Review and Comments on Reasonable Progress Four-Factor Analyses for Sulfur Dioxide and Nitrogen Oxide Pollution Controls Evaluated as Part of the Louisiana Regional Haze Plan for the Second Implementation Period

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I. Introduction

The Clean Air Act's regional haze provisions require states to adopt periodic, comprehensive revisions to their implementation plans for regional haze on 10-year increments to achieve reasonable progress towards the national visibility goal. The next plan revision for the second implementation period must be submitted to EPA by July 31, 2021.[1] As part of the comprehensive revisions to their regional haze plan, states must submit a long-term strategy that includes enforceable emission limits and other measures as may be necessary to make reasonable progress towards the national visibility goal.[2]

To that end, in May of 2021, the Louisiana Department of Environmental Quality (LDEQ) made available its plan for addressing reasonable progress toward the national visibility goal for Class I areas.[3] LDEQ has proposed to include orders resulting from existing Consent Decrees to reduce emissions from Birla Carbon USA – North Bend Plant, Orion Engineered Carbons LLC – Ivanhoe Carbon Black Plant, Tokai Carbon CB Ltd – Addis Facility, and from Cleco Power LLC – Dolet Hills Power Station which is taking an enforceable requirement to shut down by its planned retirement date of December 31, 2021.[4] However, there are several other facilities that met LDEQ's criteria for selecting sources to evaluate for controls in its regional haze plan for the second implementation period[5] for which LDEQ is not proposing to adopt any new controls as part of its second round regional haze plan. LDEQ has not provided a review of any of those four-factor submittals in its draft regional haze plan and instead, simply states for those sources that it is "deferring a determination" on these sources until a later implementation period.[6] Yet, there are pollution controls for sulfur dioxide (SO2) and nitrogen oxides (NOx) that could be cost effectively installed at these sources to significantly reduce emissions of the visibility-impairing pollutants.

The four factors that must be considered in determining appropriate emissions controls for the second implementation period are as follows: (1) the costs of compliance, (2) the time necessary for compliance, (3) the energy and non-air quality environmental impacts of compliance, and

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[1] 40 C.F.R. §51.308(f).

[2] 40 C.F.R. §51.308(f)(2)(i); 42 U.S.C. § 7491(b)(2). Under the Clean Air Act, state implementation plans must include "include enforceable emission limitations and other control measures, means, or techniques . . . , as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements of this chapter." 42 U.S.C. § 7491(a)(2)(A). An emission limitation is a "requirement" that "limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction." *Id*. § 7602(k).

[3] May 2021 Draft Louisiana Regional Haze State Implementation Plant for the Second Implementation Period (hereinafter "May 2021 Draft LA Regional Haze Plan").

[4] May 2021 Draft LA Regional Haze Plan at 15, 18-20, and at Appendix C (Draft Orders).

[5] *See* LDEQ's Summary of Criteria for Source Selection and LDEQ's Source Selection Spreadsheet, both revised 4/16/2020 and available at https://www.deq.louisiana.gov/index.cfm/page/261F2280-D9F2-E391-3F6CA81C44D4FD38.

[6] *See e.g.*, May 2021 Draft LA Regional Haze Plan at 17, 21-24 (deferring determinations for Canal, Nelson Industrial Steam, Ninemile, R.S. Nelson, Big Cajun II).

(4) the remaining useful life of any source being evaluated for controls.[7] EPA states that it anticipates the cost of controls being the predominant factor in the evaluation of reasonable progress controls and that the other factors will either be considered in the cost analysis or not be a major consideration.[8] Such is the case with the add-on SO2 and NOx controls evaluated in this report. Specifically, the remaining useful life of a source is taken into account in assessing the length of time the pollution control will be in service to determine the annualized costs of controls. If there are no enforceable limitations on the remaining useful life of a source, the expected life of the pollution controls is generally considered the remaining life of the source.[9] In addition, costs of energy and water use of wet and dry flue gas desulfurization (FGD), dry sorbent injection (DSI), selective noncatalytic reduction (SNCR), and selective catalytic reduction (SCR) at a particular source are considered in determining the annual costs of these controls, which means that the bulk of the non-air quality and energy impacts are generally taken into account in the cost effectiveness analyses as is the remaining useful life of a unit. With respect to the length of time to install controls, that is not generally an issue of concern for FGD systems, SCR or SNCR which can and have been installed within three to five years of promulgation of a requirement to install such controls.[10] In any event, EPA's August 20, 2019 regional haze guidance states that, with respect to controls needed to make reasonable progress, the "time necessary for compliance" factor does not limit the ability of EPA or the states to impose controls that might not be able to be fully implemented within the planning period; more specifically, when considering the time necessary for compliance, a state may not reject a control measure because it cannot be installed and become operational until after the end of the implementation period."[11]

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[7] 40 C.F.R. §51.308(f)(2)(i).

[8] *See* U.S. EPA, August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 37.

[9] *Id.* at 33. While we are aware that some EGUs evaluated in this report have planned decommission dates, we are not aware that any of those dates are enforceable. Thus, for all of the EGUs evaluated for add-on NOx controls in this report, we assumed that the expected useful life of the pollution control being evaluated was the remaining useful life of the source, as directed to by EPA in its August 2019 guidance.

[10] For example, in Colorado, SCR was operational at Hayden Unit 1 in August of 2015 and at Hayden Unit 2 in June of 2016, according to data in EPA's Air Markets Program Database, within 3.5 years of EPA's December 31, 2012 approval of Colorado's regional haze plan. In Wyoming, SCR was operational at Jim Bridger Units 3 and 4 in 2015 and 2016, less than three years from EPA's January 30, 2014 final approval of Wyoming's regional haze plan. In addition, FGDs were installed in 3-4 years from design to operation at several coal-fired power plants, including Dan E Karn Units 1 and 2, Gallatin Units 1-4, Homer City Units 1 and 2, JH Campbell Units 2 and 3, La Cygne Units 1 and 2, Michigan City Unit 12, and RM Schahfer Units 14 and 15. As will be discussed below, both DSI and SNCR installation are much less complex than SCR and FGD, requiring primarily a sorbent storage and distribution system and boiler/ductwork injection ports, and thus installation of DSI and SNCR will take less time than FGD and SCR.

[11] *See* U.S. EPA, August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 41 (it would be inconsistent with the regional haze regulations to discount an otherwise reasonable control "simply because the time frame for implementing it falls outside the regulatory established implementation period.").

This report comments on the four-factor analyses of pollution controls for the power generating units in Louisiana for which LDEQ requested but did not evaluate or consider in its draft regional haze plan. Specifically, this report addresses the four-factor analyses of controls for Roy S Nelson Unit 6, Big Cajun II Unit 3, Ninemile Point Units 4 and 5, and Nelson Industrial Steam Company (NISCO) Units 1A and 2A. In addition, this report includes a four-factor analysis of controls for Unit 2 of Brame Energy Center, which was a facility that apparently did not meet LDEQ's criteria for evaluation for controls during this second round regional haze plan.

One overarching issue found with the control cost analyses is that each of the facilities evaluated in this report used a very high interest rate of 7% in amortizing capital costs of control. The use of the current bank prime rate of 3.25% is a more appropriate interest rate to use and is more consistent with the EPA's Control Cost Manual. Use of the current bank prime rate is also consistent with the overnight cost methodology of the EPA Control Cost Manual. The use of an inappropriately high interest rate will result in an artificial overestimate of the annualized costs of control and will improperly inflate cost effectiveness numbers. Other issues found with the analyses including not evaluating the full pollutant removal capabilities of controls, assuming unjustified high costs for operational expenses, and assuming too short of a life of controls for some units.

Because the companies' four-factor analyses typically overestimated the costs for control, this report provides independent four-factor analyses of controls for several sources using the current bank prime interest rate of 3.25% and addressing other issues with the companies' analysis. The results of the four-factor analyses provided herein, which in some cases is also shown with the companies' analyses of controls, are that cost-effective controls are available for SO2 and NOx for at least the following plants and pollutants: SO2 and NOx controls at RS Nelson Unit 6, SO2 controls at Big Cajun II Unit 3, NOx controls at Ninemile Point Units 4 and 5, SO2 controls at NISCO Units 1A and 2A, and SO2 and NOx controls at Brame Unit 2. With the exception of Brame Unit 3, LDEQ identified these sources as contributing to visibility impairment at Louisiana's Class I area, Breton National Wilderness Class I area, and at Caney Creek and Upper Buffalo Wilderness Class I areas in Arkansas.[12] Given that cost-effective controls exist for these sources, LDEQ should adopt pollution control requirements for these sources as part of its regional haze plan for the second implementation period. LDEQ should also consider adopting control requirements for Brame Unit 2 to achieve reasonable progress towards the national visibility goal.

[12] May 2021 Draft LA Regional Haze Plan at 12-14. Note that other Louisiana sources were also identified as contributing to visibility impairment at these Class I areas, but this report focuses on the power plants and the NISCO steam plant.

II. Entergy – Roy S Nelson Plant

A. Background on RS Nelson Unit 6

The Roy S Nelson ("RS Nelson") Plant is a three-unit plant, with Units 3 and 4 primarily burning natural gas and Unit 6 primarily burning coal. The plant is owned and operated by Entergy Services LLC and Entergy Louisiana LLC ("Entergy"). Entergy's RS Nelson Unit 6 is a 556 MW EGU that burns subbituminous Powder River Basin (PRB) coal. RS Nelson Unit 6 is equipped with separated overfire air (SOFA) and a low NOx concentric firing system (LNCFS) for NOx control. RS Nelson Unit 6 is also equipped with an electrostatic precipitator (ESP) for particulate matter (PM) control. RS Nelson Unit has no SO2 controls. LDEQ states that it is deferring a determination of regional haze controls on this unit until a later implementation period.[13]

RS Nelson Unit 6 was subject to BART in the regional haze plan for the first implementation period, but LDEQ did not require the facility to install any pollution controls to meet BART. Instead, the state of Louisiana adopted an SO2 BART limit of 0.6 lb/MMBtu for RS Nelson Unit 6 to be met by utilizing lower sulfur coal, with a compliance deadline of three years from the effective date of EPA's approval of the SIP. EPA approved that SO2 limit as meeting BART on December 21, 2017, and EPA also approved LDEQ's reliance on the ozone-season NOx requirements of the Cross State Air Pollution Rule (CSAPR) applicable to Louisiana in lieu of meeting BART limits for NOx.[14]

Entergy submitted a report on regional haze pollutant controls for the RS Nelson plant to LDEQ in response to a March 18, 2020 Information Collection Request.[15] Although LDEQ is deferring a determination of regional haze controls on RS Nelson Unit 6 until a later date, comments on the Entergy analysis of controls for RS Nelson Unit 6, as well as an independent cost analysis of regional haze pollution controls, are provided below.

B. Analysis of SO2 Controls for RS Nelson Unit 6

The July 2020 RS Nelson Four-Factor submittal did not include a current four-factor analysis of controls and instead relied on Entergy's BART analysis for RS Nelson Unit 6 from April 2016, with those costs escalated to 2019 dollars using the Chemical Engineering Plant Cost Index

[13] *Id.* at 23.
[14] 82 Fed. Reg. 60,520 at 60,524 (Dec. 21, 2017).
[15] July 24, 2020 Response to March 18, 2020 Regional Haze Four-Factor Analysis Information Collection Request, Roy S Nelson Electric Generating Plant (hereinafter "July 2020 RS Nelson Four-Factor Submittal"), in Appendix B of May 2021 Draft LA Regional Haze plan, at pages pdf 333 to pdf 482 of the Draft LA Plan.

(CEPCI) values.[16] However, as EPA noted in its Technical Assistance Document for the RS Nelson BART analysis, Entergy included costs in its 2016 BART analysis that are not typically allowed or provided for under the EPA's Control Cost Manual, such as owners' costs, escalation during construction, and a 25% contingency factor.[17] Further, given that the Nelson Unit 6 is now limited to meet a 0.6 lb/MMBtu SO2 limit, new cost effectiveness analyses should have been done to assess cost effectiveness of SO2 controls that could be applied to RS Nelson Unit 6 considering its lower SO2 limit. Revised cost-effectiveness analyses are provided below.

1. Baseline Emissions of SO2 for RS Nelson Unit 6

According to July 2020 RS Nelson Four-Factor submittal, LDEQ required that baseline emissions be calculated based on the maximum monthly value during a baseline period of January 1, 2018 to December 31, 2019."[18] Entergy claimed that multiplying maximum monthly emissions by 12 resulted in baseline emissions that were greater than annual emissions during that timeframe, and so Entergy used the annual average value during the 2018-2019 baseline period.[19] Entergy did not present the maximum monthly lb/MMBtu SO2 rate during the 2018-2019 timeframe. Based on emissions data reported to EPA's Air Markets Program Database, RS Nelson Unit 6 had a maximum monthly lb/MMBtu SO2 rate of 0.77 during 2018-2019. Note that RS Nelson Unit 6 was not required to comply with the 0.6 lb/MMBtu SO2 BART emission limit until January 22, 2021. The 2018-2019 baseline emissions and operational characteristics of RS Nelson Unit 6 are listed in Table 1 below.

Table 1. 2018-2019 Average Annual Emissions and Operational Characteristics of RS Nelson Unit 1.[20]

RS Nelson	SO2, tpy	SO2 Rate, lb/MMBtu	NOx, tpy	Heat Input, MMBtu/yr	Gross Load, MW-hrs/yr	Operating Hours/yr
Unit 6	9,465	0.68	2,540	27,623,112	2,523,487	6,184

2. Remaining Useful Life of RS Nelson Unit 6

The July 2020 RS Nelson Four-Factor submittal indicates that Entergy has "no plans to shut down or cease burning coal at Nelson Unit 6," and therefore a remaining useful life of 30-years

[16] July 2020 RS Nelson Four-Factor Submittal at 2-3 to 2-4 (pdf pages 340-41 of May 2021 Draft LA Regional Haze plan).
[17] EPA Technical Assistance Document at 16 (in Docket ID EPA-R06-OAR-2017-0129-0024 at Appendix F – LA_RH_Nelson_TSD); EPA Technical Support Document at 18 (Docket ID EPA-R06-OAR-2017-0025), attached to this report in Exs. 14 and 15.
[18] July 2020 RS Nelson Four-Factor Submittal at 2-1 (pdf page 338 of May 2021 Draft LA Regional Haze plan).
[19] *Id.*
[20] Based on data reported to EPA's Air Markets Program Database.

was used in evaluating the cost effectiveness of controls for the unit.[21] The same 30-year life of controls will be used in the cost-effectiveness analysis presented here.

3. SO2 Control Options and Achievable Emission Rates for Nelson Unit 6

RS Nelson Unit 6 has no SO2 controls, other than the limitation on sulfur in coal required to meet the 0.6 lb/MMBtu SO2 BART limit. It is uncommon for a coal-fired power plant to be operated in 2021 without a wet or dry FGD system, or at the very least without a DSI system to reduce SO2 emissions. Three add-on SO2 control options are available for RS Nelson Unit 6: wet FGD, dry FGD, and DSI. Within the category of dry FGD is a circulating dry scrubber (CDS), which can achieve higher SO2 removal than a traditional spray dryer absorber (SDA). Because cost effectiveness is calculated based on annual costs and annual emission reductions, it is important to determine the annual lb/MMBtu SO2 rate achievable with controls to be considered in a cost effectiveness analysis, which is evaluated for these SO2 control options at RS Nelson Unit 6 below.[22]

Wet scrubbers are the most effective SO2 control technology available. EPA's IPM cost module for wet FGD systems indicates a typical wet FGD retrofit of 98% control.[23] Although the January 2017 IPM cost module for wet FGD systems states that the lowest SO2 emissions guarantees for wet FGD systems is 0.04 lb/MMBtu,[24] that is presumably an emission limit guarantee that would apply on a 30-boiler operating day average or shorter basis. A review of the lowest emitting coal-fired power plant units with wet scrubbers shows that several achieve SO2 rates lower than 0.04 lb/MMBtu on an annual basis, as shown in the table below. Further, these units also have achieved 30-boiler operating day averages of 0.04 lb/MMBtu or lower while meeting annual lb/MMBtu SO2 emission rates of 0.03 lb/MMBtu or lower.[25]

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[21] July 2020 RS Nelson Four-Factor Submittal at 2-2 (pdf page 339 of May 2021 Draft LA Regional Haze plan).
[22] *See*, e.g., 83 Fed. Reg. 51,403 at 51,409 (Oct. 11, 2018), in which EPA assumed for a cost effectiveness analysis of SCR that an annual NOx rate of 0.04 lb/MMBtu would be achieved with SCR at the Laramie River Station under a 0.06 lb/MMBtu NOx limit applicable on a 30-day average basis.
[23] Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, Wet FGD Cost Development Methodology, January 2017, at 2 (available at https://www.epa.gov/airmarkets/retrofit-cost-analyzer and attached as Ex. 1).
[24] *Id.*
[25] *See* Ex. 2, spreadsheet with 30-boiler operating day average rates achieved in 2020 for these units, based on emissions data reported to EPA's Air Markets Program Database.

Table 2. Lowest Annual SO2 Rates in 2020 at Coal-Fired EGUs with Wet FGD Systems with 30-Boiler Operating Day Average Rates at or Below 0.04 lb/MMBtu[26]

State	Plant	Unit	2020 SO2 Rate, lb/MMBtu	Max 30- Boiler Operating Day Avg, lb/MMBtu
WI	South Oak Creek	5	0.001	0.001
WI	South Oak Creek	6	0.001	0.001
AZ	Coronado Generating Station	U2B	0.003	0.005
AZ	Coronado Generating Station	U1B	0.004	0.007
AL	James H Miller Jr	3	0.007	0.009
WI	South Oak Creek	7	0.007	0.009
WI	South Oak Creek	8	0.008	0.011
AL	James H Miller Jr	2	0.008	0.019
TX	J K Spruce	**2	0.009	0.014
AL	James H Miller Jr	1	0.01	0.02
IA	Muscatine	9	0.01	0.02
AL	James H Miller Jr	4	0.01	0.02
MS	Daniel Electric Generating Plant	1	0.01	0.03
WI	Elm Road Generating Station	1	0.01	0.02
MN	Boswell Energy Center	3	0.01	0.01
GA	Scherer	1	0.01	0.03
IN	R M Schahfer Generating Station	14	0.01	0.01
WI	Elm Road Generating Station	2	0.01	0.02
GA	Scherer	4	0.01	0.03
TX	Sam Seymour	1	0.01	0.02
IN	R M Schahfer Generating Station	15	0.02	0.02
TX	Sam Seymour	3	0.02	0.02
KS	La Cygne	2	0.02	0.03
MO	Iatan	1	0.02	0.03
KS	Lawrence Energy Center	4	0.02	0.03
GA	Scherer	2	0.02	0.02
GA	Scherer	3	0.02	0.02
SC	Wateree	WAT1	0.02	0.03
KS	Jeffrey Energy Center	2	0.02	0.04
AL	Barry	5	0.02	0.03
KS	Jeffrey Energy Center	3	0.02	0.04
KS	Lawrence Energy Center	5	0.02	0.04
TX	Sam Seymour	2	0.02	0.04
NC	G Allen	5	0.03	0.03

[26] Based on data reported to EPA's Air Markets Program Database.

NC	Cliffside	6	0.03	0.04
KS	Jeffrey Energy Center	1	0.03	0.04
MN	Sherburne County	2	0.03	0.04
MO	Iatan	2	0.03	0.04
MN	Sherburne County	1	0.03	0.04
NC	G Allen	4	0.03	0.04

The majority of the units listed in Table 2 above use or blend with low sulfur coal, such as Powder River Station coal. The RS Nelson Unit 6 Four-Factor Submittal assumes that wet FGD could only achieve an SO2 emissions rate of 0.04 lb/MMBtu.[27] However, the data presented above shows that wet FGD can work very effectively to reduce SO2, even when inlet sulfur content is low, to achieve long term average SO2 rates of 0.03 lb/MMBtu or lower, while still meeting no higher than a 0.04 lb/MMBtu 30-boiler operating day average emission rate. Based on the required 30-day average SO2 limit of 0.6 lb/MMBtu applicable to RS Nelson Unit 6 on a 30-day average basis, the unit should readily be able to achieve a 30-day average rate of 0.04 lb/MMBtu and an annual rate of 0.03 lb/MMBtu, which reflect approximately 93% to 95% control with wet FGD. Since cost effectiveness is based on annualized costs and annual emission reductions, the cost analysis for wet FGD at RS Nelson Unit 6 will assume annual emission reductions based on an annual controlled SO2 rate of 0.03 lb/MMBtu. In contrast, the four-factor analysis for Nelson Unit 6 assumed that a 0.04 lb/MMBtu SO2 rate could be met with wet FGD.[28]

With respect to a dry FGD system at RS Nelson Unit 6, a controlled SO2 emission rate of 0.06 lb/MMBtu was assumed.[29] However, dry FGD systems can achieve lower SO2 emission rates than 0.06 lb/MMBtu. While the January 2017 IPM cost module for SDA FGD systems states that the lowest SO2 emissions guarantees for wet FGD systems is 0.06 lb/MMBtu,[30] that is presumably an emission limit guarantee that would apply on a 30-boiler operating day average or shorter basis. Dry FGD systems can achieve annual emission rates lower than 0.06 lb/MMBtu and SO2 removal efficiencies of 95% control or even better for circulating dry scrubbers. A review of the lowest emitting coal-fired power plant units with dry scrubbers shows that several achieve SO2 rates lower than 0.06 lb/MMBtu on an annual basis, as shown in the table below. Further, these units also have achieved 30-boiler operating day averages of 0.06 lb/MMBtu or lower while meeting annual lb/MMBtu SO2 emission rates of 0.05 lb/MMBtu or lower. Note that the table below does not include circulating fluidized bed boilers equipped with SDA systems, as the data is intended to show the emission rates that can be achieved at coal-fired boilers similar to RS Nelson Unit 6.

[27] *See* July 2020 RS Nelson Four-Factor Submittal at 2-1 (pdf page 338 of May 2021 Draft LA Regional Haze plan).
[28] *Id.*
[29] *Id.*
[30] Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, January 2017, at 1 (available at https://www.epa.gov/airmarkets/retrofit-cost-analyzer and attached as Ex. 3.

Table 3. Lowest Annual SO2 Rates in 2020 at Coal-Fired EGUs with Dry FGD Systems with 30-Boiler Operating Day Average Rates at or Below 0.06 lb/MMBtu[31]

State	Facility Name	Unit ID	2020 SO2 Rate, lb/MMBtu	Max 30- Boiler Operating Day Avg, lb/MMBtu
NV	TS Power Plant	1	0.02	0.03
OK	Sooner	2	0.02	0.04
OK	Sooner	1	0.02	0.03
MN	Boswell Energy Center	4	0.02	0.03
KY	John S. Cooper	2	0.04	0.04
WI	Weston	4	0.04	0.04
AR	John W. Turk Jr. Power Plant	SN-01	0.04	0.05
WY	Wygen III	1	0.04	0.06
WI	Genoa	1	0.05	0.05
WI	Edgewater (4050)	5	0.05	0.06
IA	Lansing	4	0.05	0.05
AR	Flint Creek Power Plant	1	0.05	0.06

The majority of units equipped with dry scrubbers utilize SDAs, although Sooner Units 1 and 2 with the lowest annual SO2 rate of 0.02 lb/MMBtu have circulating dry scrubbers, as does Flint Creek Power Plant and Lansing Unit 4. The EPA's IPM cost module for SDAs indicates that a typical SDA retrofit provides for 95% control.[32] A CDS can achieve even higher levels of SO2 removal than an SDA and thus lower SO2 emission rates. Sargent & Lundy has indicated a CDS can meet SO2 removal efficiencies of 98% or greater over a wide range of uncontrolled SO2 rates.[33] Sargent & Lundy reported in their January 2017 SDA FGD Cost Development Methodology that the lowest SO2 emission guarantees for a circulating dry scrubber are 0.04 lb/MMBtu.[34] Sargent & Lundy also states that "[r]ecent industry experience has shown that a CDS FGD system has a similar installed cost to a comparable SDA FGD system and has been the technology of choice in the last four years."[35] In fact, the Alstom Novel Integrated Desulfurization system (NID™), which is based on the J-reactor,[36] has been selected as the most cost effective scrubber option when compared to other technologies in several recent evaluations including Flint Creek (558 MW),[37] Homer City (2 x 660 MW),[38] and Boswell Unit 4 (585

[31] Based on data reported to EPA's Air Markets Program Database. *See* Ex. 4, which is a spreadsheet with the 30-boiler operating day average SO2 rates calculated for these EGUs.
[32] Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, January 2017, at 1 (Ex. 3).
[33] *Id.* at 2.
[34] *Id.*
[35] *Id.*
[36] Lawrence Gatton, Alstom Power, Next Generation NID™ for PC Market, Coal-Gen, August 17-19, 2011 (Ex. 5)
[37] *See* February 8, 2012 Direct Testimony of Christian T. Beam on behalf of Southwestern Electric Power Company, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding that Installation

MW).[39] The NID™ system, like the conventional dry FGD, integrates a baghouse with the absorber.[40] Based on the above data, I evaluated the cost effectiveness of SDA FGD to meet an annual SO2 emission rate of 0.05 lb/MMBtu which, based on the data in Table 3 above, would equate to meeting a 0.06 lb/MMBtu emission limit on a 30-boiler operating day average. I also evaluated the cost effectiveness of installing a CDS such as a NID™ scrubber, for which I assumed an achievable annual SO2 emission rate of 0.04 lb/MMBtu. These annual SO2 emission rates are lower than the 0.06 lb/MMBtu SO2 rate assumed for an SDA FGD in the Entergy RS Nelson Unit 6 Four-Factor Submittal.[41]

DSI is another technology that can be used for SO2 control as well as other acid gases. DSI is more effective at coal-fired boilers equipped with baghouses, as opposed to units equipped with ESPs like RS Nelson Unit 6. Further, a balance must be met in not injecting so much sorbent that adverse impacts occur on the particulate control method or that PM emission rates increase. While the Sargent & Lundy IPM DSI Cost Development Methodology indicates maximum SO2 removal targets of 80% using milled trona for units with ESPs, Sargent & Lundy also indicates in the DSI IPM documentation that the removal rate with an ESP should be set at 50%.[42]

Trinity's analysis of DSI at RS Nelson Unit 6 analysis assumed a controlled SO2 rate of 0.47 lb/MMBtu.[43] That reflects about 22% control of SO2 from the 0.6 lb/MMBtu SO2 rate currently required to be met by RS Nelson Unit 6 and reflects about 31% SO2 control from the 2018-2019 annual average SO2 rate of 0.68 lb/MMBtu. For the purpose of the cost effectiveness analysis presented here, two levels of control will be assumed: (1) 30% SO2 control (an annual SO2 rate of 0.42 lb/MMBtu from the 0.6 lb/MMBtu limit that currently applies to RS Nelson Unit 6) and (2) 50% control (or an annual average rate from the 0.6 lb/MMBtu SO2 limit that currently applies (an annual SO2 rate of 0.30 lb/MMBtu). The low end of control was to assume an SO2 removal efficiency similar to what was assumed in the RS Nelson Four-Factor submittal and the high end of control was to assume the level of control assumed by Sargent & Lundy for coal-fired units equipped with an ESP.

of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Before the Arkansas Public Utilities Commission, Docket 12-008-U (Ex. 6).

[38] *See* "Alstom to supply NID™ emission control system for the Homer City Generating Station," 4/13/12 Alstom press release, available at https://www.alstom.com/press-releases-news/2012/4/alstom-to-supply-nidtm-emission-control-system-for-the-homer-city-generating-station.

[39] *See* "Alstom emission control system to cut environmental footprint of Minnesota Power's largest power plant," available at https://www.alstom.com/press-releases-news/2013/8/alstom-emission-control-system-to-cut-environmental-footprint-of-minnesota-powers-largest-power-plant.

[40] *See* Alstom Brochure, NID™ Flue Gas Desulfurization System for the Power Industry at 3 (Ex. 7).

[41] *See* July 2020 RS Nelson Four-Factor Submittal at 2-1 (pdf page 338 of May 2021 Draft LA Regional Haze plan).

[42] Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO2 Control Cost Development Methodology, April 2017, at 4. (Available at https://www.epa.gov/airmarkets/retrofit-cost-analyzer and attached as Ex. 8).

[43] *See* July 2020 RS Nelson Four-Factor Submittal at 2-1 (pdf page 338 of May 2021 Draft LA Regional Haze plan).

4. Cost Effectiveness of Analysis for SO2 Controls at RS Nelson Unit 6

Below I provide cost effectiveness analyses for wet FGD, SDA, a NID™ CDS, and DSI for RS Nelson Unit 6. For the wet FGD and SDA, I used the cost effectiveness calculation spreadsheets that EPA recently made available with its revised chapter on costs of control for wet and dry scrubbers.[44] EPA's cost spreadsheets are based on Integrated Planning Model (IPM) Version 6 cost modules. For SDA costs, the EPA cost spreadsheet made available with its wet and dry scrubber Control Cost Manual update includes the costs of a baghouse which is a necessary part of an SDA system to achieve the highest levels of SO2 control.[45] For DSI, I used the framework for DSI SO2 from EPA's Retrofit Cost Tool[46] which is also based on the 2017 IPM cost module for DSI. EPA has relied on these cost algorithms in its IPM model which has been used as the basis for several rulemakings including CSAPR and recent updates to that rule, among others.[47] EPA relied on an earlier version of the SO2 control IPM cost modules in its proposed rulemaking for the Texas regional haze plan.[48]

I also calculated the costs of circulating dry scrubber with a baghouse integrated within the system. For this analysis, I assumed the Alstom Novel Integrated Desulfurization system (NID™) system would be installed[49] because it has been selected as the most cost effective scrubber option when compared to other technologies in several recent evaluations including Flint Creek (558 MW)[50], Homer City (2 x 660 MW),[51] and Boswell Unit 4 (585 MW).[52] Although there is no specific IPM cost module for a NID™ scrubber, the dry FGD cost module has been shown to provide a reasonable estimate of the costs of a NID™ scrubber. In fact, the dry FGD cost module may overstate the costs of a NID™ scrubber. In comments submitted by several conservation organizations on EPA's proposed Montana regional haze FIP, extensive analysis and documentation was provided to show that the annual costs of a NID™ circulating dry scrubber system would be about 1-2% lower than the annual costs of an SDA.[53] Thus, the

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[44] *See* Wet and Dry Scrubbers for Acid Gas Control Cost Calculation Spreadsheet, available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[45] *See* EPA, Control Cost Manual, Section 5, Chapter 1, Wet and Dry Scrubbers for Acid Gas Control, at 1-49.
[46] Available at https://www.epa.gov/airmarkets/retrofit-cost-analyzer.
[47] *See* https://www.epa.gov/airmarkets/power-sector-modeling.
[48] 79 Fed. Reg. 74,817 (Dec. 16, 2014); see also 82 Fed. Reg. 912 (Jan. 4, 2017).
[49] Lawrence Gatton, Alstom Power, Next Generation NID™ for PC Market, Coal-Gen, August 17-19, 2011 (Ex. 5).
[50] *See* February 8, 2012 Direct Testimony of Christian T. Beam on behalf of Southwestern Electric Power Company, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding that Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Before the Arkansas Public Utilities Commission, Docket 12-008-U (Ex. 6).
[51] *See* "Alstom to supply NID™ emission control system for the Homer City Generating Station," 4/13/12 Alstom press release, available at https://www.alstom.com/press-releases-news/2012/4/alstom-to-supply-nidtm-emission-control-system-for-the-homer-city-generating-station.
[52] *See* "Alstom emission control system to cut environmental footprint of Minnesota Power's largest power plant," available at https://www.alstom.com/press-releases-news/2013/8/alstom-emission-control-system-to-cut-environmental-footprint-of-minnesota-powers-largest-power-plant.
[53] *See* Technical Support Document to Comments of Conservation Organizations, Proposed Montana Regional Haze FIP – June 15, 2012, at 59-65 (Ex. 9). *See also* Sargent & Lundy, White Bluff Station Units 1 and 2, Evaluation of

SDA IPM cost module provides a conservative estimate of the costs of a NID™ system but should be used with a higher assumed SO2 removal efficiency and a lower SO2 rate than would be assumed for an SDA system. As stated above, I assumed that a wet FGD could achieve an annual SO2 rate of 0.03 lb/MMBtu and that an SDA FGD could achieve an annual SO2 rate of 0.05 lb/MMBtu. For the NID™ circulating dry scrubber system, I assumed it could achieve an annual SO2 rate of 0.04 lb/MMBtu, which is somewhat better than the assumed for SDA FGD but not as low as would be achieved by a wet FGD system. For DSI, I evaluated 30% control (0.42 lb/MMBtu controlled annual SO2 rate) and 50% control (0.30 lb/MMBtu controlled annual SO2 rate).

The following provides the other relevant inputs made to the cost modules to estimate SO2 control costs for RS Nelson Unit 6:

a. **Retrofit Difficulty:** I used the default retrofit factor of "1" for all cost analyses for RS Nelson Unit 6. The cost algorithms in the EPA cost spreadsheets and the underlying IPM cost modules are based on the actual cost data to retrofit these controls to existing coal-fired power plants, which generally were not designed to take into account the retrofit of future pollution controls.
b. **Unit Size:** 556 MW.
c. **Gross Heat Rate:** This was calculated from the Gross Load (MW-hours) and the heat input (MMBtu/hr) reported to EPA's Air Markets Program Database over 2018-2019 and averaged over the two-year period.
d. **SO2 Rate**: This input is used to calculate the rates for limestone (wet FGD)/lime (SDA)/trona (DSI), scrubber waste, auxiliary power, and makeup water, and also for base scrubber model and reagent handling capital costs. For this input, I used the 0.6 lb/MMBtu SO2 limit that the unit is currently required to meet through the use of low sulfur coal. Given that the unit was not required to comply with this limit until three years after EPA's approval of the BART determination, or by January 22, 2021, there is not much actual SO2 emissions data available to determine currently uncontrolled SO2 emission rates.
e. **Operating SO2 Removal**: This was calculated based on the percent removal from 0.6 lb/MMBtu annual uncontrolled SO2 in the coal to get to an annual SO2 rate of 0.03 lb/MMBtu for wet FGD (i.e., 95.0%), to get to an annual SO2 rate of 0.04 lb/MMBtu for an SDA FGD intended to reflect the cost of a NID™ circulating dry scrubber (i.e., 93.3%), and to get to an annual SO2 rate of 0.05 lb/MMBtu for an SDA (i.e., 91.7%). In comparison, Entergy evaluated wet FGDs to achieve an SO2 removal efficiency of 93.3% and SDA FGD to achieve an SO2 removal efficiency of 90%.[54] For DSI, two operating

Wet vs. Dry FGD Technologies, Prepared for Entergy Arkansas, Inc., Rev. 3, Oct. 28, 2008 (Ex. 10); Sargent & Lundy, Big Sandy Plant Unit 2, Order-of-Magnitude FGD Cost Estimate, Volume 1 – Summary Report, Sept. 29, 2010 (Ex. 11).

[54] *See* July 2020 RS Nelson Four-Factor Submittal at 2-1 (pdf page 338 of May 2021 Draft LA Regional Haze plan).

SO2 removal efficiencies were evaluated: 30% (to achieve an SO2 rate of 0.42 lb/MMBtu) and 50% (to achieve an SO2 rate of 0.30 lb/MMBtu).

f. **Costs of Limestone (for Wet FGD), lime (for SDA FGD or NID™ CDS), trona (for DSI), Waste Disposal, Makeup Water, and Operating Labor**: The default values from the EPA cost spreadsheets for Wet FGD, SDA FGD, and DSI were used for these costs.

g. **Auxiliary Power Cost**: EPA's cost spreadsheet uses the average power plant operating expenses as reported to the Energy Information Administration for 2016 of $0.0361/kW-hr for auxiliary power cost calculations in its cost effectiveness spreadsheets provided with its Control Cost Manual.[55] I used the most recent final EIA data which, for 2019, is $0.0367/kW-hr.[56] In all cases, I included auxiliary power costs in the variable operating and maintenance costs.

h. **Elevation:** 21 feet above sea level[57]

i. **Interest rate:** The current bank prime interest rate of 3.25% was used for the cost effectiveness calculations, as this is what EPA currently recommends for cost effectiveness analyses. For example, EPA's Wet and Dry Scrubber Cost Estimation spreadsheets state that "User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/)."[58] In the past five years, the bank prime rate has not been higher than 5.5%,[59] and the current bank prime rate is 3.25%.[60] Entergy's RS Nelson Unit 6 Four-Factor Analysis used an interest rate of 7%.[61] Entergy's justification for assuming such a high interest rate was to evaluate the range of interest rates over the past 20 years, which it indicated averaged 4.86%, and to rely on the Office of Management and Budget's Circular A-94 which indicated that an interest rate of 7% should be used as a base-case for regulatory analysis.[62] However, that OMB Circular A-94 has not been updated since 2003 and thus is 18 years old. EPA's Control Cost Manual indicates that the use of the current bank prime interest rate is justified for cost effectiveness calculations,[63] and thus that is what was used for the cost effectiveness analyses presented herein. Moreover, given that the Control Cost Manual mandates an

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[55] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[56] *See* EIA, October 2020, Electric Power Annual 2019, Table 8.4, available at https://www.eia.gov/electricity/data/eia923/.

[57] *See* July 2020 RS Nelson Four-Factor Submittal, SCR cost spreadsheet (pdf page 442 of May 2021 Draft LA Regional Haze plan).

[58] *See* EPA's Wet and Dry Scrubber Cost Spreadsheet, row 60 of tab entitled "Data Inputs." Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[59] https://fred.stlouisfed.org/series/PRIME.

[60] https://www.federalreserve.gov/releases/h15/.

[61] *See* July 2020 RS Nelson Four-Factor Submittal at 2-4 to 2-5 (pdf pages 341-42 of May 2021 Draft LA Regional Haze plan).

[62] *Id.* at 2-5.

[63] EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 15.

"overnight" cost methodology, it is most appropriate to use the bank prime interest rate as it exists today, not an estimate of what the interest rate may be at some point in the future.

j. **Equipment lifetime**: A 30-year life was assumed in amortizing capital costs for wet FGD, SDA FGD, and DSI. The Entergy RS Nelson Four-Factor Submittal also assumed a 30-year life of controls.[64]

k. **Baseline emissions**: As discussed in Section I.B.1. above, 2018-2019 average emissions at RS Nelson Unit 6 were used as baseline emissions and operational characteristics (heat input, heat rate, megawatt-hours generated). However, for SO2 emissions, since the unit has been subject to a 0.6 lb/MMBtu SO2 emission rate since January of 2021, the SO2 baseline emissions were reduced to reflect compliance with that limit. Specifically, the SO2 annual baseline emissions were calculated based on multiplying annual heat input for 2018 and 2019 by the 0.6 lb/MMBtu SO2 limit that became applicable in 2021 to RS Nelson Unit 6 and taking the average of those revised 2018 and 2019 emissions.

The following table summarize the cost effectiveness calculations for SO2 controls at RS Nelson Unit 6.

Table 4. Cost Effectiveness of SO2 Controls at RS Nelson Unit 6, Based on 30-Year Life of Controls and the EPA Cost Spreadsheets (2019 $)[65]

	Annual SO2 Rate, lb/MMBtu	Capital Cost	O&M Costs	Total Annualized Costs	SO2 Reduced, tpy	Cost Effectiveness, $/ton
Wet FGD	0.03	$286,960,813	$9,474,076	$24,693,492	7,873	$3,137
NID™ CDS	0.04	$262,032,828	$9,160,678	$23,046,926	7,734	$2,980
SDA	0.05	$262,032,828	$9,160,678	$23,046,926	7,596	$3,034
DSI at 50% Control	0.42	$18,855,266	$10,607,463	$11,600,791	4,143	$2,800
DSI at 30% Control	0.30	$16,039,256	$7,880,344	$8,725,320	2,486	$3,510

While DSI at 50% SO2 control is the most cost-effective, it is not nearly as least effective at reducing SO2 emissions from RS Nelson Unit 6 as a dry or wet FGD system. All of the three FGD options evaluated (wet FGD, NID™ circulating dry scrubber, and SDA) would achieve 92-95% (or better) SO2 control and would be very cost-effective. The costs of all of these controls

[64] July 2020 RS Nelson Four-Factor Submittal at 2-2 (pdf page 339 of May 2021 Draft LA Regional Haze plan).
[65] *See* EPA Control Cost Manual cost spreadsheets for Wet FGD, SDA, and CDS for RS Nelson Unit 6, attached as Ex. 12.

should be considered as cost effective by LDEQ. These costs are well below the cost effectiveness thresholds that other states or EPA have proposed or are currently planning to use for deciding cost effective controls to require in their regional haze plans for the second implementation period. For example, Texas is using $5,000/ton as a cost effectiveness threshold.[66] Arizona is using $4,000 to $6,500/ton.[67] New Mexico is using $7,000 per ton,[68] and Oregon is using $10,000/ton or possibly even higher.[69] Washington is using $6300/ton for Kraft pulp and paper power boilers.[70]

5. Comments on Entergy's SO2 Cost Analysis for RS Nelson Unit 6

The SO2 control cost estimates presented in Entergy's July 2020 RS Nelson Four-Factor Submittal are much higher than the cost estimates using EPA's cost estimation spreadsheets. Part of the reason for that is that a much higher 7% interest rate was used by Entergy in determining annualized capital costs which, as discussed above, was not a reasonable assumption given the low interest rates. Other reasons for the cost estimates being so much higher in the July 2020 RS Nelson Four-Factor Submittal have previously been identified by EPA. Specifically, Entergy's July 2020 RS Nelson Four-Factor Submittal relies on an April 2016 cost analysis for SO2 controls that EPA had previously reviewed as part of the analysis of BART controls.[71] However, as EPA noted in its Technical Assistance Document for the RS Nelson BART analysis, the April 2016 Entergy cost analysis included costs that are not typically allowed or provided for under the EPA's Control Cost Manual, such as owners' costs, escalation during construction, and a 25% contingency factor.[72] The April 2016 Entergy SO2 control cost estimate also included escalation of materials and labor based on the typical schedule of installation of controls.[73] Such escalation is at odds with the overnight cost methodology of the

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[66] *See* https://www.tceq.texas.gov/assets/public/implementation/air/sip/haze/2021RHSIP_pro.pdf.

[67] *See*, e.g., Arizona Department of Environmental Quality, 2021 Regional Haze Four-Factor Initial Control Determination, Tucson Electric Power Springerville Generating Station, at 15, available at https://www.azdeq.gov/2021-regional-haze-sip-planning.

[68] *See* NMED and City of Albuquerque, Regional Haze Stakeholder Outreach Webinar #2, at 12, available at https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED_EHD-RH2_8_25_2020.pdf.

[69] *See*, e.g., September 9, 2020 letter from Oregon Department of Environmental Quality to Collins Forest Products, at 1-2, available at https://www.oregon.gov/deq/aq/Documents/18-0013CollinsDEQletter.pdf.

[70] *See*, e.g., Washington Department of Ecology, Draft Responses to comments for chemical pulp and paper mills, at 5, 6, and 8, attached as Ex. 13.

[71] *See* July 2020 RS Nelson Four-Factor Submittal at 2-3 to 2-4 and at attachment entitled Entergy, Nelson Unit 6, SO2 BART Control Technology Summary, prepared by Sargent & Lundy (pdf pages 340-41 and pdf page 347 of May 2021 Draft LA Regional Haze plan).

[72] *See* 82 Fed. Reg. 32,294 at 32,298 (July 13, 2017). *See* also EPA Technical Assistance Document for the Louisiana State Implementation Plan for the Entergy Nelson Facility at 16 (in Docket ID EPA-R06-OAR-2017-0129-0024 at Appendix F – LA_RH_Nelson_TSD); EPA Technical Support Document for EPA's Proposed Action on the Louisiana State Implementation Plan for the Entergy Nelson Facility at 18 (Docket ID EPA-R06-OAR-2017-0025), attached as Exs. 14 and 15.

[73] *See* July 2020 RS Nelson Four-Factor Submittal at attachment entitled Entergy, Nelson Unit 6, SO2 BART Control Technology Summary, prepared by Sargent & Lundy, Dry FGD Cost Estimate Basis Document and Wet FGD Cost Estimate Basis (at pdf pages 367 and 422 of May 2021 Draft LA Regional Haze plan).

EPA's Control Cost Manual. The interest rate assumed during construction was 7.8%, even higher than the unreasonably high 7% interest rate used to amortize capital costs.[74] These assumptions, which were inconsistent with the EPA Control Cost Manual, resulted in capital cost estimates of SDA and wet FGD that were significantly higher than a cost estimate would have been which followed EPA's Control Cost Manual.

Further, Entergy's operating costs for SDA were based on a much higher uncontrolled SO2 rate of 0.70 lb/MMBtu and an assumed 94% SO2 design removal rate, but Entergy only assumed a controlled outlet SO2 rate of 0.06 lb/MMBtu which reflects only 91% control[75] For the cost analysis of wet FGD, Entergy's April 2016 analysis assumed an uncontrolled SO2 rate of 0.70 lb/MMBtu and a design removal efficiency of 96% but only assumed a controlled outlet rate of 0.04 lb/MMBtu, which reflects a lower removal efficiency than assumed for the cost analysis of 94%.[76] Also, a 62% annual capacity factor was used in Entergy's SO2 cost analyses, but RS Nelson Unit 6 operated at approximately a 52% capacity factor over 2018-2019.[77] Entergy's assumptions of a higher uncontrolled SO2 rate, when the unit is now subject to a 0.6 lb/MMBtu SO2 limit, and a higher operating capacity factor will mean that operating and maintenance costs of the SO2 controls are overstated. Further, Entergy's April 2016 analysis assumed higher costs for lime for SDA and for limestone for wet FGD than EPA's FGD cost spreadsheet, which is based on more recent cost data.[78] Indeed, Entergy's assumed costs for reagent for the SDA at Nelson Unit 6 and for limestone for wet FGD at Nelson Unit 6 in its April 2016 analysis are more than 3 times higher than the costs estimated by the EPA FGD cost spreadsheet.[79] All of these assumptions in Entergy's April 2016 analyses will result in an overstatement of costs of control, particularly for the RS Nelson Unit 6 as it currently operates and under the 0.6 lb/MMBtu SO2 limit which it is currently subject to.

For DSI, Entergy's 2016 analysis assumed sorbent costs for an even higher uncontrolled SO2 rate of 0.96 lb/MMBtu and assumed 40% control, even though it assumed emission reductions from a 0.74 lb/MMBtu baseline uncontrolled SO2 rate to meet an emission limit of 0.47 lb/MMBtu (which only reflected 36% reduction).[80] In comparison, EPA assumed 50% control

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[74] *See* EPA Control Cost Manual, Section 1, Chapter 2, Cost Estimation: Concepts and Methodology, at 11, available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[75] *Id.* at 4 (pdf page 358 of May 2021 Draft LA Regional Haze Plan).

[76] *Id.*, Wet FGD Cost Estimate Basis Document at 4, at pdf page 414 of May 2021 Draft LA Regional Haze Plan.

[77] *Id.*, Attachment entitled Entergy, Nelson Unit 6, SO2 BART Control Technology Summary, prepared by Sargent & Lundy at 3 (pdf page 353 of May 2021 Draft LA Regional Haze Plan).

[78] *Id.*, Dry FGD Cost Basis at 13 and Wet FGD Cost Basis at 13 (pdf pages 367 and 423 of May 2021 Draft LA Regional Haze Plan). Sargent & Lundy assumed $130/ton of lime and $40/ton of limestone, whereas EPA's spreadsheet assumed $125/ton of lime and $30/ton of limestone based on Sargent & Lundy documentation for 2017 power sector modeling.

[79] *Id.*, Dry FGD Cost Estimate Basis Document at 14 (Table 3-2) and Wet FGD Cost Estimate Basis Document at 13 (at pdf page 368 and page 423 of May 2021 Draft LA Regional Haze plan).

[80] *Id.*, DSI Cost Estimate Basis Document at 2 (at pdf page 376 of May 2021 Draft LA Regional Haze plan).

with DSI for Nelson Unit 6 in its 2017 rulemaking on the Louisiana Regional Haze Plan in its BART evaluation for SO2.[81] In addition, Cleco assumed 50% SO2 control with DSI at Big Cajun II Unit 3 in its four-factor controls analysis, and that unit burns similar sulfur content coal and has an ESP for particulate control like RS Nelson Unit 6.[82] Entergy's DSI costs also included costs to increase carbon consumption rate "to mitigate any impacts on mercury performance associated with ACI/DSI interface."[83] Sorbent costs are the primary expense associated with DSI, which has low capital costs, and thus these assumptions would have resulted in a significant overestimate of DSI costs.

For the reasons identified above and in EPA's Technical Assistance Document for the RS Nelson BART analysis, Entergy's April 2016 Entergy SO2 cost data are unreasonably high estimates that do not comport with the EPA Control Cost Manual methodology.[84] Moreover, Entergy's Four-Factor Submittal for RS Nelson Unit 6 used the cost estimates from its April 2016 analysis that reflected operation of the unit at a higher capacity factor of 62% and reflected higher uncontrolled SO2 emissions, but then Entergy calculated the emission reductions that would occur from more recent (2018-2019) emissions when the unit was operating at a lower capacity factor of around 52% and with lower uncontrolled SO2 emissions of 0.68 lb/MMBtu.[85] Thus, costs were assumed for a higher-emitting and higher-capacity factor unit, but emission reductions were based on a lower-emitting and lower-capacity factor unit. This is another reason why the RS Nelson Unit 6 SO2 cost estimates significantly overstate costs and understate cost effectiveness. As shown in Table 4 above, all of the SO2 control options are cost effective for RS Nelson Unit 6. Both dry and wet FGD systems would achieve significant SO2 reductions from Nelson Unit 6 and provide reasonable progress toward the national visibility goal.

6. Consideration of Energy and Non-Air Environmental Impacts of SO2 Controls

For the factor regarding energy and non-air quality impacts of a pollution control being considered, it must be noted that the SO2 controls that have been evaluated for Nelson Unit 6 are widely used by coal-fired EGUs and have been for many years. Thus, in general, these SO2 controls do not pose any unusual energy and non-air quality impacts. Further, the energy and non-air quality impacts are typically taken into account by including costs for additional energy use or for things like scrubber waste disposal is the analyses of the costs of control.

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[81] 82 Fed. Reg. 32,294 at 32,298 (July 13, 2017).

[82] July 2020 Cleco Four-Factor Submittal at 304 (at pdf pages 82-83 of LDEQ's May 2021 Draft LA Regional Haze Plan).

[83] *Id.*

[84] *See* EPA Technical Assistance Document for the Louisiana State Implementation Plan for the Entergy Nelson Facility at 16 (in Docket ID EPA-R06-OAR-2017-0129-0024 at Appendix F – LA_RH_Nelson_TSD) (Ex. 14).

[85] *See* July 2020 RS Nelson Four-Factor Submittal at 2-1 to 2-4 (pdf pages 338-341 of May 2021 Draft LA Regional Haze Plan).

Of all of the FGD systems evaluated, circulating dry scrubbers have the lowest energy usage, as well as low freshwater usage and zero liquid discharge.[86] The Southwestern Electric Power Company (SWEPCO) has recently installed a NID™ system at the Flint Creek Power Plant in Arkansas. Flint Creek is a 528 MW unit that burned low sulfur Powder River Basin coal with a 0.8 lb/MMBtu uncontrolled SO2 rate.[87] After evaluating several SO2 control systems, SWEPCO selected a NID™ system for SO2 control for the following benefits of a NID™ system: lowest capital and operation and maintenance costs on a 30-year cumulative present worth basis, lowest water consumption, lowest auxiliary power usage, lowest reagent usage, smallest footprint, best for mercury reduction with activated carbon injection, best for SO3 removal, and best for future National Pollution Discharge Elimination System (NPDES) permit compliance.[88]

7. Consideration of Length of Time to Install Controls

The Trinity Four-Factor Submittal for RS Nelson Unit 6 states that "[a] minimum of five (5) years, counting from the effective date of an approved determination, would be needed for implementing either the [wet FGD or dry FGD] options."[89] However, during the adoption of the Mercury and Air Toxics Standards (MATS), EPA found that EGUs could install required controls, including scrubbers, within 3 years. Specifically, EPA stated in 2011 that "[u]nits that choose to install dry or wet scrubbing technology should be able to do so within the compliance schedule required by the [Clean Air Act] as this technology can be installed within the 3-year window."[90] In support of this claim, EPA referenced a letter to Senator Carper dated November 3, 2010, in which David Foerter, executive director of the Institute of Clean Air Companies (ICAC), stated that wet scrubbers could be installed in 36 months, dry scrubbing technology could be installed in 24 months, and dry sorbent injection could be installed in 12 months.[91] ICAC's claims were based on 7 years of pollution control installation at coal-fired EGUs under the Clean Air Interstate Rule (CAIR) and under the NOx SIP Call. The ICAC letter states that, between 2008 to 2010, flue gas desulfurization (FGD) controls were installed at numerous EGUs with combined capacity of 60 gigawatts (GW) while, concurrently, selective catalytic reduction

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[86] *See* https://www.babcock.com/products/circulating-dry-scrubber-cds.
[87] *See* February 8, 2012 Direct Testimony of Christian T. Beam on behalf of Southwestern Electric Power Company, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding that Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Before the Arkansas Public Utilities Commission, Docket 12-008-U, at 5, 18 (Ex. 6).
[88] *Id.* at 19-21.
[89] *Id.* at 2-2 (pdf page 339 of May 2021 Draft LA Regional Haze Plan).
[90] 76 Fed. Reg. 24976, 25054 (May 3, 2011).
[91] *Id.*, fn 172.

was installed at roughly 20 GW of EGUs.[92] During that timeframe of significant pollution control installation, there were no labor shortages.[93]

EPA's predictions regarding MATS provided to be true, as many scrubbers were installed to meet MATS within three to four years, at most. The table below provides several examples of EGUs which are in the process of installing SO2 scrubbers and which will be completed within three to four years.

Table 5. Example Installation Timeframes for FGD.

State	Facility	Unit	Time to Install FGD
MI	Dan E Karn	1 and 2	Contract for design and supply for dry scrubbers was issued in August 2011.[94] According to CAMD, dry lime scrubber began operation at Unit 1 on June 6, 2014. The scrubber on Unit 2 became operational in May of 2015.[95]
TN	Gallatin	1, 2, 3, 4	FGD design for all four units began in September 2011. The FGD at Unit 4 was expected to be in operation by April 2015, Unit 3 by June 2015, Unit 1 by November 2015, and Unit 2 by January 2016.[96]
PA	Homer City	1 and 2	Construction of FGDs began in 2012 and final tie-in to be completed by end of third quarter of 2015.[97]
MI	JH Campbell	2, 3	Engineering for the Unit 2 FGD began in late 2012 and the FGD is expected to be installed and operational by early 2016.[98]

[92] *See* November 3, 2010 letter from David C. Foerter, Institute of Clean Air Companies (ICAC) to Senator Carper, at 4 (Ex. 16).
[93] *Id.*
[94] *See* August 3, 2011 "B&W gets contract for dry scrubber project at Karn coal plant." (Ex. 17).
[95] *See* December 17, 2014 Extension Request for Consumers Energy Company's D.E. Karn Plant (SRN B2840) Units 1 & 2 for Compliance with the Mercury and Air Toxics Standard (40 CFR 63 Subpart UUUUU) and the Michigan Mercury Rule (R336.2501) at 2 (Ex. 18). Exact date of scrubber startup obtained from EPA's Air Markets Program Database.
[96] *See* July 9, 2014 TVA – Gallatin Fossil Plant (GAF) – Request for Compliance Extension - Mercury and Air Toxics (MATS), Enclosure at page 4 (Ex. 19). Based on information in EPA's Air Markets Program Database, Unit 4's FGD became operational in April of 2015, Unit 3's FGD was operational in April 2015, and Unit 2's FGD was operational in January 2016.
[97] *See* November 5, 2013 Request for One-Year Extension of the Compliance Deadline for the Mercury and Air Toxics Standards and of the Expiration Date of the Plan Approval for the Installation of Flue Gas Desulfurization Units at 1-2 (Ex. 20). Based on information in EPA's Air Markets Program Database, Homer City Unit 1's FGD was operational in October 2015 and Unit 2's FGD was operational in April 2016.
[98] *See* October 4, 2012 Construction Extension for Consumers Energy Company's JH Campbell Facility Pursuant to the Mercury and Air Toxics Standard (40 CFR 63 Subpart UUUUU, also known as MATS) as well as the Michigan

KS	La Cygne	1, 2	Contract for design and supply of wet FGD systems issued in December 2011.[99] Installation of wet FGD systems to be completed by June 1, 2015.[100]
IN	Michigan City	12	Planning for the dry FGDs began in 2011 with final operation scheduled for 1st quarter 2016 for Unit 12.[101]
IN	RM Schahfer	14, 15	Co-located with the Michigan City Plant, FGD systems were installed and became operational at Unit 14 on November 1, 2013 and at Unit 15 on October 26, 2014 according to CAMD.[102]

Trinity assumed that it would take 3 years to install DSI, but DSI can be more readily installed in timeframes of 21-24 months.[103]

Mercury Rule (R336.2501, *et seq*), Exhibit B, Figures B-1c and B-1d (Ex. 21). Based on information in EPA's Air Markets Program Database, J H Campbell Unit 2's FGD was operational in May 2016 and Unit 3's FGD was operational in August 2016.

[99] *See* "Hitachi Power Systems America Awarded Contract to Supply Pollution Controls Equipment for KCP&L." (Ex. 22).

[100] *See* June 22, 2012 Request for Extension of the Mercury and Air Toxics Standards (MATS) Compliance Deadline KCP&L La Cygne, Source ID No. 1070005, at 1 (Ex. 23). Based on information in EPA's Air Markets Program Database, La Cygne Unit 1's FGD was operational in March 2015 and Unit 2's FGD was operational in October 2014.

[101] *See* January 30, 2013 NIPSCO – Michigan City and R.M. Schahfer Generation Stations Request for Extension of Time to Comply with the Utility MATS NESHAP at 1. (Ex. 24). Based on information in EPA's Air Markets Program Database, Michigan City Unit 1's FGD was operational in November 2015.

[102] *See* EPA's Clean Air Markets Database for RM Schahfer. *See also* January 30, 2013 NIPSCO – Michigan City and R.M. Schahfer Generation Stations Request for Extension of Time to Comply with the Utility MATS NESHAP at 1 (Ex. 24).

[103] *See*, e.g., Staudt, James, Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants, prepared for Northeast States for Coordinated Air Use Management, March 31, 2011, at 4, available at https://www.nescaum.org/documents/nescaum-comments-nj-s126-petition-to-epa-20110525-combo-final.pdf. *See also* https://www.downtoearth.org.in/news/energy/in-a-first-a-thermal-power-plant-decides-to-use-dsi-technology-to-curb-so2-emission-60823. Also see a number of consent decrees that require that DSI be operational in less than two years from the date of execution, such as this one: https://www.epa.gov/enforcement/consent-decree-cinergy-corporation-et-al-duke-energy-civil-action-no-199-cv-01693-ljm.

C. Evaluation of NOx Control Options

R S Nelson Unit 6 is a tangentially-fired boiler with a low NOx concentric firing system (low NOx burners LNB)) and separated overfire air. Unit 6's annual NOx rate averaged over 2018-2019 was 0.19 lb/MMBtu, but the unit's monthly average NOx rates varied widely over 2018 to 2019, from a maximum monthly NOx rate of 0.33 lb/MMBtu to a minimum monthly NOx rate of 0.12 lb/MMBtu.[104]

The top two options for add-on NOx controls for coal-fired EGUS like RS Nelson Unit 6 are SCR and SNCR. The Entergy four-factor submittal did evaluate SCR and SNCR for RS Nelson Unit 6. Provided below are comments on Entergy's SCR and SNCR cost analysis and a revised analysis of these controls. In addition, combustion control upgrades should be evaluated for RS Nelson Unit 6.

1. NOx Control Options and Achievable Emission Rates for Nelson Unit 6

a) Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction is the most effective add-on control technology for the control of NOx from coal-fired EGUs like RS Nelson Unit 6. SCR systems are routinely designed to achieve 90% or greater NOx control efficiency.[105] Annual average NOx emission rates with SCR, along with existing low NOx burners and overfire air, can be as low as 0.04 lb/MMBtu and, for some EGUs, even lower.[106]

SCR uses an ammonia-type reagent to reduce NOx to nitrogen gas and NOx removal is greatly enhanced with the use of a metal-based catalyst with activated sites which increase the rate of NOx removal. The ammonia-type reagent is injected into the flue gas downstream of the combustion process through injection sites in the ductwork, which then goes into an SCR reactor chamber that includes the catalyst. The hot gases and ammonia-type reagent diffuse through the catalyst and contact activated sites where NOx is reduced to nitrogen and water with the hot flue gases providing energy for the reaction.[107]

There are several EGUs that have achieved NOx emission rates of 0.04 lb/MMBtu or lower on an annual average basis. A review of the lowest-emitting 2020 annual NOx rates at coal-fired EGUs from EPA's Air Markets Program Database is provided in the table below.

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[104] *See* RS Nelson Unit 6 Monthly Emissions from AMPD 2018 to 2019, in attached Ex. 25.
[105] *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 5 (available at https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf), attached as Ex. 26.
[106] *Id.*
[107] *Id.* at pdf page 13.

Table 6. Coal-Fired EGUs Equipped with SCR Emitting 0.04 lb/MMBtu on an Annual Average Basis in 2020[108]

Power Plant	Unit	2020 Annual NOx Rate, lb/MMBtu
Edgewater	5	0.04
Trimble County	2	0.04
J K Spruce	**2	0.04
Dry Fork	1	0.04
Jeffrey Energy Center	1	0.04
E W Brown	3	0.04
Walter Scott Jr.	4	0.04
Lansing	4	0.04
John W Turk Jr	SN-01	0.04
W A Parish	WAP7	0.04
Sandy Creek Energy Station	S01	0.04

In its recent regional haze revision for the Laramie River Station in Wyoming, EPA assumed 0.04 lb/MMBtu would be achieved with SCR on an annual average basis under a 0.06 lb/MMBtu NOx limit applicable on a 30-day average basis.[109] However, in its response to comments on its initial NOx BART finding for the San Juan Generating Station,[110] EPA found significant support in actual emissions data for its finding that a 0.05 lb/MMBtu NOx limit was achievable on a 30-boiler operating day average basis, including a study that identified 25 units that are achieving NOx emission rates less than 0.05 lb/MMBtu on an hourly basis.[111] EPA also cited to NOx emission rates at Seminole Units 1 and 2 (achieving 0.04 lb/MMBtu), Morgantown Units 1 and 2 (achieving 0.043 to 0.054 lb/MMBtu), Trimble Unit 1 (achieving 0.032 lb/MMBtu), as well as the Mountaineer plant and Cliffside Unit 5.[112] EPA also analyzed emissions data for the lowest NOx emitting units to calculate rolling 30-day averages (on both a calendar year basis and on a

[108] Based on data reported to EPA's Air Markets Program Database for 2020.
[109] 83 Fed. Reg. 51,403 at 51,408 (Oct. 11, 2018).
[110] This NOx BART finding was subsequently replaced with a BART alternative, *see* 79 Fed. Reg. 60,985-60,993 (Oct. 9, 2014).
[111] *See* U.S. EPA, Complete Response to Comments for NM Regional Haze/Visibility Transport FIP, 8/5/11 (Docket EPA-R06-OAR-2010-0846) at 53 (Ex. 27). EPA also cites to Clay Erickson, Robert Lisauskas, and Anthony Licata, What New in SCRs, DOE's Environmental Control Conference, May 16, 2006., p. 28. Available here: http://www.netl.doe.gov/publications/proceedings/06/ecc/pdfs/Licata.pdf; LG&E Energy, Selective Catalytic Reduction: From Planning to Operation, Competitive Power College, December 2005, p. 75-77. (Ex.28); and M.J. Oliva and S.R. Khan, Performance Analysis of SCR Installations on Coal-Fired Boilers, Pittsburgh Coal Conference, September 2005 (Ex. 29).
[112] *See* U.S. EPA, Complete Response to Comments for NM Regional Haze/Visibility Transport FIP , EPA-R06-OAR-2010-0846-0127, at 53-54 (Ex. 27).

30-boiler operating day basis).[113] EPA found several units emitting NOx at or below 0.05 lb/MMBtu, including Havana Unit 9, Parish Unit 7, and Parish Unit 8.[114]

All of this long term, actual emissions data for units equipped with SCR shows that those units with unit-specific emission limits that are more closely linked to the capabilities of the unit's NOx pollution controls consistently have met NOx rates at 0.04 lb/MMBtu on an annual average basis. Thus, for the purposes of the cost analyses presented herein, it will be assumed that RS Nelson Unit 6 can meet a 0.04 lb/MMBtu NOx rate on an annual average basis. For an EGU that is already achieving a low NOx rate before the addition of SCR, it is possible that annual average rates as low as 0.03 lb/MMBtu could be achieved. Given that cost-effectiveness is based on annual average costs, it is most appropriate to evaluate the NOx emission reductions achievable on an annual average basis in determining cost effectiveness.

RS Nelson Unit 6 had an annual average NOx emission rate over 2018-2019 of 0.19 lb/MMBtu, and thus an annual controlled NOx rate with SCR of 0.04 lb/MMBtu reflects an annual NOx reduction efficiency across the SCR of 80% which is readily achievable with SCR. As EPA states in its Control Cost Manual, SCR systems are routinely designed to achieve 90% control.[115] Although EPA acknowledges that the design removal efficiency may be less than 90% when the SCR is following combustion controls like low NOx burners,[116] that does not mean that high NOx removal efficiencies cannot be achieved by an SCR following combustion controls.

All major SCR catalyst vendors can and have guaranteed at least 90% efficiency for SCRs burning coals with a wide range of properties. Vendor experience lists[117] indicate that SCRs are routinely designed for 90% NOx control, depending on purchaser specifications. In 2003, Sargent and Lundy, an engineering firm that designs SCRs, stated:

> [A]ll Sargent & Lundy-designed SCR reactors at coal-fired units, which have been placed into service, have achieved their guaranteed NOx reduction efficiencies within the specified ammonia slip limits. The minimum design NOx reduction efficiency was 85% and the maximum reduction efficiency was in excess of 90%. Design ammonia slip levels ranged between 2 ppm and 3 ppm at the end of catalyst life. Although no SCR installations have yet operated for the guaranteed catalyst life duration, it is anticipated that the NOx reduction and ammonia slip performance guarantees will continue to be met over that period. Operational installations include pulverized coal units burning PRB coal, Illinois low- to high-sulfur coal, and eastern low to high-sulfur coal; one cyclone unit

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[113] *Id.* at 56 -58.
[114] *Id.*
[115] *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 5.
[116] *Id.*
[117] *See, e.g.*, Haldor Topsoe, SCR Experience List, October 2009 (Ex. 30), Hitachi, NOx Removal Coal Plant Supply List, October 17, 2006 (Ex. 31); Argillon Experience List U.S. Coal Plants (Ex. 32); Hitachi, SCR System and NOx Catalyst Experience, Coal, February 2010 (Ex. 33).

> burning PRB coal; and two cyclone units burning Illinois low-sulfur coal. SCR reactor designs have included 2+1 and 3+1 catalyst level installation sequences and have used plate, honeycomb, and corrugated type catalysts. Design of SCR reactors for removal efficiencies greater than 90% at ammonia slip levels less than 2 ppm to 3 ppm has been demonstrated and should be considered as a feasible design criterion.[118]

Thus, for all of these reasons discussed above, it is more than reasonable to evaluate the cost effectiveness of SCR at RS Nelson Unit 6 to meet a NOx emission rate of 0.04 lb/MMBtu on an annual basis. The Entergy RS Nelson Four-Factor Submittal only assumed an annual controlled NOx emission rate of 0.05 lb/MMBtu in its cost effectiveness analysis which only reflects 73% control of NOx across the SCR.[119]

b) Selective Noncatalytic Reduction (SNCR)

Selective noncatalytic reduction (SNCR) is the next most effective NOx reduction technology for coal-fired EGUs, but its NOx removal capabilities are much lower than achievable with SCR. SNCR involves injecting ammonia or an ammonia-type reactant into the furnace of a coal-fired boiler, similar to SCR, but there is no catalyst to enhance NOx removal as with SCR. In SNCR, the ammonia-type reagent mixes with hot flue gases, and the reagent reacts with NOx in the gas stream to convert some of it to nitrogen gas thereby reducing nitrogen oxides.

EPA describes the SNCR system as follows in its Control Cost Manual:

> The mechanical equipment associated with an SNCR system is simple compared to an SCR, semi-dry FGD, or wet scrubber and thereby requires lower capital costs ($/MMBtu/hr basis). Installation of SNCR equipment requires minimum downtime. Although simple in concept, it is challenging in practice to design an SNCR system that is reliable, economical, and simple to control and that meets other technical, environmental, and regulatory criteria. Practical application of SNCR is limited by the boiler design and operating conditions.[120]

The NOx reduction efficiency of SNCR can vary greatly. According to EPA, "[t]emperature, residence time, type of NOx reducing agent, reagent injection rate, uncontrolled NOx level, distribution of reagent in the flue gas, and [carbon monoxide and oxygen (CO and O2)]

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[118] Kurtides, T., Sargent and Lundy, Lessons Learned from SCR Reactor Retrofit, COAL-GEN, Columbus, OH, August 6-8, 2003; http://www.adeq.state.ar.us/ftproot/pub/commission/p/Closed%20Permit%20Dockets%202006-2010/08-007-P%20AEP%20Service%20Corp%20&%20Swepco-Hempstead%20Co%20Hunting%20Club/2008-12-03, (Ex. 34).

[119] *See* July 2020 RS Nelson Four-Factor Submittal at 3-1 (pdf page 343 of May 2021 Draft LA Regional Haze Plan).

[120] *See* EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, revised 4/25/2019, at 1-6, available at https://www.epa.gov/sites/production/files/2017-12/documents/sncrcostmanualchapter7thedition20162017revisions.pdf and attached as Ex. 35.

concentrations all affect the reduction efficiency of the SNCR."[121] EPA and states, in evaluating the NOx removal efficiency of SNCR in prior analyses under the regional haze program, have assumed NOx control efficiencies with SNCR at coal-fired EGUs in the range of 15% - 40%.[122] EPA's Control Cost Manual indicates that the majority of coal-fired boilers are achieving between 20%-40% NOx control with SNCR, and EPA provided a graph indicating a connection between the NOx inlet emission rate and the control efficiency, with higher NOx removal efficiencies achieved with higher inlet NOx emission rates.[123] EPA provided a best fit equation to estimate NOx removal efficiency achievable with SNCR based on NOx inlet level:

NOx Reduction Efficiency, %, = 22.554*Inlet NOx Rate, lb/MMBtu + 16.725.[124]

For the purpose of the SNCR cost-effectiveness evaluation provided here for RS Nelson Unit 6, this report uses the equation provided by EPA to estimate NOx removal efficiency and achievable NOx emission rates for each EGU based on its inlet NOx emissions rate. The estimated annual NOx removal efficiency and annual emission rate achievable with SNCR at RS Nelson Unit 6 based on this equation are presented in the following table.

Table 7. RS Nelson Unit 6- Estimated NOx Removal Efficiency and Emission Rate with SNCR Based on EPA's Control Cost Manual for SNCR[125]

RS Nelson Unit	2018-2019 Annual NOx Rate, lb/MMBtu	NOx Reduction Efficiency Expected with SNCR	Annual Controlled NOx Rate with SNCR, lb/MMBtu
6	0.19	21.0%	0.15

The Entergy RS Nelson Unit 6 analysis also assumed a 0.15 lb/MMBtu NOx emission rate was achievable with SNCR.[126] Based on the formula provided in the SNCR chapter of the Control Cost Manual, the assumed 0.15 lb/MMBtu NOx rate with SNCR at RS Nelson Unit 6 is a reasonable assumption.

[121] *Id.* at 1-1. *See also* Institute of Clean Air Companies White Paper, Selective Non-Catalytic Reduction (SNCR) for Controlling NOx Emissions, February 2008, at 5, attached as Ex. 36.
[122] For example, Colorado assumed, 29.5% NOx removal with SNCR for Comanche Unit 1, 15% NOx removal for SNCR at Craig Units 1, 2, and 3, 37% NOx removal with SNCR at Hayden Unit 1 and 43% removal at Hayden Unit 2, 30% NOx removal at Martin Drake Units 5 and 6 and 28% NOx removal at Martin Drake Unit 7 (77 Fed. Reg. 18066, 18068-72, 18087 (3/26/12).
[123] EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, 4/25/2019, at 1-3 to 1-4.
[124] *Id.* at Figure 1.1c (on page 1-4).
[125] *Id.*
[126] *See* July 2020 RS Nelson Four-Factor Submittal at 3-1 (pdf page 343 of May 2021 Draft LA Regional Haze Plan).

c) *Combustion Control Upgrades and Optimization*

Combustion control upgrades are a third control option for RS Nelson Unit 6. Entergy did not evaluate options to optimize combustion controls at Nelson Unit 6. While Unit 6 has a low NOx concentric firing system and separated overfire air, the unit's NOx rates are not as low as other tangentially-fired boilers burning subbituminous coal. Indeed, EPA's presumptive BART limit for tangentially-fired units utilizing subbituminous coal is 0.15 lb/MMBtu, which is 21% lower than the annual average NOx rate that the unit emitted at over 2018-2019 and is significantly lower than the 0.33 lb/MMBtu maximum monthly average NOx rate the unit emitted over 2018-2019.

Although the exact date of installation of the low NOx controls at Nelson Unit 6 is unknown, NOx combustion control technology has evolved over the past two decades. More modern and efficient combustion controls and techniques are available. While the precise degree of NOx reduction with newer NOx combustion controls is site-specific, the following table of average annual NOx emission rates achieved in 2020 at tangentially-fired coal-fired EGUs that strongly indicates that the NOx combustion controls on Unit 6 can be further improved:[127]

[127] These data were downloaded from EPA's Air Markets Program Data website at https://ampd.epa.gov/.

Table 8: Lowest Annual NOx Emission Rates in 2020 of Tangentially-Fired EGUs with Combustion Controls

Facility Name	Unit ID	2020 Avg. NOx Rate (lb/MMBtu)
Weston	3	0.06
Rush Island	1	0.08
Rush Island	2	0.09
Labadie	4	0.09
Labadie	1	0.09
Labadie	2	0.09
Bridgeport Harbor Station	BHB3	0.10
Labadie	3	0.10
Antelope Valley	B2	0.11
Brunner Island, LLC	2	0.11
Brunner Island, LLC	3	0.11
Waukegan	7	0.11
Rawhide Energy Station	101	0.11
Genoa	1	0.11
Antelope Valley	B1	0.11
Joppa Steam	5	0.12
Sooner	2	0.12
Northeastern	3313	0.12
Waukegan	8	0.12
Sam Seymour	2	0.12
Sooner	1	0.12
Joppa Steam	6	0.12
Comanche (470)	1	0.12
Sherburne County	2	0.12
Columbia	1	0.12
Sherburne County	1	0.12
Lawrence Energy Center	4	0.13
Sam Seymour	1	0.13
Lawrence Energy Center	5	0.13
Coal Creek	2	0.13
Sam Seymour	3	0.13
Brunner Island, LLC	1	0.13
Harrington Station	062B	0.13
Dave Johnston	BW44	0.13
Harrington Station	063B	0.13
Newton	1	0.13
Colstrip	3	0.14

Burlington (IA)	1	0.14
Colstrip	2	0.14
Trenton Channel	9A	0.14
Colstrip	4	0.14
Coleto Creek	1	0.14
Harrington Station	061B	0.15
Martin Lake	2	0.15
Martin Lake	3	0.16
J K Spruce	**1	0.16
Cholla	1	0.16
Tolk Station	171B	0.16
Ghent	2	0.16
St. Clair	7	0.16
Coal Creek	1	0.16
Centralia	BW22	0.16
R M Schahfer Generating Station	17	0.17
Martin Lake	1	0.17
Tolk Station	172B	0.17
R M Schahfer Generating Station	18	0.17
White Bluff	1	0.17
Jim Bridger	BW72	0.17
White Bluff	2	0.17
Independence	2	0.18
Cholla	4	0.18
Platte	1	0.18
Jim Bridger	BW71	0.18
Independence	1	0.18

As can be seen from the above table, RS Nelson Unit 6's NOx rate is significantly worse than that of the top performing tangentially-fired boilers with similar combustion controls. LDEQ should require Entergy to evaluate replacing the low NOx concentric firing system with state-of-the-art low NOx burners and/or upgrading the overfire air system to make sure it is optimized for NOx reduction. Neural networks controls are another control option that LDEQ should require Entergy to evaluate. Neural networks provide for real-time combustion optimization, which can reduce NOx emissions, control carbon monoxide emissions and improve heat rate (which reduces all pollutants).[128] LDEQ should also require Entergy to evaluate the option of more frequent and comprehensive boiler tune-ups. As with neural network controls, comprehensive

[128] *See*, e.g., Using Neural Network Combustion Optimization for MATS Compliance, Power Magazine, February 1, 2014, available at https://www.powermag.com/using-neural-network-combustion-optimization-for-mats-compliance/.

boiler tune-ups can reduce NOx and CO and improve heat rate which will reduce emissions on an annual basis.[129]

Cost effectiveness analyses for two NOx controls which most assuredly can be applied at RS Nelson Unit 6 and can significantly reduce NOx emissions are provided below.

2. Cost Effectiveness Evaluation for SCR and SNCR at RS Nelson Unit 6

The July 2020 Entergy RS Nelson Four-Factor Submittal included cost effectiveness analyses for SCR and SNCR at RS Nelson Unit 6 based on EPA's SCR and SNCR cost spreadsheets made available with its Control Cost Manual.[130] However, those analyses used an unreasonably high 7% interest rate in amortizing capital costs of control.[131] In addition, Entergy's SCR cost analysis assumed an achievable NOx rate of 0.05 lb/MMBtu. For the reasons discussed in Section I.C.1.a) above, a lower annual average NOx rate of 0.04 lb/MMBtu should be readily achievable with SCR at RS Nelson Unit 6. The 0.04 lb/MMBtu NOx rate reflects only 80% control across the SCR, when SCR systems can achieve in excess of 90% control. Even from the worst-case monthly NOx rate at Nelson Unit 6 over 2018-2019 of 0.33 lb/MMBtu, a 0.04 lb/MMBtu emission rate with SCR reflects only 88% control which is readily achievable with SCR as discussed above. Thus, the SCR cost analysis presented herein assumes a 0.04 lb/MMBtu annual NOx rate would be achieved with SCR and also assumes the current bank prime interest rate of 3.25% in amortizing capital costs.

In terms of the remaining useful life of the controls, EPA's Control Cost Manual indicates that, for EGUs, SCR has a useful life of 30-years and SNCR has a useful life of 20 years.[132] According to EPA, SCR has been used to control NOx emissions from fossil fuel-fired combustion units since the 1970's and has been installed on more than 300 coal-fired power plants in the U.S.[133] Thus, in its Control Cost Manual, EPA has found that the useful life of an SCR system at a power plant would be 30 years, and EPA cited one analysis that assumed a design lifetime of 40 years.[134] With respect to SNCR, there is also ample support for assuming a useful life for SNCR of 30 years, so that is what I assumed in the SNCR cost effectiveness analysis. While EPA states in the SNCR Control Cost Manual chapter that it is assumed than an SNCR would have a life of 20 years, EPA also states: "As mentioned earlier in this chapter,

[129] *See*, e.g., Improving Load Response and NOx Emissions with Boiler Turning and Coal-Fired Unit Optimization, Power Magazine, March 1, 2021, available at https://www.powermag.com/improving-load-response-and-nox-emissions-with-boiler-tuning-and-coal-fired-unit-optimization/.

[130] July 2020 RS Nelson Four-Factor Submittal at 3-1 to 3-3 and at Appendix B (pdf pages 343-345 and at pdf pages 429-467).

[131] *Id.*

[132] *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 80, and s*ee* EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, revised 4/25/2019, at 1-54.

[133] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 5.

[134] *Id.* at pdf page 80.

SNCR control systems began to be installed in Japan the late 1980's. Based on data EPA collected from electric utility manufacturers, at least 11 of approximately 190 SNCR systems on utility boilers in the U.S. were installed before January 1993. In responses to another ICR, petroleum refiners estimated SNCR life at between 15 and 25 years."[135] Therefore, based on a 1993 SNCR installation date, these SCNR systems that EPA refers to are at least 28 years old, which all other considerations aside, strongly argue for a 30-year equipment life. Furthermore, an SNCR system is much less complicated than a SCR system, for which EPA clearly indicates the life should be 30 years. In an SNCR system, the only parts exposed to the exhaust stream are lances with replaceable nozzles. The injection lances must be regularly checked and serviced, but this can be done relatively quickly, if necessary, is relatively inexpensive, and should be considered a maintenance item. In this regard, the lances are analogous to SCR catalyst, which is not considered when estimating equipment life. All other items, which comprise the vast majority of the SNCR system capital costs, are outside the exhaust stream and should be considered to last the life of the facility or longer. Given that EPA has assumed a 30-year life of SNCR in control cost calculations for coal-fired EGUs in the context of the regional haze program,[136] it is reasonable to assume a 30-year life of SNCR for application to RS Nelson Unit 6, as well as for SCR. Entergy's analysis assumed a 30-year life for SCR, but only a 20-year life for SNCR at Nelson Unit 6.[137]

Entergy's report evaluated both urea and ammonia as reagents for both SCR and SNCR and assumed costs for those reagents that were higher than the EPA default values, but Entergy's report did not provide a citation for the assumed higher costs. For the analyses presented herein, ammonia was assumed to be the reagent for SCR and urea was assumed to be the reagent for SNCR, given that these are the most commonly used reagents with each control at EGUs.[138] The default EPA costs for these reagents were also used.

Similar to Entergy's analysis for RS Nelson Unit 6, EPA's cost calculation spreadsheets, made available with its Control Cost Manual Chapters for SNCR and for SCR,[139] were used for the cost effectiveness analyses presented herein. The following provides the other relevant inputs made to the cost modules to estimate NOx control costs for RS Nelson Unit 6:

a. **Retrofit Difficulty**: I used a retrofit factor of "1" for the SCR and SNCR cost analyses at RS Nelson Unit 6, which is also what the Trinity Consultants' analysis assumed.
b. **Unit Size**: 556 MW

[135] EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, revised 4/25/2019, at 1-54.
[136] *See*, e.g., 80 Fed. Reg. 18944 at 18968 (April 8, 2015).
[137] July 2020 RS Nelson Four-Factor Submittal at 3-1 to 3-3 and at Appendix B (pdf pages 343-345 and at pdf pages 429-467).
[138] *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019 at pdf page 5, and EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, revised 4/25/2019, at 1-1, 1-6.
[139] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

c. **Higher heating value of the fuel and sulfur content**: 8,411 Btu/lb, 0.35% sulfur, and 5.84% ash content were used, which is what was used in the Entergy analyses.
d. **Actual MW-hours**: I used the average of 2018-2019 gross MW-hours reported for Nelson Unit 6 to EPA's Air Markets Program Database.
e. **Net Heat Rate**: This was calculated from the Gross Load (MW-hours) and the heat input (MMBtu/hr) reported to EPA's Air Markets Program Database over 2018-2019.
f. **Elevation**: 21 feet.
g. **Number of Days SCR operates**: 365 days.
h. **Inlet and Outlet NOx rates**: I used the 2018-2019 annual average NOx rates at Nelson Unit 6 as the inlet rate, 0.04 lb/MMBtu as an outlet NOx rate for SCR, and 0.15 lb/MMBtu as outlet NOx rates for SNCR.
i. **Interest rate**: I used a 3.25% interest rate.
j. **Equipment life**: I used 30 years for both SCR and SNCR.
k. **Other inputs**: I used the defaults for the other cost inputs from EPA's SCR and SNCR spreadsheets for reagent, catalyst, labor, electricity, and water, and assumed use of 29.4% aqueous ammonia as the SCR reagent and urea as the SNCR reagent. For fuel costs, I used $1.97/MMBtu, which was the value used in the Entergy analysis and is purportedly site-specific.
l. **Baseline emissions**: 2018-2019 average emissions were used as baseline emissions for this analysis. Costs of controls are based on reductions from RS Nelson Unit 6's annual NOx rate averaged over 2018-2019 of 0.19 lb/MMBtu.

The following table summarizes the cost effectiveness calculations for these NOx controls at RS Nelson Unit 6.

Table 9. Cost Effectiveness of Post-Combustion NOx Controls at RS Nelson Unit 6, Based on 30-Year Life of Controls and the EPA Control Cost Manual Spreadsheets[140]

Control	Annual NOx Rate, lb per MMBtu	Capital Cost (2019$)	O&M Costs	Total Annualized Costs	NOx Reduced from 2017-2019 Baseline, tpy	Cost Effective-ness, $/ton
SCR	0.04	$188,909,545	$2,269,098	$12,238,594	2,067	$5,922/ton
SNCR	0.15	$12,247,428	$1,635,787	$2,286,738	550	$4,156/ton

As shown above, SCR would reduce NOx emissions by 2,067 tons per year at cost effectiveness of $5,922/ton. SNCR would achieve much lower NOx reductions of 550 tons per year but is more cost effective. However, the SCR costs are within the range that other states are planning

[140] *See* SCR and SNCR Cost Manual Spreadsheets for RS Nelson Unit 6, attached as Exs. 37 and 38.

to use to determine cost effectiveness of controls in their regional haze plans for the second implementation period. Arizona is using $4,000 to $6,500/ton.[141] New Mexico is using $7,000 per ton,[142] and Oregon is using $10,000/ton or possibly even higher.[143] Washington is using $6,300/ton for Kraft pulp and paper power boilers.[144] SCR is a cost-effective NOx control for RS Nelson Unit 6 that would reduce NOx emissions by over 2,000 tons per year.

3. Consideration of Energy and Non-Air Environmental Factors of SCR and SNCR

The use of SCR and SNCR presents several non-air quality and energy impacts, most of which are taken into account in EPA's SCR and SNCR cost spreadsheet in estimating the annualized costs of control. For SCR, those issues include the parasitic load of operating an SCR system, which requires additional energy (fuel and electricity) to maintain the same steam output at the boiler.[145] The costs for the additional fuel and electricity are taken into account in EPA's SCR cost spreadsheet. The spent SCR catalyst must be disposed of in an approved landfill if it cannot be recycled or reused, although it is not generally considered hazardous waste.[146] Further, the use of regenerated catalyst can reduce the amount of spent catalyst that needs to be disposed.[147] The EPA's SCR cost spreadsheet assumed regenerated catalyst will be used and includes costs for catalyst disposal. If anhydrous ammonia is used, which EPA acknowledges is commonly used at SCR installations, there would be an increased need for risk management and implementation and associated costs.[148] If urea or aqueous ammonia is used as the reagent, the hazards from the use of pressurized anhydrous ammonia do not apply. Nonetheless, anhydrous ammonia is commonly used in SCR installations, because it lowers SCR control costs, and any issues with the handling of pressurized ammonia are well known and commonly addressed. Indeed, SCR technology is widely used at coal-fired EGUs. There are typically not overarching non-air quality or energy concerns with this technology, and many of the concerns are addressed in the cost analysis.

[141] *See*, e.g., Arizona Department of Environmental Quality, 2021 Regional Haze Four-Factor Initial Control Determination, Tucson Electric Power Springerville Generating Station, at 15, available at https://www.azdeq.gov/2021-regional-haze-sip-planning.

[142] *See* NMED and City of Albuquerque, Regional Haze Stakeholder Outreach Webinar #2, at 12, available at https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED_EHD-RH2_8_25_2020.pdf.

[143] *See*, e.g., September 9, 2020 letter from Oregon Department of Environmental Quality to Collins Forest Products, at 1-2, available at https://www.oregon.gov/deq/aq/Documents/18-0013CollinsDEQletter.pdf.

[144] *See*, e.g., Washington Department of Ecology, Draft Responses to comments for chemical pulp and paper mills, at 5, 6, and 8, attached as Ex. 13.

[145] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf pages 15-16, and 48.

[146] *Id. a*t pdf 18.

[147] *Id.* at pdf 18-19.

[148] Anhydrous ammonia is a gas at standard temperature and pressure, and so it is delivered and stored under pressure. It is also a hazardous material and typically requires special permits and procedures for transportation, handling, and storage. *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 15.

SNCR reduces the thermal efficiency of the boiler, which requires additional energy (fuel and electricity) to maintain the same steam output at the boiler.[149] The EPA's cost spreadsheet also takes into consideration increased ash disposal as a result of burning more fuel, as well as increased water consumption and treatment costs.[150] SNCR technology is also widely used at coal-fired EGUs, and there are typically not overarching non-air quality or energy concerns with this technology.

4. Consideration of Length of Time to Install Controls

SCR systems are typically installed within a 3- to 5-year timeframe. For example, in Colorado, SCR was operational at Hayden Unit 1 in August of 2015 and at Hayden Unit 2 in June of 2016, according to data in EPA's Air Markets Program Database, within 3.5 years of EPA's December 31, 2012 approval of Colorado's regional haze plan. In Wyoming, SCR was operational at Jim Bridger Units 3 and 4 in 2015 and 2016, less than three years from EPA's January 30, 2014 final approval of Wyoming's regional haze plan.

SNCR installation is much less complex than an SCR installation, and thus it can typically be installed more quickly. In a 2006 document, the Institute of Clean Air Companies indicated that SNCR could be installed in 10-13 months.[151]

D. Summary – There are Several Cost-Effective Pollution Control Options for RS Nelson Unit 6 that Should Warrant Adoption of Control Measures as Part of LDEQ's Long Term Strategy for Achieving Reasonable Progress Towards the National Visibility Goal

As shown in Table 4, a wet or dry FGD system at RS Nelson Uni 6 would be very cost effective at approximately $3,000/ton of SO2 removed and would reduce SO2 emissions by over 7,500 tons per year from the low sulfur coal BART emissions level (based on meeting a pre-control SO2 rate of 0.6 lb/MMBtu). Even Entergy's cost analysis, which used an unreasonably high 7% interest rate and which included costs that EPA has found are not consistent with its Control Cost Manual as discussed in Section I.B.5 above, would still be considered cost effective at $5,800 to $6,000/ton, when compared to the cost effectiveness thresholds being used by other states for their regional haze plans for the second implementation period. In addition, NOx controls at RS Nelson Unit 6 would also be cost effective as shown in Table 9 above, with SCR achieving the over 2,000 tons per year of NOx reduction at costs of $5,900/ton and SNCR achieving 550 tons per year of NOx reduction at $4,150/ton. Based on LDEQ's criteria for selecting sources to

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[149] EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, revised 4/25/2019, at 1-28 to 1-29.
[150] *Id.* at 1-46, 1-49 to 1-53.
[151] Institute of Clean Air Companies, Typical Installation Timelines for NOx Emission Control Technologies on Industrial Sources, December 4, 2006, at 4-5, available at https://cdn.ymaws.com/www.icac.com/resource/resmgr/ICAC_NOx_Control_Installatio.pdf.

evaluate for controls in its regional haze plan for the second implementation period,[152] the RS Nelson facility is one of the Louisiana's sources that met all of LDEQ's criteria for selection for control. Given that cost-effective controls exist for this facility and that none of the other three factors (remaining useful life, non-air and energy impacts, and time to install controls) would be an impediment to successful and cost-effective implementation of controls, LDEQ should reconsider its proposed action to defer a determination of regional haze controls on this unit until a later implementation period.[153]

III. Big Cajun II Unit 3

A. Background on Big Cajun II

Big Cajun II power plant is located near New Roads, Louisiana in Pointe Coupee Parish. It is owned and/or operated by Cleco Power, Cleco Cajun LLC, and Louisiana Generating LLC (collectively, Cleco).[154] The power plant includes two coal-fired boilers, Units 1 and 3, that use subbituminous coal from the Powder River Basin. Each boiler is rated at 6,420 MMBtu/hr, and the units each have a generating capacity of 575 MW. Boiler No 2 was converted from coal to natural gas in 2015. Unit 1 has had a DSI system for SO2 since 2015, but Unit 3 has no SO2 controls. Units 1 and 3 have ESPs for PM emissions. All three units are equipped with combustion controls and SNCR for NOx. Unit 2 installed SNCR in 2015 and has been achieving NOx emission rates in the range of 0.08-0.09 lb/MMBtu, according to data in EPA's Air Markets Program Database. Units 1 and 3 installed SNCR in 2014 and have been achieving NOx rates of approximately 0.12 lb/MMBtu, according to EPA's Air Markets Program Database.

Trinity Consultants prepared a report on behalf of Cleco to address LDEQ's information collection request with a four-factor analysis of controls for Big Cajun II.[155] The July 2020 Cleco Four-Factor Submittal indicates that Cleco is required, per a consent decree, to either retire Unit 1 or convert the unit from coal to gas by April 1, 2025. Cleco's Four-Factor submittal also states that Cleco is planning to retire Units 2 and 3 no later than December 31, 2032 and is willing to take a federally enforceable limit on the operation of these units.[156] However, LDEQ has proposed to defer a determination on this source until a subsequent regional haze

[152] *See* LDEQ's Summary of Criteria for Source Selection and LDEQ's Source Selection Spreadsheet, both revised 4/16/2020 and available at https://www.deq.louisiana.gov/index.cfm/page/261F2280-D9F2-E391-3F6CA81C44D4FD38.
[153] *Id.* at 23.
[154] Entergy Louisiana owns part of Big Cajun II Unit 3.
[155] May 2021 Draft LA Regional Haze Plan, Appendix B, July 24, 2020 Response to March 18, 2020 Regional Haze Four-Factor Analysis Information Collection Request, Cleco Big Cajun II Power Plant, prepared by Trinity Consultants (hereinafter "July 2020 Cleco Four-Factor Submittal"), at pdf pages 64 to 125 of LDEQ's May 2021 Draft LA Regional Haze Plan.
[156] *Id.*, July 2020 Cleco Four-Factor Submittal at 1-1 (pdf page 67 of May 2021 Draft LA Regional Haze Plan).

implementation period, and LDEQ is not even proposing to adopt an enforceable requirement that Units 2 and 3 retire no later than December 1, 2032.[157]

Big Cajun II Units 1 and 2 were considered BART-eligible but were determined by LDEQ to not be subject to BART.[158] Big Cajun II Unit 3 was not considered BART-eligible. This unit began operation in 1984, according to data reported to the Energy Information Administration.

With the Consent Decree requiring Big Cajun II Unit 1 to retire or convert to natural gas-firing by April 1, 2025, Cleco did not evaluate installing additional SO2 controls for Unit 1.[159] LDEQ should make these requirements an enforceable part of the Louisiana SIP, given that LDEQ would have otherwise required Big Cajun II Unit 1 to evaluate controls in a four-factor analysis. The July 2020 Cleco Four-Factor Submittal includes a four-factor analysis for SO2 controls for the coal-fired Big Cajun II Unit 3 power plant. This report provides comments on that analysis and provides an independent analysis of SO2 controls.

B. SO2 Controls for Big Cajun II Unit 3

July 2020 Cleco Four-Factor Submittal includes an analysis of SO2 controls for Big Cajun II Unit 3. Specifically, wet FGD was evaluated to achieve an SO2 emission rate of 0.04 lb/MMBtu, dry FGD was evaluated to achieve an SO2 emission rate of 0.06 lb/MMBtu, and DSI was evaluated to achieve an SO2 emission rate of 0.32 lb/MMBtu.[160] In support of the cost effectiveness analyses for these controls, the Cleco Four-Factor submittal included a cost evaluation prepared by Sargent & Lundy.[161] Cleco's cost estimate assumed approximately a four-year life of controls, based on an assumption that controls would not be installed until February 1, 2028 and that the unit would retire by December 2032.[162] However, assuming that controls would not be installed until 6.5 years after the regional haze SIP is due to be submitted to EPA (i.e., July of 2021) is an unreasonably long timeframe for installation of controls. As demonstrated in Section I.B.6 of these comments (in the section on RS Nelson Unit 6), a wet or dry scrubber should be able to be installed within 3 years, and DSI should be able to be installed within 2 years. Installing these controls by December 31, 2025, which is 4.5 years after the SIP is due to be submitted to EPA, should be considered a reasonable timeframe for compliance. If

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[157] May 2021 Draft LA Regional Haze Plan at 24.
[158] 82 Fed. Reg. 60520 at 60524 (Table 3) (Dec. 21, 2017).
[159] May 2021 Draft LA Regional Haze Plan, Appendix B July 2020 Cleco Four-Factor Submittal, at 2-1 (pdf page 69 of the May 2021 Draft LA Regional Haze Plan). *See also* Consent Decree resulting from *U.S. v. Louisiana Generating LLC* (Civil Action No. 09-100-JBB-DLD). Note that under Paragraph 63 of the Consent Decree, Louisiana Generating notified EPA on May 2, 2019 that it elected not to retrofit Big Cajun II Unit 1 with controls. Therefore, the unit must be retired or converted to natural gas-firing by April 1, 2025.
[160] *Id.*
[161] July 2020 Cleco Four-Factor Submittal, Appendix A (at pdf page 76 of LDEQ's May 2021 Draft LA Regional Haze Plan).
[162] July 2020 Cleco Four-Factor Submittal at 3-3 and Appendix A to that submittal at 13 (pdf page 74 and 92 of the May 2021 Draft LA Regional Haze Plan).

an enforceable requirement was imposed to retire Unit 3 by December 2032, then the life of the SO2 controls in a cost-effective analysis should not be any shorter than 7 years.

Moreover, an assumed retirement date (or conversion to natural gas-firing) of 2032 should not be given any weight unless LDEQ is going to adopt an enforceable limitation on the remaining useful life of Big Cajun II Unit 3. EPA states in its 2019 regional haze guidance that "[t]he remaining useful life factor is closely related to the cost of compliance factor, with the calculated cost of compliance generally increasing with a shorter remaining useful life based on the decreasing amortization period."[163] EPA further states that if a source is expected to close by December 31, 2028 or even a date after 2028 and the closure of such source is an enforceable requirement, then a state may decide not to consider that source for control in its evaluation of controls to achieve reasonable progress towards the national visibility goal.[164] However, without LDEQ imposing an enforceable requirement for Big Cajun II Unit 3 to retire or convert to natural gas-firing by 2032, it is unreasonable for LDEQ to not consider Big Cajun II Unit 3 for controls in its regional haze plan for the second implementation period. This is especially because SO2 controls would be very cost effective for this unit, as will be demonstrated further below.

1. Baseline Emissions of SO2 for Big Cajun II Unit 3

According to July 2020 Cleco Four-Factor submittal, LDEQ required that baseline emissions be calculated based on the maximum monthly value during a baseline period of January 1, 2018 to December 31, 2019."[165] Cleco claimed that multiplying maximum monthly emissions by 12 resulted in baseline emissions that greater than annual emissions during that timeframe, and so Cleco stated that it used the annual average value during the 2018-2019 baseline period.[166] It appears that Cleco determined the monthly average SO2 emissions from all months with operating data, determined an average monthly rate, and multiplied that by 12 to arrive at a baseline emissions level of 8,241 tpy of SO2.[167] The 2018-2018 annual average SO2 emissions are somewhat lower than represented by Cleco in its four-factor submittal, as shown in the table below.

[163] August 20, 2019 EPA Guidance on Regional Haze Plans for the Second Implementation Period at 20.
[164] *Id.*
[165] July 2020 Cleco Four-Factor Submittal at 2-1 (pdf page 69 of May 2021 Draft LA Regional Haze plan).
[166] *Id.*
[167] *Id.*

Table 10. 2018-2019 Average Annual Emissions and Operational Characteristics of Big Cajun II Unit 3.[168]

Big Cajun II	SO2, tpy	SO2 Rate, lb/MMBtu	NOx, tpy	Heat Input, MMBtu/yr	Gross Load, MW-hrs/yr	Operating Hours/yr
Unit 3	7,898	0.63	1,526	24,592,942	2,342,202	5,865

Based on emissions data reported to EPA's Air Markets Program Database, Big Cajun II Unit 3 had a maximum monthly lb/MMBtu SO2 rate of 0.73 lb/MMBtu during 2018-2019.[169]

2. Remaining Useful Life of Big Cajun II Unit 3

As discussed above, Cleco is planning to retire Unit 3 by December 31, 2032, but LDEQ has not proposed an enforceable limit on the remaining operation of the unit despite Cleco's willingness to take a federally enforceable limit on the operation of the unit.[170] Thus, in any cost effectiveness analysis for SO2 controls at Unit 3, the remaining useful life of the unit should be considered equal to the remaining useful life of the controls. If LDEQ imposed an enforceable requirement that Big Cajun II Unit 3 had to retire the unit by December 31, 2032, then it would be consistent with EPA regulations and policy to consider that date as a limitation on the remaining useful life of the unit. However, without an enforceable limitation requiring Unit 3 to retire by 2032, the remaining useful life of Big Cajun II Unit 3 should be considered equivalent to the remaining useful life of the SO2 controls in a cost effectiveness analysis.

3. SO2 Control Options and Achievable Emission Rates for Big Cajun II Unit 3

Big Cajun II Unit 3 has no SO2 controls. In 2021, it is uncommon for a coal-fired power plant to be operated without a wet or dry FGD system or at the very least without a DSI system to reduce SO2 emissions. Three add-on SO2 control options are available for Big Cajun II Unit 3: wet FGD, dry FGD (SDA or CDS), and DSI. Within the category of dry FGD is a CDS, which can achieve higher SO2 removal than a traditional SDA. Because cost effectiveness is calculated based on annual costs and annual emission reductions, it is important to determine the annual

[168] Based on data reported to EPA's Air Markets Program Database.
[169] *See* Big Cajun II Unit 3 Monthly Emissions from AMPD 2018 to 2019, in attached Ex. 25.
[170] July 2020 Cleco Four-Factor Submittal at 1-1 (pdf page 67 of May 2021 Draft LA Regional Haze Plan).

lb/MMBtu SO2 rate achievable with controls to be evaluated in a cost effectiveness analysis, which is evaluated for these SO2 control options below.[171]

According to data in the Energy Information Administration's Coal Data Browser for Big Cajun II, the plant uses low sulfur coal from the Powder River Basin. Over 2018-2019, the uncontrolled SO2 emissions from Big Cajun II Unit 3 averaged 0.63 lb/MMBtu.[172] Cleco's four-factor submittal evaluated wet FGD to achieve a controlled SO2 emission rate of 0.04 lb/MMBtu, dry FGD to achieve a controlled SO2 emission rate of 0.06 lb/MMBtu, and DSI to achieve a controlled emission rate of 0.32 lb/MMBtu.[173] These controlled rates reflect a control efficiency from current annual average uncontrolled SO2 levels of 93.7% with wet FGD, 90.5% control with dry FGD, and 49.2% with DSI. As discussed at length in Section I.B.3 above, wet scrubbers can achieve 98% control, and dry scrubbers can achieve 95-98% control. Thus, the Cleco analysis does not reflect the maximum SO2 removal capabilities of wet and dry FGD systems. For the same reasons discussed above in Section I.B.3. and 4 above, wet FGD should be able to achieve an annual average SO2 rate at Big Cajun II Unit 3 of 0.03 lb/MMBtu, which reflects 95.2% SO2 removal efficiency from the current uncontrolled SO2 rate. An SDA should be able to achieve an annual average SO2 rate of 0.05 lb/MMBtu and a NID™ CDS should be able to achieve an annual average SO2 rate of 0.04 lb/MMBtu (which reflects 92.1% removal across the SDA and 93.7% SO2 removal across the CDS from the current uncontrolled SO2 rate). For the reasons previously discussed in Section I.B.3 above, these emission rates and levels of control should be readily achievable at Big Cajun II Unit 3.

Cleco evaluated DSI to achieve approximately 50% SO2 control. That is consistent with the Sargent & Lundy IPM DSI Cost Development Methodology documentation, which indicates that the SO2 removal rate with DSI and an ESP should be set at 50%.[174]

4. Cost Effectiveness Analysis for SO2 Controls at Big Cajun II Unit 3

Below I provide cost effectiveness analyses for wet FGD, SDA, a NID™ CDS, and DSI for Big Cajun II Unit 3. For the wet FGD and SDA, I used the cost effectiveness calculation spreadsheets that EPA recently made available with its revised chapter on costs of control for wet and dry scrubbers.[175] I also used EPA's SDA cost algorithms to estimate the costs of a

[171] *See*, e.g., 83 Fed. Reg. 51,403 at 51,409 (Oct. 11, 2018), in which EPA assumed for a cost effectiveness analysis of SCR that an annual NOx rate of 0.04 lb/MMBtu would be achieved with SCR at the Laramie River Station under a 0.06 lb/MMBtu NOx limit applicable on a 30-day average basis.
[172] Based on emissions data reported to EPA's Air Markets Program Database.
[173] July 2020 Cleco Four-Factor Submittal at 2-1 (pdf page 69 of May 2021 Draft LA Regional Haze Plan).
[174] Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO2 Control Cost Development Methodology, April 2017, at 4. (Available at https://www.epa.gov/airmarkets/retrofit-cost-analyzer and attached as Ex. 8).
[175] *See* Wet and Dry Scrubbers for Acid Gas Control Cost Calculation Spreadsheet, available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

NID™ CDS. As discussed in Sections I.B.3 and 4, the SDA cost algorithms are reasonable to estimate the costs of a CDS or may even overstate the costs. For DSI, I used the framework for DSI SO2 from EPA's Retrofit Cost Tool[176] which is also based on the 2017 IPM cost module for DSI.

The following provides the other relevant inputs made to the cost modules to estimate SO2 control costs for Big Cajun 2 Unit 3:

a. **Retrofit Difficulty:** I used the default retrofit factor of "1" for all cost analyses for Big Cajun II Unit 3. The cost algorithms in the EPA cost spreadsheets and the underlying IPM cost modules are based on the actual cost data to retrofit these controls to existing coal-fired power plants, which generally were not designed to take into account the retrofit of future pollution controls.
b. **Unit Size:** 575 MW.
c. **Gross Heat Rate:** This was calculated from the Gross Load (MW-hours) and the heat input (MMBtu/hr) reported to EPA's Air Markets Program Database over 2018-2019 and averaged over the two-year period.
d. **SO2 Rate**: This input is used to calculate the rates for limestone (wet FGD)/lime (SDA)/trona (DSI), scrubber waste, auxiliary power, and makeup water, and also for base scrubber model and reagent handling capital costs. For this input, I used the annual average SO2 emission rate based on 2018-2019 emissions data reported to EPA's Air Markets Program Database, which was 0.63 lb/MMBtu.
e. **Operating SO2 Removal**: This was calculated based on the percent removal from the current 0.63 lb/MMBtu annual SO2 rate to achieve an annual SO2 rate of 0.03 lb/MMBtu for wet FGD (i.e., 95.2%), to get to an annual SO2 rate of 0.04 lb/MMBtu for an SDA FGD intended to reflect the cost of a NID™ circulating dry scrubber (i.e., 93.7%), and to get to an annual SO2 rate of 0.05 lb/MMBtu for an SDA (i.e., 92.1%). In comparison, comparison, Cleco evaluated wet FGD to achieve an SO2 removal efficiency of 93.7% and SDA FGD to achieve an SO2 removal efficiency of 90.5%.[177] For DSI, 50% control was evaluated (to achieve an SO2 rate of 0.32 lb/MMBtu).
f. **Costs of Limestone (for Wet FGD), lime (for SDA FGD or NID™ CDS), trona (for DSI), Waste Disposal, Makeup Water, and Operating Labor**: The default values from the EPA cost spreadsheets for Wet FGD, SDA FGD, and DSI were used for these costs.
g. **Auxiliary Power Cost**: EPA's cost spreadsheet uses the average power plant operating expenses as reported to the Energy Information Administration for 2016 of $0.0361/kW-hr for auxiliary power cost calculations in its cost effectiveness spreadsheets provided

[176] Available at https://www.epa.gov/airmarkets/retrofit-cost-analyzer.
[177] *See* July 2020 RS Nelson Four-Factor Submittal at 2-1 (pdf page 338 of May 2021 Draft LA Regional Haze plan).

with its Control Cost Manual.[178] I used the most recent final EIA data which, for 2019, is \$0.0367/kW-hr.[179] In all cases, I included auxiliary power costs in the variable operating and maintenance costs.

h. **Elevation:** 46 feet above sea level[180]

l. **Interest rate:** The current bank prime interest rate of 3.25% was used for the cost effectiveness calculations, as this is what EPA currently recommends for cost effectiveness analyses. For example, EPA's Wet and Dry Scrubber Cost Estimation spreadsheets state that "User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/)."[181] In the past five years, the bank prime rate has not been higher than 5.5%,[182] and the current bank prime rate is 3.25%.[183] Cleco's Four-Factor Analysis used an interest rate of 7%.[184] EPA's Control Cost Manual indicates that the use of the current bank prime interest rate is justified for cost effectiveness calculations,[185] and thus that is what was used for the cost effectiveness analyses presented herein. Moreover, given that the Control Cost Manual mandates an "overnight" cost methodology, it is most appropriate to use the bank prime interest rate as it exists today, not an estimate of what the interest rate may be at some point in the future.

i. **Equipment lifetime**: A 30-year life was assumed in amortizing capital costs for wet FGD, SDA FGD, and DSI. EPA states that the useful life of an FGD system is at least 30-years.[186] In addition, to reflect the possibility that LDEQ may impose a limitation on the remaining useful life of Big Cajun II Unit 3 to retire by December 31, 2032, a cost effectiveness evaluation assuming a 7-year life of controls was also conducted, which is based on the controls being installed by 12/2025. As discussed above in in Section I.B.6., scrubbers should be able to be installed within 2-3 years. Assuming installation of controls by 12/2025 provides 4.5 years from when the regional haze SIP is due to be submitted to EPA, which should be more than enough time to install the controls.

j. **Baseline emissions**: As discussed in Section II.B.1. above, 2018-2019 average emissions at Big Cajun II Unit 3 were used as baseline emissions and operational characteristics (heat input, heat rate, megawatt-hours generated).

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178 Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

179 *See* EIA, October 2020, Electric Power Annual 2019, Table 8.4, available at https://www.eia.gov/electricity/data/eia923/.

180 Estimate for location based on elevation of Waterloo, LA.

181 *See* EPA's Wet and Dry Scrubber Cost Spreadsheet, row 60 of tab entitled "Data Inputs." Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

182 https://fred.stlouisfed.org/series/PRIME.

183 https://www.federalreserve.gov/releases/h15/.

184 *See* July 2020 Cleco Four-Factor Submittal, Appendix A, Cleco Cajun LLC, Cost Evaluation to Support Four Factor Analysis, July 23, 2020 at 13 (pdf page 92 of May 2021 Draft LA Regional Haze plan).

185 EPA Control Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, at 15.

186 *See* EPA, Control Cost Manual, Section 5, Chapter 1, Wet and Dry Scrubbers for Acid Gas Control, April 2021, at 1-8, available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution and attached as Ex. 39

The following table summarize the cost effectiveness calculations for SO2 controls at Big Cajun II Unit 3.

Table 11. Cost Effectiveness of SO2 Controls at Big Cajun II, Based on 30-Year Life of Controls and the EPA Cost Spreadsheets (2019 $)[187]

	Annual SO2 Rate, lb/MMBtu	Capital Cost (2019 $)	O&M Costs (2019 $)	Total Annualized Costs (2019 $)	SO2 Reduced, tpy	Cost Effectiveness, $/ton (2019 $)
Wet FGD	0.03	$288,582,799	$9,149,995	$24,455,181	7,396	$3,307
NID™ CDS	0.04	$263,580,897	$8,812,213	$22,780,323	7,272	$3,132
SDA	0.05	$263,580,897	$8,812,213	$22,780,323	7,149	$3,186
DSI at 50% Control	0.32	$19,081,803	$9,760,508	$10,765,770	3,949	$2,726

While DSI at 50% SO2 control is the most cost-effective, it is the least effective at reducing SO2 emissions from Big Cajun II Unit 3. All of the three FGD options evaluated (wet FGD, NID™ circulating dry scrubber, and SDA) would achieve 90-95% (or better) SO2 control very cost-effectively. The costs of all of these controls should be considered as cost effective by LDEQ. These costs are well below the cost effectiveness thresholds that other states have proposed or are currently planning to use for deciding cost effective controls to require in their regional haze plans for the second implementation period. For example, Texas is using $5,000/ton as a cost effectiveness threshold.[188] Arizona is using $4,000 to $6,500/ton.[189] New Mexico is using $7,000 per ton,[190] and Oregon is using $10,000/ton or possibly even higher.[191] Washington is using $6,300/ton for Kraft pulp and paper power boilers.[192]

[187] *See* EPA Control Cost Manual cost spreadsheets for Wet FGD, SDA, CDS, and DSI for Big Cajun II Unit 3, attached as Ex. 40.
[188] *See* https://www.tceq.texas.gov/assets/public/implementation/air/sip/haze/2021RHSIP_pro.pdf
[189] *See*, e.g., Arizona Department of Environmental Quality, 2021 Regional Haze Four-Factor Initial Control Determination, Tucson Electric Power Springerville Generating Station, at 15, available at https://www.azdeq.gov/2021-regional-haze-sip-planning.
[190] *See* NMED and City of Albuquerque, Regional Haze Stakeholder Outreach Webinar #2, at 12, available at https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED_EHD-RH2_8_25_2020.pdf.
[191] *See*, e.g., September 9, 2020 letter from Oregon Department of Environmental Quality to Collins Forest Products, at 1-2, available at https://www.oregon.gov/deq/aq/Documents/18-0013CollinsDEQletter.pdf.
[192] *See*, e.g., Washington Department of Ecology, Draft Responses to comments for chemical pulp and paper mills, at 5, 6, and 8, attached as Ex. 13.

5. Comments on Cleco's SO2 Cost Analysis and Consideration of a Shortened Remaining Useful Life of Big Cajun II Unit 3

The SO2 control cost estimates presented in the July 2020 Cleco Four-Factor Submittal for Big Cajun II Unit 3 are much higher than the cost estimates using EPA's cost estimation spreadsheets presented in Table 11 above. Specifically, Cleco calculated the cost effectiveness of wet FGD as $16,209/ton, for dry FGD as $13,809/ton, and for DSI as $5,250/ton.[193] A significant reason for that is because Cleco only assumed a 4-year life of the controls, assuming the unit would retire by December of 2032 and that it would take until 6.5 to install controls. As discussed in Section II.B.2, it was unreasonable to assume such a long time to install SO2 controls, and it also is not appropriate to consider a reduced remaining useful life without an enforceable requirement for Big Cajun II Unit 3 to shut down by 2032 without an enforceable requirement to do so. Instead, it would be more reasonable to assume these controls would be installed within 4.5 years of the July 2021 SIP submittal deadline, which should be readily achievable, and if an enforceable requirement was imposed to retire Unit 3 by December 2032, then the life of the SO2 controls in a cost-effective analysis should not be shorter than 7 years.

Another reason for Cleco's highest costs is that Cleco assumed a much higher 7% interest rate in annualizing capital costs which, as discussed above, was not a reasonable assumption given how low interest rates are currently. As discussed above, my cost analysis used the current bank prime rate of 3.25%. Cleco also included owner's costs and expenses for taxes and insurance for the new SO2 controls.[194] Owner's costs are not consistent with the EPA Control Cost Manual methodology.[195] Further, taxes generally do not apply to the purchase of pollution control equipment,[196] and the added insurance cost for a scrubber or DSI should be minimal. Another expense that the Cleco cost analysis took into account was lost fly ash sales with dry FGD and DSI, yet its four-factor analysis did not include documentation to verify the quantity of fly ash sold in recent years and the profit from the sales.[197] Further, Cleco assumed a 53% capacity factor in its costs for SO2 controls, when Big Cajun II Unit 3 operated at a 46.5% capacity factor over 2018-2019.[198] Assuming a higher capacity factor would increase cost of lime, limestone and trona along with waste disposal costs. Further, the quantity of lost fly ash sales could be overstated as well. Cleco assumed a scrubber waste disposal rate of $49 per ton, which is much higher than the waste disposal rate used by EPA of $30/ton.[199]

[193] July 2020 Cleco Four-Factor Submittal at 2-3 (pdf page 71 of May 2021 Draft LA Regional Haze Plan).
[194] *See* July 2020 Cleco Four-Factor Submittal, Appendix A, Cleco Cajun LLC, Cost Evaluation to Support Four Factor Analysis, July 23, 2020 at Appendix A (pdf pages 112 to 114 of May 2021 Draft LA Regional Haze plan).
[195] See EPA, Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction at pdf page 65-66.
[196] *See* https://revenue.louisiana.gov/TaxForms/1050(2_13).pdf.
[197] *See* July 2020 Cleco Four-Factor Submittal, Appendix A, Cleco Cajun LLC, Cost Evaluation to Support Four Factor Analysis, July 23, 2020 at 19-20 and 23-24 (pdf pages 98-99 and 101-102 of May 2021 Draft LA Regional Haze plan).
[198] *Id.* at Appendix A (pdf pages 112 to 114 of May 2021 Draft LA Regional Haze plan). 2018-2019 average annual capacity factor was calculated based on the two year average gross load (MW-hrs) reported to EPA's Air Markets Program Database and assuming a 575 MW capacity of Big Cajun II Unit 3.
[199] *Id.* at Appendix A (pdf pages 112 to 114 of May 2021 Draft LA Regional Haze plan).

For all of these reasons, Cleco's cost effectiveness values of $13,809/ton for dry FGD and $16,209/ton for wet FGD at a four-year life[200] are greatly inflated. Cleco's cost effectiveness of for DSI at a four-year life of $5,250/ton is also an overstatement of costs for the above reasons. However, even with Cleco's assumption of a four-year life and its assumptions that resulted in an overstatement of costs, Cleco's four-factor analysis shows that DSI over a four-year life should be considered a cost-effective control for Big Cajun II Unit 3 in that the costs are lower than the cost thresholds being used by other states in their regional haze plans for the second implementation period.

To take into account SO2 controls being installed more expeditiously than assumed in Cleco's analysis, I conducted a cost-effectiveness evaluations of SO2 controls assuming a 7-year life of controls, in the event that LDEQ adopts an enforceable requirement for Big Cajun II Unit 3 to retire by December 31, 2032. Below I provide cost effectiveness calculations for these SO2 controls for Big Cajun II Unit 3 using EPA's cost spreadsheets made available with its Control Cost Manual, assuming a 3.25% interest rate reflective of current interest rates and assuming a 7-year life of controls which, as discussed above, is very feasible even with an enforceable restriction to shut down Big Cajun II Unit 3 by December of 2032. All other inputs to the EPA cost spreadsheets are as described in Section II.B.4 above.

Table 12. Cost Effectiveness of SO2 Controls at Big Cajun II, Based on 7-Year Life of Controls and the EPA Cost Spreadsheets (2019 $)[201]

	Annual SO2 Rate, lb/MMBtu	Capital Cost (2019 $)	O&M Costs (2019 $)	Total Annualized Costs (2019 $)	SO2 Reduced tpy	Cost Effectiveness, $/ton (2019 $)
Wet FGD	0.03	$288,582,799	$9,149,995	$55,997,281	7,396	$7,572
NID™ CDS	0.04	$263,580,897	$8,812,213	$51,589,715	7,272	$7,094
SDA	0.05	$263,580,897	$8,812,213	$51,589,715	7,149	$7,216
DSI at 50% Control	0.32	$19,081,803	$9,760,508	$12,852,181	3,949	$3,255

As Table 12 demonstrates, if LDEQ adopts an enforceable requirement that Big Cajun II Unit 3 retire by December of 2032, SO2 controls would be still cost effective. DSI at 50% control would be the most cost effective but the least effective at reducing SO2 emissions. FGD systems could also be cost effective, even with a 7-year life of operation.

[200] July 2020 Cleco Four-Factor Submittal at 2-3 (pdf page 71 of May 2021 Draft LA Regional Haze Plan).
[201] *See* EPA Control Cost Manual cost spreadsheets for Wet FGD, SDA, CDS, and DSI for Big Cajun II Unit 3, attached as Ex. 40.

6. Consideration of Energy and Non-Air Environmental Impacts of SO2 Controls for Big Cajun II Unit 3

For the factor regarding energy and non-air quality impacts of a pollution control being considered, it must be noted that the SO2 controls that have been evaluated for Big Cajun II Unit 3 are widely used by coal-fired EGUs and have been for many years. Thus, in general, these SO2 controls do not pose any unusual energy and non-air quality impacts. Further, the energy and non-air quality impacts are typically taken into account by including costs for additional energy use or for things like scrubber waste disposal is the analyses of the costs of control.

7. Consideration of Length of Time to Install Controls

As previously discussed above at and at length in Section I.B.6 of this report, a wet or dry scrubber should be able to be installed within two to three years, and DSI should be able to be installed within 21-24 months. The length of time to install SO2 controls should not be considered as an impediment to requiring these controls to be installed during the second implementation period of the regional haze program.

C. Summary – SO2 Controls Should Be Considered as a Cost-Effective Control for Big Cajun II Unit 3

As shown in Tables 11 and 12 above, an FGD system should be considered as a cost effective control for Big Cajun II Unit 3, even if LDEQ imposes an enforceable limitation requiring the unit to retire by 2032. Such controls would achieve significant reductions in SO2 emissions (7,100 to 7,300 tons per year of SO2 that would be removed from the air) at costs that would be within the cost-effectiveness thresholds that other states have stated they are using for their regional haze plans for the second implementation period. Even Cleco's inflated cost analyses of SO2 controls based on the assumption that the unit would retire by 2032 shows that at least DSI would be considered a cost effective control for Unit 3. Based on LDEQ's criteria for selecting sources to evaluate for controls in its regional haze plan for the second implementation period,[202] Big Cajun II is one of the Louisiana's sources that met all of LDEQ's criteria for selection for control. Given that cost-effective controls exist for Unit 3 and that none of the other three factors (remaining useful life, non-air and energy impacts, and time to install controls) would be an impediment to the successful and cost-effective implementation of controls, LDEQ should reconsider its proposed action to defer a determination of regional haze controls on this unit until a later implementation period.[203]

[202] *See* LDEQ's Summary of Criteria for Source Selection and LDEQ's Source Selection Spreadsheet, both revised 4/16/2020 and available at https://www.deq.louisiana.gov/index.cfm/page/261F2280-D9F2-E391-3F6CA81C44D4FD38.
[203] *Id.* at 23.

IV. Brame Energy Center Unit 2

Brame Energy Center consists of three electrical generating units owned and/or operated by Cleco: Unit 1 (also known as Nesbit I) is a 440 MW natural gas-fired boiler, Unit 2 (also known as Rodemacher II) is a 523 MW wall-fired boiler that combustions Powder River Basin subbituminous coal, and Unit 3 (also known as Madison Unit 3) is a circulating fluidized bed boiler that burns petroleum coke and coal and has a generating capacity of approximately 641 MW. LDEQ did not request a four-factor submittal for any of the Brame Energy Center units in its regional haze plan for the second implementation period. This is presumably because Brame Energy Center did not exceed the criteria that LDEQ used to select sources for consideration for control.[204] However, the Brame Energy Center is a significant source of visibility-impairing emissions. On a plantwide basis, the facility averaged 5,891 tons per year of SO2 and 4,049 tons per year of NOx, according to data reported to EPA's Air Markets Program Database.

Brame Units 1 and 2 were previously subject to BART determinations. For Brame Unit 1, LDEQ imposed limits to not allow any fuel oil firing unless a BART analysis addressing fuel oil-firing is submitted to LDEQ and approved by EPA.[205] According to EPA's proposed rulemaking on the BART determinations and first round Louisiana regional haze SIP, Brame Unit 2 had LNB installed in 2009, SNCR installed in 2014, and DSI and a baghouse installed in 2015.[206] The unit also has an electrostatic precipitator (ESP).[207] LDEQ imposed an SO2 BART determination of enhanced DSI to meet an SO2 limit of 0.30 lb/MMBtu, which purportedly was reflective of 63% SO2 removal efficiency.[208] No capital expense was incurred by Cleco to implement enhanced DSI; the primary expense was an increase in operational costs of the control.[209] Brame Unit 3 is a circulating fluidized boiler with a dry lime FGD system, a selective noncatalytic reduction (SNCR) system, and a baghouse. The unit was not subject to a BART determination.

Although LDEQ did not require a four-factor evaluation of controls for the Brame Energy Center units, Brame Unit 2 should be evaluated for further emission reductions, particularly for SO2 but also for NOx. Such cost effectiveness analyses are provided herein.

A. Analysis of SO2 Controls for Brame Unit 2

[204] *See* LDEQ's Summary of Criteria for Source Selection and LDEQ's Source Selection Spreadsheet, both revised 4/16/2020 and available at https://www.deq.louisiana.gov/index.cfm/page/261F2280-D9F2-E391-3F6CA81C44D4FD38.
[205] 82 Fed. Reg. 22,936 at 22,944 (May 19, 2017).
[206] *Id.*
[207] *Id.* at 22,945.
[208] *Id.* at 22,944.
[209] *Id.*

1. Baseline Emissions of SO2 for Brame Unit 2

For other facilities, LDEQ has required that baseline emissions be calculated based on the maximum monthly value during a baseline period of January 1, 2018 to December 31, 2019."[210] The 2018-2019 baseline emissions and operational characteristics of Brame Unit 2 are listed in Table 13 below.

Table 13. 2018-2019 Average Annual Emissions and Operational Characteristics of Brame Unit 2.[211]

Brame Energy Center	SO2, tpy	SO2 Rate, lb/MMBtu	NOx, tpy	Heat Input, MMBtu/yr	Gross Load, MW-hrs/yr	Operating Hours/yr
Unit 2	3,883	0.29	2,987	26,867,553	2,529,648	7,971

Based on emissions data reported to EPA's Air Markets Program Database, Brame Unit 2 had maximum monthly lb/MMBtu SO2 rate of 0.36 lb/MMBtu during 2018-2019.[212] Based on a review of the monthly coal data reported to the Energy Information Administration for Brame Unit 2, the weighted average uncontrolled SO2 emission rate based on the sulfur in the coal averaged 0.51 lb/MMBtu with a maximum monthly uncontrolled SO2 in the coal over 2018-2019 of 0.57 lb/MMBtu.[213] On average, the DSI system at Brame Unit 2 is achieving about 43% SO2 removal from the sulfur in the coal, which is much lower than the 63% removal efficiency that was claimed would be achieved in the EPA BART rulemaking.[214]

2. Remaining Useful Life of Brame Unit 2

There are no restrictions on the remaining useful life of Brame Unit 2. Thus, for the purpose of cost effectiveness analyses presented herein, it is assumed that an FGD system installed at Brame Unit 2 would have a 30-year life which is consistent with the life of such controls assumed by EPA.[215] While Cleco has announced that it intends to cease burning coal at Unit 2 by 2028,[216] LDEQ should not consider Cleco's stated plans to cease burning coal at Unit 2 by 2028 as a restriction on the remaining useful life of the unit unless it is made into an enforceable requirement of the Louisiana SIP.

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210 *See*, e.g, July 2020 RS Nelson Four-Factor Submittal at 2-1 (pdf page 338 of May 2021 Draft LA Regional Haze plan).
211 Based on data reported to EPA's Air Markets Program Database.
212 *See* Brame Unit 2 Monthly Emissions from AMPD 2018 to 2019, in attached Ex. 25
213 See Ex. 41 with coal heat value and sulfur content of coals used at Brame Unit 2 over 2018-2019, from EIA-923.
214 82 Fed. Reg. 22,936 at 22,944 (May 19, 2017).
215 *See* EPA, Control Cost Manual, Section 5, Chapter 1, Wet and Dry Scrubbers for Acid Gas Control, April 2021, at 1-8, available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution and attached as Ex. 39.
216 https://cms-cleco.ae-admin.com/docs/default-source/ccr/rodemacher/bec-demonstrations.pdf.

3. SO2 Control Options and Achievable Emission Rates for Brame Unit 2

As stated above, the DSI system at Brame Unit 2 is currently achieving about 43% removal on an annual average basis and a controlled SO2 emission rate of 0.29 lb/MMBtu. Yet, an FGD system could reduce SO2 emissions down to the range of 0.03 to 0.05 lb/MMBtu on an annual average basis, which would be approximately 90.1% to 94.1% SO2 removal on an annual average basis. Replacement of the DSI system with a wet or dry FGD system could reduce SO2 by 3,200 to 3,500 tons per year. Given the low capital expense of DSI installation, it is reasonable to consider the replacement of the DSI system installed in 2015 at Brame Unit 2 with a more effective wet or dry FGD system.

Wet FGD should be able to achieve an annual average SO2 rate at Brame Unit 2 of 0.03 lb/MMBtu, which reflects 94.1% SO2 removal efficiency from the sulfur in the coal. An SDA should be able to achieve an annual average SO2 rate of 0.05 lb/MMBtu and a CDS should be able to achieve an annual average SO2 rate of 0.04 lb/MMBtu (which reflects 90.2% removal across the SDA and 92.2% SO2 removal across the CDS from the uncontrolled SO2 in the coal). For the reasons previously discussed in Section I.B.3 above, these emission rates and levels of control should be readily achievable at Brame Unit 2.

4. Cost Effectiveness Analysis of FGD Controls at Brame Unit 2

Below I provide cost effectiveness analyses for wet FGD, SDA, and a NID™ CDS to replace the DSI at Brame Unit 2. For the wet FGD and SDA, I used the cost effectiveness calculation spreadsheets that EPA recently made available with its revised chapter on costs of control for wet and dry scrubbers.[217] I also used EPA's SDA cost algorithms to estimate the costs of a NID™ CDS. As discussed in Sections I.B.3 and 4, the SDA cost algorithms are reasonable to estimate the costs of a CDS or may even overstate the costs.

For SDA costs, the EPA cost spreadsheet made available with its wet and dry scrubber Control Cost Manual update includes the costs of a baghouse.[218] Since Brame Unit 2 already has a baghouse, the capital and operational costs of installing and operating a baghouse can be subtracted from the SDA FGD costs calculated by the EPA SDA cost spreadsheet. EPA's Integrated Planning Model (IPM) cost module for particulate control provides cost algorithms for a baghouse,[219] which was used for this purpose. Specifically, a worksheet was created that calculated the costs for a full-scale baghouse for Brame Unit 2 with an air-to-cloth ratio of 4.0 or

[217] *See* Wet and Dry Scrubbers for Acid Gas Control Cost Calculation Spreadsheet, available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[218] *See* EPA, Control Cost Manual, Section 5, Chapter 1, Wet and Dry Scrubbers for Acid Gas Control, at 1-49.

[219] Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, Particulate Control Cost Development Methodology, April 2017, available at https://www.epa.gov/airmarkets/retrofit-cost-analyzer and attached as Ex. 42.

lower. I then subtracted the capital costs of a baghouse from the estimated cost of an SDA FGD system calculated by EPA's Control Cost Manual Wet and Dry Scrubbing Cost Spreadsheet, and I also subtracted variable and fixed operation and maintenance costs of a baghouse from the variable and fixed operation and maintenance cost of an SDA FGD system, to arrive at a capital and operational/maintenance cost estimate for an SDA system Brame Unit 2.[220]

The following provides the other relevant inputs made to the cost modules to estimate SO2 control costs for Brame Unit 2:

a. **Retrofit Difficulty:** I used the default retrofit factor of "1" for all cost analyses for Brame Unit 2. The cost algorithms in the EPA cost spreadsheets and the underlying IPM cost modules are based on the actual cost data to retrofit these controls to existing coal-fired power plants, which generally were not designed to take into account the retrofit of future pollution controls.
b. **Unit Size:** 523 MW.
c. **Gross Heat Rate:** This was calculated from the Gross Load (MW-hours) and the heat input (MMBtu/hr) reported to EPA's Air Markets Program Database over 2018-2019 and averaged over the two-year period.
d. **SO2 Rate**: This input is used to calculate the rates for limestone (wet FGD) and lime (SDA), scrubber waste, auxiliary power, and makeup water, and also for base scrubber model and reagent handling capital costs. For this input, I used the 2018-2019 average annual SO2 in the coal which I calculated from coal data reported for Brame Unit 2 to the Energy Information Administration in form EIA 923.[221] I used the uncontrolled SO2 rate from sulfur in the coal because, if a wet or dry FGD was installed, it would replace DSI, and thus it would underestimate costs if I had used the current annual SO2 emissions rate from Brame Unit 2. The annual average SO2 emission rate based on 2018-2019 coal data reported in EIA 923 is 0.51 lb/MMBtu.[222]
e. **Operating SO2 Removal**: This was calculated based on the percent removal from the current 0.51 lb/MMBtu annual SO2 rate to get to an annual SO2 rate of 0.03 lb/MMBtu for wet FGD (i.e., 94.1%), to get to an annual SO2 rate of 0.04 lb/MMBtu for an SDA FGD intended to reflect the cost of a circulating dry scrubber (i.e., 92.2%), and to get to an annual SO2 rate of 0.05 lb/MMBtu for an SDA (i.e., 90.2%).
f. **Costs of Limestone (for Wet FGD), lime (for SDA FGD or CDS), Waste Disposal, Makeup Water, and Operating Labor**: The default values from the EPA cost spreadsheets for Wet FGD, SDA and FGD were used for these costs.
g. **Auxiliary Power Cost**: EPA's cost spreadsheet uses the average power plant operating expenses as reported to the Energy Information Administration for 2016 of $0.0361/kW-

[220] *See* Cost Effectiveness Workbook for Wet FGD, SDA without baghouse and CDS for Brame Unit 2 for "SDA (wo BH) Cost Estimate" and for "BH Costs," attached as Ex. 43.
[221] *See* Ex. 41, Brame Unit 2 2018 to 2019 Coal Data from EIA-923.
[222] *Id.*

hr for auxiliary power cost calculations in its cost effectiveness spreadsheets provided with its Control Cost Manual.[223] I used the most recent final EIA data which, for 2019, is \$0.0367/kW-hr.[224] In all cases, I included auxiliary power costs in the variable operating and maintenance costs.

h. **Elevation:** 135 feet above sea level[225]
i. **Interest rate:** The current bank prime interest rate of 3.25% was used for the cost effectiveness calculations, as this is what EPA currently recommends for cost effectiveness analyses. For example, EPA's Wet and Dry Scrubber Cost Estimation spreadsheets state that "User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/)."[226] In the past five years, the bank prime rate has not been higher than 5.5%,[227] and the current bank prime rate is 3.25%.[228]
j. **Equipment lifetime**: A 30-year life was assumed in amortizing capital costs for wet FGD and dry FGD.
m. **Baseline emissions**: As discussed in Section III.B. above, 2018-2019 average operational characteristics (i.e., heat input, heat rate, megawatt-hours generated) were assumed to reflect current and future emissions at Brame Unit 2.
n. **Emissions reduced by control (i.e., the denominator in the cost effectiveness calculation):** Since the annual average uncontrolled SO2 in the coal was assumed for the design and costing of each control, I did not calculate emission reductions by simply reducing baseline emissions by the calculated percent control. Instead, I calculated controlled emission by multiplying 2018-2019 annual average heat input by the assumed SO2 annual emission rate for each control evaluated (i.e., (1) 0.03 lb/MMBtu for Wet FGD, (2) 0.04 lb/MMBtu for CDS, and (3) 0.05 lb/MMBtu for SDA). Then I subtracted the controlled annual emissions from the 2018-2019 average baseline emissions to determine the tons of pollution reduced from each control. In other words, I calculated the annual tons of SO2 reduced from the currents levels that reflect control with DSI.

The following table summarize the cost effectiveness calculations for SO2 controls at Brame Unit 2.

[223] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[224] *See* EIA, October 2020, Electric Power Annual 2019, Table 8.4, available at https://www.eia.gov/electricity/data/eia923/.
[225] Elevation for Lena, Louisiana which is near where Brame Energy Center is located.
[226] *See* EPA's Wet and Dry Scrubber Cost Spreadsheet, row 60 of tab entitled "Data Inputs." Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[227] https://fred.stlouisfed.org/series/PRIME.
[228] https://www.federalreserve.gov/releases/h15/.

Table 14. Cost Effectiveness of SO2 Controls at Brame Unit 2 (2019 $)[229]

Control	Annual SO2 Rate, lb/MMBtu	Capital Cost (2019 $)	O&M Costs (2019 $)	Total Annualized Costs	SO2 Reduced from 2018-2019 Baseline, tpy	Cost Effectiveness, $/ton (2019 $)
WFGD	0.03	$269,033,241	$8,906,990	$23,178,396	3,480	$6,661
CDS no BH	0.04	$126,078,328	$7,558,047	$14,276,528	3,346	$4,267
SDA no BH	0.05	$126,078,328	$7,544,624	$14,263,105	3,211	$4,442

The costs of all of these controls should be considered as cost effective by LDEQ. The costs for a CDS or an SDA (without a baghouse) are at or below the cost effectiveness thresholds that other states have proposed or are currently planning to use for deciding cost effective controls to require in their regional haze plans for the second implementation period. As previously discussed, Texas is using $5,000/ton as a cost effectiveness threshold.[230] Arizona is using $4,000 to $6,500/ton.[231] New Mexico is using $7,000 per ton,[232] and Oregon is using $10,000/ton or possibly even higher.[233] Washington is using $6,300/ton for Kraft pulp and paper power boilers.[234]

Further, Table 14 above shows the cost effectiveness of these SO2 controls based on the costs to install and operate the scrubbers, but Table 13 does not take into account the cost savings from not operating DSI. The operational costs can be estimated using EPA's Retrofit Cost Tool[235] which is also based on the 2017 IPM cost module for DSI. Based on the annual average uncontrolled SO2 in the coal of 0.51 lb/MMBtu and the 2018-2019 annual average SO2 emission rate achieved at Brame Unit 2 of 0.29 lb/MMBtu, EPA's Retrofit Cost Tool estimates the annual operation and maintenance costs of SO2 control with DSI to be approximately $6.8 million per

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[229] *See* EPA Control Cost Manual cost spreadsheets for Wet FGD, SDA, and CDS for Brame Unit 2, attached as Ex. 43.
[230] *See* https://www.tceq.texas.gov/assets/public/implementation/air/sip/haze/2021RHSIP_pro.pdf
[231] *See*, e.g., Arizona Department of Environmental Quality, 2021 Regional Haze Four-Factor Initial Control Determination, Tucson Electric Power Springerville Generating Station, at 15, available at https://www.azdeq.gov/2021-regional-haze-sip-planning.
[232] *See* NMED and City of Albuquerque, Regional Haze Stakeholder Outreach Webinar #2, at 12, available at https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED_EHD-RH2_8_25_2020.pdf.
[233] *See*, e.g., September 9, 2020 letter from Oregon Department of Environmental Quality to Collins Forest Products, at 1-2, available at https://www.oregon.gov/deq/aq/Documents/18-0013CollinsDEQletter.pdf.
[234] *See*, e.g., Washington Department of Ecology, Draft Responses to comments for chemical pulp and paper mills, at 5, 6, and 8, attached as Ex. 13.
[235] Available at https://www.epa.gov/airmarkets/retrofit-cost-analyzer.

year.[236] Thus, wet or dry FGD would be considered even more cost effective when one considers that the operational expenses of DSI, which reflect the majority of the costs of this control, would no longer be incurred.

Both dry and wet FGD systems would achieve significant SO2 reductions from Brame Unit 2 and provide reasonable progress toward the national visibility goal. LDEQ must consider these controls at Brame Unit 2 as part of its regional haze plan for the second implementation period.

5. Consideration of Energy and Non-Air Environmental Impacts

For the factor regarding energy and non-air quality impacts of a pollution control being considered, it must be noted that the SO2 controls that have been evaluated for Brame Unit 2 are widely used by coal-fired EGUs and have been for many years. Thus, in general, these SO2 controls do not pose any unusual energy and non-air quality impacts. Further, the energy and non-air quality impacts are typically taken into account by including costs for additional energy use or for things like scrubber waste disposal is the analyses of the costs of control.

Of all of the scrubbers evaluated, circulating dry scrubbers have the lowest energy usage, as well low freshwater usage and zero liquid discharge.[237] The Southwestern Electric Power Company (SWEPCO) has recently installed a NID™ system at the Flint Creek Power Plant in Arkansas. Flint Creek is a 528 MW unit that burned low sulfur Powder River Basin coal with a 0.8 lb/MMBtu uncontrolled SO2 rate.[238] After evaluating several SO2 control systems, SWEPCO selected a NID™ system for SO2 control for the following benefits of a NID system: lowest capital and operation and maintenance costs on a 30-year cumulative present worth basis, lowest water consumption, lowest auxiliary power usage, lowest reagent usage, smallest footprint, best for mercury reduction with activated carbon injection, best for SO3 removal, and best for future National Pollution Discharge Elimination System (NPDES) permit compliance.[239]

6. Consideration of Length of Time to Install Controls

As previously discussed above at and at length in Section I.B.6 of this report, a wet or dry scrubber should be able to be installed within two to three years.

There are several examples of FGDs being installed and integrated at units with existing baghouses. A review of a proposal for three SDA installations and tie-ins to existing baghouses

[236] *See* tab "DSI Direct Costs Saved" in Ex. 43, at cell J85.
[237] *See* https://www.babcock.com/products/circulating-dry-scrubber-cds.
[238] *See* February 8, 2012 Direct Testimony of Christian T. Beam on behalf of Southwestern Electric Power Company, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding that Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Before the Arkansas Public Utilities Commission, Docket 12-008-U, at 5, 18 (Ex. 6).
[239] *Id.* at 19-21.

shows that proper planning can provide for much of the construction work to be done while the units are operating and the tie-ins to the SDAs could be limited to less than a week. The details of such optimization of construction planning are provided in a report evaluating (among other controls) SDA systems for retrofit to Units 5, 6, and 7 of the Presque Isle power plant located in Michigan.[240] Like Brame Unit 2, each of these Presque Isle units had existing baghouses. According to a January 2013 report reviewing the retrofit optimization process for these projects, while each unit's tie-in outage was scheduled for two months, that projected timeframe was expected to be conservative.[241] SDA vessels were anticipated to be delivered in modules, to minimize field erection time and effort.[242] The ductwork arrangement "was laid out with constructability concerns in mind."[243] The tie-in outages were planned to occur within 4 to 5 days.[244] While it does not appear that these SDAs were constructed at the Presque Isle units, this report shows the planning that can be done to minimize the disruption to power plant operations while retrofitting pollution controls.

As another example, a circulating scrubber was tied into an existing baghouse at Unit 4 of the Lansing Generating Station in an outage of less than 6 weeks.[245] As stated above, circulating dry scrubbers tend to have a smaller footprint than an SDA which can help with installation upstream of an existing baghouse.

B. Analysis of NOx Controls for Brame Unit 2

According to data in EPA's Air Markets Program Database, the SNCR system at Brame Unit 2 began operating on August 30, 2013. Despite SNCR being installed on Brame Unit 2 in 2013, it is reasonable to consider a replacement of the SNCR with SCR at Brame Unit 2 to further reduce NOx in the second round of regional haze plans. SCR is much more effective at reducing NOx than SNCR, achieving 80-90% NOx removal compared to the 15-40% NOx removal achieved with SNCR. EPA has acknowledged that the installation of a new pollutant control required in the second round of regional haze plans may necessitate the removal or discontinuation of an existing pollution control.[246] Although EPA recommends against including the sunk capital costs of existing pollution controls in the cost analysis for a new pollution control being considered to achieve reasonable compliance,[247] it is important to note that SNCR itself has a

[240] *See* January 2013, Presque Isle Power Plant AQCS Retrofit Optimization Review, Revision C, available at https://www.transmissionhub.com/wp-content/uploads/2018/12/WEPCO-Feb-14-Exhibit-A.pdf.
[241] *Id.* at 34.
[242] *Id.*, Appendix 10, at 2.
[243] *Id.* at 29.
[244] *Id.* at 30.
[245] *See* Babcock & Wilcox, B&W provides CDS system for Alliant Energy's Lansing Station, available at https://www.babcock.com/products/circulating-dry-scrubber-cds and attached as Ex. 19.
[246] EPA's August 20, 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period at 31.
[247] *Id.*

low capital cost (relative to other air pollution control technologies).[248] The primary capital costs of SNCR are boiler injection ports and the reagent storage and distribution system, with the bulk of the cost of control being the cost of the reagent (a recurring annual operational expense as opposed to a capital expense). Further, the amount of reagent used with an SCR system is generally less than the amount of reagent used with an SNCR system, so the operating costs can often be lower with SCR compared to SNCR while the NOx removal efficiency is greatly improved. Replacement of the SNCR with SCR at Brame Unit 2 would greatly reduce NOx and therefore is an appropriate measure to evaluate to make reasonable progress towards the national visibility goal for the second implementation period and beyond.

1. Baseline Emissions of NOx for Brame Unit 2

The baseline emissions for Brame Unit 2 were provided in Table 13 above (in Section III.A.1. of this report). The 2018-2019 annual average NOx rate was 0.222 lb/MMBtu. For evaluating the costs to operate an SCR, a NOx baseline rate that does not reflect operation of SNCR must be used. The SNCR system at Brame Unit 2 was installed to meet requirements of the Clean Air Interstate Rule (CAIR)/Cross-State Air Pollution Control Rule (CSAPR).[249] Louisiana is only subject to CSAPR for NOx reductions during the summer ozone season.[250] Thus, one can assume that the SNCR at Brame Unit 2 is not operated outside the May through September ozone season and evaluate whether there is a difference between NOx emissions during the non-ozone season compared to the ozone season. In Table 15 below, the average monthly NOx rates during the ozone and non-ozone months as reported to EPA's Air Markets Program Database are provided.

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[248] *See* Institute of Clean Air Companies White Paper, Selective Non-Catalytic Reduction (SNCR) for Controlling NOx Emissions, February 2008, at 7, available at https://cdn.ymaws.com/icac.site-ym.com/resource/resmgr/Standards_WhitePapers/SNCR_Whitepaper_Final.pdf.

[249] *See* , e.g., October 31, 2015, Cleco Corporation Brame Energy Center, BART Five-Factor Analysis, at 1-1, in LDEQ's October 2016 Regional Haze State Implementation Plan EGU BART Analysis.

[250] *See* https://www.epa.gov/csapr/states-are-affected-cross-state-air-pollution-rule-csapr.

Table 15. Brame Unit 2 Average Monthly NOx Rates in Ozone Seasons Compared to Non-Ozone Season, 2018-2019

Non-Ozone Season NOx rates			Ozone Season NOx Rates		
Year	Month	Monthly NOx, lb/MMBtu	Year	Month	Monthly NOx, lb/MMBtu
2018	January	0.18			
2018	February	0.18	2018	May	0.22
2018	March	0.16	2018	June	0.21
2018	April	0.23	2018	July	0.23
2018	October	0.21	2018	August	0.22
2018	November	0.27	2018	September	0.21
2018	December	0.26			
2019	January	0.26			
2019	February	0.25	2019	May	0.19
2019	March	0.22	2019	June	0.19
2019	April	0.22	2019	July	0.20
2019	October	0.22	2019	August	0.20
2019	November	0.23	2019	September	0.20
2019	December	0.21			
Avg Non-Ozone Season Monthly NOx Rate, lb/MMBtu		**0.222**	**Avg Ozone Season Monthly NOx Rate, lb/MMBtu**		**0.207**

This data does show a lower NOx rate of 0.207 lb/MMBtu during the 2018-2019 ozone season months compared to the non-ozone season months. However, there is much variability between monthly NOx emission rates during both the ozone season and the non-ozone season. For the purpose of evaluation of costs to operate an SCR, a 0.222 lb/MMBtu will be assumed to be the NOx inlet rate as this appears to be the uncontrolled rate without use of the SNCR. This also happens to be the 2018-2019 annual average NOx rate.

2. Cost Effectiveness Analysis for SCR

For the SCR cost effectiveness analysis presented herein for Brame Unit 2, I used the cost calculation spreadsheet made available with EPA's Control Cost Manual Chapter for SCR.[251] For the reasons discussed in Section I.C.1 above, I evaluated SCR to meet a controlled annual NOx emission rate of 0.04 lb/MMBtu. Assuming a pre-SCR NOx rate of 0.222 lb/MMBtu, a 0.04 lb/MMBtu NOx rate reflects 82% control across the SCR, which an SCR system is more than capable of achieving.

[251] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

The following provides the other relevant inputs made to the cost modules to estimate NOx control costs for Brame Unit 2:

a. **Retrofit Difficulty**: I used a retrofit factor of "1" for the SCR analyses at Brame Unit 2.
b. **Unit Size**: 523 MW
c. **Higher heating value of the fuel and sulfur content**: 8,786 Btu/lb and 0.24% sulfur, based on the maximum monthly values in form EIA-923 for 2018 to 2019.[252]
d. **Actual MW-hours**: I used the average of 2018-2019 gross MW-hours reported for Brame Unit 2 to EPA's Air Markets Program Database.
e. **Net Heat Rate**: This was calculated from the Gross Load (MW-hours) and the heat input (MMBtu/hr) reported to EPA's Air Markets Program Database over 2018-2019.
f. **Elevation**: 135 feet.
g. **Number of Days SCR operates**: 365 days.
h. **Inlet and Outlet NOx rates**: I used the non-ozone season monthly average NOx rate of 0.222 lb/MMBtu as the SCR inlet rate and 0.04 lb/MMBtu as an outlet NOx rate for SCR.
i. **Interest rate**: I used a 3.25% interest rate.
j. **Equipment life**: 30 years, which is consistent with EPA's assumed life of SCR systems installed at utility boilers.[253]
k. **Other inputs**: I used the defaults for the other cost inputs from EPA's SCR spreadsheet for reagent, catalyst, labor, electricity, and water, and assumed use of 29.4% aqueous ammonia as the SCR reagent.
o. Emissions reduced by control (i.e., the denominator in the cost effectiveness calculation): Since the pre-SNCR NOx rate was assumed for the design and costs of SCR, I did not calculate emission reductions by simply reducing baseline emissions by the calculated percent control. Instead, I calculated controlled emission by multiplying 2018-2019 annual average heat input by the assumed NOx annual emission rate of 0.04 lb/MMBtu. Then I subtracted the SCR-controlled annual NOx emissions from the 2018-2019 average baseline NOx emissions to determine the tons of pollution reduced from each control.

The following table summarizes the cost effectiveness calculations for these NOx controls at Brame Unit 2.

[252] See Ex. 41, Brame Unit 2 2018 to 2019 Coal Data from EIA-923.
[253] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 80.

Table 16. Cost Effectiveness of Post-Combustion NOx Controls at Brame Unit 2, Based on 30-Year Life of Controls and the EPA Control Cost Manual Spreadsheet[254]

Control	Annual NOx Rate, lb per MMBtu	Capital Cost (2019$)	O&M Costs	Total Annualized Costs	NOx Reduced from 2018-2019 Baseline, tpy	Cost Effective-ness, $/ton
SCR	0.04	$175,179,094	$2,200,650	$11,445,727	2,003	$5,716/ton

As shown in the above table, SCR would reduce NOx emissions by 2,003 tons per year at cost effectiveness of $5,716/ton. The SCR costs are within the range that other states are planning to use to determine cost effectiveness of controls in their regional haze plans for the second implementation period. Arizona is using $4,000 to $6,500/ton.[255] New Mexico is using $7,000 per ton,[256] and Oregon is using $10,000/ton or possibly even higher.[257] Washington is using $6300/ton for Kraft pulp and paper power boilers.[258]

3. Consideration of Energy and Non-Air Environmental Impacts

The use of SCR presents several non-air quality and energy impacts, most of which are taken into account in EPA's SCR cost spreadsheet in estimating the annualized costs of control. Those issues include the parasitic load of operating an SCR system, which requires additional energy (fuel and electricity) to maintain the same steam output at the boiler.[259] The costs for the additional fuel and electricity are taken into account in EPA's SCR cost spreadsheet. The spent SCR catalyst must be disposed of in an approved landfill if it cannot be recycled or reused, although it is not generally considered hazardous waste.[260] Further, the use of regenerated catalyst can reduce the amount of spent catalyst that needs to be disposed.[261] The EPA's SCR cost spreadsheet assumed regenerated catalyst will be used and includes costs for catalyst disposal. If anhydrous ammonia is used, which EPA acknowledges is commonly used at SCR

[254] *See* SCR Cost Manual Spreadsheet for Brame Unit 2, attached as Ex. 44.
[255] *See*, e.g., Arizona Department of Environmental Quality, 2021 Regional Haze Four-Factor Initial Control Determination, Tucson Electric Power Springerville Generating Station, at 15, available at https://www.azdeq.gov/2021-regional-haze-sip-planning.
[256] *See* NMED and City of Albuquerque, Regional Haze Stakeholder Outreach Webinar #2, at 12, available at https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED_EHD-RH2_8_25_2020.pdf.
[257] *See*, e.g., September 9, 2020 letter from Oregon Department of Environmental Quality to Collins Forest Products, at 1-2, available at https://www.oregon.gov/deq/aq/Documents/18-0013CollinsDEQletter.pdf.
[258] *See*, e.g., Washington Department of Ecology, Draft Responses to comments for chemical pulp and paper mills, at 5, 6, and 8, attached as Ex. 13.
[259] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf pages 15-16, and 48.
[260] *Id. a*t pdf 18.
[261] *Id.* at pdf 18-19.

installations, there would be increased need for risk management and implementation and associated costs.[262] If urea or aqueous ammonia is used as the reagent, the hazards from use of pressurized anhydrous ammonia do not apply. None-the-less, anhydrous ammonia is commonly used in SCR installations, because it lowers SCR control costs, and any issues with handling of pressurized ammonia are well known and commonly addressed. Indeed, SCR technology is widely used at coal-fired EGUs. There are typically not overarching non-air quality or energy concerns with this technology, and many of the concerns are addressed in the cost analysis.

4. Consideration of Length of Time to Install Controls

SCR systems are typically installed within a 3- to 5-year timeframe. For example, in Colorado, SCR was operational at Hayden Unit 1 in August of 2015 and at Hayden Unit 2 in June of 2016, according to data in EPA's Air Markets Program Database, within 3.5 years of EPA's December 31, 2012 approval of Colorado's regional haze plan. In Wyoming, SCR was operational at Jim Bridger Units 3 and 4 in 2015 and 2016, less than three years from EPA's January 30, 2014 final approval of Wyoming's regional haze plan.

C. Summary – There are Several Cost-Effective Pollution Control Measures that Could be Applied to Brame Unit 2 that Should Warrant Inclusion in Louisiana's Regional Haze Plan for the Second Implementation Period

In summary, as shown in Tables 14 and 16 above, there are cost-effective pollution control options for Brame Unit 2. SO2 controls, particularly dry FGD systems that would be used in conjunction with the unit's existing baghouse, would be very cost effective at $4,200-$4,400/ton and would reduce SO2 emissions by 3,000-3,100 tons per year. Wet FGD would be more effective at reducing SO2 emissions and its costs at $6,600/ton would be in the range of costs that other states are considering as cost effective in their regional haze plans. Further, replacing the SNCR with SCR to achieve 2,000 tons per year reduction in NOx emissions from current emission levels would also be cost effective at $5,700/ton, given the range of costs that other states are considering as cost-effective controls. Thus, LDEQ should consider requiring controls for Brame Unit 2 in its regional haze plan for the second implementation period.

V. Ninemile Point Electrical Generating Plant

Ninemile Point Electrical Generating Plant is a power plant owned/operated by Entergy Louisiana. The facility is located in Westwego, Louisiana. The facility consists of three natural gas-fired EGUs (Units 3, 4, and 5) and one natural gas-fired combined cycle EGU (Unit 6). The generating capacity of the plant is as follows: Unit 3 – 135 MW, Unit 4 – 748 MW, Unit 5 – 763

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[262] Anhydrous ammonia is a gas at standard temperature and pressure, and so it is delivered and stored under pressure. It is also a hazardous material and typically requires special permits and procedures for transportation, handling, and storage. *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 15.

MW, and Unit 6 (640 MW). It appears that Ninemile Unit 3 has been retired since about 2016.[263]

LDEQ requested a four-factor analysis for Ninemile Point, which Entergy submitted on July 24, 2020.[264] The Units 4 and 5 boilers are equipped with induced fuel gas recirculation (IFGR) for NOx control.[265] Units 4 and 5 are allowed under their permit to burn No. 2 fuel oil as a backup fuel, but Entergy states in its four-factor report that neither unit currently has the physical capability to use fuel oil and that LDEQ could remove fuel oil as a backup fuel from the permit for these units.[266] Ninemile Unit 6 is authorized to ultra-low sulfur diesel oil, but Entergy stated in its four-factor analysis that it was not willing to remove the flexibility to burn fuel oil at Unit 6.[267] According to EPA's Air Markets Program Database, Unit 6 is equipped with water injection and SCR.[268]

Entergy provided a cost effectiveness analysis for NOx controls at the units 4 and 5 boilers. Entergy did not provide a control cost analysis for Unit 6, given that the unit has SCR. Below I provide comments on Entergy's cost analyses for Units 4 and 5 and provide an independent analysis of the costs of NOx controls at these units.

A. Comments on Entergy's Cost Analyses for NOx Controls

Entergy used EPA's cost spreadsheets for SCR and SNCR for Ninemile Point Units 4 and 5. However, Entergy's Four-Factor submittal did not identify which spreadsheets pertained to which unit, and it was difficult to figure out because the size of the unit in all spreadsheet printouts provided in the Ninemile Point Four-Factor Submittal was 750 MW, but Unit 4 is 748 MW and Unit 5 is 763 MW. Entergy also did not identify what period of baseline emissions was used for each unit, nor did Entergy identify how it determined each unit's operating megawatt-hours. A review of Entergy's cost analyses of NOx controls at Ninemile Point Units 4 and 5 showed some readily identifiable assumptions that would overestimate the costs of control, as follows:

- Entergy used a 7% interest rate in amortizing capital costs. As previously discussed in Section I.B.5, the current bank prime rate of 3.25% is a more appropriate interest rate to

[263] July 24, 2020 Response to March 18, 2020 Regional Haze Four-Factor Analysis Information Collection Request, Ninemile Point Electric Generating Plant (hereinafter "July 2020 Ninemile Point Four-Factor Submittal") at 1-1. Also, the EPA's Air Markets Program Database does not include any emissions for Unit 3 since about 2016.
[264] July 2020 Ninemile Point Four-Factor Submittal, in Appendix B of May 2021 Draft LA Regional Haze plan, at pages pdf 128 to pdf 229 of the Draft LA Plan.
[265] *Id.* at 1-1 (pdf page 131 of May 2021 Draft LA Regional Haze Plan).
[266] *Id.* at 2-1 (pdf page 131 of May 2021 Draft LA RH SIP).
[267] *Id.*
[268] Entergy's July 2020 Ninemile Point Four-Factor Submittal states that the Unit 6 turbine uses dry low-NOx combustors, lean pre-mix technology, and SCR. However, the EPA's Air Markets Program Database lists a somewhat different suite of NOx controls.

use and is more consistent with the EPA's Control Cost Manual. The use of the current bank prime rate is also consistent with the overnight cost methodology of the EPA Control Cost Manual. Entergy's use of an unreasonably higher interest rate to amortize capital costs will result in an overstatement of annual costs of control.

- For SCR at Unit 4, Entergy assumed a reagent concentration of 19% ammonia reagent, but used a density of the reagent as stored that pertained to 29.4% aqueous ammonia and then used the EPA urea reagent cost of $1.630/gallon. In contrast, EPA's SCR cost spreadsheet identifies the cost of 29.4% aqueous ammonia as $0.293/gallon, which is much lower.[269] For SCR at Unit 5, Entergy assumed a reagent concentration of 50% urea solution, but used a cost of $2.00/gallon for 50% ammonia.[270] EPA's default cost for a 50% urea solution is $1.630/gallon. Entergy did not justify these higher costs for reagent, and it also is not clear why ammonia was assumed as the reagent for SCR at Unit 4 while urea was assumed as the reagent for SCR at Unit 5. Ammonia is the most commonly used reagent with SCR at EGUs.[271] Anhydrous ammonia is commonly used in SCR installations, because it lowers SCR control costs, and any issues with the handling of pressurized ammonia are well known and commonly addressed. By assuming either a very expensive ammonia solution or a urea solution, Entergy's cost analysis overstated operational costs of SCR for NOx control at Ninemile Point Units 4 and 5. Ammonia should be the least expensive SCR reagent, but Entergy's calculations show urea as less expensive.

- Entergy applied the same approach and reagent cost values to its SNCR cost calculations but did not provide justification for the higher reagent costs compared to EPA's default cost values. For SNCR installed at EGUs, urea is the more commonly used reagent.[272]

- Entergy evaluated meeting a NOx rate with SNCR of 0.14 lb/MMBtu, which reflects approximately 35% NOx removal across the SNCR. EPA's Control Cost Manual provides a best fit equation to estimate NOx removal efficiency achievable with SNCR based on NOx inlet level. That equation is:

NOx Reduction Efficiency, %, = 22.554*Inlet NOx Rate, lb/MMBtu + 16.725.[273]

[269] *Id.* at Appendix A, EPA Cost Spreadsheet Printouts for SCR (at pdf page 142 of May 2021 Draft LA Regional Haze Plan).
[270] *Id.* at pdf page 154 of May 2021 Draft LA Regional Haze Plan.
[271] *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019 at pdf page 5.
[272] *See* EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, revised 4/25/2019, at 1-1, 1-6.
[273] *Id.* at 1-4, Figure 1.1c.

Based on this equation and assuming a pre-SNCR emission rate of 0.22 lb/MMBtu, SNCR could achieve 22.7% NOx removal across the SNCR or a NOx emission rate of 0.17 lb/MMBtu. Thus, Entergy may have overestimated the removal capabilities of SNCR at Ninemile Point Units 4 and 5.

- For SCR, Entergy assumed a NOx rate of 0.05 lb/MMBtu would be achieved, which reflects approximately 77% NOx removal. As discussed in Section I.C.1 of this report, SCR systems can achieve 90% NOx control or more. In its BART evaluation for the natural gas-fired Lake Catherine unit, Entergy assumed that SCR along with low NOx burners and separated overfire air would achieve a NOx rate of 0.03 lb/MMBtu, which reflected an assumed 84% NOx removal across the SCR.[274] A removal efficiency of 84% NOx control would reflect a NOx emissions rate of 0.04 lb/MMBtu for Ninemile Point Units 4 and 5.

Entergy also provided a cost effectiveness analysis for low NOx burners and overfire air (LNB/OFA) at Ninemile Point Units 4 and 5. Entergy stated that it relied on the cost estimate it obtained for these controls at its Lake Catherine Plant to evaluate cost effectiveness of these controls for Ninemile Point Units 4 and 5.[275] Entergy did not provide that cost study, nor did it provide any details as to how it used that cost study for the 558 MW Lake Catherine unit to estimate costs and controlled NOx rates for the Ninemile Point Units 4 and 5 which are larger than Lake Catherine at 748 MW and 763 MW, respectively. LDEQ must request more details on the costs for low NOx burners and overfire air at Ninemile Point Units 4 and 5 and make the details available for public review and comment.

Entergy's cost effectiveness analyses showed that all of these NOx controls were cost-effective for Ninemile Point Units 4 and 5, with costs ranging from approximately $3,200/ton to $4,000/ton.[276] Entergy's cost analyses showed that urea-based SCR would be the most cost effective at approximately $3,200 to $3,300/ton of NOx removed.[277] And Entergy's analysis showed that SCR would reduce NOx emissions by approximately 2,100 tons per year from Ninemile Point Unit 4 and 2,000 tons per year from Ninemile Point Unit 5, significantly more than LNB/OFA or SNCR at each unit.[278]

In fact, both SCR and SNCR would be more cost effective than shown by Entergy, because of the issues identified above especially the higher interest rate assumed by Entergy. I conducted a cost effectiveness analysis for SCR and SNCR at Ninemile Point Units 4 and 5 using the EPA

[274] 80 Fed. Reg. 18944 At 18977, Table 41 (Apr. 8, 2015).
[275] July 2020 Ninemile Point Four-Factor Submittal at 3-1 (pdf page 134 of May 2021 Draft Louisiana Regional Haze Plan).
[276] *Id.* at 3-3 to 3-4 (pdf pages 136 and 137 of May 2021 Draft LA Regional Haze Plan).
[277] *Id.*
[278] *Id.* at 3-2.

cost spreadsheets made available with its Control Cost Manual to address the issues discussed above. The details and results of these analyses are provided below.

B. Baseline NOx Emissions of Ninemile Point Units 4 and 5

Entergy's Four-Factor Submittal for Ninemile Point did not clearly present Units 4 and 5 baseline emissions. For the other four-factor analyses for EGUs, LDEQ requested that baseline emissions be based on 2018 to 2019 emissions. The 2018-2019 baseline emissions and operational characteristics of Ninemile Point Units 4 and 5 are listed in Table 17 below.

Table 17. 2018-2019 Average Annual NOx Emissions and Operational Characteristics of Ninemile Point Units 4 and 5.[279]

Ninemile Point Unit	NOx, tpy	NOx Rate, lb/MMBtu	Heat Input, MMBtu/yr	Gross Load, MW-hrs/yr	Operating Hours/yr	Annual Heat Rate, Btu/kW-hr
4	4,125	0.221	30,108,322	3,122,198	7,073	9,643
5	3,081	0.221	22,806,247	2,323,961	5,382	9,831

A review of the monthly NOx emission rates for Ninemile Point Units 4 and 5 show that they can vary significantly. Over 2018-2019, Ninemile Point Unit 4 has a maximum monthly NOx rate of 0.36 lb/MMBtu and a minimum monthly NOx rate of 0.09 lb/MMBtu.[280] Ninemile Point Unit 5 had a maximum monthly NOx rate of 0.34 lb/MMBtu and a minimum monthly NOx rate of 0.13 lb/MMBtu over 2018 to 2019.

C. Remaining Useful Life of Ninemile Point Units 4 and 5

According to Entergy's Ninemile Point Four-Factor Submittal, there are no plans to shut down Ninemile Point Units 4 and 5. Therefore, a remaining useful life of 30-years was assumed for both SCR and SNCR. According to EPA, SCR has been used to control NOx emissions from fossil fuel-fired combustion units since the 1970's and has been installed on more than 300 coal-fired power plants in the U.S.[281] Thus, in its Control Cost Manual, EPA has found that the useful life of an SCR system at a power plant would be 30 years, and EPA cited one analysis that assumed a design lifetime of 40 years.[282] With respect to SNCR, there is also ample support for assuming a useful life for SNCR of 30 years as discussed in Section I.C.2 above, so that is what I

[279] Based on data reported to EPA's Air Markets Program Database.
[280] *See* Ninemile Point Units 4 and 5 Monthly Emissions from AMPD 2018 to 2019, in attached Ex. 25.

[281] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 5.
[282] *Id.* at pdf page 80.

assumed in the SNCR cost effectiveness analysis. Indeed, EPA assumed a 30-year life of SNCR for other facilities in Arkansas in past regional haze actions.[283]

D. Cost Effectiveness of SCR and SNCR for Ninemile Point Units 4 and 5

EPA's cost calculation spreadsheets, which were made available with its Control Cost Manual Chapters for SNCR and for SCR,[284] were used for the cost effectiveness analyses presented herein. The following provides the other relevant inputs made to the cost modules to estimate NOx control costs for Ninemile Point Units 4 and 5:

a. **Retrofit Difficulty**: I used a retrofit factor of "1" for the SCR and SNCR cost analyses at Ninemile Point Units 4 and 5, which is also what the Entergy analysis assumed.
b. **Unit Size**: 748 MW for Unit 4 and 763 MW for Unit 5
c. **Higher heating value of the fuel**: I used the default heating value for natural gas-fired boilers of EPA's SCR and SNCR cost spreadsheets of 1,033 Btu/standard cubic feet.
d. **Actual MW-hours**: I used the average of 2018-2019 gross MW-hours reported for each Ninemile Point unit to EPA's Air Markets Program Database.
e. **Net Heat Rate**: This was calculated from the Gross Load (MW-hours) and the heat input (MMBtu/hr) reported to EPA's Air Markets Program Database over 2018-2019.
f. **Elevation**: 12 feet, based on Entergy's cost spreadsheets for Ninemile Point
g. **Number of Days SCR operates**: 365 days.
h. **Inlet and Outlet NOx rates**: I used the 2018-2019 annual average NOx rates at Ninemile Point Units 4 and 5, 0.04 lb/MMBtu as an outlet NOx rate for SCR, and 0.17 lb/MMBtu as outlet NOx rates for SNCR. The basis for these rates was discussed in Section IV.A. above.
i. **Interest rate**: I used a 3.25% interest rate.
j. **Equipment life**: I used 30 years for both SCR and SNCR.
k. **Auxiliary Power Cost**: EPA's cost spreadsheet uses the average power plant operating expenses as reported to the Energy Information Administration for 2016 of $0.0361/kW-hr for auxiliary power cost calculations in its cost effectiveness spreadsheets provided with its Control Cost Manual.[285] I used the most recent final EIA data which, for 2019, is $0.0367/kW-hr.[286] In all cases, I included auxiliary power costs in the variable operating and maintenance costs.
l. **Other inputs**: I used the defaults for the other cost inputs from EPA's SCR and SNCR spreadsheets for reagent, catalyst, labor, electricity, and water, and assumed use of 29.4%

[283] *See*, e.g., 80 Fed. Reg. 18944 at 18968 (April 8, 2015).
[284] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[285] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[286] *See* EIA, October 2020, Electric Power Annual 2019, Table 8.4, available at https://www.eia.gov/electricity/data/eia923/.

aqueous ammonia as the SCR reagent and urea as the SNCR reagent. For fuel costs, I used $1.65/MMBtu, which was the value used in the Entergy analysis and is purportedly site-specific.

The following table summarizes the cost effectiveness calculations for these NOx controls at Ninemile Point Units 4 and 5.

Table 18. Cost Effectiveness of Post-Combustion NOx Controls at RS Nelson Unit 6, Based on 30-Year Life of Controls and the EPA Control Cost Manual Spreadsheets[287]

Control	Annual NOx Rate, lb per MMBtu	Capital Cost (2019$)	O&M Costs	Total Annualized Costs	NOx Reduced from 2018-2019 Baseline, tpy	Cost Effective-ness, $/ton
Ninemile Point Unit 4						
SCR	0.04	$52,579,691	$1,860,866	$4,637,598	2,721	$1,704/ton
SNCR	0.17	$8,998,968	$2,008,496	$2,486,792	764	$3,255/ton
Ninemile Point Unit 5						
SCR	0.04	$53,634,097	$1,666,643	$4,499,006	2,063	$2,181/ton
SNCR	0.17	$9,116,760	$1,557,324	$2,041,880	578	$3,532/ton

As Table 18 demonstrates, SCR is much more cost effective than SCR at $1,700/ton to $2,200/ton, and SCR would reduce NOx emissions by close to 4,800 tons per year from Ninemile Point Unit 4 and 5. Even Entergy's cost effectiveness calculations of SCR, which took into account factors that would overstate the costs of SCR, show that SCR is cost effective at $3,200 to $3,500/ton of NOx removed.[288] As discussed in other sections of this report, several other states including Arizona,[289] New Mexico,[290] Washington,[291] and Oregon[292] are using cost effectiveness thresholds higher than Entergy's estimated cost effectiveness, in the range of $4,000/ton to as high as $10,000/ton. The analyses presented herein shows that SCR should be very cost effective for the Ninemile Point Units 4 and 5. SNCR would also be cost effective at the Ninemile Point units but would not be nearly as effective for reducing NOx emissions.

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[287] *See* SCR and SNCR Cost Manual Spreadsheets for Ninemile Point Units 4 and 5, attached as Exs. 45 through 48.
[288] July 2020 Ninemile Four-Factor Submittal at 3-3 (at pdf page 136 of May 2021 Draft LA Regional Haze plan).
[289] *See*, e.g., Arizona Department of Environmental Quality, 2021 Regional Haze Four-Factor Initial Control Determination, Tucson Electric Power Springerville Generating Station, at 15, available at https://www.azdeq.gov/2021-regional-haze-sip-planning.
[290] *See* NMED and City of Albuquerque, Regional Haze Stakeholder Outreach Webinar #2, at 12, available at https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED_EHD-RH2_8_25_2020.pdf.
[291] *See*, e.g., Washington Department of Ecology, Draft Responses to comments for chemical pulp and paper mills, at 5, 6, and 8, attached as Ex. 13.
[292] *See*, e.g., September 9, 2020 letter from Oregon Department of Environmental Quality to Collins Forest Products, at 1-2, available at https://www.oregon.gov/deq/aq/Documents/18-0013CollinsDEQletter.pdf.

E. Consideration of Energy and Non-Air Environmental Impacts

The use of SCR presents several non-air quality and energy impacts, most of which are taken into account in EPA's SCR cost spreadsheet in estimating the annualized costs of control. Those issues include the parasitic load of operating an SCR system, which requires additional energy (fuel and electricity) to maintain the same steam output at the boiler.[293] The costs for the additional fuel and electricity are taken into account in EPA's SCR cost spreadsheet. The spent SCR catalyst must be disposed of in an approved landfill if it cannot be recycled or reused, although it is not generally considered hazardous waste.[294] Further, the use of regenerated catalyst can reduce the amount of spent catalyst that needs to be disposed.[295] The EPA's SCR cost spreadsheet assumed regenerated catalyst will be used and includes costs for catalyst disposal. If anhydrous ammonia is used, which EPA acknowledges is commonly used at SCR installations, there would be increased need for risk management and implementation and associated costs.[296] If urea or aqueous ammonia is used as the reagent, the hazards from use of pressurized anhydrous ammonia do not apply. None-the-less, anhydrous ammonia is commonly used in SCR installations, because it lowers SCR control costs, and any issues with handling of pressurized ammonia are well known and commonly addressed. Indeed, SCR technology is widely used at coal-fired EGUs. There are typically not overarching non-air quality or energy concerns with this technology, and many of the concerns are addressed in the cost analysis.

F. Consideration of Length of Time to Install Controls

SCR systems are typically installed within a 3 to 5 year timeframe. For example, in Colorado, SCR was operational at Hayden Unit 1 in August of 2015 and at Hayden Unit 2 in June of 2016, according to data in EPA's Air Markets Program Database, within 3.5 years of EPA's December 31, 2012 approval of Colorado's regional haze plan. In Wyoming, SCR was operational at Jim Bridger Units 3 and 4 in 2015 and 2016, less than three years from EPA's January 30, 2014 final approval of Wyoming's regional haze plan. SNCR installation is much less complex than an SCR installation, and thus it can typically be installed more quickly. In a 2006 document, the Institute of Clean Air Companies indicated that SNCR could be installed in 10-13 months.[297] In either case, the length of time to install controls should not be considered as an impediment to requiring installation of such controls as part of the regional haze plan requirements.

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[293] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf pages 15-16, and 48.

[294] *Id. a*t pdf 18.

[295] *Id.* at pdf 18-19.

[296] Anhydrous ammonia is a gas at standard temperature and pressure, and so it is delivered and stored under pressure. It is also a hazardous material and typically requires special permits and procedures for transportation, handling, and storage. *See* EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 15.

[297] Institute of Clean Air Companies, Typical Installation Timelines for NOx Emission Control Technologies on Industrial Sources, December 4, 2006, at 4-5, available at https://cdn.ymaws.com/www.icac.com/resource/resmgr/ICAC_NOx_Control_Installatio.pdf.

G. Summary – NOx Controls Are Very Cost Effective for Ninemile Point Units 4 and 5 and Should Warrant Inclusion in Louisiana's Regional Haze Plan for the Second Implementation Period

As shown in Table 18, SCR at Ninemile Point Units 4 and 5 would be very cost effective at approximately $1,700/ton to $2,200/ton of NOx removed and would reduce NOx emissions by over 4,700. Even Entergy's cost analysis, which used an unreasonably high 7% interest rate and which included costs that would tend to overstate cost effectiveness as discussed in Section IV.A above, would still be considered cost effective at $3,200/ton to $3,600/ton when compared to the cost effectiveness thresholds being used by other states for their regional haze plans for the second implementation period. In addition, SNCR would also be a cost effective control, although SCR would be more cost effective and would remove an additional 3,400 tons of NOx from the air per year in comparison to SNCR. Based on LDEQ's criteria for selecting sources to evaluate for controls in its regional haze plan for the second implementation period,[298] the Ninemile Point facility is one of the Louisiana's sources that met all of LDEQ's criteria for selection for control. Given that cost-effective controls exist for this facility and that none of the other three factors (remaining useful life, non-air and energy impacts, and time to install controls) would be an impediment to successful and cost-effective implementation of controls, LDEQ should reconsider its proposed action to defer a determination of regional haze controls on this unit until a later implementation period.[299]

VI. Nelson Industrial Steam Company

Nelson Industrial Steam Company (NISCO) is cogeneration facility owned and operated by Entergy Louisiana (Entergy) that is located in Westlake, Louisiana. It consists of two circulating fluidized bed (CFB) boilers that primarily burn pet coke with natural gas used for startup. The maximum heat input capacity of each unit is 1,222 MMBtu/hour, according to LDEQ.[300] The units have fabric filter baghouses for PM control, and limestone is added to the circulating fluidized bed boilers for SO2 control.[301] Entergy submitted a report to address LDEQ's information collection request with a four-factor analysis of controls for NISCO Units 1 and 2, although the submittal only focused on NOx controls.[302] LDEQ has proposed to defer a

[298] *See* LDEQ's Summary of Criteria for Source Selection and LDEQ's Source Selection Spreadsheet, both revised 4/16/2020 and available at https://www.deq.louisiana.gov/index.cfm/page/261F2280-D9F2-E391-3F6CA81C44D4FD38.
[299] May 2021 Draft LA Regional Haze Plan at 22.
[300] May 2021 Draft LA Regional Haze Plan at 21.
[301] *Id.*
[302] May 2021 Draft LA Regional Haze Plan, Appendix B, August 27, 2020 Response to April 15, 2020 Regional Haze Four-Factor Analysis Information Collection Request, Entergy Louisiana LLC Nelson Industrial Steam Company, prepared by Trinity Consultants (hereinafter "August 2020 NISCO Four-Factor Submittal"), at pdf pages 230 to 332 of LDEQ's May 2021 Draft LA Regional Haze Plan.

determination on this source until a subsequent regional haze implementation period.[303] To our knowledge, the NISCO facility was not addressed in Louisiana's regional haze plan for the first planning period, and it was not a BART-eligible facility.

Entergy did not evaluate any additional controls for SO2 at the NISCO CFB boilers. Yet, the units burn pet coke, which is very high in sulfur content, and emit approximately 6,100 tons per year of SO2 on average.[304] CFB boilers often utilize a dry lime flue gas desulfurization (FGD), in addition to a CFB boiler with limestone, to achieve the lowest SO2 emission rates. Indeed, a dry FGD system added to an existing CFB boiler can reduce SO2 emissions by at least 90% from what the CFB boiler with added limestone is achieving. This report provides an independent analysis of a dry FGD system to significantly reduce SO2 emissions from the NISCO CFB boilers.

Entergy did provide a four-factor analysis for SCR and SNCR to reduce NOx emissions from the NISCO CFB boilers. This report provides comments on those NOx control cost analyses.

A. Baseline Emissions for NISCO CFB Boilers

Neither Entergy nor LDEQ provided current actual SO2 or NOx emissions specific for each NISCO boiler. Some of the details of the actual emissions from the plant can be ascertained from Entergy's NOx control analysis.

LDEQ's Source Selection Spreadsheet[305] identifies the 2017 actual emissions of the NISCO facility as 992 tons per year of NOx and 6,195 tons per year of SO2. However, for its NOx control cost analysis, Entergy used 2018-2019 average operations and emissions data, and use of somewhat more recent data is consistent with what LDEQ has required of other Louisiana facilities. Entergy's one exception to use of 2018-2019 emissions data was that Entergy used the Unit 2A lb/MMBtu NOx emission rate to reflect NOx emissions at both units, claiming that evaporative wing walls that were installed at Unit 2A in 2018 and reduced NOx emissions will be installed at Unit 1A in 2023.[306]

A review of the NISCO Four-Factor submittal shows that the assumed baseline annual heat input can be derived from the annual NOx rate and NOx emissions. Although the NISCO Four-Factor Submittal did not identify the baseline NOx emissions, one can calculate it based on adding the controlled NOx rates with SCR or with SNCR and the NOx emission reductions with SCR or

[303] May 2021 Draft LA Regional Haze Plan at 21.
[304] May 2021 Draft LA Regional Haze Plan at 21. *See also* LDEQ's spreadsheet entitled "RH_PP2_SourceSelection_Version_2-1.xls," available at https://www.deq.louisiana.gov/index.cfm/page/261F2280-D9F2-E391-3F6CA81C44D4FD38.
[305] Available at https://www.deq.louisiana.gov/index.cfm/page/261F2280-D9F2-E391-3F6CA81C44D4FD38.
[306] August 2020 NISCO Four-Factor Submittal at 3-1 (pdf page 237 of May 2021 Draft LA Regional Haze Plan).

with SNCR.[307] The annual heat input can then be calculated by converting the annual NOx emissions to pounds and dividing the annual NOx emissions by Entergy's assumed uncontrolled annual NOx rate of 0.091 lb/MMBtu.[308] Based on this data, I calculated the following baseline NOx emission rates and heat input that it appears were assumed by Entergy as baseline.

Unit 1A Projected Average Annual NOx:	451 tpy
Unit 1A Projected Average NOx Rate:	0.091 lb/MMBtu
Unit 1A Average Annual Heat Input:	9,912,088 MMBtu/year
Unit 2A Average Annual NOx:	449 tpy
Unit 2 Average Annual NOx Rate:	0.091 lb/MMBtu
Unit 2A Average Annual Heat Input:	9,857,143 MMBtu/year

Since there was no similar information on SO2 emissions over 2018-2019, those emissions were estimated based on the following information:

Sulfur content of fuel:	6%
Higher heating value of fuel:	15,013 Btu/lb coal
Uncontrolled SO2 emissions in fuel:	7.99 lb SO2 per MMBtu
SO2 Removal Efficiency across CFB:	90%
Controlled SO2 Emission Rate:	0.80 lb/MMBtu

The sulfur content and the heat value of the fuel used at each NISCO boiler was listed in the SCR and SNCR spreadsheets provided in Appendix A of the NISCO Four-Factor Submittal. Because the units are subject to a 90% SO2 removal requirement pursuant to New Source Performance Standard limitations,[309] a 90% control efficiency was assumed across the CFB from the uncontrolled SO2 in the pet coke to arrive at a controlled SO2 rate of 0.80 lb/MMBtu. From that information, the uncontrolled SO2 emissions from the pet coke could be calculated using the annual heat input calculated above:

Unit 1A SO2 Emissions Estimate:	3,961 tons per year
Unit 2A SO2 Emissions Estimate:	3,939 tons per year

[307] *Id.* at 3-2 (Table 3-2), at pdf page 238 of May 2021 Draft LA Regional Haze Plan. Note that the sum of the controlled emission rate plus the emission reduction for each control at each unit was a bit different for SCR compared to SNCR, which was likely due to rounding errors. For example, the controlled NOx and emissions reductions from SCR at Unit 1A sum up to 238 tpy + 219 tpy = 457 tpy, whereas the controlled NOx and emission reductions from SNCR at Unit 1A sum up to 445 tpy (333 tpy + 112 tpy). For the purposes of quantifying baseline emissions, the average of these two calculated uncontrolled emissions is presented here.
[308] This uncontrolled NOx rate is listed in all of the SCR and SNCR cost spreadsheets provided in Appendix A of the August 2020 NISCO Four-Factor Submittal.
[309] August 2020 NISCO Four-Factor Submittal at 2-1. *See also* 40 C.F.R. 60.42b(a) and (g).

These SO2 emissions total approximately 7,900 tons per year, which is much higher than the 6,195 tons per year from 2017 reported in LDEQ's Source Selection spreadsheet. Thus, these emissions are identified as an estimate, because of being based on what is assumed to be worst case sulfur content of the pet coke and because of being based on an estimate of the 90% SO2 removal efficiency across the CFB boiler with added limestone. Actual SO2 removal at the NISCO CFB boilers could be higher than 90%. However, a 90% SO2 removal efficiency is generally assumed as the SO2 removal efficiency across a CFB boiler with limestone in air permit applications.

B. Remaining Useful Life of NISCO CFB Boilers

Entergy indicated it had no plans to retire the NISCO units. Thus, the useful life of the controls will be considered as the remaining useful life of the unit. Even though the NISCO units are not classified as utility boilers, Entergy considers these cogeneration units as part of its power fleet.[310] These are power generating units, and they appear to operate at a baseload level of capacity. For these reasons, the life of SO2 and NOx controls at these units should be no different than for utility boilers. As previously discussed, EPA considers the life of FGD systems to be 30 years,[311] and EPA considers the life of SCR systems for utility boilers to be 30 years.[312] As discussed in Section I.C.2 above, there is also ample support for assuming a useful life for SNCR of 30 years.

C. SO2 Control Options for NISCO Boilers

There are two primary SO2 control options for the NISCO CFB boilers: dry FGD and wet FGD. However, generally dry FGD systems are used with CFB boilers. There have been several permit applications in recent years for power plants which proposed dry FGD in addition to a CFB boiler with limestone injection.

Due to the use of petroleum coke for fuel, the NISCO boilers (even though they are CFB boilers with limestone injection) likely have high SO2 emissions of about 0.80 lb/MMBtu as discussed above.[313] Thus, while the CFB boilers with limestone achieve a high level of SO2 control, a much higher level of SO2 control can be achieved with a dry scrubber. Indeed, a dry scrubber should be able to achieve 95% control of SO2 from the flue gas exiting the CFB boiler. However, for the purposes of the analysis presented herein, it will be conservatively assumed that a dry FGD would achieve 90% control from current emissions of the NISCO CFB boilers,

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[310] *See* https://www.entergy.com/about_entergy/.
[311] EPA, Control Cost Manual, Section 5, Chapter 1, Wet and Dry Scrubbers for Acid Gas Control, April 2021, at 1-8.
[312] EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019, at pdf page 80.
[313] As stated in Section V.A., this is an estimate based on sulfur content and high heating value of the fuel and an assumed 90% SO2 removal across the CFB boiler.

with a controlled SO2 emission rate of 0.08 lb/MMBtu. This is similar to how the Cleco Brame Unit 3 SO2 controls are designed, with about 90% SO2 removal across the CFB boiler with limestone and an additional 90% SO2 removal across the dry FGD system.[314]

To estimate the cost effectiveness of a dry scrubber at each NISCO boiler, the EPA's FGD cost spreadsheet made available with its Control Cost Manual was used.[315] For SDA costs, the EPA cost spreadsheet made available with its wet and dry scrubber Control Cost Manual update includes the costs of a baghouse.[316] Because each NISCO boiler has an existing baghouse, the capital and operating cost of a baghouse was subtracted from capital and operating costs of a dry FGD system, similar to how dry FGD costs were calculated for Brame Unit 2 in Section III.A.4. As previously discussed, EPA's IPM cost module for particulate control provides cost algorithms for a baghouse,[317] which was used for this purpose. A worksheet was created that incorporated the costs for a full-scale baghouse for each NISCO unit with an air-to-cloth ratio of 4.0 or lower. I then subtracted the capital costs of a baghouse from the estimated cost of an SDA FGD system calculated by EPA's Control Cost Manual Wet and Dry Scrubbing Cost Spreadsheet, and I also subtracted variable and fixed operation and maintenance costs of a baghouse from the variable and fixed operation and maintenance cost of an SDA FGD system, to arrive at a capital and operational/maintenance cost estimate for an SDA system at each NISCO unit.[318]

The following provides the other relevant inputs made to the cost modules to estimate SO2 control costs for Brame Unit 2:

a. **Retrofit Difficulty:** I used the default retrofit factor of "1" for all cost analyses for each NISCO unit. The cost algorithms in the EPA cost spreadsheets and the underlying IPM cost modules are based on the actual cost data to retrofit these controls to existing coal-fired power plants, which generally were not designed to take into account the retrofit of future pollution controls.
b. **Unit Size:** The EPA FGD cost spreadsheet does not have an option to indicate that the boiler is a non-utility boiler, so the unit size in megawatts is necessary to estimate the capital costs of the control. With the information provided in Entergy's SCR and SNCR cost spreadsheets for the NISCO units, including the net plant heat rate of 11.895555 MMBtu/MW, I could estimate what would be the megawatt rating of a similar plant by

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[314] *See* POWER, August 1, 2010, Cleco's Madison Unit 3 Uses CFB Technology to Burn Petcoke and Balance the Fleet's Fuel Portfolio, available at https://www.powermag.com/clecos-madison-unit-3-uses-cfb-technology-to-burn-petcoke-and-balance-the-fleets-fuel-portfolio/.
[315] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[316] *See* EPA, Control Cost Manual, Section 5, Chapter 1, Wet and Dry Scrubbers for Acid Gas Control, at 1-49.
[317] Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, Particulate Control Cost Development Methodology, April 2017, available at https://www.epa.gov/airmarkets/retrofit-cost-analyzer and attached as Ex. 42.
[318] *See* Cost Effectiveness Workbook for SDA without baghouse for NISCO Unit 1A and 2A, attached as Exs. 49 and 50.

dividing the 1,222 maximum hourly heat input rating by the net plant heat input rate to arrive at a unit size of 103 megawatts per NISCO unit.

c. **Gross Heat Rate:** I used the net plant heat rate of 11.895555 MMBtu/MW that was provided in Entergy's SCR and SNCR cost spreadsheets in its four-factor submittal for the NISCO facility.

d. **SO2 Rate**: I used 0.80 lb/MMBtu as the SO2 input rate to the dry FGD system. This was the rate I calculated in Section V.B. above as the current baseline emission rate from the uncontrolled SO2 emissions in the fuel and assuming a 90% SO2 removal efficiency across the CFB boilers with limestone injection.

e. **Operating SO2 Removal**: As stated above, I conservatively assumed 90% control was the control rate across the dry FGD system and considering the effect of the existing baghouse (assuming the dry FGD would be installed upstream of the baghouse). It is very likely a higher level of SO2 control could be achieved across a dry FGD system.

f. **Costs of Lime, Waste Disposal, Makeup Water, and Operating Labor**: The default values from the EPA cost spreadsheet for dry FGD were used for these costs.

g. **Auxiliary Power Cost**: I used $0.0676/kW-hr, which is the default rate in EPA's SCR and SNCR cost spreadsheets for industrial boilers and is also what Entergy used in its four-factor analysis of NOx controls for the NISCO boilers. However, I question whether it is appropriate to use such a high cost of power that typically applies to industrial plants when the NISCO facility is a power generating facility. Thus, this assumption may overstate the power costs to run an FGD system at the NISCO units. I included auxiliary power costs in the variable operating and maintenance costs.

h. **Elevation:** 18 feet above sea level, which is what Entergy assumed in its NOx cost effectiveness spreadsheets.

i. **Interest rate:** The current bank prime interest rate of 3.25% was used for the cost effectiveness calculations, as this is what EPA currently recommends for cost effectiveness analyses. For example, EPA's Wet and Dry Scrubber Cost Estimation spreadsheets state that "User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/)."[319] In the past five years, the bank prime rate has not been higher than 5.5%,[320] and the current bank prime rate is 3.25%.[321] Entergy used a 7% interest rate in its NOx cost effectiveness calculations, but for the reasons previously discussed, this was an unrealistically high interest rate. Further, use of a higher interest rate than the current bank prime rate not consistent with the overnight method of EPA's Control Cost Manual.

j. **Equipment lifetime**: A 30-year life was assumed in amortizing capital costs for dry FGD.

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319 *See* EPA's Wet and Dry Scrubber Cost Spreadsheet, row 60 of tab entitled "Data Inputs." Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

320 https://fred.stlouisfed.org/series/PRIME.

321 https://www.federalreserve.gov/releases/h15/.

p. Baseline emissions: The emissions and operational characteristics, which I derived from data in Entergy's NOx control cost spreadsheets provided in Appendix A of its August 2020 NISCO Four-Factor Submittal were used to estimate SO2 emission rates, emissions, and annual heat input, as presented in Section V.A above.

The following table summarize the cost effectiveness calculations for dry FGD systems at NISCO Units 1A and 2A.

Table 19. Cost Effectiveness of Dry FGD Systems (Using the Existing Baghouses), Based on 30-Year Life of Controls and the EPA Control Cost Manual Spreadsheets[322]

NISCO Unit	Annual SO2 Rate, lb per MMBtu	Capital Cost (2019$)	O&M Costs	Total Annualized Costs	SO2 Reduced from 2018-2019 Baseline, tpy	Cost Effective-ness, $/ton
1A	0.08	$48,035,549	$3,851,867	$6,427,744	3,568	$1,801/ton
1B	0.08	$48,035,549	$3,842,725	$6,418,602	3,549	$1,809/ton

As demonstrated in Table 19, a dry FGD system to achieve an additional 90% SO2 control from each NISCO unit would be very cost effective at $1,800/ton. These costs are well below the range that other states are using to define cost effective controls for their regional haze plans for the second implementation period. As previously discussed in other sections of this report, several other states including Arizona,[323] New Mexico,[324] Washington,[325] and Oregon[326] are using cost effectiveness thresholds higher than Entergy's estimated cost effectiveness, in the range of $4,000/ton to as high as $10,000/ton. The analyses presented herein shows that installation of a dry FGD system to use with the existing baghouse should be very cost effective for NISCO Units 1A and 2A.

D. NOx Control Options for the NISCO Boilers

While Entergy did not evaluate SO2 controls for the NISCO CFB boilers, Entergy did evaluate NOx controls – specifically, SCR and SNCR. However, several of the assumptions made by

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322 *See* Dry FGD Cost Manual Spreadsheets for NISCO Units 1A and 2A, attached as Exs. 49 and 50.
323 *See*, e.g., Arizona Department of Environmental Quality, 2021 Regional Haze Four-Factor Initial Control Determination, Tucson Electric Power Springerville Generating Station, at 15, available at https://www.azdeq.gov/2021-regional-haze-sip-planning.
324 *See* NMED and City of Albuquerque, Regional Haze Stakeholder Outreach Webinar #2, at 12, available at https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED_EHD-RH2_8_25_2020.pdf.
325 *See*, e.g., Washington Department of Ecology, Draft Responses to comments for chemical pulp and paper mills, at 5, 6, and 8, attached as Ex. 13.
326 *See*, e.g., September 9, 2020 letter from Oregon Department of Environmental Quality to Collins Forest Products, at 1-2, available at https://www.oregon.gov/deq/aq/Documents/18-0013CollinsDEQletter.pdf.

Entergy would overestimate costs for these controls or are otherwise not appropriate. Those issues include the following:

1. *Use of 7% interest rate to amortize capital costs, rather than the current bank prime rate.* Entergy cited to the Control Cost Manual and OMB Circular A-94 to support its use of a 7% interest rate in amortizing capital costs of SCR and SNCR.[327] However, that OMB Circular A-94 has not been updated since 2003 and thus is 18 years old. EPA's Control Cost Manual indicates that the use of the current bank prime interest rate is justified for cost effectiveness calculations. The current bank prime rate is 3.25%.[328] Moreover, the Control Cost Manual methodology is the overnight cost method, and thus the current interest rate is what should be used for determining cost effectiveness rather than an estimate of what future interest rates might be.

2. *Assumption of operating at maximum heat input capacity for each hour of the year in determining annual operating and maintenance costs.* A review of the SCR and SNCR cost spreadsheet printouts in the NISCO Four-Factor Submittal shows that Entergy's estimated annual fuel consumption of 713,044,289.2 pounds per year with a fuel heating value of 15,012.7 Btu/lb reflects each unit operating at the maximum hourly heat input rate of 1,222 MMBtu/hour for every hour of the year.[329] Specifically, operating at the stated annual fuel use and fuel heating value reflects an annual heat input of 10,704,720 MMBtu/year at each NISCO unit. However, as shown in Section V.A. above, Entergy's assumed NOx emissions and reductions reflect a lower annual heat input of 9,857,143 to 9,912,088 MMBtu/year at NISCO Units 2A and 1A, respectively. Entergy stated that controlled emission rates from 2018-2019 were used for net plant heat rate, operating hours, and baseline emissions,[330] but clearly a higher operating rate was assumed for the operating costs of each control. Because Entergy assumed the maximum possible fuel throughput at full capacity in the SCR and SNCR cost spreadsheets, Entergy overstated operational and maintenance costs for these controls. Entergy's analysis also resulted in inflated cost effectiveness values by dividing total annual costs at 100% capacity factor by NOx reductions from a lower operating capacity factor (i.e., based on 2018-2019 average operations/emissions).

3. *Entergy used a much high cost for electricity than it typically used for SCR and SNCR at utility boilers.* EPA's SCR and SNCR cost spreadsheets assume a cost of electricity for a utility boiler of \$0.0676/kW-hr, which is what Entergy used. However, for utility boilers, EPA's cost spreadsheets assume a lower cost of electricity of \$0.0361/kW-hr. Given that the NISCO units are cogeneration units and do make electricity, assuming the costs that a typical industrial boiler

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[327] August 2020 NISCO Four-Factor Submittal at 3-4 to 3-5 (pdf pages 240-1 of May 2021 Draft Louisiana Regional Haze Plan).
[328] https://www.federalreserve.gov/releases/h15/.
[329] That is, 1,222 MMBtu/hour x 8,760 hours of operation per year = 10,704,720 MMBtu/year.
[330] NISCO Four-Factor Submittal at 3-1.

would have to pay to purchase electricity likely overstates the costs that NISCO would have to incur to operate SCR or SNCR.

4. *Higher costs for ammonia and urea.* Entergy assumed costs for ammonia that were much higher than EPA's default costs for ammonia ($2.630/gallon versus EPA's $0.293/gallon) and for urea ($2.00/gallon versus EPA's $1.66/gallon). However, Entergy did not explain or provide the basis for assuming these higher costs.

5. *Entergy only assumed a 20-year life of SCR and SCR.* Given that these cogeneration units operate similarly if not identical to utility boilers, a 30-year life of controls should be justified for these units similar to the 30-year life of SCR and SNCR that is typically assumed for utility boilers.

For these reasons, Entergy's NOx cost analysis for the NISCO boilers overstates the costs of control.

In addition to the above issues, Entergy assumed a lower baseline NOx emission rate of 0.091 lb/MMBtu for both Units 1A and 2A. While Entergy states that the NOx emissions rate decreased at Unit 2A due to the installation of evaporative wing walls, Entergy assumed that Unit 1A would also achieve that lower NOx emission rate with evaporative wing walls that are planned for installation in 2023. However, unless the lower emission rates are an enforceable requirement, it was not appropriate for Entergy to consider this lower NOx rate for Unit 2A in the cost effectiveness analysis for NOx controls. EPA states in its 2019 regional haze guidance that "[g]enerally, the estimate of a source's 2028 emissions is based at least in part on the source's operation and emissions in a representative historical period."[331] EPA identifies "enforceable requirements" as one reasonable basis for assuming that 2028 operations will differ from historical emissions.[332] EPA also lists energy efficiency, renewable energy, and other programs as potentially another basis for assuming that 2028 operations will differ from historical operations where "there is a documented commitment to participate and a verifiable basis for quantifying any change in future emissions due to operational changes."[333] Entergy has not identified any enforceable requirement or documented commitment that it will install the evaporative wing walls at Unit 1A in 2023, nor has Entergy documented how the evaporative wing walls would reduce NOx emissions. Indeed, LDEQ should require that Entergy provide more details on how the evaporative wing walls reduced NOx emission rates at Unit 2A, including an evaluation of how permanent those emission reductions will be.

[331] August 20, 2019 EPA Guidance on Regional Haze Plans for the Second Implementation Period at 17.
[332] *Id.*
[333] *Id.*

E. Consideration of Energy and Non-Air Environmental Impacts of Controls

For the factor regarding energy and non-air quality impacts of a pollution control being considered, it must be noted that the dry FGD and SNCR systems are widely used at CFB boilers and have been used at numerous other coal-fired boilers for many years. Thus, in general, these SO2 and NOx controls do not pose any unusual energy and non-air quality impacts. Further, the energy and non-air quality impacts are typically taken into account by including costs for additional energy use or for things like scrubber waste disposal is the analyses of the costs of control. Thus, the consideration of energy and non-air environmental impacts should not be considered as a limiting factor to the use of these SO2 and NOx controls.

F. Consideration of Length of Time to Install Controls

As previously discussed above at and at length in Section I.B.6 of this report, a wet or dry scrubber should be able to be installed within two to three years. As discussed in Section I.C.4 of this report, SCR systems can typically be installed in 3-5 years. An SNCR installation is much less complex than an SCR installation, and thus it can typically be installed more quickly. In a 2006 document, the Institute of Clean Air Companies indicated that SNCR could be installed in 10-13 months.[334]

Also as previously discussed in Section III.A.6 of this report, there are several examples of FGDs being installed and integrated at units with existing baghouses without the need for an extensive outage. An SDA can be constructed while the units are operating, with the tie-in conducted during a scheduled maintenance outage. Thus, the length of time to install controls should not be considered as a limiting factor to the use of SO2 or NOx controls at the NISCO boilers.

[334] Institute of Clean Air Companies, Typical Installation Timelines for NOx Emission Control Technologies on Industrial Sources, December 4, 2006, at 4-5, available at https://cdn.ymaws.com/www.icac.com/resource/resmgr/ICAC_NOx_Control_Installatio.pdf.

G. Summary – SO2 Controls Are Cost Effective for NISCO Units 1A and 2A

Based on the above analysis and discussion of controls for the NISCO CFB boilers, LDEQ should consider the addition of dry FGD systems to the existing NISCO boilers as cost-effective controls for its regional haze plan. As shown in Table 19, a dry FGD system could reduce SO2 emissions by about 3,500 tons per year from each unit at a very reasonable cost of $1,800/ton.

Entergy's justification for not evaluating SO2 controls for the NISCO units was that it was a source that already has an effective control technology in place and that EPA's regional haze guidance does not require a four-factor analysis for sources with effective control technology.[335] However, EPA's 2019 regional haze guidance does not justify Entergy's decision to eliminate evaluation of SO2 controls for the NISCO units. EPA specifically states that "[i]n general, if post-combustion controls were selected and installed fairly recently…to meet a [Clean Air Act] requirement, there will be only a low likelihood of a significant technological advancement that could provide further reasonable emission reductions…."[336] The NISCO boilers do not have post combustion controls and, ss discussed in Section V.C. above, a dry FGD system added to the NISCO units could reduce SO2 emissions by at least 90% from the current SO2 emission levels. Thus, there is a high likelihood of significant SO2 reduction with FGD systems installed at each NISCO boiler. Further, the NISCO CFB boilers have been in operation since approximately the mid-1990's, and thus they do not meet the suggested criteria of EPA's 2019 guidance of having undergone a best available control technology (BACT) determination on or after July 31, 2013.[337] Moreover, the NISCO units do not have add-on SO2 controls, nor do the units meet EPA's 2012 Mercury and Air Toxics Rule limit for units that burn oil-derived fuel of 0.3 lb/MMBtu.[338] Indeed, the NISCO units do not satisfy any of the criteria that EPA's 2019 regional haze guidance suggests could negate further evaluation of controls in the regional haze plans for the second implementation period. Thus, it is not appropriate for LDEQ to not evaluate or consider the available controls to reduce SO2 from the NISCO units.

Based on LDEQ's criteria for selecting sources to evaluate for controls in its regional haze plan for the second implementation period,[339] the NISCO facility is one of the Louisiana's sources that met all of LDEQ's criteria for selection for control. Given that cost-effective controls exist for this facility and that none of the other three factors (remaining useful life, non-air and energy impacts, and time to install controls) would be an impediment to successful and cost-effective implementation of controls, LDEQ should reconsider its proposed action to defer a determination of regional haze controls on this unit until a later implementation period.[340]

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[335] NISCO Four-Factor Submittal at 2-1.
[336] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (EPA-457/B-19-003), August 20, 2019, at 22.
[337] *Id.* at 23.
[338] *Id.*
[339] *See* LDEQ's Summary of Criteria for Source Selection and LDEQ's Source Selection Spreadsheet, both revised 4/16/2020 and available at https://www.deq.louisiana.gov/index.cfm/page/261F2280-D9F2-E391-3F6CA81C44D4FD38.
[340] May 2021 Draft LA Regional Haze Plan at 21.

List of Exhibits

Exhibit Number	Description
1	Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, Wet FGD Cost Development Methodology, January 2017
2	Spreadsheet with 30-boiler operating day average rates achieved in 2020 for these units, based on emissions data reported to EPA's Air Markets Program Database.
3	Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, January 2017
4	Spreadsheet with the 30-boiler operating day average SO2 rates calculated for Lowest-Emitting EGUs with SDAs
5	Lawrence Gatton, Alstom Power, Next Generation NID™ for PC Market, Coal-Gen, August 17-19, 2011
6	February 8, 2012 Direct Testimony of Christian T. Beam on behalf of Southwestern Electric Power Company, In the Matter of Southwestern Electric Power Company's Petition for a Declaratory Order Finding that Installation of Environmental Controls at the Flint Creek Power Plant is in the Public Interest, Before the Arkansas Public Utilities Commission, Docket 12-008-U
7	Alstom Brochure, NID™ Flue Gas Desulfurization System for the Power Industry
8	Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO2 Control Cost Development Methodology, April 2017
9	Technical Support Document to Comments of Conservation Organizations, Proposed Montana Regional Haze FIP – June 15, 2012
10	Sargent & Lundy, White Bluff Station Units 1 and 2, Evaluation of Wet vs. Dry FGD Technologies, Prepared for Entergy Arkansas, Inc., Rev. 3, Oct. 28, 2008
11	Sargent & Lundy, Big Sandy Plant Unit 2, Order-of-Magnitude FGD Cost Estimate, Volume 1 – Summary Report, Sept. 29, 2010
12	EPA Control Cost Manual cost spreadsheets for Wet FGD, SDA, and CDS for RS Nelson Unit 6
13	Washington Department of Ecology, Draft Responses to comments for chemical pulp and paper mills
14	EPA Technical Assistance Document for the Louisiana State Implementation Plan for the Entergy Nelson Facility
15	EPA Technical Support Document for EPA's Proposed Action on the Louisiana State Implementation Plan for the Entergy Nelson Facility
16	November 3, 2010 letter from David C. Foerter, Institute of Clean Air Companies (ICAC) to Senator Carper
17	August 3, 2011 "B&W gets contract for dry scrubber project at Karn coal plant."
18	December 17, 2014 Extension Request for Consumers Energy Company's D.E. Karn Plant (SRN B2840) Units 1 & 2 for Compliance with the Mercury and Air Toxics Standard (40 CFR 63 Subpart UUUUU) and the Michigan Mercury Rule (R336.2501)
19	July 9, 2014 TVA – Gallatin Fossil Plant (GAF) – Request for Compliance Extension - Mercury and Air Toxics (MATS)

20	November 5, 2013 Request for One-Year Extension of the Compliance Deadline for the Mercury and Air Toxics Standards and of the Expiration Date of the Plan Approval for the Installation of Flue Gas Desulfurization Units
21	October 4, 2012 Construction Extension for Consumers Energy Company’s JH Campbell Facility Pursuant to the Mercury and Air Toxics Standard (40 CFR 63 Subpart UUUUU, also known as MATS) as well as the Michigan Mercury Rule (R336.2501, *et seq*)
22	“Hitachi Power Systems America Awarded Contract to Supply Pollution Controls Equipment for KCP&L.”
23	June 22, 2012 Request for Extension of the Mercury and Air Toxics Standards (MATS) Compliance Deadline KCP&L La Cygne, Source ID No. 1070005
24	January 30, 2013 NIPSCO – Michigan City and R.M. Schahfer Generation Stations Request for Extension of Time to Comply with the Utility MATS NESHAP
25	RS Nelson Unit 6 Monthly Emissions from AMPD 2018 to 2019
26	EPA Control Cost Manual, Section 4, Chapter 2 Selective Catalytic Reduction, June 2019
27	U.S. EPA, Complete Response to Comments for NM Regional Haze/Visibility Transport FIP, 8/5/11 (Docket EPA-R06-OAR-2010-0846)
28	LG&E Energy, Selective Catalytic Reduction: From Planning to Operation, Competitive Power College, December 2005
29	M.J. Oliva and S.R. Khan, Performance Analysis of SCR Installations on Coal-Fired Boilers, Pittsburgh Coal Conference, September 2005
30	Haldor Topsoe, SCR Experience List, October 2009
31	Hitachi, NOx Removal Coal Plant Supply List, October 17, 2006
32	Argillon Experience List U.S. Coal Plants
33	Hitachi, SCR System and NOx Catalyst Experience, Coal, February 2010
34	Kurtides, T., Sargent and Lundy, Lessons Learned from SCR Reactor Retrofit, COAL-GEN, Columbus, OH, August 6-8, 2003
35	EPA Control Cost Manual, Section 4, Chapter 1 Selective Noncatalytic Reduction, revised 4/25/2019
36	Institute of Clean Air Companies White Paper, Selective Non-Catalytic Reduction (SNCR) for Controlling NOx Emissions, February 2008
37	SCR Control Cost Manual Spreadsheet for RS Nelson Unit 6
38	SNCR Control Cost Manual Spreadsheet for RS Nelson Unit 6
39	EPA, Control Cost Manual, Section 5, Chapter 1, Wet and Dry Scrubbers for Acid Gas Control, April 2021
40	EPA Control Cost Manual cost spreadsheets for Wet FGD, SDA, CDS, and DSI for Big Cajun II Unit 3
41	Brame Unit 2 2018 to 2019 Coal Data from EIA 923
42	Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, Particulate Control Cost Development Methodology, April 2017
43	Cost Effectiveness Workbook for Wet FGD, SDA without baghouse and CDS for Brame Unit 2
44	SCR Cost Manual Spreadsheet for Brame Unit 2

45	SCR Cost Manual Spreadsheet for Ninemile Point Unit 4
46	SCR Cost Manual Spreadsheet for Ninemile Point Unit 5
47	SNCR Cost Manual Spreadsheet for Ninemile Point Unit 4
48	SNCR Cost Manual Spreadsheet for Ninemile Point Unit 5
49	Cost Effectiveness Workbook for SDA without baghouse for NISCO Unit 1A
50	Cost Effectiveness Workbook for SDA without baghouse for NISCO Unit 2A