage collapse, but could require some load shedding to mitigate violations. Projects required to be constructed in order to mitigate the constraints observed in the system in the 2027 study year are as follows:
Table 3: “Requested Case B2” Transmission Upgrades

<table>
<thead>
<tr>
<th>Project</th>
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<th>Total Project Cost</th>
<th>Need-by Date</th>
</tr>
</thead>
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<td>230kV</td>
<td>$5,125,000</td>
<td>Summer 2027</td>
</tr>
</tbody>
</table>

Requested Case C

The results of the reliability assessment conducted for the Requested Case C indicates that while several reliability constraints are observed in the early study years of the assessments, planned transmission projects that are expected to be in-service by 2020 mitigate these constraints. As a result of these transmission projects and the resources contemplated in Case C, the latter study years of the Company’s assessment of Requested Case C showed no constraints on the system. In the 2019 study year, a breaker failure at the Ninemile 230 kV substation was observed to result in three 230 kV transmission line overloads and one 115 kV transmission line overload. In addition, a category P6 contingency in the ENO transmission grid results in no risk of cascading outages or a voltage collapse. In the 2024 and 2027 study years, no constraints were observed in the system that resulted from either the breaker failure or the category P6 contingency.

Q17. PLEASE SUMMARIZE THE RESULTS OF THE REQUESTED CASES.

A. As stated earlier, with respect to Requested Case A, (the “No NOPS” scenario in Q10), the grid will not remain reliable if no local generation is added and the
Company will need to construct costly transmission upgrades to comply with NERC requirements. Under this scenario, the Company’s service territory would face the risk of cascading outages.

Both Requested Cases B1 and C are reliable in the long-term planning horizon after other transmission projects, which are already in the Company’s long-term transmission plan, are placed into service. Requested Case B2 will require transmission upgrades in order to remain NERC compliant throughout the planning horizon.

Regarding Requested Case D (the “226 MW” scenario in Q10), adding the CT will eliminate all reliability issues within the 10-year planning horizon without the need for additional transmission projects.

Q18. DO YOU CONTEND THAT SOLAR AND DSM HAVE NO RELIABILITY VALUE?

A. No. The effectiveness of solar resources to meet the reliability need in DSG depends largely on the characteristics, point(s) of interconnection, and capacity associated with such resources. Given the intermittent nature of the renewable resources that will be practical in an urban environment like the New Orleans metropolitan area, the amount of dependable power that such resources will be able to produce at the summer and winter peak hours is unknown at this time. In addition, the location of a solar resource will have a significant effect on any reliability benefits that it may produce and ENO does not know where the solar resources assumed in Requested Cases B through C will be located. Thus, while intermittent resources will likely
have some long-term reliability value, it is clear that in this case, such resources do not provide the certainty that a local gas-fired generator under the Company’s control would provide. Thus, while these renewable resources could provide economic and environmental benefits, they cannot offer the reliability benefits of a local gas-fired resource to the Company’s customers.

IV. BENEFITS OF LOCAL GENERATION

Q19. IN YOUR DIRECT TESTIMONY, YOU HIGHLIGHTED THE LOCAL RELIABILITY BENEFITS OF LOCALLY SITED GENERATION. PLEASE REITERATE THOSE BENEFITS IN A SUMMARY MANNER.

A. As explained more fully in my Direct Testimony, siting a new resource at a location that enhances reliability is consistent with the best interest of customers. Reliability is enhanced when that location is in close proximity to the load that the generation resource serves. In sum, constructing NOPS in its proposed location would enhance reliability in the following ways:

- Making the region less dependent on importing power to serve load;
- Reducing transmission usage in the area and thereby allowing for more flexible outage scheduling to facilitate maintenance activities on the system;
- Providing reactive power support to the region; and
- Providing additional operational flexibility during system restorations following major storm events such as hurricanes.

Q20. WOULD THE CONSTRUCTION OF THE ORIGINAL UNIT PROPOSED, THE 226 MW CT, CREATE SIGNIFICANT RELIABILITY BENEFITS?
A. Yes. The CT originally proposed would have more benefits than a unit with a lower output in the following ways:

- **Operational Flexibility**: a larger unit would result in less dependence on transmission assets to import power. This reduced dependence on the electric grid to serve the Company’s loads resulting from lower levels of power flows on the transmission lines and transformers makes it easier to schedule planned outages for maintenance of transmission facilities or generators in the area.

- **Reactive Capability**: The reactive capability of a machine defines its ability to regulate the flow of reactive power to the electric network in order to support voltages in the area and maintain a transmission network stiff enough to support the large starting currents required to switch on large industrial motors. Generators are particularly useful because they can increase or reduce the reactive injection into the power system quickly and respond to sudden system changes in the grid, such as the loss of another generator or transmission asset such as a line, a transformer, or a capacitor bank. Thus, increasing the reactive capability of a generator increases the reliability of the surrounding transmission system and enhances its ability to appropriately respond to system disturbances. The 226 MW CT would provide about 50% more reactive power than the Alternative Peaker.

- **Economic Development**: A larger NOPS resource is well positioned to support future economic development in ENO. The Company reviewed at least seven independent requests for block load additions in the New Orleans area in 2016. Requests varied in scope, but some requests were as large as 40
MW for a single project. A larger resource in close proximity to a potential load interconnection reduces the likelihood that commercial/industrial growth in New Orleans will be inhibited by transmission expenses associated with delivering power from more remote resources to these loads.

- **Transmission Capability**: The CT would reduce the need to import power into New Orleans. One MW produced at NOPS will not only reduce the DSG interface flows by a little more than one MW (to account for losses in the transmission system resulting from the flow of the imported power), but will also reduce the need for imports into New Orleans via the key transmission river crossings over the Mississippi river. Once the power flow through these river-crossing transmission lines reaches the rated capacity of these lines, increasing the import capability into ENO will likely require the construction of a new river-crossing transmission line as the existing transmission lines crossings the river share the same tower, which makes scheduling outages to both lines in order to carry out construction work very difficult to obtain. If the proposed 226 MW NOPS interconnects at the Michoud facility, these river-crossing transmission lines are not anticipated to limit the import capability into the ENO area for at least 10 years.

**Q21.** **WOULD THE ALTERNATIVE PEAKER STILL PROVIDE SOME OF THE BENEFITS OFFERED BY THE ORIGINALLY PROPOSED CT?**

**A.** Yes. The Alternative Peaker will provide all of the aforementioned reliability benefits, albeit to a lesser degree because its output is 100 MW lower than the
original 226 MW NOPS CT. However, as stated above, the Alternative Peaker will likely satisfy NERC reliability requirements for the planning term. Additionally, it should be noted that the Alternative Peaker also includes black-start capability, which could enable it to be even more beneficial in the event of wide-spread transmission system outages during a major storm.

Q22. PLEASE ELABORATE ON THE CURRENT BLACK-START PLAN AND HOW THE ALTERNATIVE PEAKER’S BLACK-START CAPABILITY COULD BENEFIT THE CITY OF NEW ORLEANS.

A. The Company’s current black-start plan involves the commencement of the restoration of power from the Waterford Unit 4 black-start resource, which can then be used to energize a cranking path to the Waterford 1 or Waterford 2 resource. Power from the Waterford natural gas-fired resources can then be used to continue the restoration of power by energizing the Waterford – Ninemile transmission corridor. If necessary or possible, the Ninemile Units 4 or 5 can be started with the restoration of power in the Ninemile switchyard. The restoration of electric supply can then continue along the Ninemile – Derbigny – Tricou – Arabi – Michoud transmission path to bring power into the city.

While this black-start procedure is certainly robust and sufficient to provide power to the Company’s customers if a complete loss of electric power supply were to occur, the plan still relies upon the transmission grid to import power into the ENO footprint from Ninemile. Any damage to the transmission grid, either from the Ninemile facility into the city or from the Waterford facility towards Ninemile would
impair the Company’s ability to provide electric service to ENO customers if a complete loss of electric power supply were to occur. On the other hand, the ability of the Alternative Peaker to black-start greatly reduces ENO’s dependence on the transmission grid for restoring electric service to customers. Provided that the distribution system is sufficiently robust to serve load, the ability to black-start the Alternative Peaker enables the Company to restore power to loads from this resource, which will be in close electrical proximity to the electric demand, enabling much more effective voltage and frequency response during the black-start process. Thus, the Alternative Peaker’s ability to black-start will greatly enhance the Company’s ability to restore electric service, should a complete loss of service on the electric system occur.

Q23. PLEASE PROVIDE AN UPDATE REGARDING THE COMPANY’S CURRENT PLAN TO RECEIVE NETWORK RESOURCES INTERCONNECTION SERVICE (“NRIS”) FOR THE ALTERNATIVE PEAKER.

A. The Company has reduced the amount of Network Resource Interconnection Service (“NRIS”) requested in the MISO generator interconnection process to reflect the Alternative Peaker. The Company’s interconnection request is part of the pool of resources submitted for evaluation in the August 2016 DPP cycle and which is now in Phase II of a possible three Phases. The Company has received assurances from MISO that this substitution in resources does not produce an impact to the system that is more adverse than the original interconnection request, i.e., the impact on the transmission system estimated for the Alternative Peaker is either equal to or less than
that resulting from the original 226 MW interconnection request. This means that the
Company’s interconnection request can proceed through the interconnection process
without having to re-study any of the prior deliverability assessments performed in
Phase I of the August 2016 DPP process.

Q24. DOES THIS CONCLUDE YOUR SUPPLEMENTAL DIRECT TESTIMONY?
A. Yes, at this time.
AFFIDAVIT

STATE OF MISSISSIPPI

COUNTY OF Hinds

NOW BEFORE ME, the undersigned authority, personally came and appeared, CHARLES W. LONG, 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.

[Signature]
Charles W. Long

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 15th DAY OF JUNE, 2017

[Signature]
Aletta B. Walker
NOTARY PUBLIC

My commission expires: 4/22/20
Results of ENO’s Transmission Analysis and Advisor Requested Analysis

July, 2017
ENO’s Updated Transmission Analysis

Thermal and voltage reliability violations that were observed on the transmission system for the following scenarios are provided in the following slides for the 2019-2027 time horizon:

- No NOPS resource
- NOPS modeled at 110 MW (approximately the capacity of the seven Wärtsilä 18V50SG Reciprocating Internal Combustion Engine generator sets)
- NOPS modeled at 226 MW (approximately the capacity of the G-frame combustion turbine-generator)

• All of the above analyses assumes a 350 MW resource (comprising of two CTs) at the Washington Parish Energy Center* at Bogalusa.

• All MTEP16 Appendix A and MTEP17 target Appendix A transmission projects in the study region were included in these analyses.

Updated load forecasts were incorporated into this transmission reliability assessment.

* This resource is included in the Entergy Operating Companies’ long-term resource plan
Results of reliability analysis

No NOPS resource

The following reliability constraints are observed in the absence of any generator at the Michoud substation:

- A contingency involving the failure of a breaker to clear a short-circuit results in overloaded transmission lines in the two regions encircled in red in the map.

- The overloads range from approx. 121% in 2019\(^1\) to 102% in 2022 and rise in magnitude to approx. 109% in 2027.

- These constraints necessitate the upgrades of approx. 18.1 miles of transmission lines in the New Orleans area.

\[\text{Legend:} \quad \text{Geographical extent of reliability constraints resulting from the breaker failure contingency}\]

\(^1\text{Planned transmission upgrades help reduce the overload in 2022.}\]
The following reliability constraints are observed in the absence of any generator at the Michoud substation:

- Two sequential outages (a category P6 NERC contingency) results in a severely overloaded transmission line (shown in the region encircled in red).

- Zone 3 tripping of this line results in similar severely overloaded lines (shown in yellow) which eventually result in cascading outages and rapid load shedding in the region shown in orange.

These constraints necessitate the upgrades of approx. 18 miles of transmission lines in the New Orleans area.

- Scheduling outages for construction work is becoming increasingly difficult in the New Orleans area.
Results of reliability analysis

No NOPS resource

The following transmission upgrades are required to be constructed in the absence of any generator at the Michoud substation:

<table>
<thead>
<tr>
<th>Project</th>
<th>Voltage</th>
<th>Total Project Cost</th>
<th>Need-by Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avenue C to Pauger Line Upgrade</td>
<td>115kV</td>
<td>$21,050,000</td>
<td>Summer 2021</td>
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<tr>
<td>Chalmette to Patterson Line Upgrade</td>
<td>115kV</td>
<td>$12,979,000</td>
<td>Summer 2021</td>
</tr>
<tr>
<td>Michoud to Curran  Line Upgrade</td>
<td>230kV</td>
<td>$100,000</td>
<td>Summer 2027</td>
</tr>
<tr>
<td>Almonaster to Curran  Line Upgrade</td>
<td>230kV</td>
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<td>Summer 2021</td>
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<td>Southport to Joliet  Line Upgrade</td>
<td>230kV</td>
<td>$5,125,000</td>
<td>Summer 2021</td>
</tr>
</tbody>
</table>
The following reliability constraints are observed if a 110 MW generator were to interconnect at the Michoud substation:

- A contingency involving the failure of a breaker to clear a short-circuit results in overloaded transmission lines in the two regions encircled in red in the map.
- The overloads are approx. 102% in 2027.
- These constraints necessitate the upgrades of approx. 11.5 miles of transmission lines in the New Orleans area.
- Scheduling outages for construction work is becoming increasingly difficult in the New Orleans area.

Geographical extent of reliability constraints resulting from the breaker failure contingency

Legend:

- \[\text{Exhibit CWL-6}\]
- \[\text{CNO Docket No. UD-16-02}\]
- \[\text{Page 6 of 17}\]
Results of reliability analysis

110 MW NOPS resource

The following reliability constraints are observed in the absence of any generator at the Michoud substation:

- Two sequential outages (a category P6 NERC contingency) no longer results in any overloads in the New Orleans area.

- While a 110 MW resource at Michoud will still requires upgrades to the system resulting from the breaker failure, this resource option is effective in preventing cascading outages in the New Orleans area.
Results of reliability analysis

110 MW NOPS resource

The following transmission upgrades are required to be constructed if a 110 MW generator were to be interconnected at Michoud:

<table>
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</tr>
</tbody>
</table>
Results of reliability analysis

226 MW NOPS resource

If a 226 MW generator were to interconnect at the Michoud substation:

• None of the constraints mentioned above in the 2022, 2024, or the 2027 study years were observed

• No upgrades would be required if NOPS were to interconnect to the transmission grid at Michoud as scheduled
Advisor Requested Cases

Thermal and voltage reliability violations that were observed on the transmission system for the following scenarios are provided in the following slides for the 2019-2027 time horizon:

- Requested Case B1 (100 MW solar resource, the Council’s 2% DSM goal$^1$ plus the 226 MW G-Frame CT)
- Requested Case B2 (100 MW solar resource, the Council’s 2% DSM plus an additional 100 MW solar resource)
- Requested Case C (100 MW solar resource, the Council’s 2% DSM goal plus a 128 MW resource which represents seven Wärtsilä 18V50SG Reciprocating Internal Combustion Engine generator sets)

- All of the above analyses assumes a 350 MW resource (comprising of two CTs) at the Washington Parish Energy Center* at Bogalusa.

All MTEP16 Appendix A and MTEP17 target Appendix A transmission projects in the study region were included in these analyses.

Updated load forecasts were incorporated into this transmission reliability assessment.

---

$^1$The Council’s 2% DSM goal involves the development of Energy Smart Program years by 0.2% per year, until the program generates energy savings at a rate equal to 2% of annual energy sales of the Company.

* This resource is included in the Entergy Operating Companies’ long-term resource plan.
Results of reliability analysis

Requested Case B1

The following reliability constraints are observed in 2019 if the Requested Case B1 were implemented:

• A contingency involving the failure of a breaker to clear a short-circuit results in overloaded transmission lines in the three regions encircled in red in the map.

• The worst overload is approx. 108% in 2019 for a 230 kV transmission line.

• The two sequential outages (a category P6 NERC contingency) do not result in a risk of cascading outages, though load may potentially have to be curtailment under this double contingency scenario.
Results of reliability analysis

Requested Case B1

- However, planned transmission upgrades that are expected to be in-service by 2020 will help to reduce the loading on the transmission system beyond 2020.

- As a result, no transmission constraints are observed in the transmission system, from either the breaker failure contingency or the category P6 contingency, beyond 2020 if Requested Case B1 were to be implemented.

- Therefore, no transmission upgrades are necessary if Requested Case B1 were to be implemented.
Requested Case B2

The following reliability constraints are observed in 2019 if the Requested Case B2 were implemented:

- A contingency involving the failure of a breaker to clear a short-circuit results in overloaded transmission lines in the two regions encircled in red in the map.

- The worst overload is approx. 117% in 2019 for a 230 kV transmission line.

- Two sequential outages (a category P6 NERC contingency) results in a severely overloaded transmission line (shown in the region encircled in purple).

- Zone 3 tripping of this line results in similar severely overloaded lines (shown in yellow) which eventually result in cascading outages and rapid load shedding in the region shown in orange.
Results of reliability analysis

Requested Case B2

However, planned transmission upgrades that are expected to be in-service by 2020 help to reduce the loading on the transmission system beyond 2020.

- The two residual constraints that remain in the system after 2020 under the Requested Case B2 is the contingency involving the failure of a breaker to clear a short-circuit results in overloaded transmission lines in the two regions encircled in red in the map.

- The worst overload is approx. 105% in 2027 for a 230 kV transmission line.

Beyond 2020, the Requested Case B2 is also effective in preventing cascading outages in the New Orleans area resulting from the P6 contingency, though there may potentially be a risk of load curtailment under this double contingency scenario.
Results of reliability analysis

Requested Case B2

To mitigate the remaining constraints resulting from the breaker-failure contingency, the following transmission upgrades are required to be constructed if the Requested Case B2 were to be implemented:

<table>
<thead>
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<td>230kV</td>
<td>$5,125,000</td>
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</tbody>
</table>
Results of reliability analysis

Requested Case C

The following reliability constraints are observed in 2019 if the Requested Case C were implemented:

- A contingency involving the failure of a breaker to clear a short-circuit results in overloaded transmission lines in the three regions encircled in red in the map.

- The worst overload is approx. 111% in 2019 for a 230 kV transmission line.

- The two sequential outages (a category P6 NERC contingency) do not result in a risk of cascading outages, though load may potentially have to be curtailment under this double contingency scenario.
Results of reliability analysis

Requested Case C

- However, planned transmission upgrades that are expected to be in-service by 2020 help to reduce the loading on the transmission system beyond 2020.

- As a result, no transmission constraints are observed in the transmission system, from either the breaker failure contingency or the category P6 contingency, beyond 2020 if Requested Case C were to be implemented.

- Therefore, no transmission upgrades are necessary if Requested Case C were to be implemented.
BEFORE THE
COUNCIL FOR THE CITY OF NEW ORLEANS

SUPPLEMENTAL AND AMENDING APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF DOCKET NO. UD-16-02

SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY

OF

BLISS M. HIGGINS

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

JULY 2017
# TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS .............................................................................. 5
   A. Introduction ......................................................................................................................... 5
   B. Qualifications ...................................................................................................................... 5

II. PURPOSE OF TESTIMONY ....................................................................................................... 14

III. NOPS-REQUIRED ENVIRONMENTAL PERMITS .................................................................. 16
   A. Overview of Required Environmental Permits ................................................................. 16
   B. Overview of NOPS Air Quality Permitting ...................................................................... 17

IV. THE PSD PROGRAM AND MAJOR VS. MINOR MODIFICATIONS .................................... 21
   A. Brief Overview of the PSD Program ................................................................................ 21
   B. Major and Minor Modifications ........................................................................................ 23
   C. Air Permitting Review of Minor Modifications ............................................................... 27

V. TYPES OF REGULATED AIR POLLUTANTS......................................................................... 30

VI. NATIONAL AMBIENT AIR QUALITY STANDARDS (“NAAQS”) ........................................ 32
   A. Overview of the NAAQS .................................................................................................. 32
   B. Process for Establishing the NAAQS ............................................................................... 36
   C. Process for Implementing the NAAQS ............................................................................. 39

VII. THE PM$_{2.5}$ NAAQS .......................................................................................................... 42

VIII. CONCERNS RAISED REGARDING PM$_{2.5}$ AND NOPS .................................................. 46
   A. Reliance on the NAAQS to Assure Protection of Public Health ......................................... 46
   B. Consideration of the Michoud Unit Shutdowns .................................................................. 47
   C. Air Quality Modeling of the NOPS Project ....................................................................... 49
<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>BACT</td>
<td>Best Available Control Technology</td>
</tr>
<tr>
<td>CAA</td>
<td>Clean Air Act</td>
</tr>
<tr>
<td>CASAC</td>
<td>Clean Air Scientific Advisory Committee</td>
</tr>
<tr>
<td>CNO</td>
<td>Council of the City of New Orleans</td>
</tr>
<tr>
<td>CO</td>
<td>Carbon monoxide</td>
</tr>
<tr>
<td>CO₂</td>
<td>Carbon dioxide</td>
</tr>
<tr>
<td>CT</td>
<td>Combustion turbine</td>
</tr>
<tr>
<td>CUP</td>
<td>Coastal Use Permit</td>
</tr>
<tr>
<td>ENO</td>
<td>Entergy New Orleans</td>
</tr>
<tr>
<td>EPA</td>
<td>United States Environmental Protection Agency</td>
</tr>
<tr>
<td>GHG</td>
<td>Greenhouse gases</td>
</tr>
<tr>
<td>HAP</td>
<td>Hazardous Air Pollutant</td>
</tr>
<tr>
<td>LDEQ</td>
<td>Louisiana Department of Environmental Quality</td>
</tr>
<tr>
<td>LDNR</td>
<td>Louisiana Department of Natural Resources</td>
</tr>
<tr>
<td>LPDES</td>
<td>Louisiana Pollutant Discharge Elimination System</td>
</tr>
<tr>
<td>LTAP</td>
<td>Louisiana Toxic Air Pollutant</td>
</tr>
<tr>
<td>MACT</td>
<td>Maximum Achievable Control Technology</td>
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<tr>
<td>MSA</td>
<td>Metropolitan Statistical Area</td>
</tr>
<tr>
<td>MW</td>
<td>Megawatt</td>
</tr>
<tr>
<td>NAAQS</td>
<td>National Ambient Air Quality Standard</td>
</tr>
<tr>
<td>NCEA</td>
<td>National Center for Environmental Assessment</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Description</td>
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<tr>
<td>--------------</td>
<td>-------------</td>
</tr>
<tr>
<td>NESHAP</td>
<td>National Emission Standards for Hazardous Air Pollutants</td>
</tr>
<tr>
<td>NOPS</td>
<td>New Orleans Power Station</td>
</tr>
<tr>
<td>NO$_x$</td>
<td>Nitrogen oxides</td>
</tr>
<tr>
<td>NO$_2$</td>
<td>Nitrogen dioxide</td>
</tr>
<tr>
<td>NSPS</td>
<td>New Source Performance Standard</td>
</tr>
<tr>
<td>O$_3$</td>
<td>Ozone</td>
</tr>
<tr>
<td>Pb</td>
<td>Lead</td>
</tr>
<tr>
<td>PM</td>
<td>Particulate Matter</td>
</tr>
<tr>
<td>PM$_{10}$</td>
<td>Particulate matter 10 microns or less in diameter</td>
</tr>
<tr>
<td>PM$_{2.5}$</td>
<td>Particulate matter 2.5 microns or less in diameter</td>
</tr>
<tr>
<td>PSD</td>
<td>Prevention of Significant Deterioration</td>
</tr>
<tr>
<td>RICE</td>
<td>Reciprocating Internal Combustion Engine</td>
</tr>
<tr>
<td>SIL</td>
<td>Significant Impact Level</td>
</tr>
<tr>
<td>SIP</td>
<td>State Implementation Plan</td>
</tr>
<tr>
<td>SO$_2$</td>
<td>Sulfur Dioxide</td>
</tr>
<tr>
<td>SWPPP</td>
<td>Stormwater Pollution Prevention Plan</td>
</tr>
<tr>
<td>USACE</td>
<td>United States Army Corps of Engineers</td>
</tr>
<tr>
<td>VOC</td>
<td>Volatile Organic Compound</td>
</tr>
</tbody>
</table>
I. INTRODUCTION AND QUALIFICATIONS

A. Introduction

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bliss M. Higgins. My business address is 8235 YMCA Plaza Drive, Baton Rouge, Louisiana 70810.

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

A. I am currently employed by Ramboll Environ Holdings (“Ramboll”), an international environmental consultancy. I have been employed by Ramboll or its predecessor, ENVIRON International Corporation, since June 2002. I am a Principal of the firm and I work as an environmental consultant, primarily in the areas of environmental permitting and regulatory compliance.

B. Qualifications

Q3. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. My formal education was 100% Louisiana. I attended public elementary schools in New Orleans, and later in St. Tammany Parish, then graduated Valedictorian from a parochial high school in Covington. I then attended undergraduate school and graduate school at Louisiana State University (“LSU”) in Baton Rouge. I have a B.S. in Professional Geology from LSU. I subsequently attended graduate school in Geology, until leaving school to become a full-time mother with my first child, and later attended additional
graduate-level chemistry and biochemistry courses as a non-matriculating student while working full-time at LSU as a Research Assistant in the Biochemistry Department.

Q4. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE, BEGINNING WITH YOUR EMPLOYMENT AT THE LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY.

A. The foundation of my expertise in air quality and other environmental regulatory programs was built during my employment from 1990 to 2002 at the Louisiana Department of Environmental Quality (“LDEQ”), the agency responsible for implementing all state and federal air quality laws and regulations in Louisiana, a state which is home to a very large and diverse industrial base. During that time, I worked extensively in air quality program development and implementation. I played a lead role in developing and implementing the Louisiana air toxics standards and program, and was the author of the Louisiana air toxics regulation. I was also responsible for developing the Louisiana air permitting regulations for preconstruction and operating permits, including authoring the regulations to implement the federal operating permit program under Title V of the federal Clean Air Act (“CAA”) and securing the U.S. Environmental Protection Agency (“EPA”) approval of those regulations. I was also actively engaged in the Department’s enforcement program and activities.

While employed at LDEQ, my work included detailed permitting, compliance and enforcement reviews for hundreds of major facilities across the state, including numerous electric power plants. I began my work there at the entry staff level in the Air
Enforcement Division. I was subsequently promoted to supervisor and manager levels for various programs within the Air Division. While serving as the Coordinator of the Air Toxics Program, I reviewed compliance with Louisiana air toxic ambient air standards for all major sources subject to the standards. In this position, I was also responsible for the coordination and implementation of the federal National Emission Standards for Hazardous Air Pollutants ("NESHAP") standards. I served as Program Manager of the Air Permits Program from 1997 to 1999. When the Department was reorganized in 1999, I served as Environmental Manager of the Industrial Permits Section responsible for multimedia permitting (air, water, and waste permitting) for industrial sources, including power plants. These positions included the responsibility for reviewing air permit applications and air permits to ensure that all applicable regulatory requirements and all provisions of both the Title V and Prevention of Significant Deterioration ("PSD") programs were properly applied and implemented.

My work at LDEQ also involved the development, implementation, interpretation and application of federal air quality, water quality and other permitting requirements, regulations, emissions standards, policy and guidance on a daily basis for facilities of all industrial types and sizes. In addition, over the course of my employment, I worked extensively with air regulators across the country at the national level to respond to and influence federal programs and initiatives.
Q5. AFTER SERVING AS A PROGRAM MANAGER AT LDEQ, IN WHAT CAPACITY DID YOU NEXT SERVE?

A. In February 2000, I was appointed by Governor Mike Foster to serve as Assistant Secretary of the LDEQ Office of Environmental Services, and was responsible for final permit decision making for all permit actions taken by the Department, including air quality, water, and hazardous waste permits. I served in that position until January 2002.

Q6. HAVE YOU SERVED ON ANY EPA OR OTHER GOVERNMENT ADVISORY COMMITTEES RELATED TO AIR QUALITY AND AIR PERMITTING?

A. Yes, many. I am nationally recognized as having been an active participant in the implementation of Titles III and V of the Clean Air Act Amendments of 1990, which establish the federal hazardous air pollutant and air operating permit programs. In recognition of my expertise, I was selected by EPA and by my state colleagues to serve on numerous regulatory and policy advisory committees and workgroups. For example, I served on EPA stakeholder advisory groups and workgroups related to New Source Review Reform and Title V program development. I also served on several workgroups to develop several federal NESHAP known as Maximum Achievable Control Technology (“MACT”) standards and other federal air emission standard regulations, including the MACT standards for petroleum refineries, pulp and paper mills, and chemical manufacturing facilities, and the Consolidated Air Rule for the chemical manufacturing industry. I served on a subcommittee of the EPA CAA Advisory Committee, a Federal Advisory Committee, to advise EPA on the development of the
Integrated Air Toxics Strategy. I accepted an invitation from the U. S. Congress Committee on Commerce, Subcommittee on Oversight and Investigations to provide testimony regarding EPA’s implementation of the CAA.

Q7. WHAT PATH DID YOUR CAREER TAKE UPON YOUR LEAVING LDEQ?
A. After resigning from LDEQ in 2002, I began working as an environmental consultant with ENVIRON International Corporation. ENVIRON merged with Ramboll effective December 31, 2014, and my consulting career has continued with Ramboll since that time.

Q8. WHAT DOES YOUR WORK AS AN ENVIRONMENTAL CONSULTANT ENTAIL?
A. My 15-year consulting practice includes permitting and compliance assistance for all media (air, water and waste) for many types of industrial facilities in several states, including power plants, petroleum refineries, chemical plants, pulp and paper mills, oil and gas production, sulfuric acid and lime plants. I routinely evaluate the applicability of environmental regulations to affected facilities and the specific compliance obligations those facilities must meet. I have led several multi-media compliance audits, assisting facilities in identifying and resolving compliance issues. I evaluate the potential for air quality impacts resulting from existing and proposed facility operations and develop emission control strategies and compliance assurance monitoring plans. I have worked with a number of facilities to self-disclose noncompliance to LDEQ, respond to LDEQ
notices of violation, compliance orders and potential penalties, and to reach settlement agreements.

In addition to my work with industrial clients, my practice includes working with business and commerce groups, and with local and state governments. For example, I have provided consulting services to the American Chemistry Council. I have provided environmental consulting services to the City of Baton Rouge/Parish of East Baton Rouge Office of the Mayor, the Baton Rouge Chamber of Commerce, the State of Louisiana, and the National Association of Clean Air Agencies.

Q9. DO YOU CURRENTLY SPECIALIZE IN AIR PERMITTING MATTERS?
A. Yes. My work involves environmental permitting and compliance matters under air, water, and waste programs, as well as wetlands and various other environmental programs; however, a significant portion of my work is in air quality. In my consulting practice, I have assisted multiple facilities in identifying, reporting and resolving retrospective CAA PSD compliance issues. I have performed numerous project reviews on behalf of clients to determine whether the proposed changes would constitute a minor or a major modification under the PSD program, and I have developed the appropriate permit applications. On behalf of my clients, I have obtained both PSD and minor modification permits for proposed modifications to their facilities. I have performed MACT applicability and compliance assessments. I have evaluated toxic air pollutant air quality impacts resulting from facility operations and developed compliance assurance monitoring plans.
Q10. ARE YOU CURRENTLY WORKING ON OTHER TYPES OF ENVIRONMENTAL PERMITTING PROJECTS?

A. Yes, my recent and current work includes numerous projects to support environmental permitting and compliance for large-scale greenfield industrial developments in Louisiana. Those projects typically involve developing applications for several environmental permits in addition to air permits, including construction stormwater permits, water discharge permits, wetlands permits, and permits to authorize the construction of ship and barge docks and cooling water intake structures.

Q11. PLEASE DESCRIBE ANY PROFESSIONAL AFFILIATIONS AND THE TYPES OF PUBLICATIONS AND PRESENTATIONS YOU HAVE AUTHORED.

A. My professional affiliations include serving on the Board of Directors of the Louisiana Section of the Air and Waste Management Association for more than ten years beginning in 1995, including multiple terms as Director, a two-year term as Vice Chair (2003 – 2004), a two-year term as Chair (2005- 2006), and a two-year term as Past Chair (2007 – 2008). For the State and Territorial Air Pollution Program Administrators, I served as Chair of the Air Toxics Committee from 1996 to 2002 and as Vice President in 2001 and 2002. My role as Air Toxics Committee Chair involved serving as a liaison between EPA and the State Air Directors, including compiling and preparing comments on behalf of State Air Directors across the country on EPA rulemakings for MACT standards and other Clean Air Act regulations.
As for publications, my career has been focused on the development, writing and promulgation of air quality regulations to implement state and federal air quality statutes. Over the course of my career I have been a frequent speaker for many groups and events, including the American Bar Association, the American Chemistry Council, the International Air and Waste Management Association, the Society of Women Engineers, the Clean Air Information Network, the Massachusetts Institute of Technology Symposium on Air Toxics, the Environmental Protection Agency, and the National Association of Clean Air Agencies (formerly State and Territorial Air Pollution Program Administrators). My presentations have included regulatory training, policy, environmental quality trends and developments, and other topics related to state and federal environmental program development and implementation. I frequently develop and present training materials for clients on state and federal permitting requirements, CAA compliance and enforcement topics.

Q12. HAVE YOU PREVIOUSLY BEEN QUALIFIED AS AN EXPERT WITNESS AT TRIAL, PROVIDED EXPERT WITNESS TESTIMONY, OR PROVIDED DEPOSITIONS OR AFFIDAVITS IN MATTERS RELATED TO ENVIRONMENTAL REGULATIONS AND PERMITTING REQUIREMENTS?

A. Yes. While serving at LDEQ, I provided testimony on numerous occasions to the Louisiana legislature, as well as sworn testimony before the U.S. Congress, and I was called upon to provide sworn deposition testimony in several environmental litigation matters in relation to my role as an environmental regulator.

II. PURPOSE OF TESTIMONY

Q13. ON WHOSE BEHALF ARE YOU PROVIDING THIS DIRECT TESTIMONY?

A. I am testifying on behalf of Entergy New Orleans, Inc. (“ENO”), in relation to ENO’s Supplemental and Amending Application (“Supplemental Application”) for the proposed New Orleans Power Station (“NOPS”).
Q14. PLEASE BRIEFLY DESCRIBE THE TWO ALTERNATIVES PRESENTED IN ENO’S SUPPLEMENTAL APPLICATION.

A. The first alternative, which was presented in the Application previously filed with the Council of the City of New Orleans (“CNO” or “Council”) on June 20, 2016, is the 226 megawatt\(^1\) (“MW”) natural-gas-fired combustion turbine (“CT”) project. This option is composed of a single natural-gas fired turbine generator with associated ancillary equipment.

The second alternative included in ENO’s Supplemental Application is the 128 MW natural-gas-fired reciprocating internal combustion engines (“RICE”) project. This option is composed of seven 18 MW natural gas-fired reciprocating internal combustion engines (“RICE”) with associated ancillary equipment.

Q15. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is: 1) to provide an overview of the environmental permits required for the proposed NOPS; 2) to provide information about the air permitting process and air quality review as required by the New Source Review and Title V air permitting programs, including the process for considering proposed emissions increases and contemporaneous emissions decreases; 3) to provide an overview of the types of

\(^1\) The maximum output of the CT is dependent on ambient conditions (e.g., temperature, humidity, elevation, etc.) In summer conditions, the maximum output of the CT is approximately 226 MW. Under ISO conditions (i.e., standardized conditions established for this technology by the International Organization for Standardization), maximum output is approximately 246 MW.
regulated air pollutants considered in the permitting process; and 4) to provide
information about the National Ambient Air Quality Standards (“NAAQS”) for criteria
pollutants, including EPA’s process for establishing the NAAQS and how states
implement the NAAQS and consider them in the air permitting process. I will also
address some specific concerns raised by certain intervenors, and in particular by Dr. George Thurston in his Direct Testimony submitted on behalf of the Alliance for Affordable Energy, the Deep South Center for Environmental Justice, and the Sierra Club, with regard to PM$_{2.5}$ emissions from the proposed NOPS in relation to the NAAQS and air permitting.

III. NOPS-REQUIRED ENVIRONMENTAL PERMITS

A. Overview of Required Environmental Permits

Q16. HOW DO THE TWO ALTERNATIVE PROJECTS COMPARE FROM THE PERSPECTIVE OF ENVIRONMENTAL PERMITTING?

A. While some of the specific standards and permit terms would differ, in general the two alternatives require the same environmental permits. For either option, the environmental permits ENO would be required to obtain include the following:

1) Air Permits: Under the requirements of the federal Clean Air Act, a Title I preconstruction permit is required to authorize construction, and a modification to the existing Michoud Plant Title V operating permit is required for operation of the NOPS. The LDEQ air permitting procedures combine these preconstruction and operating permitting programs under a single permit application, review and issuance process, which ENO must complete prior to commencement of construction. That is, prior to construction of the facility LDEQ performs the preconstruction review and the review of all state and federal air quality requirements that will apply to operation of the facility.
2) Construction Stormwater Permit: For either alternative, the discharge of stormwater from the construction site will be regulated under LDEQ’s Construction Stormwater General Permit. ENO must submit a Notification of Intent to obtain coverage under the General Permit prior to disturbance of land at the construction site. For either alternative, ENO must develop and implement a Stormwater Pollution Prevention Plan (SWPPP) to minimize the discharge of pollutants in stormwater effluent from the construction site.

3) Water Discharge Permits: Under the requirements of the federal Clean Water Act, ENO must obtain a modification to the facility’s Louisiana Pollutant Discharge Elimination System (“LPDES”) permit for either alternative, which will regulate the level of pollutants contained in wastewater and stormwater discharges from the facility. The LPDES permit will also require the implementation of a SWPPP for the operating phase of the project, for either alternative.

In addition to the LPDES permit, for either alternative ENO must comply with City of New Orleans ordinances and permit requirements for stormwater management to reduce urban runoff, diminish subsidence, and encourage sustainable development.

4) Coastal Use Permit: Because the project is located in the Louisiana Coastal Zone, for either alternative ENO must obtain a Coastal Use Permit (“CUP”) from Louisiana Department of Natural Resources (“LDNR”), or a determination that the project would not require a CUP, prior to the disturbance of land at the project site.

5) Section 404 Wetlands/Waters of the U.S. Permit: ENO is working with LDNR and the United States Army Corps of Engineers (“USACE”) to identify the required permitting actions for NOPS construction, and will obtain any required permits to address potential impacts to wetlands or other jurisdictional waters of the U.S.

B. **Overview of NOPS Air Quality Permitting**

Q17. **SPECIFICALLY WITH REGARD TO AIR EMISSIONS, HOW DO THE TWO ALTERNATIVES COMPARE?**

A. Either alternative would result in substantial decreases in permitted (allowable) emissions for the NOPS as compared to the currently permitted Michoud Power Plant. The tables
below present the “Before” and “After” permitted emissions for each alternative, based on currently available project information.

### Table 1
Comparison of “Before” and “After” Permitted Emission Rates
NOPS Alternative 1, 226 MW CT Project

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>“Before” Currently Permitted Michoud Power Plant Emissions (tons per year)</th>
<th>“After” Anticipated Permitted NOPS Emissions(^2) 226 MW CT Project (tons per year)</th>
<th>Change in Permitted Emissions (tons per year)</th>
<th>Percent Reduction (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM(_{10})</td>
<td>283.55</td>
<td>13.82</td>
<td>-269.73</td>
<td>95.1%</td>
</tr>
<tr>
<td>PM(_{2.5})</td>
<td>283.55</td>
<td>13.82</td>
<td>-269.73</td>
<td>95.1%</td>
</tr>
<tr>
<td>SO(_2)</td>
<td>22.55</td>
<td>7.26</td>
<td>-15.79</td>
<td>67.8%</td>
</tr>
<tr>
<td>NO(_x)</td>
<td>8,596.89</td>
<td>273.12</td>
<td>-8,323.77</td>
<td>96.8%</td>
</tr>
<tr>
<td>CO</td>
<td>3,132.53</td>
<td>657.04</td>
<td>-2,475.49</td>
<td>79.0%</td>
</tr>
<tr>
<td>VOC</td>
<td>205.35</td>
<td>102.82</td>
<td>-102.53</td>
<td>49.9%</td>
</tr>
</tbody>
</table>

\(^2\) Based on LDEQ proposed Permit No. 2140-00014-V5, Activity No. PER20160002, EDMS Document No. 10454574, retrieved June 20, 2017. Proposed permitted emissions are subject to change based on updated project information or subsequent LDEQ review.
Table 2  
Comparison of “Before” and “After” Permitted Emission Rates  
NOPS Alternative 2, 128 MW RICE Project

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>“Before” Currently Permitted Michoud Power Plant Emissions (tons per year)</th>
<th>“After” Anticipated Permitted NOPS Emissions 128 MW RICE Project (tons per year)</th>
<th>Change in Permitted Emissions (tons per year)</th>
<th>Percent Reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM$_{10}$</td>
<td>283.55</td>
<td>97.61</td>
<td>-185.94</td>
<td>65.6%</td>
</tr>
<tr>
<td>PM$_{2.5}$</td>
<td>283.55</td>
<td>97.61</td>
<td>-185.94</td>
<td>65.6%</td>
</tr>
<tr>
<td>SO$_2$</td>
<td>22.55</td>
<td>2.87</td>
<td>-19.68</td>
<td>87.3%</td>
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<tr>
<td>NO$_x$</td>
<td>8,596.89</td>
<td>50.39</td>
<td>-8,546.50</td>
<td>99.4%</td>
</tr>
<tr>
<td>CO</td>
<td>3,132.53</td>
<td>89.31</td>
<td>-3,043.22</td>
<td>97.1%</td>
</tr>
<tr>
<td>VOC</td>
<td>205.35</td>
<td>105.38</td>
<td>-99.97</td>
<td>48.7%</td>
</tr>
</tbody>
</table>

Q18. BASED ON YOUR CURRENT KNOWLEDGE OF THE TWO ALTERNATIVES, DO YOU EXPECT THE TYPE OF AIR QUALITY REVIEW OR THE AIR PERMITTING PROCESS TO DIFFER?

A. No, I expect both alternatives to require the same level of air quality review and the same type of air quality permit, and to undergo the same air permitting procedures. In fact, ENO is preparing an air permit application that will present both alternatives for LDEQ review and approval, so that either alternative can be constructed consistent with CNO’s decision.

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Based on preliminary emissions calculations provided by ENO June 2017. Emissions estimates are subject to change based on updated project information or LDEQ review.
Q19. PLEASE SUMMARIZE THE AIR PERMITTING PROCESS THAT WILL APPLY FOR NOPS, BASED ON THE PROJECT INFORMATION AVAILABLE TO YOU AT THIS TIME.

A. First, with regard to the preconstruction review program, either alternative would be considered a “minor modification” under the PSD program, with substantial net emission decreases of some pollutants and net emissions increases below EPA-established significance thresholds for all pollutants. As discussed further below, the net emissions change is based on a comparison of the proposed permitted emissions for the project to the actual emissions that occurred from the Michoud Units 1, 2, and 3, which are now retired. Because actual emissions for a unit are typically much lower than its permitted emissions, this comparison is not an “apples to apples” analysis. Rather, it is very conservative and can result in a projection of net emission increases even for cases where the actual change in emissions is expected to be a decrease. Because the NOPS project is expected to be a minor modification under the preconstruction review program based on this conservative analysis of emission changes, a major modification PSD permit would not be required for either alternative.

With regard to the Title V operating permit program, the required air permit for either alternative would be issued as a modification to the existing Michoud Plant Title V permit. As I previously stated, ENO will submit an air permit application to the LDEQ to

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4 Michoud Unit 1 has not been operated to generate electric power for several years, but has continued to be operated as a steam generating boiler to support startup of Unit 3 until January 2016.
provide the information required for both the preconstruction review and the operating permits review. An application addressing each alternative will be submitted, either combined or concurrently. LDEQ will review the application submittal to assure no adverse air quality impacts would result from the project, and to identify all applicable state and federal regulations and standards for the proposed equipment. When the permitting review procedures are complete, including any associated public or EPA review and comment periods on the draft permit and application materials, LDEQ would take final action on the Title V permit modification request. A final permit to modify the Title V permit would also include LDEQ authorization to construct the NOPS.

IV. THE PSD PROGRAM AND MAJOR VS. MINOR MODIFICATIONS

A. Brief Overview of the PSD Program

Q20. YOU INDICATED THAT EITHER ALTERNATIVE FOR THE NOPS PROJECT WOULD BE CONSIDERED A MINOR MODIFICATION UNDER THE PSD PROGRAM. CAN YOU BRIEFLY EXPLAIN WHAT THE PSD PROGRAM IS?

A. Yes. First, under the federal CAA, EPA sets the NAAQS for pollutants of concern, and each state is required to implement a plan for attaining and maintaining compliance with the NAAQS for all regions of the state. The CAA also establishes a preconstruction permitting program, called New Source Review, by which state permitting authorities review proposed new stationary sources and proposed modifications to existing stationary sources prior to commencement of construction, to assist in meeting the NAAQS and protecting air quality. New Source Review is composed of two separate but related
programs – one that applies if the area where the project would be located has not yet
attained air quality that meets the NAAQS (called “nonattainment areas”), and one that
applies if the area where the project would be located is in attainment with the NAAQS
(called “attainment areas”). The same project can be subject to both programs for
different pollutants, if the area has a different attainment status for different NAAQS.
Orleans Parish is in attainment with all of the NAAQS, meaning the air quality in the
parish meets all federal air quality standards. Therefore, only the New Source Review
program for attainment areas applies here.

The PSD program is the New Source Review preconstruction permitting program
designed to help states maintain compliance with these federal air quality standards in
attainment areas. As the name implies, the PSD program is intended to prevent any
significant deterioration of air quality in those areas. To accomplish this goal, the PSD
program requires permit applicants for any new major stationary source or any major
modification to an existing major stationary source to undergo a control technology
review and to conduct an air quality analysis to demonstrate that the proposed emissions
would not cause or contribute to an exceedance of the NAAQS and would not cause an
exceedance of allowable pollution increases, called PSD increments, for the area.
B. Major and Minor Modifications

Q21. WHAT IS A MINOR MODIFICATION UNDER THE PSD PROGRAM, AND HOW IS THE NOPS PROJECT DETERMINED TO BE A MINOR MODIFICATION?

A. In brief, each proposed project to modify an existing facility (that is, any physical change or change in the method of operation at an existing stationary source) is classified as either a minor modification or major modification based on the level of the emissions change that will result from the project for PSD-regulated pollutants. A project is a major modification if two criteria are met:

1) A significant emissions increase will result from the project; and,

2) A significant net emissions increase will result from the proposed project considered together with any other creditable emissions increases and decreases occurring during the contemporaneous time period.

Any modification project that does not meet these two criteria is classified as a minor modification because the emissions changes associated with the project have been determined by EPA to be de minimis with regard to their potential for adversely impacting air quality.  

The procedures for calculating the emissions increase from the project and the net emissions increase over the contemporaneous time period can be complex, but are designed to assure the protection of air quality in attainment areas such as Orleans Parish. Each PSD-regulated pollutant is reviewed separately, and EPA has established pollutant-specific significant emissions rates, also referred to as de minimis emission rates, which

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5 Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers (PM$_{2.5}$), EPA, Final Rule, 73 FR 28,332, May 16, 2008.
are based on the environmental and health effects of the pollutant and the corresponding
NAAQS. If the project emissions increase and/or the net emissions increase resulting
from a proposed modification are less than the pollutant-specific significant emission rate
for all PSD-regulated pollutants, then EPA considers the emissions change to be *de
minimis* and the modification is classified as minor. If a significant project emissions
increase and a significant net emissions increase would occur for one or more PSD-
regulated pollutant(s), then the project is a major modification and must undergo PSD
review with respect to the particular pollutant(s) for which a significant increase would
occur.

The PSD significant emissions rates for the PSD-regulated pollutants of interest
are shown in Table 3 for reference.

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>SPD Significant Emission Increase Level (tons per year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM$_{10}$</td>
<td>15</td>
</tr>
<tr>
<td>PM$_{2.5}$</td>
<td>10</td>
</tr>
<tr>
<td>SO$_{2}$</td>
<td>40</td>
</tr>
<tr>
<td>NO$_{x}$</td>
<td>40</td>
</tr>
<tr>
<td>CO</td>
<td>100</td>
</tr>
<tr>
<td>VOC</td>
<td>40</td>
</tr>
</tbody>
</table>
Q22. UNDER THE FIRST PART OF THE DETERMINATION OF WHETHER A PROPOSED CHANGE IS A MAJOR OR MINOR MODIFICATION, HOW IS THE PROJECT EMISSIONS INCREASE DETERMINED?

A. For projects such as NOPS, which proposes to install only new emissions units, the project emissions increase for each pollutant is the sum of the proposed permitted emission rates for that pollutant, from all emissions units that will emit that pollutant. Thus, the project emissions increase is based on the maximum potential emissions that could occur in any given year, assuming every proposed emissions unit emits the pollutant at the full annually permitted rate. This is a very conservative estimate of the emissions increases that would actually occur from the project. Furthermore, this first step in the process does not consider any emissions reductions that would also occur as a result of or during the same time period as the project. Only proposed emission increases are considered at this stage.

For the NOPS 226 MW CT and the 128 MW RICE alternatives, the project emissions increases are represented by the “After” Anticipated Permitted Emissions listed in Table 1 and Table 2, respectively.

Q23. UNDER THE SECOND STEP OF THE DETERMINATION OF WHETHER A PROJECT IS A MAJOR MODIFICATION, HOW IS THE NET EMISSIONS INCREASE DETERMINED?

A. Under this step, the permit applicant and the permitting authority consider any other creditable increases or decreases in emissions that have occurred or will occur within the
contemporaneous period for the proposed project. The net emissions change associated
with the proposed project is the sum of all of the increases and decreases for the
particular pollutant over the contemporaneous time period of the project. This procedure
is commonly referred to as “netting.” Again, the procedures for calculating the level of
emissions increases or decreases are conservative, meaning that they are intended to
avoid any underestimation of an emissions increase and to avoid any overestimation of an
emissions decrease.

The contemporaneous period is defined as the time period beginning five years
before the projected commencement of construction on the proposed project, and ending
on the date that the increase in emissions from the proposed project will occur. For the
NOPS project, the contemporaneous period would be approximately January 2013 to
October 2019.\(^6\)

To be considered a creditable decrease in emissions, several factors must be met.
For example, the emission reduction must be permanent and enforceable. Also, an
applicant cannot get “credit” simply for reducing permitted emissions; only reductions in
actual emissions are creditable. Also, any actual emissions that were above permitted
emission levels or other applicable emission standards are not creditable, but must be
excluded from the determination.

\(^6\) Based on anticipated commencement of construction in January 2018, and anticipated commencement of
operation in October 2019.
For the recently retired Michoud Units 1, 2, and 3, creditable emission reductions are determined by calculating the level of actual emissions that occurred from each unit representative of normal operation during the defined baseline period. The calculations are based on actual monitoring or test data or EPA-approved emission factors together with the actual operating data of the units. Based on my understanding of the project information, the Michoud Unit 1, 2, and 3 shutdowns are the only contemporaneous emission changes in the netting window.

In summary, construction of the proposed NOPS is a minor modification under the PSD program because, for every PSD-regulated pollutant that would be emitted from the new units, the proposed permitted emission rate and/or the contemporaneous actual net emissions change is less than that pollutant’s PSD significant emission rate as shown in Table 3. Based on this determination, the project would not be expected to adversely impact air quality with regard to the NAAQS.

C. Air Permitting Review of Minor Modifications

Q24. WHY ISN’T PSD REVIEW REQUIRED FOR A MINOR MODIFICATION?

A. To reiterate, PSD review is not required for a minor modification such as the proposed NOPS because any contemporaneous emissions increase that would result from a minor modification is less than the pollutant-specific significant emission rate. Such an increase is considered *de minimis* and therefore would not be expected to cause or contribute to an exceedance of the NAAQS or to have an adverse impact on the air quality of the area.
In establishing the significant emission rates, EPA identified a level of emission increase that would be unlikely to cause ambient impacts above the significant impact level for the NAAQS. For example, the original significant emission rate for particulate matter (25 tons per year) was set by EPA using an air quality modeling analysis to determine the level of emissions that would be unlikely to cause ambient impacts above 4 percent of the PM NAAQS. The NAAQS itself is set at a level protective of public health and the environment, and the potential impacts from a minor modification would be at levels that are only a very small fraction of the NAAQS.

Q25. NONETHELESS, DOES LDEQ REVIEW MINOR MODIFICATIONS TO ASSURE AIR QUALITY IS PROTECTED?

A. Yes. As an initial matter, LDEQ as the permitting authority is responsible for reviewing the emissions calculations provided by the applicant to assure they are technically sound and correct, and that any emission increases resulting from the modification have been appropriately identified and estimated. Once the emissions estimates have been verified, LDEQ may reasonably conclude emission increases less than the significant emission rate, by definition, would not result in adverse air quality impacts, as that is the fundamental purpose of the significant emission rates as established by EPA – to define

the level of emissions that is *de minimis* and therefore unlikely to result in significant impacts to air quality.

In addition, LDEQ assesses and incorporates into the draft permit applicable emission control requirements, emission limitations, work practices, monitoring, recordkeeping and reporting requirements based on the type of equipment or activities proposed and the level of potential emissions from the equipment. Despite the *de minimis* nature of the emission changes, projects that constitute minor modifications are still subject to numerous air quality emission standards and associated monitoring, recordkeeping and reporting requirements. Also, LDEQ establishes specific allowable mass emission rates for individual emission units or groups of emission units through the permitting process, including both short-term (lb/hr) and annual (ton per year) limits. LDEQ also reviews the application with regard to pollutants not addressed by the NAAQS, including federal hazardous air pollutants and Louisiana toxic air pollutants.

Furthermore, LDEQ may choose to perform air dispersion modeling of the proposed emissions to model predicted ambient concentrations resulting from the proposed facility. Also, LDEQ has broad authority under LDEQ air permitting regulations to incorporate into the permit any conditions the agency deems reasonable and necessary to protect air quality.⁸

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Q26. WHAT ARE SOME OF THE SPECIFIC AIR QUALITY REGULATIONS AND STANDARDS TO BE ADDRESSED IN THE MINOR MODIFICATION THAT NOPs MUST MEET?

A. Several state and federal regulations and standards will apply to the facility regardless of the alternative selected, including, for example:

1) If the 226 MW CT is selected, the equipment must meet New Source Performance Standards (“NSPS”) emission limits for CO₂, NOₓ, and SO₂, as well as associated monitoring, recordkeeping and reporting requirements;

2) If the 128 MW RICE project is selected, the equipment must be certified to meet NSPS emission limits applicable to stationary engines;

3) Emergency engines, such as emergency generators or firefighting pump engines, are also subject to federal NSPS emission standards and work practice standards;

4) State regulations governing emissions of particulate matter, emissions reporting, housekeeping and maintenance practices, and maintenance of control devices apply to the facility; and

5) ENO is subject to requirements for emissions monitoring and reporting, and the payment of annual emissions fees.

V. TYPES OF REGULATED AIR POLLUTANTS

Q27. YOU MENTIONED THAT LDEQ REVIEWS SOME POLLUTANTS THAT ARE NOT ADDRESSED BY THE NAAQS. WHAT ARE THE MAIN CATEGORIES OF AIR POLLUTANTS THAT LDEQ REVIEWS IN THE AIR PERMITTING PROCESS?

A. There are several categories of regulated air pollutants, as described below.⁹

1) The “criteria pollutants” are the six pollutants for which EPA has established a

⁹ See LAC 33:III.502 for the regulatory definition of “Regulated Air Pollutant.”
NAAQS. These are lead ("Pb"); carbon monoxide ("CO"); nitrogen dioxide ("NO₂"); sulfur dioxide ("SO₂"); particulate matter ("PM"), for which PM₁₀ and PM₂.₅ have been established as indicators; and ground-level ozone ("O₃"), which is regulated through the ozone precursors nitrogen oxides ("NOₓ") and volatile organic compounds ("VOC").

2) Any pollutant subject to an emission standard under Section 111 of the Clean Air Act (generally, the New Source Performance Standards), is a regulated pollutant. In addition to the criteria pollutants, these include pollutants such as Greenhouse Gases (GHGs), ammonia and hydrogen sulfide.

3) Any pollutant subject to an emission standard under Section 112 of the Clean Air Act, which are the National Emission Standards for Hazardous Air Pollutants (HAP). There are currently 187 listed HAP. These include organic compounds, such as benzene and toluene; metals and metal compounds, such as mercury and chromium; and additional compounds such as glycol ethers.

4) Any pollutant subject to review under the PSD program, which includes, in addition to the criteria pollutants, Greenhouse Gases ("GHG"), reduced sulfur compounds, sulfuric acid mist, and others;

5) Any pollutant listed as a Louisiana Toxic Air Pollutant ("LTAP"), including all federal HAP and numerous other compounds.

See https://www.epa.gov/haps/initial-list-hazardous-air-pollutants-modifications
VI. NATIONAL AMBIENT AIR QUALITY STANDARDS (“NAAQS”)

A. Overview of the NAAQS

Q28. YOU HAVE DISCUSSED THE NAAQS IN RELATION TO AIR PERMITTING UNDER THE NEW SOURCE REVIEW PROGRAM. WHAT ARE THE NAAQS?

A. The NAAQS are federal air quality standards, expressed as an allowable concentration of pollution in the air, set by EPA to protect public health and the environment. EPA sets two types of NAAQS, primary and secondary. Primary NAAQS are set to protect public health, including “sensitive” populations such as asthmatics, children, and the elderly. Secondary NAAQS are set to protect public welfare, including visibility, animals, crops, vegetation, and architecture. Each NAAQS includes three components: a pollutant concentration level, an averaging time, and the “form” of the standard, which is the statistical basis or method used to determine whether an area is meeting the standard. Table 4 provides a listing of the current NAAQS.

11 See https://www.epa.gov/criteria-air-pollutants/naaqs-table
12 See https://www.epa.gov/criteria-air-pollutants/naaqs-table
## Table 4
### Current National Ambient Air Quality Standards

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Primary/Secondary</th>
<th>Averaging Time</th>
<th>Level</th>
<th>Form</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon Monoxide (CO)</td>
<td>Primary</td>
<td>8 hours</td>
<td>9 ppm</td>
<td>Not to be exceeded more than once per year</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1 hour</td>
<td>35 ppm</td>
<td></td>
</tr>
<tr>
<td>Lead (Pb)</td>
<td>Primary and Secondary</td>
<td>Rolling 3 month average</td>
<td>0.15 μg/m³ (1)</td>
<td>Not to be exceeded</td>
</tr>
<tr>
<td>Nitrogen Dioxide (NO₂)</td>
<td>Primary</td>
<td>1 hour</td>
<td>100 ppb</td>
<td>98th percentile of 1-hour daily maximum concentrations, averaged over 3 years</td>
</tr>
<tr>
<td></td>
<td>Primary and Secondary</td>
<td>1 year</td>
<td>53 ppb (2)</td>
<td>Annual Mean</td>
</tr>
<tr>
<td>Ozone (O₃)</td>
<td>Primary and Secondary</td>
<td>8 hours</td>
<td>0.070 ppm (3)</td>
<td>Annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years</td>
</tr>
<tr>
<td>Particle Pollution (PM)</td>
<td>PM₂.₅ Primary</td>
<td>1 year</td>
<td>12.0 μg/m³</td>
<td>Annual mean, averaged over 3 years</td>
</tr>
<tr>
<td>Pollutant</td>
<td>Primary/Secondary</td>
<td>Averaging Time</td>
<td>Level</td>
<td>Form</td>
</tr>
<tr>
<td>---------------------------</td>
<td>------------------</td>
<td>----------------</td>
<td>-------------</td>
<td>----------------------------------------------------------------------</td>
</tr>
<tr>
<td></td>
<td>Secondary</td>
<td>1 year</td>
<td>15.0 μg/m³</td>
<td>Annual mean, averaged over 3 years</td>
</tr>
<tr>
<td></td>
<td>Primary and</td>
<td>24 hours</td>
<td>35 μg/m³</td>
<td>98th percentile, averaged over 3 years</td>
</tr>
<tr>
<td></td>
<td>Secondary</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>PM₁₀</strong></td>
<td>Primary and</td>
<td>24 hours</td>
<td>150 μg/m³</td>
<td>Not to be exceeded more than once per year on average over 3 years</td>
</tr>
<tr>
<td></td>
<td>Secondary</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Primary</td>
<td>1 hour</td>
<td>75 ppb (4)</td>
<td>99th percentile of 1-hr daily maximum concentrations, averaged over 3 yrs</td>
</tr>
<tr>
<td></td>
<td>Secondary</td>
<td>3 hours</td>
<td>0.5 ppm</td>
<td>Not to be exceeded more than once per year</td>
</tr>
</tbody>
</table>

1 (1) In areas designated nonattainment for the Pb standards prior to the promulgation of the current (2008) standards, and for which implementation plans to attain or maintain the current (2008) standards have not been submitted and approved, the previous standards (1.5 μg/m³ as a calendar quarter average) also remain in effect.
2 (2) The level of the annual NO₂ standard is 0.053 ppm. It is shown here in terms of ppb for the purposes of clearer comparison to the 1-hour standard level.
4 (4) The previous SO₂ standards (0.14 ppm 24-hour and 0.03 ppm annual) will additionally remain in effect in certain areas: (1) any area for which it is not yet 1 year since the effective date of designation under the current (2010) standards, and (2) any area for which an implementation plan providing for attainment of the current (2010) standard has not been submitted and approved and which is designated nonattainment under the previous SO₂ standards or is not meeting the requirements of a State Implementation Plan (“SIP”) call under the previous SO₂ standards (40 CFR 50.4(3)). A SIP call is an EPA action requiring a state to resubmit all or part of its SIP to demonstrate attainment of the required NAAQS.
Q29. WHAT DO YOU MEAN WHEN YOU SAY EPA SETS THE PRIMARY NAAQS “TO PROTECT PUBLIC HEALTH”?

A. The Clean Air Act directs EPA to set primary NAAQS as necessary to protect the public health with “an adequate margin of safety.”\textsuperscript{13} In determining the level and form of the standard required, the CAA explicitly states that EPA must assure the standard reflects “the latest scientific knowledge useful in indicating the kind and extent of all identifiable effects on public health or welfare which may be expected from the presence of such pollutant in the ambient air, in varying quantities,” including variable factors that may produce an adverse health effect, such as atmospheric conditions and the interaction of the air pollutant with other air pollutants.\textsuperscript{14}

EPA notes that the CAA requires the agency “to reach a public health policy judgment as to what standards would be requisite – neither more nor less stringent than necessary – to protect public health with an adequate margin of safety, based on scientific evidence and technical assessments that have inherent uncertainties and limitations.”\textsuperscript{15} EPA further interprets the CAA to require the NAAQS to be set not only to prevent pollution concentrations that have been \textit{demonstrated} to be harmful, but also “to prevent lower concentrations…that may pose an unacceptable risk of harm.”\textsuperscript{16} That is, EPA

\textsuperscript{13} 42 U.S.C. § 7409.
\textsuperscript{14} 42 U.S.C. § 7408.
\textsuperscript{16} \textit{Ibid.}
considers the public health risk associated with exposure to pollution based on the full body of scientific evidence available, and sets the NAAQS at a level that considers the inherent uncertainties of the science and the potential risk of harm suggested by the science, to provide an adequate margin of safety to protect the health of sensitive populations.

Once a NAAQS has been established, the CAA also requires EPA to periodically review and revise the NAAQS based on the latest science available. Notably, the cost of achieving the NAAQS is not a consideration of EPA in establishing the NAAQS.

**B. Process for Establishing the NAAQS**

**Q30. WHAT IS THE PROCESS EPA FOLLOWS TO ESTABLISH THE NAAQS?**

**A.** EPA must undergo notice and comment rulemaking, under the federal Administrative Procedures Act, to adopt a new or revised NAAQS. This process involves extensive public outreach, public comment, and review. Nonetheless, even before beginning the official rulemaking procedures, EPA follows a four-phased approach to develop the proposed NAAQS. Each of these stages also involves significant involvement and input from the public and scientific communities.

1) Integrated Review Plan: The first phase is the planning phase, which begins with EPA hosting a science policy workshop to get initial input from the public and scientists. Based on these discussions and EPA’s own considerations, EPA develops an Integrated Review Plan, outlining the review schedule and process, and summarizing the key policy and science issues that will be considered.
2) Integrated Science Assessment: EPA performs an extensive and comprehensive review, synthesis and evaluation of the policy-relevant science. EPA integrates the available scientific information in a manner that will provide a framework for assessing public health risks, and documents the review in the Integrated Science Assessment.

3) Risk/Exposure Assessment: The next phase builds on the evaluation developed in the Integrated Science Assessment to develop quantitative characterizations of exposures and associated risks to human health and the environment. In the Risk/Exposure Assessment, EPA considers the known or likely effects and risks associated with exposure at recent or current air quality conditions and at conditions meeting the current NAAQS and alternative NAAQS under considerations. EPA also characterizes the uncertainties associated with the exposure and risk estimates.

4) Policy Assessment: EPA publishes a Policy Assessment that documents the EPA staff analysis of the scientific basis for alternative NAAQS for consideration by senior EPA management and the Administrator.

Q31. WHO PROVIDES INPUT TO EPA’S REVIEW OF THE NAAQS?

A. In general, anyone who chooses to be involved can do so through attending public workshops, meetings and hearings and through providing comment to EPA. EPA’s National Center for Environmental Assessment (“NCEA”) hosts numerous meetings and workshops specifically for the purpose of bringing together the public and scientific community to discuss issues surrounding public health and the NAAQS.

Even at the planning stage in developing the Integrated Review Plan, EPA actively seeks the feedback and input of interested parties and recognized scientific experts. For example, in adopting the current PM$_{2.5}$ NAAQS, EPA consulted with the
Clean Air Scientific Advisory Committee ("CASAC") on the draft Integrated Review Plan, and revised the draft to take CASAC comments into account.\(^{17}\) Also, EPA must consider the input of virtually every scientist who has published peer-reviewed work on the pollutant in question, through the Integrated Science Assessment. For the recent PM\(_{2.5}\) NAAQS development, EPA published a draft Integrated Science Assessment in the Federal Register and took comment from the public and from CASAC at a meeting held for that specific purpose. This was followed by publication in the Federal Register of a second draft, and a second meeting of the public and CASAC to provide feedback before a final Integrated Science Assessment was issued.\(^{18}\) A similar process of public involvement was then undertaken to develop the Risk/Exposure Assessment, followed by a similar process for developing the Policy Assessment. Only after these multiple rounds of public notice and comment, including specific outreach to the scientific community, on each of the four development phases and documents did EPA begin the formal rulemaking process for the current PM\(_{2.5}\) NAAQS, with publication of the proposed decision to revise the NAAQS for PM.\(^{19}\)

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Q32. WHEN EPA PROMULGATES A FINAL RULE TO ADOPT A NEW OR REVISED NAAQS, IS IT SUBJECT TO CHALLENGES SUCH AS AN ADMINISTRATIVE APPEAL OR COURT ACTION?

A. Absolutely. NAAQS are subject to the same opportunities for challenge and appeal as any other federal rule, and are in fact frequently challenged. It is common for EPA’s decision to be challenged both as being overly protective of health, and as being too lax in protecting public health.

C. Process for Implementing the NAAQS

Q33. ONCE A NAAQS HAS BEEN ESTABLISHED BY EPA, HOW IS IT IMPLEMENTED?

A. Once EPA has set a new or revised NAAQS, it is each state’s responsibility to meet the standard in all areas of the state. Each state implements the NAAQS through a State Implementation Plan (“SIP”) which is composed of the state laws, regulations, policies, guidelines, and programs necessary to govern air quality and specifically as needed to achieve and maintain compliance with the NAAQS across the state.

First, each state must assess the current air quality across the state. This is frequently done on a county-by-county (or parish-by-parish) basis, but some area quality areas are designated as multi-county or multi-parish areas, or based on Metropolitan Statistical Areas (MSAs), particularly where the air quality across a broader area is influenced by the same or similar features or emission sources. Each state makes a recommendation to EPA as to whether, based on available air quality data, each area of
the state is in “attainment” or “nonattainment” with the NAAQS, or is “unclassifiable”
due to the lack of available data. EPA then reviews and approves or disapproves the
state’s recommendations for area designations, and ultimately makes official designations
of area attainment status across the country.

For any area that is designated “nonattainment” the state must develop and
implement an attainment plan as part of its SIP, to achieve the NAAQS by a deadline
established under federal regulation. The state must demonstrate, for EPA’s approval,
that the suite of emission reductions, control measures or other elements of the plan will
result in attainment of the NAAQS. The attainment demonstration relies upon ambient
monitoring networks, airshed modeling, rule effectiveness studies, and other information
as prescribed by EPA.

In addition, each state must develop and submit for EPA approval an
“infrastructure SIP” that provides the state the authority to implement and enforce the
necessary framework for attaining and maintaining compliance with the NAAQS. The
infrastructure SIP covers both attainment and nonattainment areas, and includes the
authority and necessary regulatory provisions for the state to perform New Source
Review permitting for proposed minor and major new stationary sources and
modifications to existing stationary sources, to assure those projects would not cause or
contribute to an exceedance of the NAAQS.
Q34. HOW DOES LDEQ DETERMINE WHETHER A PROPOSED PROJECT WOULD CAUSE OR CONTRIBUTE TO AN EXCEEDANCE OF THE NAAQS?

A. As I previously explained, the approach is different depending on whether the location of the project is an attainment or nonattainment area, and depending on whether the project is a minor or major modification.

In nonattainment areas, proposed new major sources and proposed major modifications must apply controls that meet the Lowest Achievable Emission Rate (“LAER”) and also must obtain creditable emission reductions or “offsets” to offset the proposed emission reductions, thereby assuring the level of emissions to the airshed of the area are not increasing significantly. Because the area is in nonattainment (that is, the air quality exceeds the NAAQS) and because offsets are being provided in the form of emission reduction credits, air quality modeling is not performed for Nonattainment New Source Review permitting. LDEQ oversees the review and “banking” of available emission reduction credits that can be relied upon as offsets, and regulates the use of offsets through the permitting program. New minor sources and minor modifications in nonattainment areas, analogous to minor sources and minor modifications in attainment areas, are considered de minimis increases unlikely to adversely impact air quality. Therefore, LAER and offsets are not required.

In attainment areas, proposed new major stationary sources and proposed major modifications must apply controls that meet the Best Available Control Technology (“BACT”), and the applicant must perform an air quality analysis to demonstrate the project would not cause or contribute to a NAAQS exceedance or the consumption of the
PSD increments. The air quality analysis is multi-tiered, with the first tier composed of conducting an air dispersion model of the proposed emissions increases to assess the potential impact for the project to cause or contribute to an exceedance of the NAAQS. If the model’s predicted ambient concentrations in this first tier, called “significance modeling,” are below EPA-established Significant Impact Levels (“SIL”), then the model has demonstrated the project would not cause or contribute to an exceedance of the NAAQS and no further review is necessary. The SILs are set at a value that is a small fraction of the corresponding NAAQS, which is considered a *de minimis* impact. If the significance modeling predicts impacts over the SIL, then more refined modeling is required, inclusive of the emissions of other nearby sources.

As previously discussed, this type of air quality modeling analysis is not required for minor modifications, because the associated increases (or decreases) are below the significant emission rates and are not anticipated to have the potential for adverse air quality impacts.

**VII. THE PM$_{2.5}$ NAAQS**

Q35. INTERVENORS HAVE RAISED CONCERNS ABOUT THE EMISSIONS OF PM$_{2.5}$ THAT WOULD RESULT FROM THE PLANT. WHAT IS PM$_{2.5}$?

A. PM$_{2.5}$ is a specific classification of the regulated criteria pollutant, particulate matter (PM). First, PM is categorized for regulatory purposes under the CAA based on the size of the particle, and that is what the numbers represent. PM$_{10}$ is particulate matter that is 10 microns or less in diameter. PM$_{2.5}$, also called “fine particulate,” is particulate matter that is 2.5 microns or less in diameter. These distinctions are made in recognition of the
size of particles that are small enough to enter the airway and therefore affect human health.

In addition to distinguishing between size fractions, PM is divided into two distinct components based on its physical state at stack testing conditions: filterable and condensable PM. Filterable PM refers to the fraction of PM emissions that is a solid or a liquid at sampling conditions, and that generally adheres to the filter portion of the sample train. Condensable PM is the fraction of PM that is vapor at sampling conditions, but which will condense into liquid or solid PM once cooled. The extent to which filterable and condensable fractions will correspond to the PM$_{2.5}$, PM$_{10}$, or larger fractions depends on the test and the sampling equipment being used. Total PM is the sum of the condensable and filterable components, and includes all fractions. Generally, the smaller size particles are concentrated in the condensable portion of the sample, therefore the condensable portion is often considered to be comprised mostly or wholly of PM$_{2.5}$.

Q36. HAS EPA ESTABLISHED A NAAQS FOR PM$_{2.5}$?

A. Yes, as shown in Table 4, EPA has established multiple NAAQS for PM, including for PM$_{2.5}$. The first PM$_{2.5}$ NAAQS were adopted in 1997, with a revision adopted in 2006. The current PM$_{2.5}$ NAAQS were adopted in 2012. These include an annual primary
NAAQS of 12.0 µg/m³; an annual secondary NAAQS of 15.0 µg/m³; and, a 24-hour primary and secondary NAAQS of 35 µg/m³.  

Q37. ARE THE PM$_{2.5}$ NAAQS DESIGNED TO BE PROTECTIVE OF HUMAN HEALTH?
A. Yes, as I’ve described, EPA is required to set the primary NAAQS at a level protective of public health, including sensitive populations, with an adequate margin of safety.

Q38. YOU’VE DESCRIBED EPA’S PROCESS FOR ESTABLISHING A NAAQS. DID EPA FOLLOW THIS PROCESS TO ADOPT THE 2012 PM$_{2.5}$ NAAQS?
A. Yes. Overall, the process took approximately five and a half years, and included numerous rounds of public notice and comment and scientific advisory reviews. For the current PM$_{2.5}$ NAAQS, EPA’s review process began in June 2007 and extended through December 2012. It included all of the phases previously enumerated, with multiple iterations of draft publications, public meetings and comment periods, and solicitation of views from the CASAC. EPA held at least 11 public meetings and workshops, published 15 notices of availability and opportunities for public comment on pre-rulemaking documents, and published four rulemaking notices and notices of public hearings.  

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21 https://www3.epa.gov/ttn/naaqs/standards/pm/s_pm_2007_fr.html
extensive response to comments document and regulatory impact analysis was published with the final rulemaking to adopt the standards.

Q39. WHAT SCIENTIFIC STUDIES AND EVIDENCE DID EPA CONSIDER?

A. In short, EPA considered the full body of peer-reviewed journal articles and studies, including epidemiological studies, and focused on studies relating health effects to PM$_{2.5}$ exposure. EPA stated that, in developing the NAAQS, the agency “has drawn upon an integrative synthesis of the entire body of evidence concerning exposure to ambient fine particles and a broad range of health endpoints, focusing on those endpoints for which the Integrated Science Assessment concludes that there is a causal or likely causal relationship with long- or short-term PM$_{2.5}$ exposures. The EPA has also considered health endpoints for which the Integrated Science Assessment concludes there is evidence suggestive of a causal relationship with long-term PM$_{2.5}$ exposures.”\textsuperscript{22} In adopting the 2012 PM$_{2.5}$ NAAQS, EPA stated, “This intensive evaluation of the scientific evidence and quantitative assessments has provided a comprehensive and adequate basis for regulatory decision making at this time.”\textsuperscript{23}

\textsuperscript{22} 78 FR 3097, January 15, 2013.

\textsuperscript{23} Ibid.
Q40. WERE THE 2012 PM$_{2.5}$ NAAQS CHALLENGED IN COURT?

A. Yes. Several parties challenged the final NAAQS as adopted by EPA. The challengers asserted that EPA acted unreasonably, under the arbitrary and capricious standard, in amending the level and form of the NAAQS, amending the provisions for ambient monitoring networks, and adopting final revisions to the standards prior to publishing certain implementation documents. The case was argued before the DC Circuit Court of Appeals on February 20, 2014. On May 9, 2014, the Court upheld EPA’s decisions and denied the petitions for review on all counts.\(^{24}\)

VIII. CONCERNS RAISED REGARDING PM$_{2.5}$ AND NOPS

A. Reliance on the NAAQS to Assure Protection of Public Health

Q41. IN HIS TESTIMONY ON BEHALF OF THE INTERVENORS, DR. THURSTON TESTIFIES THAT THE PM$_{2.5}$ NAAQS “ARE NOT EFFECTIVE IN PROTECTING THE PUBLIC HEALTH.” BASED ON YOUR EXPERT KNOWLEDGE OF THE NAAQS, DO YOU AGREE?

A. No, I do not agree. In my opinion, it is unreasonable to dismiss the NAAQS as ineffective in protecting public health or to disregard the NAAQS in making decisions regarding the approval of the proposed NOPS.

Based on my knowledge of the Clean Air Act and of the process EPA adheres to in establishing the NAAQS, including the comprehensive and robust consideration of all

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\(^{24}\) See, Nat’l Assoc. of Manufacturers v. EPA, 750 F.3d 921 (D.C. Cir. 2014).
relevant scientific studies relating the health effects of exposure to PM\textsubscript{2.5}, I consider it appropriate and reasonable -- indeed, important -- to consider the NAAQS and the well-established framework under New Source Review for evaluating emissions increases and decreases in evaluating proposed power plants and other proposed projects. Dr. Thurston’s opinion, which amounts to an assertion that only zero emissions could be considered protective of public health, represents the view of a single scientist. In contrast, the PM\textsubscript{2.5} NAAQS was developed through an extensive, comprehensive, robust and dynamic process involving the work and input of hundreds of interested individuals and scientists (including Dr. Thurston), the full body of relevant available science, and the careful and deliberate balancing of the risk, exposure, and policy considerations to arrive at a set of standards requisite to protect public health, including sensitive populations, with an adequate margin of safety. Those standards have been subsequently challenged and upheld by the D.C. Circuit Court of Appeals.

B. Consideration of the Michoud Unit Shutdowns

Q42. IN HIS TESTIMONY ON BEHALF OF THE INTERVENORS, DR. THURSTON TESTIFIES THAT BECAUSE THE DEACTIVATED MICHoud UNITS 1, 2, AND 3 WERE SHUT DOWN BEFORE THE NEW NOPS TURBINE WOULD COMMENCE OPERATION, IT WOULD NOT BE REASONABLE TO CONSIDER THEIR EMISSIONS AS PART OF THE “BASELINE.” DO YOU AGREE?

A. No, Dr. Thurston is incorrect in his premise that the emissions from the shutdown Michoud units should be ignored, and his testimony is unreasonable if he means to
suggest that the shutdowns should have been delayed to occur after the startup of the new NOPS unit(s). In fact, the New Source Review regulations require that contemporaneous decreases must take place and must be permanent and enforceable before, or no later than, the startup of any proposed increases in order for those emission reductions to be creditable in the netting analysis for the contemporaneous period.

What is occurring here is precisely consistent with the intent of the regulations. First, ENO shut down and permanently retired the Michoud units. The resulting reductions are made enforceable by deleting the units from the air permit, such that they are no longer authorized to operate under the CAA. In regulatory terms, a “baseline” of emissions representative of normal operations is established for each of the retired units, in order to determine the level of the emission reductions considered contemporaneous with the proposed NOPS project. Thus, these actual emission reductions, which clearly occurred during the contemporaneous period, are quantified, permanent and enforceable, and can be relied upon in considering the proposed 226 MW CT or the 128 MW RICE project.

Q43. IS THIS THE SAME “CONTEMPORANEOUS PERIOD” YOU PREVIOUSLY DESCRIBED IN RELATION TO DETERMINING IF A MODIFICATION IS MAJOR OR MINOR UNDER THE PSD PROGRAM?

A. Yes, it is. For the NOPS project, the contemporaneous period is approximately January 2013 (five years before commencement of construction) until approximately October 2019 (the anticipated date of startup). Since the shutdown of the Michoud units all
occurred in 2016, the reductions are clearly within the contemporaneous window and should be considered in determining the net emissions change.

C. Air Quality Modeling of the NOPS Project

Q44. AS PART OF THE 2016 AIR PERMIT REVIEW FOR THE 226 MW CT, DID LDEQ REQUIRE ENO TO MODEL THE PROPOSED EMISSION INCREASES TO ASSESS THE AIR QUALITY IMPACT OF THE PROJECT?

A. No, LDEQ did not require modeling to be performed, and that is not surprising. The project is a minor modification, with significant reductions of some pollutants and no significant net emissions increases proposed. As previously discussed, it is reasonable for LDEQ to determine that no adverse impacts to air quality will occur based on the level of emission changes, without air quality modeling.

Q45. DESPITE THE FACT THAT ENO HAS MADE SIGNIFICANT, PERMANENT EMISSION REDUCTIONS BY RETIRING THE MICHOUD UNITS, AND THAT AIR QUALITY MODELING WAS NOT REQUIRED BY LDEQ FOR AIR PERMITTING, ENO CONTRACTED WITH CK ASSOCIATES TO PERFORM A SCREENING AIR QUALITY MODEL OF POTENTIAL NOPS EMISSIONS IMPACTS. HAVE YOU REVIEWED THE ASSOCIATED MODELING REPORT, AND WHAT ARE YOUR OBSERVATIONS?

A. Yes, I have reviewed the report that was included with Jonathan E. Long’s Supplemental Direct Testimony on behalf of ENO in November 2016. Table 3, Screening Model
Results, presents model-predicted ambient concentrations from the NOPS emissions sources that are well below the NAAQS for every pollutant modeled. Notably, this model considered only the new emissions proposed for the 226 MW CT and ancillary equipment. It did not take into account the reductions in emissions from the retired Michoud Units 1, 2, and 3. This modelling exercise demonstrates that, even when the substantial emission reductions are not taken into account, the NOPS CT project would not cause an exceedance of the NAAQS.

Q46. DID ENO PERFORM A SIMILAR MODELLING EXERCISE FOR ALTERNATIVE 2, THE RICE PROJECT?

A. Yes, ENO again contracted with CK Associates to perform a screening model exercise, using the full anticipated permitted emission rates for the RICE project, without taking into consideration the emission reductions associated with the Michoud Unit 1, 2, and 3 shutdowns. The model-predicted ambient concentrations from the NOPS emissions sources for Alternative 2 are also well below the NAAQS for every pollutant modeled.

Q47. DOES DR. THURSTON DISPUTE THE CONCLUSION THAT EMISSIONS FROM NOPS WILL NOT CAUSE THE AIR QUALITY TO EXCEED THE NAAQS OR OTHER REGULATORY STANDARDS?

A. No, Dr. Thurston has not alleged that the NAAQS would be exceeded or that the NOPS emissions would cause any environmental or health-based regulatory standard to be
violated. Instead, as noted previously, Dr. Thurston opines that the PM$_{2.5}$ NAAQS “are not effective in protecting the public health.”

Q48. DR. THURSTON TESTIFIES THAT ENO’S ANALYSIS OF AIR QUALITY IMPACTS IS INADEQUATE BECAUSE ENO DID NOT PERFORM A “HEALTH-RISK ANALYSIS OF PM$_{2.5}$ EMISSIONS FROM THE PROPOSED FACILITY.” DO YOU AGREE?

A. No, I do not agree. Dr. Thurston fails to recognize the well-established framework for protection of public health through the establishment and implementation of the NAAQS and the associated New Source Review program. Under the framework for air quality protection in the United States, a uniform standard is applied that is protective of public health. First, EPA establishes the level of ambient concentration that is protective of public health, with an adequate margin of safety (i.e., NAAQS). Second, states continuously monitor the ambient air quality and compare the actual measured concentrations to the NAAQS to assess air quality in relation to the health-based standard. If an area is not attaining the NAAQS, then the state must require reductions in emissions from contributing sources as part of an attainment plan. Third, when a company such as ENO proposes a project, the projected emissions increases from the project and net emissions change associated with the project is evaluated prior to construction, to assure that air quality and public health are protected.

Notably, it is not required, nor would it be appropriate or practical, for individual permit applicants to perform a detailed health-risk analysis of the type described by Dr.
Thurston as part of the permitting process for every change. This type of analysis is much more suited to a larger scale study covering a broader geographic area and inventory of emissions, such as those conducted by EPA. An individual permit applicant simply could not accomplish the level of robust review that EPA’s review and establishment of the NAAQS entails.

Q49. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.
AFFIDAVIT

STATE OF LOUISIANA
PARISH OF EAST BATON ROUGE

NOW BEFORE ME, the undersigned authority, personally came and appeared, BLISS M. HIGGINS, 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.

Bliss M. Higgins

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 25TH DAY OF JUNE, 2017

Kyle Beall
NOTARY PUBLIC

My commission expires: AT DEATH

Kyle B. Beall
Bar Roll 24957
BEFORE THE
COUNCIL FOR THE CITY OF NEW ORLEANS

SUPPLEMENTAL AND AMENDING APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF

SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY OF

DR. GEORGE LOSONSKY, PH.D., P.G.

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

JULY 2017
**TABLE OF CONTENTS**

I. INTRODUCTION ........................................................................................................ 3

II. SUMMARY .................................................................................................................. 5

III. THE C-K TECHNICAL REPORT ............................................................................... 7

IV. FURTHER ANALYSIS OF SUBSIDENCE ISSUES ............................................... 11
   A. Drawdown Calculations ...................................................................................... 12
   B. Consolidation Settlement Calculation ................................................................. 15

V. THE CB&I REPORT .................................................................................................. 17

VI. DR. KOLKER’S SUBSIDENCE TESTIMONY ....................................................... 19

VII. FLOOD RISKS ........................................................................................................... 23

VIII. CONCLUSION ........................................................................................................... 29

**EXHIBITS**

Exhibit GL-1  Curriculum vitae of Dr. George Losonsky, Ph.D., P.G.

Exhibit GL-2  Addendum to CK Technical Report

Exhibit GL-3  Informational Submittal: Evaluation of Proposed Groundwater Withdrawals and Subsidence – Entergy New Orleans Power Station
I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.
A. My name is George Losonsky, Ph.D., P.G., President of Losonsky & Associates, Inc. of 4207 Rhoda Drive, Baton Rouge, Louisiana 70816.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING?
A. I am testifying on behalf of Entergy New Orleans, Inc. (“ENO” or the “Company”) in support of the Company’s Supplemental and Amending Application for Approval to Construct the New Orleans Power Station (“NOPS”) and Request for Cost Recover and Timely Relief (“Supplemental Application”).

Q3. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL, PROFESSIONAL, ACADEMIC, AND BUSINESS EXPERIENCE.
A. I graduated from Munich American High School in Munich, Germany in 1976. I attended Oberlin College in Oberlin, Ohio from 1976 through 1980, where I earned a BA degree in Geology. I attended the University of Cincinnati, where I earned M.S. and Ph.D. degrees in Geology in 1983 and 1992. My areas of study were Physical and Chemical Processes in Geology; Tectonics; Structural Geology; and Sedimentology. At the University of Cincinnati, I worked as a Graduate Assistant and Instructor between 1980 and 1986. From 1986 to 1990, I was a Research Associate for the Center Hill Research Lab under contract to the U.S. E.P.A. Risk Reduction Engineering Laboratory in Cincinnati, Ohio. From 1990 to 1991, I was the Chief Hydrogeologist for Midwest Water Resource, Inc. in Charlotte, Michigan. From 1991 to 1992, I was the Manager of
Environmental Applications for Baker Hughes, Inc. in Houston, Texas. From 1993 to 2002, I was the Technical Project Manager for IT Corporation/IT Group/Shaw Environmental & Infrastructure, in Lake Charles, Louisiana, with assignments in Tampa, Florida; Concord, California; and Kaiserslautern/Ramstein Air Base, Germany. From 2002 to 2004, I was a Technical Associate for Geosyntec in Baton Rouge, Louisiana. From 2004 to 2005, I was a Project Manager for CH2M HILL in New Orleans, Louisiana. Since 2005, I have been the President of Losonsky & Associates, Inc. in Baton Rouge, Louisiana. I also served as a Commissioner of the Southeast Louisiana Flood Protection Authority-East from 2007 until 2012. My Curriculum Vitae (“CV”) is attached as Exhibit GL-1.

Q4. WHAT ARE YOUR RESPONSIBILITIES AS THE PRESIDENT OF LOSONSKY AND ASSOCIATES, INC.?
A. I manage the company and perform hydrogeological, geochemical, and engineering geology evaluations for environmental, infrastructure, well design, well installation, well testing, and water supply projects.

Q5. PLEASE BRIEFLY DESCRIBE YOUR ROLES AND RESPONSIBILITIES AS A COMMISSIONER OF THE SOUTHEAST LOUISIANA FLOOD PROTECTION AUTHORITY – EAST.
A. I attended monthly board meetings, served as Chairman of the Finance Committee, attended various monthly committee meetings on engineering, geotechnical, legal and management topics, attended Association of Levee Boards of Louisiana annual meetings,
visited and met with the U.S. Army Corps of Engineers (“USACE”) to discuss and help coordinate levee and coastal flood protection related projects. My work in board and committee meetings included review, discussion, and recommendations for actions and work performed by the Orleans, Lake Borgne and East Jefferson Levee Districts; the USACE; and the Coastal Protection and Restoration Authority (“CPRA”). The work encompassed the improvements and levee lifting of the southeast Louisiana levee protection system, coastal restoration projects, and Master Plan development for New Orleans area flood protection and coastal restoration.

Q6. DID YOU CONTRIBUTE TO THE C-K TECHNICAL REPORT, ATTACHED TO THE SUPPLEMENTAL TESTIMONY OF ENO’S WITNESS, JONATHAN E. LONG, AS EXHIBIT JEL-6?
A. Yes.

Q7. PLEASE BRIEFLY DESCRIBE YOUR ROLE IN PREPARING THE C-K TECHNICAL REPORT.
A. I wrote, co-wrote, and reviewed sections relating to the operation of groundwater recovery wells at the proposed NOPS site and subsidence related issues. I also developed the Figures relating to subsidence that are depicted in the C-K Technical Report.

II. SUMMARY
Q8. WHAT IS THE PURPOSE OF YOUR TESTIMONY?
A. The purpose of my testimony is to sponsor, introduce, and briefly discuss the Addendum
to the C-K Associates Technical Report of November 16, 2016: Evaluation of Predicted Drawdown and Consolidation Settlement Resulting from Proposed NOPS Pumping ("Addendum to C-K Technical Report" or the "Addendum"), which I attach to my testimony as Exhibit GL-2. My testimony also discusses the Evaluation of Proposed Groundwater Withdrawals and Subsidence – Entergy New Orleans Power Station report prepared by CB&I Government Solutions, Inc. ("CB&I"), which I attach to my testimony as Exhibit GL-3 (the "CB&I Report").

Additionally, my testimony seeks to clarify errors and misrepresentations contained in the Direct Testimony of Dr. Alexander Kolker of January 6, 2017, submitted on behalf of Alliance for Affordable Energy, Deep South Center for Environmental Justice, and Sierra Club.

Q9. PLEASE SUMMARIZE YOUR TESTIMONY.

A. In my testimony, I discuss the analyses I performed in preparing the Addendum to the C-K Technical Report. Specifically, I discuss my updated analyses on considerations related to groundwater usage required to operate the Combustion Turbine ("CT") initially proposed in the Application filed on June 20, 2016. I also discuss the analyses of these same considerations that I performed concerning the groundwater usage required for the operation of the seven Wärtsilä 18V50SG Reciprocating Internal Combustion Engine ("RICE") Generator sets ("Alternative Peaker") that ENO’s Supplemental Application proposes as an alternative to the CT. These supplemental analyses led me to conclude that groundwater withdrawal associated with the Alternative Peaker, like the CT, will not exacerbate subsidence or cause damage to infrastructure in New Orleans East. I also
briefly discuss the analyses performed for the initial C-K Technical Report and the conclusions drawn from the initial analyses, which conclusions are consistent with and verified by the Addendum to the C-K Technical Report.

With regard to Dr. Kolker's Direct Testimony, I note that his testimony is not based on a valid conceptual model of subsidence and related damage to infrastructure caused by the operation of groundwater extraction wells. His testimony contains incorrect statements about technical concepts related to potential impacts of the proposed operation of NOPS. His testimony contains statements on a variety of topics that are correct in general, but do not have the direct bearing on NOPS or New Orleans East communities that his testimony implies. His testimony also includes statements that misrepresent technical content of the C-K Technical Report to the Council.

III. THE C-K TECHNICAL REPORT

Q10. WHAT DID THE C-K TECHNICAL REPORT CONCLUDE WITH REGARD TO THE EFFECTS OF GROUNDWATER WITHDRAWAL ASSOCIATED WITH THE CT UNIT PROPOSED FOR NOPS?

A. The C-K Technical Report concluded that groundwater withdrawal associated with the CT unit proposed for NOPS will not exacerbate ground subsidence or cause damage to infrastructure in New Orleans East.

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Q11. WHAT IS THE BASIS FOR THIS CONCLUSION?

A. The proposed groundwater withdrawal rate is too small to directly affect subsidence or cause damage to buildings and infrastructure at NOPS or in New Orleans East. This statement is supported by a review of recent testing data for the groundwater wells at the Michoud Facility. As noted in the C-K Technical Report, the specific capacity of the wells located at the proposed NOPS site range from 36.4 to 49.7 gallons per minute ("gpm")/ft. Wells of this capacity range would cause only a minimal drawdown of the water levels in the Gonzales-New Orleans aquifer, which drawdown would be within the range of what one might expect as part of natural variation due to changes in rainfall or river water levels. This minimal drawdown level, coupled with the overall trend of rising water levels in the Gonzales-New Orleans aquifer, which were depicted in Figure 5 in the C-K Technical Report, led me to conclude that the operation of the proposed CT Unit at NOPS (with an anticipated groundwater withdrawal rate of 96 gpm) will not exacerbate subsidence in New Orleans East or cause damage to infrastructure in the area. As I discuss below, the analyses performed for the Addendum also support this conclusion.

Q12. WHAT DID THE C-K TECHNICAL REPORT CONCLUDE WITH REGARD TO CONCERNS THAT PAST GROUNDWATER USAGE BY THE DEACTIVATED MICHOUD UNITS HAS CAUSED DAMAGE TO INFRASTRUCTURE AND RESIDENCES IN NEW ORLEANS EAST?

A. The C-K Technical Report concluded that "groundwater withdrawal at the Michoud Plant is not the cause of observed damage to infrastructure in New Orleans East including
buildings, roads, and flood protection structures.”2

Q13. WHAT ANALYSIS FORMED THE BASIS OF THIS CONCLUSION?

A. The C-K Technical Report discusses differential settlement of structures, which is an effect that can be caused by subsidence due to consolidation settlement of subsurface sediments. The distinction between the cause and effect is crucial to determining whether groundwater withdrawal can cause damage to infrastructure. Under certain conditions, groundwater withdrawal can contribute to consolidation settlement, which in turn can cause differential settlement that may cause damage to infrastructure such as buildings, roads, and flood protection structures. Consolidation settlement due to groundwater withdrawal occurs in the deep subsurface. Differential settlement observed throughout the New Orleans metropolitan area is caused by localized shallow dewatering due to vegetation, drainage, and other shallow infrastructure. As noted in the C-K Technical Report, groundwater withdrawal from improperly managed wells does have the ability to cause differential settlement. However, where groundwater withdrawal does cause differential settlement, signs of differential settlement (such as damage to buildings and other infrastructure) would be visible at or near the wells themselves.

Based on (i) observations made during visits to the NOPS/Michoud site and surrounding areas, (ii) data relating to operation and testing of groundwater wells at the Michoud facility, (iii) area-wide water level and groundwater production data, and (iv) discussions with Company personnel about historical operation and maintenance at the

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2 See Exhibit JEL-6 at p. 1.
site, I noted the absence of any such signs of differential settlement at the Michoud site. The absence of any evidence of differential settlement at the site of the wells used to provide groundwater for the operation of the deactivated Michoud Units supports my conclusion that any past groundwater pumping at these deactivated Units did not lead to differential settlement or damage to infrastructure, buildings, or flood protection structures located in New Orleans East.

Q14. DOES THE C-K TECHNICAL REPORT CONCLUDE THAT THERE HAS BEEN NO SUBSIDENCE IN THE MICHOUD AREA?

A. No, and the statement in Dr. Kolker’s testimony concerning this matter misrepresents the substance of the C-K Technical Report to the Council. In fact, the C-K Technical Report states that “subsidence has occurred in New Orleans East and was caused by multiple factors.” The C-K Technical Report accurately describes the role of isostatic sag in the geologic history of the New Orleans area, along with other processes, in contributing to subsidence. Dr. Kolker, as well as individuals who have studied subsidence in the New Orleans area, agree that multiple processes cause subsidence. In fact, Ms. Cathleen Jones – the lead author of the 2016 study Dr. Kolker discusses, has

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3 See Pre-Filed Direct Testimony of Dr. Alexander S. Kolker on Behalf of Alliance for Affordable Energy, Deep South Center for Environmental Justice, and Sierra Club, submitted in this proceeding on January 6, 2017 (“Kolker Testimony”), at p. 3 (“The CK Report [sic] relied upon by Entergy [sic] suggested that there was no subsidence in the Michoud area.”).

4 See Exhibit JEL-6 at p. 2.

5 See Kolker Testimony at p. 3.

stated that “additional research is needed to directly link groundwater pumping to the subsidence rates,” and that, with regard to the Michoud area, it is “unclear whether the subsidence there results from groundwater withdrawal, compaction of soft soils and other soil processes, or because of geologic processes, such as a nearby ‘Michoud fault.’”

Such additional research was performed for the C-K Technical Report, which led to the conclusion that groundwater withdrawal associated with the deactivated Michoud Units did not contribute “to differential settlement (i.e. structural damage) in New Orleans East.”

IV. FURTHER ANALYSIS OF SUBSIDENCE ISSUES

Q15. WHAT ADDITIONAL ANALYSES DID YOU PERFORM FOR THE ADDENDUM TO THE C-K TECHNICAL REPORT?

A. I performed drawdown calculations using standard analytical methods used in groundwater hydrogeologic evaluation of aquifer response to the operation of pumping wells. The analytical methods I employed for this purpose are the Theis solution and the Hantush-Jacobs solution. For both solutions, as well as for the settlement calculations I discuss below, I assumed NOPS would operate 24 hours a day, 365 days a year. Although I understand that neither the CT nor the Alternative Peaker is expected to operate at this level of frequency, my assumption was intended to provide the most conservative evaluation possible of groundwater and subsidence related issues for the Council. I also

affiliation of some of the report authors with the Jet Propulsion Laboratory, which is a NASA-affiliated research institute associated with the California Institute of Technology.


8 See Exhibit JEL-6 at p. 2.
performed consolidation settlement calculations using analytical solutions simulating the hydrogeologic setting of the NOPS site, with thick clay overlying the confined New Orleans-Gonzalez aquifer.

A. Drawdown Calculations

Q16. PLEASE DESCRIBE THE THEIS AND HANTUSH-JACOB SOLUTIONS.

A. The Theis solution is the basic equation for calculating drawdown at different distances away from a groundwater withdrawal well, and it applies known physical characteristics (aquifer parameters) that are specific to the New Orleans-Gonzalez aquifer, including hydraulic conductivity and storage coefficient. The Hantush-Jacob solution is a more complex equation and is more site-specific for NOPS as it accounts for the natural hydraulic communication between the New Orleans-Gonzalez aquifer and overlying clay units.

Q17. WHAT IS THE PURPOSE OF PERFORMING A DRAWDOWN CALCULATION WHEN ASSESSING THE EFFECTS OF GROUNDWATER PUMPING?

A. If settlement were to occur as a result of groundwater withdrawal, it would develop in response to drawdown in accordance with the standard drawdown solutions. As such, drawdown calculations help to provide more certainty and accuracy around assessments of possible consolidation settlement associated with groundwater withdrawal.

Q18. WHAT FACTORS ARE TAKEN INTO ACCOUNT FOR THE DRAWDOWN CALCULATIONS?

A. Aquifer properties including the hydraulic conductivity of the aquifer, the storage
coefficient of the aquifer, its thickness, whether it is confined or unconfined, whether it is leaky or non-leaky, and well specifications including the screen interval and the flow rate.

Q19. HOW DO THESE DRAWDOWN CALCULATIONS COMPARE TO THE WELL-CAPACITY ANALYSIS YOU DESCRIBED PERFORMING FOR THE C-K TECHNICAL REPORT?

A. The specific capacity measurement is based on short term testing of the well over the course of several hours. It relates to water levels in the well, not in the aquifer at a distance away from the well. As a result, the drawdown calculations performed for the Addendum to the C-K Technical Report represent a more thorough analysis of drawdown potential associated with NOPS.

Q20. WHAT RESULTS DID THE DRAWDOWN CALCULATIONS YIELD WITH REGARD TO THE CT UNIT?

A. The site-specific calculations (Hantush-Jacob solution) predict a maximum drawdown over a 10-year period of about one foot near the NOPS pumping well, diminishing to half a foot or less at a distance of several thousand feet away, and one quarter foot or less at a distance of two miles from the well. It should be noted that a confined aquifer such as the Gonzales-New Orleans aquifer will reach steady-state drawdown long before 10 years, and drawdown will remain essentially unchanged after about 5 years or less.

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As discussed in the Addendum to the C-K Technical Report, at p. 2 and 3, a 10-year period is calculated because it is a conservative (high end) estimate of how long it would take to reach maximum drawdown.
Q21. WHAT CONCLUSIONS DO YOU DRAW FROM THESE RESULTS CONCERNING THE CT UNIT’S POTENTIAL EFFECTS ON SUBSIDENCE?

A. The CT unit will create insufficient drawdown to exacerbate subsidence.

Q22. HOW DO THESE CONCLUSIONS COMPARE WITH THE CONCLUSIONS STATED IN THE C-K TECHNICAL REPORT?

A. These conclusions are in agreement with the conclusions of the C-K Technical Report.

Q23. WHAT RESULTS DID THE DRAWDOWN CALCULATIONS YIELD WITH REGARD TO THE ALTERNATIVE PEAKER?

A. The site-specific calculations (Hantush-Jacob solution) predict a maximum drawdown over a 10-year period of half an inch or less near the NOPS pumping well, diminishing to approximately one hundredth of an inch several thousand feet away from the well. As noted above, this drawdown is expected to remain the same long-term, beyond 10 years.

Q24. WHAT CONCLUSIONS DO YOU DRAW FROM THESE RESULTS CONCERNING THE ALTERNATIVE PEAKER’S POTENTIAL EFFECTS ON SUBSIDENCE?

A. The Alternative Peaker unit will create insufficient drawdown to exacerbate subsidence.
B. Consolidation Settlement Calculation

Q25. WHAT IS THE PURPOSE OF PERFORMING A CONSOLIDATION SETTLEMENT CALCULATION WHEN ASSESSING THE EFFECTS OF GROUNDWATER PUMPING?

A. The consolidation settlement calculation predicts total possible settlement due to drawdown caused by groundwater pumping. For the analysis presented in the Addendum to the C-K Technical Report, the consolidation settlement calculations predict settlement occurring between 500-650 feet below the surface of the earth.\(^\text{10}\)

It should also be noted that where groundwater pumping has already occurred at a site, pumping at or below the levels of the previous pumping will not cause additional settlement. In other words, the consolidation settlement calculations presented in the Addendum to the C-K Technical Report do not represent incremental increases to settlement likely to occur at the NOPS site. Rather, they present the calculated total possible consolidation settlement levels associated with the calculated drawdown assuming no prior groundwater pumping has occurred.

Q26. WHAT FACTORS ARE TAKEN INTO ACCOUNT WHEN PERFORMING THE CONSOLIDATION SETTLEMENT CALCULATIONS?

A. Consolidation settlement calculations account for soil properties including density, void ratio, and compression index; aquifer properties including thickness, groundwater elevation, and hydraulic conductivity.

\(^{10}\) See Exhibit GL-2 at Table 1.
Q27. WHAT RESULTS DID THE CONSOLIDATION SETTLEMENT CALCULATIONS YIELD WITH REGARD TO THE CT UNIT?

A. The calculated total possible consolidation settlement for the CT unit is in the range of 0.7 to 4.7 millimeters (0.027 to 0.18 inch) for a flow rate of 96 gpm. (The low end of this range is more likely considering the geological characteristics of the New Orleans-Gonzalez aquifer.) Since a higher flow rate has already been applied to the New Orleans-Gonzalez aquifer in the past, this settlement has already occurred, and continued pumping at the level proposed for operation at the CT unit will not cause additional settlement.

Q28. WHAT CONCLUSIONS DO YOU DRAW FROM THESE RESULTS CONCERNING THE CT UNIT’S POTENTIAL EFFECTS ON SUBSIDENCE?

A. The CT unit cannot exacerbate subsidence because the settlement it can create is very small and will already have occurred during past groundwater withdrawal. Once the potential settlement has occurred, pumping at the same or lower flow rates cannot cause additional settlement.

Q29. HOW DO THESE CONCLUSIONS COMPARE WITH THE CONCLUSIONS STATED IN THE C-K TECHNICAL REPORT?

A. These conclusions are in agreement with those stated in the C-K Technical Report.
Q30. WHAT RESULTS DID THE CONSOLIDATION SETTLEMENT CALCULATIONS YIELD WITH REGARD TO THE ALTERNATIVE PEAKER?

A. The calculated total possible consolidation settlement for the Alternative Peaker is in the range of 0.03 to 0.19 millimeter (0.001 to 0.007 inch) for a flow rate of 3.9 gpm. Since a higher flow rate has already been applied to the New Orleans-Gonzalez aquifer in the past, this settlement has already occurred, and continued pumping at the level proposed for operation of the Alternative Peaker will not cause additional settlement.

Q31. WHAT CONCLUSIONS DO YOU DRAW FROM THESE RESULTS CONCERNING THE ALTERNATIVE PEAKER’S POTENTIAL EFFECTS ON SUBSIDENCE?

A. The Alternative Peaker cannot exacerbate subsidence because the settlement it can create is negligible.

V. THE CB&I REPORT

Q32. YOU MENTIONED A REPORT PREPARED BY CB&I. HAVE YOU REVIEWED THIS REPORT?

A. Yes.

Q33. WHAT DOES THE REPORT CONCLUDE?

A. It concludes, based on drawdown calculations and settlement calculations (taking known aquifer characteristics into account), that the proposed NOPS groundwater withdrawals will be too small to contribute to any subsidence in the Michoud area.
Q34. HOW DO THE ANALYTICAL METHODS DESCRIBED IN THE CB&I REPORT COMPARE TO THOSE YOU DESCRIBED PERFORMING FOR THE ADDENDUM TO THE CK REPORT?

A. The analytical methods employed for the Addendum and the CB&I Report are founded on the same hydrogeologic and geotechnical principles. The additional analyses that I performed build on the analyses presented in the CB&I Report. The Hantush-Jacob drawdown solution is based on the same Theis solution as the Cooper-Jacob approximation used in the CB&I Report, and in addition it accounts for a leaky aquifer. The Niu-Wang-Chen-Li solution for consolidation settlement is based on the same soil mechanics principles of Karl Terzaghi as the Freeze and Cherry approximation used in the CB&I Report, extended beyond one-dimensional analysis and applied to a groundwater withdrawal well in a confined sandy aquifer, taking into account the overlying clay.

Q35. DO THE ANALYSES YOU PERFORMED FOR THE ADDENDUM TO THE C-K REPORT SUPPORT THE CONCLUSIONS DRAWN IN THE CB&I REPORT?

A. Yes.

Q36. DO YOU AGREE WITH THE CONCLUSIONS DRAWN IN THE CB&I REPORT?

A. Yes.
VI. DR. KOLKER’S SUBSIDENCE TESTIMONY

Q37. IN HIS DIRECT TESTIMONY, DR. KOLKER IDENTIFIES AS AN AREA OF CONCERN “THE POTENTIAL FOR THE PROPOSED NOPS TO FURTHER CONTRIBUTE TO SUBSIDENCE AT THE NOPS SITE, IN THE SURROUNDING COMMUNITY, AND POTENTIALLY IN NEW ORLEANS’ RECENTLY UPGRADED STORM RISK REDUCTION SYSTEM.”¹¹ DO YOU FIND DR. KOLKER’S CONCERN TO BE A LEGITIMATE ONE?

A. No. As noted in the C-K Technical report, my analyses of the groundwater withdrawal associated with the operation of NOPS, as well as of the water levels in the Gonzales New Orleans Aquifer, lead me to conclude that the proposed groundwater withdrawal associated with NOPS will not exacerbate subsidence in New Orleans East. The updated analyses provided in the Addendum to the C-K Technical Report provide further support for these conclusions and indicate that neither the CT nor the Alternative Peaker will exacerbate subsidence or cause damage to infrastructure in New Orleans.

In contrast, Dr. Kolker’s Direct Testimony does not reflect any analysis of the water levels in the Gonzales-New Orleans aquifer or the specific groundwater withdrawals, drawdown levels, or consolidation calculations associated with the proposed operation of NOPS. It is my professional opinion that, at minimum, an analysis of aquifer water levels and specific well capacities is necessary to substantiate any opinion concerning the possible effects of groundwater withdrawal from a generator. Dr. Kolker’s failure to specifically consider these issues with respect to NOPS renders his

¹¹ See Pre-Filed Direct Testimony of Dr. Alexander S. Kolker on Behalf of Alliance for Affordable Energy, Deep South Center for Environmental Justice, and Sierra Club, submitted in this proceeding on January 6, 2017 (“Kolker Testimony”), at p. 2.
Q38. DR. KOLKER’S TESTIMONY DISCUSSES A DIFFERENCE BETWEEN “SUBSIDENCE AND DIFFERENTIAL CONSOLIDATION,” AND CONCLUDES THAT “DIFFERENTIAL CONSOLIDATION SHOULD BE THOUGHT OF AS ONE MODE OF SUBSIDENCE, AND NOT DISTINCT FROM IT.”¹² DOES DR. KOLKER’S DISCUSSION OF THIS ISSUE REFLECT A CORRECT UNDERSTANDING OF THE CONCEPT OF “DIFFERENTIAL SETTLEMENT,” WHICH THE C-K TECHNICAL REPORT DISCUSSES AT LENGTH?

A. No. Dr. Kolker confuses cause and effect. The C-K Technical Report discusses differential settlement of structures (i.e., the effect), which can be caused by subsidence due to consolidation settlement of subsurface sediments. As I noted above, the distinction between cause and effect is critical to analyzing possible effects of subsidence. Dr. Kolker’s confusion about cause in the subsurface and effect at the surface leads him to fail to distinguish between consolidation occurring hundreds of feet deep and consolidation near the ground surface. Consequently, he fails to identify or analyze the actual cause of damage to buildings and infrastructure in New Orleans East and instead points the finger at NOPS and the Deactivated Michoud Units despite having no scientific basis for that conclusion.

¹² See Kolker Testimony at p. 3.
Q39. HOW WOULD YOU RESPOND TO DR. KOLKER’S CONCLUSION THAT “THE DATA PRESENTED BY THE CK REPORT [SIC] ARE WOEFLULLY INSUFFICIENT TO JUDGE SUBSIDENCE RISKS”?\(^{13}\)

A. The data presented in the C-K Technical Report, as detailed above, is sufficient for the conclusions drawn in the Report, and far more substantial than what is presented in Dr. Kolker's testimony. The C-K Technical Report relied on analyses of water level trends and specific capacities of the wells, along with lengthy discussion of the geology and subsidence process, to evaluate subsidence risks. Moreover, the supplemental analyses presented in the Addendum to the C-K Technical Report offer further substantiations for the conclusions drawn in the initial C-K Technical Report concerning the negligible impact of the operation of NOPS on subsidence.

Q40. DOES DR. KOLKER’S TESTIMONY CONTAIN ANY DISCUSSION OF ISSUES NOT RELEVANT TO ASSESSING SUBSIDENCE RISKS SPECIFIC TO THE OPERATION OF NOPS?

A. Yes. The references to faulting, peat layers, and sediment loading in the Mississippi birdfoot delta are not directly relevant to the evaluation of potential effects of proposed groundwater withdrawal at NOPS. No significant faulting has been identified that would influence the effects of operating the groundwater wells. Sediment loading in the birdfoot delta in downstream portions of the Mississippi river will not change the effects of operating the groundwater wells. Operating the groundwater wells will not affect peat

\(^{13}\) Id.
layers near the ground surface.

Q41. WHAT DOES THE DISCUSSION OF THESE ISSUES LEAD YOU TO CONCLUDE ABOUT THE ADEQUACY OF DR. KOLKER’S ANALYSIS WITH REGARD TO SUBSIDENCE ISSUES SPECIFICALLY ASSOCIATED WITH NOPS?

A. His discussion of issues not related to the process of groundwater withdrawal and its potential effects on subsidence at NOPS suggests that Dr. Kolker's analysis is unfocused and to a large extent irrelevant.

Q42. WERE YOU ABLE TO REVIEW THE CV ATTACHED TO DR. KOKLER’S TESTIMONY AS EXHIBIT 1?

A. Yes.

Q43. IS THERE ANYTHING ABOUT DR. KOLKER’S CV THAT YOU BELIEVE THE COUNCIL SHOULD CONSIDER WHEN ASSESSING HIS QUALIFICATION TO PROVIDE OPINION TESTIMONY CONCERNING SUBSIDENCE OR FLOOD RISKS ASSOCIATED WITH NOPS?

A. Yes. Dr. Kolker's background is in surficial coastal processes, but he lacks the background in groundwater wells and subsurface geology to assess the effects of operating NOPS on subsidence or the specific causes of damage to buildings and infrastructure observed in New Orleans East. He also does not seem to have any background specifically related to southeast Louisiana flood protection infrastructure.
VII. FLOOD RISKS

Q44. YOU MENTIONED SERVING AS A COMMISSIONER ON THE SOUTHEAST LOUISIANA FLOOD PROTECTION AUTHORITY – EAST (“SLFPA-E”); PLEASE DESCRIBE THE PURPOSE AND SCOPE OF YOUR WORK AS A COMMISSIONER.

A. The SLFPA-East was created in response to flooding associated with Hurricane Katrina; its mission was flood protection in the Orleans, Lake Borgne, and East Jefferson Levee Districts. This included protection from flooding due to hurricanes, rain, or other storm surges. The primary goal of the SLFPA-East was upgrading and maintaining the Hurricane and Storm Damage Risk Reduction System (“HSDRRS”). As commissioner, I reviewed and participated in SLFPA-East's discussions to evaluate plans and proposals of the USACE for the improvement of the New Orleans area levee system with the goal of providing “100 year hurricane flood protection,” or 1 percent flood risk. This work involved many engineering and geotechnical issues, including ground elevations, subsidence, modeling predictions of storm surges, surge barriers, canals, and pumping systems. I also reviewed and participated in SLFPA-East's discussions to evaluate the 2012 Master Plan developed by the CPRA, which Dr. Kolker references in his testimony. The work also involved assessing the possible effects on sea level rise and climate change of flood risks within the SLFPA-East’s jurisdiction.

Q45. DO YOU SHARE DR. KOLKER’S CONCERNS REGARDING THE SUPPOSED VULNERABILITY OF THE PROPOSED NOPA SITE TO FLOODING?

A. No. While it is always good practice to be concerned in general, Dr. Kolker's specific
concerns do not take into account the risk mitigating effects of the existing HSDRRS or
the specific site design proposed for NOPS. In ENO witness Jonathan E. Long’s
Supplemental Direct Testimony, he describes the specific measures within the HSDRRS
that provide added flood protection to the proposed NOPS site. Mr. Long also discusses
the process through which the project team determined the appropriate Top of Concrete
(“TOC”) level for the site and determined that a TOC elevation for NOPS at 3.5 feet
above sea level, which is 2.5 feet higher than the Federal Emergency Management
Agency (“FEMA”) Advisory recommendation, would adequately mitigate any risks of
damage due to flooding at the proposed NOPS site. Dr. Kolker’s testimony fails to take
these site-specific factors into account and instead provides an analysis that is too general
and lacks the specificity to be of real value in determining flood risks at the proposed
NOPS site.

Q46. DR. KOLKER STATES THAT THE 2012 MASTER PLAN INDICATES THAT THE
AREA NEAR NOPS “IS LIKELY TO SEE FLOOD DEPTHS OF 10-15 FEET AT
SOME POINT OVER THE NEXT FIFTY YEARS.”¹⁴ DOES THE 2012 MASTER
PLAN REPRESENT THE MOST CURRENT EVALUATION OF THIS RISK?

A. No, the 2017 CPRA Master Plan does.¹⁵ Dr. Kolker refers to a flood estimate that was
based on flood protection measures as they existed when the 2012 Master Plan was
developed, prior to completion of the HSDRRS. As noted in Jonathan E. Long’s

¹⁴ See Kolker Testimony at p. 7-8.
¹⁵ See http://coastal.la.gov/our-plan/2017-coastal-master-plan/
I will note that as of the date Dr. Kolker filed his testimony, the 2017 Draft Master Plan represented the most
current evaluation of the risks Dr. Kolker discussed by referencing the 2012 Master Plan. The CPRA has since
published the finalized version of the 2017 Master Plan.
Supplemental Direct Testimony, the HSDRRS includes a series of levees and storm surge barriers and upgrades to pumping capacity. These upgrades have significantly increased the defense against storm surge in New Orleans East, including at the proposed site of NOPS. The 2017 Master Plan takes these improvements into account and, as a result, predicts no flooding in the same scenario described in Dr. Kolker’s testimony. In fact, the flood protection measures that have been installed eliminate estimated flooding (i.e., predicts no flooding) at the proposed NOPS site under the “high scenario” over a 50 year time frame (worst case scenario considered under the Master Plan). This is a significant change compared to the 2012 Master Plan.

Q47. TO YOUR KNOWLEDGE, DOES THE DESIGN OF THE MEASURES COMPRISING THE HSDRRS TAKE INTO ACCOUNT ANY INCREASE IN FLOOD RISKS THAT MAY BE ASSOCIATED WITH REGIONAL SUBSIDENCE AND SEA LEVEL RISE?

A. Yes. To my knowledge the USACE and the CRPA are aware of the effects of sea level rise and subsidence and include appropriate safety factors in their planning and design. The CRPA states in the 2012 and 2017 Master Plans that estimates of sea level rise and subsidence are included in the plans. The 2017 Master Plan includes a plan for levee improvements in year 30 of the plan to account for sea level rise and subsidence. As such, the 2017 Master Plan’s prediction of no flooding at the NOPS site, even in the “worst case” scenario described above, includes a consideration of regional subsidence and sea level rise.

16 See, e.g., 2017 Master Plan at p. 72.
Q48. DR. KOLKER RELIES ON THE 2017 DRAFT MASTER PLAN AS SUPPORT FOR
HIS STATEMENT THAT “FOR MUCH OF LOUISIANA, FLOOD RISKS ARE
LIKELY TO INCREASE IN THE YEARS AHEAD.”¹⁷ IS THIS AN ACCURATE
REPRESENTATION OF THE DRAFT MASTER PLAN AND ITS CONCLUSIONS
REGARDING THE RISKS OF FLOODING SPECIFICALLY ASSOCIATED WITH
THE PROPOSED SITE OF NOPS?

A. No. As noted above, the construction of the HSDRRS has significantly reduced flooding
risk at the proposed NOPS site. The design and operation of the HSDRRS has taken into
account the projected sea level rise.

Q49. DR. KOLKER ALSO CLAIMS THAT A “10-YEAR” RAINFALL “COULD LEAD TO
ABOUT ONE FOOT OF FLOODING IN AREAS NEAR THE PROPOSED NOPS
PLANT.” IS THIS AN ACCURATE ASSESSMENT WITH REGARD TO THE
SPECIFIC SITE OF NOPS?

A. No. A storm water management model (“SWMM”) was used to estimate existing
flooding as well as the efficacy of proposed storage and drainage projects and best
management practices proposed throughout the greater New Orleans area. This model
was used as a proof of concept for proposed projects. Only low resolution outputs of the
model were provided in reports and websites referenced by Dr. Kolker and detailed
assumptions used for basis of the model were not available for review. Based on the
outputs, the model does not appear to predict significant flooding in the vicinity of

¹⁷ See Kolker Testimony at p. 9.
NOPS. Due to the large scale of the model, it is likely that conservative assumptions were used, and the model is intended for evaluating regional impacts and not flooding in any discrete area without additional supporting modeling. I would be hesitant to use the model Dr. Kolker relies upon to evaluate flood risk of a specific, local area.

Q50. DOES THE SPECIFIC SITE DESIGN OF NOPS MITIGATE THE RISK OF DAMAGE DUE TO FLOODING IN THE 10-YEAR RAINFALL SCENARIO DR. KOLKER DEScribes?

A. While Dr. Kolker's description of his scenario is not specific enough to definitely evaluate this risk, as noted in Jonathan E. Long’s Supplemental Direct Testimony, the proposed TOC of the proposed NOPS is 1 foot higher than the observed Hurricane Katrina flooding and 2.5 feet higher than the recommended FEMA flooding elevation. Based on the information available, it appears that the planned elevation of the NOPS site is sufficient to protect against flood risk. As noted above, Dr. Kolker’s testimony does not appear to have taken this into account.

Q51. HAVE YOU REVIEWED THE SET OF PROBABILITIES DR. KOLKER LISTS IN TABLE 1 OF THIS TESTIMONY?

A. Yes.

Q52. DOES THAT TABLE PROVIDE AN ACCURATE DEPICTION OF THE “CHANCE OF FLOODING” DURING THE LIFE OF NOPS, AS DR. KOLKER HAS REPRESENTED TO THE COUNCIL?
A. No. Dr. Kolker’s description of the table is misleading. While the table does present the chance of a 100-year storm, it does not directly relate to flooding. In the paragraphs preceding Table 1, Dr. Kolker describes how the 2012 Master Plan predicts no flooding in a 100-year storm, but he includes those values in the Table as corresponding to a “chance of flooding.” This is an internal inconsistency within Dr. Kolker’s analyses. Moreover, as noted above, the 2017 Master Plan takes into account the 500 year and 100 year events and predicts no flooding at the proposed NOPS location. Regardless, Table 1 shows probabilities of representative rainfall events, but it does not present the probability of flooding, contrary to what Dr. Kolker has represented to the Council.

Q53. HAVE YOU REVIEWED DR. KOLKER’S ANALYSIS OF “THE RANGE OF RELATIVE SEA LEVEL RISE SCENARIOS FOR THE AREA AROUND THE PROPOSED NOPS”18?
A. Yes.

Q54. WHAT IS YOUR OPINION ABOUT THE VALIDITY OF DR. KOLKER’S CALCULATIONS OF RELATIVE SEA LEVEL RISE?
A. Dr. Kolker’s analysis uses conservative assumptions about sea-level rise and the flawed assumption that subsidence will continue at a steady rate over the next 50 years. The calculations do not take into account the protection of the HSDRRS and are therefore an invalid basis on which to assess flood risks for the proposed NOPS site.

18 See Kolker Testimony at p. 9-10.
VIII. CONCLUSION

Q55. WHAT WOULD YOU REPRESENT TO THE COUNCIL ABOUT ANY CONCERN RELATED TO GROUNDWATER USAGE FROM EITHER THE CT OR THE ALTERNATIVE PEAKER POTENTIALLY CAUSING DAMAGE IN NEW ORLEANS EAST DUE TO GROUNDWATER WITHDRAWAL?

A. I would assure the Council that given the location, the subsurface conditions, the history of groundwater usage, and the proposed groundwater withdrawal rates, usage from either the CT or the Alternative Peaker has no potential for causing damage in New Orleans East due to groundwater withdrawal.

Q56. WHAT IS YOUR OPINION OF DR. KOLKER’S RECOMMENDATIONS TO THE COUNCIL?

A. The additional studies Dr. Kolker recommends related to subsidence and flood risks are unnecessary because the analysis undertaken for the C-K Technical Report was based on geotechnical data, hydrogeological data, soil boring logs, well construction logs, the CPRA master plan, and other reports that considered storm surge models and climate projections. The C-K Technical Report used this information to develop a geotechnical/hydrogeological conceptual site model, which was presented in the Report. The Addendum to the C-K Technical Report presents a more detailed analysis of concerns related to subsidence and groundwater usage and concludes that operation of either the CT or the Alternative Peaker will not exacerbate subsidence in New Orleans.
Q57. DOES DR. KOLKER’S TESTIMONY PROVIDE ADEQUATE SUPPORT FOR HIS
   CONCERNS RELATED TO NOPS?
   A. No.

Q58. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?
   A. Yes.
AFFIDAVIT

STATE OF LOUISIANA
PARISH OF

NOW BEFORE ME, the undersigned authority, personally came and appeared, GEORGE LOSONSKY, PH.D., P.G., 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.

Dr. George Losonsky, Ph.D., P.G.

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 18TH DAY OF JUNE, 2017

NOTARY PUBLIC

My commission expires:

[Stamp: TERRI L. REESE
Notary Public
State of Louisiana
Notary ID # 847900
My Commission is for Life]
GEORGE LOSONSKY, Ph.D., P.G.

Groundwater and Soil Gas Flow and Transport Modeling
Environmental Remediation and Management
Well Design and Rehabilitation

Losonsky & Associates, Inc.

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225 293 0196 Fax

EDUCATION
University of Cincinnati: Ph.D., Hydrogeology and Sedimentology, 1992
University of Cincinnati: M.S., Physical and Chemical Processes in Geology, 1983
Oberlin College: B.A., Geology, 1980
University of Missouri-Columbia: Geology Field Camp, 1979

PROFESSIONAL HISTORY
Losonsky & Associates, Inc., 2005 -
CH2M HILL Inc., New Orleans, Louisiana, 2004- 2005
GeoSyntec Consultants, Baton Rouge, Louisiana, 2002 - 2004
IT Corporation/IT Group/Shaw Environmental & Infrastructure, 1992 – 2002
IT Infrastructure & Environmental GmbH, Kaiserslautern, Germany, General Manager, 2000 – 2002
Customer Program Manager, Concord, California, 1999 – 2000
Project Manager, Lake Charles, Louisiana/Houston, Texas, 1993 – 1997
University of Cincinnati, Cincinnati, Ohio, Instructor/Research Assistant/Teaching Assistant, 1980 – 1986

REPRESENTATIVE EXPERIENCE

Dr. Losonsky has over 30 years of experience in environmental and water resources problem solving and management. He has extensive experience in design, installation, testing and rehabilitation of production,
testing, monitoring, remediation and mitigation wells completed using hollow-stem auger, mud and air rotary, direct push technology, cone penetrometer testing, hydraulic fracturing, sonic drilling, downhole steerable mud motor drilling, and directional jetting tool drilling. His experience includes logging, correlating and modeling a wide variety of sedimentary, metamorphic and igneous basins and tectonic systems worldwide. Through his academic background and work experience he has gained in-depth, working knowledge of the physical and chemical mechanisms governing groundwater flow and production, aquifer management, and both soil vapor and groundwater plume migration. He has developed and managed soil and groundwater remediation or vapor mitigation programs at military bases, chemical plants, drycleaning facilities, petrochemical refineries, fuel storage facilities, hazardous waste landfills, food processing plants, pharmaceutical industry facilities, and various manufacturing plants. He has assisted in the development of state and regional environmental assessment, remediation, and risk evaluation programs for the drycleaning and retail petroleum industries. He helped organize a vapor intrusion guidance development videoconference between USEPA Region 6 and state regulators. Dr. Losonsky served from 2007 - 2012 on the Board of Commissioners of the Southeast Louisiana Flood Protection Authority-East.

Dr. Losonsky is a recognized expert in subsurface remediation and water supply using horizontal wells, has published numerous technical papers and taught seminars on this subject, and is a founding member of the Horizontal Environmental Technical Committee of the National Ground Water Association, for which has served as Chairperson of the Horizontal Well Interest Group and editor of Horizontal News. Dr. Losonsky was among the pioneers of horizontal environmental wells as Manager of Environmental Applications for Baker Hughes/Eastman Christensen in the early 1990’s, and since then he has designed and managed construction and operation of innovative horizontal well systems for the Department of Defense, Brownfields programs, municipal water systems, real estate developers, drycleaners, petroleum retailers, and the chemical industry.

As a member of the US Environmental Protection Agency (USEPA) Remedial Technologies Development Forum (RTDF) on In Situ Flushing Technologies, the Interstate Technology and Regulatory Cooperation Work Group (ITRC) on In Situ Chemical Oxidation of Contaminated Soil and Groundwater, and the National Ground Water Association’s Water Well Grouting and Decommissioning Task Groups, and the USEPA Risk Reduction Engineering Laboratory/Center Hill Research Facility, Dr. Losonsky has helped develop regulatory guidance and national strategies for implementation of water wells and of hydraulic fracturing, surfactant, co-solvent, partitioning tracer and chemical oxidation technologies for subsurface remediation.

As technical manager, he has applied multiphase, fractured-media flow modeling, statistical modeling, plume stability prediction, and three-dimensional visualization to site characterization, and he has used a wide range of in-situ remedial technologies, including soil vapor extraction, multiple phase extraction, air sparging, bioremediation, chemical oxidation, surfactant flushing, hydraulic fracturing, and electrical resistance heating. In addition to his focus on in situ remediation, Dr. Losonsky’s experience as a hydrogeologist includes design and operation and maintenance of pump-and-treat, treated groundwater reinjection, municipal water extraction and distribution, pumping-monitoring systems, vapor mitigation systems and agricultural non-point source control systems in diverse and complex hydrogeologic settings. Dr. Losonsky has worked in North America, Europe, Africa, Australia, Japan, and South Korea.
EXPERIENCE AND BACKGROUND

• Provides environmental site management, well design and performance testing, well rehabilitation, hydrogeologic and water resources evaluation, real time high resolution site characterization, groundwater and vapor transport modeling, remedial design services worldwide:
  • Losonsky & Associates, Inc., volunteered its efforts and resources in aiding victims of hurricanes Katrina and Rita, and of the Southeast Louisiana flood of August 2016. Dr. Losonsky has supported the hurricane and flood protection efforts in Louisiana through his service as Commissioner of the Southeast Louisiana Flood Protection Authority-East.
  • Environmental Claims Management, Mansfield, Texas. Completed Louisiana Risk Evaluation Corrective Action Program (RECAP) risk assessment for Collette Oil Company site in Baton Rouge, Louisiana.
  • Eagle Environmental Services, Inc., Baton Rouge, Louisiana. Designed and executed aquifer testing program, including slug tests and multi-zone pumping tests to determine groundwater classification in Mississippi River related sedimentary deposits.
  • Senversa Pty Ltd, Adelaide, Australia. Provided hydrogeologic and geochemical analysis in support of an investigation of the effects of copper mining slag emplacement in the former Korrongulla swamp in Primbee, New South Wales.
  • Eagle Environmental Services, Shreveport, Louisiana. Evaluated groundwater-surface water interaction to determine impact of petroleum hydrocarbon impacts on stream water. Designed and implemented in situ remediation system of alluvial sediments using direct push technology to deliver chemical oxidants.
  • CH2M HILL, Marietta, Ohio. Completed horizontal well design review for air sparge system in heterogeneous sand, gravel and clay deposits.
  • Arcadis US, Inc. and Department of Defense Environmental Security Technology Certification Program. Performed hydrogeological and geotechnical evaluation and analysis in support of the Demonstration and Validation of the Horizontal Reactive Media Treatment (HRX) well for Managing Contaminant Plumes in Complex Geological Environments program.
  • Ramboll Environ, Baton Rouge, Louisiana. Evaluated groundwater withdrawal well field design, calculated water well drawdown, and assessed salt water intrusion in Chicot aquifer in southwest Louisiana. Evaluated alternative horizontal well design for mitigating salt water intrusion.
  • Confidential client, Fort Collins, Colorado. Designed horizontal trench in gravel aquifer for high-volume groundwater recovery for long-term dewatering.
  • CH2M HILL, Anchorage, Alaska. Performed hydrogeologic analysis in support of groundwater remediation system for the Former Galena Forward Operating Location. Designed eight horizontal wells in coarse sand and gravel sediments with large seasonal water level fluctuations.
  • Arcadis US, Inc., Bethpage, New York. Supported design of a groundwater withdrawal well to be installed 600 to 650 feet deep in glacial coastal plain sediments. The well required entry 1300 feet laterally displaced from well screen location in a logistically challenging urban setting in Bethpage, New York. The evaluation included consideration of directional drilling methods for deep water well installation.
• Parsons Environment and Infrastructure Group, Inc., Houston, Texas. Designed infiltration gallery using continuous trenching methods featuring two overlapping trench sections. Treated water from pump-and-treat system in nearby source area is infiltrated into the subsurface, acting as a hydraulic barrier downgradient of the source area and accelerating groundwater restoration.

• Senversa Pty Ltd, Adelaide, Australia. Provided Environmental Auditor support for the hydrogeologic evaluation of the Management Plan for Placement of Water Treatment Residuals to Hillbank Quarry. Evaluated leachate transport modeling in vadose and phreatic zones, aquifer testing, and post placement groundwater monitoring programs for four quarries in complex, fractured granite, metamorphic, and sandstone environments.

• Arcadis US, Inc. and Ford Motor Company, Developed specifications for a 2000 foot long hydraulic barrier system consisting of three horizontal wells to prevent offsite migration of groundwater contaminant plumes in heterogeneous sedimentary depositional environment.

• Senversa Pty Ltd, Sydney, Australia. Developed hydrogeologic testing and assessment strategy for the Country Fire Authority to address perfluorinated compounds (PFCs) in groundwater in a complex basaltic extrusive regime, including lava tube formations, in Penshurst, Victoria.

• Senversa Pty Ltd, Melbourne, Australia. Assisted in site characterization and remedial alternatives development for CSL pharmaceutical manufacturing facility in Parkville, Victoria.

• CH2M HILL, Charlotte, North Carolina. Evaluated aquifer testing and groundwater modeling results at the Union Carbide/DOW Texas City facility and designed a horizontal extraction well to remediate a chlorinated hydrocarbon impacts in groundwater.

• Eagle Environmental, Baton Rouge, Louisiana. Compiled database of subsurface hydrogeologic data based on 30 years of site investigation at Rubicon-Huntsman chemical manufacturing facility in Geismar, Louisiana, and developed 3-D model of site hydrogeology and organic compound constituent groundwater plumes. Assisted in preparation of site-wide conceptual site model as part of a corrective action framework required by Louisiana Department of Environmental Quality and U.S. Environmental Protection Agency.

• Senversa Pty Ltd, Melbourne, Australia. Evaluated efficacy of LNAPL recovery trench and assisted in developing sitewide remedial strategy at South Dynon Rail Yard, VicTrack, Docklands, Victoria.

• Senversa Pty Ltd, Melbourne, Australia. Evaluated in situ chemical oxidation pilot trials using potassium permanganate and ozone at Bosch Chassis Systems Manufacturing Facility, East Bentleigh, Victoria, performed remedial technology alternatives screening, and assisted in developing probabilistic cost estimate of site closure costs for confidential client.

• Senversa Pty Ltd, Melbourne, Australia. Evaluated long-term plume stability monitoring data at Former North Geelong Gasworks manufactured gas plant and identified appropriate geostatistical tools and decision tree to determine monitoring endpoints.

• Senversa Pty Ltd, Melbourne, Australia. Designed horizontal multiple phase extraction well system for BP facility in Geelong, Victoria, Australia.

• CH2M HILL, Atlanta, Georgia. Designed a shallow horizontal soil vapor extraction well to operate concurrently with horizontal air sparging wells crossing multiple roads at Savannah Air National Guard site in Garden City, California.
- Senversa Pty Ltd, Adelaide, Australia. Provided regulatory audit review of groundwater fate and transport model supporting site clean-up strategy for the Nyrstar Port Pirie smelter and refinery, Port Pirie, South Australia.


- Senversa Pty Ltd, Adelaide, Australia. Provided regulatory audit review of vadose zone fate and transport model and supporting metals leach testing for the assessment of water treatment residuals from water treatment plants as rehabilitation material for placement at various rock quarries in South Australia by the South Australian Water Corporation.

- S.M. Stoller Corporation, Largo, Florida. Served as horizontal well expert in project team responsible for scope of work development, engineering and construction contractor procurement, and supervision of design, installation, operation and maintenance of a horizontal well bioremediation amendment injection system at a legacy Department of Energy facility.


- S&ME, Inc., Greensboro, North Carolina. Contributed to a corrective action plan for Novozymes North America using numerical groundwater flow and transport modeling to address non-point source nitrate and TDS impacts of a regional drinking water aquifer in partially weathered and unweathered, fractured igneous and metamorphic formations, including long-term plume stability projections and optimization of locations, flow rates and screen intervals of recovery wells.

- Du Pont de Nemours and Company, Oakley, California. Developed technical specifications and requirements for horizontal bioremediation amendment injection wells at various depths at a former chemical manufacturing facility that produced chlorofluorocarbons, anti-knock compounds and titanium dioxide. Completed a sensitivity analysis of the effect of viscosity of the bioamendment solution.

- Senversa Pty Ltd, Australia. Provided expert independent review of groundwater flow and reactive transport model and related sequential batch leach testing to assess metals plume stability and risk to surface water at the Former Port Kembla Copper Smelter and Refinery, Port Kembla, New South Wales, for Port Kembla Copper Pty Ltd.

- Arcadis U.S., Inc., Augusta, Georgia. Designed a horizontal hydraulic barrier well for a rail operating facility to protect an offsite, down-gradient residential neighborhood. The well fills a gap in an existing hydraulic barrier system in a strongly heterogeneous shallow water-bearing zone consisting of sandy clay and clayey sand. Assisted in contractor procurement, prepared well development protocol, and provided guidance during well development.

- Senversa Pty Ltd, Adelaide, Australia. Evaluated solvent plume migration at General Motors Holden automobile parts manufacturing facility in Elizabeth, South Australia.

- Senversa Pty Ltd, Melbourne, Australia. Provided regulatory audit review of site characterization and corrective action plan for a solvent plume in mixed igneous and sedimentary environment with complex porosity distribution at Ericsson manufacturing site in Preston, Victoria, Australia.

- CH2M HILL, Charlotte, NC. Designed system of horizontal biosparging and soil vapor extraction wells in petroleum hydrocarbon impacted silty sands at a pipeline facility.
- CH2M HILL, Charlotte, NC. Developed a treatability study for horizontal soil vapor extraction design at Pearl Harbor-Hickam Air Force Base, Hawaii. Designed a system of horizontal subslab extraction wells to mitigate vapor intrusion.

- Senversa Pty Ltd, Melbourne, Australia. Supervised installation and development of a 900-foot horizontal soil vapor extraction well installed in fractured basalt rock under an automobile manufacturing facility. Conducted extensive performance testing of the horizontal well, evaluating both flow and diffusion effects. Conducted an efficiency test of a vertical soil vapor extraction system at the same facility and performed a performance evaluation comparing the horizontal and vertical soil vapor extraction systems.


- CH2M HILL, Atlanta, GA. Designed system of horizontal soil vapor extraction wells and a horizontal potassium permanganate injection well at Tinker Air Force Base, Oklahoma.

- C-K Associates, Houston, Texas. Compared horizontal well and trench system specifications and installation requirements for petroleum and metals migration control at oil and gas production facilities, west Texas.

- Eagle Environmental, Baton Rouge, Louisiana. Developed high volume horizontal water supply well system design for power plant.


- CH2M HILL, Atlanta, Georgia. Designed variable application horizontal air sparge and biosparge wells for chlorinated hydrocarbon remediation at chemical manufacturing facility in Marietta, Ohio.

- Senversa Pty Ltd, Melbourne, Australia. Horizontal soil vapor extraction well feasibility evaluation and design for basaltic rock at automobile manufacturing facility.

- CH2M HILL, Marietta, Georgia. Performed numerical multiphase transport modeling of gas flow through the saturated and unsaturated zones to assess the effectiveness of a horizontal air sparge well remediation system. Assisted in the design and implementation of a sulfur hexafluoride and helium tracer injection test of a 1000-foot horizontal air sparge well at a defense contractor facility. Used gas transport modeling to optimize the flow rate and cyclic injection schedule of the horizontal air sparge well system.

- Louisiana Department of Environmental Quality, Sulphur, Louisiana. Developed Triad real-time mobile laboratory-driven site characterization at state-owned orphaned former waste impoundment site. Prepared corrective measures screening study.

- GES Environmental Services, confidential clients, New York. Designed combination air sparge and soil vapor extraction systems using horizontal wells in highly heterogeneous hydrogeologic settings.
• CB&I, Baton Rouge, LA. Prepared feasibility study for horizontal methane gas relief wells at the Bayou Corne sinkhole, Louisiana.

• Save Lake Peigneur, New Iberia, Louisiana. Prepared critique of salt dome cavern permit application to Louisiana DNR by Jefferson Island Storage & HUB LLC.

• Golder Associates and Directional Technologies, Inc. Designed and oversaw installation of 600-foot horizontal hydraulic barrier well at waste oil impoundment facility in Zapata, Texas.

• Woodard & Curran and Directional Technologies, Inc. Tewksbury, Mass, Designed and variable use, SVE and subslab depressurization system of horizontal wells under 500,000 square foot manufacturing facility. Provided site QC support during installation.

• AECOM and Directional Technologies, Inc. Designed and provided QA/QC and real-time wellhead surveying guidance for the installation of two blind 550-foot long horizontal multiple-phase extraction wells at a coke manufacturing facility in Port Lavaca, Texas, June 2012.

• AMEC and Directional Technologies, Inc. Designed and provided QA/QC and real-time wellhead surveying guidance for the installation of four blind air sparge and four blind soil vapor extraction wells at an industrial site in downtown Tallahassee, Florida August 2012.

• Alliance for Site Closure, LLC. Designed high-resolution triad investigation for the Concord Custom Cleaners drycleaner site in Michigan City, Indiana, utilizing mobile laboratory real-time data analysis of drycleaning solvent plume in groundwater under a residential neighborhood, including geochemical and geotechnical parameters required for three-dimensional numerical flow and transport modeling to assess plume migration and determine timeframe for reaching plume stability. Constructed multilayer numerical model simulating hydraulic gradient adjustments to changing drought conditions and changes in recharge caused by construction and storm drains. Identified discrete groundwater flow and contaminant transport channels and horizons within layered and vertically anisotropic hydrostratigraphy.

• Pacific Crest Environmental, North Bend, Washington. Designed system of two horizontal air sparge wells and two horizontal soil vapor extraction wells at Marine Iron Works, Tacoma, Washington.

• Specialty Earth Sciences, LLC. Designed horizontal blind well soil vapor extraction system at drycleaner site in Indianapolis, Indiana.

• Groundwater & Environmental Services, Inc. Designed and supervised the installation of a horizontal air sparge and soil vapor extraction well pilot system at John F. Kennedy International Airport, Jamaica, New York.

• Sesco Group, Indianapolis, Indiana. Designed and implemented a high-resolution Triad investigation for former Harmon Becker manufacturing plant in Martinsville, Indiana, using direct sampling ion trap mass spectrometer mobile laboratory to isolate multiple source areas beneath a large manufacturing building and in adjacent residential and commercial neighborhoods. Constructed and calibrated a three-dimensional flow and transport model to simulate chlorinated solvent plume migration and to design an enhanced in situ bioremediation program using whey as carbon source. Recalibrated model post-bioremediation to assess reductive dechlorination progress.

• O’Brien & Gere Engineers, Inc. Designed horizontal subslab air extraction mitigation system at General Motors Plant in Syracuse, New York.

• Sesco Group, Indianapolis, Indiana. Planned and implemented environmental site investigation for D.E. Markeys of over 2 km long chlorinated hydrocarbon plume migrating through multiple aquifer zones separated by a series of fractured aquitards creating varying degrees of leakance. Developed and implemented multiple three-dimensional pumping tests for acquiring horizontal and vertical hydraulic conductivity and anisotropy values using multilevel and multiple completion monitoring wells. Developed a three-dimensional, finite difference groundwater flow and transport model with a 10 km² area model domain to predict plume migration and stability in various aquifer zones. Used flow and transport model to determine acceptable locations and production rates for water wells used by a greenhouse operation, irrigation wells, and residential water wells.

• CH2M HILL, Inc., Waukegan, Illinois. Provided QA/QC of 1000-foot long horizontal air sparge barrier well at OMC Plant 2 Superfund site.

• Roux Associates, Inc., Rochelle Park, New Jersey, supervised the installation of six-inch diameter black iron pipe dual-purpose soil vapor extraction wells and horizontal electrodes for in-situ six-phase heating of impacted soils beneath a manufacturing facility.

• Groundwater & Environmental Services, Inc. Designed and supervised the installation of two horizontal air sparge wells and one horizontal soil vapor extraction well in gravelly, boulder-rich soils at a retail gas station in Winsted, Connecticut.

• Weston Solutions, Inc., and Professional Technical Support Services, Inc. Designed and implemented a rehabilitation program for a horizontal hydraulic barrier well at a chemical manufacturing facility in Deer Park, Texas. The well was rehabilitated without mobilization of a directional drilling rig.

• Parsons Engineering and Professional Technical Support Services, Inc., Pascagoula, Mississippi. Designed and implemented a rehabilitation program for a 1000-foot groundwater recovery at a chemical manufacturing facility. The rehabilitation program avoided the use of a drilling rig or other heavy equipment.

• Sesco Group, Indianapolis, Indiana. Designed and implemented a whey injection system to pilot test chlorinated hydrocarbon impacts to groundwater at Bowes manufacturing in Indianapolis. Used system performance data to construct and calibrate a three-dimensional numerical groundwater flow and transport model for the purpose of evaluating long-term impact of the pilot test, and to design full-scale remediation.

• MACTEC Engineering and Consulting, Tallahassee, Florida. Designed and supervised the installation of four horizontal air sparge wells and four horizontal soil vapor extraction wells under a retail gasoline station, a high-density residential neighborhood, a major U.S. highway intersection, and a fast-food restaurant and parking lot. The wells were between 600 and 900 feet long, and 35 to 50 feet deep. Designed screen slotting to achieve even flow distribution for air injection and extraction.

• Shaw Environmental & Infrastructure, Inc., Trenton, New Jersey. Designed and supervised the installation of four horizontal wells under an office building and parking lot for potassium permanganate injection at the Former Raritan Arsenal Site, a former U.S. Army facility redeveloped under the U.S. EPA Brownfields program. Designed screen slotting to achieve even fluid injection. Used three-dimensional, finite difference flow and transport modeling to predict
aquifer response and permanganate transport, and to manage the injection and monitoring program.

- **S&ME, Inc., Greensboro, North Carolina.** Performed three-dimensional numerical groundwater modeling to help design vertical and horizontal groundwater remediation wells to address non-point-source pollution in a complex igneous and metamorphic setting that includes fractured granitic formations, diabase intrusives, weathered bedrock, and saprolite. Developed groundwater model to compare hydraulic effectiveness of vertical and horizontal wells for hydraulic barriers and local dewatering.

- **CH2M HILL, Chicago, Illinois.** Designed two horizontal well groundwater extraction systems for site-wide dewatering and multiple-phase extraction systems at railroad sites in Phoenix, Arizona, using three-dimensional, finite difference groundwater flow modeling. Predicted short-term and long-term flow rates and troughs of groundwater depression.

- **CH2M HILL, Marietta, Georgia.** Designed 3 horizontal air sparge wells and one SVE well at the Lockheed Martin manufacturing facility. Provided field supervision during the installation of the horizontal wells. The wells ranged in depth from 25 to 85 feet, and total well length ranged from 750 to 1050 feet. Two air sparge wells were placed along the edges of an LNAPL pool to prevent lateral spreading. A third, deeper air sparge well was placed along the axis of the LNAPL pool to reduce LNAPL thickness. The SVE well was placed below manufacturing buildings to prevent vapor intrusion.

- **Franklin Company, Queens, New York.** Provided design advice and installation oversight for TRC Co of New York, New York for 15 horizontal wells for bioamendment injection beneath multiple rail lines at the repair and maintenance terminal of the Long Island Rail Road in Queens, New York. The wells were installed around multiple generations of subsurface utilities. The soil was saturated with LNAPL resulting from 100 years of rail car maintenance operations.

- **Professional Technical Support Services, Baton Rouge, Louisiana.** Provided design and field implementation support for URS Corporation in Baton Rouge for structural repairs to subsurface sumps associated with horizontal wells at the DOW Plaquemine facility.

- **SKA Consulting LLC, Houston, Texas.** Used three-dimensional numerical groundwater flow modeling to design a system of vertical, multiple-phase extractions wells for localized dewatering of an unconfined aquifer, and rapid removal of petroleum hydrocarbons at a Brownfields/real estate development site.

- **PPG Industries, Lake Charles, Louisiana.** Provided hydrogeologic consulting services in support of management of the facility-wide Hazardous and Solid Waste Amendments (HSWA) program, including completion of a Corrective Measures Study, optimization of environmental well systems, and regulatory compliance in a multilayered system that includes fractured clays, alluvial sands, silts, and regional drinking water aquifers. Provided technical management of a sitewide RCRA Facility Investigation of chlorinated solvents in soil, sediment and groundwater using Cone Penetrometer Testing technology and statistical methods for three-dimensional evaluation of the horizontal and vertical extent of constituents. Applied innovative analytical testing methods for the assessment of sitewide distribution of Dense, Non-Aqueous Liquids. Participated in the development of a sitewide DNAPL management strategy. Designed and installed various corrective measures addressing solvents in a fluvial sedimentary setting comprising clay aquitard formations, regional drinking water aquifers, and intermediate water-bearing units.
Shaw Environmental, Inc, Trenton, New Jersey. Provided design support for in situ chemical oxidation system at the Annapolis Towne Center-Parole Growth Management Area near Annapolis, Maryland, addressing extensive drycleaning solvent plumes. Designed 14 horizontal wells for injection of potassium permanganate at various depths, including screen design and groundwater flow and transport modeling. Designed 5 horizontal soil vapor extraction wells for solvents remediation beneath a drycleaning facility. Design included screen slotting specifications, and groundwater flow and transport modeling to specify well spacing and operational details of the injection system. Provided field QA/QC and oversight during horizontal well installation, which was concurrent with building foundation and infrastructure construction activities. Evaluated the efficacy of the injection system and recommended optimization measures using three-dimensional, finite difference groundwater flow and transport modeling.

Royston Rayzor, Houston, Texas. Provided expert opinion on issues related to Hazardous and Solid Waste Amendments (HSWA) at a Citgo Petroleum facility in Lake Charles, Louisiana.

URS Corporation, Baton Rouge, Louisiana. Developed rehabilitation program for a series of environmental horizontal wells at the Dow Chemical facility in Plaquemine, Louisiana, using camera survey and chemical evaluation. Provided field oversight during well rehabilitation.

SKA Consultants, Houston, Texas. Presented series of 8-hour training seminars in basic hydrogeology, contaminant transport, geochemistry, and bioremediation.

ERM Japan, Tokyo, Japan. Compiled a comprehensive survey of the most recent innovative tools for site investigation, remediation, and performance monitoring.

Sesco Group, Indiana. Designed a horizontal biosparge and soil vapor extraction well system at the Rensberger bulk fuel storage facility in South Bend, Indiana, including air flow modeling, screen design, engineering specifications of horizontal and vertical wells, drilling plan and fluids management program, and surface plumbing design. Provided field supervision during installation and development.

Environmental Standards, Charlottesville, Virginia. Developed procurement documents for horizontal well leachate collection system at a landfill, including conceptual design, performance specifications, and engineering specifications. Assisted in preparation for Public Meeting. Providing field supervision of horizontal well installation.

Star Environmental, Orlando, Florida. Assisted in design, drilling plan, and contractor procurement for a horizontal groundwater sparging well installed under a highway and commercial building. Provided installation oversight and well materials QA/QC testing.

Sesco Group, Indianapolis, Indiana. Designed horizontal bioventing well system at the Miller Oil petroleum bulk storage facility in Columbus, Indiana, including determination of corrective action objectives, air flow modeling, screen design, engineering specifications of horizontal wells, drilling plan and fluids management program. Provided field supervision during installation and development.

Served as project manager for CH2M HILL, New Orleans, Louisiana, 2004-2005. Projects included:

Phoenix Environmental, High Point, North Carolina. Developed a three-dimensional numerical groundwater flow and contaminant transport model of an 11 square mile area in fractured and weathered igneous and metamorphic Piedmont terrain, including simulation of non-point sources, fractures, and uptake of nitrogen by riparian vegetation in evapo-transpiration zones.
• PPG Industries, Lake Charles, Louisiana. Evaluated various groundwater remediation systems to determine their efficacy and relevance to corrective action objectives, and to recommend optimization measures. Provided guidance in development of Corrective Measures Study under the Louisiana Department of Environmental Quality Risk Evaluation Corrective Action Program (RECAP). Evaluated feasibility of in-situ chemical oxidation and bio-augmentation using field screening methods. Developed conceptual design of innovative methods of reactive barrier placement along shoreline.

• Union Carbide/Dow Chemical Corporation, St. Charles, Louisiana. Managed development and implementation of a facility-wide Risk Evaluation Corrective Action Plan (RECAP) strategy under the Louisiana Department of Environmental Quality RECAP program.

• DOW Chemical, Plaquemine, Louisiana. Evaluated management alternatives for optimizing sitewide environmental remediation program.

• Implemented hydrogeologic and environmental assessments and remediation designs for GeoSyntec in Baton Rouge, Louisiana, 2002-2004 including:

  • Honeywell International, Baton Rouge, Louisiana. Beneficial reuse evaluation of calcium chloride and effluent treatment sludge. Alternative uses in construction, agronomy, and waste management were identified based on a detailed analysis of chemical and geotechnical characteristics of the waste streams.

  • PPG Industries, Lake Charles, Louisiana. Designed and implemented an innovative program for testing and rehabilitation of a system of 9 horizontal DNAPL recovery wells in a former waste impoundment.

  • Florida Dept. of Environmental Quality. Developed Remedial Action Plans for facilities in the Hazardous Waste Division Statewide Drycleaner Cleanup Program. Remedial strategies included natural and enhanced attenuation, bio-augmentation, multiple phase extraction, and hydraulic control measures. Used finite difference groundwater flow and transport modeling results to optimize remediation systems.

  • National Aeronautics and Space Administration, Cape Canaveral, Florida. Designed multiple horizontal well groundwater injection and extraction system for in situ remediation of chlorinated solvents. The design featured parallel horizontal wells stacked vertically for shallow injection of chemical oxidant and deep extraction of treated groundwater. Fiberglass pipe dimensions and screen slotting configuration were specified to account for pipe strength requirements (including tensile and hoop stresses), effective roughness factor, slot aperture limitations, and open area requirements for gravity-driven injection of potassium permanganate solution. Well spacing and well paths were determined by calculated zones of influence, subsurface hydrogeology, topography, and anticipated drilling conditions to provide efficient delivery of potassium permanganate, and prevent venting problems during installation and operation.

  • SKA Consultants, Houston, Texas. Design, subcontractor procurement, and installation supervision of horizontal well multiple-phase extraction system for the Federal Reserve Bank of Dallas, Houston Branch, under a compressed schedule to accommodate bank construction. Two blind horizontal wells were designed to extract groundwater and liquid petroleum products from highly heterogeneous fluvial sediments. The horizontal wells have a gentle grade and intersect vertical sumps at their terminations in the subsurface, requiring a complex screen and sump design. Three-dimensional numerical groundwater modeling was used to design the well paths and screens, and to predict flow rates and dewatering zones. The site was successfully closed by
the TCEQ after approximately two years of operation. The horizontal well system has been nominated for the EPA’s Phoenix award for best Brownfields project of the year in Region VI.

- Phoenix Environmental, High Point, North Carolina. Designed and conducted a series of week-long pumping tests to determine aquifer characteristics in igneous and metamorphic Piedmont terrain including fractured granite, diabase intrusions, and various degrees of near-surface weathering, in support of site characterization and numerical groundwater flow and contaminant transport modeling for Novozymes North America.

- Connelly, Baker, Wotring & Jackson, L.L.P. Evaluated groundwater remediation system design and cost estimate, including horizontal well system for the Port of Houston Authority. Contributed to cost reasonableness evaluation for assessment costs incurred during litigation. Evaluated consistency of three-dimensional hydrogeologic models used for predicting contaminant transport.


- BFI/Ellender Ferry Landfill, Louisiana. Characterized subsurface stratigraphy and contaminant distribution.

- Bechtel/Cingular Wireless, Mississippi. Completed environmental audit at wireless tower locations in Mississippi.


- Founded and served as managing director of IT Infrastructure & Environmental GmbH in Kaiserslautern, Germany, in 2000-2002, serving Department of Defense programs for remediation and construction in Europe, and to collaborate with European partner companies in developing and implementing environmental infrastructure projects. Specific projects included:
  - Ramstein Air Base, Ramstein, Germany/Air Force Center for Environmental Excellence. Completed construction specifications, procured German subcontractors, and supervised field construction for groundwater extraction and reinjection wells in fractured sandstone regional drinking water aquifer underlying Petroleum Oil Lubricants underground storage facility. Designed and implemented enhanced delivery and recovery using hydraulic fracturing.
  - Ramstein Air Base, Ramstein, Germany/Air Force Center for Environmental Excellence. Supervised completion of engineering specifications, procured German subcontractor, and negotiated installation and operation and maintenance contract for 200 gallon per minute groundwater treatment system, including underground piping, pretreatment for iron separation, activated carbon adsorption, and air stripping.
  - Ramstein Air Base, Ramstein, Germany/Air Force Center for Environmental Excellence. Developed and implemented program of monitored natural attenuation of petroleum hydrocarbons plume at storage tank facility.
  - Ramstein, Vogelweh, Sembach, and Landstuhl Air Bases, Kaiserslautern, Germany/Air Force Center for Environmental Excellence. Implemented multiple-base program of inspection and removal of oil-water separators and grease traps at diverse military support facilities, including engine repair and testing buildings, runways, taxiways, liquid oxygen plants, and food service facilities. Negotiate permits with German regulatory agencies.
• NATO Strategic Headquarters Allied Partners Europe, Mons, Belgium/US Army Corps of Engineers. Managed structural investigation, including force protection requirements, of military barracks building for purpose of preparing cost-benefit analysis of building renovation.

• AK Chemie, Biebesheim, Germany. Performed field sampling and laboratory bench testing program to evaluate the feasibility of bio-augmentation and chemical oxidation of soil and groundwater contaminated with organic lead compounds.

• Thrallcar/Vagonka Studenka, Ostrava, Czech Republic. Completed detailed environmental audit of 100-year-old rail car manufacturing facility in the Czech Republic for a potential U.S. investor.

• Ministry of Environment, Wojvodina of Silesia, Poland. Participated in flood control management program for communities along the Odra River.

• Ludwigshafen and Munich, Germany. Contributed to program of brownfields development, including financing, remedial measures cost estimating, and property redevelopment concept definition, at former railroad facilities in urban/industrial districts.

• Designed and implemented pilot tests for IT Group at various locations in Japan in 1999-2001 to demonstrate in situ remediation technologies for Kurita Water Industries, including chemical oxidation and electrochemical geo-oxidation. Designed and implemented potassium permanganate injection system using hydraulic fracturing technology to achieve mass reduction and migration control of chlorinated solvents in lacustrine clay and silt formations at a specialized components manufacturing facility. Helped design pump-and-treat systems. Facilitated negotiations in 2001-2002 between Kurita Water Industries of Japan and several potential German partner companies specializing in electrochemical in-situ methods, permeable reactive barriers, soil washing, and mechanochemical dehalogenation of PCBs, Dioxin, and other halogenated organic compounds in soils and industrial materials.

• Managed and developed client programs for IT Group in California in 1999-2000 for management of solvents contamination, including food service industry, dry cleaners, retail petroleum, and landfills. Developed horizontal well drilling and testing programs. Managed evaluation and implementation of innovative in situ remediation technologies, including chemical oxidation and hydraulic fracturing. Specific projects included:
  • Nestle USA, Burbank, California. Managed groundwater contamination from decaffeination process. Remediation strategy included Potassium permanganate pilot test, and groundwater modeling to improve municipal water supply management. Managed groundwater modeling for developing large-volume municipal water extraction and distribution strategy for City of Ripon, California.
  • Chevron USA, Pleasanton, California. Developed nationwide strategy for evaluating risk of MtBE contamination of local water supply by retail stations, with focus on California, Texas, Florida, and Louisiana. Managed development of GIS database cross-referencing hydrogeological, chemical, and demographic factors.
  • Kelly Air Force Base, Texas. Designed, procured contractor, and evaluated efficiency of horizontal well system for hydraulic control of volatile organic compound contamination. Developed drilling and installation specifications for horizontal wells, designed aquifer test, and performed groundwater modeling.
  • Panoche Landfill, Benicia, California. Served as technical supervisor and regulatory interface for closure of IT Corporation Waste Management Units.

• Provided continuing technical management support of Florida DEP Hazardous Waste Division Drycleaners cleanup program.

• Managed IT Group environmental engineering consulting business line in Tampa, Miami, and Clermont (Orlando), Florida in 1997-1999. Program activities included:
  • Directed Florida DEP Hazardous Waste Division Drycleaners cleanup program, in which CPT technology, geo-statistics and 3-D visualization are employed to isolate specific points of release, and optimal site closure strategies are developed by applying hydraulic analysis, natural attenuation evaluation, and innovative remedial technologies, such as passive iron walls, horizontal wells, and chemical oxidation.
  • Directed Florida DEP Pre-approval and State Lead programs, in which site closure strategies are combined with pay-for-performance criteria. Managed and contributed to site characterization using Cone Penetrometer Testing technology and statistical methods of indicator kriging to produce three-dimensional models of the extent of drycleaner solvents and their daughter products in hydrogeologic settings representing varying degrees of heterogeneity. Used cost-effective methods of three-dimensional groundwater modeling to develop site-specific remedial strategies, and used spatial rendering of solvent plumes to optimize remediation systems. Helped design standardized methodologies for drycleaner site characterization and remedial alternatives screening for the state-wide drycleaner program.
  • Supported Department of Defense Business Development initiatives at various Air Force Bases in Florida. Helped implement technology demonstration pilot testing at Cape Canaveral for NASA and Patrick Air Force Base.
  • Provided regulatory support, ecological risk assessment, and wetlands reconstruction.
  • Provided litigation support for cases involving DNAPL contamination and brine waste.

• Co-managed assessment and remediation activities as Task Manager for IT Corporation’s project office at PPG Industries, Lake Charles, Louisiana in 1992-1998 for Resource Conservation and Recovery Act (RCRA) Facility Investigation (RFI) and Corrective Measures Study. Activities included:
  • Developed design specifications, procured installation contractor, and tested horizontal well systems, including nine horizontal wells for dense, non-aqueous phase liquid recovery in a waste impoundment.
  • Performed geotechnical evaluation of consolidation settlement effects due to groundwater recovery.
  • Implemented water flooding through trenches to enhance DNAPL recovery.
  • Managed surfactant flushing pilot test project; evaluated full-scale feasibility.
  • Managed flow and transport modeling, including multiple phases and fractured media.
  • Helped develop DNAPL management strategy for large, complex industrial site.
  • Developed and implemented multilevel cone penetrometer testing and sampling program for hydrogeologic characterization of DNAPL-contaminated system.
• Managed development of 3-D visualization techniques for contamination assessment and salt dome solution mining.

• Evaluated horizontal well system effectiveness at Williams Air Force Base, Arizona.

• Managed environmental horizontal drilling projects for Baker-Hughes/Eastman Christensen Environmental Systems, Houston, Texas, 1991-1993. Activities included:
  • Designed and installed horizontal well systems.
  • Managed software development for hydrogeological and hydraulic modeling of horizontal well performance.
  • Managed development of new products and product applications in the field of horizontal well installation and sampling.
  • Managed Health and Safety Program for horizontal drilling operations.
  • Developed nationwide customer base and defined marketing strategies.
  • Collaborated with AFCEE to develop horizontal well remediation system strategies for various Air Force Bases, including Brooks AFB, Kelly AFB, and Williams AFB.

• Managed hydrogeology division budget for Midwest Water Resource/MWR, Inc., Lansing, Michigan. Responsibilities included:
  • Directed environmental consulting activities of remediation and consulting company with approximately 30 employees.
  • Developed and implemented engineering strategies for soil and groundwater remediation systems for commercial clients, including Clark Equipment in Michigan; Taylor Forge in New Jersey, Chevron Industries in Indiana, and AIG/Herz-Penske in Ohio.
  • Coordinated research and development activities and defined research and development objectives.

• Managed, co-managed and participated in research projects at the Center Hill Research Facility/USEPA Risk Reduction Engineering Laboratory, Cincinnati, Ohio. Projects included contaminant transport modeling, hydraulic fracturing, bioremediation, steam and polymer injection, waste stabilization, and expert systems development. Specific activities included:
  • Co-developed method of increasing flow for delivery and recovery of fluids into unconsolidated materials, such as silts and clays, using hydraulic fractures. Conducted bench testing of fracturing techniques, including proppant chemistry. Implemented technique at two pilot tests in Cincinnati, Ohio (Elda Landfill and Gettle Corp.), creating stacks of sand-filled fractures over 10 feet deep with up to 100 foot diameter. Helped design and build direct-push hydraulic fracture apparatus currently still in use by USEPA for full-scale field applications of hydraulic fracturing for enhancement of flow through soils with low permeability.
  • Authored successful NSF grant proposal for $97K to study diffusive mass transport processes in porous media at the University of Cincinnati in Cincinnati, Ohio. Other activities as graduate research and teaching assistant included:
    • Compiled radiocarbon data for surficial processes study under NSF grant.
• Directed ion beam sample preparation for transmission electron microscopy to study composite materials.
• Taught ten courses and laboratory sections in geology and engineering geology.

FOREIGN LANGUAGES

Fluent in German, Czech, Slovak
Proficient in French

PROFESSIONAL AFFILIATIONS

Association of Engineering Geologists
Hazardous Materials Control Research Institute
National Ground Water Association
Association of Ground Water Scientists and Engineers
Sigma XI/The Scientific Research Society
American Chemical Society
Society of Economic Paleontologists and Mineralogists

PROFESSIONAL CERTIFICATIONS

Professional Geologist, licensed by Texas Board of Professional Geoscientists, License No. 2596
Professional Geoscientist, licensed by Louisiana Board of Professional Geoscientists, License No. 981
Traveling Workers Identification Card (TWIC)
40-hour OSHA training, 29 CFR 1910.120 and annual 8-hour refreshers
8-hour DOT training
12 Basic Plus Association of Reciprocal Safety Councils 8-hour training and annual 2-hour refreshers
DuPont Safety Management Training
LIST OF PUBLICATIONS

GEORGE LOSONSKY


84-1 Losonsky, G., 1984, *Stylolites, in Guidebook to Mammoth Cave*, Kentucky, University of Cincinnati.


Hydrocarbons Conference, National Groundwater Association/American Petroleum Institute, Houston.


Environmental Health and Sciences (AEHS) Foundation, University of Massachusetts, Amherst, Massachusetts, October 15-18, 2012, Abstract Book, p. 61.


ADDENDUM TO C-K & ASSOCIATES’ TECHNICAL REPORT OF NOVEMBER 16, 2016:

EVALUATION OF PREDICTED DRAWDOWN AND CONSOLIDATION SETTLEMENT RESULTING FROM PROPOSED NOPS PUMPING

JUNE 28, 2017

PREPARED BY:
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&

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George Losonsky
June 30, 2017
Introduction

This report was prepared as an Addendum to the C-K Associates’ Technical Report – Evaluation of Groundwater Withdrawal and Air Quality dated November, 16 2016 (C-K Technical Report). The C-K Technical Report describes how subsidence is caused by consolidation of sediments, and how primary consolidation is controlled by natural processes while a combination of natural and man-made processes, including groundwater withdrawal, can cause secondary consolidation. The C-K Technical Report compares historical pumping rates in the Gonzales-New Orleans aquifer with pumping rates for the Combustion Turbine (CT) unit originally proposed by Entergy New Orleans, Inc. (“ENO”) for the New Orleans Power Station (NOPS). This Addendum addresses an important change in ENO’s proposed plan. ENO is presently considering the use of seven Wärtsilä 18V50SG Reciprocating Internal Combustion Engine (RICE”) Generator sets (Alternative Peaker) as an alternative to the previously proposed CT unit. The Alternative Peaker significantly reduces the required groundwater usage rate. This Addendum utilizes drawdown calculations and consolidation settlement calculations to more accurately assess the potential impact of groundwater withdrawal on subsidence for both the CT unit and the Alternative Peaker. 1

The C-K Technical Report used the proposed maximum required pumping rate for the CT unit, 96 gallons per minute (gpm), to evaluate NOPS’s potential impact on subsidence. The C-K Technical Report noted that this rate, which is an order of magnitude less than historical pumping rates in the Gonzalez-New Orleans aquifer,2 would create a drawdown level within the range of natural water level variations. Based on engineering estimates provided by the equipment vendor and EPC contractor, the Alternative Peaker will require a reduced pumping rate of 3.9 gpm. The anticipated pumping rate for the Alternative Peaker is less than one tenth of the pumping rate for the CT, and two orders of magnitude less than historical pumping rates. When compared to the original CT unit proposed flow of 96 gpm, Alternative Peaker usage rate will result in a groundwater use reduction of 95% and, when compared the deactivated Michoud units discussed in the C-K Technical Report, a 99.9% groundwater use reduction.

Based on this information, and the calculations described herein, it is reasonable and accurate to conclude that:

1) The groundwater withdrawal associated with the proposed CT unit will not exacerbate subsidence or cause damage to infrastructure in New Orleans East.

2) The groundwater withdrawal associated with the proposed RICE units will not exacerbate subsidence or cause damage to infrastructure in New Orleans East.

Drawdown Calculations

Consolidation settlement due to groundwater withdrawal can, under certain conditions, lead to subsidence. Louisiana aquifer systems comprise alternating sand aquifer units and intervening clay aquitards. Clay aquitards are an important part of the aquifer system. Slow but persistent leakage of groundwater vertically through

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1 This Technical Addendum does not address changes associated with air quality as that will be addressed by other witnesses.

2 See C-K Technical Report at pg. 11.
aquitards influences changes in hydraulic pressure in aquifers below or above the clay in response to the operation of water wells screened in the aquifer. Aquitards also have an important role in consolidation settlement, which can occur in both sandy aquifers and the clay aquitards, and which is influenced by water pressure in both the aquifers and aquitards.

Hydrogeologists and engineers designing groundwater withdrawal wells have been successfully using analytical solutions to predict the hydraulics of aquifer response to pumping since the 1930’s, when Charles V. Theis applied the proven physical principles of heat transfer to solve the basic equation of groundwater flow to a well in radial coordinates (Jacob, 1950; Freeze and Cherry, 1979):

$$\frac{\partial^2 h}{\partial r^2} + \frac{1}{r} \frac{\partial h}{\partial r} = \frac{S}{T} \frac{\partial h}{\partial t}$$

(Equation 1)

In Equation 1, $r$ is the distance from the well, $h$ is hydraulic head, $S$ is the non-dimensional storage coefficient of the aquifer, $t$ is time, and $T$ is the transmissivity of the aquifer which equals the product of the hydraulic conductivity (in units of distance per time) and the aquifer thickness.

**Theis Solution for Drawdown**

Using assumptions typical of analytical solutions that focus the equation on the fundamental aspects of the process and make the solution universally applicable by eliminating unnecessarily complicating details, Theis derived an equation for drawdown in and around a groundwater withdrawal well (Theis, 1935):

$$Theis\ Drawdown(r, S, T, t) = \frac{-Q}{4\pi T} \int_{u(r,S,T,t)}^{\infty} \frac{e^{-u}}{u} \ du$$

(Equation 2a)

where $u$ is

$$u(r,S,T,t) = \frac{r^2}{4 \left( \frac{T}{S} \right) t}$$

(Equation 2b)

The integral in Equation 2a is known as the Theis well function, and more detailed analytical solutions for drawdown use a more elaborate well function to reflect specific conditions.

To apply the Theis solution for drawdown to the New Orleans-Gonzalez aquifer beneath the New Orleans East area, we use 14,300 square feet per day for transmissivity, and 0.0001 as the storage coefficient. To simulate the proposed groundwater withdrawal wells at NOPS, the well is assumed to have a 100-foot long screen across the New Orleans-Gonzalez aquifer. If the well were to operate 24 hours a day, for 365 days a year,\(^3\) at a pumping

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\(^3\) It should be noted that neither proposed unit is expected to operate at this level of frequency. However, the assumption used herein presents the most conservative analysis possible by assuming maximum possible operation.
rate of 96 gallons per minute for 10 years\textsuperscript{4}, the Theis solution (Equation 2) predicts drawdown of about two feet at a distance 5 feet away from the well, 1.9 feet at a distance 100 feet away, 1.7 feet at a distance 250 feet away, and 1 foot at a distance 10,000 feet away from the pumping well. The red curve in Figure 1 is a plot of drawdown as it changes with distance away from the well pumping 96 gallons per minute. For the proposed NOPS flow rate of 3.9 gallons per minute\textsuperscript{5}, the Theis solution predicts drawdown of about 0.08 foot within 100 feet of the well, 0.07 foot 250 feet away, and 0.05 foot at a distance 10,000 feet away from the pumping well. The red curve in Figure 2 is a plot of drawdown as it changes with distance away from the well pumping 3.9 gallons per minute, calculated using the Theis solution.

Cooper-Jacob Approximation of Theis Solution

A commonly used approximation of the Theis equation eliminates the need to perform the integration in Equation 2, and was developed by Hilton H. Cooper and Charles E. Jacob (Cooper and Jacob, 1946):

$$ Cooper\text{-}Jacob\ Drawdown(r,S,T,t) = -\frac{Q}{4\pi T} \left( -0.5772 - \ln \left( \frac{r^2 S}{4 T t} \right) \right) $$

(Equation 3)

The dashed black curve seen superimposed on the red curve for the Theis solution in Figure 1 is a drawdown plot derived by applying the Cooper-Jacob approximation of drawdown to the New Orleans-Gonzalez aquifer using the same parameters as above for the Theis solution and assuming a groundwater withdrawal rate of 96 gallons per minute. The Cooper Jacob approximation plot is virtually identical to the Theis solution plot for the 10-year timeframe and for the distance up to 10,000 feet away from the pumping well. The two solutions would diverge at shorter timeframes and at greater distances from the well. The dashed black curve in Figure 2, also superimposed on the red Theis solution curve, is plot of drawdown as it changes with distance away from the well pumping 3.9 gallons per minute, calculated using the Cooper-Jacob approximation.

Hantush and Jacob Leaky Aquifer Solution

The Theis Solution and Cooper-Jacob solutions both assume that the aquifer has uniform thickness, is confined, and non-leaky, which means that it receives no water from formations lying above and below the aquifer. The New Orleans-Gonzalez aquifer is part of the Southern Hills aquifer system of southeastern Louisiana, in which the clay aquitards separating the aquifers slow down but do not arrest the movement of water downward or upward into an individual aquifer (Buono, 1983; Morgan, 1963). The New Orleans-Gonzalez aquifer is no exception to this hydraulic connectivity, or leakance, and it is therefore appropriate to analyze the New Orleans-Gonzalez aquifer as a leaky aquifer (Freeze and Cherry, 1979).

Building on the principals of the Theis solution, Mahdi S. Hantush and Charles E. Jacob used an expanded well function that reflects the clay aquitard thickness, $b_{aqt}$, and the hydraulic conductivity of the clay aquitard, $K_{aqt}$, in their solution for drawdown in and around a groundwater withdrawal well in a leaky aquifer:

\textsuperscript{4} The 10 year timeframe is standard input for Theis, Cooper-Jacob, Hantush-Jacob or similar drawdown solution applied to a confined sandy aquifer. A confined aquifer will reach virtual steady-state long before 10 years, and drawdown will be essentially unchanged after about 5 years or less.

\textsuperscript{5} This rate was also assumed for operation of 24 hours a day, 365 days per year for 10 years to provide the most conservative analysis possible.

\[ HantushLeaky\ Drawdown(r,S,T,t,B) = \frac{-Q}{4\pi T} \int_{u(r,S,T,t)}^{\infty} \frac{e^{-u \frac{r^2}{4B^2u}}}{u} \, du \]  

[Equation 4a]

where \( u \) is defined identically as in Equation 2b, for the Theis solution, and

\[ B = \sqrt{\frac{T b_{agt}}{K_{agt}}} \]  

[Equation 4b]

The vertical hydraulic conductivity of clay aquitards in southern and southeastern Louisiana falls within the normal range for similar deposits around the world, typically between 0.15 and 0.003 feet per day. The solid blue curve in Figure 1 is a plot of drawdown predicted by Equation 4a as it changes with distance away from the well pumping 96 gallons per minute, assuming the vertical hydraulic conductivity of the overlying clay aquitard is 0.15 feet per day, and the other parameters are the same in the previous calculations using the Theis solution and the Cooper-Jacob approximation. The 10-year timeframe of the drawdown calculation is especially conservative for this calculation. The Hantush and Jacob leaky confined aquifer solution predicts drawdown of approximately 0.8 foot within 100 feet of the well, 0.6 foot 250 feet away, and less than 0.02 foot at a distance 10,000 feet away from the pumping well. The dashed blue line in Figure 1 represents the same calculation for the low end vertical hydraulic conductivity of the clay aquitard, 0.003 foot per day. Drawdown with the low-end leakance assumption is approximately 1.2 feet within 100 feet of the pumping well, 1.0 foot 250 feet away, and 0.27 foot at a distance 10,000 feet away. The solid blue curve in Figure 2 is a plot of drawdown as it changes with distance away from the well pumping 3.9 gallons per minute, calculated using the Hantush and Jacob leaky confined aquifer solution assuming the vertical hydraulic conductivity of the overlying clay aquitard is 0.15 feet per day. Drawdown is approximately 0.03 foot within 100 feet of the well, 0.02 foot 250 feet away, and at a distance 10,000 feet away from the pumping well the drawdown is not measurable by normal methods. The farthest detectable drawdown, 0.005 foot, is predicted to develop approximately 3500 feet away from the well. The dashed blue line in Figure 2 represents drawdown with vertical hydraulic conductivity of the clay aquitard at the low end, 0.003 foot per day. The low leakance drawdown is approximately 0.05 foot per day within 100 feet of the well, 0.04 foot 250 feet away, and 0.01 foot per day at a distance 10,000 feet away.

Consolidation Settlement Calculations

Consolidation settlement calculations for soils are rooted in the concept of effective stress which refers to the grain-to-grain contact stress and was defined by Karl von Terzaghi (Terzaghi, 1925; Terzaghi and Peck, 1967). The effective stress \( \sigma_e \) varies with the change in hydraulic head \( h \):

\[ d\sigma_e = -\rho g \, dh \]  

[Equation 5]
where \( \rho \) is pore fluid density and \( g \) is gravitational acceleration. The compressibility \( \alpha \) of a soil is defined in terms of the void ratio \( e \) which is the ratio of the volume of voids to the volume of solid grains (without the pores):

\[
\alpha = \frac{-d e/(1 + e_o)}{d \sigma_e}
\]

[Equation 6]

where \( e_o \) is the initial void ratio before compression. If compressibility of the soil is known, a linear approximation of the compaction of an aquifer in response to declining hydraulic head (increasing drawdown) is (Freeze and Cherry, 1979):

\[
db = -\alpha \cdot b \cdot \rho \cdot g \cdot dh
\]

[Equation 7]

where \( b \) is the initial thickness of the aquifer. Based on Terzaghi’s principle expressed in Equation (5), Wen-Jie Niu developed a solution for the total settlement in a sandy aquifer overlain by a clay layer due groundwater withdrawal from a well (Niu et al., 2013):

\[
Total\ Settlement = \int_0^{D_c} db = \int_0^{D_c} C_c \frac{1}{1 + e_o(z)} \log \frac{\sigma_{e_o} + \sigma_z}{\sigma_{e_o}} \, dz
\]

[Equation 8]

where \( D_c \) is the thickness of the aquifer, \( e_o(z) \) is the initial void ratio at depth \( z \), \( \sigma_z \) is the vertical stress in the aquifer at the well (where the radial coordinate \( r \) equals 0), \( \sigma_{e_o} \) is the initial effective stress at a point in the aquifer, and \( C_c \) is the compression index (Freeze and Cherry, 1979):

\[
C_c = -\frac{d e}{d (\log \sigma_e)}
\]

[Equation 9]

Substituting an expression for \( \sigma_z \) that is specifically derived for a groundwater withdrawal well in a confined aquifer and applying Terzaghi’s principle expressed in Equation 5, Equation 8 becomes (Niu et al., 2013):

\[
Total\ Settlement
\]

\[
= \int_0^{D_c} C_c \frac{1}{1 + e_o(z)} \log \left( \frac{D \rho_1 g + z \rho_2 g -(H_0 - D_c + z) \rho_w g}{D \rho_1 g + z \rho_2 g -(H_0 - D_c + z) \rho_w g} \right) dz
\]

[Equation 10]
where $D$ is the thickness of the clay layer, $\rho_1$, $\rho_2$, and $\rho_w$ are the densities of the overlying clay, the aquifer sand, and the pore water, respectively; $H_0$ is the static water elevation with respect to the base of the confined aquifer, $R$ is the zone of influence of the well at a given flow rate $Q$, and $A$ is:

$$A = \left(\frac{Q}{2\pi KD_c}\right) \rho_w g$$

[Equation 11]

where $K$ is the hydraulic conductivity of the aquifer. Table 1 below summarizes calculated total possible settlement (in millimeters and in inches) for two or three values for each of the following parameters:

- Static water level measured from the base of the New Orleans-Gonzalez aquifer, $H_0$ (in feet)
- Compression index, $C_c$
- Void ratio, $e_o$
- Flow rate of the groundwater withdrawal well, $Q$ (in gallons per minute)

These values represent the total settlement that might be expected as a result of groundwater withdrawal from the New Orleans-Gonzalez aquifer at the proposed flow rates for NOPS operation. The settlement would occur within the aquifer, in the depth range of 500 to 650 feet. The calculated amount of settlement is not repeatable with successive pumping events, and does not accumulate. The settlement can occur fairly rapidly after the onset of pumping and is not expected to be drawn out over years.

<table>
<thead>
<tr>
<th>$H_0$ (ft)</th>
<th>$C_c$</th>
<th>$e_o$</th>
<th>$Q = 3.9$ gpm</th>
<th>$Q = 96$ gpm</th>
<th>$Q = 3.9$ gpm</th>
<th>$Q = 96$ gpm</th>
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<tbody>
<tr>
<td>580</td>
<td>0.05</td>
<td>0.3</td>
<td>0.04</td>
<td>1.0</td>
<td>0.0016</td>
<td>0.037</td>
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<tr>
<td>580</td>
<td>0.05</td>
<td>0.8</td>
<td>0.03</td>
<td>0.7</td>
<td>0.0012</td>
<td>0.027</td>
</tr>
<tr>
<td>580</td>
<td>0.13</td>
<td>0.3</td>
<td>0.10</td>
<td>2.5</td>
<td>0.0039</td>
<td>0.097</td>
</tr>
<tr>
<td>580</td>
<td>0.13</td>
<td>0.8</td>
<td>0.07</td>
<td>1.8</td>
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<tr>
<td>580</td>
<td>0.23</td>
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<td>0.18</td>
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</tr>
<tr>
<td>580</td>
<td>0.23</td>
<td>0.8</td>
<td>0.13</td>
<td>3.1</td>
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</tr>
<tr>
<td>620</td>
<td>0.05</td>
<td>0.3</td>
<td>0.04</td>
<td>1.0</td>
<td>0.0016</td>
<td>0.040</td>
</tr>
<tr>
<td>620</td>
<td>0.05</td>
<td>0.8</td>
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<td>0.7</td>
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<td>0.029</td>
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<tr>
<td>620</td>
<td>0.13</td>
<td>0.3</td>
<td>0.11</td>
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<tr>
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<td>0.08</td>
<td>1.9</td>
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<tr>
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<tr>
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<td>0.8</td>
<td>0.14</td>
<td>3.4</td>
<td>0.0055</td>
<td>0.134</td>
</tr>
</tbody>
</table>
Settlement values range from 0.001 inch to 0.185 inch; such calculated settlements, if they occurred, would occur at depths exceeding 500 feet from the ground surface. Calculated settlement increases with the compression index and to a lesser extent with decreasing initial void ratio. The three values used for compression index represent a range from the relatively low compression index of a clean beach sand (0.05) to the almost two orders of magnitude higher compression index of clay (0.23). The lower of the two void ratios used (0.3) is equivalent to 23 percent porosity and represents sand, and the higher void ratio (0.8) is equivalent to 45 percent porosity, which is typical of clay-rich soils.

Predicted total settlement is less than one fifth of an inch regardless of the soil parameters, and using the compression index corresponding to the soil type of the New Orleans-Gonzalez aquifer the calculated settlement is 0.04 inch (1 mm) or less if the flow rate is 96 gpm, and less than 0.002 inch (0.04 mm) at the proposed flow rate of 3.9 gpm.

**Conclusion**

Drawdown and consolidation settlement analyses for the proposed NOPS groundwater withdrawal support the conclusions of the C-K Technical Report concerning subsidence and differential settlement. The analyses show that operating the proposed NOPS units may cause limited settlement within the aquifer at depths exceeding 500 feet. Furthermore, since the proposed pumping rates do not exceed historical pumping rates, the operation of the wells is expected to produce no additional settlement. Finally, the calculations assume continuous pumping, 24 hours a day and 365 days a year, which adds up to significantly higher pumping volumes than is expected under normal operating conditions. Therefore, the calculated settlement values are conservative estimates. If any settlement were to occur it would be too small and too deep to cause damage to buildings, infrastructure, and flood protection structures at the ground surface. Drawdown created by either of the two pumping rates considered is insufficient to reverse regional trends of water level rise. Neither differential settlement nor regional subsidence will be exacerbated by the operation of the proposed NOPS wells.
References


Figures

![Figure 1: Drawdown at 10 years (96 gallons per minute)](image)
FIGURE 2

Drawdown at 10 years (3.9 gallons per minute)
INFORMATION SUBMITTAL

Evaluation of Proposed Groundwater Withdrawals and Subsidence
Entergy New Orleans Power Station

Entergy
New Orleans, Orleans Parish, Louisiana

MVN-2015-2311

Project No. 155004

Prepared for:

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Prepared by:

CB&I Government Solutions, Inc.
4171 Essen Lane
Baton Rouge, LA 70809

June 16, 2017
# Table of Contents

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>List of Figures</td>
<td>ii</td>
</tr>
<tr>
<td>List of Appendices</td>
<td>ii</td>
</tr>
<tr>
<td>List of Acronyms</td>
<td>iii</td>
</tr>
<tr>
<td>1.0 Introduction</td>
<td>1-1</td>
</tr>
<tr>
<td>2.0 Evaluation of Subsidence at Michoud</td>
<td>2-1</td>
</tr>
<tr>
<td>2.1 Site Geology and Hydrogeology</td>
<td>2-2</td>
</tr>
<tr>
<td>2.2 Groundwater Withdrawals and Drawdowns, Gonzales-New Orleans Aquifer</td>
<td>2-4</td>
</tr>
<tr>
<td>2.3 Estimated Subsidence from Proposed Groundwater Withdrawals</td>
<td>2-7</td>
</tr>
<tr>
<td>2.4 Discussion of Subsidence Measurements</td>
<td>2-10</td>
</tr>
<tr>
<td>3.0 Conclusions</td>
<td>3-1</td>
</tr>
<tr>
<td>3.1 Gonzales-New Orleans Aquifer Conditions at Michoud</td>
<td>3-1</td>
</tr>
<tr>
<td>3.2 Possible Subsidence Conditions at Michoud</td>
<td>3-2</td>
</tr>
<tr>
<td>4.0 References</td>
<td>4-1</td>
</tr>
</tbody>
</table>
List of Figures

Figure 1       Site Location Map
Figure 2       Location of Geologic Cross Sections
Figure 3       West-East Geologic Cross Section
Figure 4       North-South Geologic Cross Section
Figure 5       Potentiometric Map, September 1963, Gonzales-New Orleans Aquifer
Figure 6       Potentiometric Map, Spring 1993, Gonzales-New Orleans Aquifer
Figure 7       Potentiometric Map, Spring 2008, Gonzales-New Orleans Aquifer
Figure 8       Groundwater Level Trends
Figure 9       Groundwater Quality Distribution, Gonzales-New Orleans Aquifer
Figure 10      NOPS Water Wells
Figure 11      Estimated Maximum Drawdown, Proposed Pumping at 96 GPM
Figure 12      Estimated Maximum Drawdown Cross Section, Proposed Pumping at 96 GPM
Figure 13      Michoud Area Subsidence Rates from Dixon (2006)
Figure 14      Michoud Area Subsidence Rates from Jones et al., (2016)

List of Appendices

Appendix A       Michoud Plant Water Well Information
### List of Acronyms

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
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<tbody>
<tr>
<td>bgs</td>
<td>Below ground surface</td>
</tr>
<tr>
<td>ENOI</td>
<td>Entergy New Orleans Inc.</td>
</tr>
<tr>
<td>ft/day</td>
<td>Feet per day</td>
</tr>
<tr>
<td>ft²/day</td>
<td>Feet squared per day</td>
</tr>
<tr>
<td>gpd</td>
<td>Gallons per day</td>
</tr>
<tr>
<td>gpd/ft</td>
<td>Gallons per day per foot</td>
</tr>
<tr>
<td>gpm</td>
<td>Gallons per minute</td>
</tr>
<tr>
<td>gpm/ft</td>
<td>Gallons per minute per foot</td>
</tr>
<tr>
<td>MCL</td>
<td>Maximum Contaminant Level</td>
</tr>
<tr>
<td>MGD</td>
<td>Million gallons per day</td>
</tr>
<tr>
<td>mg/l</td>
<td>Milligrams per liter</td>
</tr>
<tr>
<td>mm</td>
<td>Millimeters</td>
</tr>
<tr>
<td>mm/yr</td>
<td>Millimeters per year</td>
</tr>
<tr>
<td>MW</td>
<td>Megawatts</td>
</tr>
<tr>
<td>m²/Newton</td>
<td>Meter squared per Newton</td>
</tr>
<tr>
<td>NOPS</td>
<td>New Orleans Power Station</td>
</tr>
<tr>
<td>RICE</td>
<td>Reciprocating Internal Combustion Engine</td>
</tr>
<tr>
<td>S</td>
<td>Storage Coefficient</td>
</tr>
<tr>
<td>SCGT</td>
<td>Simple Cycle Gas Turbine</td>
</tr>
<tr>
<td>T</td>
<td>Transmissivity</td>
</tr>
<tr>
<td>USACE</td>
<td>U.S. Army Corps of Engineers</td>
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</table>
1.0 Introduction

Entergy New Orleans, Inc. (ENOI) a subsidiary of the New Orleans based Entergy Corporation is proposing to construct the New Orleans Power Station (NOPS). The NOPS will be located within the boundary of the property on which ENOI’s existing Electric Generating Plant is located in the New Orleans East area. Figure 1 shows the site location.

The Michoud Plant was operated starting in the 1950s with three units with a generating capacity of 805 megawatts (MW). Units 1, 2, and 3 were deactivated in 2016. During its operation, the Michoud Plant used groundwater from the Gonzales-New Orleans aquifer and surface water. The groundwater usage is reported to have ranged from 2.99 to 20.7 million gallons per day (MGD) during the operation of the Michoud Plant. The proposed NOPS facility will use either (i) a Simple Cycle Gas Turbine (SCGT) generator with an output capacity of 246 MW\(^1\) or (ii) Reciprocating Internal Combustion Engine (RICE) generators with an output of 128 MW.

For both of these generating alternatives, the makeup water for process water, service water, and fire protection may be derived from the existing water-supply well system that would withdraw groundwater from the Gonzales-New Orleans aquifer (also known as the 700-Foot Sand). The SCGT alternative is expected to need a maximum groundwater supply of up to 96 gallons per minute (gpm), which is approximately 138,000 gallons per day (gpd) or 0.138 MGD. The RICE alternative is expected to need a groundwater supply of 3.9 gpm (0.005 MGD). The proposed groundwater usage for these alternatives is only a small percentage of the historical use of groundwater by the Michoud Plant during its operation.

The New Orleans District, U.S. Army Corps of Engineers (USACE) recently met with citizens of the New Orleans East area who cited questions about potential land subsidence associated with the proposed groundwater withdrawals for the NOPS generating facility. ENOI has engaged qualified outside experts to carefully evaluate the geologic and hydrogeologic conditions of the Michoud area in reference to the potential for any additional subsidence to address the citizens’ questions. ENOI presented a summary of this evaluation in a meeting at the USACE New Orleans District on May 11, 2017 at the request of the New Orleans District. Our detailed evaluation is presented in this document, which demonstrates the following positions:

- The proposed NOPS groundwater withdrawal will be significantly lower than the historical pumping of the Gonzales-New Orleans aquifer at Michoud and will have

\(^1\) According to the Application filed with the Council for the City of New Orleans, ENOI estimates that the SCGT will provide approximately 226 MW (nominal) of summer generating capacity. The actual maximum output of the unit will depend on the following variable factors and conditions: ambient air temperature, relative humidity, Btu content of natural gas delivered at the unit, and number of operating hours since the last maintenance interval.
groundwater level drawdowns in the range of 1 to 2.1 feet within a 2-mile radius of the well.

- The proposed NOPS groundwater withdrawals will be too small to contribute to any subsidence in the Michoud area.

- Recent research on subsidence in the Michoud area shows conflicting and inconsistent results, and can be explained by subsidence being related to compaction of shallow organic-rich sediments such as peat and settlement associated with large structures.

Section 2.0 of this document provides an evaluation of any possible subsidence at the NOPS facility that could be related to the proposed groundwater withdrawals. This includes a summary of the geology and hydrogeologic conditions of the Gonzales-New Orleans aquifer and the historical groundwater withdrawals and groundwater level drawdowns of the Gonzales-New Orleans aquifer. This section also evaluates any possible subsidence associated with the proposed groundwater withdrawals. Section 2.0 also includes a discussion of recent subsidence measurements and research articles addressing subsidence in the Michoud area. Section 3.0 of this document presents the conclusions of this evaluation concerning the conditions of the Gonzales-New Orleans aquifer at Michoud and the unlikelihood that subsidence will be induced by the proposed groundwater withdrawals.
2.0 Evaluation of Subsidence at Michoud

Subsidence is the sinking or settlement of the land surface, due to any of several processes (Poland et al., 1972). Subsidence can be uniform or can be spatially irregular. Spatially uniform subsidence is referred to as regional subsidence. Spatially irregular or localized subsidence is referred to as differential subsidence or differential settlement (Holzer, 1991; Galloway et al., 1999).

Subsidence can be caused by a diverse set of natural processes and human activities (National Research Council, 1991; Galloway et al., 1999; and Allison et al., 2016). The principal subsidence processes affecting New Orleans and the surrounding area include (Allison et al., 2016):

- Tectonic subsidence of the crust (lithosphere)
- Sediment loading from regional sediment accumulation
- Isostatic adjustment of the crust to Quaternary glaciation and sea level changes
- Sediment compaction (consolidation) on regional and local scales
- Fluid withdrawal from the subsurface

The subsidence processes related to tectonics, regional sediment loading, and isostatic adjustment give rise to regional-scale subsidence, but can also show local variations causing differential subsidence adjacent to growth faults.

Sediment compaction or consolidation is the decrease in thickness of a layer of sediment as a result of application of a sustained load to the sediment. Compaction is a natural process and typically causes broad regional subsidence as sedimentation occurs. Compaction can be enhanced by the application of additional loads such as buildings or fill material. In the New Orleans area, compaction of shallow organic-rich soils is an important driver of subsidence. Drainage of organic soils such as peat and backswamp clay deposits induces biological oxidation, desiccation, and collapse resulting in compaction and subsidence of the land surface. Compaction of organic-rich soils can be highly variable and localized resulting in differential subsidence. In the New Orleans area, peat deposits have the greatest potential for subsidence when drained because of their high water content and ease of drainage (Snowden et al., 1980; Kolb and Saucier, 1982). Differential subsidence related to drainage of organic-rich soils has been considered the greatest subsidence problem in New Orleans because of the widespread damage to roads, utilities, and structures caused by this process (Snowden et al., 1980).

 Withdrawal of groundwater or oil and gas from aquifers or reservoirs in the subsurface can contribute to subsidence. The decrease of the fluid pressure because of pumping causes more of the overburden load to be supported by the sediment grains. This increase of the effective stress induces compaction of the aquifer or reservoir. The magnitude of subsidence induced by fluid
withdrawal is related to the decrease of the fluid pressure. In groundwater aquifers, the largest subsidence will occur in the central portion of the cone of depression of the potentiometric surface of the pumped aquifer and will decrease radially outward. In the greater New Orleans area, the principal fluid withdrawal has been historical pumping of groundwater from the Gonzales-New Orleans aquifer for industrial water supply. Oil and gas production has occurred in the area surrounding New Orleans, but has been minor in the city and adjacent suburbs. The objective of this section is to describe the geologic and hydrogeologic conditions that are relevant to the potential for subsidence to occur in the Michoud area as a result of the proposed groundwater pumping at the NOPS facility.

2.1 Site Geology and Hydrogeology

The New Orleans area is underlain by Pleistocene and Holocene coastal-plain deposits of the Mississippi River deltaic plain (Kolb, 1962; Kolb et al., 1975; Dunbar et al., 1994, Saucier, 1994). These deposits form the upper portion of the Gulf Coast sedimentary basin in which sedimentary deposition has occurred between the Jurassic Period and the present day. In the area of the NOPS facility near Michoud, the Holocene deposits range from 50 to 60 feet thick (Kolb et al., 1975; Dunbar et al., 1994; Saucier, 1994) and are underlain by undifferentiated alluvial and coastal plain deposits of the Pleistocene-age Prairie Formation (Prairie Complex).

The Holocene section at the NOPS site from the ground surface downwards consists of approximately 10 feet of natural levee and swamp deposits (silt and clay) underlain by approximately 40 feet of intradelta sand and silt and interdistributary clay. The intradelta deposits were deposited between 3,000 and 1,000 years before present by the Bayou Sauvage Distributary, which is located on the north side of the facility. The main channel of the Mississippi River was located along the Bayou Sauvage Distributary during that time and discharged to the east in the St. Bernard delta lobe of the Mississippi River delta. To the north and east of the NOPS site, the upper part of the Holocene section includes up to 10 to 15 feet of marsh deposits of the St. Bernard lobe of the Mississippi River delta. The marsh deposits consist of dark gray and black watery ooze and very soft organic clay and peat with high moisture contents and low strengths (Kolb, 1962).

The Pleistocene Prairie Complex consists of undifferentiated alluvial and coastal plain deposits extending to depths of 200 to 250 feet (Kolb et al., 1975). The Prairie Complex ranges from 150 to 200 feet in thickness and consists of clay, silt, and sand deposited in alluvial environments. The top surface of the Pleistocene Prairie Complex forms a distinctive lithologic interface recognized by its contrast in color, soil consistency and strength, and water content (Kolb, 1962). The upper portion of the Pleistocene generally is tan, reddish brown, or brown in color as a result of its oxidation and weathering during exposure prior to the Holocene deposition. The overlying Holocene sediments typically are dark gray in color and have high water content and lower strength.
The Pleistocene sediments extend to depths of approximately 1,500 feet below ground surface (bgs) in the New Orleans East area (DuBar et al., 1991; Jones et al., 1996). The Pleistocene section includes sand zones identified as the Gramercy aquifer (200-Foot Sand), Norco aquifer (400-Foot Sand), Gonzales-New Orleans aquifer (700-Foot Sand), and the 1,200-Foot Sand (Tomaszewski, 2003; Prakken, 2009). These sand zones have been utilized as aquifers for groundwater supply in parts of the New Orleans area and adjacent areas.

Geologic cross section D-D’ of Prakken (2009) and the north-south cross section labeled North-South intersect at the NOPS site and depict the stratigraphy of the Pleistocene aquifer sand units. Figure 2 shows the locations of the geologic cross sections. Figure 3 presents the west-east cross section D-D’ (Prakken, 2009). The Gramercy aquifer and the Norco aquifer are thin or missing along this line of section and occur in the western portion of Orleans Parish and in Jefferson Parish (Prakken, 2009). The Gonzales-New Orleans aquifer is continuous along section D-D’ and the top of the aquifer occurs at elevations ranging from -400 to -590 feet relative to the National Geodetic Vertical Datum of 1929. The aquifer dips at a low angle from east to west. The thickness of the Gonzales-New Orleans aquifer ranges from approximately 70 feet to 170 feet. The west-east cross section shows that the upper sand unit of the Gonzales-New Orleans aquifer is discontinuous and occurs intermittently along the cross section with thicknesses of up to 20 to 50 feet. The 1,200-Foot Sand is shown as discontinuous sand bodies occurring at elevations of -600 to -850 feet elevation.

Figure 4 shows a north-south cross section prepared for this report from well logs of water wells and petroleum test wells and from geologic data from Cardwell et al., (1967) and Prakken (2009). This section shows that the sand units dip to the southeast and south. The Gramercy and Norco aquifers also are thin and discontinuous or missing along this line of section. The Gonzales-New Orleans aquifer is continuous along the north-south cross section from the Slidell, Louisiana area to south of the proposed NOPS location. The top of the Gonzales-New Orleans aquifer ranges from an elevation of approximately -200 feet at the north end in the Slidell area to approximately -530 feet at the south end of the cross section south of the Intracoastal Waterway. The dip of the top of the Gonzales-New Orleans aquifer ranges from 15 to 20 feet per mile along the north-south cross section. In the Slidell area and elsewhere along the north shore of Lake Pontchartrain, the aquifer occurring between elevations -200 and -400 feet is known as the Shallow aquifer (Nyman and Fayard, 1978). The north-south cross section shows that the Shallow aquifer is the updip equivalent of the Gonzales-New Orleans aquifer and is stratigraphically continuous with the Gonzales-New Orleans aquifer. The thickness of the Gonzales-New Orleans aquifer ranges from 145 to over 200 feet along the north-south cross section. In the area near Michoud and the proposed NOPS, the thickness of the Gonzales-New Orleans aquifer ranges from 155 to 170 feet in agreement with the aquifer thickness map of Prakken (2009). The north-south cross section also shows that the upper sand unit of the Gonzales-New Orleans aquifer occurs as a continuous...
sand unit from the proposed NOPS northward. The upper sand unit is 20 to 50 feet thick and is separated from the Gonzales-New Orleans aquifer by 25 feet to 100 feet of clay. The north-south cross section shows that the 1,200-Foot Sand occurs at elevations of -650 to -820 feet elevation and is continuous.

The Gonzales-New Orleans aquifer consists of fine to medium-grained sand (Rollo, 1966; Dial, 1983). Grain-size analyses of sand samples collected during the installation of Michoud water well #1 (Or-124) and water well #2 (Or-125) show that the proportions of fine and medium sand are approximately equal except in the basal portion, which is predominantly finer grained consisting primarily of fine sand. The electric logs of water wells and petroleum test wells in the area indicate that the basal portion of the Gonzales-New Orleans aquifer is finer grained than the middle and upper portions of the aquifer.

The hydraulic properties of the Gonzales-New Orleans aquifer have been assessed from pumping tests (Rollo, 1966; Dial, 1983; Dial and Sumner, 1989) and the hydraulic conductivity was estimated to range from 80 to 120 feet per day (ft/day). The transmissivity was estimated to range from 12,000 to 24,000 feet squared per day (ft²/day), which is equivalent to approximately 90,000 to 180,000 gallons per day per foot (gpd/ft). The storage coefficient was estimated to range from 0.0001 to 0.001 (dimensionless). The specific capacities of water wells in the Gonzales-New Orleans aquifer have been reported to range from 8 to 67 gallons per minute per foot (gpm/ft) (Eddards et al., 1956). At the Michoud Plant, the specific capacities of the water wells in the Gonzales-New Orleans aquifer have ranged from 24.6 to 49.7 gpm/ft and the average specific capacity was estimated to be 37.5 gpm/ft. These values of specific capacities are high and indicate that the water wells have high efficiency and productivity.

The recharge area of the Gonzales-New Orleans aquifer is north of Lake Pontchartrain in broad areas of southern St. Tammany and Tangipahoa Parishes and southern Livingston Parish (Walters, 1995). The Gonzales-New Orleans aquifer is stratigraphically continuous with the Shallow aquifer north of Lake Pontchartrain and groundwater levels in the Shallow aquifer of the Slidell area have been below sea level (Nyman and Fayard, 1978) in areas with limited groundwater pumpage. Therefore, the Gonzales-New Orleans aquifer is in hydrologic continuity with the recharge area. The groundwater average linear velocities in the cone of depression of the Gonzales-New Orleans aquifer were estimated to range from 100 to 350 feet per year (Walters, 1995). At these groundwater flow rates, the travel time from the north side of Lake Pontchartrain to the eastern part of New Orleans would be on the order of 150 to 500 years.

2.2 Groundwater Withdrawals and Drawdowns, Gonzales-New Orleans Aquifer

The Gonzales-New Orleans aquifer has been the principal source of groundwater supply for industry in the greater New Orleans area. Development of the aquifer started in the late 1800s (Rollo, 1966) and included wells used for public water supply. In 1903, the groundwater levels in
the Gonzales-New Orleans aquifer were near the ground surface (Eddards et al., 1956) and the total groundwater pumpage from the aquifer was estimated to be approximately 5 MGD (Rollo, 1966). The groundwater withdrawal from the Gonzales-New Orleans aquifer increased to approximately 23 MGD in Orleans Parish by 1953 and the groundwater levels had declined to 94 feet bgs by 1954 in the areas of greatest pumping (Eddards et al., 1956). During the time period from the 1950s through the present day, the groundwater withdrawals from the Gonzales-New Orleans aquifer have been used by industry. Groundwater from the Gonzales-New Orleans aquifer has not been considered satisfactory for public water supply since the early 1900s because of its yellow color. The yellow color is of organic origin from leaching of natural organic matter and gives the water a displeasing appearance (Rollo, 1966). The color of the Gonzales-New Orleans aquifer groundwater generally exceeds 100 platinum-cobalt color units in Orleans Parish and is greater than 300 platinum-cobalt color units in some wells (Dial, 1983). In comparison, the U.S. Environmental Protection Agency Secondary Maximum Contaminant Level (MCL) standard for color is 15 platinum-cobalt color units. The principal uses of the water by industry have been cooling water for manufacturing plants and electrical generation and cooling water for air conditioning of commercial buildings.

In the period from the 1950s through 1980s, the major centers of groundwater withdrawal from the Gonzales-New Orleans aquifer were in downtown New Orleans, the Industrial Canal area near Lake Pontchartrain, and the Michoud area (Michoud Plant and other industry). The total groundwater withdrawals in Orleans Parish during this time interval were reported by the U.S. Geological Survey to range from 35 to 43 MGD (Snider and Forbes, 1961; Bieber and Forbes, 1966; Dial, 1970; Cardwell and Walter, 1979; Walter, 1982; Lurry, 1987). Figure 5 shows the potentiometric surface of the Gonzales-New Orleans aquifer in September 1963 (Rollo, 1966). The distribution of the cone of depression of the potentiometric surface indicates the effects of the groundwater withdrawals on the groundwater levels. The lowest groundwater levels (elevations of -120 to -130 feet) occurred in the center of the cone of depression centered on the downtown area and the Industrial Canal area. The groundwater withdrawal at the Michoud area generated a small secondary cone of depression with groundwater levels at an elevation of approximately -100 feet in the center of the cone of depression. In 1963, the groundwater withdrawal at the Michoud Plant was estimated to be approximately 6 MGD (Rollo, 1966) and was a small percentage of the total groundwater withdrawal in Orleans Parish.

In the 1990s the groundwater withdrawals from the Gonzales-New Orleans aquifer had decreased significantly because of plant closings in the downtown area and decrease of groundwater use for commercial air conditioning (Dial, 1983; Walters, 1995). In the 1990 to 1995 time interval, the total groundwater withdrawals in Orleans Parish were reported by the U.S. Geological Survey to range from approximately 13 to 22 MGD (Lovelace, 1991; Lovelace and Johnson, 1996). Figure 6 shows the potentiometric surface of the Gonzales-New Orleans aquifer in the Spring of 1993.
(Walters, 1995). The configuration of the cone of depression shifted to being centered on the Industrial Canal area. The groundwater levels rose approximately 10 to 15 feet since the late 1980s in the downtown area as a result of decreased groundwater pumpage in that area (Walters, 1995). The 1993 potentiometric map shows that the cone of depression was elongated to the east toward the industrial groundwater pumping in the Michoud area.

The groundwater withdrawals from the Gonzales-New Orleans aquifer decreased further by 2000 because of less usage in the Industrial Canal area. The total groundwater withdrawals in Orleans Parish during the 2000 to 2010 time interval were reported by the U.S. Geological Survey to range from approximately 5 to 13 MGD (Sargent, 2002; Sargent, 2007; Sargent, 2012). Figure 7 shows the potentiometric surface of the Gonzales-New Orleans aquifer in the Spring of 2008 (Prakken, 2009). The configuration of the cone of depression had shifted farther eastward to be centered on the Michoud area. The groundwater levels in the downtown area and Industrial Canal area had recovered by an additional 40 to 50 feet from the groundwater levels shown by the 1993 potentiometric map as a result of the decreased groundwater pumpage in those areas. The groundwater levels in the center of the cone of depression in the Michoud area had elevations that ranged from -110 to -120 feet elevation. Prakken (2009) estimated the groundwater pumping at Michoud in 2007 to include 9.7 MGD at the Michoud Plant and 1.9 MGD at industry located on the east side of the Michoud Canal.

The groundwater pumping at the Michoud Plant was estimated by ENOI to be approximately 10.87 MGD from 2010 until the deactivation in 2016. The groundwater pumping subsequently was decreased significantly after deactivation of the facility.

Groundwater levels in monitoring wells in the Gonzales-New Orleans aquifer show upward trends resulting from the significant decreases of groundwater withdrawals from the aquifer. Figure 8 shows graphs of groundwater levels in observation well Or-206 located west of Michoud, observation well Or-203 located north of Michoud, and observation well Or-175 located to the east of Michoud. Wells Or-203 and Or-175 are located on the northeast and east sides of the cone of depression. Well Or-206 is located in the area that was the center of pumping from the Industrial Canal area and more recently (in 2008 as shown in Figure 7) was located in the western part of the cone of depression. The groundwater levels in these wells showed stabilization by the 1990s and strong upward recovery or rebound after 2000. The rapid rebound of groundwater levels is a result of the high hydraulic diffusivity (ratio of transmissivity to storage coefficient) of the Gonzales-New Orleans aquifer and the hydrologic continuity of the Gonzales-New Orleans aquifer with the region of higher hydraulic heads in the Shallow aquifer of the recharge area located north of Lake Pontchartrain.

The distribution of groundwater salinity in the Gonzales-New Orleans aquifer in 2008 is shown in Figure 9 (Prakken, 2009). In this figure, fresh groundwater contains less than 250 milligrams per
liter (mg/l) of chloride. The Gonzales-New Orleans aquifer contains fresh groundwater to the north of the Mississippi River and the Intracoastal Waterway. The north-south geologic cross section (Figure 4) shows that fresh groundwater occurs in the Gonzales-New Orleans aquifer from the recharge area north of Lake Pontchartrain to the area north of the NOPS facility. The west east geologic cross section (Figure 3) shows that fresh groundwater occurs in the Gonzales-New Orleans aquifer west of the NOPS facility. Saline groundwater occurs in the aquifer at the NOPS facility and in the area to the east. The aquifer contains saline water to the south of the freshwater area. The interface between saline groundwater and fresh groundwater has occurred north of the NOPS site since the onset of groundwater use at the Michoud Plant. In 2008, the wells at the Michoud Plant had chloride concentrations of 458 to 559 mg/l and the total dissolved solids (TDS) have ranged from 685 to over 1,000 mg/l (Dial, 1983; Prakken, 2009). The Secondary MCL standard for chloride is 250 mg/l and for TDS is 500 mg/l so the groundwater at the NOPS site is not considered to be potable. In addition, the high color of the Gonzales-New Orleans aquifer groundwater exceeds the secondary MCL for color.

The locations of centers of groundwater withdrawals in areas at and south of the interface between fresh and saline groundwater has stabilized the position of the interface (Rollo, 1966) during the period of groundwater withdrawals since the late 1800s. Rollo (1966) recommended that the use of brackish and slightly saline groundwater by industry be encouraged as a means to limit potential encroachment of saline groundwater into the region of fresh groundwater in the Gonzales-New Orleans aquifer.

2.3 Estimated Subsidence from Proposed Groundwater Withdrawals

ENOI is evaluating two alternatives for electrical generation at the NOPS facility. For both of these generating alternatives, the makeup water for process water, service water, and fire protection may be derived from the existing water-supply well system in the Gonzales-New Orleans aquifer. The SCGT alternative is expected to need a groundwater supply of 96 gpm (0.138 MGD). The RICE generating alternative is expected to need a groundwater supply of 3.9 gpm (0.005 MGD). The proposed groundwater usage for these alternatives is significantly lower than the historical use of groundwater by the Michoud Plant during its operation.

The NOPS facility has seven water wells installed in the Gonzales-New Orleans aquifer including well #2, well #3, well #4, well #5, well #6, well #7, and well #8. Figure 10 shows the locations of the water wells at the facility. The water wells can be pumped at rates ranging from approximately 1,200 gpm to over 2,200 gpm. Appendix A includes information on the ENOI Michoud Plant water wells. To supply the water volume needed on a daily basis by the NOPS facility, it is expected that one of two of the water wells would be used periodically to fill a water storage tank. ENOI is proposing to use well #5 and well #6 for the groundwater pumping, with one of the two wells serving as a redundancy to the other.
The drawdown of groundwater levels in the Gonzales-New Orleans aquifer that could be induced by pumping of the site water wells has been estimated with the modified non-equilibrium Cooper-Jacob equation for well drawdown (Driscoll, 1987). The drawdown, s, in feet is given by the following equation in dimensional form:

\[ s = \frac{264Q}{T} \log \frac{0.3Tt}{r^2S} \]

where \( Q \) is the pumping rate in gpm, \( T \) is the aquifer transmissivity in units of gallons per day per foot (gpd/ft), \( \log \) is the logarithm function to the base 10, \( t \) is time of pumping in days, \( r \) is the radial distance from the pumping point in feet, and \( S \) is the dimensionless storage coefficient. This equation will be referred to as the drawdown equation. This equation is a commonly-used modification of the well-known Theis drawdown equation and is appropriate for use when the well function \( W(u) \) can be approximated by the logarithm function. This occurs when the value of \( u: \)

\[ u = \frac{1.87Sr^2}{Tt} \]

is less than 0.05. For the range of parameter values used in the estimation of drawdown in the site area, the values of \( u \) are less than 0.05 so that the drawdown equation is a valid approximation of the Theis drawdown equation.

Based on inspection of the drawdown equation, it can be seen that the drawdown will increase as the pumping rate is increased and as the transmissivity is decreased. The drawdown also will increase as the time duration of pumping is increased. The drawdown will decrease with increasing distance from the point of pumping. The drawdown also is related to the storage coefficient and will decrease if the storage coefficient is higher.

Use of the drawdown equation is one approach for estimating hydraulic impacts of groundwater pumping. For well-defined aquifers that have large areal extent, relatively uniform thickness, moderately uniform hydraulic properties, and that are bounded by well-defined aquitards, the use of the drawdown equation provides an effective and simple means for estimating conservative drawdown values or for calculating ranges of possible drawdown values. In contrast, use of a numerical model to evaluate groundwater-level drawdowns for the same aquifer setting would require more extensive data input to yield similar predictions and would require estimation of poorly-constrained input parameters to include leakage and recharge.

The drawdown distributions were calculated with the drawdown equation for the proposed pumping rates of 96 gpm and 3.9 gpm. Conservative values of the hydraulic properties of the Gonzales-New Orleans aquifer were assigned based on the NOPS site conditions and hydraulic properties data for the aquifer. The transmissivity value for the Gonzales-New Orleans aquifer
was assigned as 14,300 ft²/day (106,964 gpd/ft). The storage coefficient was assigned to be 0.0001 (dimensionless). The drawdown was calculated for a time duration of 10 years of pumping. The drawdown is predicted to stabilize prior to this time and to undergo minor increases after that time. For the pumping rate of 96 gpm (the highest proposed pumping rate), the estimated drawdown will range from 2.1 feet within 50 feet of the pumped well to 1.0 feet at a distance of 2 miles (10,560 feet). For the 3.9 gpm pumping rate, the drawdowns will range from 0.08 feet (approximately 1 inch) to less than 0.04 feet at distances of 1 to 2 miles.

Figure 11 shows the estimated drawdown distribution to a distance of 1 mile from the location of well #6 at the NOPS facility. The water-level drawdown will be imposed on the background groundwater levels. Because the Gonzales-New Orleans aquifer has been undergoing significant rebounding of water levels on the order of 30 to 50 feet since 2000, the groundwater levels in the Michoud area are expected to continue to rise. The recent rate of rise of groundwater levels is 1.5 to 2 feet per year. The ongoing recovery of groundwater levels in 1 year would exceed the drawdown caused by the proposed pumping. Therefore, the proposed pumping rates are too low to generate and maintain a significant cone of depression in the aquifer’s groundwater levels.

As requested by the New Orleans District, USACE in the meeting of May 11, 2017, the profile of groundwater level drawdowns has been evaluated in the area of the Hurricane Protection Levee adjacent to the Intracoastal Waterway. Figure 12 shows the topographic cross section between well #6 and the Hurricane Protection Levee on the southeast side of the NOPS site. The drawdowns generated by the 96 gpm pumping rate are shown on Figure 12. The drawdown distribution is close to uniform in the area less than 250 feet from the pumping well and ranges from 2.1 to 1.7 feet. In the pumped well, the drawdown will be approximately 2.2 to 2.6 feet based on the high specific capacities of the water wells (37.5 to 41.8 gpm/ft). For the alternative case of pumpage at 3.9 gpm, the drawdowns in the area from the well to a distance of 250 feet would be 0.08 feet (approximately 1 inch).

The estimated drawdowns for both alternatives of groundwater pumping rate are less than the groundwater level fluctuations in the Gonzales-New Orleans aquifer caused by variations in regional pumpage, tidal fluctuations, or the time-dependent effects of groundwater recharge north of Lake Pontchartrain. Review of the records of groundwater levels in observation wells located away from the centers of groundwater withdrawal in the Gonzales-New Orleans aquifer shows that annual fluctuations in the groundwater elevations range from 1 to 2 feet. Observation well Or-22 located to the east of Michoud near Chef Menteur was monitored from 1936 to 1962 and showed groundwater levels ranging from 0 to -7 feet elevation in an area distant from groundwater withdrawals. Observation well Or-22 was installed in a sand zone thought to be within the Gonzales-New Orleans aquifer, but now interpreted to be in the top of the 1,200-Foot Sand. Figure 8 shows the location of observation well Or-22.
The maximum amount of subsidence in an aquifer potentially related to the decrease of water level in the aquifer can be estimated with the linear approximation (Freeze and Cherry, 1979):

\[ db = \alpha b \rho g \, dh \]

where \( db \) is the change in aquifer thickness, \( \alpha \) is the aquifer compressibility, \( b \) is the original thickness of the aquifer, \( \rho \) is the density of the groundwater, \( g \) is the acceleration of gravity, and \( dh \) is the total drawdown. The change in thickness of the aquifer resulting from groundwater level drawdown is the amount of compaction of the aquifer induced by pumping. The compaction of the aquifer provides an upper limit to the potential subsidence of the land surface above the aquifer that could result from the compaction of the aquifer alone. Based on aquifer compressibility values of \( 10^{-8} \) to \( 10^{-7} \) meters squared per Newton (m²/Newton) for unconsolidated sands (Freeze and Cherry, 1979) and the thickness of the aquifer of 160 feet, the change of the aquifer thickness and ultimate amount of possible subsidence would range from 1.4 to 14 millimeters (mm) (0.05 to 0.5 inch) within the cone of depression in the 1-mile radius of the pumping well. The potential subsidence associated with the lower pumping rate of 3.9 gpm would be less than 1 mm within the one-mile radius. The potential total amount of subsidence would be lower at greater distances from the pumping well. The potential amounts of subsidence that could be induced by the proposed pumping would not be measurable relative to the variable amounts of subsidence estimated to be occurring in the Michoud area.

The ongoing rise of groundwater levels in the Gonzales-New Orleans aquifer will counteract the potential for any subsidence to be associated with the proposed groundwater pumping. The higher groundwater levels could stabilize any potential subsidence related to the historical pumping of the Gonzales-New Orleans aquifer and could potentially reverse subsidence in the aquifer.

### 2.4 Discussion of Subsidence Measurements

The question of subsidence induced by groundwater pumping in the New Orleans area received public attention after the publication in May 2016 of the research paper by Jones et al., (2016). This report has been referred to in the local press as the “NASA report” because of the affiliation of some of the report authors with the Jet Propulsion Laboratory, which is a NASA-affiliated research institute associated with the California Institute of Technology. Jones et al., (2016) assessed subsidence rates measured with interferometric Synthetic Aperture Radar (InSAR) images from two radar images of June 16, 2009 and July 2, 2012. The two radar images were collected from an aircraft flying at an altitude of 41,000 feet, which can provide higher spatial resolution in the radar image than satellite-acquired InSAR data. InSAR evaluation measures phase variations of the radar signal to assess elevation differences between separate synthetic aperture radar images (Ketelaar, 2009; Ferretti, 2014). Jones et al., (2016) stated that the subsidence rates determined by InSAR supported the conclusion that groundwater withdrawal is the primary subsidence driver in areas with major industry around New Orleans, particularly in...
Norco and Michoud. This conclusion had been previously presented by Dokka (2011) based on InSAR data from Dixon et al., (2006). The subsidence rates reported by Jones et al., (2016) for Norco and Michoud ranged from 15 to 30 mm per year (mm/yr). Jones et al., (2016) further concluded that shallow drainage of surficial soils is the most important driver of subsidence in the urban areas. Jones et al., (2016) stated that the subsidence rates can extend to flood control structures located several kilometers distant from areas of higher subsidence rate. The conclusions of the Jones et al. (2016) report were widely reported in the New Orleans area after its publication.

Dixon et al., (2006) conducted a more-detailed evaluation of subsidence with InSAR data derived from a series of 33 satellite-acquired radar images from the period from 2002 to 2005. The Dixon et al., (2006) subsidence rates for the Michoud area are presented in **Figure 13** from Dokka’s (2011) additional evaluation of the results. The Dixon et al., (2006) data showed subsidence rates ranging from 7 to 11 mm/yr in the area of the Michoud Plant. These rates are similar to and slightly larger than the average subsidence rates of 5 to 10 mm/yr in the New Orleans area resulting from compaction of the Holocene sediments (Tornqvist et al., 2008). Dokka (2011) suggested that subsidence in the Michoud area had been associated with the occurrence of groundwater pumping in the area, but did not evaluate the physical conditions of the Gonzales-New Orleans aquifer relative to the potential for subsidence that could be induced by groundwater withdrawal. Dokka (2011) did not evaluate the relationship of the distribution of subsidence rates to the amounts of groundwater drawdown or to the extent of the cone of depression in the Gonzales-New Orleans aquifer. Dokka (2011) concluded that the subsidence had slowed after 2001 and noted that there could be a potential for subsidence reversal associated with the rise of groundwater levels.

**Figure 14** shows the Jones et al., (2016) subsidence rates for the Michoud area. The central portion of the cone of depression of the Gonzales-New Orleans aquifer had occupied the area within 1 mile of the Michoud Plant. This area had groundwater level drawdowns of 110 to 120 feet and would be expected to have the greatest amount of any subsidence induced by groundwater withdrawal. The subsidence rates shown by Jones et al., (2016) in the central portion of the cone of depression were highly variable and not consistent with the distribution of drawdown. The highest rates of subsidence in this radial area were in the range of 20 to 30 mm/yr and were interspersed with subareas with much lower subsidence rates on the order of 10 to 20 mm/yr. At distances of 0.5 to 1 mile from the Michoud Plant, the subsidence rates were lower (predominantly 10 to 15 mm/yr). However, the Jones et al., (2016) data showed higher subsidence rates at locations occupied by large structures (NASA Michoud facility) at distances greater than 1 mile from the Michoud Plant.

Jones et al., (2016) noted that a major limitation of their study was that only two radar images were used for the InSAR evaluation so that the effects of seasonal and environmental variations prior to and between the dates of the radar images could not be evaluated. They noted that river levels were higher in 2009 than in 2012. In addition, there were significant differences in other
hydrologic conditions between the two radar images. Review of U.S. Drought Monitor weekly drought classifications for Orleans Parish showed that no drought conditions occurred before the time of the 2009 radar image, but widespread drought conditions occurred in the month prior to the 2012 radar image. Variations in soil moisture can contribute to elevation changes, with higher ground elevations in wetter conditions and lower elevations in drier conditions. In this case, the drier conditions of the later (2012) radar image could have contributed to the elevation differences assessed between the two radar images. Jones et al., (2016) also stated that the uncertainties in the subsidence rates were high in the Michoud area because of the distance from the aircraft flight path and the high incidence angle of the radar. The uncertainties at the Michoud area were 15 to 25 mm/yr and were larger than the total subsidence rates reported by Dixon et al., (2006) and Dokka (2011).

In statements to the New Orleans area media\(^2\), the lead author C.E. Jones of Jones et al., (2016) stated “additional research is needed to directly link groundwater pumping to the subsidence rates.” In addition, Jones stated that it’s unclear whether the subsidence results from groundwater withdrawal, compaction of soft soils and other geologic processes, or because of geologic processes, such as a nearby “Michoud fault”.

The variability of the reported subsidence rates and their distribution suggest that the subsidence in the Michoud area is related to compaction of near-surface soils and peat and to the concentrated loads provided by large industrial structures.

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3.0 Conclusions

This section summarizes the conclusions of the evaluation of proposed groundwater pumping and subsidence at the proposed NOPS facility in Michoud. The conditions of the Gonzales-New Orleans aquifer in the NOPS area are presented followed by the conclusions concerning the potential for subsidence.

3.1 Gonzales-New Orleans Aquifer Conditions at Michoud

The Gonzales-New Orleans aquifer is of Pleistocene age and occurs in the depth range of between approximately 500 feet to 700 feet below sea level in the Michoud area. The north-south cross section (Figure 4) shows that the Gonzales-New Orleans aquifer is stratigraphically continuous with the Shallow aquifer of the north side of Lake Pontchartrain. The Shallow aquifer is the updip equivalent of the Gonzales-New Orleans aquifer and the recharge area.

In the area near Michoud and the proposed NOPS, the thickness of the Gonzales-New Orleans aquifer ranges from 155 to 170 feet. The top of the aquifer occurs at elevations ranging from -522 to -530 feet relative to sea level (NGVD 1929). The Gonzales-New Orleans aquifer consists of fine to medium sand and has hydraulic conductivity estimated to range from 80 to 120 ft/day. The transmissivity was estimated to range from 12,000 to 24,000 ft²/day (approximately 90,000 to 180,000 gpd/ft). The storage coefficient is estimated to range from 0.0001 to 0.001 (dimensionless). The specific capacities of water wells in the Gonzales-New Orleans aquifer at the Michoud Plant have ranged from 24.6 to 49.7 gpm/ft and the average specific capacity was estimated to be 37.5 gpm/ft. These values of specific capacities are high and indicate that the water wells have high efficiency and productivity.

The Gonzales-New Orleans aquifer has been the principal source of groundwater supply for industry in the New Orleans area. In the period from the 1950s through 1980s, the major centers of groundwater withdrawal from the Gonzales-New Orleans aquifer were in downtown New Orleans, the Industrial Canal area near Lake Pontchartrain, and the Michoud area (Michoud Plant and other industry). The total groundwater withdrawals in Orleans Parish during this time interval were reported by the U.S. Geological Survey to range from 35 to 43 MGD.

In the 1990s the groundwater withdrawals from the Gonzales-New Orleans aquifer had decreased significantly because of plant closings in the downtown area and decrease of groundwater use for commercial air conditioning. The groundwater withdrawals from the
Gonzales-New Orleans aquifer decreased further by 2000 because of less usage in the Industrial Canal area. The total groundwater withdrawals in Orleans Parish during the 2000 to 2010 time interval were reported by the U.S. Geological Survey to range from approximately 5 to 13 MGD. The configuration of the cone of depression had shifted farther eastward to be centered on the Michoud area.

Groundwater levels in monitoring wells in the Gonzales-New Orleans aquifer show upward trends resulting from the significant decreases of groundwater withdrawals from the aquifer. The groundwater levels showed stabilization by the 1990s and strong upward recovery or rebound of 1.5 to 2 feet per year after 2000. The rapid rebound of groundwater levels is a result of the high hydraulic diffusivity of the Gonzales-New Orleans aquifer and the hydrologic continuity of the Gonzales-New Orleans aquifer with the region of higher hydraulic heads in the Shallow aquifer of the recharge area located north of Lake Pontchartrain.

Saline groundwater occurs in the aquifer at the NOPS facility and in the area to the east. The aquifer contains saline water to the south of the freshwater area. The interface between saline groundwater and fresh groundwater has occurred north of the NOPS site since the onset of groundwater use at the Michoud Plant. In 2008, the wells at the Michoud Plant had chloride concentrations of 458 to 559 mg/l and the TDS values have ranged from 685 to over 1,000 mg/l (Dial, 1983; Prakken, 2009). The Secondary MCL standard for chloride is 250 mg/l and for TDS is 500 mg/l so the groundwater at the NOPS site is not potable. In addition, the high color of the Gonzales-New Orleans aquifer groundwater exceeds the Secondary MCL for color.

### 3.2 Possible Subsidence Conditions at Michoud

ENOI is evaluating two alternatives for electrical generation at the NOPS facility. The makeup water for process water, service water, and fire protection for these alternatives may be derived from the existing water-supply well system in the Gonzales-New Orleans aquifer. The SCGT alternative is expected to need a maximum groundwater supply of up to 96 gpm (0.138 MGD). The RICE generating alternative is expected to need a groundwater supply of up to 3.9 gpm (0.005 MGD). The proposed groundwater usage for these alternatives is significantly lower than the historical use of groundwater by the Michoud Plant during its operation.

The drawdown distributions were calculated with the drawdown equation for the proposed pumping rates of 96 gpm and 3.9 gpm. The transmissivity value for the Gonzales-New Orleans aquifer was assigned as 14,300 ft²/day (106,964 gpd/ft). The storage coefficient was assigned to be 0.0001 (dimensionless). The drawdown was calculated for a time duration of 10 years of pumping. For the pumping rate of 96 gpm (the highest proposed pumping rate), the
estimated drawdown will range from 2.1 feet within 50 feet of the pumped well to 1.0 feet at a distance of 2 miles (10,560 feet). For the 3.9 gpm pumping rate, the drawdowns will range from 0.08 feet (approximately 1 inch) to less than 0.04 feet at distances of 1 to 2 miles.

The proposed NOPS groundwater withdrawals will be too small to contribute to any subsidence in the Michoud area. For the 96 gpm pumping rate, the change of the aquifer thickness and ultimate amount of possible subsidence is estimated to range from 1.4 to 14 mm (0.05 to 0.5 inch) within the cone of depression in the 1-mile radius of the pumping well. The possible subsidence associated with the lower pumping rate of 3.9 gpm is estimated to be less than 1 mm within the 1-mile radius. The possible total amount of subsidence would be lower at greater distances from the pumping well. The possible amounts of subsidence that could be induced by the proposed pumping would not be measurable relative to the variable amounts of subsidence estimated to be occurring in the Michoud area.

Recent research on subsidence rates in the Michoud area shows conflicting and inconsistent results. The estimated rates of subsidence presented by Jones et al., (2016) are highly variable within the center of the cone of depression within the 1-mile radius of the Michoud Plant and do not coincide with the region that had the largest groundwater level drawdowns. The subsidence rates presented by Dixon et al., (2006) and Dokka (2011) for the Michoud area are similar to the average subsidence rates of the New Orleans area. The Jones et al., (2016) subsidence rates had very high uncertainties of 15 to 25 mm/yr in the Michoud area. The uncertainties were related to the flight path of the aircraft collecting the InSAR data and the high incidence angle of the radar reflections. The uncertainties were on the order of the reported subsidence rates and call into question the validity of the Jones et al., (2016) conclusion that groundwater withdrawal is the primary subsidence driver in Michoud. The research results on subsidence rates in the Michoud area can be explained by subsidence being related to compaction of shallow organic-rich sediments such as peat and settlement associated with large structures.
4.0 References


Driscoll, F., 1987, Groundwater and Wells, Johnson Division.


Ferretti, A., 2014, Satellite InSAR Data, EAGE Publications.

Freeze, R.A. and Cherry, J., 1979, Groundwater, Prentice-Hall.


Kolb, C.R., 1962, Distribution of Soils Bordering the Mississippi River from Donaldsonville to Head of Passes, U.S. Army Engineer Waterways Experiment Station, Corps of Engineers, Technical Report No. 3-601.


Saucier, R.T., 1994, Geomorphology and Quaternary Geologic History of the Lower Mississippi Valley, U.S. Army Engineer Waterways Experiment Station, Corps of Engineers.


Figures
REFERENCE:
Coordinates provided in Geodetic Datum NAD 83, Latitude and Longitude is shown in Degrees, Minutes, Seconds.

NOPS ENTRANCE
LAT: 30° 0' 44.75"
LONG: 89° 56' 14.43"

SITE LOCATION
REFERENCE:
Prakken, 2009: Figure 7. Hydrogeologic section D-D' showing major sand units from central Orleans Parish to northeastern Orleans Parish, New Orleans area, southeastern Louisiana.
REFERENCE:
REFERENCE:
Walters, 1995: Figure 3. Potentiometric surface of the Gonzales-New Orleans aquifer, spring 1993.
REFERENCE:

J:\Drafting\Entergy\155004 (NOPS)\ArcView\GIS_Documents\Project_Maps\nops_155004_0032_pot_map_2008.mxd; Analyst: debbie.comeaux; Date: 5/30/2017 11:29:00 AM
Legend

- Location of Proposed NOPS

**GROUNDWATER LEVEL TRENDS**

**FIGURE NUMBER** 8

**NEW ORLEANS POWER STATION PROJECT**
**NEW ORLEANS, ORLEANS PARISH, LOUISIANA**

CB&I Government Solutions, Inc.
4171 Essen Lane
Baton Rouge, Louisiana 70809
Groundwater quality distribution, Gonzales-New Orleans aquifer

REFERENCE:
Coordinates provided in Geodetic Datum NAD 83, Latitude and Longitude is shown in Degrees, Minutes, Seconds.
ESTIMATED MAXIMUM DRAWDOWN, PROPOSED PUMPING AT 96 GPM

FIGURE 11

EXHIBIT GL-3
CNO Docket No. UD-16-02

REFERENCE:
Coordinates provided in Geodetic Datum NAD 83, Latitude and Longitude is shown in Degrees, Minutes, Seconds.

CB&I Government Solutions, Inc.
4171 Essen Lane
Baton Rouge, Louisiana 70809
NOTE: Calculation of drawdown profile based on pumping of Well #6 (or Well #5) at an average rate of 96 gpm. Cross section based on site topography. Calculated drawdown in feet in parentheses.
Figure 11. Map of the Michoud area of New Orleans showing vertical velocities derived from InSAR analysis of Dixon et al. [2006]. The heavy dashed black line is the Michoud fault of Dokka [2006]; this fault is probably best described as a shear zone (black ruled zone). InSAR velocities for 2003–2005, in mm yr\(^{-1}\): red dots, –17; yellow, –17 to –13; orange, –13 to –7; green, –7 to 0; blue triangles, water wells. Field investigation showed that InSAR permanent scatterers in the area correlate mainly with reflecting surfaces on single-story homes. It has been standard construction practice in New Orleans since the 1950s to build such homes on pilings that completely penetrate Holocene deposits (C. Mignonier, personal communication, 2010). Because the monumentation of the InSAR is similar to both leveling and water level gauge measurements, the results are comparable. See text for discussion.
Figure 4 from Jones et al (2016) showing INSAR subsidence rates in mm/yr based on 2009 and 2012 radar imagery.
Appendix A

Michoud Plant Water Well Information
<table>
<thead>
<tr>
<th>Field</th>
<th>Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>WELL OWNER:</td>
<td>New Orleans Public Service, Inc.</td>
</tr>
<tr>
<td>ADDRESS</td>
<td>317 Baronne Street, New Orleans, La.</td>
</tr>
<tr>
<td>OWNERS WELL NUMBER (if any)</td>
<td>Well #1</td>
</tr>
<tr>
<td>LOCATION OF WELL</td>
<td>Orleans in SECTION 42</td>
</tr>
<tr>
<td>TOWNSHIP, PARISH, RANGE</td>
<td>125 13E</td>
</tr>
<tr>
<td>Well is near (Crossroads, Town, Railroad, any Landmark, etc.)</td>
<td>at Michoud Generating Station</td>
</tr>
<tr>
<td>Old Gentilly and Parish Road</td>
<td></td>
</tr>
<tr>
<td>(IF POSSIBLE PLEASE ATTACH MAP OR PLAT SHOWING LOCATION)</td>
<td></td>
</tr>
<tr>
<td>WELL INFORMATION:</td>
<td>Depth of hole: 634 ft.</td>
</tr>
<tr>
<td></td>
<td>Depth of completed well: 634 ft.</td>
</tr>
<tr>
<td></td>
<td>Date completed: 1956</td>
</tr>
<tr>
<td></td>
<td>by (Give name and address of water-</td>
</tr>
<tr>
<td></td>
<td>well contractor who installed well or</td>
</tr>
<tr>
<td></td>
<td>hole): Menge Well &amp; Pump Co.</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>4. Describe in detail how well or hole was plugged.</td>
<td>Well plugged by</td>
</tr>
<tr>
<td></td>
<td>pumping cement through pipe at</td>
</tr>
<tr>
<td></td>
<td>bottom screen</td>
</tr>
<tr>
<td></td>
<td>100% coverage by Halliburton.</td>
</tr>
<tr>
<td></td>
<td>All screen &amp;</td>
</tr>
<tr>
<td></td>
<td>casing left in hole.</td>
</tr>
<tr>
<td>5. REMARKS:</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>I certify that this work was done and completed in accordance with</td>
<td></td>
</tr>
<tr>
<td>Rules and Regulations of the State on 1969 by (name and address</td>
<td></td>
</tr>
<tr>
<td>of contractor or owner): Menge Well &amp; Pump Co.</td>
<td></td>
</tr>
</tbody>
</table>
### CARD A (MASTER CARD)

**Owner No:** Michoud #1  
**U.S. Dept. of the Interior**  
**Geological Survey**  
**WATER RESOURCES DIVISION**  
**LOUISIANA DISTRICT**

**Well No:** CR-124

**Record by:** J.R. Rolfs  
**Date:** 12/1600  
**Source of data:** Government

**State:** LA  
**County:** Orleans  
**Lat. Long.** 30° 06'43.2"N 90° 12'00.4"W

**Lat. Long. accuracy:** 1  
**Sequential number:** 11  
**Well number:** 22 24 25

**Township:** 13 17 18 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45 46 47

**Range:** 1 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20

**Q.W. data:**  
**Frequent sampling:**  
**Periodic inventory:**  
**Pumpage:** yes  
**Log data:** yes

**Owner:** New Orleans Public Service Inc.

**Use of water:**  
**Use of well:**  
**DATA AVAILABLE:** Well data: W/L measure, Field aquifer characteristics

**Hyd. lab. data:**  
**Q.W. data:**  
**Frequent sampling:**  
**Periodic inventory:**  
**Pumpage:** yes  
**Log data:** yes

**CARD B (WELL-DESCRIPTION CARD)**

**Well depth:**  
**Est. Depth:** 634 ft  
**Method drilled:** H  
**Date drilled:** 02/1600  
**Date completed:** 02/1600

**Driller:** Menge Well & Pump Co., Inc.

**Pump intake settings:**  
**Lift:** 40 ft  
**Power:** 5 HP  
**No. of pump data:** 5

**Alt. LSD:** 3  
**Alt. LSD accuracy:** 2

**Water level:**  
**Above:** 12 ft  
**Below:** 12 ft

**Yield:**  
**Method determined:** Drawdown

**QUALITY OF WATER DATA:**  
**Iron:** 50 ppm  
**Sulfate:** 500 ppm  
**Chloride:** 50 ppm  
**Hardness:** 55 ppm

**Sp. Cond.:** 25.25  
**Temp.:** 74°F  
**Field pH:**  
**Date sampled:** 11-2-71

**CARD C (HYDROGEOLOGIC CARD)**

**Physiographic Province:** Coastal Plain  
**Section:** Mississippian Plain

**Drainage Basin:**  
**Subbasin:**  
**Topography of well site:**  

**MAJOR AQUIFER:** System Quat  
**Series:** Pliocene  
**AQUIFER thickness:** 124 ft

**Lithology:**  
**Origin:**  
**Aquifer thickness:** 124 ft

**Length of well open to:** 534 ft

**MINOR AQUIFER:** System  
**Series:**  
**AQUIFER thickness:**

**Lithology:**  
**Origin:**  
**Aquifer thickness:**

**Length of well open to:**

**Depth to consolidated rock:**  
**Source of data:**

**Coefficient of Transmissibility:**

**Coefficient of Storage:**

**Card No.:** CR}

---

**Exhibit GL-3**

**CNO Docket No. UD-16-02**

**Page 43 of 67**
**CARD A** (SUPPLEMENTAL CASING RECORD)

<table>
<thead>
<tr>
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<th>Type</th>
<th>Length</th>
<th>Depth to top</th>
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<td>5</td>
<td>29.7</td>
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<tr>
<td>1.7</td>
<td>7</td>
<td>2.1</td>
<td>2.9</td>
</tr>
<tr>
<td>1.5</td>
<td>7</td>
<td>2.0</td>
<td>5.1</td>
</tr>
<tr>
<td>1.4</td>
<td>7</td>
<td>5.1</td>
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Other data: 

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<th>Card designation</th>
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<td>A *</td>
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**CARD B** (SUPPLEMENTAL SCREEN RECORD)

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<td>5</td>
<td>1.00</td>
<td>5.3</td>
<td>4.0</td>
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Other data: 

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<th>Card designation</th>
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</thead>
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<td>B *</td>
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</table>

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**CARD C** (SUPPLEMENTAL YIELD AND SPECIFIC-CAPACITY DATA CARD)

<table>
<thead>
<tr>
<th>Yield</th>
<th>Drawdown</th>
<th>Specific Capacity</th>
<th>Pump. per. (hrs)</th>
</tr>
</thead>
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<tr>
<td>24.50</td>
<td>91</td>
<td>2.64</td>
<td>3.54</td>
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<td>16.70</td>
<td>64</td>
<td>2.41</td>
<td>3.54</td>
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<table>
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<tr>
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<th>Date meas.</th>
<th>Date meas.</th>
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<td>8-56</td>
<td>8-56</td>
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<th>Card designation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>C *</td>
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</tbody>
</table>

---

**MPZ**

MPZ is bottom inside edge of 2" gate, 3.85 above concrete slab at LSD.

Concrete slab LSD

**SPECIFIC CAPACITIES**

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<tr>
<th>Yield</th>
<th>DD</th>
<th>SpCap</th>
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<td>2.450</td>
<td>91</td>
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</tr>
<tr>
<td>1.404</td>
<td>51</td>
<td>27.5</td>
</tr>
</tbody>
</table>

---

**CHEMICAL ANALYSIS**

9-28-56 - by FJ Hoffman

- Color: Amber
- Turbidity: None
- Conductivity in Ohms @ 77°F: 650
- Total Dissolved Solids = 700 ppm
- pH = 8.35
- Ammonia Nitrogen: 0.45 ppm
- Total Alkalinity as CaCO₃ = 350 ppm
- Total Chloride as NaCl = 225 ppm
- Total Sulphates as Na₂SO₄ = Trace

---

**SKETCH AND DIAGRAM**

See sketch or-125
### CARD DR: SUPPLEMENTAL WELL-DESCRIPTION CARD

**Boxes 1-19 same as on Card 'A**

**Driller:**

- **WELL AND PUMP Co.**

- **Test hole depth:** 65 ft

- **Pumpage:** 40 gpm

- **Days/week:** 5

- **Weeks/year:** 52

- **Average rate:** 80 gpm

- **Coefficient of Permeability:** 58

- **Field pH:** 60

- **Depth interval range:** 5 to 65 feet

- **Other data:**

**NOTES:**

- "Gross cemented by Halliburton"
- "9 well numbers assigned to well site, #2 drilled prior to #1, = PLUGGED: ABANDONED - SEE LOCAL ABAND. FORM"

---

### LITHOLOGIC LOG

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<thead>
<tr>
<th>Lithology</th>
<th>Thickness</th>
<th>Depth</th>
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<td>clay</td>
<td>10</td>
<td>15</td>
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<td>sand</td>
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<tr>
<td>sand and sandy clay</td>
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<td>97</td>
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<tr>
<td>shale, sandy</td>
<td>43</td>
<td>140</td>
</tr>
<tr>
<td>shale, and sandy shale</td>
<td>43</td>
<td>140</td>
</tr>
<tr>
<td>shale, soft</td>
<td>121</td>
<td>296</td>
</tr>
<tr>
<td>shale, sticky</td>
<td>74</td>
<td>370</td>
</tr>
<tr>
<td>shale, sandy</td>
<td>86</td>
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<td>sand</td>
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</tr>
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<td>522</td>
</tr>
<tr>
<td>sand</td>
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<td>640</td>
</tr>
<tr>
<td>shale</td>
<td>8</td>
<td>654</td>
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</tbody>
</table>

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### MECHANICAL ANALYSIS

<table>
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<tr>
<th>Depth</th>
<th>0.010</th>
<th>0.014</th>
<th>0.012</th>
<th>0.015</th>
<th>0.018</th>
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<td>4</td>
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<td>23</td>
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<td></td>
</tr>
<tr>
<td>542-565</td>
<td>5</td>
<td>12</td>
<td>25</td>
<td>26</td>
<td>16</td>
</tr>
<tr>
<td>565-588</td>
<td>6</td>
<td>10</td>
<td>25</td>
<td>28</td>
<td></td>
</tr>
<tr>
<td>588-610</td>
<td>5</td>
<td>15</td>
<td>33</td>
<td>28</td>
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</tr>
<tr>
<td>618-633</td>
<td>11</td>
<td>15</td>
<td>20</td>
<td>24</td>
<td>14</td>
</tr>
<tr>
<td>633-640</td>
<td>5</td>
<td>12</td>
<td>22</td>
<td>15</td>
<td></td>
</tr>
</tbody>
</table>
Owner No. 1
Owner New Orleans Public Service, Inc.
Location Michoud Generating Station
Driller Menge Pump & Machinery Co.
Depth of test hole 654 ft., Depth of well 635'-4"
Type of well: Dug, Driven, Bored [Drilled, Jet]
Stratigraphic unit Log: D, E, (W or C)
Casings: Kind: Galvanized 
Kind: size 16" Od.; length 296' 8" ft.; between 0 and 296' 8" ft.
Kind: size 12 3/4" Od.; length 227' 3" ft.; between 296' 8" and 527' 11" ft.
Kind: size 9 3/4" Od.; length 10' 5" ft.; between 527' 11" and 533' 8" ft.
Screen record (diam., opening, setting) 9 7/8" - .009 gauge, red brass
Screen 60 mesh — 100 ft. from 533' 8" to 633' 8"
Pump: Make and Type: M DWT Stages: No. 5, Diam. 14"
Pump setting 160 ft.; length and diameter of footpiece 20 ft. 10"
Capacity 1400 gpm against 350' head; Column diameter 10"
Power, kind: Electric H.P. 150 R.P.M. 1750
Static level 6.3 ft. (sept., meas. Mar. 1956, above below)
which is ft. above, below land surface
Pumping level 154 ft. Yield 2450 gpm Mar 1956
See over
Drawdown 91 ft. after pumping — hours at 2450 gpm Mar 1956
Specific capacity 26.9 while pumping 2450 gpm Mar 1956; Hrs/day in use
Use: Irr., P.S., Dom., Stock, Obs., Test, [Balance, etc.]
Amount (gpd): Average  maximum  minimum
Quality See over
Odor
Sample Date 19 Temp. (°F)
Source of data Correspondence New Orleans Public Service 19 Jan 60
Recorded by J R Rolla Date 21 Jan 60; Rescheduled by Date
Remarks: Mech. Analyses made by driller on reverse
& Casing cemented by Halliburton
Quadrangle
(Revised May 1, 1958)
Well No. Or-124
### LOG OF WELL

<table>
<thead>
<tr>
<th>Type of rock</th>
<th>Thickness</th>
<th>Depth</th>
</tr>
</thead>
<tbody>
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</tr>
<tr>
<td>Clay</td>
<td>10</td>
<td>15</td>
</tr>
<tr>
<td>Sand</td>
<td>15</td>
<td>30</td>
</tr>
<tr>
<td>Sand + Sandy clay</td>
<td>67</td>
<td>97</td>
</tr>
<tr>
<td>Shale, sandy</td>
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<td>140</td>
</tr>
<tr>
<td>Shale + Sandy shale</td>
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<td>175</td>
</tr>
<tr>
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<td>121</td>
<td>296</td>
</tr>
<tr>
<td>Shale, sticky</td>
<td>74</td>
<td>370</td>
</tr>
<tr>
<td>Shale, sandy</td>
<td>86</td>
<td>456</td>
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<td>Sand</td>
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<td>Sand</td>
<td>124</td>
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<td>Shale</td>
<td>8</td>
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</tr>
</tbody>
</table>

### Chemical Analysis

28 Sep 56 by F. J. Hoffman

- **Color**: Amber
- **Turbidity**: None
- **Conductivity in OHMS @ 77°F**: 66
- **Total Dissolved Solids ppm**: 700
- **pH**: 8.35
- **Ammonia Nitrogen ppm**: 0.45
- **Total Alkalinity as CaCO3**: 3.85
- **Total Chlorides as NaCl ppm**: 22.5
- **Total Sulfates as Na2SO4 ppm**: Trace

### Specific Capacities

<table>
<thead>
<tr>
<th>Yield</th>
<th>D.D.</th>
<th>Sp. CDr.</th>
</tr>
</thead>
<tbody>
<tr>
<td>245.0</td>
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<td>190.4</td>
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</tbody>
</table>

### Mechanical Analysis

<table>
<thead>
<tr>
<th>Depth (ft)</th>
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<th>1014</th>
<th>1012</th>
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<td>5</td>
<td>12</td>
<td>22</td>
<td>25</td>
<td>15</td>
</tr>
</tbody>
</table>

---

**Test run by N.O.P.S on well**

Aug 27, 1959: Test run 6 min after shutdown

Water level: 78 ft

Flow: 1670 gpm

D.D. - 68 ft

Sp. CDr = 24.6

See sketch of plant for location.
**WELL SCHEDULE**

**CARD A (MASTER CARD)**

- **Owner No.** Michael #2
- **Date:** March 12
- **County:** Orleans
- **Well No.:** Or-125
- **State:** Louisiana
- **Local well number:** 12.5
- **Quadrangle:** Little Woods
- **Owner:** New Orleans Figure Co., Inc.
- **Use of water:** Yes
- **Use of well:** No
- **DATA AVAILABLE:** Yes
- **Frequency sampling:** No
- **Pumpage inventory:** No
- **Periodic test:** Yes
- **Aperture cards:** Yes
- **Log:** No
- **Frequency w/l meas.:** No
- **Field aquifer characteristics:** No
- **Log:** No
- **Frequency:** Yes
- **Water level:** 15.42 ft
- **Distance:** 0.71
- **LSD type:** 113
- **Calculate:** 1400 gpm
- **Alt:** 40
- **MP description:** 40
- **Drill:** Negrin Figure Co., Inc.
- **Address:** New Orleans, lo.
- **Shallow:** 1400 gpm
- **LSD comp.:** Yes
- **Method:** Drilled
- **Depth tested:** 10 ft
- **Well depth:** 50 ft
- **Accuracy:** Yes
- **Type:** Steel
- **Diam.:** 1.8
- **Finish:** Not provided
- **Well number:** UD-16-02
- **Latitude:** 30.0024
- **Longitude:** -89.95617
- **Sequential number:** 44
- **Lat-long accuracy:** 1.5
- **Source:** Answer
- **County:** Orleans
- **City:** New Orleans

**CARD B (WELL-DESCRIPTION CARD)**

- **Subbasin:** 14.5
- **Subbasin:** 14.5
- **Major Aquifer:** 112.5
- **Subbasin:** 14.5
- **Aquifer formation:** Yes
- **Aquifer thickness:** 9.16
- **Length of well open to:** 1.700
- **Depth to top of aquifer:** 5.125
- **Aquifer:** Yes
- **Series:** 44
- **Series:** 44
- **Aquifer formation:** Yes
- **Aquifer thickness:** 3.54
- **Lithology:** Yes
- **Origin:** 1.5
- **Aquifer thickness:** 3.54
- **Length of well open to:** 1.700
- **Depth to top of aquifer:** 5.125
- **Aquifer:** Yes
- **Series:** 44
- **Series:** 44
- **Aquifer formation:** Yes
- **Aquifer thickness:** 3.54
- **Lithology:** Yes
- **Origin:** 1.5
- **Aquifer thickness:** 3.54
- **Length of well open to:** 1.700
- **Depth to top of aquifer:** 5.125
- **Aquifer:** Yes
- **Series:** 44
- **Series:** 44
- **Aquifer formation:** Yes
- **Aquifer thickness:** 3.54
## CARD A (SUPPLEMENTAL CASING RECORD)

<table>
<thead>
<tr>
<th>Boxes 1-19 same as on Card A</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diameter Fract. Type</td>
</tr>
<tr>
<td>----------------------</td>
</tr>
<tr>
<td>1.6</td>
</tr>
<tr>
<td>1.2</td>
</tr>
<tr>
<td>2</td>
</tr>
<tr>
<td>Other data:</td>
</tr>
<tr>
<td>Card No.: 78 79 80</td>
</tr>
<tr>
<td>Card designation: A *</td>
</tr>
</tbody>
</table>

## CARD B (SUPPLEMENTAL SCREEN RECORD)

<table>
<thead>
<tr>
<th>Boxes 1-19 same as on Card A</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diameter Fract. Type</td>
</tr>
<tr>
<td>----------------------</td>
</tr>
<tr>
<td>9.5</td>
</tr>
<tr>
<td>54</td>
</tr>
<tr>
<td>Other data:</td>
</tr>
<tr>
<td>Card No.: 78</td>
</tr>
<tr>
<td>Card designation: B *</td>
</tr>
</tbody>
</table>

## CARD C (SUPPLEMENTAL YIELD AND SPECIFIC-CAPACITY DATA CARD)

<table>
<thead>
<tr>
<th>Boxes 1-19 same as on Card A</th>
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</thead>
<tbody>
<tr>
<td>Yield</td>
</tr>
<tr>
<td>1.6</td>
</tr>
<tr>
<td>24 25 26 27 28 29 30 31 32 33 34 35</td>
</tr>
<tr>
<td>Date meas. 8/28/59</td>
</tr>
<tr>
<td>Date meas.</td>
</tr>
<tr>
<td>Card No.: 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95 96 97 98 99 100</td>
</tr>
<tr>
<td>Card designation: C *</td>
</tr>
</tbody>
</table>

## SKETCH AND DIAGRAM
CARD D(SUPPLEMENTAL WELL-DESCRIPTION CARD)

Box 1-19 same as on Card 'A''

Briller: MENNINGE PUMP AND MACH. CO.

Test hole depth: 1678 Pumpage: Hrs/day\[\text{40}\] Days/week\[\text{50}\] Weeks/year\[\text{55}\] Average rate\[\text{55}\] 55 55

Coefficient of Permeability:

Pumpage:

Field phi:

Lithologic samples available:

Depth interval range:

Other data:

Card designation: [DX]

NOTES: Moh. Abad. by Diller 527-620

LITHOLOGIC LOG

Lithology | Thickness | Depth | Aquifer or unit name

<p>| AE | yellow | 11.00 | 11.00 |</p>
<table>
<thead>
<tr>
<th>Lithology</th>
<th>Thickness</th>
<th>Depth</th>
<th>Aquifer or unit name</th>
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</thead>
<tbody>
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</tbody>
</table>
Owner No. 2
Elevation 35

United States Department of the Interior Geological Survey

Well No. Or-125
Parish Orleans


Location Michoud Generating Station Sec. 42, T. 12 S., R. 13 E.

Driller Menge Pump & Machinery Co., Inc. Address 549 Dryades St. New Orleans 12, La.

Depth of test hole 678 ft., Depth of well 633' 8" f

Type of well: Dug, Driven, Bored, Drilled, Jet Completed 10 Oct 19

Stratigraphic unit Log: DJ, E., (W or C)

Casings: Kind: 2 1/2" Galv. Size: 6" OD; length 313-2 ft.; between 0 and 313-2 f

Kind: De. Size: 7" OD; length 29-0 ft.; between 313-2 and 532-2 f

Kind: De. Size: 7" OD; length 27-10 ft.; between 532-2 and 504-2 f

Screen record (diam., opening, setting) 9 5/8" OD - 0.009 Red Brass Screen

50 + 60 mesh Standard Hardware - 542-2 to 632-2

Pump: Make and Type F-M, OWT Stages: No. 5, Diam. 14

Pump setting 160 ft.; length and diameter of footpiece 10 ft. 10 ft.

Capacity 1400 gpm @ 350' to 1, Height 10 ft. Column diameter 10 ft.

Power, kind: Electric H.P. 150 R.P.M. 1750

Static level 73 ft., rep. meas. Aug 29 1960, above below

which is ft. above, below land surf.


Drawdown 67 ft. after pumping 10 min. hours at 1645 gpm Aug 28 1955

Specific capacity 24.1 while pumping 1645 gpm Aug 28 1955; Hrs/day in use

Use: Irr., P.S., Dom., Stock, Obs., Test,

Amount (gpd): Average , maximum , minimum

Quality See Over

Odor Sample Date 19 Temp. (°F)

Source of data Correspondence, New Orleans Public Service 19 Jan 60

Recorded by JR Rollo Date 21 Jan 60; Rescheduled by Date

Remarks: * Casing cemented

Mechanical Analyses by Driller or back

Quadrangle

(Revised May 1, 1958)
## LOG OF WELL

<table>
<thead>
<tr>
<th>Type of rock</th>
<th>Thickness</th>
<th>Depth</th>
<th>27 Sept 56</th>
<th>FJ Hoffman</th>
</tr>
</thead>
<tbody>
<tr>
<td>Top soil + sticky clay</td>
<td>10</td>
<td>10</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Clay, sandy</td>
<td>6</td>
<td>16</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Log</td>
<td>1</td>
<td>17</td>
<td></td>
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</tr>
<tr>
<td>Clay, sandy</td>
<td>13</td>
<td>30</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sand, fine</td>
<td>26</td>
<td>56</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shale, sandy and shells</td>
<td>36</td>
<td>92</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shale, soft + streaks sand</td>
<td>93</td>
<td>185</td>
<td></td>
<td></td>
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<tr>
<td>Shale</td>
<td>140</td>
<td>325</td>
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</tr>
<tr>
<td>Shale, sandy</td>
<td>35</td>
<td>360</td>
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</tr>
<tr>
<td>Shale, sticky</td>
<td>20</td>
<td>380</td>
<td></td>
<td></td>
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<td>Shale, sandy</td>
<td>11</td>
<td>391</td>
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<td>Shale, sandy and sand</td>
<td>54</td>
<td>445</td>
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<td></td>
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<tr>
<td>Shale, hard and streaks sand</td>
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<td>475</td>
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<tr>
<td>Shale</td>
<td>49</td>
<td>524</td>
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<td></td>
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<tr>
<td>Sand, fine</td>
<td>16</td>
<td>540</td>
<td></td>
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</tr>
<tr>
<td>Sand</td>
<td>80</td>
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<tr>
<td>Shale</td>
<td>58</td>
<td>678</td>
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</table>

### Mechanical Analysis

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<tr>
<th>Depth</th>
<th>0.014</th>
<th>0.012</th>
<th>0.010</th>
<th>0.008</th>
<th>% Retained</th>
</tr>
</thead>
<tbody>
<tr>
<td>524</td>
<td>0</td>
<td>0</td>
<td>11</td>
<td>37</td>
<td>%</td>
</tr>
<tr>
<td>540</td>
<td>Trace</td>
<td>19</td>
<td>35</td>
<td>41</td>
<td>%</td>
</tr>
<tr>
<td>541-563</td>
<td>0</td>
<td>26</td>
<td>24</td>
<td>5</td>
<td>%</td>
</tr>
<tr>
<td>563-573</td>
<td>0</td>
<td>5</td>
<td>24</td>
<td>31</td>
<td>%</td>
</tr>
<tr>
<td>573-585</td>
<td>Trace</td>
<td>21</td>
<td>32</td>
<td>28</td>
<td>%</td>
</tr>
<tr>
<td>585-596</td>
<td>19</td>
<td>30</td>
<td>25</td>
<td>21</td>
<td>%</td>
</tr>
<tr>
<td>596-608</td>
<td>Trace</td>
<td>18</td>
<td>33</td>
<td>37</td>
<td>%</td>
</tr>
<tr>
<td>608-620</td>
<td>0</td>
<td>15</td>
<td>38</td>
<td>28</td>
<td>%</td>
</tr>
</tbody>
</table>

### Sketch and Diagram
**Exhibit GL-3**

**CNO Docket No. UD-16-02**

**Page 56 of 67**

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**WELL SCHEDULE**

**Owner No:** Michaud #3  
**U.S. Dept. of the Interior**  
**Geological Survey**  
**Water Resources Division**  
**Louisiana District**  

**Card A (Master Card)**  
**Record by:** J.R. Rolfe  
**Date:** 5-17-62  
**Source of data:** Observations, C.M. Weber  
**State:** Louisiana  
**County:** Orleans  
**Latitude:** 30° 14' 36"  
**Longitude:** 90° 39' 56.1"  
**Sequential number:** 1  
**Lat-long accuracy:** 1  
**Local well number:** 170  
**Township:** 12S  
**Range:** 13W  
**Quadrangle:** Little Woods  
**Section:** 42  
**Owner:** New Orleans Public Service Inc.  
**Use of water:**  
**Use of well:**  
**Data Available:** Well data  
**Frequency W/L meas.:**  
**Field aquifer characteristics:**  
**Hyd. Lab. data:**  
**Q.W. data:**  
**Pumping Inventory:**  
**Frequency sampling:**  
**Frequency:**  
**Period:**  
**Aperture Card:**  

**Card B (Well-Description Card)**  
**Well Depth:** 645 ft  
**Ext. Rep.:**  
**Accuracy:** 2  
**Depth Cased:** (ft. perf.)  
**530**  
**Driller:** L.J. La F., Co.  
**Address:**  
**Pump intake setting:** 200  
**Pump type:** Deep  
**H.P.:** 2  
**Power type:**  
**Alt. LSD:** -3  
**Other Pump data:** Stage 15  
**Column diam.:** 10 ft  
**Length:** 20 ft  
**Diam.:** 10 ft  
**Capacity:** 1400 gpm  
**Gpm Against:** 400 ft. head  
**Alt. LSD accuracy:** 3  
**MP Description:** Top of casing 3.0 ft  
**LSD:**  
**Water level:** 75.20  
**Accuracy:** 4  
**Date meas:** 1-1-62  
**762**  
**Yield:** 2020 gpm  
**Method determined:**  
**Drawdown:** 4  
**Accuracy:** 5  
**Pumping Period:**  

**Card C (Hydrogeologic Card)**  
**Physiographic Province:** Coastal plain  
**Section:** Mississippi Delta plain  
**Drainage Basin:** Lower Mississippi  
**Subbasin:**  
**MAJOR AQUIFER:** System Oyster  
**Series** clinic  
**Aquifer, formation, "700 ft." Sand  
**Lithology:** Sand  
**Origin:**  
**Aquifer thickness:**  
**Depth to top of aquifer:**  
**Length of well open to:** 115 ft  
**MINOR AQUIFER:** System Oyster  
**Series**  
**Aquifer, formation, or group:**  
**Lithology:**  
**Origin:**  
**Aquifer thickness:**  
**Depth to top of aquifer:**  
**Length of well open to:**  
**Depth to consolidated rock:**  
**Source of data:**  
**Coefficient of transmissibility:**  
**Coefficient of Storage:**  
**Card no.:** 16-40.
### CARD ZA (SUPPLEMENTAL CASING RECORD)

<table>
<thead>
<tr>
<th>Diameter Fract.</th>
<th>Type</th>
<th>Length</th>
<th>Depth to top</th>
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</thead>
<tbody>
<tr>
<td>16</td>
<td>23</td>
<td>323</td>
<td>30</td>
</tr>
<tr>
<td>7</td>
<td>23</td>
<td>217</td>
<td>303</td>
</tr>
<tr>
<td>5</td>
<td>23</td>
<td>7</td>
<td>443</td>
</tr>
<tr>
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<tr>
<td>Other data:</td>
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<tr>
<td>Card designation:</td>
<td>Z A</td>
<td>Card No.: 80</td>
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</tr>
</tbody>
</table>

### CARD ZB (SUPPLEMENTAL SCREEN RECORD)

<table>
<thead>
<tr>
<th>Diameter Fract.</th>
<th>Type</th>
<th>Length</th>
<th>Depth to top</th>
<th>Opening size</th>
</tr>
</thead>
<tbody>
<tr>
<td>9</td>
<td>23</td>
<td>115</td>
<td>570</td>
<td>530</td>
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<tr>
<td>Card designation:</td>
<td>Z B</td>
<td>Card No.: 80</td>
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</tbody>
</table>

### CARD ZC (SUPPLEMENTAL YIELD AND SPECIFIC-CAPACITY DATA CARD)

#### STEP-DRAWDOWN TEST

<table>
<thead>
<tr>
<th>Yield</th>
<th>Drawdown</th>
<th>Specific Capacity</th>
<th>Pump. per. (hrs)</th>
<th>Date meas.</th>
</tr>
</thead>
<tbody>
<tr>
<td>14.04</td>
<td>300</td>
<td>14.70</td>
<td>B</td>
<td>6-20-62</td>
</tr>
<tr>
<td>161</td>
<td>3.68</td>
<td>4.38</td>
<td>B</td>
<td>6-20-62</td>
</tr>
<tr>
<td>171</td>
<td>4.00</td>
<td>4.28</td>
<td>B</td>
<td>6-20-62</td>
</tr>
</tbody>
</table>

| Boxes 1-19 same as on Card A | | | |
|-----------------------------|---|---|
| 1809                        | 432 | 419 | B |
| 1910                        | 451 | 417 | B |
| 2020                        | 491 | 411 | B |

| Boxes 1-19 same as on Card A | | | |
|-----------------------------|---|---|
| 1809                        | 432 | 419 | B |
| 1910                        | 451 | 417 | B |
| 2020                        | 491 | 411 | B |

Card designation: Z C Card No.: 77 78

---

**SKETCH AND DIAGRAM**

*SEE SKETCH OR 124*
CARD ZD (SUPPLEMENTAL WELL-DESCRIPTION CARD)

<table>
<thead>
<tr>
<th>Boxes 1-19 same as on Card A</th>
</tr>
</thead>
</table>

Driller: LAYNE LOUISIANA CO

Test hole depth: 666

Pumpage: Hrs/day

Days/week

Weeks/year

Average rate

Accuracy

Pumpage

Coefficient of Permeability

Field pH

Lithologic samples available: yes

Depth interval range: 70 to 74

Other data: Z C

NOTES: 34" water column - grand well

Card designations: Z C

Periodic WA data

LITHOLOGIC LOG

<table>
<thead>
<tr>
<th>Lithology</th>
<th>Thickness</th>
<th>Depth</th>
<th>Aquifer or unit name</th>
</tr>
</thead>
<tbody>
<tr>
<td>La Mont 2</td>
<td>70</td>
<td>74</td>
<td></td>
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<tr>
<td>Lithology</td>
<td>Thickness</td>
<td>Depth</td>
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</tbody>
</table>
**WELL SCHEDULE**

**CARD A (MASTER CARD)**

- **Owner No.** Michael #4
- **U.S. DEPT. OF THE INTERIOR**  
**WATER RESOURCES DIVISION**
- **Geological Survey**
- **Punched and Verified**
- **Rolla Computation Branch**

**Record by:** Halter, W. T.  
**Date:** 4/5/69

- **State:** Louisiana  
**County:** Orleans

- **Latitude:** 30°09'05" N  
**Longitude:** 90°19'36" W

- **Sequential number:** 19  
**Lat-long accuracy:** 50

- **Local well number:** 21
- **Township:** L 25 S  
**Range:** E 30 W  
**Section:** 142

- **Quadrangle:** Little Woods  
**Use of well:** W  
**Use of water:** L  
**Field aquifer characteristics:**

- **Ownership:** New Orleans Public Service, Inc.

- **Drillers:** Louisiana Drilling Co.

- **Address:** Lake Charles, La.

- **Pump intake setting:** 20.0 Lift

- **Other pump data:** No. 4  
**Column Diam:** 15  
**Length:** 60  
**Capacity:** 1400 gpm against 20 ft. head

- **Alt. LSD accuracy:** 2  
**MP description:**

- **Water level:** above

- **Column:**  
**Yield determined:**

- **QUALITY OF WATER DATA:**
  - Iron: 9
  - Sulfate: 40
  - Chloride: 71
  - Hard: 5

- **Sp. Cond:**  
**Temp:** 73  
**pH:** 8.5  
**Field U.S.G.E. Date sampled:** 6/9/69

**CARD B (WELL-DESCRIPTION CARD)**

- **Boxes 1-19 same as on Card A**
- **Depth:** 24 ft.

- **Casing type:** Steel  
**Diam:** 1 6

- **Drillers:** Louisiana Drilling Co.

- **Address:** Lake Charles, La.

- **Pump intake setting:** 20.0 Lift

- **Other pump data:** No. 4  
**Column Diam:** 15  
**Length:** 60  
**Capacity:** 1400 gpm against 20 ft. head

- **Alt. LSD accuracy:** 2  
**MP description:**

- **Water level:** above

- **Column:**  
**Yield determined:**

- **QUALITY OF WATER DATA:**
  - Iron: 9
  - Sulfate: 40
  - Chloride: 71
  - Hard: 5

- **Sp. Cond:**  
**Temp:** 73  
**pH:** 8.5  
**Field U.S.G.E. Date sampled:** 6/9/69

**CARD C (HYDROGEOLOGIC CARD)**

- **Boxes 1-19 same as on Card A**

- **Physiographic Province:** Coastal Plain

- **Section:** 213  
**Topography of well site:**

- **MAJOR AQUIFER:** System Aquifer #3  
**Series:** Pleist 6  
**Aquifer formation:** sediments of "700 flow"  
**Aquifer thickness:** 52 ft.

- **Lithology:** Sand

- **Length of well open to:** 52 ft.

- **MINOR AQUIFER:** System Aquifer #4  
**Series:** Pleist 6  
**Aquifer formation:** sediments of "700 flow"  
**Aquifer thickness:** 52 ft.

- **Lithology:** Sand

- **Length of well open to:** 52 ft.

- **Depth to consolidated rock:** 60 ft.

- **Surficial material:** Infiltration coefficient

- **Coefficient of transmissibility:**

- **Coefficient of Storage:**

- **Card no. 1:**
### CARD A (SUPPLEMENTAL CASING RECORD)

<table>
<thead>
<tr>
<th>Diameter</th>
<th>Fract. Type</th>
<th>Length</th>
<th>Depth to top</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.62</td>
<td>5</td>
<td>30.3</td>
<td>31</td>
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<tr>
<td>1.44</td>
<td>5</td>
<td>21.7</td>
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<tr>
<td>0.95</td>
<td>5</td>
<td>8.3</td>
<td>41.7</td>
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</table>

Other data: 86 70 71 72 73 74 75 76 77

Card No.: 78
Card designation: A

### CARD B (SUPPLEMENTAL SCREEN RECORD)

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<th>Fract. Type</th>
<th>Length</th>
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<th>Opening size</th>
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</thead>
<tbody>
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<td>9.5</td>
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<td>53.0</td>
<td>11</td>
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<tr>
<td>3.0</td>
<td>5</td>
<td>2.0</td>
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Other data: 86 70 71 72 73 74 75 76 77

Card No.: 78
Card designation: B

### CARD C (SUPPLEMENTAL YIELD AND SPECIFIC-CAPACITY DATA CARD)

<table>
<thead>
<tr>
<th>Yield</th>
<th>Drawdown</th>
<th>Specific Capacity</th>
<th>Pump. per. (hrs)</th>
<th>Date meas.</th>
</tr>
</thead>
<tbody>
<tr>
<td>117.40</td>
<td>3.85</td>
<td>4.52</td>
<td>35 34 33 32</td>
<td>26/3</td>
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<tr>
<td>39 40 41</td>
<td>43 44 45 46</td>
<td>48 50 51</td>
<td>52 53 54</td>
<td>71 72 73</td>
</tr>
</tbody>
</table>
| 58 59 60 61| 63 64 65 66  | 67 68 69 70    | 74 75 76         | Card No.: 77 Card desig: C

### SKETCH AND DIAGRAM
**CARD D** (SUPPLEMENTAL WELL-DESCRIPTION CARD)

Boxes 1-19 same as on Card A

**LAYNE LOUISIANA COMPANY**

Drilling:
- Depth:
  - 45
  - 46
  - 47
  - 48

Test hole depth:
- 1665

Pumpage:
- Hr/day
- Days/week
- Weeks/year
- Average rate

Accuracy
- Year
- 58
- 59
- 60
- 61

Coefficient of Permeability
- 62
- 63
- 64
- 65

Field pH
- 66
- 67
- 68

Lithologic samples available:
- 69

Depth interval range:
- 70
- 71
- 72
- 73
- 74
- 75
- 76
- 77
- Other data:

NOTES

Card designation:
- D

**LITHOLOGIC LOG**

<table>
<thead>
<tr>
<th>Lithology</th>
<th>Thickness</th>
<th>Depth</th>
<th>Aquifer or unit name</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>11</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lithology</td>
<td>Thickness</td>
<td>Depth</td>
<td>Aquifer or unit name</td>
</tr>
<tr>
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</tr>
</tbody>
</table>
BEFORE THE
COUNCIL OF THE CITY OF NEW ORLEANS

SUPPLEMENTAL AND AMENDING )
APPLICATION OF ENTERGY NEW )
ORLEANS, INC. FOR APPROVAL TO )
CONSTRUCT NEW ORLEANS POWER )
STATION AND REQUEST FOR COST )
RECOVERY AND TIMELY RELIEF

SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY

OF

ORLANDO TODD

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

JULY 2017
TABLE OF CONTENTS

I. INTRODUCTION .............................................................................................................. 1

II. ESTIMATED FIRST-YEAR NON-FUEL REVENUE REQUIREMENT FOR NOPS ... 2

III. PROPOSED COST RECOVERY PLAN........................................................................... 5

EXHIBIT LIST

Exhibit OT-1R Revised CT Estimated First-Year Non-Fuel Revenue Requirement

Exhibit OT-2 Alternative Peaker Estimated First-Year Non-Fuel Revenue Requirement
I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, TITLE AND CURRENT BUSINESS ADDRESS.
A. My name is Orlando Todd. I am the Finance Director for Entergy New Orleans, Inc. (“ENO” or the “Company”). My business address is 1600 Perdido Street, New Orleans, Louisiana 70112.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?
A. I am testifying on behalf of ENO.

Q3. ARE YOU THE SAME ORLANDO TODD THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING?
A. Yes.

Q4. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY?
A. My Supplemental and Amending Direct Testimony (“Supplemental Direct Testimony”) supports the Supplemental and Amending Application (“Supplemental Application”) in this proceeding, which seeks, among other things, approval to construct the New Orleans Power Station (“NOPS”), which will consist of either a combustion turbine (“CT”) resource with a summer capacity of 226 megawatts (“MW”), or alternatively, seven Wärtsilä 18V50SG Reciprocating Internal Combustion Engine (“RICE”) Generator sets (“Alternative Peaker”). My testimony here supports the application by providing the estimated first-year revenue
requirement of the Alternative Peaker and ENO’s proposed rate recovery plan, as well as updating the first-year revenue requirement of the proposed CT that was originally provided in my direct testimony offered in this proceeding.

II. ESTIMATED FIRST-YEAR NON-FUEL REVENUE REQUIREMENT FOR BOTH NOPS OPTIONS

Q5. PLEASE PROVIDE AN OVERVIEW OF THE INCREMENTAL COSTS AND REVENUES ASSOCIATED WITH THE ALTERNATIVE PEAKER.

A. For purposes of my testimony, the incremental costs associated with the Alternative Peaker will fall within two broad categories that I discussed in my direct testimony: non-fuel costs, such as operations and maintenance expense (“O&M”) and capital investment, that is, the cost to construct the Project; and (2) fuel expense and any revenue or expense resulting from Midcontinent Independent System Operator, Inc. (“MISO”) market settlements.

Q6. HOW WAS THE ESTIMATED RATE BASE FOR THE ALTERNATIVE PEAKER DETERMINED?

A. The first step in the process is the derivation of the rate base for the Project during the first year of service, which is derived on Page 2 of Exhibit OT-2. As may be seen, the starting point is the estimated total construction cost including Allowance for Funds Used During Construction (“AFUDC”) of approximately $210.0 million, which estimate is discussed in detail by Company witness Jonathan E. Long. This value constitutes the plant in service amount on the first day of operation. During the
first year of operation, depreciation expense at the rate of 3.3% per year will be
accrued in the amount of approximately $7.0 million, giving rise to an accumulated
reserve for depreciation in that amount. The final component of rate base is the
deduction for accumulated deferred income taxes ("ADIT"), which arises due to
timing differences between book straight-line depreciation and accelerated tax
depreciation. The end result is a total Alternative Peaker rate base of approximately
$179.3 million at the end of the first year following commercial operation.

Q7. WHY DID ENO USE A DEPRECIATION RATE OF 3.3% FOR THE ESTIMATED
REVENUE REQUIREMENT?

A. The Direct Testimony of Mr. Jonathan Long contains the basis for the 3.3%
depreciation rate used for the CT. For the same reasons, ENO believes this
depreciation rate is appropriate to use for the Alternative Peaker.

Q8. DID THE COMPANY USE THE SAME WEIGHTED AVERAGE COST OF
CAPITAL ("WACC") USED IN THE ESTIMATED FIRST-YEAR REVENUE
REQUIREMENT OF THE CT TO CALCULATE THE REVENUE
REQUIREMENT OF THE ALTERNATIVE PEAKER?

A. Yes. As discussed later in my testimony, ENO intends to use its WACC, including its
actual capital structure, at the time the Project commences commercial operation for
interim cost recovery purposes.
Q9. WHAT IS THE BASIS FOR THE ESTIMATED O&M FOR THE ALTERNATIVE PEAKER SHOWN IN EXHIBIT OT-2?

A. The basis of the estimated O&M is the estimate attached to the Supplemental and Amending Direct Testimony of Company witness Robert A. Breedlove. The estimated O&M used in the first-year non-fuel revenue requirement does not include Long-Term Service Agreements (“LTSA”) costs, as the Company has not yet made a determination regarding the feasibility of entering into an LTSA if the Alternative Peaker unit is selected by the Council.

Q10. WERE PROPERTY TAXES ESTIMATED IN THE SAME MANNER AS FOR THE CT?

A. Yes. Property taxes were assumed to be zero because the Project would be subject to a property-tax exemption.

Q11. PLEASE SUMMARIZE THE ESTIMATED FIRST-YEAR NON-FUEL REVENUE REQUIREMENT FOR THE ALTERNATIVE PEAKER.

A. The estimated first-year non-fuel revenue requirement for the alternative peaker is $34.4 million. This estimated amount assumes the construction cost of the Project, including AFUDC, totals $210.0 million.
Q12. HAVE THERE BEEN ANY CHANGES TO THE ESTIMATED COST OF THE CT THAT ENO ORIGINALLY PROPOSED FOR THE NOPS?

A. Yes. As discussed in the supplemental direct testimony of Mr. Jonathan Long, the estimated capital investment necessary to complete the CT has increased.

Q13. HAS ENO FACTORED THE CHANGE IN THE ESTIMATE INTO ITS CALCULATION OF THE FIRST-YEAR REVENUE REQUIRED FOR THE CT?

A. Yes. Exhibit OT-1R reflects the updated first-year revenue requirement as a result of the increase in the capital costs of the CT. The estimated O&M included in the first-year revenue requirement has not changed.

III. PROPOSED COST RECOVERY PLAN

Q14. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I discuss how the Company proposes to recover the costs associated with the Alternative Peaker, as the cost recovery plan for the CT has not changed.

Q15. HAVE THE COMPANY’S REGULATORY ASSUMPTIONS CHANGED REGARDING RATEMAKING IN EFFECT WHEN THE PROJECT BEGINS COMMERCIAL OPERATION?

A. No. The Company expects, if selected by the Council, the CT would commence commercial operation by November 2020, or the Alternative Peaker in October 2019. In either circumstance, the Company still expects that the Combined Rate Case
described in Paragraph 8 of the Algiers Transaction Agreement in Principle approved
in Council Resolution R-15-194, dated May 14, 2015, will have been completed with
all of ENO’s customers subject to a single set of Council-approved base rates and
riders.1 Also, the Company expects that the recovery of the capacity costs associated
with the Ninemile 6 Unit and associated with Union Power Station Power Block 1
will have been realigned from the Purchased Power and Capacity Acquisition Cost
Recovery Rider (“PPCACR Rider”) to base rates. Finally, the Company expects that
ENO will be subject to a formula rate plan (“FRP”) following the Combined Rate
Case. These are the principal regulatory assumptions that are the context for ENO’s
proposed cost recovery plan.

Q16. IS THE COMPANY’S PROPOSAL TO RECOVER THE NON-FUEL REVENUE
REQUIREMENT OF THE ALTERNATIVE PEAKER DIFFERENT THAN ITS
PROPOSAL FOR THE CT?

A. No. ENO proposes that the first-year non-fuel revenue requirement associated with
the Alternative Peaker initially (first twelve months) be recovered contemporaneous
with commercial operation of the Project through the PPCACR Rider, which would
be modified for such purpose, or a similar exact cost recovery rider. This rider would
use the Company’s WACC, including its actual capital structure, at the time the
Project commences commercial operation to determine the return on the Company’s

1 Currently, the Company serves electric customers in the Fifteenth Ward of the City of New Orleans, that is,
Algiers, using base rates approved in Council Docket No. UD-13-01, when Entergy Louisiana, LLC served
these customers. The Company serves electric customers outside of Algiers using base rates resulting from
Council Docket No. UD-08-03 and subsequent formula rate plan proceedings.
investment in the Project, and the return on equity authorized by the Council as a result of the Combined Rate Case. The non-fuel revenue requirement would be recovered from all of the Company’s customers, including Algiers customers, which today do not pay charges pursuant to the PPCACR Rider.

Following the initial twelve-month’s dollar-for-dollar recovery, the Project’s non-fuel revenue requirement would be realigned so as to be recovered through the FRP Rate Adjustment.

Q17. IS IT IMPORTANT TO ENO’S FINANCIAL CONDITION THAT ENO RECEIVES TIMELY RECOVERY OF THE ALTERNATIVE PEAKER’S NON-FUEL REVENUE REQUIREMENT?

A. Yes. As I explained in my Direct Testimony in this proceeding with respect to the CT, once a project commences commercial operation, ENO will begin incurring costs that are not expected to be reflected in ENO’s base rates until the project is placed in service. If the Council takes no action to address these costs, then those expenditures will have a significant adverse effect on ENO’s financial condition.

For example, assuming an October 2019 commercial operation date for the Alternative Peaker, ENO will begin to incur depreciation and O&M expenses related to the Project in October 2019. Without timely rate recovery, i.e., contemporaneous in-service rate recovery, ENO will not begin to recover any depreciation and O&M expenses until the next rate change, which under an assumed FRP may not be until the third quarter of 2020. Similarly, the Company would not be recovering any return
on the Project during this same period. This approximate twelve-month delay in recovery would have a detrimental effect on ENO’s financial condition and metrics.

Q18. WILL THE ESTIMATED FIRST-YEAR NON-FUEL REVENUE REQUIREMENT BE UPDATED PRIOR TO COMMERCIAL OPERATION?

A. Yes. Irrespective of which alternative the Council authorizes, the Company proposes that the estimated first-year non-fuel revenue requirement be updated and a revised PPCACR Rider or a similar exact cost recovery rider be filed with the Council on or about 60 days prior to the anticipated start of commercial operation.

Q19. HOW WOULD THESE COSTS BE RECOVERED IF THERE IS NO FRP IN PLACE AFTER THE COMBINED RATE CASE?

A. ENO proposes that the selected project’s non-fuel revenue requirement be recovered through the PPCACR Rider or a similar exact cost recovery rider until such time that ENO’s base rates are reset.

Q20. AT THIS TIME, DOES THE COMPANY ANTICIPATE ENTERING INTO AN LTSA FOR THE ALTERNATIVE PEAKER?

A. As I mentioned earlier in my testimony, ENO has not determined whether it is cost beneficial to enter into an LTSA for the Alternative Peaker. However, if the Company does enter into an LTSA before the commencement of commercial operations, similar to its proposal for the CT, the Company proposes that the LTSA expenses be recovered through the fuel adjustment clause (“FAC”). Such an LTSA
would likely require payment for certain major maintenance activities, with such payments varying based on the utilization of the resource, including the number of unit starts and hours of run-time. The variable nature of these expenses makes them appropriate for recovery through the Company’s FAC. FAC recovery is appropriate as it will ensure that customers pay the actual LTSA costs when such costs are actually incurred. Recovering these costs through base rates gives rise to the possibility that the Company would recover amounts greater or less than the actual costs incurred.

Q21. IF ANY MAINTENANCE COSTS ARE INCURRED ON A NON-VARIABLE OR TRANSACTIONAL BASIS, IS ENO PROPOSING TO RECOVER SUCH EXPENSES THROUGH THE FAC?

A. No. ENO would anticipate that any fees for maintenance outside of the base scope of work of a potential LTSA would require negotiation of a separate contract or work order. Such fees would be recovered through base rates.

Q22. IS ENO’S PROPOSED RECOVERY OF MISO-RELATED REVENUES AND EXPENSES FOR THE ALTERNATIVE PEAKER DIFFERENT THAN THAT PROPOSED BY ENO FOR THE CT?

A. No. Regardless of what alternative is selected, ENO proposes that the MISO market settlement revenues and expenses associated with the Alternative Peaker, except those falling in the Administration accounting category, should be included in the Company’s FAC. Any revenues or expenses falling in the Administration accounting
category would be recovered through ENO’s MISO Cost Recovery Rider. This
treatment is consistent with the currently-approved treatment of those MISO market
settlement revenues and expenses attributable to other ENO resources.

Q23. WILL THE ENVIRONMENTAL ADJUSTMENT CLAUSE (“EAC”) INCLUDE
EXPENSES ASSOCIATED WITH THE PROJECT?
A. It may, if emission allowances are required to operate the Project.

Q24. DOES THIS CONCLUDE YOUR SUPPLEMENTAL AND AMENDING DIRECT
TESTIMONY?
A. Yes.
AFFIDAVIT

STATE OF LOUISIANA
PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and
appeared, ORLANDO TODD, 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.

Orlando Todd

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 11TH DAY OF JUNE, 2017

NOTARY PUBLIC

My commission expires: upon death

Harry M. Barton
Notary Public
Notary ID# 90845
Parish of Orleans, State of Louisiana
My Commission is for Life
## Entergy New Orleans, Inc.

**NEW ORLEANS POWER STATION REVENUE REQUIREMENT**

**DERIVATION OF THE RATE BASE**

(Dollars in Thousands)

<table>
<thead>
<tr>
<th>Item</th>
<th>1st Full Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rate Base</td>
<td></td>
</tr>
<tr>
<td>A. Plant In Service</td>
<td>232,000</td>
</tr>
<tr>
<td>B. Accumulated Depreciation</td>
<td>(7,733)</td>
</tr>
<tr>
<td>C. Accumulated Deferred Income Taxes</td>
<td>(26,150)</td>
</tr>
<tr>
<td>D. Rate Base</td>
<td>198,117</td>
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</table>
## Entergy New Orleans, Inc.

### NEW ORLEANS STATION REVENUE REQUIREMENT

### DERIVATION OF THE REVENUE REQUIREMENT
(Dollars in Thousands)

<table>
<thead>
<tr>
<th>Section</th>
<th>Description</th>
<th>Amount (in Thousands)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>A. Operation and Maintenance Expense</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Payroll</td>
<td></td>
<td>1,591</td>
</tr>
<tr>
<td>2. O&amp;M - Fixed, excluding payroll</td>
<td></td>
<td>963</td>
</tr>
<tr>
<td>3. O&amp;M - Variable, excluding payroll</td>
<td></td>
<td>654</td>
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<tr>
<td>4. Total Operation and Maintenance Expense</td>
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<td>3,209</td>
</tr>
<tr>
<td><strong>B. Other Operating Expenses</strong></td>
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<td></td>
</tr>
<tr>
<td>1. Insurance</td>
<td></td>
<td>200</td>
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<tr>
<td>2. Property Tax</td>
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<td>0</td>
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<tr>
<td>3. Total Other Operating Expense</td>
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<td>200</td>
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<tr>
<td><strong>C. Total Operating Expenses</strong></td>
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<td>3,409</td>
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<tr>
<td><strong>D. Return Of and On Rate Base</strong></td>
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<tr>
<td>1. Pre-Tax Return</td>
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<td>22,932</td>
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<td>2. Depreciation and Amortization Expense</td>
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<td>7,733</td>
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<td>3. Equity AFUDC Gross Up</td>
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<td></td>
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<tr>
<td>4. Total Return Of and On Rate Base</td>
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<td>30,664</td>
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<tr>
<td><strong>E. Revenue Requirement</strong></td>
<td></td>
<td>34,073</td>
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</table>
### Entergy New Orleans, Inc.

**NEW ORLEANS POWER STATION REVENUE REQUIREMENT**

**DERIVATION OF THE COST OF CAPITAL**

**ASSUMED 50% COMMON EQUITY**

**JUNE 30, 2016**

*(Dollars in Thousands)*

<table>
<thead>
<tr>
<th>Item</th>
<th>Amount</th>
<th>Ratio</th>
<th>Cost Rate</th>
<th>Post Tax</th>
<th>Pre Tax</th>
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</thead>
<tbody>
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<td>47.22%</td>
<td>4.96%</td>
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<td>2.34%</td>
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<tr>
<td>B. Preferred Stock</td>
<td>20,004</td>
<td>2.78%</td>
<td>4.82%</td>
<td>0.13%</td>
<td>0.21%</td>
</tr>
<tr>
<td>C. Common Equity</td>
<td>360,119</td>
<td>50.00%</td>
<td>11.10%</td>
<td>5.55%</td>
<td>9.02%</td>
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<tr>
<td><strong>D. Total</strong></td>
<td><strong>720,239</strong></td>
<td><strong>100.00%</strong></td>
<td><strong>8.02%</strong></td>
<td><strong>11.57%</strong></td>
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</table>

**Weighted Cost Rate**

### NOTE: Items may not foot due to rounding
### ESTIMATED FIRST-YEAR REVENUE REQUIREMENT

**DERIVATION OF THE ESTIMATED REVENUE REQUIREMENT**

*Dollars in Thousands*

<table>
<thead>
<tr>
<th>Category</th>
<th>Amount</th>
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</thead>
<tbody>
<tr>
<td><strong>A. Operation and Maintenance Expense</strong></td>
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<tr>
<td>1. Payroll</td>
<td>3,631</td>
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<tr>
<td>2. O&amp;M - Fixed, excluding payroll</td>
<td>460</td>
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<tr>
<td>3. O&amp;M - Variable, excluding payroll</td>
<td>2,564</td>
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<tr>
<td>4. Total Operation and Maintenance Expense</td>
<td>6,655</td>
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<tr>
<td><strong>B. Other Operating Expenses</strong></td>
<td></td>
</tr>
<tr>
<td>1. Insurance</td>
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</tr>
<tr>
<td>2. Property Tax</td>
<td>0</td>
</tr>
<tr>
<td>3. Total Other Operating Expense</td>
<td>0</td>
</tr>
<tr>
<td><strong>C. Total Operating Expenses</strong></td>
<td>6,655</td>
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<tr>
<td><strong>D. Return Of and On Rate Base</strong></td>
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</tr>
<tr>
<td>1. Pre-Tax Return</td>
<td>20,750</td>
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<tr>
<td>2. Depreciation and Amortization Expense</td>
<td>6,993</td>
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<tr>
<td>3. Equity AFUDC Gross Up</td>
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</tr>
<tr>
<td>4. Total Return Of and On Rate Base</td>
<td>27,744</td>
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<tr>
<td><strong>E. Revenue Requirement</strong></td>
<td>34,399</td>
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</table>
**ENTERGY NEW ORLEANS, INC.**

**NEW ORLEANS POWER STATION**

**ESTIMATED FIRST-YEAR REVENUE REQUIREMENT**

**DERIVATION OF THE ESTIMATED RATE BASE**

(Dollars in Thousands)

<table>
<thead>
<tr>
<th>Item</th>
<th>1st Full Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rate Base</td>
<td></td>
</tr>
<tr>
<td>A. Plant In Service</td>
<td>209,800</td>
</tr>
<tr>
<td>B. Accumulated Depreciation</td>
<td>(6,993)</td>
</tr>
<tr>
<td>C. Accumulated Deferred Income Taxes</td>
<td>(24,354)</td>
</tr>
<tr>
<td>D. Inventory</td>
<td>819</td>
</tr>
<tr>
<td>E. Rate Base</td>
<td>179,272</td>
</tr>
</tbody>
</table>
### Entergy New Orleans, Inc.

**New Orleans Power Station**

**Estimated First-Year Revenue Requirement**

**Derivation of the Estimated Cost of Capital**

**Assumed 50% Common Equity Ratio**

**Projected June 30, 2016**

(Dollars in Thousands)

<table>
<thead>
<tr>
<th>Item</th>
<th>Amount</th>
<th>Ratio</th>
<th>Weighted Cost Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Post Tax</td>
</tr>
<tr>
<td>A. Long Term Debt</td>
<td>340,116</td>
<td>47.22%</td>
<td>4.96%</td>
</tr>
<tr>
<td>B. Preferred Stock</td>
<td>20,004</td>
<td>2.78%</td>
<td>4.82%</td>
</tr>
<tr>
<td>C. Common Equity</td>
<td>360,119</td>
<td>50.00%</td>
<td>11.10%</td>
</tr>
<tr>
<td><strong>D. Total</strong></td>
<td><strong>720,239</strong></td>
<td><strong>100.00%</strong></td>
<td><strong>8.02%</strong></td>
</tr>
</tbody>
</table>

**Note:** Items may not foot due to rounding
BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

SUPPLEMENTAL AND AMENDING )
APPLICATION OF ENTERGY NEW )
ORLEANS, INC. FOR APPROVAL TO )
CONSTRUCT NEW ORLEANS POWER )
STATION AND REQUEST FOR COST )
RECOVERY AND TIMELY RELIEF )

DOCKET NO. UD-16-02

SUPPLEMENTAL AND AMENDING DIRECT TESTIMONY

OF

ROBERT A. BREEDLOVE

ON BEHALF OF

ENTERGY NEW ORLEANS, INC.

JULY 2017
TABLE OF CONTENTS

I. INTRODUCTION AND SUPPLEMENTAL TESTIMONY ........................................... 1

LIST OF EXHIBITS

Exhibit RAB-2 Estimate of O&M Costs for Alternative Peaker
I. INTRODUCTION AND SUPPLEMENTAL TESTIMONY

Q1. PLEASE STATE YOUR NAME AND CURRENT BUSINESS ADDRESS.
A. My name is Robert A. Breedlove. My business address is 10055 Grogan’s Mill Road, The Woodlands, Texas 77380.

Q2. ARE YOU THE SAME ROBERT A. BREEDLOVE THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING?
A. Yes.

Q3. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?
A. My Supplemental and Amending Direct Testimony (“Supplemental Direct Testimony”) supports the Supplemental and Amending Application (“Supplemental Application”) in this proceeding, which seeks, among other things, approval to construct the New Orleans Power Station (“NOPS”), which will consist of either a combustion turbine (“CT”) resource with a summer capacity of 226 megawatts (“MW”), or alternatively, seven Wärtsilä 18V50SG Reciprocating Internal Combustion Engine (“RICE”) Generator sets (“Alternative Peaker”). My testimony provides the estimated operation and maintenance (“O&M”) costs for the Project.
Q4. HAS THE COMPANY PREPARED AN ESTIMATE OF O&M COSTS THAT WILL BE INCURRED IN OPERATING THE ALTERNATIVE PEAKER?

A. Yes. Entergy New Orleans, Inc. (“ENO”) has prepared an estimate, and has provided that to Company witness Orlando Todd for use in estimating the first-year non-fuel revenue requirement associated with the Alternative Peaker, based on the current best understanding of what equipment will be installed at the site, and based on a number of other assumptions related to operating systems and conditions at the unit beginning in 2019. That estimate is attached hereto as Exhibit RAB – 2.

Q5. HOW WAS THE ESTIMATE DEVELOPED?

A. The cost estimates were developed using cost data provided by Wärtsilä, the equipment manufacturer for the RICE technology being considered as the Alternative Peaker. Additionally, other industry sources were consulted, including data by the Electric Power Research Institute and visits to in-service plants that use similar Wärtsilä engine technology.

Q6. DOES THE COMPANY EXPECT TO ENTER INTO A LONG-TERM SERVICE AGREEMENT FOR THE ALTERNATIVE PEAKER?

A. At this time, it has not been determined whether the Company will enter into a LTSA for the Alternative Peaker. The Company would not, however, incur any costs under a potential LTSA until the Alternative Peaker enters commercial operation, which (if approved by the Council) is expected in October 2019.
Q7. HAVE ANY OF THE ESTIMATES INCLUDED IN YOUR DIRECT TESTIMONY RELATED TO THE ORIGINALLY PROPOSED CT CHANGED?

A. No.

Q8. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY AT THIS TIME?

A. Yes.
AFFIDAVIT

STATE OF TEXAS
COUNTY OF MONTGOMERY

NOW BEFORE ME, the undersigned authority, personally came and appeared, ROBERT A. BREEDLOVE, 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.

Robert A. Breedlove

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 3RD DAY OF JULY, 2017

My commission expires: January 27, 2019

TARA SCHWEGLER
Notary Public, State of Texas
My Commission Expires
January 27, 2019
BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

SUPPLEMENTAL AND AMENDING
APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO
CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST
RECOVERY AND TIMELY RELIEF

DOCKET NO. UD-16-02

EXHIBIT RAB-2

PUBLIC VERSION

HIGHLY SENSITIVE PROTECTED MATERIALS
PURSUANT TO COUNCIL RESOLUTION R-07-432
HAVE BEEN REDACTED

JULY 2017