APPENDIX B

ANALYSIS OF CONTROL STRATEGIES TO ESTABLISH REASONABLE PROGRESS GOALS

2021 Regional Haze State Implementation Plan Revision

PROJECT NUMBER 2019-112-SIP-NR

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SELECTION OF SOURCES FOR POSSIBLE ADDITIONAL CONTROLS

The Texas Commission on Environmental Quality (TCEQ) focused its control strategy analysis on stationary point source emissions of nitrogen oxides (NO_X) and sulfur dioxide (SO_2) for the second planning period of the Regional Haze Program (2019 through 2028). This appendix presents the technical bases and information the TCEQ relied on in evaluation of emission reduction measures necessary to make reasonable progress in each Class I area affected by emissions from Texas as required under 40 Code of Federal Regulations (CFR), §51.308(f)(2) of the Regional Haze Rule. The discussion on the Area of Influence (AOI) and emissions-over-distance (Q/d) screening techniques as they relate to source selection in Section 7.2.1: *Area of Influence and Q/d Analysis for Source Selection* of Chapter 7: *Long-Term Strategy to Establish Reasonable Progress Goals* provides more detail on the source selection process used by the TCEQ. Emissions used for the Q/d analysis can be found at: https://www.tceq.texas.gov/assets/public/implementation/air/sip/haze/EWRT_AMDA_Pivot_final.xlsx.

1.1 DETERMINATION OF POTENTIAL CONTROLS

The TCEQ performed the four-factor analysis for this planning period, and the types of industry and potential controls considered for evaluation under the four statutory factors are described below and in the tables that follow in Section 1.2: *Determination of Potential Control Costs* for each source selected. Table B-1: *Sources Selected for Four-Factor Analysis* shows the 18 sources selected for four-factor analysis based on the AOIs and Q/d threshold criteria. Additional discussion on the 18 sources that were selected for four-factor analysis based on the AOIs and Q/d threshold criteria, can be found in Chapter 7, Section 7.2.1 of this SIP revision.

- SO_2 control at 30 units from 13 sites
  - Electric Generating Units (EGU) - Dry-Sorbent Injection (DSI), Dry Scrubbers, Wet Scrubbers, and Wet Scrubber Upgrades
  - Cement Kilns - Wet Scrubber Upgrades
  - Flat Glass Furnaces - multi-pollutant control (SO_2 reducing reagent)
  - Carbon Black Incinerator, Dryers, Boilers, and Flare - DSI, Dry Scrubbers, and Wet Scrubbers
  - Petroleum Coke Calcining Kilns - DSI, Dry Scrubbers, and Wet Scrubbers
  - Lightweight Aggregate Kiln - DSI, Dry Scrubbers, and Wet Scrubbers

- NO_X control at 31 units from seven sites
  - EGUs - Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR)
  - Flat Glass Furnaces - multi-pollutant control (NO_X reducing reagent)
  - Kraft Pulp Paper Mill - Low-NO_X Burners (LNB) and SCR
  - Gas Compressor Station Reciprocating Engines - Low-Emission Combustion (LEC) Retrofit and SCR
  - Gas Compressor Station Gas Turbines - LNB and SCR
  - Cement Kilns - LNB, SNCR, and SCR

Table B-1: Sources Selected for Four-Factor Analysis

Company, Site Name	Unit(s)	Class I Area(s)	Pollutant(s)
Coleto Creek Power LLC, Coleto Creek Power Station	(1) coal boiler	Wichita Mountains	SO_2
Southwestern Electric Power Company, Welsh Power Plant	(2) coal boilers	Caney Creek & Wichita Mountains	SO_2
Southwestern Electric Power Company, AEP Pirkey Power Plant	(1) coal boiler	Caney Creek & Wichita Mountains	SO_2
NRG Energy LLC, Limestone Electric Generating Station	(2) coal boilers	Wichita Mountains	SO_2
Vistra Energy LLC, Martin Lake Electric Station	(3) coal boilers	Caney Creek & Wichita Mountains	SO_2
San Miguel Electric Cooperative, San Miguel Electric Plant	(1) coal boiler	Guadalupe Mountains & Wichita Mountains	SO_2
Public Service Company of Oklahoma, Oklaunion Power Station	(1) coal boiler	Wichita Mountains	SO_2 and NO_X
Vistra Energy LLC, Oak Grove Steam Electric Station	(2) coal boilers	Wichita Mountains	SO_2
Holcim Texas LP, Midlothian Plant	(2) cement kilns	Wichita Mountains	SO_2
Vitro Flat Glass LLC, Works No 4 Wichita Falls Plant	(2) glass melting furnaces	Wichita Mountains	SO_2 and NO_X
Graphic Packaging International LLC, Texarkana Mill	(4) boilers	Caney Creek	NO_X
El Paso Natural Gas Company LLC, Keystone Compressor Station	(15) reciprocating engines	Guadalupe Mountains & Salt Creek	NO_X
El Paso Natural Gas Company LLC, Cornudas Plant	(6) turbines	Guadalupe Mountains	NO_X
El Paso Natural Gas Company LLC, Guadalupe Compressor Station	(1) turbine	Guadalupe Mountains	NO_X
GCC Permian LLC, Odessa Cement Plant	(2) cement kilns	Guadalupe Mountains	NO_X
Orion Engineered Carbons LLC, Orange Carbon Black Plant	(1) incinerator, (4) dryers, (2) tail gas and NG boilers, (1) flare	Caney Creek	SO_2
Oxbow Calcining LLC, Oxbow Calcining-Port Arthur	(4) coke calcining kilns	Caney Creek	SO_2
TRNLWS LLC, Streetman Plant	(1) lightweight aggregate kiln	Wichita Mountains	SO_2

Baseline emissions were used to evaluate potential control measures for each source selected. 2016 TCEQ point source emissions inventory data were used for non-EGUs.

The 2018 United States Environmental Protection Agency (EPA) Clean Air Markets Division, Air Markets Program Data (AMPD) emissions data were used for EGUs, with supporting information from the Energy Information Administration (EIA). Selected sources triggered four-factor analysis on an individual pollutant basis (SO_2 or NO_X) with some sources triggering analysis for both pollutants.

The TCEQ only considered control technologies demonstrated as technically feasible for units at each source type and evaluated those controls using the unit-specific data available. A control technology was demonstrated to be technically feasible if it was identified in the RACT/BACT/LAER Clearinghouse, where RACT stands for Reasonably Available Control Technology, BACT stands for Best Available Control Technology, and LAER stands for Lowest Achievable Emission Rate, or operated in industrial applications for units within an industry type not in a performance "trial" phase. The TCEQ did not speculate whether a control technology applied to a site in the performance evaluation period would be deemed technically demonstrated or feasible. The TCEQ identified three sources during the four-factor analysis for the second implementation period for which no technically demonstrated controls were identified. Additional detail is provided in the following source-by-source discussions relevant to those specific sites. Generally, DSI, spray dryer absorber (SDA), and wet limestone scrubbing systems are available post-combustion control options for controlling SO_2 emissions. Similarly, in general, controls that are available options for controlling NO_X emissions are LNB and LEC, as combustion modification control techniques, and SNCR and SCR as post-combustion control techniques. These controls have been applied to many different industry sectors and are considered technically demonstrated and feasible for such sectors.

The TCEQ does not consider a control measure or technique that has been established as technically demonstrated or feasible in one industry type to extend automatically to other industry types, even if the other industry types may have similar exhaust stream characteristics. Furthermore, while the TCEQ is aware of fuel switching and fuel and raw material sulfur content reduction techniques, these control techniques were not applied to the sources selected for the four-factor analysis as an SO_2 control option. The TCEQ instead chose to rely on post-combustion control techniques for potential control of SO_2 emissions because the TCEQ anticipates greater resulting SO_2 emission reductions from the application of post-combustion control techniques relative to those such as fuel switching or fuel or raw material sulfur reduction. Further, information necessary to evaluate these kinds of control techniques is not always publicly available and contemplating the emission reductions and costs associated with these control techniques would require much broader and resource-intensive engineering and economic analyses. Therefore, the TCEQ did not evaluate pre-combustion control techniques except as specifically discussed below for Orion Engineered Carbons LLC, Oxbow Calcining LLC, and TRNLWS LLC.

All units identified as emitting the pollutant for which a source was selected for application of the four statutory factors were evaluated for application of potential control measures. However, as part of the cost analysis, units at a source selected for application of the four statutory factors with NO_X or SO_2 emissions of less than 5% of the total site's emissions of the same pollutant were removed from further control measure analysis screening. Excluding those units with relatively smaller emissions was considered reasonable regarding application of the cost of compliance criterion. Controlling these smaller units would not be justified at this time by the likely benefit considering both the cost to control and the anticipated improvement in visibility. This approach allowed focus on the NO_x and SO_2 units with relatively greater emissions at a source.

1.1.1 Coleto Creek Power LLC, Coleto Creek Power Station and Southwestern Electric Power, Welsh Power Plant

Both sites are coal-fired EGUs meeting the source selection criteria for SO_2 emissions and were evaluated for visibility impairment at Wichita Mountains for Coleto Creek and at Caney Creek and Wichita Mountains for Welsh Power Plant. The units evaluated for this four-factor analysis were one coal-fired utility boiler at Coleto Creek and two coal-fired utility boilers at Welsh Power Plant. 2018 data for both sites showed no existing SO_2 post-combustion controls. Therefore, DSI, SDA, and wet limestone scrubbing systems were considered for these units assuming an uncontrolled basis. The TCEQ conservatively assumed SO_2 control efficiencies of 90% for DSI, 95% for SDA, and 98% for wet limestone scrubbers based on data found in Sargent & Lundy 2017 technical support documents for flue gas desulfurization cost development methodologies.

1.1.2 Southwestern Electric Power, AEP Pirkey Power Plant

Pirkey Power Plant is a coal-fired EGU meeting the source selection criteria for SO_2 emissions and was evaluated for visibility impairment at Caney Creek and Wichita Mountains. The unit evaluated for this four-factor analysis was the one coal-fired utility boiler. A wet scrubber upgrade analysis was performed for the unit at this site based on 2018 EPA AMPD, along with 2018 EIA data, indicating the unit operated with a wet limestone scrubber. The TCEQ relied on the EPA's Technical Support Document (TSD) for the Reasonable Progress Federal Implementation Plan (FIP) for Texas (81 *Federal Register* (FR) 296; January 5, 2016) for reference baselines for existing scrubber SO_2 control, or removal, efficiencies for the unit at the Pirkey site. The EPA's November 2014 "Cost of Controls Calculations for the Texas Regional Haze Federal Implementation Plan (Cost TSD)," herein referred to as the EPA's November 2014 Cost TSD, was supplemental information to the EPA's final rule on the Texas FIP to address Texas' 2009 Regional Haze State Implementation Plan. The November 2014 Cost TSD contains a footnote (page 27) explaining the existing wet limestone scrubber system consistently removed nearly 80% of SO_2 and 79% removal efficiency was used as the baseline for the potential scrubber upgrade. The Western Regional Air Partnership (WRAP) data for potential scrubber upgrades and a WRAP spreadsheet from August 2010 containing data for EGUs with proposed Best Available Retrofit Technology SO_2 controls were relied on for information. The spreadsheet data indicated the greatest increase in scrubbing system efficiency an existing system could achieve, from baseline levels, was 95%. Therefore, the TCEQ evaluated a potential system upgrade from 79% to 95%. The TCEQ considered a wet scrubbing system employing limestone as the SO_2 reducing reagent to offer a very high, if not the highest, level of SO_2 emissions control in current practice for SO_2 post-combustion flue-gas cleanup, and other SO_2 post-combustion control technologies were not considered.

1.1.3 NRG Energy LLC, Limestone Electric Generating Station

Limestone Electric Generating Station is a coal-fired EGU meeting the source selection criteria for SO_2 emissions and was evaluated for visibility impairment at Wichita Mountains. The units evaluated for this four-factor analysis were two coal-fired utility boilers. A wet scrubber upgrade analysis was performed for the two coal-fired utility boilers at this site based on 2018 EPA AMPD, along with 2018 EIA data, indicating the units operated with wet limestone scrubbers. The EPA's November 2014 Cost TSD indicated the two existing SO_2 scrubber systems operated with SO_2 removal efficiencies of approximately 78% for Unit 1 and approximately 77% for Unit 2. The TCEQ used these values as the baselines for the potential scrubber upgrades to 95% control, or removal, efficiency for both systems for both units. The TCEQ considered a wet scrubbing system employing limestone as the SO_2 reducing reagent to offer a very high, if not the highest, level of SO_2 emissions control in current practice for SO_2 post-combustion flue-gas cleanup, and other SO_2 post-combustion control technologies were not considered.

1.1.4 Vistra Energy LLC, Martin Lake Electric Station

Martin Lake Electrical Station is a coal-fired EGU meeting the source selection criteria for SO_2 emissions and was evaluated for visibility impairment at Caney Creek and Wichita Mountains. The units evaluated for this four-factor analysis were three coal-fired utility boilers. A wet scrubber upgrade analysis was performed for the three coal-fired utility boilers at this site based on 2018 EPA AMPD, along with 2018 EIA data, indicating the units operated with wet limestone scrubbers. The EPA's November 2014 Cost TSD indicated the three existing SO_2 scrubber systems operated with SO_2 removal efficiencies of approximately 69% for Unit 1, approximately 72% for Unit 2, and approximately 70% for Unit 3. The TCEQ used these values as the baselines for the potential scrubber upgrades to 95% control, or removal, efficiency for all three systems for all three units. The TCEQ considered a wet scrubbing system employing limestone as the SO_2 reducing reagent to offer a very high, if not the highest, level of SO_2 emissions control in current practice for SO_2 post-combustion flue-gas cleanup, and other SO_2 post-combustion control technologies were not considered.

1.1.5 San Miguel Electric Cooperative, San Miguel Electric Plant

San Miguel Electric Plant is a coal-fired EGU meeting the source selection criteria for SO_2 emissions and was evaluated for visibility impairment at Guadalupe Mountains and Wichita Mountains. The unit evaluated for this four-factor analysis was the one coal-fired utility boiler. A wet scrubber upgrade analysis was performed for the one coal-fired utility boiler at this site based on 2018 EPA AMPD, along with 2018 EIA data, indicating the unit operated with a wet limestone scrubber. The EPA's November 2014 Cost TSD indicated the one existing SO_2 scrubber system operated with an SO_2 removal efficiency of approximately 94%. This value was used as the baseline for the potential scrubber upgrade to 95% control, or removal, efficiency for this system for this unit. In 2015, the existing SO_2 scrubbing system achieved around 95.4% SO_2 control efficiency. Despite the historical performance showing that the site may be capable of achieving a 95% control efficiency without a scrubber system upgrade, increases in annual costs would be expected to be incurred by the site to establish and maintain a constant 95% SO_2 scrubber efficiency. Even though the assumption of a scrubber upgrade to maintain 95% presents a conservatively high estimate of costs, this potential control measure met the $5,000 per ton threshold for further analysis. The TCEQ considered a wet scrubbing system employing limestone as the SO_2 reducing reagent to offer a very high, if not the highest, level of SO_2 emissions control in current practice for SO_2 post-combustion flue-gas cleanup, and other SO_2 post-combustion control technologies or increases in scrubber efficiency were not considered.

1.1.6 Public Service Company of Oklahoma, Oklaunion Power Station

Oklaunion Power Station is a coal-fired EGU meeting the source selection criteria for SO_2 and NO_X emissions and was evaluated for visibility impairment at Wichita

Mountains. The unit evaluated for this four-factor analysis was the one coal-fired utility boiler. A wet scrubber upgrade analysis was performed for the one coal-fired utility boiler at this site based on 2018 EPA AMPD, along with 2018 EIA data, indicating the unit operated with a wet limestone scrubber. The TCEQ relied on an air permit for information indicating the assumed baseline for a potential scrubber upgrade. TCEQ New Source Review (NSR) Permit Number 9015/PSDTX325M2, last renewed August 29, 2017, contains a special condition requiring the site to achieve a minimum 70% reduction in uncontrolled SO_2 emissions. This value was used as the baseline for the potential scrubber upgrade to 95% control, or removal, efficiency for this system for this unit. The TCEQ considered a wet scrubbing system employing limestone as the SO_2 reducing reagent to offer a very high, if not the highest, level of SO_2 emissions control in current practice for SO_2 post-combustion flue-gas cleanup, and other SO_2 post-combustion control technologies were not considered.

The NO_X control evaluation consisted of evaluating SNCR and SCR for the one coal-fired utility boiler at this site. 2018 EPA AMPD indicated the unit operated with LNB for NO_X control. The TCEQ assumed NO_X control efficiencies of 50% for SNCR and 98% for SCR. While the TCEQ recognizes that these control technologies may achieve greater NO_X control, these conservative control efficiencies for NO_X emission reductions were assumed to be well within the ranges of historical literature of 35% to 50% for SNCR and of 70% to 98% for SCR. The TCEQ also considered these values in accounting for the age of this unit and the potential difficulty of achieving higher control efficiencies. The SNCR and SCR control technologies were also evaluated as techniques in addition to the existing LNB system, i.e. the assumption the site would not remove the LNB system to install and operate either an SNCR or SCR NO_X control system. The TCEQ also notes that this site announced retirement for 2020; however, the site has not surrendered its air permit. Therefore, the potential shutdown of the unit is not yet enforceable. For this reason, this site, like the other 17 sites meeting the source selection analysis criteria, was considered in the four-factor analysis.

The TCEQ notes an error in the proposed SIP revision associated with the potential control efficiencies it used for evaluation of SNCR and SCR for the Oklaunion Power Station. For Unit 1 at the Oklaunion Power Station, the TCEQ originally used a potential 40% control efficiency for SNCR and an 80% control efficiency for SCR. This was corrected to 50% for SNCR and 98% for SCR. The potential costs to control NO_X emissions from the source were based on control efficiencies of 50% and 98%, respectively; however, the estimated NO_X emission reductions were based on the values of 40% and 80%, respectively. The correct estimates for potential NO_X emission reductions and subsequent cost-effectiveness values, on a dollar per ton basis, are now reflected in the Table on page B-23. Considering the correction to the NO_X control efficiencies for the Oklaunion facility, the potential NO_X reductions would be 3,402 tpy due to SNCR and 6,668 tpy due to SCR. The resulting cost-effectiveness values would be approximately $4,152 per ton due to SNCR and $6,455 per ton due to SCR.

1.1.7 Vistra Energy LLC, Oak Grove Steam Electric Station

Oak Grove Steam Electric Station is a coal-fired EGU meeting the source selection criteria for SO_2 emissions and was evaluated for visibility impairment at Wichita Mountains. The units evaluated for this four-factor analysis were two coal-fired utility boilers. 2018 EPA AMPD, along with 2018 EIA data, indicated the two coal-fired utility boilers at this site operated with wet limestone scrubbers, with the wet scrubber systems for both units achieving +98% control efficiency for SO_2. The TCEQ considered a wet scrubbing system employing limestone as the SO_2 reducing reagent to offer a very high, if not the highest, level of SO_2 emissions control in current practice for SO_2 post-combustion flue-gas cleanup, especially at 98% SO_2 control, and other SO_2 post-combustion control technologies or increases in scrubber efficiency were not considered.

1.1.8 Holcim Texas LP, Midlothian Plant

The Midlothian Plant is a cement manufacturing plant meeting the source selection criteria for SO_2 emissions and was evaluated for visibility impairment at Wichita Mountains. The units evaluated for this four-factor analysis were two cement kilns. A wet scrubber upgrade analysis was performed for the two cement kilns at this site based on 2016 TCEQ Point Source Emissions Inventory (EI) data, in conjunction with TCEQ NSR air permit file information, indicating the two cement kilns operated with wet limestone scrubbers. While the exact SO_2 control efficiency of either wet limestone scrubber system on either kiln could not be confirmed, air permit information indicated the site represented the installation of, and received an NSR air permit for, wet limestone scrubber systems achieving about 90% SO_2 control efficiencies. These values were used as the baselines for the potential scrubber upgrades to 95% control, or removal, efficiency for these two systems for these two units. The TCEQ considered a wet scrubbing system employing limestone as the SO_2 reducing reagent to offer a very high, if not the highest, level of SO_2 emissions control in current practice for SO_2 post-combustion flue-gas cleanup, and other SO_2 post-combustion control technologies were not considered.

1.1.9 Vitro Flat Glass LLC, Works No 4 Wichita Falls Plant

The Works No 4 Glass Plant is a flat glass manufacturing plant meeting the source selection criteria for SO_2 and NO_X emissions and was evaluated for visibility impairment at Wichita Mountains. The units evaluated for this four-factor analysis were two glass melting furnaces. The TCEQ obtained a vendor quote for a potential air pollution control device that would simultaneously abate emissions of particulate matter (PM), NO_X, and SO_2. While the control device manufacturer could not reveal the exact design and abatement mechanisms for NO_X and SO_2, the TCEQ assumed the device would rely on a reducing reagent and a catalyst for NO_X control, an SO_2 reducing reagent for SO_2 control, and ultimately on a fabric filter for collection of SO_2 and PM particles. This hybrid system for multi-pollutant control was considered for the two glass melting furnaces, showing no existing SO_2 or NO_X post-combustion control systems based on 2016 TCEQ Point Source EI data. The Glass Melting Furnace Number 1 was re-built with low-NO_X oxy-fuel injection technology around October 2007 to reduce NO_X emissions. The vendor quoted a control efficiency of approximately 80% for all pollutants on each of the furnaces, and this efficiency was used to evaluate the control options for NO_X and SO_2 independently. The multi-pollutant control system was evaluated as a technique in addition to the existing low-NO_X oxy-fuel injection technology for Furnace Number 1, assuming the site would not remove the system to install and operate the post-combustion multi-pollutant control system instead.

1.1.10 Graphic Packaging International LLC, Texarkana Mill

The Texarkana Mill is a kraft pulp paper plant meeting the source selection criteria for NO_X emissions and was evaluated for visibility impairment at Caney Creek. The units evaluated for this four-factor analysis were two power boilers and two recovery boilers. Low-NO_X burners and SCR were considered for the two power boilers and two recovery boilers/furnaces at this site based on 2016 TCEQ Point Source EI data showing no existing NO_x post-combustion control systems. Based on the available EI data and air permit file information, the TCEQ concluded the exhaust temperatures of the four boilers did not reach the design temperature operating range for SNCR, i.e. the exhaust temperatures were too low for SNCR to be technically feasible. Therefore, SNCR was not considered. The TCEQ assumed NO_x control efficiencies of 40% for LNB and 80% for SCR. While the TCEQ recognizes that these control technologies may achieve greater NO_x control, these conservative control efficiencies for NO_x emission reductions were assumed to be well within the ranges of historical literature of 25% to 50% for LNB and of 70% to 95% for SCR.

1.1.11 El Paso Natural Gas Company LLC, Keystone Compressor Station

The Keystone Compressor Station is a natural gas compressor plant meeting the source selection criteria for NO_x emissions and was evaluated for visibility impairment at Guadalupe Mountains and Salt Creek. The units evaluated for this four-factor analysis were 15 stationary reciprocating internal combustion engines. The TCEQ identified 15 stationary reciprocating engines at this site through the 2016 Point Source EI data, with no existing NO_x post-combustion control systems or NO_x combustion modification techniques. The NO_x emissions, on an individual basis, from nine of the engines were less than 5% of the total NO_x emissions from all 15 units at this site. Therefore, the TCEQ evaluated only the six reciprocating engines with emissions, each, of at least 5% of the total site's NO_x emissions for possible control measures as part of the four-factor analysis for this second planning period. The TCEQ considered LEC retrofit technologies and SCR for these remaining six engines. Both control technologies are widely applied and established as technically demonstrated and feasible options for controlling NO_x emissions from stationary reciprocating engines. The TCEQ assumed NO_x control efficiencies of 40% for LEC and 80% for SCR. While the TCEQ recognizes that these control technologies may achieve greater NO_x control, these conservative control efficiencies for NO_x emission reductions were assumed to be well within the ranges of historical literature of 25% to 50% for LEC and of 70% to 95% for SCR for stationary reciprocating engines.

1.1.12 El Paso Natural Gas Company LLC, Cornudas Plant

The Cornudas Plant is a natural gas compressor plant meeting the source selection criteria for NO_x emissions and was evaluated for visibility impairment at Guadalupe Mountains. The units evaluated for this four-factor analysis were six stationary gas turbines. The TCEQ identified six stationary gas turbines at this site through the 2016 Point Source EI data, with no existing NO_x post-combustion control systems or NO_x combustion modification techniques. Based on available air permit file information for two gas turbines, the TCEQ found the site installed these two gas turbines around 2003 with LNB achieving 25 parts per million as Best Available Control Technology (BACT) for NSR permitting purposes. Based on the available EI data and air permit file information for these two units, the TCEQ concluded the exhaust temperatures of these two gas turbines did not reach the design temperature operating range for SNCR, i.e. the exhaust temperatures were too low for SNCR to be technically feasible. Therefore, SNCR was not considered for these two units, and only SCR was a possible remaining control option to evaluate. For the remaining four gas turbines, based on the available EI data and air permit file information for these four units, the TCEQ similarly concluded the exhaust temperatures of these four gas turbines did not reach the design temperature operating range for SNCR, i.e. the exhaust temperatures were too low for SNCR to be technically feasible. Therefore, SNCR was not considered for these four units. Consequently, LNB and SCR with assumed NO_x control efficiencies of

40% for LNB and 80% for SCR were considered. While the TCEQ recognizes that these control technologies may achieve greater NO_x control, these conservative control efficiencies for NO_x emission reductions were assumed to be well within the ranges of historical literature of 25% to 50% for LNB and of 70% to 95% for SCR for stationary gas turbines.

1.1.13 El Paso Natural Gas Company LLC, Guadalupe Compressor Station

The Guadalupe Compressor Station is a natural gas compressor plant meeting the source selection criteria for NO_x emissions and was evaluated for visibility impairment at Guadalupe Mountains. The unit evaluated for this four-factor analysis was a stationary gas turbine. The TCEQ identified the one stationary gas turbine at this site through the 2016 Point Source EI data. The 2016 EI data indicated the turbine had no existing NO_x post-combustion control systems or NO_x combustion modification techniques. The TCEQ considered LNB and SCR with assumed NO_x control efficiencies of 40% for LNB and 80% for SCR. While the TCEQ recognizes that these control technologies may achieve greater NO_x control, these conservative control efficiencies for NO_x emission reductions were assumed to be well within the ranges of historical literature of 25% to 50% for LNB and of 70% to 95% for SCR for stationary gas turbines.

1.1.14 GCC Permian LLC, Odessa Cement Plant

The Odessa Cement Plant is a cement manufacturing plant meeting the source selection criteria for NO_x emissions and evaluated for visibility impairment at Guadalupe Mountains. The units evaluated for this four-factor analysis were two cement kilns at the site. While SCR was initially considered as a possible NO_x control option for the units, the TCEQ concluded it was not a viable control option given the two cement kilns operate with exhaust temperatures much greater than the lower temperature operating range required for SCR. The TCEQ further concluded the existing operating high exhaust temperatures were the reason the units currently use SNCR. The TCEQ identified through NSR air permit file information that the site intends to shutdown Kiln Number 1 and replace it with a new Kiln Number 3 by December 2020. According to the permit, the site intends to cease operation of Kiln Number 1 when construction of Kiln Number 3 begins. Kiln Number 3 has been permitted to install and operate SNCR as its method of NO_x control to meet BACT, and Kiln Number 2 already operates with SNCR to meet BACT for NSR permitting purposes. The TCEQ did not rely on the shutdown of Kiln Number 1 as part of the four-factor analysis for this site because an air permit revision making federally enforceable the shutdown of Kiln Number 1 has not yet been submitted to the TCEQ.

1.1.15 Orion Engineered Carbons LLC, Orange Carbon Black Plant

The Orange Carbon Black Plant is a carbon black manufacturing plant meeting the source selection criteria for SO_2 emissions and evaluated for visibility impairment at Caney Creek. The units evaluated for this four-factor analysis were the hydrocarbons incinerator, four carbon black pellet dryers, and two boilers. One boiler is used for process steam and one is used for on-site electric power generation (steam to a steam turbine). The boilers may combust carbon black tail gas as fuel from upstream units such as the dryers. Other than removing the flare, the only known viable option would be to re-route process gas to other process units but was not further contemplated due to data limitations and complex engineering and economic analyses warranted for such a consideration. As potential SO_2 post-combustion control techniques for controlling flue-gas SO_2 emissions, DSI, SDA, and wet limestone scrubbing systems were considered for each of these units because, as discussed in this appendix, these

SO_2 controls were accepted as generally available SO_2 post-combustion control techniques. The TCEQ queried the EPA's RACT/BACT/LAER Clearinghouse for information on technically feasible control options demonstrated for this source type for possible controls on these types of units at carbon black manufacturing plants, both pre-combustion and post-combustion control options. The TCEQ determined that no such technically demonstrated SO_2 post-combustion control options existed for the units at this site. For those carbon black manufacturing sites in the United States under consent decrees with the EPA to control SO_2 emissions from carbon black process units, some will be required to use either dry or wet scrubbers, to reduce SO_2 emissions by up to 90%, and will not be required to demonstrate compliance until 2023 at the earliest. Other sites had later compliance dates for which the EPA will know the results of the required application of either dry or wet flue gas desulfurization techniques to units located at carbon black plants. Other than the sites currently under consent decree with the EPA, the TCEQ is not aware of and did not identify any carbon black sites with DSI, SDA, or wet limestone scrubbers in operation. Therefore, even though some carbon black manufacturing sites will be testing dry or wet scrubbers to determine the effectiveness of potential SO_2 control in accordance with the consent decrees, this does not constitute those technologies as technically demonstrated for this industry sector. The implementation results of these technologies will not be available in time to evaluate for the second planning period.

The TCEQ identified through the RACT/BACT/LAER Clearinghouse some carbon black manufacturing sites that had implemented low-sulfur carbon black oil feedstock, i.e. reduced the sulfur content of the oil feedstock. However, this site has already implemented changes to a low-sulfur carbon black oil feedstock as a result of consent decree requirements. Additional raw material sulfur content reduction techniques were not evaluated due to data limitations and the complex engineering and economic analyses needed for such a consideration of reducing the sulfur content of raw carbon black feedstock oils from petroleum refining processes. Therefore, there were no technically demonstrated post-combustion SO_2 control options available for evaluation for this four-factor analysis for this site.

1.1.16 Oxbow Calcining LLC, Oxbow Calcining-Port Arthur

The Oxbow Calcining, Port Arthur plant is a petroleum coke calcining plant meeting the source selection criteria for SO_2 emissions and evaluated for visibility impairment at Caney Creek. The units evaluated for this four-factor analysis were the four petroleum coke calcining kilns. As potential SO_2 post-combustion control techniques for controlling flue-gas SO_2 emissions, DSI, SDA, and wet limestone scrubbing systems were considered for each of these units because, as discussed in this Appendix, these SO_2 controls were accepted as generally available SO_2 post-combustion control techniques. The TCEQ queried the EPA's RACT/BACT/LAER Clearinghouse for information on technically feasible control options demonstrated for a petroleum coke calcining kiln at a petroleum coke calcining manufacturing plant for possible control options, both pre-combustion and post-combustion control options. The TCEQ did not identify any technically demonstrated SO_2 post-combustion control techniques currently in operation on petroleum coke calcining kilns at petroleum coke calcining plants. The TCEQ furthermore did not identify any technically demonstrated pre-combustion control techniques, such as fuel switching or raw material sulfur content reduction techniques, implemented at petroleum coke calcining kilns at petroleum coke calcining plants. Therefore, there were no technically demonstrated post-combustion SO_2 control options available for evaluation for this four-factor analysis for this site. Furthermore, raw material sulfur content reduction techniques were not evaluated due to data limitations and the complex engineering and economic analyses needed for such a consideration of reducing the sulfur content of raw petroleum coke derived from petroleum refining processes. Although SO_2 controls are technically demonstrated for other types of kilns for other source categories and industry sectors, there was no information indicating those same controls are technically demonstrated on a petroleum coke calcining kiln.

1.1.17 TRNLWS LLC, Streetman Plant

The Streetman Plant is a lightweight aggregate manufacturing plant meeting the source selection criteria for SO_2 emissions and evaluated for visibility impairment at Wichita Mountains. The unit evaluated for this four-factor analysis was the one lightweight aggregate kiln. As potential SO_2 post-combustion control techniques for controlling flue-gas SO_2 emissions, DSI, SDA, and wet limestone scrubbing systems were considered for the lightweight aggregate kiln at this site because, as discussed in this Appendix, these SO_2 controls were accepted as generally available SO_2 post-combustion control techniques. The TCEQ queried the EPA's RACT/BACT/LAER Clearinghouse for information on technically feasible control options demonstrated for a lightweight aggregate kiln at a lightweight aggregate manufacturing plant for possible control options, both pre-combustion and post-combustion control options. The TCEQ did not identify in the RACT/BACT/LAER Clearinghouse any technically demonstrated SO_2 post-combustion control techniques currently in operation on lightweight aggregate kilns at lightweight aggregate plants. Additionally, the TCEQ did not identify any pre-combustion control techniques, such as fuel switching or raw material sulfur content reduction techniques, implemented at lightweight aggregate kilns at lightweight aggregate manufacturing plants. Based on this available information, there were no technically demonstrated post-combustion SO_2 control options available for evaluation for this four-factor analysis for this site. Furthermore, raw material sulfur content reduction techniques were not evaluated due to data limitations and the complex engineering and economic analyses needed for such a consideration of reducing the sulfur content of the raw materials used in the production of lightweight aggregate. Although SO_2 controls are technically demonstrated for other types of kilns for other source categories and industry sectors, there was no information indicating those same controls are technically demonstrated on a lightweight aggregate kiln.

1.2 DETERMINATION OF POTENTIAL CONTROL COSTS

The most recent data available from Sargent and Lundy for EGUs were used for estimating capital and annual costs for SO_2 and NO_X post-combustion controls for EGUs. Readily available cost data and information from the EPA and the literature were used for estimating capital and annual costs for SO_2 and NO_X post-combustion controls and techniques for non-EGUs. The TCEQ was able to rely on vendor cost information for one non-EGU, the glass melting furnaces, for estimating capital cost of control equipment.

Factors and parameters the TCEQ relied on for estimations of capital and annual costs for EGUs include the size of the unit in megawatts (MW) and estimated unit gross heat rate, based on 2018 EPA AMPD reported gross load, in megawatt-hours, and unit heat input, in million British thermal units (MMBtu). Other parameters include estimated SO_2 emission rates in pounds of SO_2 per MMBtu, or lb SO_2/MMBtu based on reported 2018 EPA AMPD emissions data in heat input. The type of coal burned, such as subbituminous or lignite, based on 2018 EIA reported data, was also considered in the estimations of capital and annual costs. As inputs to the cost equations provided by Sargent and Lundy for estimations associated with SO_2 control, the TCEQ assumed milled Trona with a baghouse would be considered, with an assumed 90% control efficiency on the high end of the anticipated range of SO_2 control efficiency associated with the use of a DSI system. Based on available data and literature for use with the cost equations from Sargent and Lundy, the TCEQ further assumed control efficiencies of 95% for SDA and up to 98% for wet scrubbing systems using limestone as the reducing reagent. As inputs to the cost equations for estimating costs of control associated with NO_X post-combustion control techniques, the TCEQ assumed control efficiencies of up to 50% for SNCR, which the TCEQ considers to be on the high end of the anticipated range of NO_X control efficiency associated with an SNCR system using either urea or ammonia as the reducing reagent. Similarly, the TCEQ assumed control efficiencies of up to 98% for SCR, which the TCEQ considers to be on the high end of the anticipated range of NOx control efficiency associated with an SCR system using either urea or ammonia as the reducing reagent.

<u>Example wet scrubber costs for a 622 MW unit:</u>

Wet Scrubber Capital Cost ($/kilowatt (kW)): 502 $/kW
Wet Scrubber Fixed Operating and Maintenance (FOM) Cost ($/kW-yr): 8.38 $/kW-yr
Wet Scrubber Variable Operating and Maintenance Cost (VOM) ($/MWh): 1.53 $/MWh

<u>Example SDA costs for a 622 MW unit:</u>

SDA Capital Cost ($/kW): 432 $/kW
SDA FOM Cost ($/kW-yr): 6.03 $/kW-yr
SDA VOM Cost ($/MWh): 1.77 $/MWh

Example DSI costs for a 622 MW unit:

DSI Capital Cost ($/kW): 35 $/kW
DSI FOM Cost ($/kW-yr): 0.69 $/kW-yr
DSI VOM Cost ($/MWh): 6.00 $/MWh

<u>Example SCR costs for a 720 MW unit:</u>

SCR Capital Cost ($/kW): 334 $/kW
SCR FOM Cost ($/kW-yr): 0.79 $/kW-yr
SCR VOM Cost ($/MWh): 1.73 $/MWh

Example SNCR costs for a 720 MW unit:

SNCR Capital Cost ($/kW): 20 $/kW
SNCR FOM Cost ($/kW-yr): 0.18 $/kW-yr
SNCR VOM Cost ($/MWh): 1.92 $/MWh

Example average wet scrubber upgrade costs for a 537 MW unit:

Scrubber Upgrade Capital Cost ($/kW): 37.84 $/kW
Scrubber Upgrade Operating and Maintenance Cost ($/kW-yr): 3.09 $/kW-yr

Factors and parameters the TCEQ relied on for estimations of capital and annual costs for non-EGUs include the size of the unit, based on heat input in units of million British thermal units per hour (MMBtu/hr) or based on power output in units of horsepower (hp). Other parameters include, using a stationary gas turbine potentially retrofitted with an SCR system for NO_x control as an example, direct purchase equipment cost and installation costs, with indirect costs associated with engineering, construction, and performance costs, to arrive at an estimated total capital investment for the control technique on the unit. The TCEQ relied on previous cost estimations work for other regulatory actions and where appropriate, relied on vendor and manufacturer quotes on control costs for specific combustion unit types to perform the appropriate scaling to the sources selected for four-factor analysis for the second planning period of this Regional Haze SIP revision. Other factors and parameters the TCEQ relied upon include anticipated additional electricity consumption to power the potentially new post-combustion control device, operating and supervisory labor, maintenance, reducing reagent use, catalyst replacement in the case of SCR, and other indirect annual costs to arrive at an estimated total annual cost associated with the control technique for the unit.

Example average wet scrubber upgrade costs for a 480 MMBtu/hr unit:

Scrubber Upgrade Capital Cost ($/MMBtu/hr): 17,293 $/MMBtu/hr
Scrubber Upgrade Operating and Maintenance Cost ($/MMBtu/hr-yr): 474 $/MMBtu/hr-yr

Example SCR costs for a 995 MMBtu/hr unit:

SCR Capital Cost ($/MMBtu/hr): 6,491 $/MMBtu/hr
SCR Operating and Maintenance Cost ($/MMBtu/hr-yr): 2,925 $/MMBtu/hr-yr

Example LNB costs for a 995 MMBtu/hr unit:

LNB Capital Cost ($/MMBtu/hr): 3,618 $/MMBtu/hr
LNB Operating and Maintenance Cost ($/MMBtu/hr-yr): 0 $/MMBtu/hr-yr

Example SCR costs for a 1,404 hp stationary reciprocating engine:

SCR Capital Cost ($/hp): 680 $/hp
SCR Operating and Maintenance Cost ($/hp-yr): 416 $/hp-yr

Example LEC costs for a 1,404 hp stationary reciprocating engine:

LEC Capital Cost ($/hp): 155 $/hp
LEC Operating and Maintenance Cost ($/hp-yr): 0 $/hp-yr

Example SCR costs for a 5,400 hp stationary gas turbine:

SCR Capital Cost ($/hp): 439 $/hp
SCR Operating and Maintenance Cost ($/hp-yr): 236 $/hp-yr

Example LNB costs for a 5,400 hp stationary gas turbine:

LNB Capital Cost ($/hp): 82 $/hp
LNB Operating and Maintenance Cost ($/hp-yr): 0 $/hp-yr

For both the EGUs and the non-EGUs, the TCEQ relied on a capital recovery factor based on a capital life of 15 years and an interest rate of 10% resulting in an estimated capital recovery factor of approximately 0.131.

The TCEQ relied on the EPA's [Control Cost Manual](https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution) (most updated version; https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution) for estimating annualized capital costs for EGUs and for non-EGUs, where appropriate. The TCEQ assumed an interest rate of 10% for all sources and units evaluated because it was assumed that regulated entities would be able to secure, on average, this rate when attempting to finance capital investments associated with air pollution control devices and abatement equipment. It is expected that some sources depending on their financial institution and method of financing, would have interest rates higher or lower than 10%, but the TCEQ conservatively assumed that a constant 10% interest rate would be a reasonable 'mid-point' to use across all source categories.

Annualized capital costs were calculated by multiplying the capital costs by capital recovery factors. Capital recovery factors were estimated using the techniques listed in the EPA's Control Cost Manual. After assuming a constant 10% for interest financing, the TCEQ evaluated time periods of five, 15, and 30 years for the capital life of equipment and subsequently the capital recovery factors. The EPA's estimation of a capital recovery factor accounts for source financing of air pollution control equipment. Annual operating and maintenance costs associated with the potential control measure were estimated from the same data and information used for estimating capital costs for each source. The annualized capital cost was then summed with the annual operating cost for a control measure to arrive at a final total annualized cost for each potential control option. After estimating total potential emission reductions of each NO_X and SO_2 control option using baseline emissions for EGUs and non-EGUs, the total annualized cost was divided by the tons of pollutant emissions reduced to estimate the cost per ton of emissions reduced.

The TCEQ determined that a capital life of five years may be too short since most of the units selected for cost control analysis for this planning period could reasonably be expected to continue to operate longer than five years. As discussed in Chapter 7, Section 7.2.1 of this SIP revision, a capital life of 15 years was considered a reasonable 'mid-point' given that some of the selected Texas EGUs could not reasonably be expected to operate an additional 30 years and given the difficulty in estimating remaining source life for non-EGUs.

In addition to the different capital recovery factors, the TCEQ further considered cost effectiveness thresholds of $2,700 per ton, $5,000 per ton, and $10,000 per ton of NO_X and of SO_2 emissions reduced. Maximum emission reductions for NO_X and SO_2, were estimated at all three cost effectiveness thresholds with constant capital recovery factors over each time period. The TCEQ also concluded that the threshold of $5,000 per ton of NO_X and of SO_2 emissions reduced represented a reasonable 'mid-point' to select units with total annualized control costs and NO_X and SO_2 emission reductions resulting from potential control measures that could be applied in a cost-effective manner for the purpose of demonstrating reasonable progress.

For the lower end of the cost thresholds, $2,700 per ton of NO_X and of SO_2 emissions reduced was considered because it was applied as an initial screening tool to limit source population with relatively cost-effective control strategies for the first planning period. This value was based on the EPA's Clean Air Interstate Rule. However, $2,700 per ton of pollutant reduced was determined to be too low for source selection refinement for the second planning period since it could screen out controls on units that could be applied in a cost-effective manner.

For the upper-end of the cost thresholds, \$10,000 per ton of NO_X and of SO_2 emissions reduced was considered because this threshold may be used for permitting new, modified, and reconstructed sources of air pollutants under the New Source Review (NSR) air permitting program. This threshold may be used for the NSR air permitting program authorizing construction of new sources and modification or reconstruction at existing sources undergoing a best available control technology review. However, for purposes of demonstrating reasonable progress for the second planning period, this threshold was determined to be inappropriate to apply to existing sources not undergoing any kind of physical or operational change. Therefore, the TCEQ did not consider potential control measures at this cost threshold to be reasonable for purposes of refined source selection for the second planning period.

Table B-2: Coleto Creek Power LLC, Coleto Creek Power Station

Unit 1 coal-fired utility boiler (622 MW[1])

13,213 tons of SO_2 emissions[2]

	DSI Expected 90% Control Efficiency	SDA Expected 95% Control Efficiency	Wet scrubber Expected 98% Control Efficiency
Capital Cost ($)	21,536,315	268,972,704	312,251,905
5-year Annualized Capital Cost ($)	5,681,226	70,954,322	82,371,266
15-year Annualized Capital Cost ($)	2,831,461	35,362,857	41,052,937
30-year Annualized Capital Cost ($)	2,284,556	28,532,422	33,123,447
Annual Operating & Maintenance Cost ($)	33,103,197	13,394,030	13,525,968
5-year Life Total Annual Cost ($)	38,784,423	84,348,351	95,897,233
15-year Life Total Annual Cost ($)	35,934,658	48,756,887	54,578,905
30-year Life Total Annual Cost ($)	35,387,753	41,926,452	46,649,415
Emissions Removed (tons per year)	11,892	12,552	12,949
5-year Life Cost Effectiveness ($/ton)	3,261	6,720	7,406
15-year Life Cost Effectiveness ($/ton)	3,022	3,884	4,215
30-year Life Cost Effectiveness ($/ton)	2,976	3,340	3,603

Table B-3: Southwestern Electric Power, Welsh Power Plant

Unit 1 coal-fired utility boiler (558 MW[1])

7,528 tons of SO_2 emissions[2]

	DSI Expected 90% Control Efficiency	SDA Expected 95% Control Efficiency	Wet scrubber Expected 98% Control Efficiency
Capital Cost ($)	19,313,158	264,796,490	290,981,731
5-year Annualized Capital Cost ($)	5,094,762	69,852,647	76,760,248
15-year Annualized Capital Cost ($)	2,539,174	34,813,795	38,256,467
30-year Annualized Capital Cost ($)	2,048,725	28,089,413	30,867,123
Annual Operating & Maintenance Cost ($)	24,759,202	11,534,014	12,002,203
5-year Life Total Annual Cost ($)	29,853,965	81,386,661	88,762,451
15-year Life Total Annual Cost ($)	27,298,376	46,347,809	50,258,671
30-year Life Total Annual Cost ($)	26,807,928	39,623,427	42,869,327
Emissions Removed (tons per year)	6,775	7,152	7,377
5-year Life Cost Effectiveness ($/ton)	4,406	11,380	12,032
15-year Life Cost Effectiveness ($/ton)	4,029	6,481	6,812
30-year Life Cost Effectiveness ($/ton)	3,957	5,540	5,811

Unit 3 coal-fired utility boiler (558 MW[1])
6,694 tons of SO_2 emissions[2]

	DSI Expected 90% Control Efficiency	**SDA Expected 95% Control Efficiency**	**Wet scrubber Expected 98% Control Efficiency**
Capital Cost ($)	19,116,940	261,579,410	287,500,522
5-year Annualized Capital Cost ($)	5,043,001	69,003,989	75,841,913
15-year Annualized Capital Cost ($)	2,513,376	34,390,833	37,798,779
30-year Annualized Capital Cost ($)	2,027,911	27,748,147	30,497,839
Annual Operating & Maintenance Cost ($)	23,961,574	11,263,667	11,783,950
5-year Life Total Annual Cost ($)	29,004,575	80,267,656	87,625,864
15-year Life Total Annual Cost ($)	26,474,950	45,654,500	49,582,730
30-year Life Total Annual Cost ($)	25,989,485	39,011,814	42,281,789
Emissions Removed (tons per year)	6,025	6,359	6,560
5-year Life Cost Effectiveness ($/ton)	4,814	12,622	13,357
15-year Life Cost Effectiveness ($/ton)	4,394	7,179	7,558
30-year Life Cost Effectiveness ($/ton)	4,314	6,135	6,445

Table B-4: Southwestern Electric Power, AEP Pirkey Power Plant

Unit 1 coal-fired utility boiler (721 MW[1])

5,085 tons of SO_2 emissions[2]

	Wet scrubber Upgrade, Increase from 79% to 95%
Capital Cost ($)	99,921,030
5-year Annualized Capital Cost ($)	26,358,916
15-year Annualized Capital Cost ($)	13,136,995
30-year Annualized Capital Cost ($)	10,599,548
Annual Operating & Maintenance Cost ($)	2,740,188
5-year Life Total Annual Cost ($)	29,099,104
15-year Life Total Annual Cost ($)	15,877,183
30-year Life Total Annual Cost ($)	13,339,736
Emissions Removed (tons per year)	3,874
5-year Life Cost Effectiveness ($/ton)	7,511
15-year Life Cost Effectiveness ($/ton)	4,098
30-year Life Cost Effectiveness ($/ton)	3,443

Table B-5: NRG Energy LLC, Limestone Electric Generating Station

Unit 1 coal-fired utility boiler (893 MW[1])
4,156 tons of SO_2 emissions[2]

	Wet scrubber Upgrade, Increase from 78% to 95%
Capital Cost ($)	123,757,947
5-year Annualized Capital Cost ($)	32,647,035
15-year Annualized Capital Cost ($)	16,270,925
30-year Annualized Capital Cost ($)	13,128,150
Annual Operating & Maintenance Cost ($)	3,393,881
5-year Life Total Annual Cost ($)	36,040,915
15-year Life Total Annual Cost ($)	19,664,805
30-year Life Total Annual Cost ($)	16,522,031
Emissions Removed (tons per year)	3,212
5-year Life Cost Effectiveness ($/ton)	11,222
15-year Life Cost Effectiveness ($/ton)	6,123
30-year Life Cost Effectiveness ($/ton)	5,145

Unit 2 coal-fired utility boiler (957 MW[1])
4,164 tons of SO_2 emissions[2]

	Wet scrubber Upgrade, Increase from 77% to 95%
Capital Cost ($)	132,627,498
5-year Annualized Capital Cost ($)	34,986,800
15-year Annualized Capital Cost ($)	17,437,038
30-year Annualized Capital Cost ($)	14,069,025
Annual Operating & Maintenance Cost ($)	3,637,115
5-year Life Total Annual Cost ($)	38,623,915
15-year Life Total Annual Cost ($)	21,074,153
30-year Life Total Annual Cost ($)	17,706,140
Emissions Removed (tons per year)	3,259
5-year Life Cost Effectiveness ($/ton)	11,853
15-year Life Cost Effectiveness ($/ton)	6,467
30-year Life Cost Effectiveness ($/ton)	5,434

Table B-6: Vistra Energy LLC, Martin Lake Electric Station

Unit 1 coal-fired utility boiler (793 MW[1])
19,282 tons of SO_2 emissions[2]

	Wet scrubber Upgrade, Increase from 69% to 95%
Capital Cost ($)	109,899,275
5-year Annualized Capital Cost ($)	28,991,152
15-year Annualized Capital Cost ($)	14,448,873
30-year Annualized Capital Cost ($)	11,658,032
Annual Operating & Maintenance Cost ($)	3,013,827
5-year Life Total Annual Cost ($)	32,004,979
15-year Life Total Annual Cost ($)	17,462,700
30-year Life Total Annual Cost ($)	14,671,859
Emissions Removed (tons per year)	16,172
5-year Life Cost Effectiveness ($/ton)	1,979
15-year Life Cost Effectiveness ($/ton)	1,080
30-year Life Cost Effectiveness ($/ton)	907

Unit 2 coal-fired utility boiler (793 MW[1])
17,167 tons of SO_2 emissions[2]

	Wet scrubber Upgrade, Increase from 72% to 95%
Capital Cost ($)	109,899,275
5-year Annualized Capital Cost ($)	28,991,152
15-year Annualized Capital Cost ($)	14,448,873
30-year Annualized Capital Cost ($)	11,658,032
Annual Operating & Maintenance Cost ($)	3,013,827
5-year Life Total Annual Cost ($)	32,004,979
15-year Life Total Annual Cost ($)	17,462,700
30-year Life Total Annual Cost ($)	14,671,859
Emissions Removed (tons per year)	14,101
5-year Life Cost Effectiveness ($/ton)	2,270
15-year Life Cost Effectiveness ($/ton)	1,238
30-year Life Cost Effectiveness ($/ton)	1,040

Unit 3 coal-fired utility boiler (793 MW[1])
19,749 tons of SO_2 emissions[2]

	Wet scrubber Upgrade, Increase from 70% to 95%
Capital Cost ($)	109,899,275
5-year Annualized Capital Cost ($)	28,991,152
15-year Annualized Capital Cost ($)	14,448,873
30-year Annualized Capital Cost ($)	11,658,032
Annual Operating & Maintenance Cost ($)	3,013,827
5-year Life Total Annual Cost ($)	32,004,979
15-year Life Total Annual Cost ($)	17,462,700
30-year Life Total Annual Cost ($)	14,671,859
Emissions Removed (tons per year)	16,458
5-year Life Cost Effectiveness ($/ton)	1,945
15-year Life Cost Effectiveness ($/ton)	1,061
30-year Life Cost Effectiveness ($/ton)	891

Table B-7: San Miguel Electric Cooperative, San Miguel Electric Plant

Unit 1 coal-fired utility boiler (410 MW[1])
12,006 tons of SO_2 emissions[2]

	Wet scrubber Upgrade, Increase from 94% to 95%
Capital Cost ($)	56,820,558
5-year Annualized Capital Cost ($)	14,989,120
15-year Annualized Capital Cost ($)	7,470,413
30-year Annualized Capital Cost ($)	6,027,482
Annual Operating & Maintenance Cost ($)	1,558,221
5-year Life Total Annual Cost ($)	16,547,341
15-year Life Total Annual Cost ($)	9,028,634
30-year Life Total Annual Cost ($)	7,585,703
Emissions Removed (tons per year)	2,001
5-year Life Cost Effectiveness ($/ton)	8,270
15-year Life Cost Effectiveness ($/ton)	4,512
30-year Life Cost Effectiveness ($/ton)	3,791

Table B-8: Public Service Company of Oklahoma, Oklaunion Power Station

Unit 1 coal-fired utility boiler (720 MW[1])
2,191 tons of SO_2 emissions[2]

	Wet scrubber Upgrade, Increase from 70% to 95%
Capital Cost ($)	99,782,444
5-year Annualized Capital Cost ($)	26,322,357
15-year Annualized Capital Cost ($)	13,118,775
30-year Annualized Capital Cost ($)	10,584,847
Annual Operating & Maintenance Cost ($)	2,736,387
5-year Life Total Annual Cost ($)	29,058,745
15-year Life Total Annual Cost ($)	15,855,162
30-year Life Total Annual Cost ($)	13,321,234
Emissions Removed (tons per year)	1,826
5-year Life Cost Effectiveness ($/ton)	15,913
15-year Life Cost Effectiveness ($/ton)	8,682
30-year Life Cost Effectiveness ($/ton)	7,295

Unit 1 coal-fired utility boiler (720 MW[1])
6,804 tons of NO_X emissions[2]

	SNCR Expected 50% Control Efficiency	SCR Expected 98% Control Efficiency
Capital Cost ($)	14,215,789	240,211,062
5-year Annualized Capital Cost ($)	3,750,089	63,367,073
15-year Annualized Capital Cost ($)	1,869,003	31,581,456
30-year Annualized Capital Cost ($)	1,508,000	25,481,409
Annual Operating & Maintenance Cost ($)	12,255,215	11,461,553
5-year Life Total Annual Cost ($)	16,005,304	74,828,626
15-year Life Total Annual Cost ($)	14,124,218	43,043,008
30-year Life Total Annual Cost ($)	13,763,215	36,942,961
Emissions Removed (tons per year)	3,402	6,668
5-year Life Cost Effectiveness ($/ton)	4,705	11,222
15-year Life Cost Effectiveness ($/ton)	4,152	6,455
30-year Life Cost Effectiveness ($/ton)	4,046	5,541

List B-1: Vistra Energy LLC, Oak Grove Steam Electric Station
Unit 1 coal-fired utility boiler (917 MW[1])
4,453 tons of SO_2 emissions[2]

Unit 2 coal-fired utility boiler (879 MW[1])
3,165 tons of SO_2 emissions[2]

Both utility boilers already operate with wet limestone scrubbers. The wet scrubber systems for both units achieve +98% control efficiency for SO_2.

Table B-10: Holcim Texas LP, Midlothian Plant

Cement Kiln No 1[3]

522 tons of SO_2 emissions[3]

	Wet scrubber Upgrade, Increase from 90% to 95%
Capital Cost ($)	8,196,683
5-year Annualized Capital Cost ($)	2,162,264
15-year Annualized Capital Cost ($)	1,077,649
30-year Annualized Capital Cost ($)	869,498
Annual Operating & Maintenance Cost ($)	224,782
5-year Life Total Annual Cost ($)	2,387,046
15-year Life Total Annual Cost ($)	1,302,431
30-year Life Total Annual Cost ($)	1,094,280
Emissions Removed (tons per year)	261
5-year Life Cost Effectiveness ($/ton)	9,138
15-year Life Cost Effectiveness ($/ton)	4,986
30-year Life Cost Effectiveness ($/ton)	4,189

Cement Kiln No 2[3]

856 tons of SO_2 emissions[3]

	Wet scrubber Upgrade, Increase from 90% to 95%
Capital Cost ($)	8,300,438
5-year Annualized Capital Cost ($)	2,189,635
15-year Annualized Capital Cost ($)	1,091,290
30-year Annualized Capital Cost ($)	880,504
Annual Operating & Maintenance Cost ($)	227,627
5-year Life Total Annual Cost ($)	2,417,262
15-year Life Total Annual Cost ($)	1,318,917
30-year Life Total Annual Cost ($)	1,108,132
Emissions Removed (tons per year)	428
5-year Life Cost Effectiveness ($/ton)	5,647
15-year Life Cost Effectiveness ($/ton)	3,081
30-year Life Cost Effectiveness ($/ton)	2,589

Table B-11: Vitro Flat Glass LLC, Works No 4 Wichita Falls Plant

Glass Melting Furnace Line No 1 (215 MMBtu/hr[3])
136 tons of SO_2 emissions[3]

	Tri-Mer Cat Controls (for SO_2 and NO_x) Expected 80% Control Efficiency
Capital Cost ($)	23,628,500
5-year Annualized Capital Cost ($)	6,233,140
15-year Annualized Capital Cost ($)	3,106,528
30-year Annualized Capital Cost ($)	2,506,494
Annual Operating & Maintenance Cost ($)	3,561,590
5-year Life Total Annual Cost ($)	9,794,730
15-year Life Total Annual Cost ($)	6,668,118
30-year Life Total Annual Cost ($)	6,068,084
Emissions Removed (tons per year)	109
5-year Life Cost Effectiveness ($/ton)	15,100
15-year Life Cost Effectiveness ($/ton)	10,300
30-year Life Cost Effectiveness ($/ton)	9,400

Glass Melting Furnace Line No 2 (215 MMBtu/hr[3])
301 tons of SO_2 emissions[3]

	Tri-Mer Cat Controls (for SO_2 and NO_x) Expected 80% Control Efficiency
Capital Cost ($)	23,628,500
5-year Annualized Capital Cost ($)	6,233,140
15-year Annualized Capital Cost ($)	3,106,528
30-year Annualized Capital Cost ($)	2,506,494
Annual Operating & Maintenance Cost ($)	4,165,380
5-year Life Total Annual Cost ($)	10,398,520
15-year Life Total Annual Cost ($)	7,271,908
30-year Life Total Annual Cost ($)	6,671,874
Emissions Removed (tons per year)	241
5-year Life Cost Effectiveness ($/ton)	4,600
15-year Life Cost Effectiveness ($/ton)	3,200
30-year Life Cost Effectiveness ($/ton)	2,900

Glass Melting Furnace Line No 1 (215 MMBtu/hr[3])
674 tons of NO_x emissions[3]

	Tri-Mer Cat Controls (for SO_2 and NO_x) Expected 80% Control Efficiency
Capital Cost ($)	23,628,500
5-year Annualized Capital Cost ($)	6,233,140
15-year Annualized Capital Cost ($)	3,106,528
30-year Annualized Capital Cost ($)	2,506,494
Annual Operating & Maintenance Cost ($)	3,561,590
5-year Life Total Annual Cost ($)	9,794,730
15-year Life Total Annual Cost ($)	6,668,118
30-year Life Total Annual Cost ($)	6,068,084
Emissions Removed (tons per year)	539
5-year Life Cost Effectiveness ($/ton)	15,100
15-year Life Cost Effectiveness ($/ton)	10,300
30-year Life Cost Effectiveness ($/ton)	9,400

Glass Melting Furnace Line No 2 (215 MMBtu/hr[3])
2,533 tons of NO_x emissions[3]

	Tri-Mer Cat Controls (for SO_2 and NO_x) Expected 80% Control Efficiency
Capital Cost ($)	23,628,500
5-year Annualized Capital Cost ($)	6,233,140
15-year Annualized Capital Cost ($)	3,106,528
30-year Annualized Capital Cost ($)	2,506,494
Annual Operating & Maintenance Cost ($)	4,165,380
5-year Life Total Annual Cost ($)	10,398,520
15-year Life Total Annual Cost ($)	7,271,908
30-year Life Total Annual Cost ($)	6,671,874
Emissions Removed (tons per year)	2,026
5-year Life Cost Effectiveness ($/ton)	4,600
15-year Life Cost Effectiveness ($/ton)	3,200
30-year Life Cost Effectiveness ($/ton)	2,900

Table B-12: Graphic Packaging International LLC, Texarkana Mill

Power Boiler No 1 (995 MMBtu/hr[3])
109 tons of NO_X emissions[3]

	LNB Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	3,600,000	6,458,900
5-year Annualized Capital Cost ($)	949,671	1,703,842
15-year Annualized Capital Cost ($)	473,306	849,176
30-year Annualized Capital Cost ($)	381,885	685,155
Annual Operating & Maintenance Cost ($)	0	1,447,858
5-year Life Total Annual Cost ($)	949,671	3,151,700
15-year Life Total Annual Cost ($)	473,306	2,297,034
30-year Life Total Annual Cost ($)	381,885	2,133,014
Emissions Removed (tons per year)	44	87
5-year Life Cost Effectiveness ($/ton)	21,788	36,200
15-year Life Cost Effectiveness ($/ton)	10,859	26,350
30-year Life Cost Effectiveness ($/ton)	8,762	24,469

Power Boiler No 2 (1,000 MMBtu/hr[3])
692 tons of NO_X emissions[3]

	LNB Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	3,700,000	6,490,900
5-year Annualized Capital Cost ($)	976,051	1,712,280
15-year Annualized Capital Cost ($)	486,453	853,383
30-year Annualized Capital Cost ($)	392,493	688,550
Annual Operating & Maintenance Cost ($)	0	2,056,520
5-year Life Total Annual Cost ($)	976,051	3,768,800
15-year Life Total Annual Cost ($)	486,453	2,909,903
30-year Life Total Annual Cost ($)	392,493	2,745,070
Emissions Removed (tons per year)	277	554
5-year Life Cost Effectiveness ($/ton)	3,525	7,100
15-year Life Cost Effectiveness ($/ton)	1,757	5,254
30-year Life Cost Effectiveness ($/ton)	1,417	4,956

Recovery Boiler/Furnace No 1 (650 MMBtu/hr[3])
275 tons of NO_X emissions[3]

	LNB Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	3,100,000	4,268,400
5-year Annualized Capital Cost ($)	817,772	1,125,990
15-year Annualized Capital Cost ($)	407,569	561,183
30-year Annualized Capital Cost ($)	328,846	452,789
Annual Operating & Maintenance Cost ($)	0	1,472,410
5-year Life Total Annual Cost ($)	817,772	2,598,400
15-year Life Total Annual Cost ($)	407,569	2,033,593
30-year Life Total Annual Cost ($)	328,846	1,925,199
Emissions Removed (tons per year)	110	220
5-year Life Cost Effectiveness ($/ton)	7,438	11,800
15-year Life Cost Effectiveness ($/ton)	3,707	9,248
30-year Life Cost Effectiveness ($/ton)	2,991	8,755

Recovery Boiler/Furnace No 2 (1,000 MMBtu/hr[3])
674 tons of NO_X emissions[3]

	LNB Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	3,700,000	6,490,900
5-year Annualized Capital Cost ($)	976,051	1,712,280
15-year Annualized Capital Cost ($)	486,453	853,383
30-year Annualized Capital Cost ($)	392,493	688,550
Annual Operating & Maintenance Cost ($)	0	2,056,520
5-year Life Total Annual Cost ($)	976,051	3,768,800
15-year Life Total Annual Cost ($)	486,453	2,909,903
30-year Life Total Annual Cost ($)	392,493	2,745,070
Emissions Removed (tons per year)	270	539
5-year Life Cost Effectiveness ($/ton)	3,619	7,000
15-year Life Cost Effectiveness ($/ton)	1,804	5,395
30-year Life Cost Effectiveness ($/ton)	1,455	5,089

Table B-13: El Paso Natural Gas Company, Keystone Compressor Station

Reciprocating Internal Combustion Engine, A01 (1,404 horsepower (hp[3]))
131 tons of NO_X emissions[3]

	LEC Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	217,400	955,200
5-year Annualized Capital Cost ($)	57,350	251,980
15-year Annualized Capital Cost ($)	28,582	125,584
30-year Annualized Capital Cost ($)	23,062	101,327
Annual Operating & Maintenance Cost ($)	0	584,320
5-year Life Total Annual Cost ($)	57,350	836,300
15-year Life Total Annual Cost ($)	28,582	709,904
30-year Life Total Annual Cost ($)	23,062	685,647
Emissions Removed (tons per year)	53	105
5-year Life Cost Effectiveness ($/ton)	1,091	7,956
15-year Life Cost Effectiveness ($/ton)	544	6,754
30-year Life Cost Effectiveness ($/ton)	439	6,523

Reciprocating Internal Combustion Engine, A02 (1,404 hp[3])
7 tons of NO_X emissions[3]

	LEC Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	217,400	955,200
5-year Annualized Capital Cost ($)	57,350	251,980
15-year Annualized Capital Cost ($)	28,582	125,584
30-year Annualized Capital Cost ($)	23,062	101,327
Annual Operating & Maintenance Cost ($)	0	519,520
5-year Life Total Annual Cost ($)	57,350	771,500
15-year Life Total Annual Cost ($)	28,582	645,104
30-year Life Total Annual Cost ($)	23,062	620,847
Emissions Removed (tons per year)	3	6
5-year Life Cost Effectiveness ($/ton)	19,209	129,200
15-year Life Cost Effectiveness ($/ton)	9,573	108,036
30-year Life Cost Effectiveness ($/ton)	7,724	103,974

Reciprocating Internal Combustion Engine, A03 (1,404 hp[3])
133 tons of NO_X emissions[3]

	LEC Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	217,400	955,200
5-year Annualized Capital Cost ($)	57,350	251,980
15-year Annualized Capital Cost ($)	28,582	125,584
30-year Annualized Capital Cost ($)	23,062	101,327
Annual Operating & Maintenance Cost ($)	0	585,120
5-year Life Total Annual Cost ($)	57,350	837,100
15-year Life Total Annual Cost ($)	28,582	710,704
30-year Life Total Annual Cost ($)	23,062	686,447
Emissions Removed (tons per year)	53	106
5-year Life Cost Effectiveness ($/ton)	1,078	7,900
15-year Life Cost Effectiveness ($/ton)	537	6,677
30-year Life Cost Effectiveness ($/ton)	433	6,449

Reciprocating Internal Combustion Engine, A04 (1,404 hp[3])
14 tons of NO_X emissions[3]

	LEC Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	217,400	955,200
5-year Annualized Capital Cost ($)	57,350	251,980
15-year Annualized Capital Cost ($)	28,582	125,584
30-year Annualized Capital Cost ($)	23,062	101,327
Annual Operating & Maintenance Cost ($)	0	523,120
5-year Life Total Annual Cost ($)	57,350	775,100
15-year Life Total Annual Cost ($)	28,582	648,704
30-year Life Total Annual Cost ($)	23,062	624,447
Emissions Removed (tons per year)	6	11
5-year Life Cost Effectiveness ($/ton)	9,989	67,500
15-year Life Cost Effectiveness ($/ton)	4,978	56,494
30-year Life Cost Effectiveness ($/ton)	4,017	54,381

Reciprocating Internal Combustion Engine, A05 (1,404 hp[3])
24 tons of NO_X emissions[3]

	LEC Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	217,400	955,200
5-year Annualized Capital Cost ($)	57,350	251,980
15-year Annualized Capital Cost ($)	28,582	125,584
30-year Annualized Capital Cost ($)	23,062	101,327
Annual Operating & Maintenance Cost ($)	0	528,120
5-year Life Total Annual Cost ($)	57,350	780,100
15-year Life Total Annual Cost ($)	28,582	653,704
30-year Life Total Annual Cost ($)	23,062	629,447
Emissions Removed (tons per year)	10	19
5-year Life Cost Effectiveness ($/ton)	5,964	40,600
15-year Life Cost Effectiveness ($/ton)	2,972	33,990
30-year Life Cost Effectiveness ($/ton)	2,398	32,729

Reciprocating Internal Combustion Engine, A06 (1,404 hp[3])
17 tons of NO_X emissions[3]

	LEC Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	217,400	955,200
5-year Annualized Capital Cost ($)	57,350	251,980
15-year Annualized Capital Cost ($)	28,582	125,584
30-year Annualized Capital Cost ($)	23,062	101,327
Annual Operating & Maintenance Cost ($)	0	524,220
5-year Life Total Annual Cost ($)	57,350	776,200
15-year Life Total Annual Cost ($)	28,582	649,804
30-year Life Total Annual Cost ($)	23,062	625,547
Emissions Removed (tons per year)	7	13
5-year Life Cost Effectiveness ($/ton)	8,664	58,600
15-year Life Cost Effectiveness ($/ton)	4,318	49,085
30-year Life Cost Effectiveness ($/ton)	3,484	47,253

Reciprocating Internal Combustion Engine, A07 (1,404 hp[3])
14 tons of NO_X emissions[3]

	LEC Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	217,400	955,200
5-year Annualized Capital Cost ($)	57,350	251,980
15-year Annualized Capital Cost ($)	28,582	125,584
30-year Annualized Capital Cost ($)	23,062	101,327
Annual Operating & Maintenance Cost ($)	0	522,820
5-year Life Total Annual Cost ($)	57,350	774,800
15-year Life Total Annual Cost ($)	28,582	648,404
30-year Life Total Annual Cost ($)	23,062	624,147
Emissions Removed (tons per year)	6	11
5-year Life Cost Effectiveness ($/ton)	10,278	69,400
15-year Life Cost Effectiveness ($/ton)	5,122	58,102
30-year Life Cost Effectiveness ($/ton)	4,133	55,928

Reciprocating Internal Combustion Engine, A08 (1,404 hp[3])
18 tons of NO_X emissions[3]

	LEC Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	217,400	955,200
5-year Annualized Capital Cost ($)	57,350	251,980
15-year Annualized Capital Cost ($)	28,582	125,584
30-year Annualized Capital Cost ($)	23,062	101,327
Annual Operating & Maintenance Cost ($)	0	531,020
5-year Life Total Annual Cost ($)	57,350	783,000
15-year Life Total Annual Cost ($)	28,582	656,604
30-year Life Total Annual Cost ($)	23,062	632,347
Emissions Removed (tons per year)	12	24
5-year Life Cost Effectiveness ($/ton)	4,851	33,100
15-year Life Cost Effectiveness ($/ton)	2,418	27,769
30-year Life Cost Effectiveness ($/ton)	1,951	26,743

Reciprocating Internal Combustion Engine, A09 (1,404 hp[3])
16 tons of NO_X emissions[3]

	LEC Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	217,400	955,200
5-year Annualized Capital Cost ($)	57,350	251,980
15-year Annualized Capital Cost ($)	28,582	125,584
30-year Annualized Capital Cost ($)	23,062	101,327
Annual Operating & Maintenance Cost ($)	0	523,720
5-year Life Total Annual Cost ($)	57,350	775,700
15-year Life Total Annual Cost ($)	28,582	649,304
30-year Life Total Annual Cost ($)	23,062	625,047
Emissions Removed (tons per year)	6	13
5-year Life Cost Effectiveness ($/ton)	9,154	61,900
15-year Life Cost Effectiveness ($/ton)	4,562	51,821
30-year Life Cost Effectiveness ($/ton)	3,681	49,885

Reciprocating Internal Combustion Engine, A10 (1,404 hp[3])
60 tons of NO_X emissions[3]

	LEC Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	217,400	955,200
5-year Annualized Capital Cost ($)	57,350	251,980
15-year Annualized Capital Cost ($)	28,582	125,584
30-year Annualized Capital Cost ($)	23,062	101,327
Annual Operating & Maintenance Cost ($)	0	547,120
5-year Life Total Annual Cost ($)	57,350	799,100
15-year Life Total Annual Cost ($)	28,582	672,704
30-year Life Total Annual Cost ($)	23,062	648,447
Emissions Removed (tons per year)	24	48
5-year Life Cost Effectiveness ($/ton)	2,377	16,600
15-year Life Cost Effectiveness ($/ton)	1,185	13,940
30-year Life Cost Effectiveness ($/ton)	956	13,437

Reciprocating Internal Combustion Engine, A11 (1,404 hp[3])
34 tons of NO_X emissions[3]

	LEC Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	217,400	955,200
5-year Annualized Capital Cost ($)	57,350	251,980
15-year Annualized Capital Cost ($)	28,582	125,584
30-year Annualized Capital Cost ($)	23,062	101,327
Annual Operating & Maintenance Cost ($)	0	533,520
5-year Life Total Annual Cost ($)	57,350	785,500
15-year Life Total Annual Cost ($)	28,582	659,104
30-year Life Total Annual Cost ($)	23,062	634,847
Emissions Removed (tons per year)	14	27
5-year Life Cost Effectiveness ($/ton)	4,178	28,600
15-year Life Cost Effectiveness ($/ton)	2,083	24,011
30-year Life Cost Effectiveness ($/ton)	1,680	23,127

Reciprocating Internal Combustion Engine, A12 (1,404 hp[3])
8 tons of NO_X emissions[3]

	LEC Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	217,400	955,200
5-year Annualized Capital Cost ($)	57,350	251,980
15-year Annualized Capital Cost ($)	28,582	125,584
30-year Annualized Capital Cost ($)	23,062	101,327
Annual Operating & Maintenance Cost ($)	0	519,620
5-year Life Total Annual Cost ($)	57,350	771,600
15-year Life Total Annual Cost ($)	28,582	645,204
30-year Life Total Annual Cost ($)	23,062	620,947
Emissions Removed (tons per year)	3	6
5-year Life Cost Effectiveness ($/ton)	18,554	124,800
15-year Life Cost Effectiveness ($/ton)	9,247	104,367
30-year Life Cost Effectiveness ($/ton)	7,461	100,443

Reciprocating Internal Combustion Engine, B01 (2,017 hp[3])
29 tons of NO_X emissions[3]

	LEC Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	297,000	1,204,600
5-year Annualized Capital Cost ($)	78,348	317,770
15-year Annualized Capital Cost ($)	39,048	158,373
30-year Annualized Capital Cost ($)	31,506	127,783
Annual Operating & Maintenance Cost ($)	0	592,330
5-year Life Total Annual Cost ($)	78,348	910,100
15-year Life Total Annual Cost ($)	39,048	750,703
30-year Life Total Annual Cost ($)	31,506	720,113
Emissions Removed (tons per year)	12	23
5-year Life Cost Effectiveness ($/ton)	6,727	39,100
15-year Life Cost Effectiveness ($/ton)	3,353	32,227
30-year Life Cost Effectiveness ($/ton)	2,705	30,914

Reciprocating Internal Combustion Engine, B02 (2,017 hp[3])
83 tons of NO_X emissions[3]

	LEC Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	297,000	1,204,600
5-year Annualized Capital Cost ($)	78,348	317,770
15-year Annualized Capital Cost ($)	39,048	158,373
30-year Annualized Capital Cost ($)	31,506	127,783
Annual Operating & Maintenance Cost ($)	0	620,430
5-year Life Total Annual Cost ($)	78,348	938,200
15-year Life Total Annual Cost ($)	39,048	778,803
30-year Life Total Annual Cost ($)	31,506	748,213
Emissions Removed (tons per year)	33	66
5-year Life Cost Effectiveness ($/ton)	2,365	14,200
15-year Life Cost Effectiveness ($/ton)	1,179	11,755
30-year Life Cost Effectiveness ($/ton)	951	11,293

Reciprocating Internal Combustion Engine, B03 (2,017 hp[3])
66 tons of NO_X emissions[3]

	LEC Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	297,000	1,204,600
5-year Annualized Capital Cost ($)	78,348	317,770
15-year Annualized Capital Cost ($)	39,048	158,373
30-year Annualized Capital Cost ($)	31,506	127,783
Annual Operating & Maintenance Cost ($)	0	612,130
5-year Life Total Annual Cost ($)	78,348	929,900
15-year Life Total Annual Cost ($)	39,048	770,503
30-year Life Total Annual Cost ($)	31,506	739,913
Emissions Removed (tons per year)	26	53
5-year Life Cost Effectiveness ($/ton)	2,958	17,600
15-year Life Cost Effectiveness ($/ton)	1,474	14,543
30-year Life Cost Effectiveness ($/ton)	1,189	13,965

Table B-14: El Paso Natural Gas Company, Cornudas Plant

Gas Turbine, A1 (5,400 hp[3])
69 tons of NO_X emissions[3]

	LNB Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	200,000	2,371,900
5-year Annualized Capital Cost ($)	52,759	625,700
15-year Annualized Capital Cost ($)	26,295	311,843
30-year Annualized Capital Cost ($)	21,216	251,609
Annual Operating & Maintenance Cost ($)	0	899,800
5-year Life Total Annual Cost ($)	52,759	1,525,500
15-year Life Total Annual Cost ($)	26,295	1,211,643
30-year Life Total Annual Cost ($)	21,216	1,151,409
Emissions Removed (tons per year)	28	55
5-year Life Cost Effectiveness ($/ton)	1,913	27,700
15-year Life Cost Effectiveness ($/ton)	954	21,972
30-year Life Cost Effectiveness ($/ton)	769	20,879

Gas Turbine, A2 (5,400 hp[3])
50 tons of NO_X emissions[3]

	LNB Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	445,000	2,371,900
5-year Annualized Capital Cost ($)	117,390	625,700
15-year Annualized Capital Cost ($)	58,506	311,843
30-year Annualized Capital Cost ($)	47,205	251,609
Annual Operating & Maintenance Cost ($)	0	896,100
5-year Life Total Annual Cost ($)	117,390	1,521,800
15-year Life Total Annual Cost ($)	58,506	1,207,943
30-year Life Total Annual Cost ($)	47,205	1,147,709
Emissions Removed (tons per year)	20	40
5-year Life Cost Effectiveness ($/ton)	5,823	37,742
15-year Life Cost Effectiveness ($/ton)	2,902	29,958
30-year Life Cost Effectiveness ($/ton)	2,341	28,464

Gas Turbine, A3 (5,400 hp[3])
63 tons of NO_x emissions[3]

	LNB Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	445,000	2,371,900
5-year Annualized Capital Cost ($)	117,390	625,700
15-year Annualized Capital Cost ($)	58,506	311,843
30-year Annualized Capital Cost ($)	47,205	251,609
Annual Operating & Maintenance Cost ($)	0	912,700
5-year Life Total Annual Cost ($)	117,390	1,538,400
15-year Life Total Annual Cost ($)	58,506	1,224,543
30-year Life Total Annual Cost ($)	47,205	1,164,309
Emissions Removed (tons per year)	25	51
5-year Life Cost Effectiveness ($/ton)	4,623	30,292
15-year Life Cost Effectiveness ($/ton)	2,304	24,112
30-year Life Cost Effectiveness ($/ton)	1,859	22,926

Gas Turbine, B1 (7,850 hp[3])
104 tons of NO_X emissions[3]

	LNB Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	593,000	3,088,500
5-year Annualized Capital Cost ($)	156,432	814,740
15-year Annualized Capital Cost ($)	77,964	406,057
30-year Annualized Capital Cost ($)	62,905	327,626
Annual Operating & Maintenance Cost ($)	0	1,094,860
5-year Life Total Annual Cost ($)	156,432	1,909,600
15-year Life Total Annual Cost ($)	77,964	1,500,917
30-year Life Total Annual Cost ($)	62,905	1,422,486
Emissions Removed (tons per year)	42	83
5-year Life Cost Effectiveness ($/ton)	3,748	22,878
15-year Life Cost Effectiveness ($/ton)	1,868	17,982
30-year Life Cost Effectiveness ($/ton)	1,507	17,042

Gas Turbine, C1 (7,654 hp[3])
18 tons of NO_X emissions[3]

	SCR Expected 80% Control Efficiency
Capital Cost ($)	3,021,300
5-year Annualized Capital Cost ($)	797,010
15-year Annualized Capital Cost ($)	397,222
30-year Annualized Capital Cost ($)	320,497
Annual Operating & Maintenance Cost ($)	1,041,390
5-year Life Total Annual Cost ($)	1,838,400
15-year Life Total Annual Cost ($)	1,438,612
30-year Life Total Annual Cost ($)	1,361,887
Emissions Removed (tons per year)	14
5-year Life Cost Effectiveness ($/ton)	129,955
15-year Life Cost Effectiveness ($/ton)	101,694
30-year Life Cost Effectiveness ($/ton)	96,270

Gas Turbine, C2 (7,654 hp[3])
18 tons of NO_X emissions[3]

	SCR Expected 80% Control Efficiency
Capital Cost ($)	3,021,300
5-year Annualized Capital Cost ($)	797,010
15-year Annualized Capital Cost ($)	397,222
30-year Annualized Capital Cost ($)	320,497
Annual Operating & Maintenance Cost ($)	1,041,390
5-year Life Total Annual Cost ($)	1,838,400
15-year Life Total Annual Cost ($)	1,438,612
30-year Life Total Annual Cost ($)	1,361,887
Emissions Removed (tons per year)	14
5-year Life Cost Effectiveness ($/ton)	129,955
15-year Life Cost Effectiveness ($/ton)	101,694
30-year Life Cost Effectiveness ($/ton)	96,270

Table B-15: El Paso Natural Gas Company, Guadalupe Compressor Station

Gas Turbine, C-1 (24,720 hp[3])

56 tons of NO_X emissions[3]

	LNB Expected 40% Control Efficiency	SCR Expected 80% Control Efficiency
Capital Cost ($)	1,186,000	4,937,600
5-year Annualized Capital Cost ($)	312,864	1,302,530
15-year Annualized Capital Cost ($)	155,928	649,165
30-year Annualized Capital Cost ($)	125,810	523,777
Annual Operating & Maintenance Cost ($)	0	1,826,170
5-year Life Total Annual Cost ($)	312,864	3,128,700
15-year Life Total Annual Cost ($)	155,928	2,475,335
30-year Life Total Annual Cost ($)	125,810	2,349,947
Emissions Removed (tons per year)	23	45
5-year Life Cost Effectiveness ($/ton)	13,897	69,485
15-year Life Cost Effectiveness ($/ton)	6,926	54,975
30-year Life Cost Effectiveness ($/ton)	5,588	52,190

Table B-16: GCC Permian LLC, Odessa Cement Plant

Cement Kiln No 2[3]

427 tons of NO_x emissions[3]

	LNB Expected 40% Control Efficiency
Capital Cost ($)	2,046,100
5-year Annualized Capital Cost ($)	539,756
15-year Annualized Capital Cost ($)	269,008
30-year Annualized Capital Cost ($)	217,049
Annual Operating & Maintenance Cost ($)	0
5-year Life Total Annual Cost ($)	539,756
15-year Life Total Annual Cost ($)	269,008
30-year Life Total Annual Cost ($)	217,049
Emissions Removed (tons per year)	171
5-year Life Cost Effectiveness ($/ton)	3,163
15-year Life Cost Effectiveness ($/ton)	1,576
30-year Life Cost Effectiveness ($/ton)	1,272

Cement Kiln No 3 - permitted as Kiln No 1 replacement for which construction is expected to begin by December 6, 2020; expected to be operated with SNCR as BACT[4]

No NO_x emissions (Kiln No 1 emitted 476 tons of NO_x in 2016)[3]

List B-2: Orion Engineered Carbons LLC, Orange Carbon Black Plant
Incinerator (for carbon black tail gas) (145 MMBtu/hr[3])
2,495 tons of SO_2 emissions[3]

Dryer No 1 (carbon black pellet dryer) (14 MMBtu/hr[3])
286 tons of SO_2 emissions[3]

Dryer No 2 (carbon black pellet dryer) (14 MMBtu/hr[3])
286 tons of SO_2 emissions[3]

Dryer No 3 (carbon black pellet dryer) (14 MMBtu/hr[3])
286 tons of SO_2 emissions[3]

Dryer No 4 (carbon black pellet dryer) (14 MMBtu/hr[3])
286 tons of SO_2 emissions[3]

For the incinerator, flare for VOC and hazardous air pollutants, and four pellet dryers, no SO_2 post-combustion control or technique could be identified as technically demonstrated on this source category. The process boiler and the steam boiler used for electric generation emitted very low SO_2 emissions relative to the incinerator, flare, and four dryers based on the 2016 TCEQ Point Source EI data.

List B-3: Oxbow Calcining LLC, Oxbow Calcining-Port Arthur

Coke Calcining Kiln No 2 (40 MMBtu/hr[3])
1,299 tons of SO_2 emissions[3]

Coke Calcining Kiln No 3 (60 MMBtu/hr[3])
3,481 tons of SO_2 emissions[3]

Coke Calcining Kiln No 4 (60 MMBtu/hr[3])
2,983 tons of SO_2 emissions[3]

Coke Calcining Kiln No 5 (100 MMBtu/hr[3])
3,416 tons of SO_2 emissions[3]

For all four petroleum coke calcining kilns, no SO_2 post-combustion control or technique could be identified as technically demonstrated on this source category.

List B-4: TRNLWS LLC, Streetman Plant

Lightweight Aggregate Kiln (90 MMBtu/hr[3])
3,422 tons of SO_2 emissions[3]

For lightweight aggregate kilns, no SO_2 post-combustion control or technique could be identified as technically demonstrated on this source category.

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[1] 2018 Energy Information Administration Data
[2] Baseline emissions from 2018 EPA Air Markets Program Data
[3] Unit data and baseline emissions from 2016 TCEQ Point Source Emissions Inventory
[4] Most recently available TCEQ air permitting information