REGIONAL HAZE FOUR-FACTOR REASONABLE PROGRESS ANALYSIS

Oklahoma Gas and Electric - OGE Energy Corp.
Horseshoe Lake Generating Station

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1. INTRODUCTION

Trinity Consultants (Trinity) prepared this report on behalf of Oklahoma Gas and Electric Company - OGE Energy Corp. (OG&E) in response to the July 1, 2020 "Notification of request for 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program" (the July 1, 2020 request) from the Oklahoma Department of Environmental Quality (the ODEQ) to OG&E's Horseshoe Lake Generating Station (Horseshoe Lake) located in Harrah, Oklahoma (OK).

OG&E operates five (5) electric generating units (EGUs) at Horseshoe Lake under the authority of ODEQ Part 70 Operating Permit No. 2018-1482-TVR3 ("the permit"): Unit 6, Unit 7, Unit 8, Unit 9, and Unit 10.

Unit 6 is a Babcock & Wilcox dry-bottom wall-firing boiler that was installed in 1958. It has a heat input capacity of 1,740 million British thermal units per hour (MMBtu/hr). It burns primarily natural gas and secondarily (but with no restrictions in the permit) #2 and #6 fuel oils and company-generated non-hazardous materials including, but not limited to, used oil, used solvents, corrosion inhibitors, on-line cleaning solution, and antifreeze.

Unit 7 is a Babcock & Wilcox boiler that was installed in 1963. It has a heat input capacity of 2,379 MMBtu/hr. It burns primarily natural gas and secondarily (but with no restrictions in the permit) #2 and #6 fuel oils and company-generated non-hazardous materials including, but not limited to, used oil, used solvents, corrosion inhibitors, on-line cleaning solution, and antifreeze. Unit 7 was previously a combined-cycle unit with a gas-fired turbine. The gas turbine was retired in 2015 (it stopped operating in January 2015), and it was removed from the permit in March 2017.

Unit 8 is a Combustion Engineering tangential firing boiler that was installed in 1968. It has a heat input capacity of 4,150 MMBtu/hr. It burns natural gas only.

Units 7 and 8 were BART-eligible units during the development of the initial state implementation plan (SIP) for the Regional Haze Program. Both the state and EPA approved a determination that these units did not cause or contribute to visibility impairment in any Class I area. At a minimum, that determination should still apply to these two units. That determination also suggests that emission reductions from the other units at Horseshoe Lake may not reasonably be anticipated to have any effect on visibility conditions in Class I areas. The visibility data for the Wichita Mountains Class I area further suggests that the steps taken by OG&E at other units pursuant to the Regional Haze Program have resulted in visibility improvements beyond what the state is required to achieve in the upcoming SIP.

Unit 9 and Unit 10 are GE/LM6000 PC Sprint natural-gas fired turbines. Both were installed in 2000, and each has a heat input capacity of 550 MMBtu/hr. They are limited by the permit to 4,000 hours of operation per year. Water injection is used for the control of nitrogen oxide (NO_X) emissions for both units.

The following specific technical and economic information, where applicable, is provided in this report for each emissions reduction option considered for Horseshoe Lake Units 6, 7, 8, 9, and 10 in accordance with instructions in the July 1, 2020 request:

- Technical feasibility
- Control effectiveness
- Emissions reductions

- Time necessary for implementation[1]
- Remaining useful life[1]
- Energy and non-air quality environmental impacts[1]
- Costs of implementation[1]

The information was developed in consultation with Sargent & Lundy (S&L), which completed a thorough site-specific control cost evaluation. S&L's report is included in Appendix A.

Additionally, Appendices B and C include reports related to additional factors that should be considered by the ODEQ in its development of a long-term strategy (LTS) and SIP for the regional haze second planning period (2PP). Those reports suggest that reasonable progress toward natural visibility conditions in the relevant Class I areas will be made without any emission reductions at Horseshoe Lake. Specifically, Appendix B demonstrates that the current projected emissions reductions by sources in Oklahoma (including several sources owned and operated by OG&E) are sufficient to show reasonable progress without the installation of any additional controls during this planning period. In addition, even if additional emission reductions were necessary or desirable for the 2PP SIP, the Appendix C report shows that Horseshoe Lake is not a good candidate source for those reductions because it is upwind from Wichita Mountains only 0.02 % of the time on the 20 % most impaired days.

[1] These are the four factors that must be included in evaluating emission reduction measures necessary to make reasonable progress determinations. *See* 40 CFR § 51.308(f)(2)(i).

2. NO_X EMISSIONS REDUCTION OPTIONS

This report addresses the following potentially applicable NO_X emissions reduction options for the two types of EGUs at Horseshoe Lake based on knowledge of the power generation industry and in consultation with S&L:

- Boilers (Units 6, 7, and 8)
  - Selective Catalytic Reduction (SCR),
  - Selective Non-Catalytic Reduction (SNCR), and
  - Combustion Technologies, i.e., Low-NO_X Burners (LNB), Overfire Air (OFA), and Flue Gas Recirculation (FGR).
- Turbines (Units 9 and 10)
  - SCR

2.1 Technical Feasibility

SCR is technically feasible for the Unit 6 and Unit 8 boilers. It is not technically feasible for Unit 7 due to the low flue gas temperatures of Unit 7. As described in S&L's report, this issue could be potentially remedied via additional combustion, but that would create more combustion emissions and it would clearly be economically infeasible based on the cost estimates for Units 6 and 8 (Unit 7 costs would be even greater). SCR is also technically feasible for the Unit 9 and Unit 10 turbines.

SNCR is technically feasible for the Unit 6, Unit 7, and Unit 8 boilers. As described in S&L's report, SNCR is not technically feasible for the Units 9 and 10 combustion turbines. LNB+OFA+FGR is technically feasible for the Unit 6, Unit 7, and Unit 8 boilers. These technologies are not options for combustion turbines. Note again that water injection is already employed at Units 9 and 10.

2.2 Control Effectiveness

Table 2-1 lists the expected emission rates for the technically feasible NO_X emissions reduction options.

Table 2-1. Emission Rates of NO_X Emissions Reduction Options

NO_X Reduction Option	Unit(s)	Controlled Emission Rate (lb/MMBtu)
SCR	6 and 8	0.02 [2]
	9 and 10	0.01 [2]
SNCR	6	0.15
	7 and 8	0.12
LNB+OFA+FGR	6, 7, and 8	0.15

[2] It should be noted that these values are significantly less than (and thus more conservative) than what is presented by EPA in the Air Pollution Control Cost Manual spreadsheet for SCR, which specifies 0.05 lb/MMBtu. The values used here reflect engineering experience with contemporary SCR installation.

Compared to actual "baseline" emission rates based on Air Markets Program Data (AMPD)[3] for 2016,[4] the control efficiencies for SCR are 90 % for Units 8, 9, and 10, and 92 % for Unit 6; the control efficiencies for SNCR are 30 % for Unit 7, 40 % for Unit 8, and 41 % for Unit 6; and the control efficiencies for LNB+OFA+FGR are 12 % for Unit 7, 27 % for Unit 8, and 41 % for Unit 6.

2.3 Emissions Reductions

Table 2-2 presents the baseline emission rates (from 2016), controlled emission rates, and emission reduction potentials for the technically feasible NO_X emissions reduction options.

Table 2-2. Baseline and Controlled Emission Rates and Emissions Reduction Potentials of NO_X Emissions Reduction Options

Unit	NO_X Reduction Option	Baseline Emission Rate (tpy)	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)
Unit 6	SCR	257	20	237
	SNCR		151	106
	LNB+OFA+FGR		151	106
Unit 7	SNCR	188	132	56
	LNB+OFA+FGR		165	23
Unit 8	SCR	332	32	300
	SNCR		200	133
	LNB+OFA+FGR		242	91
Unit 9	SCR	28	3	25
Unit 10	SCR	28	3	25

2.4 Time Necessary for Implementation

Counting from the effective date of an approved determination, a minimum of four years would be needed for implementing SCR on one unit, and a minimum of two years would be needed for implementing either SNCR or LNB+OFA+FGR on one unit. If controls were to be required for multiple units then additional time would be needed for planning staggered outages.

2.5 Remaining Useful Life

There are no enforceable limitations on the remaining useful life (RUL) of any of the Horseshoe Lake units. However, Unit 8 is 52 years old, Unit 7 is 57 years old, and Unit 6 is 62 years old, and it is not realistic to expect these units to operate for more than another 20 years at most. Therefore, for the purposes of the control cost assessment, a 20-year RUL is used for Units 6, 7, and 8. A 30-year RUL is used for Units 9 and 10.

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[3] https://ampd.epa.gov/ampd/.

[4] 2016 was selected as the base case year because it is the year used by the ODEQ for screening sources for four-factor analyses and because it is a reasonable representation of expected 2028 operations and emissions. Emission rates for 2016, calculated as total annual emissions divided by total annual heat input, were 0.26 lb/MMBtu, 0.17 lb/MMBtu, 0.21 lb/MMBtu, 0.10 lb/MMBtu, and 0.10 lb/MMBtu for Units 6, 7, 8, 9, and 10, respectively.

2.6 Energy and Non-air Quality Environmental Impacts

SCR and SNCR systems create a demand for electricity that currently does not exist. SCR also creates a new solid waste stream (spent catalyst) that must be managed. Both options also pose as threats for potentially significant non-air quality environmental impacts because both require the storage of large amounts of ammonia or urea. The storage of aqueous ammonia in quantities greater than 10,000 pounds (lbs) is regulated by EPA's risk management program (RMP) because the accidental release of ammonia has the potential to cause serious injury and death.

Additionally, SCR and SNCR will result in emissions of unreacted ammonia to the atmosphere (i.e., ammonia slip) during any periods of time when temperatures are too low for effective operation or if too much ammonia is injected (possibly in an attempt to reduce NO_X further). Ammonia emissions will react to directly form ammonium sulfate and ammonium nitrate – the anthropogenically emitted compounds most responsible for regional haze in the Wichita Mountains Class I area. The amount of the potential visibility impact attributable to the use of ammonia in a SCR has not been quantified, but it would presumably negate some of the calculated visibility improvement that would otherwise be associated with the NO_X emission reductions.

2.7 Costs

The following tables summarize the total and annualized capital costs and annual operations and maintenance (O&M) costs for each technically feasible NO_X reduction option based on the site-specific evaluation completed by S&L. The cost effectiveness based on the emission reduction values from Table 2-2 are also presented. All costs are based on current-year (2020) pricing.

Table 2-3. Estimated Costs of NO_X Emissions Reduction Options for Unit 6

NO_X Reduction Option	Capital Costs ($M)	Annualized Capital Costs ($M/year)	Annual O&M Costs ($M/year)	Total Annual Costs ($M/year)	Average Cost Effectiveness ($/ton)
LNB+OFA+FGR	11,221	1,059	444	1,503	14,179
SNCR	13,308	1,256	1,344	2,600	24,528
SCR	40,651	3,837	2,532	6,369	26,873

Table 2-4. Estimated Costs of NO_X Emissions Reduction Options for Unit 7

NO_X Reduction Option	Capital Costs ($M)	Annualized Capital Costs ($M/year)	Annual O&M Costs ($M/year)	Total Annual Costs ($M/year)	Average Cost Effectiveness ($/ton)
LNB+OFA+FGR	22,235	2,099	877	2,976	129,391
SNCR	9,842	929	1,093	2,022	36,107

Table 2-5. Estimated Costs of NO_X Emissions Reduction Options for Unit 8

NO_X Reduction Option	Capital Costs ($M)	Annualized Capital Costs ($M/year)	Annual O&M Costs ($M/year)	Total Annual Costs ($M/year)	Average Cost Effectiveness ($/ton)
LNB+OFA+FGR	27,904	2,634	1,105	3,739	41,088
SNCR	18,103	1,709	1,573	3,282	36,066
SCR	40,110	3,786	2,675	6,461	21,537

Table 2-6. Estimated Costs of NO_X Emissions Reduction Options for Unit 9

NO_X Reduction Option	Capital Costs ($M)	Annualized Capital Costs ($M/year)	Annual O&M Costs ($M/year)	Total Annual Costs ($M/year)	Average Cost Effectiveness ($/ton)
SCR	17,160	1,383	1,390	2,773	110,920

Table 2-7. Estimated Costs of NO_X Emissions Reduction Options for Unit 10

NO_X Reduction Option	Capital Costs ($M)	Annualized Capital Costs ($M/year)	Annual O&M Costs ($M/year)	Total Annual Costs ($M/year)	Average Cost Effectiveness ($/ton)
SCR	17,160	1,383	1,390	2,773	110,920

2.8 Conclusions

All technically feasible NO_X emissions reduction options are economically infeasible based on a thorough site-specific evaluation. Therefore, no additional controls should be required for Horseshoe Lake for the regional haze second planning period.

APPENDIX A. SITE-SPECIFIC CONTROL COST EVALUATION

HORSESHOE LAKE STATION UNIT 6-10

OKLAHOMA REGIONAL HAZE SECOND PLANNING PERIOD COST EVALUATION TO SUPPORT FOUR-FACTOR ANALYSIS

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ABBREVIATIONS/ACRONYMS

Abbreviation/Acronym	Explanation
AMPD	US EPA Air Markets Program Data
BART	Best Available Retrofit Technology
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2	carbon dioxide
EPA	Environmental Protection Agency
FGR	flue gas recirculation
G&A	general and administration
HSL	Horseshoe Lake Station
LNB	Low-NO_X burner
MMBtu	million British thermal units
MW	megawatt
MWg	megawatt gross
NH_3	ammonia
NO_X	nitrogen oxides
ODEQ	Oklahoma Department of Environmental Quality
OFA	overfire air
O&M	operations and maintenance
PI	process information data
RRI	rich reagent injection
S	sulfur
S&L	Sargent & Lundy, L.L.C.
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SOFA	separated overfire air

1. INTRODUCTION

The Oklahoma Department of Environmental Quality (ODEQ) requested that Oklahoma Gas & Electric (OG&E) prepare a Reasonable Progress four-factor analysis for the control of nitrogen oxide (NO_X) emissions from Horseshoe Lake Station Unit 6-10. As a result, OG&E engaged Sargent & Lundy (S&L) to prepare a technical and economic evaluation of potential NOx control technologies. Trinity Consultants ("Trinity") will be preparing the overall four-factor analysis (FFA).

Horseshoe Lake Station is located in Oklahoma County, approximately 20 miles east of Oklahoma City, OK. Horseshoe Lake Station consists of five units located in two main areas. Units 6, 7 and 8 are located close to the center of Horseshoe Lake and went into operation in 1958, 1963 and 1969 respectively. Units 9 and 10 are located approximately 2000 feet to the northwest and went into operation in 2001. All five units burn natural gas supplied by pipeline.

Unit 6 is a wall-fired natural gas boiler with flue gas recirculation, initially installed for temperature controls. Unit 7 is a wall-fired natural gas boiler that originally had a gas turbine discharging into a combustion duct, combined with forced draft fan discharge. Therefore, Unit 7 does not have an air heater, similar to traditional wall fired boilers. The gas turbine was taken out of service in 2015. In addition, Unit 7 has a gas recirculation duct installed for gas tempering. Unit 8 is a tangential-fired natural gas boiler. Units 9 and 10 are both simple cycle combustion turbines, LM6000 machines, made by General Electric.

The evaluation includes an assessment of potentially available emission reduction measures for two of the four statutory factors listed in 40 CFR 51.308(f)(2), and takes into consideration U.S. Environmental Protection Agency's (EPA's) *Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period* (the "Draft EPA Guidance"). Technically feasible NO_X emission reduction measures are evaluated for the following four statutory factors:

- Factor 1: The cost of compliance
- Factor 2: The time necessary to achieve compliances
- Factor 3: The energy and non-air quality environmental impact of compliance
- Factor 4: The remaining useful life of any existing source subject to such requirements

Factors 3 and 4 are not discussed in this report.

1.1 UNIT OVERVIEW

Unit 6 is a 167 MW gross, Babcock and Wilcox (B&W) natural gas wall-fired boiler which went into commercial operation 1958. It is original equipped with a flue gas recirculation (FGR) system primarily used for load/steam temperature control and not used for NOx control. Based on the B&W Contract Data Sheet, Unit 6 has an original MCR rating of 1,200,000 lb/hr main steam flow at 1935 psig and 1005°F. The original reheat steam flow rate is 1,015,000 lb/hr at 470 psig and 1005°F (with all feedwater heaters in service).

Unit 7 is a 210 MW gross, Babcock and Wilcox (B&W) natural gas wall-fired boiler which went into commercial operation 1963. It was original equipped with a combustion gas turbine which exhausted in the secondary windbox but was decommissioned and no longer operated since 2015. Based on the B&W Contract Data Sheet, Unit 7 was designed for natural gas, coal and fuel oil as standby and has an original MCR rating of 1,339,404 lb/hr main steam flow at 1930 psig and 1005°F. The original reheat steam flow rate is 1,307,000 lb/hr at 422 psig and 1005°F.

Unit 8 is a 404 MW gross, Combustion Engineering (now GE Power) natural gas tangentially-fired boiler which went into commercial operation 1969. Based on the Combustion Engineering Contract Data Sheet, Unit 8 has an original MCR rating of 2,781,000 lb/hr main steam flow at 2460 psig and 1005°F (peak output of 3,075,000 lb/hr at 2,610 psig and 1005°F). The original reheat steam flow rate is 2,411,000 lb/hr at 519 psig and 1005°F.

Units 9 and 10 are both 45.5 MW gross, General Electric LM6000 PC simple cycle machines. Both units have existing water spray systems, installed for NOx control when the units went online in 2001.

1.2 BASELINE NO_X EMISSIONS

The first step in developing the Four Factor Analysis is to establish Horseshoe Lake Unit 6-10 baseline NO_X emissions. To establish representative baseline emissions to be used for determining annual emissions reductions for each control option, S&L evaluated data obtained from the Horseshoe Lake Unit 6-10 continuous emissions monitoring system (CEMS) that was reported to EPA's Clean Air Markets in 2016. The year 2016 was used for this evaluation as it has been deemed most representative of 2028 operation. The annual average emission rate during the representative time period was used to establish baseline annual emissions (in terms of tons per year). Representative baseline emission factors (in terms of pounds per million British Thermal Units (lb/MMBtu)) were developed using baseline annual average emissions and the respective baseline annual heat inputs.

Table 1-1 provides a summary of the Horseshoe Lake Unit 6-10 NO_X representative baseline emissions.

Table 1-1. Horseshoe Lake Unit 6-10 Baseline Emissions

Unit No.	Baseline Controls	Baseline Emissions		Heat Input	Capacity Factor
		lb/MMBtu	tons/yr	MMBtu/yr	
U6	None	0.26	256.8	2,010,462.0	10%
U7	None	0.17	188.4	2,203,618.8	7%
U8	None	0.21	332.4	3,220,554.0	7%
U9	Water Injection	0.10	27.6	577,177.2	12%
U10	Water Injection	0.10	27.6	573,142.8	12%

1.3 TECHNOLOGIES EVALUATED

S&L used a top-down approach to identify and evaluate the technical feasibility and effectiveness of potentially available NOx control measures. S&L followed Steps 1 through 3 of the top-down approach described in the Best Available Retrofit Technologies (BART) Guidelines to identify all available retrofit emission control measures, eliminate technically infeasible options, and evaluate the effectiveness of the technically feasible options.

1.3.1 NOX Control Technologies Evaluated

Based on a review of available NOx control technologies, as well as equipment optimization of existing control systems, potentially available options to control NOx emissions from Units 6-10 are listed below.

- Selective Catalytic Reduction (SCR) (Unit 6, 8, 9, 10)
- Selective Non-Catalytic Reduction (SNCR) (Unit 6, 7, 8)
- Low-NO_X burner (LNB)/overfire air (OFA) and Flue Gas Recirculation (FGR) (Units 6, 7, 8)
- Rich Reagent Injection (RRI) (N/A on all units)
- Gas Reburn (N/A on all units)

1.4 APPROACH

S&L evaluated each control technology's reduction capability on an individual unit basis, as compared to the current emissions using vendor information and similarly sized projects to determine if meaningful improvements could be achieved. In order to determine the additional emission reduction potential, S&L conducted a desktop review of the existing systems: including review of Process Information (PI) Data, the U.S. Environmental Protection Agency's (EPA) Air Markets Program Data (AMPD), existing equipment and component data pages, and process flow diagrams (PFD). Based on this review, current operations were evaluated, limitations of the systems were determined, and the list of potential control technologies were finalized.

2. NO_X EMISSIONS TECHNOLOGY EVALUATIONS

Horseshoe Lake Units 6, 7 & 8 do not currently have any NOx emissions controls systems. Horseshoe Lake Units 9 & 10 have water injection spray systems installed for NOx emissions controls. It has been assumed that the water injection on Units 9 and 10 continue to operate for all of the technologies discussed below.

2.1 SCR

SCR is a process by which ammonia reacts with nitric oxide (NO) and nitrogen dioxide (NO_2), collectively NOx, in the presence of a catalyst to reduce the NO_X to nitrogen (N_2) and water. SCR technology has been applied to NO_X-bearing flue gases generated from power generating facilities burning various types of coal and natural gas. The principal reactions resulting in NO_X reduction are:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NO_2 + 8NH_3 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

Because these reactions proceed slowly at typical boiler exit gas temperatures, a catalyst is used to increase the reaction rate between NO_X and ammonia. Depending on the specific constituents in the flue gas, a typical temperature window of 550°F to 780°F is necessary to achieve normal performance of the catalyst. Horseshoe Lake Unit 7 does not have an air heater, meaning the inlet air to the boiler is ambient prior to combustion. The economizer outlet flue gas temperature is approximately 500-525°F. Therefore, SCR technology was not evaluated further for Unit 7.

The temperature window for this process, in a typical boiler, is downstream of the economizer and upstream of the air preheater (APH). SCR technology can be applied as a "full-scale" SCR, which consists of an independent reactor vessel including inlet and outlet ducting and multiple catalyst layers, or an "in-line" SCR, which utilizes the current ductwork (modified as required to expand the dimensions) to hold a single catalyst layer. The "full-scale" SCR is a more common approach for coal-fired applications. The "In-line" SCR is typically more applicable to gas-fired units. Installation of an "in-line" SCR requires expanding the ductwork to reduce the normal 60 feet per second (fps) flue gas velocities to the required 20 to 25 fps range. Thus, physical space must be available around the existing ductwork to accommodate the larger duct dimensions.

In the case of Horseshoe Lake Units 6 & 8, the space between the economizer outlet and the air heater inlet is limited for ductwork modifications. The area around the existing ductwork is limited as well; therefore, separate reactor structures were assumed as the basis. For Units 6 and 8, the estimated emission with SCR is 0.02 lb/MMBtu on an annual average. In the case of Horseshoe Lake Units 9 & 10, an "in-line" SCR was the basis for the estimate where the top of the stack would be removed to facilitate addition of the SCR. The SCR structure was assumed to be supported separately from the stack, with the top of the stack being replaced on top of the SCR structure. For Units 9 and 10, the estimated emission with SCR is 0.01 lb/MMBtu on an annual average.

The emission rates stated above should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis taking into consideration the corresponding averaging time; however, additional margin would likely be needed to account for off-design operating conditions.

2.2 SNCR

SNCR involves the direct injection of ammonia (NH_3) or urea ($CO(NH_2)_2$) at high flue gas temperatures (approximately 1,600ºF – 2,100ºF) in an oxidizing environment. The ammonia or urea reacts with NOx in the flue gas to produce nitrogen gas (N_2) and water as shown below.

$$(NH_2)\,2CO + 2NO + \tfrac{1}{2}O_2 \rightarrow 2H_2O + CO_2 + 2N_2$$

$$2NH_3 + 2NO + \tfrac{1}{2}O_2 \rightarrow 2N_2 + 3H_2O$$

Flue gas temperature at the point of reagent injection can greatly affect NOx removal efficiencies and the quantity of NH_3 or urea that will pass through the SNCR unreacted (referred to as NH_3 slip). In general, SNCR reactions are effective in the range of 1,600ºF – 2,100ºF. At temperatures below the desired operating range, the NOx reduction reactions diminish and unreacted NH3 emissions increase. Above the desired temperature range, NH3 is oxidized to NOx resulting in low NOx reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is an important factor to SNCR performance. In large boilers, the physical distance over which reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Furnace geometry, urea spray coverage, and droplet size must be considered when developing good mixing of reagent and flue gas, delivery of reagent in the proper temperature window, and sufficient residence time of the reagent and flue gas in that temperature window. As the boiler cycles in load, the optimum injection region may change; thus, most facilities require multiple injection zones which are placed in and out of service as the unit ramps in load. This can include modifying the zones of injectors that are operating at different loads and temperatures.

In addition to temperature and mixing, several other factors influence the performance of an SNCR system, including residence time, reagent-to-NOx ratio, and fuel sulfur content. Increasing urea solution flow through the injectors or changing the concentration of urea in the solution can improve NOx removal. However, too high of reagent injection rates will increase the ammonia slip beyond the recommended 10 ppmvd limit. Above this concentration, there are expected to be major impacts to the formation of ammonia salts on the boiler tube banks, reducing heat transfer efficiency, and air heater baskets, causing corrosion.

Based on the boiler residence time, temperature profile, and stoichiometry, it is estimated that an SNCR system could achieve an average controlled NO_X emission rate of approximately 0.15 lb/MMBtu for Unit 6 and 0.12 lb/MMBtu for Units 7 and 8 while limiting ammonia slip to 10 ppmvd. It should be noted that computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the reduction in NO_X emission is achievable without creating unacceptable operational issues.

2.3 LNB/OFA/FGR

LNB and OFA optimize combustion to reduce NOx emissions. LNBs are designed to control fuel and air mixing at each burner in order to create larger and more branched flames. Peak flame temperature is thereby reduced, and results in less NOx formation. The improved flame structure also reduces the amount of oxygen available in the hottest part of the flame thus limiting oxygen availability for NOx formation. OFA diverts combustion air from the primary combustion zone to allow for staged combustion that limits the required combustion temperature and in turn the reduces the formation of thermal NOx.

FGR controls NOx by recycling a portion of the flue gas from the economizer outlet and back into the primary combustion zone in the windbox. The recycled air lowers NOx emissions by two mechanisms: (1) the recycled gas, consisting of products which are inert during combustion, lowers the combustion temperatures; and (2) the recycled gas reduces the oxygen content in the primary flame zone. The amount of recirculation is based on flame stability requirements. The mixed flue gas/combustion air flow supplied to the windbox should be controlled such that the windbox oxygen content is not lower than approximately 17%. Lower oxygen content impacts flame stability and could promote the formation of excess CO and VOC emissions. It is estimated that low NOx burners, OFA ports and FGR could achieve an average controlled NO_X emission rate of 0.15 lb/MMBtu for Units 6, 7 and 8. Units 9 & 10 are simple cycle LM6000 machines, therefore this technology does not apply to Units 9 & 10.

2.4 RRI

Similar to SNCR, the concept of rich reagent injection (RRI) is to use a nitrogen-containing additive (e.g., urea) injected into a reducing environment to promote NO_X removal. RRI is a commercial technology for cyclone boilers only. Therefore, this technology is not applicable to the units at Horseshoe Lake Station and was not considered further.

2.5 GAS REBURN

Gas reburn is a retrofit technique that has been used to control NO_X emissions from coal- and oil-fired boilers. Gas reburn involves combustion in three distinct zones within the boiler: (1) a primary combustion zone, where the primary fuel is fired using conventional burners; (2) a reburn zone, where secondary fuel, typically natural gas, is introduced into the boiler; and (3) an OFA burnout zone. The units at Horseshoe Lake do not burn coal or oil as the primary fuel. Therefore, this technology is not applicable to any of the evaluated units.

3. SUMMARY OF EMISSIONS TECHNOLOGY EVALUATION

Table 3-1 below provides a summary of the average achievable emission rates for the feasible NOx options evaluated.

Table 3-1. Feasible Control Technologies

Control Option	Design Emission Rate (lb/MMBtu)[1]				
	Unit 6	Unit 7	Unit 8	Unit 9	Unit 10
NO_X					
SCR	0.02	N/A	0.02	0.01	0.01
SNCR	0.15	0.12	0.12	N/A	N/A
LNB/OFA/FGR	0.15	0.15	0.15	N/A	N/A

1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions. Emission rates are provided for comparative purposes and should not be construed to represent proposed permit emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Appendix A provides a summary of the control technologies per unit, including control efficiency, emission rates and total reduction in emissions per year.

4. CAPITAL AND OPERATIONS AND MAINTENANCE COSTS

Capital and operations and maintenance (O&M) cost estimates were developed for each of the feasible NO_X control options in accordance with EPA Control Cost Manual. The Horseshoe Lake Units 6-10 cost estimates are conceptual in nature. Equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on Horseshoe Lake unit-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment.

Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects. Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit the units with the control technology. Sub-accounts for the capital cost estimate (e.g., mobilization and demobilization, consumables, Contractor General and Administrative (G&A) expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes. Capital costs were annualized using a capital recovery factor based on an annual interest rate of 7%[1]. The equipment life assumed for each of the control technologies was based on the number of years the equipment would be in service. Units 6, 7 and 8 have been in operation for approximately 60 years. Due to the advanced age of those units, an equipment life of 20 years was used for Units 6, 7 and 8. An equipment life of 30 years was used for Units 9 and 10, given their relatively recent installation. Per the EPA control cost manual, costs have been represented as overnight costs in $2020. Escalation to a construction start date after State Implementation Plan approval has not been included in the cost estimates.

The capital cost estimates generally include the following major components:

- Purchased Equipment Costs
- Equipment and material
- Instrumentation
- Sales Tax
- Freight on Materials
- Direct Installation Costs
- Labor
- Scaffolding
- Mobilization / Demobilization
- Cost due to Overtime

[1] Based on EPA Cost Manual Section 1, Chapter 2, page 16.

- Indirect Costs
- Contractor's General and Administration
- Contractor's Profit
- Engineering, Procurement and Project Services, including Owner's Cost for permitting, engineering, procurement and project services
- Construction Management/Field Engineering
- Startup and Commissioning
- Spare Parts
- Project Contingency

Direct Installation Costs include costs for equipment and balance of plant equipment and commodities. This includes piping, insulation, pipe supports, steel structures, foundations, cables, erection and others. Indirect Costs include contractors General and Administration Expense, Contractors Profit, Engineering, Procurement and Projects services, Owner's Cost, Construction Management and Field Engineering, Start up, Commissioning, and Spare Parts. Project contingency costs are included to cover unforeseen costs that may arise, such as escalation, design changes or modification of equipment. The contents of the S&L estimates are consistent with the definitions in EPA Control Cost Manual.

To confirm that the equipment was not undersized for all potential operating conditions, S&L created an equipment design basis inlet NOx value per unit. The design basis inlet NOx was determined by evaluating three years of hourly data from AMPD, starting January 1, 2017 and ending on December 31, 2019. The NOx values for the top 10% of unit output were extracted and averaged. The equipment design basis inlet NOx values are stated below in Table 4-1.

Table 4-1. Design Basis Inlet NOx for Equipment Sizing

	Inlet NOx (lb/MMBtu)				
	Unit 6	**Unit 7**	**Unit 8**	**Unit 9**	**Unit 10**
Equipment Design Basis	0.30	0.20	0.44	0.10	0.10

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements. The cost of auxiliary power requirements reflects the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing NOx controls.

Appendix B provides a summary of costs to control NOx emissions per technology discussed below.

4.1 SCR COST ESTIMATE BASIS

The following summarizes the design inputs used as the basis for the Horseshoe Lake Units 6-10 SCR System cost estimates:

Table 4-2. Design Inputs for SCR Cost Estimates

	NOx Emission Rate (lb/MMBtu)			
	Unit 6	**Unit 8**	**Unit 9**	**Unit 10**
NO_X Inlet – Equipment Design	0.30	0.44	0.09	0.09
Design NO_X Outlet	0.02	0.02	0.01	0.01

The scope of work for the SCR cost estimate includes the following major items:

- SCR equipment per unit:
    - SCR reactor boxes
    - Catalyst
    - Ammonia injection grid and mixers
    - SCR cleaning devices
- Aqueous Ammonia Unloading, Storage and Forwarding
- New Forced Draft (FD) fans, sized for the pressure drop of the new SCR system
- Civil and structural BOP including support steel, foundations, ductwork, insulation and expansion joints
- Mechanical BOP including compressed air system, eyewash/safety showers, pumps, tanks, interconnecting piping, pipe supports, valves, and insulation
- Electrical and instrumentation/controls BOP

4.1.1 Capital Cost Estimate

Table 4-3 summarizes the SCR capital cost estimate.

Table 4-3. SCR Capital Cost Estimate ($2020)

Capital Cost	Unit 6	Unit 8	Unit 9	Unit 10
Purchased Equipment	13,165,000	13,394,000	5,378,000	5,378,000
Direct Installation	11,205,000	10,653,000	4,910,000	4,910,000
Indirects	9,506,000	9,379,000	4,012,000	4,012,000
Contingency	6,775,000	6,685,000	2,860,000	2,860,000
Total Capital Investment	**40,651,000**	**40,111,000**	**17,160,000**	**17,160,000**

4.1.2 Variable O&M Costs

The following unit costs in Table 4-4 were used to develop the variable O&M costs. Values were developed based on OG&E input when unit pricing was available or assumed based on S&L's conceptual cost estimating system.

Table 4-4. SCR Variable O&M Unit Costs

Unit Cost	Units	Unit 6	Unit 8	Unit 9	Unit 10
Aqueous Ammonia	\$/gal	1.50	1.50	1.50	1.50
Catalyst Replacement and Disposal	\$/m^3	255.00	255.00	255.00	255.00
Auxiliary Power	\$/MWh	36.10	36.10	36.10	36.10

Table 4-5 below summarizes the consumption rates estimated as well as the first year variable O&M costs for the SCR system.

Table 4-5. SCR Variable O&M Consumption Rates and First-Year Costs

Parameter	Units	Unit 6	Unit 8	Unit 9	Unit 10
SCR System					
Aqueous Ammonia Consumption	gpm	2.0	3.5	0.3	0.3
Catalyst Replacement and Disposal	ft^3	2,472	4,379	1,200	1,200
Auxiliary Power Consumption	kW	1,177	2,946	59	59

Parameter	Units	Unit 6	Unit 8	Unit 9	Unit 10
First-Year Variable O&M Costs[1] (@CF)					
Aqueous Ammonia Cost	$/year	164,000	196,000	25,000	25,000
Catalyst Replacement and Disposal Cost[2]	$/year	138,000	244,000	62,000	62,000
Auxiliary Power Cost	$/year	39,000	66,000	3,000	3,000
Lost Generation Cost[3]	$/year	0	0	5,000	5,000
Total First Year Variable O&M Cost	**$/year**	**341,000**	**506,000**	**95,000**	**95,000**

Notes:
1. First-year costs are provided in $2020.
2. Catalyst replacement schedule for gas-fired units is based on 5 years.
3. Lost generation is due to the increase back pressure on the combustion turbines.

4.1.3 Fixed O&M Costs

The fixed O&M costs for the systems consist of maintenance costs (including material and labor). Based on typical design for the SCR system, the estimated staffing addition is 1 person per unit.

Operating Labor costs are estimated based on 2 shifts/day, 365 days per year at an operator charge rate of $60/hour. Supervisor labor is estimated to be 15% of the total operating labor costs.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (materials and labor) were estimated to be approximately 1.5% of the total purchased equipment cost and direct installation costs.

Table 4-6 below summarizes the first year fixed O&M costs.

Table 4-6. SCR First Year Fixed O&M Costs

First Year Fixed O&M Costs[1]	Units	Unit 6	Unit 8	Unit 9	Unit 10
Operating Labor[2]	$/year	526,000	526,000	526,000	526,000
Supervisor Labor	$/year	79,000	79,000	79,000	79,000
Maintenance Material and Labor[3]	$/year	366,000	361,000	154,000	154,000
Total First Year Fixed O&M	**$/year**	**971,000**	**966,000**	**759,000**	**759,000**

Notes:
1. First-year costs are provided in $2020.
2. Operating labor costs are based on a labor rate of $60/hr, which is based on OG&E's input.
3. Maintenance labor cost included in maintenance materials.

Table 4-7. SCR Indirect Operating Costs

Indirect Operating Costs[1]	Units	Unit 6	Unit 8	Unit 9	Unit 10
Property Taxes	$/year	0	0	0	0
Insurance	$/year	407,000	401,000	172,000	172,000
Administration	$/year	813,000	802,000	343,000	343,000
Total Indirect Operating Cost	**$/year**	**1,220,000**	**1,203,000**	**515,000**	**515,000**

Note:
1. Indirect operating costs are provided in $2020.

4.2 SNCR COST ESTIMATE BASIS

The following summarizes the design inputs used as the basis for the Horseshoe Lake Units 6-10 SNCR System cost estimates:

Table 4-8. Design Inputs for SNCR Cost Estimates

	NOx Concentrations (lb/MBtu)		
	Unit 6	**Unit 7**	**Unit 8**
NO_X Inlet – Equipment Design	0.30	0.19	0.44
Design NO_X Outlet	0.15	0.12	0.12

The scope of work for the SNCR cost estimate includes the following major items:

- SNCR equipment per unit:
  - Solutionizing tank
  - Urea storage tanks, circulating module and dilution water module
  - Metering & distribution modules
  - Injection lances
- Structural BOP including support steel, foundations, ductwork, insulation and expansion joints
- Mechanical BOP including compressed air system, eyewash/safety showers, pumps, tanks, interconnecting piping, pipe supports, valves, and insulation
- Electrical and instrumentation/controls BOP

4.2.1 Capital Cost Estimate

Table 4-9 summarizes the SNCR capital cost estimate.

Table 4-9. SNCR Capital Cost Estimate ($2020)

Capital Cost	Unit 6	Unit 7	Unit 8
Purchased Equipment	5,275,000	3,910,000	7,162,000
Direct Installation	2,703,000	1,990,000	3,691,000
Indirects	3,112,000	2,302,000	4,232,000
Contingency	2,218,000	1,640,000	3,017,000
Total Capital Investment	**13,308,000**	**9,842,000**	**18,102,000**

4.2.2 Variable O&M Costs

The following unit costs in Table 4-10 were used to develop the variable O&M costs. Values were developed based on OG&E input when unit pricing was available or assumed based on S&L's conceptual cost estimating system.

Table 4-10. SNCR Variable O&M Unit Costs

Unit Cost	Units	Unit 6	Unit 7	Unit 8
50% Urea Solution	$/gal	1.66	1.66	1.66
Demineralized Water	$/1000 gal	5.00	5.00	5.00
Auxiliary Power	$/MWh	36.10	36.10	36.10

Table 4-11 below summarizes the consumption rates estimated as well as the first year variable O&M costs for the SNCR system.

Table 4-11. SNCR Variable O&M Consumption Rates and First-Year Costs

Parameter	Units	Unit 6	Unit 7	Unit 8
SNCR System				
50% Urea Consumption	gpm	2.4	1.5	4.2
Demineralized Water Consumption	gpm	29	18	51
Auxiliary Power Consumption	kW	364	280	513
First-Year Variable O&M Costs[1] (@CF)				
Urea Cost	$/year	200,000	93,000	241,000
Demineralized Water Cost[2]	$/year	8,000	4,000	9,000
Auxiliary Power Cost	$/year	12,000	7,000	12,000
Total First Year Variable O&M Cost	**$/year**	**220,000**	**104,000**	**262,000**

Notes:
1. First-year costs are provided in $2020.

4.2.3 Fixed O&M Costs

The fixed O&M costs for the systems consist of maintenance costs (including material and labor). Based on typical design for the SNCR system, the estimated staffing addition is 1 person per unit.

Operating Labor costs are estimated based on 2 shifts/day, 365 days per year at an operator charge rate of $60/hour. Supervisor labor is estimated to be 15% of the total operating labor costs.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (materials and labor) were estimated to be approximately 1.5% of the total purchased equipment cost and direct installation costs.

Table 4-12 below summarizes the first year fixed O&M costs.

Table 4-12. SNCR First Year Fixed O&M Costs

First Year Fixed O&M Costs[1]	Units	Unit 6	Unit 7	Unit 8
Operating Labor[2]	$/year	526,000	526,000	526,000
Supervisor Labor	$/year	79,000	79,000	79,000
Maintenance Material and Labor[3]	$/year	120,000	89,000	163,000
Total First Year Fixed O&M	**$/year**	**725,000**	**694,000**	**768,000**

Notes:
1. First-year costs are provided in $2020.
2. Operating labor costs are based on a labor rate of $60/hr, which is based on OG&E's input.
3. Maintenance labor cost included in maintenance materials.

Table 4-13. SNCR Indirect Operating Costs

Indirect Operating Costs[1]	Units	Unit 6	Unit 7	Unit 8
Property Taxes	$/year	0	0	0
Insurance	$/year	133,000	98,000	181,000
Administration	$/year	266,000	197,000	362,000
Total Indirect Operating Cost	**$/year**	**399,000**	**295,000**	**543,000**

Note:
1. Indirect operating costs are provided in $2020.

4.3 LNB/OFA/FGR COST ESTIMATE BASIS

The following summarizes the design inputs used as the basis for the Horseshoe Lake Units 6-10 LNB/OFA/FGR System cost estimates:

Table 4-14. Design Inputs for LNB/OFA/FGR Cost Estimates

	NOx Concentrations (lb/MBtu)		
	Unit 6	**Unit 7**	**Unit 8**
NO_X Inlet – Equipment Design	0.30	0.19	0.44
Design NO_X Outlet	0.15	0.15	0.15

The scope of work for the LNB/OFA/FGR cost estimate includes the following major items:

- New Low NOx Burners, including modifications to natural gas supply piping and vents
- New Overfire Air Ports, including modifications to boiler and tubing

- New Flue Gas Recirculation Fans, lubricating oil skids, fan controls and associated instrumentation
- Ductwork modifications
- Civil and structural BOP including support steel, foundations, ductwork, insulation and expansion joints
- Mechanical BOP including compressed air system, eyewash/safety showers, pumps, tanks, interconnecting piping, pipe supports, valves, and insulation
- Electrical and instrumentation/controls BOP

The above list applies to all units, with exception to Unit 6. Unit 6 has existing gas recirculation fans which may be for NOx controls with modification to the ductwork. For the purposes of the cost evaluation, it has been assumed that the gas recirculation fans will be reused for NOx control, however, the fans should be assessed in further detail to confirm this assumption.

4.3.1 Capital Cost Estimate

Table 4-15 summarizes the LNB/OFA/FGR capital cost estimate.

Table 4-15. LNB/OFA/FGR Capital Cost Estimate ($2020)

Capital Cost	Unit 6	Unit 7	Unit 8
Purchased Equipment	3,340,000	9,725,000	7,730,000
Direct Installation	3,387,000	3,605,000	8,999,000
Indirects	2,624,000	5,199,000	6,524,000
Contingency	1,870,000	3,706,000	4,651,000
Total Capital Investment	**11,221,000**	**22,235,000**	**27,904,000**

4.3.2 Variable O&M Costs

The following unit costs in Table 4-16 were used to develop the variable O&M costs. Values were developed based on OG&E input when unit pricing was available or assumed based on S&L's conceptual cost estimating system.

Table 4-16. LNB/OFA/FGR Variable O&M Unit Costs

Unit Cost	Units	Unit 6	Unit 7	Unit 8
Auxiliary Power	$/MWh	36.10	36.10	36.10

Table 4-17 below summarizes the consumption rates estimated as well as the first year variable O&M costs for the LNB/OFA/FGR system.

Table 4-17. LNB/OFA/FGR Variable O&M Consumption Rates and First-Year Costs

Parameter	Units	Unit 6	Unit 7	Unit 8
Auxiliary Power Consumption	kW	224	403	775
First-Year Variable O&M Costs[1] (@CF)				
Auxiliary Power Cost	$/year	7,000	11,000	18,000
Total First Year Variable O&M Cost	**$/year**	**7,000**	**11,000**	**18,000**

Notes:
1. First-year costs are provided in $2020.

4.3.3 Fixed O&M Costs

The fixed O&M costs for the systems consist of maintenance costs (including material and labor). For LNB/OFA/FGR systems, there is no expected increase in staffing.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (materials and labor) were estimated to be approximately 1.5% of the total purchased equipment cost and direct installation costs.

Table 4-18 below summarizes the first year fixed O&M costs.

Table 4-18. LNB/OFA/FGR First Year Fixed O&M Costs

First Year Fixed O&M Costs[1]	Units	Unit 6	Unit 7	Unit 8
Operating Labor	$/year	0	0	0
Supervisor Labor	$/year	0	0	0
Maintenance Material and Labor[2]	$/year	101,000	200,000	251,000
Total First Year Fixed O&M	**$/year**	**101,000**	**200,000**	**251,000**

Notes:
1. First-year costs are provided in $2020.
2. Maintenance labor cost included in maintenance materials.

Table 4-19. LNB/OFA/FGR Indirect Operating Costs

Indirect Operating Costs[1]	Units	Unit 6	Unit 7	Unit 8
Property Taxes	$/year	0	0	0

Indirect Operating Costs[1]	Units	Unit 6	Unit 7	Unit 8
Insurance	$/year	112,000	222,000	279,000
Administration	$/year	224,000	445,000	558,000
Total Indirect Operating Cost	**$/year**	**336,000**	**667,000**	**837,000**

Note:
1. Indirect operating costs are provided in $2020.

5. SUMMARY OF COST EVALUATION

Table 5-1 through Table 5-5 summarize the annualized capital cost, annual operating cost and total annualized cost for each alternative NOx control technology per unit.

Table 5-1. Unit 6 Annualized NOx Control Costs Summary ($2020)

	Unit 6		
	SCR	SNCR	LNB/OFA/FGR
Annualized Capital Cost[1], $	3,837,000	1,256,000	1,059,000
Total Annual Operating Costs, $/yr	2,532,000	1,344,000	444,000
Total Annualized Cost, $/yr	**6,369,000**	**2,600,000**	**1,503,000**

Note:
1. Capital costs annualized using an interest rate of 7% with an evaulation period of 20 years for Unit 6.

Table 5-2. Unit 7 Annualized NOx Control Costs Summary ($2020)

	Unit 7		
	SCR	SNCR	LNB/OFA/FGR
Annualized Capital Cost[1], $/yr	N/A	929,000	2,099,000
Total Annual Operating Costs, $/yr	N/A	1,093,000	877,000
Total Annualized Cost, $/yr	N/A	**2,022,000**	**2,976,000**

Note:
1. Capital costs annualized using an interest rate of 7% with an evaulation period of 20 years for Unit 7.

Table 5-3. Unit 8 Annualized NOx Control Costs Summary ($2020)

	Unit 8		
	SCR	SNCR	LNB/OFA/FGR
Annualized Capital Cost[1], $/yr	3,786,000	1,709,000	2,634,000
Total Annual Operating Costs, $/yr	2,675,000	1,573,000	1,105,000
Total Annualized Cost, $/yr	**6,461,000**	**3,282,000**	**3,739,000**

Note:
1. Capital costs annualized using an interest rate of 7% with an evaulation period of 20 years for Unit 8.

Table 5-4. Unit 9 Annualized NOx Control Costs Summary ($2020)

	Unit 9		
	SCR	SNCR	LNB/OFA/FGR
Annualized Capital Cost[1], $/yr	1,383,000	N/A	N/A
Annualized Outage Cost, $/yr	21,000	N/A	N/A
Total Annual Operating Costs, $/yr	1,369,000	N/A	N/A
Total Annualized Cost, $/yr	**2,773,000**	N/A	N/A

Note:
1. Capital costs annualized using an interest rate of 7% with an evaulation period of 30 years for Unit 9.

Table 5-5. Unit 10 Annualized NOx Control Costs Summary ($2020)

	Unit 10		
	SCR	SNCR	LNB/OFA/FGR
Annualized Capital Cost[1], $/yr	1,383,000	N/A	N/A
Annualized Outage Cost, $/yr	21,000	N/A	N/A
Total Annual Operating Costs, $/yr	1,369,000	N/A	N/A
Total Annualized Cost, $/yr	**2,773,000**	N/A	N/A

Note:
1. Capital costs annualized using an interest rate of 7% with an evaulation period of 30 years for Unit 10.

6. TIME NECESSARY FOR COMPLIANCE (STATUTORY FACTOR TWO)

The time necessary for compliance is generally defined as the time needed for full implementation of the technically feasible control options. This includes the time needed to develop and implement the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation. If reasonable progress measures are required at Horseshoe Lake Station for the Regional Haze second planning period, the anticipated compliance deadline would be in 2028. However, this compliance deadline must provide a reasonable amount of time for the source to implement the control measure.

Table 6-1 includes estimated timeframes needed to implement each of the technically feasible control options. Notably, the estimated timeframes do not account for time needed for Oklahoma to develop and implement the regulations; nor the amount of time needed for EPA to take proposed and final action to approve Oklahoma's SIP.

Table 6-1. NO_X Emissions Control System Implementation Schedule (months after SIP approval)

NO_X Control Option	Unit 6	Unit 7	Unit 8	Unit 9	Unit 10
SCR	48	N/A	48	48	48
SNCR	22	22	22	N/A	N/A
LNB/OFA/FGR	18	18	18	N/A	N/A

Table 6-2. NO_X Emissions Control System Outage Duration (weeks)

NO_X Control Option	Unit 6	Unit 7	Unit 8	Unit 9	Unit 10
SCR	6 to 8	N/A	6 to 8	12 to 14	12 to 14
SNCR	6 to 8	6 to 8	6 to 8	N/A	N/A
LNB/OFA/FGR	6 to 8	6 to 8	6 to 8	N/A	N/A

APPENDIX A

NO_X CONTROL SUMMARY

Horseshoe Lake Station Units 6-10
NO_X Control Summary

Table 1. HSL Station Units 6-10 Operating Parameters

Parameter	Units	Unit 6	Unit 7	Unit 8	Unit 9	Unit 10	Notes
Nominal Power Output	MW	167	214	404	46	46	Source: NEEDS database
Annual Heat Input	MMBtu/yr	2,010,462	2,203,619	3,220,554	577,177	573,143	Source: Trinity Consultants
Annual Capacity Factor	%	10%	7%	7%	12%	12%	Based on Heat Input

Table 2. NO_X Control Effectiveness

	Unit 6				Unit 7				Unit 8				Unit 9				Unit 10			
Control Technology	Control Efficiency	Expected Emissions	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Expected Emissions Reduction
	(%)	(ton/year)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/MMBtu)	(ton/year)
SCR	92%	20	0.02	237					90%	32	0.02	300	90%	3	0.01	25	90%	3	0.01	25
SNCR	41%	151	0.15	106	30%	132	0.12	56	40%	200	0.12	133								
Low NOx Burner/OFA/FGR	41%	151	0.15	106	12%	165	0.15	23	27%	242	0.15	91								
Baseline (Unit 6-8 no controls, Unit 9-10 water sprays)		257	0.26			188	0.17			332	0.21			28	0.10			28	0.10	

APPENDIX B

NO_X CONTROL COST ESTIMATES

Horseshoe Lake Units 6, 8
NO_X Control Cost Evaluation
SCR

NO_X Control Option Description	SCR	
	Unit 6	Unit 8
Post Upgrade NO_X Emissions, lb/MMBtu	0.02	0.02
Capacity Factor used of Cost Estimates (%)	10.4%	7.1%

CAPITAL COSTS	Cost (2020$) Unit 6	Unit 8	Basis
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$12,538,000	$12,756,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$0	$0	0% of Equipment/Material Cost; Exempt per OG&E
Freight	$627,000	$638,000	5% of Equipment/Material Cost
Total PEC	$13,165,000	$13,394,000	
Direct Installation Costs			
Labor	$10,280,000	$9,773,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$257,000	$244,000	2.5% of Labor
Mobilization / Demobilization	$154,000	$147,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency	$514,000	$489,000	5% of Labor
Total Direct Installation Costs	$11,205,000	$10,653,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$24,370,000**	**$24,047,000**	
Indirect Costs			
Contractor's General and Administration Expense	$2,437,000	$2,405,000	10% of Total Direct Costs
Contractor's Profit	$1,219,000	$1,202,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$4,387,000	$4,328,000	18% of Total Direct Costs; includes Owner's Cost (10% of Total Direct Costs) for Owner's engineering, procurement and project services
Construction Management/Field Engineering	$975,000	$962,000	4% of Total Direct Costs
S-U / Commissioning	$366,000	$361,000	1.5% of Total Direct Costs
Spare Parts	$122,000	$120,000	0.5% of Total Direct Costs
Total Indirect Costs	**$9,506,000**	**$9,378,000**	
Contingency	**$6,775,000**	**$6,685,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$40,651,000**	**$40,110,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0944	0.0944	20 year life of equipment (years) @ 7% interest.
Annualized Capital Costs (CRF x TCI)	**$3,837,000**	**$3,786,000**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Reagent Cost	$164,000	$196,000	Based on 19% aqueous ammonia reagent cost of $1.50/gallon.
Catalyst Replacement and Disposal Cost	$138,000	$244,000	Based on catalyst cost of $227/ft^3 and catalyst replacement cost of $28 per m^3.
Auxiliary Power Cost	$39,000	$66,000	Based on auxiliary power cost of $36.10 per MWh.
Total Variable O&M Costs	$341,000	$506,000	
Fixed O&M Costs			
Additional Operators per Shift	1	1	
Operating Labor	$526,000	$526,000	Per OG&E $60/hr for each additional operator
Supervisor Labor	$79,000	$79,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$366,000	$361,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$971,000	$966,000	
Indirect Operating Cost			
Property Taxes	$0	$0	Excluded per OG&E
Insurance	$407,000	$401,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$813,000	$802,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$1,220,000	$1,203,000	
Total Annual Operating Cost	**$2,532,000**	**$2,675,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$3,837,000	$3,786,000	
Annual Operating Cost	$2,532,000	$2,675,000	
Total Annual Cost	**$6,369,000**	**$6,461,000**	

Horseshoe Lake Units 9, 10
NO_X Control Cost Evaluation
SCR

NO_X Control Option Description	SCR	
	Unit 9	Unit 10
Post Upgrade NO_X Emissions, lb/MMBtu	0.01	0.01
Capacity Factor used of Cost Estimates (%)	12%	12%

CAPITAL COSTS	Cost (2020$) Unit 9	Unit 10	Basis
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$5,122,000	$5,122,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$0	$0	0% of Equipment/Material Cost; Exempt per OG&E
Freight	$256,000	$256,000	5% of Equipment/Material Cost
Total PEC	$5,378,000	$5,378,000	
Direct Installation Costs			
Labor	$4,504,000	$4,504,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$113,000	$113,000	2.5% of Labor
Mobilization / Demobilization	$68,000	$68,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency	$225,000	$225,000	5% of Labor
Total Direct Installation Costs	$4,910,000	$4,910,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$10,288,000**	**$10,288,000**	
Indirect Costs			
Contractor's General and Administration Expense	$1,029,000	$1,029,000	10% of Total Direct Costs
Contractor's Profit	$514,000	$514,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$1,852,000	$1,852,000	18% of Total Direct Costs; includes Owner's Cost (10% of Total Direct Costs) for Owner's engineering, procurement and project services
Construction Management/Field Engineering	$412,000	$412,000	4% of Total Direct Costs
S-U / Commissioning	$154,000	$154,000	1.5% of Total Direct Costs
Spare Parts	$51,000	$51,000	0.5% of Total Direct Costs
Total Indirect Costs	**$4,012,000**	**$4,012,000**	
Contingency	**$2,860,000**	**$2,860,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$17,160,000**	**$17,160,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0806	0.0806	30 year life of equipment (years) @7% interest.
Annualized Capital Costs (CRF x TCI)	**$1,383,000**	**$1,383,000**	
OUTAGE COSTS			
Outage Costs			
Standard Outage Duration (weeks/yr)	6	6	
Outage Duration due to Retrofit (weeks/yr)	14	14	Estimate
Lost Revenue due to Retrofit	**$264,000**	**$263,000**	Based on 12 Mwg power output, '12% capacity factor, $36.01/MWh
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0806	0.0806	30 year life of equipment (years) @ 7% interest.
Annualized Outage Costs (CRF x TCI)	**$21,000**	**$21,000**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost	$0	$0	
Ammonia Reagent Cost	$25,000	$25,000	Based on 19% aqueous ammonia reagent cost of $1.50/gallon.
Catalyst Replacement and Disposal Cost	$62,000	$62,000	Based on catalyst cost of $227/ft^3 and catalyst replacement cost of $28 per m^3.
Lost Generation Cost	$5,000	$5,000	Based on auxiliary power cost of $36.10 per MWh.
Auxiliary Power Cost	$3,000	$3,000	Based on auxiliary power cost of $36.10 per MWh.
Total Variable O&M Costs	$95,000	$95,000	
Fixed O&M Costs			
Additional Operators per Shift	1	1	
Operating Labor	$526,000	$526,000	Per OG&E $60/hr for each additional operator
Supervisor Labor	$79,000	$79,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$154,000	$154,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$759,000	$759,000	
Indirect Operating Cost			
Property Taxes	$0	$0	Excluded per OG&E
Insurance	$172,000	$172,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$343,000	$343,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$515,000	$515,000	
Total Annual Operating Cost	**$1,369,000**	**$1,369,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$1,383,000	$1,383,000	
Annualized Outage Cost	$21,000	$21,000	
Annual Operating Cost	$1,369,000	$1,369,000	
Total Annual Cost	**$2,773,000**	**$2,773,000**	

Horseshoe Lake Units 6, 7, 8
NO_X Control Cost Evaluation
SNCR

NO_X Control Option Description	SNCR		
	Unit 6	Unit 7	Unit 8
Post Upgrade NO_X Emissions, lb/MMBtu	0.15	0.12	0.12
Capacity Factor used of Cost Estimates (%)	10.4%	7.5%	7.1%

CAPITAL COSTS	Cost (2020$) Unit 6	Unit 7	Unit 8	Basis
Direct Costs				
Purchased Equipment Costs (PEC)				
Equipment and Materials	$5,024,000	$3,724,000	$6,821,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0	$0	$0	Included in equipment and materials cost
Sales Tax	$0	$0	$0	0% of Equipment/Material Cost; Exempt per OG&E
Freight	$251,000	$186,000	$341,000	5% of Equipment/Material Cost
Total PEC	$5,275,000	$3,910,000	$7,162,000	
Direct Installation Costs				
Labor	$2,480,000	$1,826,000	$3,386,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$62,000	$46,000	$85,000	2.5% of Labor
Mobilization / Demobilization	$37,000	$27,000	$51,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency	$124,000	$91,000	$169,000	5% of Labor
Total Direct Installation Costs	$2,703,000	$1,990,000	$3,691,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$7,978,000**	**$5,900,000**	**$10,853,000**	
Indirect Costs				
Contractor's General and Administration Expense	$798,000	$590,000	$1,085,000	10% of Total Direct Costs
Contractor's Profit	$399,000	$295,000	$543,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$1,436,000	$1,062,000	$1,954,000	18% of Total Direct Costs; includes Owner's Cost (10% of Total Direct Costs) for Owner's engineering, procurement and project services
Construction Management/Field Engineering	$319,000	$236,000	$434,000	4% of Total Direct Costs
S-U / Commissioning	$120,000	$89,000	$163,000	1.5% of Total Direct Costs
Spare Parts	$40,000	$30,000	$54,000	0.5% of Total Direct Costs
Total Indirect Costs	**$3,112,000**	**$2,302,000**	**$4,233,000**	
Contingency	**$2,218,000**	**$1,640,000**	**$3,017,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$13,308,000**	**$9,842,000**	**$18,103,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0944	0.0944	0.0944	20 year life of equipment (years) @ 7% interest.
Annualized Capital Costs (CRF x TCI)	**$1,256,000**	**$929,000**	**$1,709,000**	
OPERATING COSTS				
Operating & Maintenance Costs				
Variable O&M Costs				
Urea Reagent Cost	$200,000	$93,000	$241,000	Based on 50% Urea cost of $1.66/gallon.
Demin Water Cost	$8,000	$4,000	$9,000	Based on a water cost of $5.00/1,000gal.
Auxiliary Power Cost	$12,000	$7,000	$12,000	Based on auxiliary power cost of $36.10 per MWh.
Total Variable O&M Costs	$220,000	$104,000	$262,000	
Fixed O&M Costs				
Additional Operators per Shift	1	1	1	
Operating Labor	$526,000	$526,000	$526,000	Per OG&E $60/hr for each additional operator
Supervisor Labor	$79,000	$79,000	$79,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$120,000	$89,000	$163,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$725,000	$694,000	$768,000	
Indirect Operating Cost				
Property Taxes	$0	$0	$0	Excluded per OG&E
Insurance	$133,000	$98,000	$181,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$266,000	$197,000	$362,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$399,000	$295,000	$543,000	
Total Annual Operating Cost	**$1,344,000**	**$1,093,000**	**$1,573,000**	
TOTAL ANNUAL COST				
Annualized Capital Cost	$1,256,000	$929,000	$1,709,000	
Annual Operating Cost	$1,344,000	$1,093,000	$1,573,000	
Total Annual Cost	**$2,600,000**	**$2,022,000**	**$3,282,000**	

Horseshoe Lake Units 6, 7, 8
NO_X Control Cost Evaluation
Low Nox Burner (LNB), Over-fired Air (OFA) and Flue Gas Recirculation (FGR)

NO_X Control Option Description	LNB, OFA & FGR		
	Unit 6	Unit 7	Unit 8
Post Upgrade NO_X Emissions, lb/MMBtu	0.15	0.15	0.15
Capacity Factor used of Cost Estimates (%)	10.4%	7.5%	7.1%

CAPITAL COSTS	Cost (2020$) Unit 6	Unit 7	Unit 8	Basis
Direct Costs				
Purchased Equipment Costs (PEC)				
Equipment and Materials	$3,181,000	$9,262,000	$7,362,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0	$0	$0	Included in equipment and materials cost
Sales Tax	$0	$0	$0	0% of Equipment/Material Cost; Exempt per OG&E
Freight	$159,000	$463,000	$368,000	5% of Equipment/Material Cost
Total PEC	$3,340,000	$9,725,000	$7,730,000	
Direct Installation Costs				
Labor	$3,107,000	$3,307,000	$8,256,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$78,000	$83,000	$206,000	2.5% of Labor
Mobilization / Demobilization	$47,000	$50,000	$124,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency	$155,000	$165,000	$413,000	5% of Labor
Total Direct Installation Costs	$3,387,000	$3,605,000	$8,999,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$6,727,000**	**$13,330,000**	**$16,729,000**	
Indirect Costs				
Contractor's General and Administration Expense	$673,000	$1,333,000	$1,673,000	10% of Total Direct Costs
Contractor's Profit	$336,000	$667,000	$836,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$1,211,000	$2,399,000	$3,011,000	18% of Total Direct Costs; includes Owner's Cost (10% of Total Direct Costs) for Owner's engineering, procurement and project services
Construction Management/Field Engineering	$269,000	$533,000	$669,000	4% of Total Direct Costs
S-U / Commissioning	$101,000	$200,000	$251,000	1.5% of Total Direct Costs
Spare Parts	$34,000	$67,000	$84,000	0.5% of Total Direct Costs
Total Indirect Costs	**$2,624,000**	**$5,199,000**	**$6,524,000**	
Contingency	**$1,870,000**	**$3,706,000**	**$4,651,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$11,221,000**	**$22,235,000**	**$27,904,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0944	0.0944	0.0944	20 year life of equipment (years) @ 7% interest.
Annualized Capital Costs (CRF x TCI)	**$1,059,000**	**$2,099,000**	**$2,634,000**	
OPERATING COSTS				
Operating & Maintenance Costs				
Variable O&M Costs				
Auxiliary Power Cost	$7,000	$10,000	$17,000	Based on auxiliary power cost of $36.10 per MWh.
Total Variable O&M Costs	$7,000	$10,000	$17,000	
Fixed O&M Costs				
Additional Operators per Shift	0	0	0	No additional operators expected.
Operating Labor	$0	$0	$0	Per OG&E $60/hr for each additional operator
Supervisor Labor	$0	$0	$0	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$101,000	$200,000	$251,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$101,000	$200,000	$251,000	
Indirect Operating Cost				
Property Taxes	$0	$0	$0	Excluded per OG&E
Insurance	$112,000	$222,000	$279,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$224,000	$445,000	$558,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$336,000	$667,000	$837,000	
Total Annual Operating Cost	**$444,000**	**$877,000**	**$1,105,000**	
TOTAL ANNUAL COST				
Annualized Capital Cost	$1,059,000	$2,099,000	$2,634,000	
Annual Operating Cost	$444,000	$877,000	$1,105,000	
Total Annual Cost	**$1,503,000**	**$2,976,000**	**$3,739,000**	

APPENDIX B. ADDITIONAL FACTOR - VISIBILITY CONDITIONS AT WICHITA MOUNTAINS CLASS I AREA

WICHITA MOUNTAINS CLASS I AREA IMPROVE MONITORING DATA SUMMARY

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September 3, 2020

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1. INTRODUCTION

This report summarizes the observed visibility impairment conditions for the Wichita Mountains Wildlife Refuge Class I area ("WIMO" or "WIMO1") from the Interagency Monitoring of Protected Visual Environments (IMPROVE) network monitoring data,[1] and compares these conditions to the Uniform Rate of Progress (URP) glidepath ("adjusted default" option) for the area from EPA's September 19, 2019 memorandum *Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling*.[2] In addition, the current visibility conditions for the clearest days are compared to projected (modeled) 2028 visibility for the clearest days.

[1] As of the drafting of this report, summarized annual IMPROVE monitoring data is available through the year 2018.

[2] https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf

2. BACKGROUND

Visibility impairment or "haze" is described by the light extinction visibility metric in units of inverse megameters (Mm^{-1}). Because the inverse-distance units are difficult to conceptualize, the deciview haze index (dv) was developed. Extinction values are converted to deciviews using a logarithmic equation[3] such that the deciview scale is nearly zero for a pristine atmosphere, and, like the decibel scale for sound, equivalent changes in deciviews are perceived similarly across a wide range of background conditions.[4] Light extinction in the Class I areas is observed via the IMPROVE network of Class I area air monitors. IMPROVE visibility data are available on the IMPROVE website.[5]

EPA has selected the deciview scale as the most appropriate visibility metric for regulatory purposes because it is more conducive to describing and comparing humanly perceptible visibility changes at different Class I areas and for a wide range of visibility conditions. According to EPA, a one-deciview change represents a "small but noticeable change in haziness" and, depending on conditions, a change of greater than one deciview may be necessary to be perceived by the human eye.[6] Other studies, however, have suggested that a "1-deciview change never produces a perceptible change in haze."[7]

Section 169A of the Clean Air Act (CAA) sets forth a national goal for the "prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution." In 1999, the Regional Haze Program was promulgated to require states to include provisions to address impairment of visibility in Class I areas in their *State Implementation Plans*.[8] The Regional Haze Program requires setting reasonable progress goals towards achieving natural visibility conditions at each Class I area. The reasonable progress goals must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period.[9] Reasonable progress goals are compared to the Uniform Rate of Progress ("URP") or "glidepath" needed to achieve natural conditions in 2064.[10] The URP is a straight line from baseline visibility conditions (average of the 20 percent most impaired days as of 2004) to natural visibility conditions (to be achieved in 2064 for the 20 percent most impaired days).

The EPA's *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (SIP Guidance)[11] provides guidance to states for the development of the implementation plans. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural (or "biogenic") and manmade

[3] Deciview = 10 × ln (Extinction ÷ 10)

[4] U.S. EPA, Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress at 1-5 - 1-7 (November 2001).

[5] http://vista.cira.colostate.edu/Improve/

[6] Regional Haze Regulations, 64 Fed. Reg. 35,725-27 (July 1999).

[7] Ronald C. Henry, "Just-Noticeable Differences in Atmospheric Haze," Journal of the Air & Waste Management Association, Vol. 52 at 1,238 (October 2002).

[8] 64 FR 35714

[9] 40 CFR 51.308(d)(1)

[10] 40 CFR 51.308(f)(1)(iv)(A)

[11] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 2019, EPA-457/B-19-003.

(or “anthropogenic”) sources of emissions. The EPA’s *Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program* (Visibility Guidance)[12] provides guidance to states on methods for selecting the twenty (20) percent most impaired days to track visibility and determining natural visibility conditions. This method has been applied by the IMPROVE group to the data collected at WIMO1.

For the second planning period, the tracking of the 20 percent clearest days remains unchanged. The selection of the 20 percent clearest days does not include any processing to factor out natural sources of impairment. The tracking of the 20 percent clearest days is to ensure that the visibility on the clearest days is not being degraded.

[12] Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program, December 2018, EPA-454/R-18-010.

3. SUMMARY AND COMPARISON FOR WICHITA MOUNTAINS

Table 3-1 presents a summary of the annual-average haze index values for each year from 2002 to 2018 for the WIMO1 monitor.

Table 3-1. Summary of Annual-Average Haze Index Values for WIMO1

Year	Average of 20 Percent Most Impaired Days (dv)	Average of 20 Percent Clearest Days (dv)
2002	9.75	22.26
2003	10.02	22.02
2004	9.56	22.16
2005	10.59	24.39
2006	9.74	20.83
2007	9.32	22.38
2008	9.85	21.06
2009	-- [A]	-- [A]
2010	9.22	20.92
2011	10.34	21.24
2012	8.88	19.44
2013	8.44	19.54
2014	9.26	20.42
2015	8.49	18.08
2016	8.08	16.45
2017	7.74	17.50
2018	8.77	18.16

[A] Summarized data are not available for WIMO1 for 2009.

Figure 3-1 presents a comparison of the annual-average haze index values for the most impaired days from Table 3-1 to the URP glidepath proposed by EPA for WIMO.[13] As seen in Figure 3-1, the actual observed visibility impairment at WIMO has declined overall and has remained below the glidepath since 2015. Thus, the current Class I area visibility conditions are better than necessary (or ahead of schedule) to achieve the goal of the regional haze program.

In addition, the projected (modeled) 2028 haze index values from EPA's September 19, 2019 memorandum *Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling* are shown in the figure. EPA's modeling shows the projected 2028 haze index values are satisfying the objective of the Regional Haze Program to improve the most impaired days and not cause additional degradation to the clearest days.

Lastly, the projected 2028 most-impaired days value from modeling completed by the Texas Commission on Environmental Quality (TCEQ) is also shown in the figure.[14] TCEQ conducted CAMx visibility modeling to

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[13] Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling, September 19, 2019 (https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf)

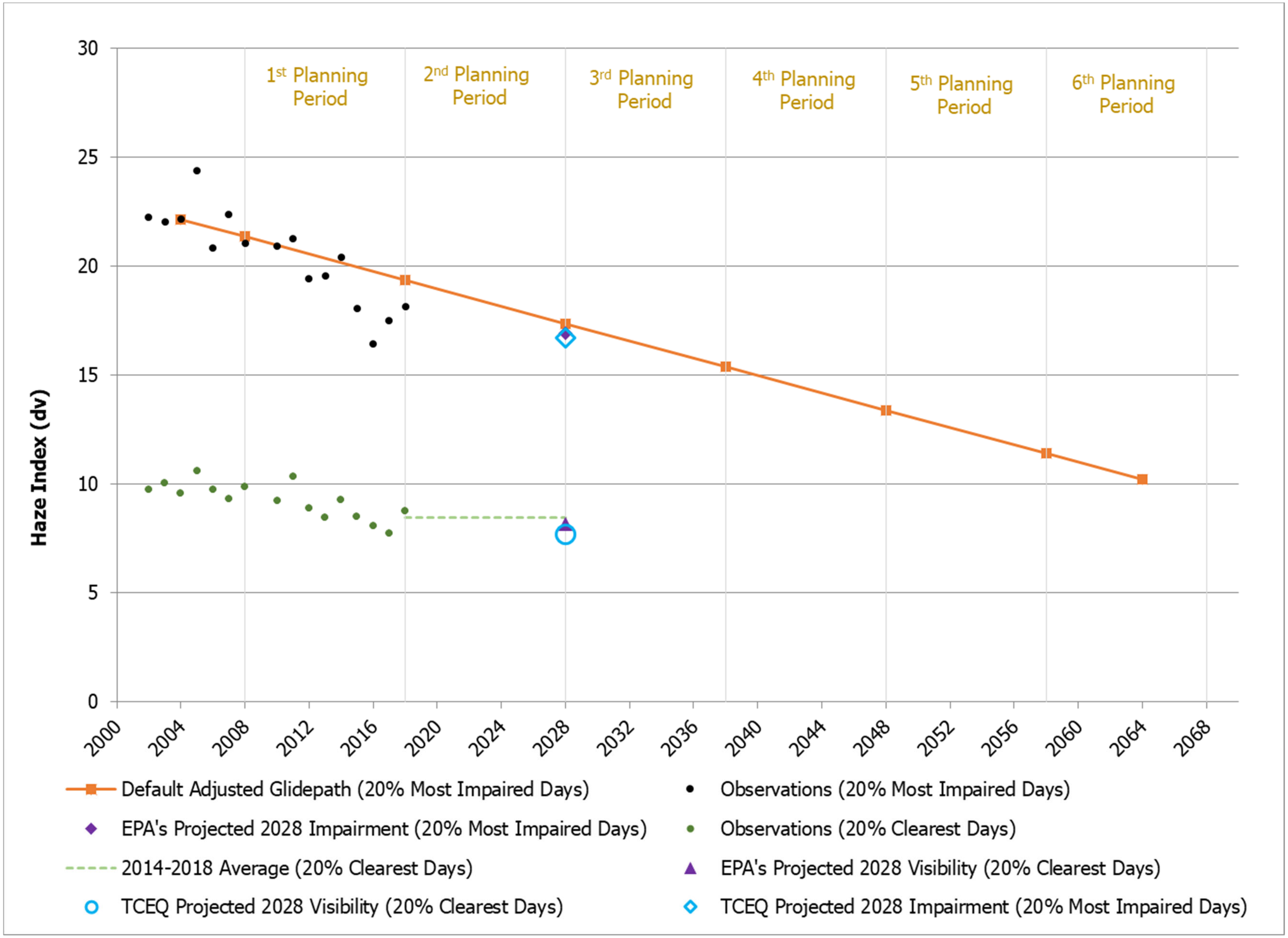
[14] Regional Haze Modeling to Evaluating Progress in Improving Visibility in and near Texas, dated January 21, 2020 (https://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/pm/5822010567009-20200121-ramboll-RegionalHazeModelingEvaluateProgressVisibility.pdf)

assist with Step 6 of the SIP Guidance.[15] It also indicates that the 2028 projected visibility impairment at WIMO is below the glidepath.

Because the EPA and TCEQ CAMx modeling for WIMO shows the projected 2028 haze index below the URP glide path, the current projected emissions reductions are sufficient to show reasonable progress and no additional controls are needed for this planning period.

[15] Step 6 of the SIP Guidance is regional scale modeling of the long-term strategy (LTS) to set the reasonable progress goals (RPGs) for 2028.

Figure 3-1. Observations Compared to Glidepaths for WIMO



APPENDIX C. ADDITIONAL FACTOR – REFINED HYSPLIT MODELING

WICHITA MOUNTAINS CLASS I AREA HYSPLIT MODELING SUMMARY

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1. INTRODUCTION

The Central States Air Resource Agencies (CenSARA) regional planning organization (RPO) completed Area of Influence (AOI) analyses for several Class I areas, including the Wichita Mountains Wildlife Refuge Class I area ("WIMO" or "WIMO1"), using the National Oceanic and Atmospheric Administration's (NOAA)'s Hybrid-Single Particle Lagrangian Integrated Trajectory Model (HYSPLIT) to assist its states, including Oklahoma, with source screening. The Oklahoma Department of Environmental Quality (ODEQ) relied on CenSARA's analysis as the basis for determining which sources would be required to complete a regional haze reasonable progress four-factor analysis.

Oklahoma Gas & Electric (OG&E) contracted with Trinity to evaluate the CenSARA modeling and complete a refined analysis for WIMO. This report summarizes the analysis completed by Trinity.

2. HYSPLIT METHODOLOGY

HYSPLIT is a hybrid model using both the Lagrangian approach, which uses a moving frame of reference for the advection and diffusion calculations as the trajectories or air parcels move from their initial location and the Eulerian methodology, which uses a fixed three-dimensional grid as a frame of reference to compute pollutant air concentrations. The dispersion of a hypothetical pollutant is calculated by assuming either puff or particle dispersion. The back-trajectory analysis utilized applies a particle model, where a fixed number of particles are advected about the model domain by the mean wind field and spread by a turbulent component. The model's default configuration assumes a 3-dimensional particle distribution (horizontal and vertical).

There are two HYSPLIT modeling techniques available: dispersion modeling, which models the concentration of dispersed pollutants in a plume, or trajectory modeling, which calculates the transport of pollution along a finite path. In its analysis, Trinity employed the trajectory modeling tool to calculate the back-trajectories for every hour of the 20 percent most impaired days from calendar years 2013 through 2016.

There are several options available for meteorological datasets. To resolve topographic features and mesoscale meteorological phenomena, the 12-km North American Model sigma-pressure hybrid dataset (NAMS) meteorological dataset was used. The following protocol was implemented:

- The HYSPLIT model was run for each hour of each visibility impaired day (i.e., 24 runs per day);
- A 72-hour back-trajectory was calculated for each of the 24 runs to capture the transport of pollutants from all nearby sources to a selected endpoint. The model calculated the back-trajectories in 1-hour time steps; and
- The sigma height option was used, with an initial target height of 0.5 sigma, which represents half the height of the boundary layer. This height is considered representative of the mean ground level of ambient air since the boundary layer is well-mixed/homogenous.

The back-trajectories were then aggregated into a residence time frequency matrix where the columns are longitude bins and rows are latitude bins. For each grid cell (i,j), the frequency, F, is calculated using the following equation:

$$F_{i,j} = \frac{1}{N} \sum T_{i,j} \qquad \text{(equation 1)}$$

where T is the number of trajectory points that are located in a grid cell (i,j), and N is the total number of trajectory points analyzed.

3. FREQUENCY COMPARISION FOR WICHITA MOUNTAINS

The residence time frequency analysis described was conducted for the WIMO monitor location. The results of this analysis reveal that the cumulative residence times of air parcels contributing to the 20 percent most impaired days in the grid cell containing the OG&E Horseshoe Lake Generating Station (Horseshoe Lake) located in Harrah, Oklahoma (OK) are less than 0.02 %. In other words, according to this analysis, Horseshoe Lake is upwind of WIMO for less than 1.5 hours of the total time represented by the 20 % most impaired days of the four modeled years. The residence time frequency analysis results for the entire region are depicted in Figure 3-1. The map was generated using the HYSPLIT "trajfreq" and "concplot" executables, which output interpolated contours based on the discrete grid cell frequency values.

Figure 3-1. HYSPLIT Residence Time Percent Frequency for WIMO