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**Received - 2022-10-24 04:35:01 PM**
**Control Number - 53719**
**ItemNumber - 209**

**SOAH DOCKET NO. 473-22-04394**
**PUC DOCKET NO. 53719**

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| **APPLICATION OF ENTERGY TEXAS, INC. FOR AUTHORITY TO CHANGE RATES** | **§<br>§<br>§** | **STATE OFFICE OF ADMINISTRATIVE HEARINGS** |

**RESPONSE OF ENTERGY TEXAS, INC.**
**TO SIERRA CLUB'S FOURTH REQUEST FOR INFORMATION:**
**SIERRA CLUB'S 4:1 THROUGH 3**

Entergy Texas, Inc. ("ETI" or the "Company") files its Response to Sierra Club's Fourth Request for Information. The response to such request is attached and is numbered as in the request. An additional copy is available for inspection at the Company's office in Austin, Texas.

ETI believes the foregoing response is correct and complete as of the time of the response, but the Company will supplement, correct or complete the response if it becomes aware that the response is no longer true and complete, and the circumstance is such that failure to amend the answer is in substance misleading. The parties may treat this response as if it were filed under oath.

Respectfully submitted,

Kristen F. Yates

Kristen Yates
ENTERGY SERVICES, LLC
919 Congress Avenue, Suite 701
Austin, Texas 78701
Office: (512) 487-3962
Facsimile: (512) 487-3958

Attachments: **SIERRA CLUB'S 4:1 THROUGH 3**

CERTIFICATE OF SERVICE

I certify that a copy of the foregoing Response of Entergy Texas, Inc. to Serra Club's Fourth Request for Information has been sent by either hand delivery, electronic delivery, facsimile, overnight delivery, or U.S. Mail to the party that initiated this request in this docket on this the 24th day of October 2022.

Kristen F. Yates
Kristen Yates

ENTERGY TEXAS, INC.
PUBLIC UTILITY COMMISSION OF TEXAS
DOCKET NO. 53719

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|---|---|
| Response of: Entergy Texas, Inc.<br>to the Fourth Set of Data Requests<br>of Requesting Party: Sierra Club | Prepared By: David Triplett<br>Sponsoring Witness: Anastasia R. Meyer<br>Beginning Sequence No. EV2433<br>Ending Sequence No. EV2873 |

Question No.: SIERRA 4-1 Part No.: Addendum:

Question:

Refer to the direct testimony of Company Witness Meyer, page 14 regarding the Company's estimate of the cost to install NOx reduction technologies at Nelson 6.

a. Indicate when the Company first became aware that it would have to install environmental controls to comply with NOx emission regulations.

b. Provide all studies any analysis the Company completed to evaluate the cost of complying with NOx emission regulations.

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Response:

Pursuant to an agreement with counsel for Sierra Club, in response to Sierra 4-1, subpart b., Entergy Texas, Inc. will provide all studies completed by the Company to evaluate the cost of complying with NOx emission regulations since 2018.

Information included in the response contains highly sensitive protected ("highly sensitive") materials. Specifically, the responsive materials are protected pursuant to Texas Government Code Sections 552.101 and/or 552.110. Highly sensitive materials will be provided pursuant to the terms of the Protective Order in this docket.

a. At this time, Entergy Texas, Inc. ("ETI") is not certain that additional environmental controls will be required for Nelson 6. Such controls may be required by either: a) a final Louisiana State Implementation Plan ("SIP") or Federal Implementation Plan ("FIP") for the second planning period of the regional haze program; or b) revisions to the Cross-State Air Pollution Rule ("CSAPR"). ETI is monitoring these rulemakings.

b. Please see the highly sensitive attachments (TP-53719-00SIE004-X001_HSPM through TP-53719-00SIE004-X007_HSPM) and the public attachments (TP-53719-00SIE004-X008 through TP-53719-00SIE004-X012). Please note that highly sensitive attachments, TP-53719-00SIE004-X001-006_HSPM and TP-53719-00SIE004-X001-007_HSPM, include the label, "Privileged and Confidential Attorney Client Communication."

ETI understands that these letters are no longer privileged and therefore agrees to provide them in response to this discovery request. Thus, this disclosure is not a waiver of privilege and should not be interpreted as a waiver of privilege to any other communications regarding this subject matter that continue to be protected as attorney-client privileged communication. Highly sensitive materials have been included on the secure ShareFile site provided to the parties that have executed protective order certifications in this proceeding.

**DESIGNATION OF PROTECTED MATERIALS PURSUANT TO PARAGRAPH 4 OF DOCKET NO. 53719 PROTECTIVE ORDER**

The Response to this Request for Information includes Protected Materials within the meaning of the Protective Order in force in this Docket. Public Information Act exemptions applicable to this information include Tex. Gov't Code Sections 552.101 and/or 552.110. ETI asserts that this information is exempt from public disclosure under the Public Information Act and subject to treatment as Protected Materials because it concerns competitively sensitive commercial and/or financial information and/or information designated confidential by law.

Counsel for ETI has reviewed this information sufficiently to state in good faith that the information is exempt from public disclosure under the Public Information Act and merits the Protected Materials Designation.

Kristen F. Yates
Entergy Services, LLC.

**STATE OF LOUISIANA**
**DEPARTMENT OF ENVIRONMENTAL QUALITY**

**OFFICE OF ENVIRONMENTAL ASSESSMENT**

| | | |
|---|---|---|
| **IN THE MATTER OF** | * | |
| | * | |
| **ENTERGY LOUISIANA, LLC** | * | **REGIONAL HAZE** |
| **R.S. NELSON GENERATING PLANT** | * | **STATE IMPLEMENTATION PLAN** |
| **CALCASIEU PARISH, LOUISIANA** | * | **EGU BART ANALYSIS** |
| | * | |
| | * | **AGENCY INTEREST NO. 19588** |
| | * | |
| **PROCEEDINGS UNDER THE LOUISIANA** | * | |
| **ENVIRONMENTAL QUALITY ACT,** | * | |
| **La. R.S. 30:2001, ET SEQ.** | * | |

## ADMINISTRATIVE ORDER ON CONSENT

The following **ADMINISTRATIVE ORDER ON CONSENT** is issued this day to **ENTERGY LOUISIANA, LLC (RESPONDENT)** by the Louisiana Department of Environmental Quality (the Department), under the authority granted by the Louisiana Environmental Quality Act (the Act), La. R.S. 30:2001, *et seq.*, and particularly by La. R.S. 30:2011(D)(6) and (D)(14). The Respondent consents to the requirements set forth below.

## FINDINGS OF FACT

I.

The Respondent owns and/or operates the R. S. Nelson Generating Plant located at 3500 Houston River Road, Westlake, Calcasieu Parish, Louisiana (the Facility). The Facility currently operates pursuant to Title V and PAL Permit Number 6250-00014-V4 issued on April 11, 2017.

II.

Under Clean Air Act (CAA) section 110, each state must prepare and submit for the EPA approval, a SIP that provides for the implementation, maintenance and enforcement of the National Ambient Air Quality Standards (NAAQS) in each air quality control region within the state.

III.

In addition to the general SIP requirements, in CAA section 169A, 42 U.S.C. §7491, Congress created a program for protecting visibility in the nation's national parks and wilderness areas. This section establishes as a national goal the "prevention of any future, and the remedying of any existing, impairment of visibility" in those national parks and wilderness areas identified as "Class I" areas under CAA section 161, 42 U.S.C. §7472(a), 42 U.S.C. §7491.

IV.

Under CAA section 169A and its associated implementing regulations, states must assure the reasonable progress toward the goal of achieving natural visibility conditions in Class I areas by preparing, and submitting for EPA approval, a Regional Haze SIP. *See generally,* 42 U.S.C. §7491; 40 C.F.R. § 51.308.

V.

To comply with the requirements set forth in CAA section 169A and the implementing regulations, the Department is concurrently submitting a proposed SIP on behalf of the State of Louisiana to EPA Region VI that addresses Best Available Retrofit Technology (BART) for the Facility. The BART analysis is based, in part, on submittals made by Respondent to the Department including, but not limited to, Respondent's submittal on May 12, 2015.

VI.

Notwithstanding the terms and conditions in this **ADMINISTRATIVE ORDER ON CONSENT**, including the above Findings of Fact, Respondent reserves its right to assert all defenses and other legal arguments during any subsequent legal challenge of the Regional Haze SIP for Louisiana.

## ADMINISTRATIVE ORDER

Based on the foregoing, the Department **hereby orders**, and the Respondent hereby **agrees** that:

I.

The Respondent shall comply with the following condition:

> If the Respondent intends to operate Unit 4 (EQT 0013) or the Unit 4 Auxiliary Boiler (EQT 0011) by combusting fuel oil, the Respondent shall conduct a BART analysis for this EGU based on this fuel type. The Respondent further agrees not to combust fuel oil until the BART analysis is approved by the LDEQ and EPA.

II.

The Respondent shall submit annual reports to the Department advising of any and all compliance measures taken to alleviate those pollutants that are associated with the causation of regional haze until Unit 6 is able to continuously meet a $SO_2$ emissions limit of 0.6 lbs/MMBtu. These reports shall be submitted to the Office of Environmental Assessment, Air Planning Division and are due by March 31 for the prior calendar year.

III.

The Respondent shall comply with the sulfur dioxide ($SO_2$) emission limitations set forth below as expeditiously as practicable, but no later than three years of the effective date of a final SIP pursuant to 40 CFR PART 51, Appendix Y:

| **Unit** | **Pollutant** | **Emission Limit lbs/ MMBtu (30-day rolling average)** |
|---|---|---|
| **6** | **$SO_2$** | **≤ 0.6*** |

* The $SO_2$ emissions limit for Unit 6 shall be based on use of significant figures and standard rounding conventions. Thus, the Respondent shall round emissions data to the tenths place to assess compliance with the 30-day rolling average limit.

IV.

The Respondent shall comply with the particulate matter less than 10 microns ($PM_{10}$) emissions limit set forth below no later than the effective date of a final SIP pursuant to 40 CFR PART 51, Appendix Y:

**Unit 6**

| Unit | Pollutant | Emission Limit lb/hr (30-day rolling average) |
|---|---|---|
| **6** | **$PM_{10}$** | **$\leq$ 317.61** |

V.

The Respondent shall continue to comply with all reporting and record keeping requirements contained within all applicable permits.

VI.

To the extent required by law, further proceedings relating to this **ADMINSTRATIVE ORDER** will be governed by the Administrative Procedure Act, La. R.S. 49.950, *et seq*.

VII.

This **ADMINISTRATIVE ORDER ON CONSENT** may be executed in counterparts, each of which may be executed by one (1) or more of the signatory parties hereto. Signature pages may be detached from the counterparts and attached to one or more copies of this Agreement to form multiple legally effective documents. Facsimile signatures shall be sufficient in lieu of original signatures.

VIII.

For each action or event described herein, the Department reserves the right to seek compliance with its rules and regulations in any manner allowed by law, and nothing herein shall be construed to preclude the right to seek such compliance.

IX.

This **ADMINISTRATIVE ORDER ON CONSENT** may be amended by mutual consent of the Department and Respondent. Such amendments shall be in writing, shall follow proper SIP procedures and be submitted to EPA as a SIP revision, and shall be final and effective upon signature by an authorized representative of the Department and signature by the authorized representative of the Respondent.

X.

The following paragraph addresses transfers of the obligations of this **ADMINISTRATIVE ORDER ON CONSENT** and the Facility:

A) The obligations of this **ADMINISTRATIVE ORDER ON CONSENT** apply to and are binding upon the State and upon the Respondent and its officers, employees, agents, subsidiaries, successors, assigns, or other entities or persons otherwise bound by law.

B) Prior to the execution of any agreement for the transfer of ownership or operation of the Facility, the Respondent shall provide notice of and a copy of this **ADMINISTRATIVE ORDER ON CONSENT** to the proposed transferee. No transfer of ownership or operation of any portion of the Facility shall relieve the Respondent of its obligation to ensure that the terms of this **ADMINISTRATIVE ORDER ON CONSENT** is implemented unless at least 30 days prior to such transfer, the Respondent provides written notice of the prospective transfer to the EPA Region 6 and the Department and the prospective transferee executes an **ADMINISTRATIVE ORDER ON CONSENT** with the Department prior to the effective date of the transfer providing for continued compliance with these standards. The Notice of Transfer shall clearly identify the parties responsible for any existing violations of this **ADMINISTRATIVE ORDER ON CONSENT** and otherwise comply with LAC 33:I.1907. Any attempt to transfer ownership or operation of the Facility without complying with this Paragraph constitutes a violation of this **ADMINISTRATIVE ORDER ON CONSENT.**

XI.

This **ADMINISTRATIVE ORDER ON CONSENT** shall be final and effective upon signature by an authorized representative of the Department and signature by the authorized representative of the Respondent.

Baton Rouge, Louisiana, this _____ day of October 2017.

______________________________
Chuck Carr Brown, Ph.D.
Secretary

**Entergy Louisiana LLC**

By: ______________________ Date: 10/20/17

Name: Philip R. May

Title: President and CEO – Entergy Louisiana

**Entergy Services, LLC**
2107 Research Forest Drive
Lake Front North II
The Woodlands, TX 77380

June 21, 2022

Administrator Michael Regan
C/O EPA Docket Center (EPA/DC)
Docket ID No. EPA-HQ-OAR-2021-0668
U.S. Environmental Protection Agency
*Fuerst.sherry@epa.gov*

RE: Proposed Rule - *Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, 87 Fed. Reg. 20036 (April 6, 2022)

**ATTN: Docket ID No. EPA-HQ-OAR-2021-0668**

Dear Administrator Regan,

Entergy Services, LLC (ESL), on behalf of Entergy Louisiana, LLC (ELL), Entergy Mississippi, LLC (EML), Entergy New Orleans, LLC (ENOL), Entergy Texas, Inc. (ETI), and Entergy Arkansas, LLC (EAL), submits these comments regarding EPA's Proposed Rule – *Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, 87 Fed. Reg. 20036 (April 6, 2022).

**EXECUTIVE SUMMARY**

Entergy, a Fortune 500 company headquartered in New Orleans, powers life for 3 million customers through its operating companies primarily across Arkansas, Louisiana, Mississippi, and Texas. Entergy is creating a cleaner, more resilient energy future for everyone with the diverse power generation portfolios of its operating companies, including increasingly carbon-free energy sources. With roots in the Gulf South region for more than a century, Entergy is a recognized leader in corporate citizenship, delivering more than $100 million in economic benefits to local communities through philanthropy and advocacy efforts annually over the last several years. Our approximately 12,500 employees are dedicated to powering life today and for future generations.[1]

As a vertically-integrated electric utility, Entergy's operating companies operate both electrical generation units and the electrical transmission and distribution infrastructure necessary to

[1] https://www.entergy.com/about_entergy/

deliver power to customers in their respective service territories. Entergy's generation fleet[2] is one of the cleanest in the nation, with a fleet-wide average $NO_X$ emission rate of less than half the national average,[3] a fleet-wide average $SO_2$ emission rate approximately one-third below the national average,[4] and a fleet-wide average $CO_2$ emission rate approximately 25% below the national average.[5]

Since 2015, the year that the current ozone standard was established, Entergy has reduced the total annual $NO_X$ emissions (tons $NO_X$ /year) from our generation fleet by more than 50%[6], and during the most recent ozone season (2021) approximately 80% of the power generated by Entergy[7] was generated at a NOx emission rate of 0.03 lb/MMBtu or less.

The Entergy operating companies are committed to improve their operations continuously by transitioning to modern low- and zero-emitting generation resources and have demonstrated this commitment by placing more than 10,800 MW of modern generation into service since 2000 and retiring thousands of MW of higher-emitting legacy generation assets over the same time period. Entergy's commitment to this fleet transformation is further demonstrated by its goal of reducing the average $CO_2$ emission rate by 50% from 2000 levels by 2030, and corresponding targets for reducing our total annual emissions of both $SO_2$ and $NO_X$ by 90% each from 2000 levels, by 2030. As of 2021, Entergy has decreased total annual $NO_X$ emissions (tons/year) from its generation fleet by more than 80% from 2000 levels,[8] despite an approximate 20% increase in total annual generation from company-owned generating units over the same period.

The electric power sector currently is in the midst of a significant transition as utilities across the country, including Entergy, continue to integrate significant renewable generation sources into their fleets. Entergy operating companies currently have over 5,000 MW of renewable

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[2] Inclusive of all company-owned generation, including the fleets of Entergy's operating companies and Entergy Wholesale Commodities.

[3] Entergy fleet average $NO_X$ rate for 2021 was 0.32 lb $NO_X$ /MWh vs. the most recent (2020) available national average rate for the electric generation sector of 0.67 lb $NO_X$ /MWh. The national average rate was calculated from annual net generation data from EIA Table 3.1.A and annual emissions from energy consumption at conventional and combined-heat-and-power plants from EIA Table 9.1. See https://www.eia.gov/electricity/annual/

[4] The Entergy fleet average $SO_2$ rate for 2021 was 0.37 lb $SO_2$/MMBtu vs. the most recent (2020) available national average rate for the electric generation sector of 0.56 lb $SO_2$/MMBtu. The national average rate was calculated from EIA Tables 3.1.A and 9.1.

[5] The Entergy fleet average $CO_2$ rate for 2021 was 0.62 lb $CO_2$/kWh vs. the most recent (2020) available national average rate for the electric generation sector of 0.85 lb $CO_2$/kWh. The national average rate was calculated from EIA Tables 3.1.A and 9.1.

[6] Calculated based on CY2015 total $NO_X$ emissions of 40,272 tons and CY2021 total $NO_X$ emissions of 19,523 tons.

[7] Calculated based on 2021 ozone season generation from Entergy-owned generation assets of 52,335,205 MWh, with 41,785,713 MWh from units emitting less than 0.03 lb $NO_X$ /MWh.

[8] Calculated based on CY2000 $NO_X$ emissions of 102,522 tons and CY2021 $NO_X$ emissions of 19,523 tons.

generation in various stages of formal planning and development,[9] and have plans to develop a total of least 11,000 MW of such generation by 2030.[10] In addition, ETI is currently developing a 1,215 MW dual-fuel combined cycle power facility, the Orange County Advanced Power Station[11] (OCAPS), capable of co-firing hydrogen and natural gas, which will be equipped with state-of-the-art $NO_X$ emission controls. These existing generation development and business plans will allow Entergy to continue to transition away from higher-emitting legacy generation assets to new modern generation sources and continue the existing significant downward trend in $NO_X$ emissions from Entergy's generation fleet.

As detailed below, EPA's proposed Federal Implementation Plan (FIP) relies on flawed assumptions regarding Entergy's existing business plans. As a result, the proposed FIP jeopardizes Entergy's ability to execute these renewable and other modern generation development plans by potentially forcing Entergy operating companies to divert significant capital investment away from continued development of new generation assets to pollution control investments in aging legacy generation units, the majority of which are likely to operate for only a handful of years beyond the 2026 ozone season.

Entergy operating companies' existing legacy generation units provide critical capacity which allows them to provide affordable and reliable electrical service to their respective customers. Entergy's ability to continue to provide reliable service would be jeopardized if these legacy units were to be retired before sufficient alternative generation is placed into commercial operation. Should EPA finalize the proposed FIP without the revisions requested below, the Entergy operating companies would be placed into a position of choosing between a limited number of unattractive options in order to meet their resulting obligations: significant and unreasonable investments in pollution control retrofits which, in most cases, would remain in service for only a handful of years, or accelerating the retirement of or otherwise significantly limiting the operation of existing legacy generation units during the ozone season, without adequate time to place sufficient alternative generation capacity into service to ensure continued reliable service. All of these options result in negative outcomes for the Entergy operating companies and their respective customers, which could be alleviated if EPA were to revise the final FIP consistent with the comments outlined below.

In addition to the specific comments outlined below, Entergy supports and incorporates the comments on this proposal submitted by the Class of '85 Regulatory Response Group (Class of '85), the Louisiana Electric Utility Environmental Group (LEUEG), the Energy and Environmental Alliance of Arkansas (EEAA), and the Association of Electric Companies of

[9] See Slide 81 at: https://entergycorporation.gcs-web.com/static-files/2a90a616-8405-4f74-b76b-97b579dd0f18

[10] It should be noted that renewable generation is not typically capable of consistently achieving comparable capacity factors in comparison to existing fossil-fuel fired generation units, and thus new renewable generation sources do not replace the capacity of legacy generation units at a 1:1 ratio.

[11] https://www.entergy.com/entergypowerstexas/project/

Texas, BCCA Appeal Group, Texas Chemical Council, and Texas Oil & Gas Association (Texas Transport Working Group). We also incorporate our comments submitted on the proposed SIP disapprovals in Arkansas (Attachment C) and Louisiana, Mississippi, and Texas (Attachment D).

## COMMENTS

### I. EPA's Cost Effectiveness Calculations are Flawed and Must be Revised

#### a. EPA Should Consider the Remaining Useful Life of a Unit when Calculating Costs

EPA's cost effectiveness calculations used in the proposed FIP are flawed because they unreasonably assume that where a unit completes an SCR retrofit, the SCR would remain in-service for 15 years afterward.[12] In the proposal and associated documents posted in the regulatory docket, EPA identifies a total of 15 Entergy-owned (or partially-owned) generating units for SCR retrofits, 6 coal-fired units and 9 gas-fired units. Under the Entergy operating companies' existing business plans, none of these units are currently expected to operate for 15 years beyond 2026. Even more significantly, only a small number of these units are currently expected to operate beyond 2030, resulting in a Remaining Useful Life (RUL), beginning in 2026, of five years or less.

EPA's own cost estimates[13] for SCR retrofits for the 15 Entergy-owned units sum to a total capital investment of approximately $2.3 billion. A summary of EPA's cost estimates for each of these units is provided in Attachment A to this letter. As part of Entergy's evaluation of the proposed FIP, Entergy replicated EPA's control cost calculations with adjustment of the capital recovery factor (CRF) for each unit consistent with Entergy's existing federally-enforceable commitments which limit the RUL of certain units, along with the currently-anticipated unit retirement dates[14] from Entergy's existing business plans. Using EPA's own cost estimation methodology, with no changes other than updating the CRF for each unit to align with the planned RULs, results in an average SCR retrofit cost effectiveness for the Entergy operating companies' fleet of over $50,000/ton of $NO_X$ removed. Unit-specific cost-effectiveness values, utilizing EPA's approach with only the CRF adjusted, exceed $100,000/ton for certain Entergy units, with values for two units

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[12] EPA, RETROFIT COST ANALYZER (UPDATE 1-26-2022), EPA-HQ-OAR-2021-0668-0118 (Feb. 2022) (noting that EPA used a capital charge rate of 14.3% the "avg of utility and merchant owned at 15-yr book life"); EPA, $NO_X$ CONTROL RETROFIT COST TOOL FLEETWIDE ASSESSMENT PROPOSED CSAPR 2015 NAAQS, EPA-HQ-OAR-2021-0668-0113 (Feb. 25, 2022) (same); EPA, REGULATORY IMPACT ANALYSIS FOR PROPOSED FEDERAL IMPLEMENTATION PLAN ADDRESSING REGIONAL OZONE TRANSPORT FOR THE 2015 OZONE NATIONAL AMBIENT AIR QUALITY STANDARD (Feb. 2022) (assuming "the book-life of the new SCRs" is 15 years).

[13] EPA, Document ID EPA-HQ-OAR-2021-0668-0113, Total Project Cost (TPC) for SCR retrofits.

[14] These dates were established prior to the issuance of this proposed FIP and do not represent any adjustments to planned retirement dates that may occur if the FIP is finalized as proposed.

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exceeding $300,000/ton. These values clearly exceed any reasonable definition of cost-effective and illustrate the significant deficiency in EPA's assumed 15-year life for SCR retrofits.

Several Entergy operating company units that were identified by EPA for SCR retrofits are subject to existing public commitments enforceable under both state and federal law which limit the remaining life of these units.[15] These units and their associated commitment dates are: Lake Catherine Unit 4 (December 31, 2027); White Bluff Units 1 & 2 (December 31, 2028); and Independence Units 1 & 2 (December 31, 2030). These existing commitments are public and should have been known to EPA at the time that the proposed FIP was developed, yet EPA did not consider these existing and enforceable dates. When these existing commitments are taken into account, the annual cost-effectiveness for SCR retrofits on these units exceeds $37,000/ton and reaches as high as $100,000+ per ton of $NO_X$ reduced.

The remaining units identified by EPA for SCR retrofits[16] are generally the oldest and least-efficient generating units in Entergy's fleet. On average, these Entergy operating company-owned units identified by EPA for SCR retrofits will be 52 years old by 2026.[17] These units will most likely retire in the near- to medium-term as the Entergy operating companies continue to modernize their generating fleets through the addition of renewable and other modern generation sources. As noted above, under the Entergy operating companies' existing business plans, all of these units are expected to retire in less than 15 years after 2026. For such units, EPA should modify the final FIP to provide a path for an owner/operator to present information on the anticipated remaining useful life of specific generating units, make an appropriate commitment to the indicated unit-specific retirement date(s), and EPA should then rely upon that information to re-assess the cost effectiveness of SCR retrofits for such units.

b. EPA Should Consider Current Inflation Data

In preparing revised cost estimates to support a final FIP, EPA should ensure that recent and significant inflation trends are incorporated into its analysis. The latest (May 2022) consumer price index reported by the US Bureau of Labor Statistics has increased by 8.6% over May 2021, which is the largest 12-month increase in over 40 years. EPA should

[15] *See* Settlement Agreement and Consent Judgment in *Sierra Club et al v. Entergy Arkansas, LLC et all*, No. 4:18-CV-00854 (entered by court on March 11, 2021).

[16] These remaining Entergy-owned units are: Little Gypsy 2 & 3, Ninemile Point 4 & 5, Nelson 6, Big Cajun II Unit 3, Gerald Andrus 1, and Sabine 3, 4, and 5.

[17] This represents the average age in 2026 of those Entergy units that were identified by EPA for SCR retrofits, but that are not yet subject to a firm commitment which limits the RUL of the unit.

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account for current and anticipated future economic conditions, including inflation, in any cost analyses which inform the final FIP.

## II. EPA Should Provide Additional Flexibility in State Emission Budgets for Units with a Limited Remaining Useful Life Beyond 2026

### a. EPA Should not Presume SCR Retrofits

In circumstances where a generating unit is subject to an existing enforceable commitment that limits the unit's RUL, or a unit operator is willing to make an appropriate commitment to limit the RUL of a unit, EPA should provide additional flexibility for such units[18] when establishing state $NO_X$ emission budgets in 2026 and beyond via EPA's proposed dynamic budgeting approach. EPA should provide such flexibility for units that already have made or are willing to make a firm commitment which limits the RUL of the unit to no later than December 31, 2030. For coal-fired units that are not already equipped with SCRs, where the owner/operator has made or is willing to make an appropriate commitment to limit the RUL of the unit to no later than December 31, 2030, EPA should exempt such units from being subject to the proposed daily backstop $NO_X$ emission rate of 0.14 lb $NO_X$ /MMBtu.

For such units, rather than presuming SCR retrofits when establishing state budgets in 2026 and beyond, EPA should instead finalize an alternative budget-setting approach. Elements of such an approach should include more reasonable emission rate assumptions for the period of limited remaining life of such units (from 2026 through the year of commitment). For such units located in states which are predicted to remain "linked" to downwind nonattainment areas in 2026, EPA could finalize a framework which would presume more limited $NO_X$ emission reductions from such units when establishing state emission budgets for 2026 through the date of commitment for the units. For such units located in states which are predicted to be linked only to downwind maintenance receptors in 2026, EPA should finalize an approach which does not presume any further emission reductions for the purpose of establishing state emission budgets for the 2026 ozone season through the date of commitment for the units.[19] This approach would provide significantly more flexibility to accommodate continued operations of such units, while achieving $NO_X$ reductions in the 2026 ozone season prior to the August 2027 attainment date for serious ozone nonattainment areas, coupled with the complete elimination of emissions from such units once they are retired.

[18] Coal-, oil-, and gas-fired units.

[19] See comment IV below for more detail.

b. EPA's Proposed Timing for SCR Retrofits is Unreasonable

EPA's presumption of SCR retrofits prior to the 2026 ozone season, only three years after the anticipated effective date of the final FIP, is problematic in several ways. First, three years is a very aggressive schedule for installation of a SCR system on an electric generating unit, and one which fails to account for all of the variables inherent in execution of such a retrofit, including permitting, engineering, procurement, construction, and testing. EPA has recognized this in the context of prior regulatory decisions, where EPA has determined that SCR installation schedules of 4 or 5 years were as "expeditiously as practicable" under the Regional Haze program. Secondly, EPA's proposed 3-year period would significantly limit the options available to a utility to plan, develop and place into service alternative generation to allow for the replacement of legacy generation units for which an SCR retrofit is simply uneconomic. Very few types of generation can be planned, developed, and placed into service within three years, and such generation tends to be smaller-scale and unable to replace the capacity provided by the sizeable generating units identified by EPA for SCR retrofits in the proposed FIP.

Investing in costly SCR retrofits on Entergy units that, on average, will be more than 52 years old in 2026 is an unsupported and unreasonable assumption for EPA to make. Allowing an alternative and more measured approach to adjusting future-year state budgets that offers some flexibility with respect to units with a limited RUL would allow Entergy and other similarly-situated utilities sufficient time to consider all possible options for development of replacement generation capacity.

Entergy has recent experience in the development of both solar and modern combined-cycle gas generation, and ETI is currently in the process of seeking regulatory approvals for the combined-cycle OCAPS facility which will be capable of co-firing natural gas and hydrogen. Based on this experience, development and deployment of utility-scale solar generation would be expected to take 5-5.5 years, on average, from initial planning to commercial operation. Similar development and deployment of modern hydrogen-capable gas generation capacity would be expected to take up to 7 years from the date that planning for such a project was initiated. Such projects are large and complex, and require numerous permits, approvals, and authorization from both state and local regulatory authorities, along with significant engineering, procurement, construction, and equipment testing. In addition, external factors, such as the current investigation by the Department of Commerce into allegations of photovoltaic cell import tariff circumvention, can create unexpected delays in the ability to execute new generation projects.[20] Details regarding Entergy's recent experience with such projects can be found in Attachment B to this letter.

[20] For information regarding the investigation, *see* Memorandum from Jose Rivera, International Trade Compliance Analyst, AD/CVD Operations, Office VII, U.S. Department of Commerce, to All Interested Parties, "Circumvention

While Entergy anticipates that much of its future generation resource needs will be met via additional solar and wind resources, the dispatchable synchronous generation provided by sources such as hydrogen-capable modern gas generation units will continue to serve an important role in the overall generation resource mix. By providing utilities with the option to make commitments to limit the RUL of units to no later than December 31, 2030, and providing a more flexible state emission budget-setting approach with respect to such units, utilities would be able to consider all possible alternatives for replacement generation capacity and place appropriate alternative capacity into service prior to deactivating units where SCR retrofits would be economically infeasible.

This approach would achieve long-term and sustainable reductions in $NO_X$ emissions, through investment in new zero- or low-emitting generation resources which would be expected to remain in-service for decades to come, rather than investment in $NO_X$ pollution control retrofits on aging generation resources which may remain in-service for only a handful of years.

As noted in more detail in Section III below, the retirement of legacy generation assets for which SCR retrofits are economically infeasible could also necessitate transmission system upgrades which can take 5-7 years to plan, develop, and implement, The proposed flexibility with respect to units which make appropriate commitments to limit their RUL to no later than December 31, 2030, seven years after the anticipated issuance of a final FIP in 2023, aligns well with this expected time to execute any necessary transmission system upgrades.

c. EPA Should Allow Operators the Flexibility to Commit to a Shortened RUL

Absent adoption of our 2030 proposal above, EPA should provide some alternative means for EGU operators to commit to a shortened remaining useful life beyond 2026 along with providing for additional state budget allotments (with respect to such units) and allowance allocations in 2026 through the year of commitment. EPA must recognize that SCR investments could not be justified for many of the sources identified for such retrofits in the proposal and provide a reasonable alternative approach that ensures long-term $NO_X$ emission reductions while allowing utilities to continue to provide affordable and reliable electrical service to their customers.

Inquiries With Respect to Cambodia, Malaysia, Thailand, and Vietnam – Potential Certification Requirements" (May 2, 2022).

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III. This Proposal Likely Will Have Implications for Electric Reliability and EPA Should Consult with Appropriate Regional Transmission Operators ("RTOs") and Other Electric Reliability Stakeholders Prior to Issuing a Final Rule

a. Allowance Availability is Essential for a Functioning Trading Program

Under both the existing and prior versions of the CSAPR trading programs, there were two significant mechanisms by which an EGU operator could generate surplus emission allowances: 1) retirement of a unit, or 2) controlling emissions from a unit to a greater extent than was contemplated by EPA in establishing the relevant state emission budgets. Either of these approaches would create surplus allowances that could be sold or traded to offset greater-than-expected emissions from another generating unit. Under EPA's proposed framework for this FIP, neither of these options are available in the same fashion as has been the case in the past.

Three aspects of EPA's proposed FIP, when considered together, leave no obvious and sustainable source of surplus emission allowances in 2026 or beyond. These aspects are: 1) the presumed SCR retrofits at certain units, for the purpose of establishing state $NO_X$ emission budgets for the 2026 and subsequent ozone seasons, which will significantly reduce state $NO_X$ budgets; 2) the proposed annual allowance bank recalibration, which will constrain a source's ability to supplement its ozone season allowance allocation via the use of banked allowances if needed; and 3) the proposed treatment of idled, suspended, and retired units in the dynamic budget process, which would eliminate a unit from the state $NO_X$ budget two years following any ozone season in which the unit did not operate, along with the elimination of allowance allocations to such units two years after the last ozone season in which the unit operated. Furthermore, EPA's proposed dynamic budget approach would nonetheless presume an SCR retrofit for an already-retired unit if that unit was identified by EPA for such a retrofit and the unit was eligible to receive allowances in 2026 or beyond.[21]

For a unit with a limited RUL where a major capital investment in $NO_X$ emission control retrofits is not economically feasible, the likely lack of any significant quantity of surplus allowances will significantly constrain the ability to continue to operate the unit during the 2026 or subsequent ozone seasons. For such a unit, the only viable compliance options for the 2026 and subsequent ozone seasons would appear to be either to accelerate retirement of the unit or to curtail operations significantly during the ozone season. Either of these

[21] An example of such a unit would be a unit without an SCR that operates during the 2025 ozone season and is retired prior to the 2026 ozone season. Under EPA's proposed dynamic budget approach, such a unit would be included in the calculation of the state $NO_X$ budget for the 2026 ozone season based on the unit's operation during the 2024 ozone season, and for the 2027 ozone season based on the unit's operation during the 2025 ozone season. However, in establishing the state $NO_X$ emission budgets for 2026 and 2027, EPA would apply an emission rate to this unit which corresponds to a presumed SCR retrofit (0.05 or 0.03 lb/mmBtu), thus leaving few surplus allowances available to provide to units that may need to increase generation as a result of the retirement.

options would limit available generation capacity during the peak summer electrical demand season.

As noted in Section II(b) above, EPA's proposed FIP significantly limits a utility's ability to plan, develop, and deploy alternative generating capacity before likely accelerated retirements are triggered as a result of the FIP occur. The North American Electric Reliability Corporation's (NERC) most recent long-term[22] and summer[23] reliability assessments identify existing reliability concerns within several RTO regions, including a high summer reliability risk in the Midcontinent Independent System Operator (MISO) region in which Entergy operates. These risks are also highlighted by the most recent OMS-MISO Survey results[24] released in June 2022, which highlight a 2.6 GW capacity deficit in 2023 that is expected to widen in future years.

Before issuance of a final FIP, EPA must consider the potential that the proposed $NO_X$ state budget presumptions and allowance constraints will cause operators to accelerate retirement decisions for units that are currently only planned to operate for a limited number of years beyond 2026, and the potential for such accelerated retirements to create issues with the reliability of the bulk electric system. EPA should consult with the RTOs and other electric reliability stakeholders on these issues and incorporate appropriate revisions into the final FIP to mitigate potential reliability issues.

b. The Majority of the Capacity Presumed for SCR Retrofits is Concentrated in Five States

For the purpose of establishing state $NO_X$ emission budgets, starting with the 2026 ozone season, EPA's proposed FIP identifies a total of 131 generating units, with a total combined capacity of approximately 58,300 MW for presumed SCR retrofits.[25] Approximately 56% of this total capacity is located in just five states in the south-central US: Arkansas, Louisiana, Mississippi, Oklahoma, and Texas. As noted above, the proposed FIP would likely incentivize some of these units to accelerate existing retirement plans and retire prior to the 2026 ozone season. With such a significant concentration of such units in these five states, including the MISO South, Electric Reliability Council of Texas (ERCOT), and portions of the Southwest Power Pool (SPP) territories, there is particular risk of regional reliability issues resulting from implementation of the proposed FIP. EPA should coordinate with the RTOs, state public service and public utility

[22] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf

[23] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf

[24] https://cdn.misoenergy.org/20220610%20OMS-MISO%20Survey%20Results%20Workshop%20Presentation625148.pdf

[25] Determined based on coal- and oil/gas-fired EGUs located in states where EPA proposes to presume SCR retrofits for the purpose of establishing 2026 state budgets and flagged by EPA for SCR retrofits in the worksheet "Unit 2026" found in Appendix A to EPA's Ozone Transport Policy Analysis.

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commissions, and FERC to ensure that it is considering regional reliability risks that may arise in these states/RTO territories and make appropriate adjustments to the final FIP to mitigate any identified reliability risks.

c. Unit Retirements May Necessitate Transmission Upgrades

The units identified by the EPA for SCR retrofits and located in MISO South total approximately 11,500 MW of capacity. Significant and costly transmission system upgrades would be expected to be necessary should some number of these generation resources choose to accelerate their respective retirements as part of a strategy to comply with the restrictive proposed state emission budgeting approach for the 2026 ozone season. Due to the time required to obtain all necessary external project approvals, complete material procurement, and to construct such upgrades, it is infeasible to complete significant transmission system upgrades by the time the units are subject to restrictive 2026 state NOx budgets that would result from EPA's proposal, which will jeopardize system reliability. External project approvals take up to 18 months, and transformer procurement requires up to 2 years. Due to the terrain and permitting requirements, new and rebuilt transmission lines in many parts of the Entergy territory take 5 to 7 years to design and construct. EPA's proposed 2026 $NO_X$ budgeting approach simply does not allow for adequate time to execute transmission system upgrades which may be necessary to accommodate the accelerated unit retirements that would almost certainly occur should EPA finalize its proposal without changes to provide additional flexibility to the program.

d. Options to Facilitate a Functioning Trading Program

Prior to issuing a final FIP, EPA should implement options to add additional flexibility to state budgets and/or to other aspects of the trading program to ensure sufficient allowance availability to accommodate the potential dispatch of higher-emitting units at greater-than-anticipated levels during the ozone season to maintain the reliability of the bulk electric system.

Such options could include:

i. revised and more flexible state emission budgets,
ii. revised budget-setting assumptions for the proposed dynamic budgeting framework with respect to units with limited RULs, such as those advocated for elsewhere in these comments,
iii. modification of the proposed dynamic budgeting approach to consider multiple years of historical operating and emissions data rather than a single historical year,
iv. extending the period in which retired units would continue to be included in the calculation of state emission budgets and subsequent unit-level allocations, which would provide additional liquidity to the $NO_X$ allowance market,

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v. elimination of the proposed allowance bank recalibration process, which would provide EGUs with greater certainty in planning for future operation,
vi. revision to or postponement of the applicability of the proposed allowance bank recalibration process, to smooth the transition to the significantly reduced state budgets which would result from EPA's proposed post-2026 state budgeting framework or,
vii. other potential flexibilities which align with the underlying obligations imposed by Section 110(a)(2)(D)(i)(I) of the Clean Air Act.

## IV. EPA Must Reconsider the Proposed $NO_X$ Emission Reductions from Certain States, Including Arkansas and Mississippi, to Ensure that they do not Constitute Overcontrol

Section 110(a)(2)(D)(i)(I) of the Clean Air Act requires that a state, or EPA when acting in the place of a state via a FIP, develop a plan which contains adequate provisions "prohibiting…emissions activity within the State from emitting any air pollutant in amounts which will contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard". Prior court decisions have concluded that the "contribute significantly to nonattainment" and "interfere with maintenance" provisions of this section of the Act are independent obligations that both must be addressed in order to provide a full remedy of a State's obligations with respect to Section 110(a)(2)(D)(i)(I).[26] In the proposed FIP, EPA properly gives independent consideration to predicted linkages between emissions from upwind states and whether those emissions would "contribute significantly to nonattainment" or "interfere with maintenance" in any downwind areas, and EPA proposes a remedy, consisting of series of emission reductions from upwind states, to address both circumstances.

However, neither the plain language of the Act nor subsequent court decisions compel EPA to propose the <u>same</u> remedy for circumstances where emissions from a state are determined to "contribute significantly to nonattainment" as for circumstances where emissions from a state are determined to "interfere with maintenance" in one or more downwind nonattainment areas.

In the proposed FIP, EPA proposes a phased approach to initially reduce state NOx emission budgets for emissions from the EGU sector, with initial emission reductions to be achieved through proposed state emission budgets for 2023 and 2024, coupled with further reductions to be determined via a dynamic budgeting approach for the 2025 and subsequent ozone seasons. Beginning with the establishment of state $NO_X$ budgets for the 2026 ozone season, EPA's dynamic budgeting approach would reduce state $NO_X$ budgets to an extraordinary extent via the application of presumed SCR retrofits for certain coal-

[26] *See* North Carolina v. EPA, 531 F.3d 896, 910 (D.C. Cir. 2008).

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oil- and gas-fired units identified by EPA. These further substantial $NO_X$ emission reductions from the EGU sector, the most significant that have ever been proposed under the "Good Neighbor" provisions of Section 110(a)(2)(D)(i)(I), are not necessary for states which are predicted to be linked only to maintenance receptors in 2026. As documented by EPA in the proposed FIP,[27] these "maintenance-only" states in 2026 are: Arkansas, Minnesota, Mississippi, Oklahoma, Wisconsin, and Wyoming.

To require such extraordinary further emission reductions from these states in 2026 would likely constitute overcontrol, that is: a greater degree of emission reductions than are necessary to prevent emissions from these states from "interfering with maintenance" in downwind areas. Other aspects of EPA's proposed FIP, if finalized, would address the obligations of these states to prevent the interference with maintenance in downwind areas. For example, the proposed dynamic budgeting approach, absent the significant budget reductions which would occur in 2026 due to the application of presumed SCR retrofits, would still result in ongoing reductions in state EGU budgets over time, as budgets are adjusted over time to account for unit retirements and changes in unit dispatch patterns. This aspect of the program will ensure that EGU sector NOx emissions continue to decrease over time, do not interfere with maintenance in any downwind areas, and are sufficient to address the "Good Neighbor" obligations for these upwind states with regard to downwind maintenance areas. Should EPA finalize a FIP which does not contain the proposed dynamic budgeting approach, then other elements of EPA's final FIP may serve a similar function that would satisfy the obligation to prevent emissions from a state which would interfere with maintenance of the NAAQS in any downwind areas.

In issuing a final FIP, EPA should eliminate the presumed dynamic budget adjustments which correspond to presumed SCR retrofits on certain coal- oil-, or gas-fired EGUs in any states predicted to be linked only to downwind maintenance receptors in 2026 and should similarly eliminate the proposed daily backstop emission rate for coal-fired EGUs in such states which are not already equipped with SCRs. EPA should conclude that the other proposed Group 3 trading program elements, or other similar elements of the final FIP, as applied to these states, are sufficient to address their respective obligations to prohibit emissions which would interfere with maintenance in any downwind areas.

When considering appropriate revisions to state budgets for states which are predicted to be linked only to downwind maintenance receptors in 2026, EPA should be especially attentive to the risk of applying aggressive emission control retrofit presumptions to units located in such states and that have either existing commitments which limit their RUL to 2030 or sooner or which are willing to make such commitments in response to the final FIP. While comments I and II above outline the program-wide issues with presuming such commitments for units with limited RULs, such aggressive emission budget reductions

[27] *See* 87 Fed. Reg. at 20072 -73, Table V.E.1-2.

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with respect to such units are particularly misaligned with the obligation to prohibit emissions which would interfere with maintenance in any downwind areas. For EPA to establish state NOx budgets based on a presumption of costly SCR retrofits for units with limited RULs and that are located in states which are linked only to downwind maintenance receptors in 2026 would be unreasonable and likely would constitute overcontrol.

## V. EPA Must Consider the Interconnected Nature of Generation Sources and the Impacts of Severe Weather Events

### a. EPA Should Consider the Influence of Zero-Emitting Generation Units

The extent to which individual generating units dispatch at any given time is a function of the total electrical system load, the other generating units available to meet that load, and the relative cost of each available generation source. This includes both fossil fuel-fired generating units, which are the focus of EPA's proposed FIP, as well as other types of generation such as nuclear, hydroelectric, solar, and wind generation which do not create $NO_X$ emissions. When relatively more load is being served by these zero-emitting generation resources, overall EGU sector $NO_X$ emissions will be less, and when the opposite is the case, EGU sector $NO_X$ emissions will be greater. As EPA proposes significant reductions in state $NO_X$ emission budgets, the implications of these interrelationships with zero-emitting generation resources become more important to the overall functioning of the CSAPR emission trading program.

When a large zero-emitting generating unit, such as a nuclear or hydroelectric unit, is not available during a portion of the ozone season, other units will necessarily be dispatched in order to meet system reliability needs and electrical demand. Similar considerations could arise in the event that generation output remains available but is significantly reduced from a zero-emitting source. The generation resources most frequently available and dispatched in such situations are fossil fuel-fired units, thereby resulting in an increase in total $NO_X$ emissions. EPA's dynamic approach for establishing state emission budgets under the proposed FIP, which presumes the most stringent technically feasible level of $NO_X$ emission controls (i.e., SCRs) for nearly all fossil fuel-fired units and considers only a single year of historical unit operating data, would produce inflexible state emission budgets. This would result in a scenario where sufficient allowances would simply not exist to accommodate the need to run a higher-emitting unit to meet electrical demand during a period in which a zero-emitting generation resource, which typically operates to serve a portion of total electrical system demand, is unavailable during some portion of the ozone season.

Prior to issuing a final FIP, EPA should evaluate available historical generation data for nuclear, hydroelectric, and other zero-emitting generation sources and assess whether the

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proposed FIP provides for adequate allowance availability in the event that a large zero-emitting unit is unavailable during the ozone season and additional fossil fuel-fired units are operated to meet electrical demand.

In addition, EPA should modify the proposed secondary emission limit for sources that contribute to an exceedance of the state's assurance level such that the secondary limit would not apply to such a source if the primary cause of the assurance provision exceedance was an unforeseeable circumstance, such as additional dispatch due to reduced availability of generation from low-or zero-emitting generation resources in the state or region, or damage to the electrical transmission or distribution system which required operation of a higher-emitting unit in order to meet local electrical demand.

b. EPA's Proposed Dynamic Budget Approach Would Penalize States Impacted by Severe Weather Events

When establishing state $NO_X$ emission budgets under the proposed dynamic budget approach, EPA must consider the impacts of severe weather events, such as hurricanes, which occur during the ozone season and which may create anomalous conditions for the bulk electric system in the regions impacted. Such weather events can cause widespread power outages, which temporarily limit electrical system demand, and can directly damage electric generating units that may remain out-of-service until necessary repairs can be completed.

This occurred within ELL's service territory in Louisiana during both the 2020 and 2021 ozone seasons due to significant impacts from tropical weather systems (hurricanes and tropical storms). For example, the Nelson 6 generating unit located in Westlake, Louisiana was damaged by Hurricane Laura on August 26, 2020, and was further impacted by Hurricane Delta approximately six weeks later. Nelson 6 did not operate again during the 2020 ozone season. Both of these storms caused damage to the electrical system in southwest Louisiana, creating anomalous system conditions in Louisiana for much of the 2020 ozone season. Similarly, portions of ELL's and ENOL's systems in southeast Louisiana were damaged by Hurricane Ida in August 2021, resulting in anomalous electrical system conditions in the region in the aftermath of that storm. These severe weather impacts resulted in less-than-usual generation and emissions from generating units located in these impacted areas in the 2020 and 2021 ozone seasons.

When establishing state $NO_X$ emission budgets, EPA should not rely solely on historical unit operating and emissions data from a single year where such severe weather impacts or other anomalous events may have occurred. Instead, EPA should modify the proposed dynamic budget approach to consider multiple years of historical operation data in setting any state budgets. EPA should also consider the potential for severe weather events to impact low- or zero-emitting generation sources, resulting in additional dispatch of higher-

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emitting units to meet electrical demand. As noted above in these comments, EPA's proposed framework for establishing state emission budgets is so restrictive that there are unlikely to be any significant number of surplus allowances available to accommodate additional and unexpected dispatch of a higher-emitting unit that may be necessary during circumstances such as those created in the aftermath of a hurricane or other severe weather event. If EPA retains the dynamic budget approach, EPA also should not adjust the budgets on an annual basis but instead should only adjust the budgets periodically, such as every three years.

## VI. EPA Should Revise the Proposed Treatment of Idled, Suspended, and Retired Units when Establishing State $NO_X$ Budgets

### a. EPA Should not Penalize Recently Deactivated Units

EPA's proposed $NO_X$ emission state budgets for the 2023 ozone season were calculated, in part, based on excluding units that operated during the 2021 ozone season but have since been idled[28] or suspended[29] or retired[30] ("deactivated"[31]), and units that are projected to operate during the 2022 ozone season but that EPA expects to be deactivated prior to the 2023 ozone season. For the 2024 ozone season, EPA followed this same approach, and excluded units projected to retire by January 1, 2024. This approach unfairly penalizes the owners of such units by treating expected unit deactivations in 2023 and 2024 differently from those that were not known to EPA prior to issuance of the FIP. The latter units would continue to be included in establishing state budgets and would continue to receive unit-level allocations for two years following the last ozone season in which the unit operated. In contrast, EPA's proposed 2023 and 2024 budgets do not continue to include projected or recently-deactivated units in the same fashion. This results in disparate treatment of those units that are deactivated after the 2021 ozone season but prior to the 2023 or 2024 ozone seasons by depriving them of allowance allocations for 2 years after they cease operating, as EPA is proposing for other units that retire after the start of the revised Group 3 trading program. This disparate treatment unfairly deprives the owners of such units of allowance allocations.[32] Prior to issuing the final FIP, EPA should revise the state budgets for 2023

[28] "Idled" is used in this context to refer to a unit which has not operated but for which no formal change in status notification has been submitted to an RTO or similar organization.

[29] "Suspended" is used here to refer to units which have been placed into "suspended" status via a formal notification process, such as MISO's Attachment Y notification process. Units may be placed into "suspended" status as a precursor step to a subsequent retirement. Such suspended units may be required by an RTO to be returned to service under certain circumstances.

[30] "Retired" is used here to refer to units which have permanently ceased operation and can no longer be returned to service.

[31] "Deactivated" is used here to include both suspended and retired units.

[32] Baxter Wilson Unit 1, which is owned by Entergy Mississippi, LLC is an example of a unit which operated during the 2021 ozone season but is not included in EPA's calculation of the 2023 state budget for Mississippi.

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and 2024 to ensure that units deactivated after the 2021 ozone season continue to be included in the state budget and allowance allocation process for at least two years following the last ozone season in which the unit operates, consistent with the proposed treatment of units that announce retirements after the final FIP has been issued. In addition, and as elaborated further below, EPA should retain units in state budgets until the units are retired.

b. EIA Form 860 Retirement Information Should not be Relied Upon to Establish State Budgets

EPA's proposal identifies anticipated unit retirements based on "…a compilation of data from DOE EIA Form 860 (where facilities report their future retirement plans) and information included in the Agency's NEEDS database.".[33] EPA further notes that the data included in these information sources provides the EPA with "high confidence" that such indicated retirements "will in fact occur". This approach places more confidence in these information sources than is warranted. In particular, the instructions provided by the EIA for Form 860[34] specify that the planned retirement dates reported to EIA should be based on a generating unit operator's "best estimate" of when the indicated retirement is expected to occur. While generation operators provide a good faith "best estimate" of this value to EIA in their Form 860 responses, this value is not equivalent to a firm commitment to a specific retirement date for the indicated unit. A generation operator may subsequently revise this date for any number of reasons, including delays to anticipated replacement generation capacity on which an operator was relying to estimate the retirement date. The current and ongoing investigation by the Department of Commerce into allegations of photovoltaic cell tariff circumvention has resulted in unexpected delays to the implementation of utility-scale solar projects across the US, which may result in some EGU operators delaying planned retirement dates for existing generation units in order to align with revised schedules for solar generation developments.

EPA's proposal would treat these "best estimates" of likely unit retirement dates as equivalent to firm commitments and would in fact indirectly make these "best estimate" retirement dates enforceable via the elimination of these units from state allowance budgets in the years that their operators estimated that they would retire, even though this estimated retirement value is subject to change. Prior to issuing a final FIP, EPA should revise their approach to identification of future unit retirements to rely only upon clear and firm retirement commitments, such as retirements mandated under existing regulatory programs, permits, or consent decrees. EPA should not eliminate any generating units from state emission budgets or subsequent unit-level allowance allocations based solely on information from EIA Form 860 responses or the EPA NEEDS database. Regardless, as

[33] 87 FR 20116

[34] See https://www.eia.gov/survey/form/eia_860/instructions.pdf, Instructions for Schedule 3, Part B, #8.

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addressed above, EPA should continue to include firm retirement commitments in the state budget and allowance allocation process for two ozone periods following their retirement dates.

As an example, EPA's proposed budgets for 2023 and 2024 appear to erroneously assume that Unit 1 at the Sabine Generating Station in Orange, TX will retire or otherwise be deactivated prior to the 2023 ozone season. EPA may have relied upon information provided for this unit in prior EIA Form 860 responses. As noted above, this value represents a "best estimate" of this date and is subject to change. This unit is currently operating during the 2022 ozone season and no final decisions have been made to deactivate this unit in 2023. ETI is currently evaluating the appropriate deactivation timing for this unit, which is expected to occur sometime between 2023 and the commercial operation date of the proposed OCAPS. As such, EPA should retain Sabine Unit 1 in the state emission budgets for Texas for 2023 and 2024 and retain consideration of this unit in any subsequent dynamic budgeting until two years after the unit is retired consistent with the requirements of the final FIP.

c. Idled and Suspended Units may be Returned to Service

EPA's proposed dynamic budget approach fails to adequately recognize the potential for units to be idled or suspended such that they do not operate during two successive ozone seasons, without being retired. Such idled or suspended units may remain available to be dispatched during future ozone seasons in order to maintain system reliability. Under EPA's proposed dynamic budget approach, such units would be eliminated from the state budget calculation two years after the unit failed to operate during the ozone season and would not receive any allowance allocations after two successive years of non-operation during the ozone season. In the event that such a unit was returned to service and operated in a subsequent ozone season, the unit would be able to obtain allowances from the New-Unit Set-Aside (NUSA) for the state, but with the NUSA for most states proposed to be established at 2% of the overall state budget, and the size of the NUSA adjusting annually along with the state budgets, only a limited number of allowances would be made available to such a unit via this mechanism.

Where a unit has been idled or suspended such that it does not operate during two successive ozone seasons, but the unit has not yet been formally retired, EPA should retain that unit in calculating the state $NO_X$ emission budget until the unit is fully and formally retired.[35] Where such units are retained in state budgets, EPA could consider expanding the NUSA to include that portion of the state budget attributable to the idled or suspended but not yet retired unit. EPA should also consider reserving the resulting expanded portion

[35] Unit 1 at the Waterford generating station in Killona, LA and Unit 1 at the Baxter Wilson generating station in Vicksburg, MS are both currently in suspended status and have not yet been formally retired.

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of the NUSA for that state such that it could only be allocated to new generating units or to the idled/suspended unit in the event that it was subsequently returned to service and operated during the ozone season. Once such a unit was formally retired, it could then be eliminated from consideration in establishing future state budgets. This revision to the final proposal would strike a reasonable balance between EPA's intent to reduce state budgets for retired units while creating a mechanism to allocate a reasonable number of allowances to such a unit in the event that it is re-activated to meet reliability needs.

## VII. EPA Should add a "Safety-Valve" Provision to Account for Potential Delays in Pollution Control Retrofits

EPA's analysis of the proposed timing for installation of SCR retrofits fails to recognize significant existing supply chain issues which initially arose during the COVID-19 pandemic, and which continue to persist. These conditions are anticipated to persist through at least the remainder of 2022 and likely beyond, given other world events. In addition to these existing and economy-wide supply chain challenges, EPA's proposal could compel hundreds of individual sources, from both the EGU and non-EGU sectors, to simultaneously seek services and materials necessary to execute SCR retrofits with the goal of placing such SCRs into service prior to the 2026 ozone season. This potentially significant demand for these resources is likely to create further bottlenecks and delays for some source owners who wish to complete SCR retrofits in response to the final FIP.

EPA should consider adding a "safety valve" provision to the proposed FIP to expand a state's 2026 $NO_X$ emission budget, with respect to a unit for which an SCR retrofit was presumed and the owner/operator made a good-faith effort to complete an SCR retrofit prior to the start of the 2026 ozone season but was unable to complete such a retrofit due to supply chain or other issues outside of the control of the owner/operator. Without such a provision, the owner/operator of such a source could face a situation where operation of a unit is necessary in order to meet system demand, but the unit is not yet equipped with a functional SCR due to installation delays and would likely face a significant allowance shortfall as a result. As noted elsewhere within these comments, due to EPA's proposed approach to aggressively reduce state emission budgets in 2026, the daily backstop emission rate for large coal-fired EGUs that would result in a 3:1 allowance surrender if the rate is exceeded, along with the proposed allowance bank recalibration which is coupled to the size of the state budgets, surplus allowances would likely be difficult, if not impossible, to obtain.

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VIII. EPA Should Consider the Cost Implications of this Proposal on Low-Income Energy Consumers

The Entergy Operating Companies' service territories includes some of the highest-poverty regions of the United States, including three[36] of the five states with the greatest percentage of population below the federal poverty line. Approximately 25% of Entergy customers live below the poverty line, and additional generation costs associated with this FIP, especially those for units already expected to be deactivated within a handful of years after 2026, risk disproportionate economic impacts for these low-income customers.

In developing the Proposed FIP, EPA analyzed the impacts of the rulemaking on communities with environmental justice concerns and engaged with stakeholders representing these communities to seek input and feedback.[37] Prior to taking final action on the proposed FIP, EPA should ensure that economic equity concerns also are addressed in its development of the final FIP. The implementation of additional costly controls as a result of the proposed FIP's stringent budgets could lead either to unreasonable investment in $NO_X$ pollution control retrofits that may remain in service for only a handful of years, and/or early unit retirements, either of which can lead to increased rates for consumers.

**CONCLUSION:**

Entergy appreciates the opportunity to review EPA's proposed FIP and to provide these comments for EPA's consideration in preparation of a final rule. As outlined above, EPA's proposal relies upon flawed cost-effectiveness calculations for proposed SCR retrofits, contains insufficient flexibility to allow for effective and efficient allowance trading, and fails to provide adequate flexibility to allow for operation of higher-emitting generating units when necessary to ensure reliable operation of the bulk electric system. Entergy welcomes the opportunity to work with EPA to address these and other concerns outlined here in our comments. Should you have questions regarding any of the comments provided here or wish to discuss any of these comments in more detail, please feel free to contact me at (281) 297-2308 or David Triplett, Manager Environmental Policy & Sustainability at (281) 297-1928.

Sincerely,

Charles Kominas
Entergy – Power Generation Environmental Director

[36] Mississippi, Louisiana, and Arkansas, source: US Census Bureau Small Area Income and Poverty Estimates (2020).

[37] 87 Fed. Reg. at 20,153

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**Attachment A: EPA Total Project Cost Estimates for Entergy-Owned Units**

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| **Facility Name** | **Unit ID** | **Unit Capacity (MW)** | **Total Project Cost[38] ($)** |
|---|---|---|---|
| Coal Units | | | |
| Big Cajun 2 | 2B3 | 580 | $ 214,020,000 |
| Independence | 1 | 809 | $ 285,806,000 |
| Independence | 2 | 842 | $ 292,852,000 |
| R S Nelson | 6 | 550 | $ 229,755,000 |
| White Bluff | 1 | 818 | $ 289,033,000 |
| White Bluff | 2 | 819 | $ 283,855,000 |
| Oil/Gas Units | | | |
| Gerald Andrus | 1 | 736 | $ 111,290,000 |
| Lake Catherine | 4 | 522 | $ 83,821,000 |
| Ninemile Point | 4 | 748 | $ 93,892,000 |
| Ninemile Point | 5 | 737 | $ 100,019,000 |
| Little Gypsy | 2 | 416 | $ 63,952,000 |
| Little Gypsy | 3 | 524 | $ 80,457,000 |
| Sabine | 3 | 411 | $ 61,302,000 |
| Sabine | 4 | 533 | $ 77,610,000 |
| Sabine | 5 | 448 | $ 66,537,000 |
| | | **Total** | **$ 2,334,201,000** |

[38] All costs are as estimated by EPA and in 2021 dollars. See the file (Docket ID: EPA-HQ-OAR-2021-0668-0113) NOx_Control_Retrofit_Cost_Tool_Fleetwide_Assessment_Proposed_CSAPR_2015_NAAQS.xlsx for additional details of these cost estimates.

## Attachment B: Entergy Generation Development Timeline Information

| Completed Projects | | | | |
|---|---|---|---|---|
| **Operating Company** | **Project Name** | **Project Generation Type** | **Project Location** | **Approximate Project Execution Time[39] (years)** |
| ELL | J. Wayne Leonard Power Station | CCGT | Montz, LA | 5 |
| ELL | Lake Charles Power Station | CCGT | Westlake, LA | 5 |
| ETI | Montgomery County Power Station | CCGT | Willis, TX | 6 |
| EML | Sunflower Solar Station | Utility-Scale Solar | Sunflower County, MS | 5 |

| Current Projects | | | | |
|---|---|---|---|---|
| **Operating Company** | **Project Name** | **Project Generation Type** | **Project Location** | **Anticipated Project Execution Time[40] (years)** |
| ETI | OCAPS | Hydrogen-Capable CCGT | Orange, TX | 7 |
| EAL | Current/Future Solar RFPs | Utility-Scale Solar | Various, AR | 5 |
| ELL | Current/Future Solar RFPs | Utility-Scale Solar | Various, LA | 5-5.5 |
| EML | Current/Future Solar RFPs | Utility-Scale Solar | Various, MS | 5 |
| ETI | Current/Future Solar RFPs | Utility-Scale Solar | Various, TX | 5 |

[39] Indicated time includes initial planning through commercial operation of the generating unit.

[40] Indicated time includes initial planning through anticipated commercial operation date of the generation unit.

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**Attachment C: Comments on Proposed Arkansas SIP Disapproval**

**Arkansas Environmental Support**
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Stan Chivers, Air Lead
Arkansas Environmental Support

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AR-22-006

April 19, 2022

Administrator Michael Regan
C/O EPA Docket Center (EPA/DC)
Docket ID No. EPA-RO6-OAR-2021-0801
U.S. Environmental Protection Agency
*Fuerst.sherry@epa.gov*

RE: Request for an Extension of the Comment Period for EPA's *Air Plan Disapproval; Arkansas, Louisiana, Oklahoma, and Texas; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards*, 87 Fed. Reg. 9798 (February 22, 2022)

**ATTN: Docket ID No. EPA-RO6-OAR-2021-0801**

Dear Administrator Regan,

Entergy Services, LLC (ESL) requests a 60-day extension of the comment deadline for EPA's *Air Plan Disapproval; Arkansas, Louisiana, Oklahoma, and Texas; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards* (Proposal) on behalf of Entergy Arkansas, LLC (EAL). Additional time is necessary to thoroughly review the voluminous record supporting the Proposal, including the state-specific 4-Step Interstate Transport results, the EPA's Ozone Transport Modeling under the 2016v2 platform, and the EPA's after-the-fact change from the EPA 2018 memorandum (2011 base year) to the 2016v2 modeling (2016 base year). ESL requests additional time because:

(1) The modeling necessary to evaluate the information presented in support of the Proposal is incredibly detailed and time consuming and additional time is necessary for evaluating this modeling with respect to facilities' individual circumstances compared to the modeling on which Arkansas relied.

(2) EPA's deviation from the standard practice of allowing States to propose alternatives to State Implementation Plans (SIP) where EPA has proposed to disapprove a SIP submittal and to do so under a two-year time cycle prevents meaningful public input on the Proposal. This deviation is particularly troubling given that EPA is basing its proposed disapproval of Arkansas's SIP on a modeling platform that was unavailable to Arkansas at the time it submitted its SIP to EPA. EPA is required to approve SIPs under

the Clean Air Act if they meet the requirements of the Act, even if EPA would have made different choices. In releasing a new modeling platform only a few months before EPA's long-delayed proposed action on the SIP and deciding that modeling platform is the standard by which all interstate transport SIPs for the 2015 ozone NAAQS must be judged, EPA failed to provide the states, including Arkansas, with sufficient notice of what is required under the Act for an approvable SIP and is now failing to give the states adequate time to review and submit a SIP revision before EPA intends to promulgate a Federal Implementation Plan (FIP) that will require facilities in Arkansas to begin making NOx emission reductions.

(3) EPA's release of a proposed FIP, with a myriad of data that must be reviewed and evaluated during much of the same timeframe.

Any of these reasons should be sufficient justification to extend the comment deadline. Taken together, these reasons should compel the EPA to grant the ESL's request for a 60-day extension.

EAL operates 3 facilities in Arkansas which would be significantly affected by the proposed FIP. The duty to develop a SIP under Section 110(a) is imposed on the State of Arkansas (the "State"). ESL and the State, under the current timeline of the Proposal, do not have sufficient time to meaningfully review and provide comment on the Proposal. The importance of this public comment process— the purposes of which include ensuring informed agency decision-making, encouraging public participation in the administrative process, and ensuring that agencies keep an open mind towards their rules—"cannot be overstated." *N.C. Growers' Ass'n v. United Farm Workers*, 702 2 F.3d 755, 763 (4th Cir. 2012). To achieve these purposes, "the opportunity to comment 'must be a meaningful opportunity.'" *Id.* (quoting *Prometheus Radio Project v. FCC*, 652 F.3d 431, 450 (3d Cir. 2011)).

ESL, the State and other experts therefore need additional time to provide their best guidance. Thank you for your consideration of ESL's request for an extension of the comment period by 60 days.

Sincerely,

Stan Chivers

Stan Chivers
Air Lead, Arkansas Environmental Support
Entergy Services, LLC

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**Attachment D: Comments on Proposed Louisiana, Mississippi, and Texas SIP Disapprovals**

**Entergy Services, LLC**
639 Loyola Avenue
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Mail Unit L-ENT-4E
New Orleans, LA 70161-1000
Tel 504 576 4928

LES-22-044

April 25, 2022

Administrator Michael Regan
C/O EPA Docket Center (EPA/DC)
Docket ID No. EPA-RO6-OAR-2021-0801-0001
Docket ID No. EPA-RO4-OAR-2021-0841-0010
U.S. Environmental Protection Agency
*Fuerst.sherry@epa.gov*

RE: Request for an Extension of the Comment Periods for EPA's *Air Plan Disapproval; Arkansas, Louisiana, Oklahoma, and Texas; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards*, 87 Fed. Reg. 9798 (February 22, 2022), and *Air Plan Disapproval; AL, MS, and TN: Interstate Transport Requirements for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 87 Fed. Reg. 9545 (February 22, 2022)*

**ATTN: Docket ID No. EPA-RO6-OAR-2021-0801-0001 (USEPA Region 6)**

**Docket ID No. EPA-RO4-OAR-2021-0841-0010 (USEPA Region 4)**

Dear Administrator Regan,

Entergy Services, LLC (ESL), on behalf of Entergy Louisiana, LLC (ELL), Entergy Mississippi, LLC (EML) and Entergy Texas, LLC (ETI) requests a 60-day extension of the comment deadline for EPA's *Air Plan Disapproval; Arkansas, Louisiana, Oklahoma, and Texas; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards*, and *Air Plan Disapproval; AL, MS, and TN: Interstate Transport Requirements for the 2015 8-Hour Ozone National Ambient Air Quality Standards* (collectively Proposals) on behalf of ELL, EMI and ETI. Additional time is necessary to thoroughly review the voluminous record supporting the Proposals, including the state-specific 4-Step Interstate Transport results, the EPA's Ozone Transport Modeling under the 2016v2 platform, and the EPA's after-the-fact change from the EPA 2018 memorandum (2011 base year) to the 2016v2 modeling (2016 base year). ESL requests additional time because:

(1) The modeling necessary to evaluate the information presented in support of the Proposals is incredibly detailed and time consuming and additional time is necessary for evaluating this modeling with respect to facilities' individual circumstances compared to the modeling on which Louisiana, Mississippi and Texas relied.

(2) EPA's deviation from the standard practice of allowing States to propose alternatives to State Implementation Plans (SIP) where EPA has proposed to disapprove a SIP submittal and to do so under a two-year time cycle prevents meaningful public input on the Proposals. This deviation is particularly

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troubling given that EPA is basing its proposed disapproval of Louisiana, Mississippi and Texas SIPs on a modeling platform that was unavailable to these states at the time they submitted their SIPs to EPA. EPA is required to approve SIPs under the Clean Air Act if they meet the requirements of the Act, even if EPA would have made different choices. In releasing a new modeling platform only a few months before EPA's long-delayed proposed action on the SIPs and deciding that modeling platform is the standard by which all interstate transport SIPs for the 2015 ozone NAAQS must be judged, EPA failed to provide the states, including Louisiana, Mississippi and Texas, with sufficient notice of what is required under the Act for an approvable SIP and is now failing to give these states adequate time to review and submit a SIP revision before EPA intends to promulgate a Federal Implementation Plan (FIP) that will require facilities in Louisiana, Mississippi and Texas to begin making NOx emission reductions.

(3) EPA's release of a proposed FIP, with a myriad of data that must be reviewed and evaluated during much of the same timeframe.

Any of these reasons should be sufficient justification to extend the comment deadline. Taken together, these reasons should compel the EPA to grant ESL's request for a 60-day extension.

ELL, EML and ETI operate 21 facilities in Louisiana, Mississippi and Texas which would be significantly affected by the proposed FIP. The duty to develop a SIP under Section 110(a) is imposed on the States of Louisiana, Mississippi and Texas (the "States"). ESL and the States, under the current timeline of the Proposals, do not have sufficient time to meaningfully review and provide comment on the Proposals. The importance of this public comment process— the purposes of which include ensuring informed agency decision-making, encouraging public participation in the administrative process, and ensuring that agencies keep an open mind towards their rules—"cannot be overstated." *N.C. Growers' Ass'n v. United Farm Workers*, 702 2 F.3d 755, 763 (4th Cir. 2012). To achieve these purposes, "the opportunity to comment 'must be a meaningful opportunity.'" *Id.* (quoting *Prometheus Radio Project v. FCC*, 652 F.3d 431, 450 (3d Cir. 2011)).

ESL, the States and other experts therefore need additional time to provide their best guidance. Thank you for your consideration of ESL's request for an extension of the comment period for the Proposals by 60 days.

Sincerely,

Charles Kominas
Entergy – Power Generation Environmental Director

# RESPONSE TO MARCH 18, 2020 REGIONAL HAZE FOUR-FACTOR ANALYSIS INFORMATION COLLECTION REQUEST

## Entergy Services LLC on behalf of Entergy Louisiana LLC
## Roy S. Nelson Electric Generating Plant

**Prepared By:**

Jeremy Jewell – Principal Consultant

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July 24, 2020

Project 203702.0085

Trinity Consultants

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# 1. INTRODUCTION

Trinity Consultants (Trinity) prepared this report on behalf of Entergy Services LLC and Entergy Louisiana LLC (together: "Entergy") in response to the March 18, 2020 Regional Haze Four-Factor Analysis Information Collection Request ("the ICR") from the Louisiana Department of Environmental Quality ("the LDEQ"). Per the ICR, this report provides information related to sulfur dioxide ($SO_2$) and nitrogen oxides ($NO_X$) emissions reduction options for Entergy's Roy S. Nelson Electric Generating Plant (Nelson) located in Westlake, Louisiana (LA).

Entergy operates one (1) electric generating unit (EGU) at Nelson under the authority of LDEQ Part 70 Operating Permit No. 0520-00014-V4 ("the permit"): "Unit 6" or "Nelson Unit 6" or "Nelson 6". Unit 6 burns primarily subbituminous coal and secondarily No. 2 and No. 4 fuel oils, it has a nominal heat input capacity of 6,216 MMBtu/hr, and it is equipped with low-$NO_X$ burners (LNB)[1] and separated overfire air (SOFA) for $NO_X$ control and an electrostatic precipitator (ESP) with flue gas conditioning for particulate matter (PM) control. Two (2) other EGUs listed in the permit – "Unit 3" and "Unit 4" – have both been retired.

The following specific technical and economic information, where applicable, is provided in this report for each emissions reduction option considered for Nelson Unit 6, in accordance with instructions in the ICR:

- Technical feasibility
- Control effectiveness
- Emissions reductions
- Time necessary for implementation[2]
- Remaining useful life[2]
- Energy and non-air quality environmental impacts[2]
- Costs of implementation[2,3]

As appropriate, this report provides the same information that was provided to the LDEQ for its regional haze rule (RHR) first planning period (1PP), or Best Available Retrofit Technology (BART), state implementation plan (SIP) development. Information from past submittals is referenced for convenience and any updates are explained.

Section 2 and Appendix A of this report present information for the $SO_2$ emissions reduction options, and Section 3 and Appendix B present information for the $NO_X$ emissions reduction options.

---

[1] The permit uses the phrase "low $NO_X$ concentric firing system (LNCFS)."

[2] These are the four factors that must be included in evaluating emission reduction measures necessary to make reasonable progress determinations. *See* 40 CFR § 308(f)(2)(i).

[3] In addition to the capital, annualized capital, and annual operations and maintenance costs requested in the ICR, this report provides average and incremental cost effectiveness values, both of which are defined in the EPA's October 1990 New Source Review Workshop Manual (Draft), available at https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf as of July 23, 2020. Average cost effectiveness is the "total annualized costs of control divided by annual emission reductions, or the difference between the baseline emission rate and the controlled emission rate" (at B.36) and "incremental cost effectiveness calculation compares the costs and emissions performance level of a control option to those of the next most stringent option" (at B.41).

In addition to the information requested by the ICR, Appendix C of this report provides a report summarizing the status of visibility impairment at the Breton Island Wilderness area (BRIS) and the Caney Creek Wilderness (CACR) area – the two Class I areas allegedly affected by Nelson.

# 2. $SO_2$ EMISSIONS REDUCTION OPTIONS

This report addresses the following four (4) $SO_2$ emissions reduction options:

- Dry Flue Gas Desulfurization (DFGD), a.k.a., Dry Scrubbing or Spray Dry Absorption (SDA);
- Wet Flue Gas Desulfurization (WFGD), a.k.a., Wet Scrubbing;
- Dry Sorbent Injection (DSI); and
- Enhanced DSI for which a new fabric filter is part of the retrofit plan.

## 2.1 Technical Feasibility

WFGD, DFGD, DSI, and Enhanced DSI are technically feasible for Unit 6.

## 2.2 Control Effectiveness

Table 2-1 summarizes the controlled emission rates for the technically feasible $SO_2$ emissions reduction options for Unit 6. These rates were taken from Entergy's April 15, 2016 Roy S. Nelson Electric Generating Plant BART Five-Factor Analysis ("Entergy's April 2016 Nelson BART report"), at 4-1 – 4-3.

**Table 2-1. Control Effectiveness of $SO_2$ Emissions Reduction Options**

| $SO_2$ Reduction Option | Controlled Emission Rate (lb/MMBtu) |
|---|---|
| WFGD | 0.04 |
| DFGD | 0.06 |
| Enhanced DSI | 0.19 |
| DSI | 0.47 |

## 2.3 Emissions Reductions

The ICR specifies a baseline period of January 1, 2018 to December 31, 2019 and states that the baseline actual emission rate for the unit is to be the maximum monthly value during the baseline period. Based on the EPA's Air Markets Program Data (AMPD)[4], this rate would be 1,681 tons/month (July 2018). Because control cost assessments are based on annual emissions values,[5] this monthly value would need to be annualized (i.e., multiplied by 12) to 20,176 tons per year (tpy). However, this value is greater than annual emissions during the baseline period or any reasonable prediction of emission rates in future operating years so there is no legitimate basis for establishing this rate as the baseline actual emission rate for the purposes of this report.

Therefore, instead of using the maximum monthly value as the baseline emission rate, Trinity and Entergy propose to use the annual average value from the baseline period: 9,466 tpy.

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[4] https://ampd.epa.gov/ampd, queried on April 2, 2020.

[5] Cost Effectiveness ($/ton) = Total Annual Cost ($/year) / Annual Emissions Reduction (tons/year).

Table 2-2 presents the baseline emission rate and the controlled emission rates and emission reduction potentials for each of the technically feasible $SO_2$ emissions reduction options.

**Table 2-2. Baseline Emission Rates (Annual Average Basis) and Controlled Emission Rates for $SO_2$ Emissions Reduction Options**

| $SO_2$ Reduction Option | Baseline Emission Rate (tpy) | Controlled Emission Rate (tpy) | Emissions Reduction (tpy) |
|---|---|---|---|
| WFGD | 9,466 | 552 | 8,913 |
| DFGD | | 829 | 8,637 |
| Enhanced DSI | | 2,624 | 6,841 |
| DSI | | 6,491 | 2,974 |

## 2.4 Time Necessary for Implementation

A minimum of five (5) years, counting from the effective date of an approved determination, would be needed for implementing either the WFGD or DFGD options. Three (3) years would be needed for implementing either DSI or Enhanced DSI. The ICR assumes an EPA approval date for the LDEQ's regional haze second planning period (2PP) SIP of January 31, 2023. Adding the times necessary for implementation to this date results in assumed implementation dates of February 1, 2028 for WFGD or DFGD, and February 1, 2026 for DSI or Enhanced DSI.

## 2.5 Remaining Useful Life

Entergy has no plans to shut down or cease burning coal at Nelson Unit 6. Therefore, a remaining useful life (RUL) value of 30 years is assumed based on EPA's preference established in the first planning period (1PP), e.g., in EPA's May 19, 2015, Section 114(a) Information Request letter for Nelson.[6]

## 2.6 Energy and Non-air Quality Environmental Impacts

### 2.6.1 WFGD

Entergy's April 2016 Nelson BART report, at 4-4, identified the negative impacts associated with WFGD:

> The negative non-air quality environmental impacts are greater with wet scrubbing systems. Wet scrubbers require increased water use and generate large volumes of wastewater and solid waste/sludge that must be managed and/or treated. This places additional burdens on the wastewater treatment and solid waste management capabilities. Moreover, if wet scrubbing produces calcium sulfite sludge, the sludge will be waterladen (sic), and it must be stabilized for landfilling. Wet scrubbing systems require increased power requirements and increased reagent usage over dry scrubbers. Thus, from an overall environmental perspective, dry scrubbing is superior to wet scrubbing.

[6] Wren Stenger, Section 114(a) Information Request letter to Paul Castanon (Entergy Gulf States), May 19, 2015.

Additionally, wet scrubbing has the potential to increase PM and sulfuric acid ($H_2SO_4$) mist emissions.

### 2.6.2 DFGD

DFGD has the following negative impacts:

> Non-air quality environmental impacts of DFGD primarily relate to available water resources and waste byproducts. DFGD systems consume a significant quantity of water, and the required water must be relatively clean. In addition, DFGD systems also generate a large waste byproduct stream, containing calcium salts, which must be landfilled. If not fixated during the disposal process, the calcium salts are soluble and may dissolve and appear in the landfill leachate.

### 2.6.3 DSI and Enhanced DSI

Sargent & Lundy's November 6, 2015 Nelson Unit 6 DSI Cost Estimates Basis Document ("S&L's November 2015 Nelson DSI report")[7], at 1 – 2, presents the negative impacts associated with DSI systems:

> The DSI process produces a dry byproduct which can be landfilled. The waste products will contain $NaSO_3$/$NaSO_4$ along with the unused sorbent and the normal fly ash. These wastes will be collected in the ESP and can be transported with conventional pneumatic fly ash handling equipment. The waste from sodium-based sorbents will have relatively high concentrations of soluble salts, which may affect the byproduct handling. With the addition of dry sorbent byproducts fly ash cannot be sold for reuse.

Additionally, because the sodium byproducts (salts) are soluble in water, the landfill used for disposal must be lined and equipped with a leachate collection system.

## 2.7 Costs

Table 2-3 summarizes the estimated costs, including total capital costs,[8] annualized capital costs (see note following the table), annual operations and maintenance (O&M) costs, and cost effectiveness based on the emission reduction values from Table 2-2 for the technically feasible $SO_2$ reduction options. The costs for each option are based on information presented in Entergy's April 2016 Nelson BART report, at 4-3 – 4-4, and Sargent & Lundy's November 6, 2015 Nelson Unit 6 $SO_2$ BART Control Technology Summary and related April 14, 2016 Addendum (together: "S&L's November 2015 Nelson $SO_2$ Control Technology Summary

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[7] S&L's November 2015 Nelson DSI report was included in Appendix A of Entergy's April 2016 Nelson BART report and is included in Appendix A of this report.

[8] The "Total Capital Investment without IDC" values from S&L's reports are used as the unescalated capital cost values for this report. As explained in the S&L report, "IDC" is Interest During Construction, a.k.a., Allowance for Funds Used During Construction (AFUDC). Despite being significant for long-term projects such as those considered in this report, this cost is excluded in accordance with EPA's preferred "overnight" costing methodology.

report")[9], at 3 and 2, respectively. The costs were based on a 2015 dollar value ($2015). These values are escalated to 2019 using the Chemical Engineering Plant Cost Index (CEPCI) values.[10]

**Table 2-3. Estimated Costs ($2019) of $SO_2$ Emissions Reduction Options**

| $SO_2$ Reduction Option | Capital Costs ($M) | Annualized Capital Costs ($M/year) | Annual O&M Costs ($M/year) | Total Annual Costs ($M/year) | Average Cost Effectiveness ($/ton) [11] | Incremental Cost Effectiveness ($/ton) |
|---|---|---|---|---|---|---|
| DSI | 108,797 | 8,769 | 14,127 | 22,896 | 7,698 | N/A |
| Enhanced DSI | 315,332 | 25,416 | 25,823 | 51,239 | 7,489 | 7,329 |
| DFGD | 430,799 | 34,722 | 17,313 | 52,035 | 6,025 | 444 |
| WFGD | 473,763 | 38,185 | 14,020 | 52,205 | 5,857 | 616 |

Note: The incremental cost effectiveness value for Enhanced DSI is a comparison to DSI, the value for DFGD is a comparison to Enhanced DSI, and the value for WFGD is a comparison to DFGD.

All annualized capital costs, i.e., capital recovery estimates, were calculated using the RULs discussed above and a 7 % social rate of interest, which, as far as Entergy is aware, has been used by EPA for all similar control cost analyses and which follows the EPA Office of Management and Budget (OMB) guidance, as discussed below.

The EPA's Control Cost Manual (CCM or "Manual") states:

> *when performing cost analysis, it is important to ensure that the correct interest rate is being used. Because this Manual is concerned with estimating private costs, the correct interest rate to use is the nominal interest rate, which is the rate firms actually face.*[12]

For this report, which evaluates equipment costs that may take place several years into the future, it is important to ensure that the selected interest rate represents a longer-term view of corporate borrowing rates. The CCM cites the bank prime rate as one indicator of the cost of borrowing as an option for use when the specific nominal interest rate is not available. Over the past 20 years, the annual-average prime

[9] S&L's November 2015 Nelson $SO_2$ Control Technology Summary report was included in Appendix A of Entergy's April 2016 Nelson BART report and is included in Appendix A of this report.

[10] From https://www.chemengonline.com/pci-home:

| Year: | 2015 | 2019 |
|---|---|---|
| CEPCI: | 556.8 | 607.5 |

[11] The cost effectiveness values presented in this report are signficantly higher (by approximately 25 to 30 percent) than the cost effectiveness values for the same controls in Entergy's April 2016 Nelson BART report because (a) costs have been escalated to $2019 and (b) the baseline emission rate used for this report is approximatley 20 percent less than the baseline rate used for the BART assessment.

[12] Sorrels, J. and Walton, T. "Cost Estimation: Concepts and Methodology," EPA Air Pollution Control Cost Manual, Section 1, Chapter 2, p. 15. U.S. EPA Air Economics Group, November 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.

rate has varied from 3.25 % to 9.23 %, with an overall average of 4.86 %.[13] The CCM adds the caution that the "base rates used by banks do not reflect entity and project specific characteristics and risks including the length of the project, and credit risks of the borrowers."[14] For this reason, the prime rate should be considered the low end of the range for estimating capital cost recovery. Actual borrowing costs are typically much higher than prime rates. For economic evaluations of the impact of federal regulations, the OMB uses an interest rate of 7 %.

> *As a default position, OMB Circular A-94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The 7 percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business capital as well as corporate capital. It approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector.*[15]

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[13] Board of Governors of the Federal Reserve System Data Download Program, "H.15 Selected Interest Rates," accessed April 16, 2020. https://www.federalreserve.gov/datadownload/Download.aspx?rel=H15&series=8193c94824192497563a23e3787878ec&filetype=spreadsheetml&label=include&layout=seriescolumn&from=01/01/2000&to=12/31/2020.

[14] Sorrels, J. and Walton, T. "Cost Estimation: Concepts and Methodology," EPA Air Pollution Control Cost Manual, Section 1, Chapter 2, p. 16. U.S. EPA Air Economics Group, November 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.

[15] OMB Circular A-4, https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf.

# 3. $NO_X$ EMISSIONS REDUCTION OPTIONS

This report addresses the following two (2) control options that could provide incremental $NO_X$ emissions reduction compared to the existing LNB and SOFA on Unit 6:

- ► Selective Catalytic Reduction (SCR) and
- ► Selective Non-Catalytic Reduction (SNCR).

## 3.1 Technical Feasibility

Both SCR and SNCR are technically feasible $NO_X$ emissions reduction options for Unit 6.

## 3.2 Control Effectiveness

Table 3-1 summarizes and ranks the controlled emission rates for the technically feasible $NO_X$ emissions reduction options for Unit 6. The controlled SCR emission rate is based on EPA's June 2019 SCR Cost Calculation Spreadsheet[16] that is published on EPA's Air Pollution Control Cost Manual (CCM) webpage.[17] The controlled SNCR emission rate is based on best engineering judgment and knowledge of other EGUs operating SNCR.[18]

**Table 3-1. Control Effectiveness of $NO_X$ Emissions Reduction Options**

| $NO_X$ Reduction Option | Controlled Emission Rate (lb/MMBtu) |
|---|---|
| SCR | 0.05 |
| SNCR | 0.15 |

## 3.3 Emissions Reductions

Controlled emission rates and emissions reduction values for SCR and SNCR are taken from EPA's June 2019 SCR and SNCR Cost Calculation Spreadsheets. Printouts from the spreadsheets are included in Appendix B.

Table 3-2 presents the controlled emission rates and emission reduction potentials for the technically feasible $NO_X$ emissions reduction options.

[16] https://www.epa.gov/sites/production/files/2019-06/scrcostmanualspreadsheet_june-2019vf.xlsm, accessed on April 20, 2020.

[17] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution, accessed on April 20, 2020.

[18] For example, per Consent Decree, Big Cajun II Unit 1 is required to operate SNCR with an emissions limit of 0.15 lb/MMBtu.

**Table 3-2. Controlled Emission Rates and Emissions Reduction Potentials of $NO_X$ Emissions Reduction Options**

| $NO_X$ Reduction Option | Controlled Emission Rate (tpy) | Emissions Reduction (tpy) |
|---|---|---|
| SCR | 860 | 1,931 |
| SNCR | 2,579 | 669 |

## 3.4 Time Necessary for Implementation

A minimum of five (5) years, counting from the effective date of an approved determination, would be needed for implementing either the SCR or SNCR option. The ICR assumes an EPA approval date for the LDEQ's regional haze 2PP SIP of January 31, 2023. Adding the times necessary for implementation to this date results in an assumed implementation date of February 1, 2028 for SCR or SNCR.

## 3.5 Remaining Useful Life

Entergy has no plans to shut down or cease burning coal at Nelson Unit 6. Therefore, remaining useful life (RUL) values of 30 years for SCR and 20 years for SNCR are used based on EPA's June 2019 SCR and SNCR Cost Calculation Spreadsheets[19] that are published on EPA's CCM webpage.[20]

## 3.6 Energy and Non-air Quality Environmental Impacts

SCR and SNCR systems require electricity to operate the ancillary equipment. The need for electricity to help power some of the ancillary equipment creates a demand for energy that currently does not exist. SCR and SNCR can also potentially cause significant environmental impacts. The primary avenue is related to the storage of ammonia. The storage of aqueous ammonia in quantities greater than 10,000 pounds (lbs) is regulated by a risk management program (RMP) because the accidental release of ammonia has the potential to cause serious injury and death to persons in the vicinity of the release. Additionally, SCR and SNCR will likely also cause the release of unreacted ammonia to the atmosphere. This is referred to as ammonia slip. Ammonia slip from SCR and SNCR systems occurs either from ammonia injection at temperatures too low for effective reaction with $NO_X$, leading to an excess of unreacted ammonia, or from over injection of reagent leading to uneven distribution; which also leads to an excess of unreacted ammonia. Ammonia released from SCR and SNCR systems will react with sulfates and nitrates in the atmosphere to form ammonium sulfate and ammonium nitrate. Together, ammonium sulfate and ammonium nitrate are the predominant sources of regional haze.

Another environmental impact associated with SCR is the disposal of catalyst waste. To maintain $NO_X$-removal effectiveness, the catalyst in an SCR system must periodically be cleaned, regenerated, or replaced. Cleaning and regeneration are preferred, but eventually the catalyst reaches the end of its useful life and

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[19] https://www.epa.gov/sites/production/files/2019-06/scrcostmanualspreadsheet_june-2019vf.xlsm and https://www.epa.gov/sites/production/files/2019-06/sncrcostmanualspreadsheet_june2019vf.xlsm, accessed on April 20, 2020.

[20] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution, accessed on April 20, 2020.

must be replaced. Ideally the exhausted catalyst can be recycled for reuse, however, if the condition of the spent catalyst does not warrant recycling or a market is unavailable, the old catalyst must be disposed of. Current regulatory interpretations indicate spent SCR catalysts are exempted from hazardous waste regulation via 40 CFR § 261.4(b)(4) (Bevill Exemption) as flue gas emission control wastes. However, ongoing efforts by EPA to increase regulatory oversight of coal combustion residuals could alter that exemption and create the potential that spent SCR catalysts would be characterized as hazardous wastes, hence increasing the cost of disposal. Regardless of the regulatory treatment of the waste, the disposal creates additional potential financial and environmental impacts associated with an SCR system.

## 3.7 Costs

Table 3-3 summarizes the estimated costs, including total and annualized capital costs (following the same methods and assumptions described in Section 2.7), annual O&M costs, and cost effectiveness based on EPA's June 2019 SCR and SNCR Cost Calculation Spreadsheets and the emission reduction values from Table 3-2 for the technically feasible $NO_X$ reduction options. The cost estimates in the spreadsheets differ depending on the reagent (ammonia or urea) choice; therefore, both are presented below. Printouts from the spreadsheets are included in Appendix B.

**Table 3-3. Estimated Costs ($2019) of $NO_X$ Emissions Reduction Options**

| $NO_X$ Reduction Option | Capital Costs ($M) | Annualized Capital Costs ($M/year) | Annual O&M Costs ($M/year) | Total Annual Costs ($M/year) | Average Cost Effectiveness ($/ton) | Incremental Cost Effectiveness ($/ton) |
|---|---|---|---|---|---|---|
| SNCR (Urea) | 12,221 | 1,154 | 2,308 | 3,461 | 5,174 | N/A |
| SNCR (Ammonia) | 12,221 | 1,154 | 2,520 | 3,673 | 5,491 | N/A |
| SCR (Urea) | 172,266 | 13,885 | 4,479 | 18,364 | 9,509 | 8,546-9,021 |
| SCR (Ammonia) | 172,266 | 13,885 | 5,084 | 18,968 | 9,822 | |

Note: The incremental cost effectiveness range is minimum and maximum of the four possible comparisons of SCR to SNCR.

# APPENDIX A. 1PP $SO_2$ CONTROLS STUDIES

- S&L's November 6, 2015 Nelson Unit 6 $SO_2$ BART Control Technology Summary, Revision 0, preceded by S&L's April 14, 2016 Nelson Unit 6 $SO_2$ BART Control Technology Summary Addendum
- S&L's November 6, 2015 Nelson Unit 6 Dry FGD Cost Estimate Basis Document, Revision 0
- S&L's November 6, 2015 Nelson Unit 6 DSI Cost Estimate Basis Document, Revision 0
- S&L's November 6, 2015 Nelson Unit 6 Enhanced DSI Cost Estimate Basis Document, Revision 0
- S&L's November 6, 2015 Nelson Unit 6 Wet FGD Cost Estimate Basis Document, Revision 0

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NELSON UNIT 6

# $SO_2$ BART CONTROL TECHNOLOGY SUMMARY

**Addendum**
April 14, 2016
Project 13027-003

Prepared by

Sargent & Lundy LLC

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# 1. PURPOSE

In response to Entergy's Regional Haze submittal on November 6, 2015, EPA submitted a request for additional information to Entergy on March16, 2016, which instructed Entergy to remove AFUDC from the BART cost estimates.

> *"The BART Guidelines require that cost estimates should be based on the OAQPS Control Cost Manual, where possible. The Control Cost Manual methodology, which uses the overnight cost method, does not allow for AFUDC to be assumed. Because AFUDC is not allowed under the Control Cost Manual approach, it should be removed from the Little Gypsy BART cost estimate, and any other BART cost estimates."*

We disagree that the *Control Cost Manual* describes an overnight approach to calculating capital costs. The *Control Cost Manual* does not once define or mention the overnight methodology as being the basis for estimating costs. Rather, the *Control Cost Manual* describes a constant dollar approach that annualizes all capital costs and O&M costs (on a constant-dollar basis) over the useful life of the project.

The term "total capital investment" is defined in the *Control Cost Manual* to include all costs required to purchase the equipment needed for the control system, the costs of labor and materials for installing that equipment, costs for site preparation and building, working capital, and off-site facilities, as well as indirect installation costs "such as engineering costs; construction and field expenses; contractor fees; start-up and performance test costs; and contingencies. AFUDC (or interest during construction) is an indirect capital cost that accounts for the time value of money associated with the distribution of construction cash flows over the construction period and should be included in capital cost estimates prepared in accordance with the methodology described in the *Control Cost Manual*.

Although specifically referenced in the *Control Cost Manual*, and more reflective of real-world project costs, Entergy has elected to exclude AFUDC in recognition of EPA's opinion that such costs should not be factored into five-factor Regional Haze BART analyses.

The cost included in the following table represent the cost of the evaluated $SO_2$ control technologies for Nelson Unit 6 excluding AFUDC (or interest during construction) based on the capital cost estimate previously developed.

| **Control Technology** | **Total Capital Investment with IDC** | **IDC Cost (Line 130)** | **Total Capital Investment without IDC** |
|---|---|---|---|
| Dry Sorbent Injection | \$104,556,900 | \$4,839,600 | \$99,717,300 |
| Enhanced Dry Sorbent Injection | \$306,150,600 | \$17,135,300 | \$289,015,300 |
| Dry Flue Gas Desulfurization | \$447,312,400 | \$52,466,600 | \$394,845,800 |
| Wet Flue Gas Desulfurization | \$491,917,000 | \$57,692,600 | \$434,224,400 |

## 2. REFERENCES

1. Entergy – Nelson Unit 6 – SO2 BART Control Technology Summary, Revision 0, November 6, 2015.
2. Entergy - Nelson Unit 6 – DSI Cost Estimate Basis Document, Revision 0, November 6, 2015.
3. Entergy - Nelson Unit 6 – Enhanced DSI Cost Estimate Basis Document, Revision 0, November 6, 2015.
4. Entergy - Nelson Unit 6 – Dry FGD Cost Estimate Basis Document, Revision 0, November 6, 2015.
5. Entergy - Nelson Unit 6 – Wet FGD Cost Estimate Basis Document, Revision 0, November 6, 2015.

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# $SO_2$ BART CONTROL TECHNOLOGY SUMMARY

**Revision 0**
November 6, 2015
Project 13027-003

Prepared by

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# 1. PURPOSE

Entergy was requested by the U.S.EPA Region 6 to provide a Best Available Retrofit Technology (BART) evaluation for Nelson Unit 6 with respect to the Regional Haze Requirements. As part of this effort, Entergy requested that Sargent & Lundy (S&L) support this evaluation, with respect to sulfur dioxide ($SO_2$) emissions. The following technologies were identified as potential $SO_2$ control technologies for Nelson Unit 6:

- Dry Sorbent Injection (DSI)
- Enhanced DSI (DSI in conjunction with a new baghouse)
- Dry Flue Gas Desulfurization (FGD)
- Wet FGD

# 2. APPROACH

For each of these technologies S&L evaluated their feasibility and limitations, as well as estimating the total capital investment and annual operating and maintenance (O&M) costs for each technology. For a detailed description of the basis for developing capital and O&M costs see the attached Cost Estimate Scope and Technical Basis Documents for each of the evaluated technologies.

## 2.1 CAPITAL COST DEVELOPMENT

The capital cost estimates were developed to account for site-specific considerations and unit-specific operating data (e.g., fuel characteristics, temperature data, and current emission rates). Equipment costs for the major components of each technology were developed based on recent in-house equipment costs provided by equipment vendors for similar projects. Balance-of-plant costs for equipment tie-ins, ductwork, foundations, structural steel, piping, pumps, conduit, etc., and associated installation costs were estimated based on pricing for similar projects.

The capital cost estimates includes the following components which comprise the total cost the Owner will incur to install for each technology evaluated:

- Equipment Island Cost supplied by a qualified System Supplier including the main process equipment

- Balance of Plant Cost including auxiliary equipment and systems, foundations and buildings, site work, demolition and relocation; allowances included as necessary
- Other Direct and Construction Indirect Costs including labor premiums, freight, contractor's G&A and profit
- Indirect Costs including engineering, startup spare parts, technical field advisors, and the additional fee associated with an EPC contracting strategy
- Owner's Costs including internal labor, insurance, and initial reagent fill
- Third Party Services including construction management oversight, start-up and commissioning oversight, Owner's Engineer services, and performance testing
- Project Contingency to cover unknown and undefined scope associated with the project which would result in additional cost to the Owner
- Escalation and Interest During Construction associated with the project duration for implementation of large air quality control technologies

The project definition and accuracy of the individual components included in this estimate result in an overall accuracy of -20 to +50%.

## 2.2 O&M COST DEVELOPMENT

Variable O&M costs, such as reagent costs, water, auxiliary power, and others were developed based on estimated commodity consumption rates and unit pricing. It should be noted that the variable O&M costs rely heavily on the amount of $SO_2$ reduction estimated for each technology and the projected capacity factor. Fixed O&M costs were calculated using general cost factors for operating and supervisory labor, maintenance materials & labor, insurance and administration, as applicable.

# 3. SUMMARY OF $SO_2$ CONTROL TECHNOLOGIES

The following table summarizes the estimated capital and O&M costs for each of the potential $SO_2$ control technologies evaluated for Nelson Unit 6:

| Control Technology | Controlled $SO_2$ Emission Rate[1] | Total Capital Investment | Annual Operating Cost[2] |
|---|---|---|---|
| Dry Sorbent Injection | 0.47 lb/MMBtu | $104,556,900 | $12,947,500 / year |
| Enhanced Dry Sorbent Injection | 0.19 lb/MMBtu | $306,150,600 | $23,667,800 / year |
| Dry Flue Gas Desulfurization | 0.06 lb/MMBtu | $447,312,400 | $15,868,000 / year |
| Wet Flue Gas Desulfurization | 0.04 lb/MMBtu | $491,917,000 | $12,850,000 / year |

Note 1: DSI and Enhanced DSI controlled $SO_2$ emission rates are based on the maximum 30-day average $SO_2$ emission rate of 0.74 lb/MMBtu between 2012 and 2014.

Note 2: Annual first year operating costs (presented in $2015) represent the total variable and fixed O&M costs based on an average capacity factor of 62% between 2012 and 2014.

# 4. ATTACHMENTS

1. Entergy - Nelson Unit 6 – DSI Cost Estimate Basis Document.
2. Entergy - Nelson Unit 6 – Enhanced DSI Cost Estimate Basis Document.
3. Entergy - Nelson Unit 6 – Dry FGD Cost Estimate Basis Document.
4. Entergy - Nelson Unit 6 – Wet FGD Cost Estimate Basis Document.

NELSON UNIT 6

# DRY FGD COST ESTIMATE BASIS DOCUMENT

**Revision 0**
November 6, 2015
Project 13027-003

Prepared by

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# 1. PURPOSE

Entergy has requested that S&L support the Best Available Retrofit Technology (BART) evaluation for Nelson Unit 6 with respect to $SO_2$ emissions. As part of this effort, Entergy has requested that S&L perform a technology evaluation and cost estimates to install a new dry flue gas desulfurization (FGD) system on Nelson Unit 6. The purpose of this document is to define the project scope and identify the assumptions that were used as the basis for the operating and maintenance (O&M) and the AACE Level 5 capital cost estimates.

# 2. TECHNOLOGY DESCRIPTION

Dry FGD technology was developed to reduce $SO_2$ emissions from low-sulfur coal; removal takes place in the absorber and the particulate collector (baghouse). The calcium in the lime slurry reacts with $SO_2$ in the flue gas to form waste solids (byproduct). The byproduct is predominately calcium sulfite ($CaSO_3$) with some calcium sulfate ($CaSO_4$). The chemical reactions are as follows:

$$Ca(OH)_2 + SO_2 + H_2O \Rightarrow CaSO_3 \cdot \tfrac{1}{2}H_2O + {}^{3}/_{2}\, H_2O$$

$$CaSO_3 \cdot \tfrac{1}{2}H_2O + {}^{3}/_{2}\, H_2O + \tfrac{1}{2}O_2 \text{ (flue gas)} \Rightarrow CaSO_4 \cdot 2H_2O$$

$SO_2$ in the flue gas is removed by injection of fresh lime slurry (typically around 30 wt% solids) into the absorber tower. The lime slurry is atomized into fine droplets by injection with dual fluid spray nozzles or rotary atomizers. The flue gas fully dries the slurry solids in the absorber. A significant portion of the solids (byproduct) are recycled to improve the lime utilization.

The dry FGD process uses (powdered) hydrated lime ($Ca(OH)_2$) or (pebble) quicklime ($CaO$). Due to the large quantities of lime consumed, quicklime is typically more cost effective. Preparation of the fresh lime slurry involves slaking the quicklime. The slaking reaction is exothermic so safety systems are required. The lime slaking reaction is:

$$CaO + H_2O \Leftrightarrow Ca(OH)_2$$

Typically, the dry FGD outlet gas is designed to be 30°F above the adiabatic saturation point (approach to saturation temperature). The 30°F approach to saturation design margin ensures that water condensation will be avoided in the downstream equipment. With a 30°F approach to saturation, the downstream equipment materials of construction are carbon steel and corrosion is generally not a concern.

# 3. APPROACH

The project capital and O&M cost estimates are based on project-specific information, including:

- An engineer-procure-construct (EPC) contracting strategy with the FGD technology supplier providing the main process equipment as a complete FGD Island.
- The cost estimate incorporates the results of a conceptual system design developed as input to the FGD estimate. The following items were estimated based on previous projects and scaled for Nelson Unit 6:
    - Auxiliary power consumption
    - Annual reagent consumption
    - Additional water consumption
    - Additional waste production
    - Flue gas handling equipment, including absorber vessels, baghouses, ductwork and booster ID fans.
    - Reagent storage, handling and preparation equipment; including storage silos and bins, lime slakers, slurry tanks, and conveying equipment.
    - Byproduct recycle and handling equipment; including storage silos, slurry tanks, and conveying equipment.

The total plant capital cost estimate includes the following:

- Equipment and material
- Installation labor
- Indirect field costs
- Freight
- Sales Tax
- General and Administration
- Erection contractor profit
- Engineering, Procurement and Project Services
- Spare parts/initial fills
- EPC Fee

As part of this project, S&L estimated the costs for Owner services and costs outside of the EPC contract including the following:

- Owner's Costs
- Owner's Engineer
- Construction Management Support
- Startup and Commissioning Support
- Performance Testing
- Contingency
- Escalation
- Interest During Construction

Cost Estimate 33593A provided in Attachment 1 represents the cost to Entergy to install DSI technology on Nelson Unit 6 including the EPC Contract price and all additional Owner's costs and third party services.

The total unit O&M cost estimate includes the following:

- Byproduct waste disposal
- Reagent consumption
- Auxiliary power consumption
- High quality and low quality make-up water consumption
- Bags and cages
- Operating labor
- Maintenance material and labor

The O&M Estimate and Cost Estimate 33593A were developed using the assumptions and scope provided in this document. The project definition and accuracy of the individual components included in this estimate result in an overall accuracy of -20 to +50%.

# 4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS

The following assumptions were made for the design basis for the Nelson Unit 6 dry FGD system:

- Design $SO_2$ inlet concentration of 0.96 lb $SO_2$/MMBtu for equipment design.
- $SO_2$ inlet concentration of 0.70 lb $SO_2$/MMBtu for annual operating costs.
- Design $SO_2$ removal efficiency of approximately 94%.
- $SO_2$ Outlet Emission of 0.06 lb $SO_2$/MMBtu.
- Annual capacity factor of 62%, based on historical operating data.
- Reagent delivery by truck.
- Compliance deadline of June 2021.

## 4.1 TOTAL INSTALLED CAPITAL INVESTMENT

The primary scope of this project is to estimate the cost to install a Dry FGD system on Nelson Unit 6. The dry FGD system supplier will provide all of the major components within the FGD Island including the absorber vessels, baghouse, and booster ID fans as well as equipment related to reagent handling and preparation and byproduct recycle and handling. The remaining BOP scope will be provided by the EPC Contractor. In addition, the EPC Contractor will install/construct the entire system including the equipment provided by the FGD system supplier.

Quantities were developed based on limited project design effort, project experience of a plant of comparable size and then adjusted based on actual size and capacity differences and also taking into consideration the specific site layout based on the general arrangement. In most cases, the costs for bulk materials and equipment were derived from S&L database and recent vendor or manufacturer's quote for similar items on other projects. The scope of work for the capital cost estimate is broken out by area below:

1. Dry FGD Island
   a. Reagent Preparation System:
      - Reagent Preparation Building, 60' x 45', including mat foundation and superstructure
      - Two lime slakers at 100% capacity, each with a grit screen, gravimetric feeder
      - Two lime slurry transfer tanks

- Slurry transfer centrifugal pumps
- Two lime slurry storage tanks
- Slurry feed centrifugal pumps
- Sump pumps and agitators
- Equipment cost is based on recent pricing for a similar project.

b. Absorber Area:

- Two 65’ diameter absorber vessels with access doors, including mat foundation and superstructure
- Penthouse enclosure for absorbers located on FGD Island (cost estimated separately)
- Two rotary atomizers and motors, one operating per absorber and one shared spare
- Vessel material carbon steel, ¼ in. – ⅝ in. carbon steel
- Heating and ventilation
- Vacuum piping
- Sump pumps and agitators
- Equipment cost is based on recent pricing for a similar project.

c. Baghouse Area

- New baghouse, including pulse jet cleaning system and all appurtenances
- Inlet and outlet plenum
- Baghouse hoppers with heaters
- Structural support steel
- Fill of bags and cages
- Equipment cost is based on recent pricing for a similar project.

d. Byproduct Recycle System

- Byproduct recycle building, 50’ x 40’, including mat foundation and superstructure
- One recycle silo with bin vent filter
- One recycle mix tank
- Two recycle slurry tanks, with slurry pumps
- Agitators for each tank
- Recycle ash pneumatic conveying system from baghouse hoppers to recycle silo
- Pneumatic pressure exhausters
- Equipment cost is based on recent pricing for a similar project.

2. Reagent Storage and Handling
   a. Lime storage silo:
      - One silo, 7-days storage, included as part of Reagent Preparation Building
      - 30' diameter and 60' height to top
      - Continuous level detection systems
      - Bin vent filter
      - Live bottom hopper outlets
      - Rotary airlock assemblies
      - Lime transfer systems:
        - Pressure pneumatic conveying system from lime storage silo to lime day bins
        - Pneumatic pressure blowers (3 x 100%)
        - One lot of pneumatic conveying piping located on a new elevated pipe rack

3. Byproduct Handling System
   a. Waste storage silo:
      - One silo, 3-days storage, including mat foundation and superstructure
      - 28' diameter and 32' height to top
      - Continuous level detection systems
      - Bin vent filter
      - Live bottom hopper outlets
      - Rotary airlock assemblies
      - Waste byproduct pneumatic transfer systems:
        - Vacuum pneumatic conveying system from baghouse to waste silo
        - Pneumatic vacuum exhausters
        - One lot of pneumatic conveying piping located on an elevated pipe rack
   b. Recycle storage silo:
      - One silo, 3-days storage, located on common mat foundation with Recycle Building
      - 50' diameter and 130' height to top
      - Continuous level detection systems
      - Live bottom hopper outlets
      - Rotary airlock assemblies
      - Recycle transfer systems:

- Pneumatic vacuum conveying system from baghouse to recycle silo
- Vacuum exhausters
- One lot of pneumatic conveying piping located on new flue gas duct support steel

4. Flue Gas Handling System
   a. ID fan outlets to absorber inlets ductwork and supports:
      - Two ID fan outlet ducts, combine to a single duct to carry flue gas to the new FGD area where the ductwork splits into two absorber inlets.
      - Carbon steel, ¼ in.
      - Velocity, 3,600 fpm

   b. Absorber outlets to baghouse inlets ductwork and supports:
      - Two separate ducts, leading from one absorber vessel to a dedicated baghouse.
      - Carbon steel, ¼ in.
      - Velocity, 3,600 fpm

   c. Baghouse outlets to Booster fans
      - Two baghouse outlet ducts, combine to a single duct, and then split into two booster fan inlets.
      - Carbon steel, ¼ in.
      - Velocity, 3,600 fpm

   d. Booster fan outlet to the stack inlet ductwork and supports:
      - Two booster fan inlets, combine to a single duct which connects to the existing chimney breeching duct.
      - Carbon steel, ¼ in.
      - Velocity, 3,600 fpm

   e. Dampers and expansion joints
   f. 6” insulation and lagging
   g. Steel support structure and concrete mat foundations for all new flue gas ductwork

5. ID Booster Fans

a. Two, approximately 3,600 hp, axial booster fans sized to overcome pressure drop associated with dry FGD
b. Includes motors - no spare motor included
c. Booster fan area foundations

6. Civil Work
    a. Site grading
    b. Soil removal earthwork
    c. Excavation, backfill, and compaction for all foundations
    d. Storm sewer work
    a. Development of a new laydown area, approximately 5 acres, including site preparation, fencing, and temporary power. It was assumed that this area would be located on existing plant property, and does not require land to be purchased.

7. Mechanical Work
    a. Interconnecting piping, above-ground
    b. Valves for interconnecting piping, above-ground
    c. Lime slaking water storage tank, approximately 24-hour storage capacity
    d. Recycle make-up water tank, approximately 8-hour storage capacity
    e. Pipe Racks, including auxiliary steel and concrete foundations
    f. BOP Pumps
        - Three (3) x 50% by-product recycle water forwarding pumps to recycle slurry
        - Two (2) x 100% by-product recycle make-up water tank supply pumps
        - Two (2) x 100% lime slaking water pumps
        - Sump pumps
    g. Instrument Air System
        - Air compressors, 2 x 100%
        - IA dryers w/filters; 2 x 100%
        - Two air receivers
        - Instrument air piping
        - Heat-traced piping
    h. Service Air System
        - Air compressors, 2 x 100%
        - Two air receivers
    i. Eye wash and safety shower stations
    j. Field painting
    k. Relocation of ACI injection location from the air heater inlet to upstream of the DFGD.

8. Demolition and Relocation

   a. Allowance of $1,000,000 is provided for demolition and relocation of existing equipment and buildings based on recent in-house cost estimates for similar projects.

9. Electrical

   a. Allowance of $27,300,000 is provided for electrical equipment upgrades and modifications based on recent in-house cost estimates for similar projects, intended to include the following scope:

      - Reserve auxiliary transformer (RAT)
      - Isolated phase UAT tap bus extension
      - Unit auxiliary transformer (UAT)
      - Power Distribution Centers (PDC) including mat foundations and concrete piers
      - Step-down transformers
      - Medium-voltage cable bus duct
      - Medium-voltage cable
      - Low voltage, control and instrumentation cable
      - Cable tray and conduit
      - Grounding
      - Lighting

10. Instrumentation

    a. Allowance of $4,500,000 is provided for DCS upgrades and added instrumentation based on recent in-house cost estimates for similar projects. Controls System based on an estimated number of I/O points for the PLC based controls for the DFGD system:

       - Approximately 1,000 I/O points are required for each absorber unit DFGD system (including reagent preparation), for a total of 2,000 I/O points
       - Approximately 2,000 I/O points for the balance of plant for the DFGD system

11. Labor Costs

    Installation/labor costs were included in the base estimate under the direct costs. Manhours are estimated for each item in the base estimate and are based on the type of work and typical estimates for similar work. The labor costs are based on the labor wage rates and labor crews developed by S&L.

    a. Labor Wage Rates

       Crew labor rates were developed using prevailing craft rates, fringe benefits and state specific worker's compensation rates as published in the 2015 edition of R.S. Means Labor Rates for Lake Charles area. Costs were added to cover FICA, workers compensation, all applicable taxes, small tools, incidentals, construction equipment, and contractor's overhead. A 1.1 geographic labor productivity multiplier is included based on the Compass International Construction Yearbook for Louisiana. The crew rates do not include an allowance for weather related delays.

b. Labor crews

Construction/erection labor cost is based on the use of applicable construction crews typically required for projects of this type. The construction crew costs were specifically developed for utility industry and are proprietary to S&L. The prevailing craft rates are incorporated into work crews appropriate for the activities, and include costs for small tools, construction equipment, insurance, and site overheads.

12. Other Direct and Construction Indirect Costs

In addition to the base labor costs, other construction indirect costs for the project were broken out in the estimate as well as other contractor direct costs. The following items were included as other direct and construction indirect costs.

a. Scaffolding and Consumables
b. Premiums and per diems ($10 per hour)
c. Overtime is included based on five 10-hour shifts per week work schedule
d. Freight on construction materials
e. Sales Tax (included at a rate of 9.75% on all material costs)
f. Contractor's General & Administration Fees (included at 10% of total direct and construction indirect costs)
g. Contractor's Profit (included at 5% of total direct and construction indirect costs)

13. EPC Indirect Costs

The final contribution to the overall EPC project price are the EPC Contractor's indirect costs; these include the EPC engineering services, startup spare parts and initial fills, technical field advisors, and the EPC risk fee.

a. EPC Engineering Services

The EPC engineering services was estimated based on recent projects with similar scopes and schedules. The total cost of the EPC engineering services was estimated to be $18,000,000.

b. Startup Spare Parts and Initial Fills

An allowance has been included for initial fills for equipment, including first fills for lubrication of any motorized equipment. The initial fill of lime was not included in the EPC Contractor's scope, as this will be supplied by the Owner and is covered as part of the Owner's Costs. The total cost of the initial fills was estimated to be $250,000.

c. Technical Field Advisors (Vendors)

Allowances were included for equipment supplier's technical field advisory services based on an estimated 150 man-days. The estimate includes technical field advisors for the DSI system supplier (including DSI system subcontractors) and the DCS supplier. The total cost of the technical field advisors was estimated to be $400,000.

d. EPC Risk Fee

An EPC approach provides an alternative which is expected to reduce risk for Entergy by placing the responsibility for the project on a single entity, the EPC Contractor. The EPC Risk Fee is a premium included by the contractor which accounts for the additional coordination and management of the project as well as the additional risk assumed by the contractor (Based on S&L's experience with recent EPC projects, an EPC Risk Fee was included at 10% of the total EPC project costs.

14. Owner's Costs and Services

Outside of the EPC Contractor's total cost, Entergy will incur other costs associated with the project, such as services procured from third parties (including Owner's engineer, construction management support, startup and commissioning support and performance testing), and other project related costs.

a. Owner's Costs

Owner's Costs are direct costs that the Owner incurs over the life of the project. The following items are real costs Entergy will incur to install Dry FGD at Nelson 6 based on the scope and schedule of this project:

- Internal Labor
- Internal Indirects
- Travel Expenses
- Legal Services
- Builders Risk Insurance
- Initial Fills (Reagent)

Owner's costs were included in the estimate at 8% of the total project cost, excluding escalation.

b. Construction management support

The construction management support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The cost of labor is based on present day cost. The total cost of the Construction Management Support was estimated to be $3,500,000.

c. Startup and commissioning support

The startup and commissioning support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform this task, and therefore it will be outsourced. The total cost of the startup and commissioning support was estimated to be $420,000.

d. Owner's Engineer

The Owner's Engineer cost was developed as a high level estimate based on a typical scope for Owner's Engineer work for this type of project; including the following tasks:

- Conceptual Study Support
- EPC Specification Supporting Documents
- Project Schedule Development
- EPC Specification Development
- EPC Bid Evaluation and Contract Conformance
- General Project Support
  - Monthly Project Status Meetings
  - Weekly Teleconferences
  - Overall Coordination
  - Project Administration
  - Site Visits and Travel
- Permitting Support
- Design Review of Drawing Submittals
- Technical support during design, fabrication, construction, commissioning, and testing
- Equipment vendor QA/QC audits

The total cost of the Owner's Engineer was estimated to be $4,000,000.

e. Performance testing

The cost for performance testing was developed as a factored estimate using costs from projects of similar scope. This cost includes the testing, performed by a third-party contractor hired by the Owner, and also includes the cost for outside assistance in the following tasks:

- Development of the test protocol
- Procuring the services of the testing contractor
- Overseeing the performance test campaign
- Evaluating the results of the testing with respect to guarantee compliance

The estimate for the third party testing contractor is based on the assumption that the contractor would be onsite for up to 3 days. The total cost of the Performance Testing was estimated to be $175,000.

f. Contingency

Contingency is included in the estimate to cover the uncertainty associated with the project costs. The cost estimate includes a recommended contingency of 25%, which is consistent with cost estimating guidelines for a conceptual design and the current level of project definition. Contingency was applied to the total project costs before escalation.

g. Escalation

Escalation was included in the estimate based on a typical schedule for implementation of Dry FGD at an escalation rate of 2.15% on equipment and materials and 3.35% on labor and indirects. These escalation rates were developed by S&L based on recent pricing and in-house escalation projections.

h. Interest During Construction

Interest during construction (IDC) accounts for the time value of money associated with the distribution of construction cash flows over the construction period. IDC was applied to the total EPC project costs including contingency. The IDC was calculated based on a typical schedule for implementation of a DSI system and a typical interest rate of 7.8% per year which was assumed based on a low interest market environment.

## 4.2 VARIABLE OPERATING AND MAINTENANCE COSTS

The following unit costs were used to develop the variable Operating and Maintenance (O&M) costs. All of these values, with the exception of the reagent, bag and cage costs, were provided by Entergy and are consistent with typical industry values. The reagent, bag and cage costs are based on recent in-house data from similar projects.

**Table 3-1: Unit Pricing for Utilities**

| Unit Cost | Units | Value |
|---|---|---|
| Reagent (Lime) | $/ton | 130.0 |
| Make-up Water (High Quality) | $/1000 gal | 1.25 |
| Make-up Water (Low Quality) | $/1000 gal | 0.50 |
| Byproduct Waste Disposal | $/ton | 7.50 |
| Aux Power | $/MWh | 40.00 |
| Bag | $/bag | 80.0 |
| Cage | $/cage | 30.0 |

Table 3-2 below summarizes the consumption rates estimated as well as the first year variable O&M costs for the Dry FGD system.

**Table 3-2: Variable O&M Rates and First Year Costs**

| **Dry FGD System Parameters** | **Units** | **Value** |
|---|---|---|
| Reagent Consumption | lb/hr | 6,300 |
| Byproduct Waste Production | lb/hr | 12,700 |
| Aux Power Consumption | kW | 9,500 |
| Make-up Water Consumption (High Quality) | gpm | 40 |
| Make-up Water Consumption (Low Quality) | gpm | 620 |
| No. of Bags in Baghouse | | 14,000 |
| **First Year[1] Variable O&M Costs (@CF[2])** | | |
| Reagent Cost | $/year | 4,448,000 |
| Byproduct Waste Disposal Cost | $/year | 517,000 |
| Aux Power Cost | $/year | 4,128,000 |
| Water Cost | $/year | 235,000 |
| Bags and Cages Replacement[3] | $/year | 840,000 |
| **Total First Year Variable O&M Cost** | **$/year** | **10,168,000** |

Note 1: First year costs are provided in $2015.

Note 2: First year costs are calculated using an annual capacity factor of 62%.

Note 3: Bags will have to be replaced every 3 years and cages are replaced every 9 years.

## 4.3 FIXED O&M COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). Based on the conceptual design for the dry FGD system, the estimated staffing additions are 21 personnel. Operating Labor costs are estimated based on 4 shifts, 40 hours a week at an operator charge rate of $57/hour.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (maintenance and labor) were estimated to be approximately 1.1% of the total EPC cost.

Table 3-3 below summarizes the first year fixed O&M costs for the design case.

**Table 3-3: First Year Fixed O&M Costs for Dry FGD**

| First Year[1] Fixed O&M Costs | Units | Value |
|---|---|---|
| Operating Labor | \$/year | 2,490,000 |
| Maintenance Material | \$/year | 1,926,000 |
| Maintenance Labor | \$/year | 1,284,000 |
| **Total First Year Fixed O&M Cost** | **\$/year** | **5,700,000** |

Note 1: First year costs are provided in \$2015.

# 5. ATTACHMENTS

1. Entergy Louisiana - Nelson Station - Unit 6 Dry FGD Addition Conceptual Cost Estimate, Sargent & Lundy Estimate No. 33593A.

# ENTERGY LOUISIANA
# NELSON STATION - UNIT 6
# DRY FGD ADDITION EPC

| | |
|---|---|
| **Estimator** | A. KOCI |
| **Labor rate table** | 15LALAK |
| **Project No.** | 13027-003 |
| **Estimate Date** | 11/04/2015 |
| **Reviewed By** | BA |
| **Approved By** | MNO |
| **Estimate No.** | 33593A |
| **Cost index** | LALAK |

| Group | Phase | Description | Subcontract Cost | Process Equipment Cost | Material Cost | Man Hours | Labor Cost | Total Cost |
|---|---|---|---|---|---|---|---|---|
| 11.00.00 | | DEMOLITION | | | | | | |
| | 11.99.00 | DEMOLITION, MISCELLANEOUS | 1,000,000 | | | | | 1,000,000 |
| | | DEMOLITION | 1,000,000 | | | | | 1,000,000 |
| 21.00.00 | | CIVIL WORK | | | | | | |
| | 21.14.00 | STRIP & STOCKPILE TOPSOIL | | | | 2,437 | 420,826 | 420,826 |
| | 21.17.00 | EXCAVATION | | | | 366 | 27,145 | 27,145 |
| | 21.19.00 | DISPOSAL | | | | 107 | 7,924 | 7,924 |
| | 21.20.00 | BACKFILL | | | 19,216 | 99 | 7,353 | 26,569 |
| | 21.39.00 | STORM DRAINAGE UTILITIES | | | 71,500 | 2,200 | 172,783 | 244,283 |
| | 21.41.00 | EROSION AND SEDIMENTATION CONTROL | | | 383,400 | 1,188 | 112,325 | 495,725 |
| | 21.53.00 | PILING | | | 1,780,800 | 23,762 | 2,532,356 | 4,313,156 |
| | 21.54.00 | CAISSON | | | 74,280 | 968 | 103,170 | 177,450 |
| | 21.67.00 | SURVEY | 150,000 | | | | | 150,000 |
| | 21.99.00 | CIVIL WORK, MISCELLANEOUS | | | 390,000 | 4,400 | 326,513 | 716,513 |
| | | CIVIL WORK | 150,000 | | 2,719,196 | 35,528 | 3,710,395 | 6,579,591 |
| 22.00.00 | | CONCRETE | | | | | | |
| | 22.13.00 | CONCRETE | | | 1,238,493 | 38,560 | 2,445,481 | 3,683,974 |
| | 22.15.00 | EMBEDMENT | | | 45,353 | 832 | 46,542 | 91,894 |
| | 22.17.00 | FORMWORK | | | 14,115 | 1,242 | 107,231 | 121,346 |
| | 22.25.00 | REINFORCING | | | 203,258 | 3,927 | 195,041 | 398,298 |
| | | CONCRETE | | | 1,501,218 | 44,561 | 2,794,294 | 4,295,512 |
| 23.00.00 | | STEEL | | | | | | |
| | 23.15.00 | DUCTWORK | | | 2,981,760 | 60,656 | 6,195,370 | 9,177,130 |
| | 23.17.00 | GALLERY | | | 732,580 | 4,010 | 262,546 | 995,126 |
| | 23.25.00 | ROLLED SHAPE | | | 5,735,465 | 40,663 | 3,641,404 | 9,376,869 |
| | | STEEL | | | 9,449,805 | 105,329 | 10,099,320 | 19,549,125 |
| 24.00.00 | | ARCHITECTURAL | | | | | | |
| | 24.15.00 | DOOR (INCL. FRAME & HARDWARE) | | | 12,640 | 62 | 4,335 | 16,975 |
| | 24.33.00 | PLUMBING FIXTURE | | | 100,000 | 264 | 18,070 | 118,070 |
| | 24.35.00 | PRE-ENGINEERED BUILDING | 926,000 | | 20,000 | 110 | 9,851 | 955,851 |
| | 24.37.00 | ROOFING | | | 33,750 | 282 | 16,932 | 50,682 |
| | 24.41.00 | SIDING | | | 507,113 | 5,182 | 459,045 | 966,158 |
| | 24.45.00 | WINDOW (INCL. HARDWARE) | | | 14,200 | 18 | 860 | 15,060 |
| | 24.99.00 | ARCHITECTURAL, MISCELLANEOUS | | | 2,000 | 35 | 1,970 | 3,970 |
| | | ARCHITECTURAL | 926,000 | | 689,703 | 5,952 | 511,063 | 2,126,766 |
| 27.00.00 | | PAINTING & COATING | | | | | | |
| | 27.17.00 | PAINTING | 150,000 | | | | | 150,000 |
| | | PAINTING & COATING | 150,000 | | | | | 150,000 |
| 31.00.00 | | MECHANICAL EQUIPMENT | | | | | | |
| | 31.17.00 | COMPRESSOR & ACCESSORIES | | 692,000 | | 1,681 | 106,674 | 798,674 |
| | 31.25.00 | CRANES & HOISTS | | 208,000 | | 282 | 17,872 | 225,872 |
| | 31.27.00 | DAMPERS & ACCESSORIES | | 620,000 | | 2,693 | 170,902 | 790,902 |
| | 31.33.00 | EXPANSION JOINT | | 462,500 | | 5,088 | 519,689 | 982,189 |

| Group | Phase | Description | Subcontract Cost | Process Equipment Cost | Material Cost | Man Hours | Labor Cost | Total Cost |
|---|---|---|---|---|---|---|---|---|
| | 31.35.00 | FANS & ACCESSORIES (EXCL HVAC) | | 5,160,000 | | 9,241 | 586,429 | 5,746,429 |
| | 31.41.00 | FIRE PROTECTION EQUIPMENT & SYSTEM | | | 79,000 | 352 | 22,175 | 101,175 |
| | 31.45.00 | FGD EQUIPMENT | | 41,000,000 | | | 37,850,000 | 78,850,000 |
| | 31.51.00 | MERCURY REMOVAL EQUIPMENT | 100,000 | | 138,000 | 2,011 | 116,000 | 354,000 |
| | 31.75.00 | PUMP | | 297,200 | | 510 | 32,393 | 329,593 |
| | 31.83.00 | TANK | 429,000 | | | | | 429,000 |
| | | MECHANICAL EQUIPMENT | 529,000 | 48,439,700 | 217,000 | 21,858 | 39,422,135 | 88,607,835 |
| 33.00.00 | | MATERIAL HANDLING EQUIPMENT | | | | | | |
| | 33.13.00 | BYPRODUCT HANDLING EQUIPMENT | | 4,140,000 | | 25,303 | 1,691,804 | 5,831,804 |
| | 33.43.00 | PNEUMATIC HANDLING SYSTEM | | 250,000 | | 2,750 | 174,532 | 424,532 |
| | 33.99.00 | MATERIAL HANDLING EQUIPMENT, MISCELLANEOUS | | 10,000 | | 66 | 4,189 | 14,189 |
| | | MATERIAL HANDLING EQUIPMENT | | 4,400,000 | | 28,119 | 1,870,525 | 6,270,525 |
| 34.00.00 | | HVAC | | | | | | |
| | 34.31.00 | DAMPER | | | 5,500 | 154 | 10,662 | 16,162 |
| | 34.41.00 | FAN | | | 45,000 | 106 | 7,311 | 52,311 |
| | 34.53.00 | UNIT HEATER | | | 38,000 | 176 | 12,186 | 50,186 |
| | | HVAC | | | 88,500 | 436 | 30,160 | 118,660 |
| 35.00.00 | | PIPING | | | | | | |
| | 35.13.01 | SS 304, ABOVE GROUND, PROCESS AREA | | | 28,160 | 944 | 80,816 | 108,976 |
| | 35.13.02 | SS 316, ABOVE GROUND, PROCESS AREA | | | 5,025 | 256 | 21,887 | 26,912 |
| | 35.13.10 | CARBON STEEL, ABOVE GROUND, PROCESS AREA | | | 101,775 | 6,900 | 590,424 | 692,199 |
| | 35.13.45 | MISC. ABOVE GROUND, PROCESS AREA | | | 30,000 | 550 | 47,068 | 77,068 |
| | 35.14.10 | CARBON STEEL, STRAIGHT RUN | | | 46,280 | 2,548 | 218,020 | 264,300 |
| | 35.35.00 | PIPE SUPPORTS, HANGERS | | | 99,082 | 4,536 | 388,153 | 487,235 |
| | 35.36.00 | PIPE SUPPORTS, RACK | | | 1,560 | 704 | 60,247 | 61,807 |
| | 35.45.00 | VALVES | | | 226,600 | 506 | 43,284 | 269,884 |
| | | PIPING | | | 538,482 | 16,944 | 1,449,898 | 1,988,380 |
| 36.00.00 | | INSULATION | | | | | | |
| | 36.13.00 | DUCT | | | 1,723,293 | 65,624 | 3,686,771 | 5,410,064 |
| | 36.15.00 | EQUIPMENT | | | 328 | 11,155 | 626,694 | 627,022 |
| | 36.17.03 | PIPE, MINERAL WOOL W/ALUMINUM JACKETING | | | 71,333 | 2,454 | 137,867 | 209,199 |
| | | INSULATION | | | 1,794,953 | 79,233 | 4,451,332 | 6,246,285 |
| 41.00.00 | | ELECTRICAL EQUIPMENT | | | | | | |
| | 41.99.00 | ELECTRICAL EQUIPMENT, MISCELLANEOUS | | 9,500,000 | 4,700,000 | | 13,100,000 | 27,300,000 |
| | | ELECTRICAL EQUIPMENT | | 9,500,000 | 4,700,000 | | 13,100,000 | 27,300,000 |
| 44.00.00 | | CONTROL & INSTRUMENTATION | | | | | | |
| | 44.99.00 | CONTROL & INSTRUMENTATION, ALLOWANCE | 4,500,000 | | | | | 4,500,000 |
| | | CONTROL & INSTRUMENTATION | 4,500,000 | | | | | 4,500,000 |
| | | TOTAL DIRECT | 7,255,000 | 62,339,700 | 21,698,856 | 337,959 | 77,439,123 | 168,732,679 |

## Estimate Totals

| Description | Amount | Totals | Hours |
|---|---|---|---|
| **Direct Costs:** | | | |
| Labor | 77,439,123 | | 337,959 |
| Material | 21,698,856 | | |
| Subcontract | 7,255,000 | | |
| Process Equipment | 62,339,700 | | |
| | **168,732,679** | **168,732,679** | |
| **Other Direct & Construction Indirect Costs:** | | | |
| 91-1 Scaffolding | 5,420,721 | | |
| 91-2 Cost Due To OT 5-10's | 10,520,400 | | |
| 91-4 Per Diem | 3,379,600 | | |
| 91-5 Consumables | 774,400 | | |
| 91-6 Freight on Material | 1,084,900 | | |
| 91-8 Sales Tax | 2,433,600 | | |
| 91-9 Contractors G&A | 12,253,900 | | |
| 91-10 Contractors Profit | 6,127,000 | | |
| | **41,994,521** | **210,727,200** | |
| **Indirect Costs:** | | | |
| 93-1 Engineering Services | 18,000,000 | | |
| 93-4 SU/S Parts/ Initial Fills | 250,000 | | |
| 93-5 Technical Field Advisors | 400,000 | | |
| 93-8 EPC Fee | 22,937,700 | | |
| | **41,587,700** | **252,314,900** | |
| **Escalation:** | | | |
| 96-1 Escalation on Material | 3,291,100 | | |
| 96-2 Escalation on Labor | 20,396,700 | | |
| 96-3 Escalation on Subcontract | 1,357,900 | | |
| 96-4 Escalation on Process Eq | 7,134,800 | | |
| 96-5 Escalation on Indirects | 7,562,600 | | |
| | **39,743,100** | **292,058,000** | |
| ***Total EPC Cost*** | | ***292,058,000*** | |
| **Owner's Costs:** | | | |
| 99-1 Owner's Costs | 20,185,200 | | |
| | **20,185,200** | **312,243,200** | |
| **Third Party Services:** | | | |
| 100 CM Oversight | 3,500,000 | | |
| 101 Start-Up Oversight | 420,000 | | |
| 102 Owner's Engineer | 4,000,000 | | |
| 103 Performance Testing | 175,000 | | |
| | **8,095,000** | **320,338,200** | |
| **Project Contingency :** | | | |
| 110 Project Contingency | 70,148,800 | | |
| | **70,148,800** | **390,487,000** | |
| **Escalation Addition:** | | | |
| 120 Escalation on Lines 99-110 | 4,358,800 | | |
| | **4,358,800** | **394,845,800** | |
| **Interest During Construction:** | | | |
| 130 Interest During Constr. | 52,466,600 | | |
| | **52,466,600** | **447,312,400** | |
| ***Total*** | | ***447,312,400*** | |

NELSON UNIT 6

# DSI COST ESTIMATE BASIS DOCUMENT

**Revision 0**
November 6, 2015
Project 13027-003

Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

# 1. PURPOSE

Entergy has requested that S&L support their Best Available Retrofit Technology (BART) evaluation for Nelson Unit 6 with respect to $SO_2$ emissions. As part of this effort, Entergy has requested that S&L perform a technology evaluation and cost estimate to install a new dry sorbent injection (DSI) system on Nelson Unit 6. System costs were scaled from other DSI projects recently completed. The purpose of this document is to define the project scope and identify the assumptions that were used as the basis for the operating and maintenance (O&M) and the AACE Level 5 capital cost estimates.

# 2. TECHNOLOGY DESCRIPTION

DSI is a proven technology, which has only recently been implemented, for moderate removal of $SO_2$ and other acid gases from coal-fired power plants. It involves injection of sodium-based sorbents into the ductwork after the boiler and prior to the particulate collection device. DSI is a relatively low capital cost, moderate $SO_2$ removal alternative to wet or dry FGD systems. No slurry equipment or separate reactor vessel is required with a DSI system. With the proper temperature profile and stoichiometry, the sorbent can effectively react with $SO_2$ and other acid gases in the flue gas. The resulting particulate matter is removed from the flue gas by a particulate collection device, typically an existing electrostatic precipitator (ESP).

The typical DSI sorbents include sodium bicarbonate ($NaHCO_3$) and Trona ($Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$). Sorbent injection into the ductwork (downstream of the boiler and upstream of the ESP) is a technology that has been tested using sodium-based sorbents. The $SO_2$ in the flue gas reacts to form sodium sulfate and sulfite. The process works through neutralization of $SO_2$ and other acid gases with the caustic sorbent; the neutralization occurs as long as the sorbent remains in contact with the gas. Sorbent injection has been proven effective on a variety of pulverized coal-fired boilers using a range of low to high sulfur coals. It is considered a commercial technology although with a limited supplier base due to the historically limited interest.

The DSI process produces a dry byproduct which can be landfilled. The waste products will contain $NaSO_3$/$NaSO_4$ along with the unused sorbent and the normal fly ash. These wastes will be collected in the ESP and can be transported with conventional pneumatic fly ash handling equipment. The waste from sodium-based sorbents will have relatively high concentrations of soluble salts, which may affect the byproduct handling. With the addition of dry sorbent byproducts fly ash cannot be sold for reuse.

# 3. APPROACH

The project capital and O&M cost estimates are based on project-specific information, including:

- An engineer-procure-construct (EPC) contracting strategy with the DSI technology supplier providing the main process equipment, including reagent storage, milling, conveyance, injection lances.
- On-site disposal of DSI byproduct with existing ESP ash handling equipment. The byproduct will be collected in the existing ESP in conjunction with the fly ash from the unit and stored in a new concrete byproduct storage silo; no additional blending equipment is required. It was assumed that the existing ash handling equipment will be sufficient to accommodate the increase loading.
- The design injection rate for the equipment is based on 40% $SO_2$ removal from an uncontrolled $SO_2$ rate of 0.96 lb $SO_2$/MMBtu, based on the maximum 24-hour average emissions between 2012 and 2014 which is consistent with the range of coal sulfur. Either sodium bicarbonate (SBC) or Trona can be used as the DSI reagent; for the purposes of this estimate Trona was used as the design reagent as this typically requires a higher injection rate and is therefore a more conservative design basis for this system. Reagent injection will be at the APH outlet, upstream of the existing ESP.
    - Annual operating costs will be based on 40% $SO_2$ removal from an uncontrolled $SO_2$ rate of 0.70 lb $SO_2$/MMBtu, based on the annual average emissions from 2012 to 2014.
    - The system will be designed to control emissions to meet a permit limit of 0.47 lb/MMBtu on a 30-boiler day rolling average, based on a maximum 30-day average $SO_2$ emission rate of 0.74 lb/MMBtu between 2012 and 2014.
- Increase in carbon consumption by 1 lb/mmacf to mitigate any impacts on mercury performance associated with ACI/DSI interference.
- The cost estimate incorporates the results of a conceptual system design developed as input to the DSI estimate. The following items were estimated based on previous projects and scaled for the predicted dry sorbent injection rate for Nelson Unit 6:
    - Auxiliary power consumption
    - Annual reagent consumption
    - Additional carbon consumption
    - Additional water consumption
    - Additional waste production
    - Reagent storage silos – quantity and size, based on approximately 10 days storage

- Byproduct storage silo
- Quantity of mills
- Quantity of blower trains

The total plant capital cost estimate includes the following:

- Equipment and material
- Installation labor
- Indirect field costs
- Freight
- Sales Tax
- General and Administration
- Erection contractor profit
- Engineering, Procurement and Project Services
- Spare parts/initial fills (other than reagent)
- EPC Fee

As part of this project, S&L estimated the costs for Owner's services and costs outside of the EPC contract including the following:

- Owner's Costs
- Owner's Engineer
- Construction Management Support
- Startup and Commissioning Support
- Performance Testing
- Contingency
- Escalation
- Interest During Construction

Cost Estimate 33591A provided in Attachment 1 represents the total cost to Entergy to install DSI technology on Nelson Unit 6 including the EPC Contract price and all additional Owner's costs and third party services.

The total unit O&M cost estimate includes the following:

- Waste disposal (DSI waste + increased carbon + unsold fly ash)
- Loss of fly ash sales
- Reagent consumption (including increased carbon consumption)
- Auxiliary power consumption
- Low quality water consumption for mill cleaning
- Operating labor
- Maintenance material
- Maintenance labor

The O&M Estimate and Cost Estimate 33591A were developed using the assumptions and scope provided in this document. The project definition and accuracy of the individual components included in this estimate result in an overall accuracy of -20 to +50%.

# 4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS

The following assumptions were made for the design basis for the Nelson Unit 6 DSI System:

- Design $SO_2$ inlet concentration of 0.96 lb $SO_2$/MMBtu for equipment design.
- $SO_2$ inlet concentration of 0.70 lb $SO_2$/MMBtu for annual operating costs.
- Design $SO_2$ removal efficiency of 40%.
- Permitted $SO_2$ Emission Limit of 0.47 lb $SO_2$/MMBtu.
- Annual capacity factor of 62%, based on historical operating data.
- Reagent injection at the APH outlet, upstream of the existing ESP.
- Reagent delivery by truck.
- Carbon silo storage time will be reduced, rather than adding additional storage silos to system.
- Compliance deadline of June 2021.

## 4.1 TOTAL INSTALLED CAPITAL INVESTMENT

The DSI system supplier will provide all of the equipment related to storing, milling, conveying and injecting the reagent; in this case, the system is designed for Trona. The remaining BOP scope will be provided by the EPC Contractor. In addition, the EPC Contractor will install/construct the entire system including the equipment provided by the DSI system supplier.

Quantities were developed based on limited project design effort, project experience of a plant of comparable size and then adjusted based on actual size and capacity differences and also taking into consideration the specific site layout based on the general arrangement. In most cases, the costs for bulk materials and equipment were derived from S&L database and recent vendor or manufacturer's quote for similar items on other projects. The scope of work for the capital cost estimate is broken out by area below:

1. DSI System Area:
   a. Reagent unloading systems:
      - Two trains (2 x 100%)
      - Pneumatic pressure blowers (1 x 100%) per train
      - One dehumidifier and chiller per train
      - Pneumatic conveying piping located on an above-grade sleeper pipe rack
      - Unloading equipment is based on recent pricing for a similar project
   b. Reagent Storage:
      - Six silos capable of storing approximately 10 days of sorbent, 2,100-tons storage total, including substructure
      - 14' diameter and 125' high, each
      - 350-tons working storage, each
      - Continuous level detection systems
      - Six bin vent filters for six silos
      - Live bottom hopper outlets
      - Rotary airlock assemblies
   c. Reagent conveying systems:
      - Two trains (2 x 100%)
      - Pneumatic pressure blowers (1 x 100%) per train
      - One dehumidifier and chiller per train

b. Reagent Milling
   - One 7.5-tph mill per train
   - One set of bypass piping per mill
c. Reagent Injection
   - Splitters with piping to two APH inlets
   - Six injection lances per injection location
d. Concrete foundations including piles for all reagent silo, blower, and mill areas
e. Blower and mill area superstructures
f. Equipment pricing based on recent vendor pricing for a similar project

2. <u>Byproduct Handling</u>
   a. One DSI by-product storage silo (approximately 7-day capacity) with bin vent filter, fluidizing system, and unloading conditioners (pin mixers)
   b. Water pumps and associated piping for unloading conditioners
   c. Compressed air system for air operated valves
   d. Storage silo substructure and superstructure
   e. Concrete foundations including piles for silos
   f. Continuous level detection system
   g. One lot pneumatic conveying piping located on an above grade pipe rack
   h. Two truck scales and substructure
   i. Cost estimate based on a recent budgetary proposal for similar project

3. <u>Civil Work</u>
   a. Site grading
   b. Soil removal earthwork
   c. Excavation, backfill, and compaction for all foundations
   d. Development of a new laydown area, approximately 2 acres, including site preparation, fencing, and temporary power. It was assumed that this area would be located on existing plant property, and does not require land to be purchased.

4. <u>Mechanical Work</u>
   a. Allowance of $1,500,000 provided for mechanical systems including transport piping, pipe rack, instrument/service air, and other miscellaneous items based on recent in-house cost estimates for similar projects

5. Demolition and Relocation

   a. Allowance of $1,000,000 is provided for demolition and relocation of existing equipment and buildings that may interfere with the new DSI system based on recent in-house cost estimates for similar projects

6. Electrical

   a. Allowance of $5,000,000 is provided for electrical equipment upgrades and modifications based on recent in-house cost estimates for similar projects

7. Instrumentation

   a. Allowance of $600,000 is provided for DCS upgrades and added instrumentation based on recent in-house cost estimates for similar projects

8. Labor Costs

   Installation/labor costs were included in the base estimate under the direct costs. Manhours are estimated for each item in the base estimate and are based on the type of work and typical estimates for similar work. The labor costs are based on the labor wage rates and labor crews developed by S&L.

   a. Labor Wage Rates

      Crew labor rates were developed using prevailing craft rates, fringe benefits and state specific worker's compensation rates as published in the 2015 edition of R.S. Means Labor Rates for Lake Charles area. Costs were added to cover FICA, workers compensation, all applicable taxes, small tools, incidentals, construction equipment, and contractor's overhead. A 1.1 geographic labor productivity multiplier is included based on the Compass International Construction Yearbook for Louisiana. The crew rates do not include an allowance for weather related delays.

   b. Labor crews

      Construction/erection labor cost is based on the use of applicable construction crews typically required for projects of this type. The construction crew costs were specifically developed for utility industry and are proprietary to S&L. The prevailing craft rates are incorporated into work crews appropriate for the activities, and include costs for small tools, construction equipment, insurance, and site overheads.

9. Other Direct and Construction Indirect Costs

   In addition to the base labor costs, other construction indirect costs for the project were broken out in the estimate as well as other contractor direct costs. The following items were included as other direct and construction indirect costs.

   a. Scaffolding and Consumables

   b. Premiums and per diems ($10 per hour)

   c. Overtime is included based on five 10-hour shifts per week work schedule

   d. Freight on construction materials

e. Sales Tax (included at a rate of 9.75% on all material costs)

f. Contractor's General & Administration Fees (included at 10% of total direct and construction indirect costs)

g. Contractor's Profit (included at 5% of total direct and construction indirect costs)

10. EPC Indirect Costs

The final contribution to the overall EPC project price are the EPC Contractor's indirect costs; these include the EPC engineering services, startup spare parts and initial fills, technical field advisors, and the EPC risk fee.

a. EPC Engineering Services

The EPC engineering services was estimated based on recent projects with similar scopes and schedules. The total cost of the EPC engineering services was estimated to be $3,500,000.

b. Startup Spare Parts and Initial Fills

An allowance has been included for initial fills for equipment, including first fills for lubrication of any motorized equipment. The initial fill of Trona was not included in the EPC Contractor's scope, as this will be supplied by the Owner and is covered as part of the Owner's Costs. The total cost of the initial fills was estimated to be $65,000.

c. Technical Field Advisors (Vendors)

Allowances were included for equipment supplier's technical field advisory services based on an estimated 150 man-days. The estimate includes technical field advisors for the DSI system supplier (including DSI system subcontractors) and the DCS supplier. The total cost of the technical field advisors was estimated to be $200,000.

d. EPC Risk Fee

An EPC approach provides an alternative which is expected to reduce risk for Entergy by placing the responsibility for the project on a single entity, the EPC Contractor. The EPC Risk Fee is a premium included by the contractor which accounts for the additional coordination and management of the project as well as the additional risk assumed by the contractor (Based on S&L's experience with recent EPC projects, an EPC Risk Fee was included at 10% of the total EPC project costs.

11. Owner's Costs and Services

Outside of the EPC Contractor's total cost, Entergy will incur other costs associated with the project, such as services procured from third parties (including Owner's engineer, construction management support, startup and commissioning support and performance testing), and other project related costs.

a. Owner's Costs

Owner's Costs are direct costs that the Owner incurs over the life of the project. The following items are real costs Entergy will incur to install DSI at Nelson 6 based on the scope and schedule of this project:

- Internal Labor
- Internal Indirects
- Travel Expenses
- Legal Services
- Builders Risk Insurance
- Initial Fills (Reagent)

Owner's costs were included in the estimate at 8% of the total project cost, excluding escalation.

b. Construction management support

The construction management support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The cost of labor is based on present day cost. The total cost of the Construction Management Support was estimated to be $1,600,000.

c. Startup and commissioning support

The startup and commissioning support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform this task, and therefore it will be outsourced. The total cost of the startup and commissioning support was estimated to be $200,000.

d. Owner's Engineer

The Owner's Engineer cost was developed as a high level estimate based on a typical scope for Owner's Engineer work for this type of project; including the following tasks:

- Conceptual Study Support
- EPC Specification Supporting Documents
- Project Schedule Development
- EPC Specification Development
- EPC Bid Evaluation and Contract Conformance
- General Project Support
    - Monthly Project Status Meetings
    - Weekly Teleconferences
    - Overall Coordination
    - Project Administration
    - Site Visits and Travel
- Permitting Support
- Design Review of Drawing Submittals
- Technical support during design, fabrication, construction, commissioning, and testing

- Equipment vendor QA/QC audits

The total cost of the Owner's Engineer was estimated to be $2,750,000.

e. Performance testing

The cost for performance testing was developed as a factored estimate using costs from projects of similar scope. This cost includes the testing, performed by a third-party contractor hired by the Owner, and also includes the cost for outside assistance in the following tasks:

- Development of the test protocol
- Procuring the services of the testing contractor
- Overseeing the performance test campaign
- Evaluating the results of the testing with respect to guarantee compliance

The estimate for the third party testing contractor is based on the assumption that the contractor would be onsite for up to 3 days. The total cost of the Performance Testing was estimated to be $175,000.

f. Contingency

Contingency is included in the estimate to cover the uncertainty associated with the project costs. The cost estimate includes a recommended contingency of 25%, which is consistent with cost estimating guidelines for a conceptual design and the current level of project definition. Contingency was applied to the total project costs before escalation.

g. Escalation

Escalation was included in the estimate based on a typical schedule for implementation of a DSI system at an escalation rate of 2.15% on equipment and materials and 3.35% on labor and indirects. These escalation rates were developed by S&L based on recent pricing and in-house escalation projections.

h. Interest During Construction

Interest during construction (IDC) accounts for the time value of money associated with the distribution of construction cash flows over the construction period. IDC was applied to the total EPC project costs including contingency. The IDC was calculated based on a typical schedule for implementation of a DSI system and a typical interest rate of 7.8% per year which was assumed based on a low interest market environment.

## 4.2 VARIABLE OPERATING AND MAINTENANCE COSTS

The following unit costs were used to develop the variable O&M costs. All of these values, with the exception of the reagent costs, were provided by Entergy. The reagent costs are based on recent in-house pricing.

**Table 1: Unit Pricing for Utilities**

| Unit Cost | Units | Value |
|---|---|---|
| Trona | $/ton | 275.00 |
| Carbon | $/ton | 1,700 |
| Low Quality Water | $/1000 gal | 0.50 |
| Waste Disposal | $/ton | 7.50 |
| Fly Ash Revenue | $/ton | 8.00 |
| Aux Power Cost | $/MWh | 40.00 |

Table 2 below summarizes the consumption rates estimated as well as the first year variable O&M costs.

**Table 2: Variable O&M Rates and First Year Costs**

| DSI System Parameters | Units | Value |
|---|---|---|
| Reagent Consumption | lb/hr | 12,600 |
| Increased Carbon Consumption | lb/hr | 160 |
| DSI Waste/Carbon/Unsold Fly Ash Rate | lb/hr | 38,800 |
| Aux Power Consumption | kW | 1,000 |
| Low Quality Water Consumption | gpm | 3 |
| **First Year[1] Variable O&M Costs (@CF[2])** | | |
| Reagent Cost | $/year | 9,410,000 |
| Waste Disposal Cost | $/year | 790,000 |
| Increased Carbon Consumption Cost | $/year | 739,000 |
| Aux Power Cost | $/year | 217,000 |
| Low Quality Water Cost | $/year | 500 |
| Loss of Fly Ash Sales[3] | $/year | 621,000 |
| **Total First Year Variable O&M Cost** | **$/year** | **11,777,500** |

Note 1: First year costs are provided in $2015.

Note 2: The first year costs are calculated using an annual capacity factor of 62%.

Note 3: Assumes 100% of the station's fly ash was being sold on an annual basis for an average of approximately $8.00 per ton.

### 4.3 FIXED O&M COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). It was assumed that no additional operating personnel would be necessary for the DSI system; the system will be controlled through the existing control room.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (maintenance and labor) were estimated to be approximately 1.6% of the total EPC cost.

Table 3 below summarizes the first year fixed O&M costs for the DSI system.

**Table 3: Fixed O&M First Year Costs**

| First Year[1] Fixed O&M Costs | Units | Value |
|---|---|---|
| Operating Labor | $/year | 0 |
| Maintenance Material | $/year | 702,000 |
| Maintenance Labor | $/year | 468,000 |
| **Total First Year Fixed O&M Cost** | **$/year** | **1,170,000** |

Note 1: First year costs are provided in $2015.

## 5. ATTACHMENTS

1. Entergy Louisiana - Nelson Station - Unit 6 DSI System (40% $SO_2$ Reduction) EPC Conceptual Cost Estimate, Sargent & Lundy Estimate No. 33591A.

# ENTERGY LOUISIANA
# NELSON STATION - UNIT 6
# DSI SYSTEM (40% SO2 REDUCTION) EPC

| | |
|---|---|
| **Estimator** | A. KOCI |
| **Labor rate table** | 15LALAK |
| **Project No.** | 13027-003 |
| **Estimate Date** | 11/04/2015 |
| **Reviewed By** | BA |
| **Approved By** | MNO |
| **Estimate No.** | 33591A |
| **Cost index** | LALAK |

| Group | Phase | Description | Subcontract Cost | Process Equipment Cost | Material Cost | Man Hours | Labor Cost | Total Cost |
|---|---|---|---|---|---|---|---|---|
| 11.00.00 | | DEMOLITION | | | | | | |
| | 11.99.00 | DEMOLITION, MISCELLANEOUS | 1,000,000 | | | | | 1,000,000 |
| | | DEMOLITION | 1,000,000 | | | | | 1,000,000 |
| 21.00.00 | | CIVIL WORK | | | | | | |
| | 21.14.00 | STRIP & STOCKPILE TOPSOIL | | | | 118 | 20,386 | 20,386 |
| | 21.17.00 | EXCAVATION | | | | 792 | 58,772 | 58,772 |
| | 21.39.00 | STORM DRAINAGE UTILITIES | | | 44,000 | 880 | 69,113 | 113,113 |
| | 21.41.00 | EROSION AND SEDIMENTATION CONTROL | | | 29,820 | 92 | 8,736 | 38,556 |
| | 21.53.00 | PILING | | | 244,860 | 3,267 | 348,199 | 593,059 |
| | 21.54.00 | CAISSON | | | 133,704 | 1,743 | 185,706 | 319,410 |
| | 21.99.00 | CIVIL WORK, MISCELLANEOUS | | | 156,000 | 1,760 | 130,605 | 286,605 |
| | | CIVIL WORK | | | 608,384 | 8,653 | 821,518 | 1,429,902 |
| 22.00.00 | | CONCRETE | | | | | | |
| | 22.13.00 | CONCRETE | | | 326,140 | 10,920 | 692,527 | 1,018,667 |
| | | CONCRETE | | | 326,140 | 10,920 | 692,527 | 1,018,667 |
| 23.00.00 | | STEEL | | | | | | |
| | 23.25.00 | ROLLED SHAPE | | | 92,160 | 634 | 56,745 | 148,905 |
| | | STEEL | | | 92,160 | 634 | 56,745 | 148,905 |
| 24.00.00 | | ARCHITECTURAL | | | | | | |
| | 24.35.00 | PRE-ENGINEERED BUILDING | | | 10,000 | 110 | 9,851 | 19,851 |
| | 24.37.00 | ROOFING | | | 56,304 | 333 | 19,994 | 76,298 |
| | 24.41.00 | SIDING | | | 62,597 | 370 | 32,787 | 95,384 |
| | 24.99.00 | ARCHITECTURAL, MISCELLANEOUS | | | 35,900 | 1,023 | 78,592 | 114,492 |
| | | ARCHITECTURAL | | | 164,801 | 1,836 | 141,224 | 306,025 |
| 26.00.00 | | MISCELLANEOUS STRUCTURAL ITEM | | | | | | |
| | 26.13.00 | CONCRETE SILO | 4,200,000 | 40,000 | | 0 | | 4,240,000 |
| | | MISCELLANEOUS STRUCTURAL ITEM | 4,200,000 | 40,000 | | 0 | | 4,240,000 |
| 31.00.00 | | MECHANICAL EQUIPMENT | | | | | | |
| | 31.99.00 | MECHANICAL EQUIPMENT, MISCELLANEOUS | 1,500,000 | 8,600,000 | | | 7,940,000 | 18,040,000 |
| | | MECHANICAL EQUIPMENT | 1,500,000 | 8,600,000 | | | 7,940,000 | 18,040,000 |
| 33.00.00 | | MATERIAL HANDLING EQUIPMENT | | | | | | |
| | 33.13.00 | BYPRODUCT HANDLING EQUIPMENT | | 6,335,000 | | 53,793 | 3,817,655 | 10,152,655 |
| | 33.57.00 | SCALE | | 182,000 | | 440 | 27,925 | 209,925 |
| | | MATERIAL HANDLING EQUIPMENT | | 6,517,000 | | 54,233 | 3,845,580 | 10,362,580 |
| 34.00.00 | | HVAC | | | | | | |
| | 34.37.00 | DUST COLLECTOR | 113,100 | | | | | 113,100 |
| | | HVAC | 113,100 | | | | | 113,100 |
| 35.00.00 | | PIPING | | | | | | |
| | 35.14.10 | CARBON STEEL, STRAIGHT RUN | | | 49,600 | 759 | 64,954 | 114,554 |
| | | PIPING | | | 49,600 | 759 | 64,954 | 114,554 |

| Group | Phase | Description | Subcontract Cost | Process Equipment Cost | Material Cost | Man Hours | Labor Cost | Total Cost |
|---|---|---|---|---|---|---|---|---|
| 41.00.00 | | ELECTRICAL EQUIPMENT | | | | | | |
| | 41.99.00 | ELECTRICAL EQUIPMENT, MISCELLANEOUS | 5,000,000 | | | | | 5,000,000 |
| | | ELECTRICAL EQUIPMENT | 5,000,000 | | | | | 5,000,000 |
| 44.00.00 | | CONTROL & INSTRUMENTATION | | | | | | |
| | 44.99.00 | CONTROL & INSTRUMENTATION, ALLOWANCE | 600,000 | | | | | 600,000 |
| | | CONTROL & INSTRUMENTATION | 600,000 | | | | | 600,000 |
| 71.00.00 | | PROJECT INDIRECT | | | | | | |
| | 71.25.00 | CONSULTANT, THIRD PARTY | 150,000 | | | | | 150,000 |
| | | PROJECT INDIRECT | 150,000 | | | | | 150,000 |
| | | TOTAL DIRECT | 12,563,100 | 15,157,000 | 1,241,085 | 77,034 | 13,562,548 | 42,523,733 |

## Estimate Totals

| Description | Amount | Totals | Hours |
|---|---|---|---|
| **Direct Costs:** | | | |
| Labor | 13,562,548 | | 77,034 |
| Material | 1,241,085 | | |
| Subcontract | 12,563,100 | | |
| Process Equipment | 15,157,000 | | |
| | **42,523,733** | **42,523,733** | |
| **Other Direct & Construction Indirect Costs:** | | | |
| 91-1 Scaffolding | 949,367 | | |
| 91-2 Cost Due To OT 5-10's | 1,858,100 | | |
| 91-4 Per Diem | 770,300 | | |
| 91-5 Consumables | 135,600 | | |
| 91-6 Freight on Material | 62,100 | | |
| 91-8 Sales Tax | 678,300 | | |
| 91-9 Contractors G&A | 1,870,600 | | |
| 91-10 Contractors Profit | 935,300 | | |
| | **7,259,667** | **49,783,400** | |
| **Indirect Costs:** | | | |
| 93-1 Engineering Services | 3,500,000 | | |
| 93-4 SU/S Parts/ Initial Fills | 65,000 | | |
| 93-5 Technical Field Advisors | 200,000 | | |
| 93-8 EPC Fee | 5,354,800 | | |
| | **9,119,800** | **58,903,200** | |
| **Escalation:** | | | |
| 96-1 Escalation on Material | 239,700 | | |
| 96-2 Escalation on Labor | 4,627,200 | | |
| 96-3 Escalation on Subcontract | 3,054,400 | | |
| 96-4 Escalation on Process Eq | 2,209,200 | | |
| 96-5 Escalation on Indirects | 2,124,100 | | |
| | **12,254,600** | **71,157,800** | |
| ***Total EPC Cost*** | | ***71,157,800*** | |
| **Owner's Costs:** | | | |
| 99-1 Owner's Costs | 4,712,300 | | |
| | **4,712,300** | **75,870,100** | |
| **Third Party Services:** | | | |
| 100 CM Oversight | 1,600,000 | | |
| 101 Start-Up Oversight | 200,000 | | |
| 102 Owner's Engineer | 2,750,000 | | |
| 103 Performance Testing | 175,000 | | |
| | **4,725,000** | **80,595,100** | |
| **Project Contingency :** | | | |
| 110 Project Contingency | 17,085,300 | | |
| | **17,085,300** | **97,680,400** | |
| **Escalation Addition:** | | | |
| 120 Escalation on Lines 99-110 | 2,036,900 | | |
| | **2,036,900** | **99,717,300** | |
| **Interest During Construction:** | | | |
| 130 Interest During Constr. | 4,839,600 | | |
| | **4,839,600** | **104,556,900** | |
| ***Total*** | | ***104,556,900*** | |

NELSON UNIT 6

# ENHANCED DSI COST ESTIMATE BASIS DOCUMENT

**Revision 0**
November 6, 2015
Project 13027-003

Prepared by

Sargent & Lundy LLC

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