Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in New Mexico

May 5, 2009

Revised Draft Report

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Scope of Document

This document provides an initial analysis of the four factors which must be considered in establishing a reasonable progress goal toward achieving natural visibility conditions in mandatory Class I areas. These factors were examined for several candidate control measures for priority pollutants and emission sources. The results of this report are intended to inform policymakers in setting reasonable progress goals for the Class I areas in the Western Regional Air Partnership (WRAP) region.

This document does not address policy issues, set reasonable progress goals, or recommend a long-term strategy for regional haze. Separate documents will be prepared by the States which address the reasonable progress goals, each state's share of emission reductions, and coordinated emission control strategies.

Disclaimer

The analysis described in this document has been funded by the Western Governors' Association. It has been subject to review by the WGA and the WRAP. However, the report does not necessarily reflect the views of the sponsoring and participating organizations, and no official endorsement should be inferred.

Contents

Abbreviations

ALAPCO	Association of Local Air Pollution Control Officials
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CEMS	Continuous Emissions Monitoring System
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DSI	Duct Sorbent Injection
EC	Elemental Carbon
EDMS	Emissions Data Management System
EGU	Electric Generating Units
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
FCCU	Fluid Catalytic Cracking Unit
FGD	Flue Gas Desulfurization
FGR	Flue Gas Recirculation
ICAC	Institute of Clean Air Companies
LNB	Low-NOx Burners
MRPO	Midwest Regional Planning Organization
N2	Nitrogen
N2O5	Dinitrogen Pentoxide
NACAA	National Association of Clean Air Agencies
NEI	National Emissions Inventory
NH3	Ammonia
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxides
OC	Organic Carbon
OFA	Overfire Air
PM	Particulate Matter
PM_{10}	Particulate Matter Particles of 10 Micrometers or Less
$PM_{2.5}$	Particulate Matter Particles of 2.5 Micrometers or Less
PSD	Prevention of Significant Deterioration
RACT	Reasonably Achievable Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
SCR	Selective Catalytic Reduction
SDA	Spray Dryer Absorber
SNCR	Selective Noncatalytic Reduction
SO_2	Sulfur Dioxide
STAPPA	State and Territorial Air Pollution Program Administrators
ULNB	Ultralow-NO_X Burners
VOC	Volatile Organic Compounds
WRAP	Western Regional Air Partnership

Units

acfm	Actual Cubic Feet per Minute
cfm	Cubic Feet per Minute
kWh	Kilowatt Hour
MM-BTU/hr	Million British Thermal Units per Hour
MW	Megawatt
ppm	Parts Per Million
ppmv	Parts per Million by Volume
scfm	Standard Cubic Feet per Minute

1. Introduction

The Regional Haze Rule requires States to set reasonable progress goals toward meeting a national goal of natural visibility conditions in Class I areas by the year 2064. The first reasonable progress goals will be established for the planning period 2008 to 2018. The Western Regional Air Partnership (WRAP), along with its member states, tribal governments, and federal agencies, are working to address visibility impairment due to regional haze in Class I areas. The Regional Haze Rule identifies four factors which should be considered in evaluating potential emission control measures to meet visibility goals. These are as follows:

1. Cost of compliance
2. Time necessary for compliance
3. Energy and non-air quality environmental impacts of compliance
4. Remaining useful life of any existing source subject to such requirements

This report has been prepared as part of a project to evaluate the above factors for possible control strategies intended to improve visibility in the WRAP region. We have identified control measures for emissions of nitrogen oxides (NO_X) and sulfur dioxide (SO_2), which can react in the atmosphere to produce visibility-obscuring particulate matter on a regional scale, and also for direct emissions of particulate matter. For direct particulate matter emissions (PM), we have evaluated the impacts of control measures on various particulate matter components, including $PM_{2.5}$, PM_{10}, elemental carbon (EC) particulate matter, and organic carbon (OC) particulate matter. A number of emission source categories have been addressed, including:

1. Reciprocating internal combustion engines and turbines
2. Oil and natural gas exploration and production field operations
3. Natural gas processing plants
4. Industrial boilers
5. Cement manufacturing plants
6. Sulfuric acid manufacturing plants
7. Pulp and paper plant lime kilns
8. Petroleum refinery process heaters

The four-factor analyses for these emission categories are documented in a separate report, entitled "Assessing Reasonable Progress for Regional Haze in the WRAP Region – Source Category Analysis."

The current report presents a the results of a four-factor analysis of potential control measures for selected emission sources at three petroleum refineries in New Mexico. The emission sources addressed in this current report were selected by the New Mexico Environment

Department. Section 2 presents the methodology employed to conduct the analyses and Section 3 presents the results of the four-factor analysis for emission sources at the three refineries.

2. Methodology

The first step in the technical evaluation of control measures for a source category was to identify the major sources of emissions from the category. Emissions assessments were initially based on 2002 emissions inventory in the WRAP Emissions Data Management System (EDMS),[1] which consists of data submitted by the WRAP states in 2004. The states then reviewed the emissions data and parameters from the EDMS used for this analysis and provided updated data when applicable. In some cases, detailed data on PM_{10} and $PM_{2.5}$ emissions were not available from the WRAP inventory. Therefore, PM_{10} and $PM_{2.5}$ data from the U.S. Environmental Protection Agency's (EPA) 2002 National Emissions Inventory (NEI) were used to supplement the WRAP inventory where necessary.

Once the important emission sources were identified within a given emission source category, a list of potential additional control technologies was compiled from a variety of sources, including control techniques guidelines published by the EPA, emission control cost models such as AirControlNET[2] and CUECost,[3] Best Available Retrofit Technology (BART) analyses, White Papers prepared by the Midwest Regional Planning Organization (MRPO),[4] and a menu of control options developed by the National Association of Clean Air Agencies (NACAA).[5] The options for each source category were then narrowed to a set of technologies that would achieve the emission reduction target under consideration. The following sections discuss the methodology used to analyze each of the regional haze factors for the selected technologies.

2.1 Factor 1 – Costs

Control costs include both the capital costs associated with the purchase and installation of retrofit and new control systems, and the net annual costs (which are the annual reoccurring costs) associated with system operation. The basic components of total capital costs are direct capital costs, which includes purchased equipment and installation costs, and indirect capital expenses. Direct capital costs consist of such items as purchased equipment cost, instrumentation and process controls, ductwork and piping, electrical components, and structural and foundation costs. Labor costs associated with construction and installation are also included in this category. Indirect capital expenses are comprised of engineering and design costs, contractor fees, supervisory expenses, and startup and performance testing. Contingency costs, which represent such costs as construction delays, increased labor and equipment costs, and design modification, are an additional component of indirect capital expenses. Capital costs also include the cost of process modifications. Annual costs include amortized costs of capital investment, as well as costs of operating labor, utilities, and waste disposal. For fuel switching options, annual costs include the cost differential between the current fuel and the alternate fuel.

The U.S. EPA's *Guidance for Setting Reasonable Progress Goals under the Regional Haze Program*[6] indicates that the four-factor analyses should conform to the methodologies given in the *EPA Air Pollution Control Cost Manual*.[7] This study draws on cost analyses which have followed the protocols set forth in the Cost Manual. Where possible, we have used the primary references for cost data. Cost estimates have been updated to 2007 dollars using the Marshall & Swift Equipment Cost Index or the Chemical Engineering Plant Cost Index, both of which are published in the journal, *Chemical Engineering.*

For Factor 1, results of the cost analysis are expressed in terms of total cost-effectiveness, in dollars per ton of emissions reduced. A relevant consideration in a cost-effectiveness calculation is the economic condition of the industry (or individual facility if the analysis is performed on that basis). Even though a given cost-effectiveness value may, in general, be considered "acceptable," certain industries may find such a cost to be overly burdensome. This is particularly true for well-established industries with low profit margins. Industries with a poor economic condition may not be able to install controls to the same extent as more robust industries. A thorough economic review of the source categories selected for the factor analysis is beyond the scope of this project.

2.2 Factor 2 – Time Necessary for Compliance

For Factor 2, we evaluated the amount of time needed for full implementation of the different control strategies. The time for compliance was defined to include the time needed to develop and implement the regulations, as well as the time needed to install the necessary control equipment. The time required to install a retrofit control device includes time for capital procurement, device design, fabrication, and installation. The Factor 2 analysis also included the time required for staging the installation of multiple control devices at a given facility.

2.3 Factor 3 – Energy and Other Impacts

Table 2-1 summarizes the energy and environmental impacts analyzed under Factor 3. We evaluated the direct energy consumption of the emission control device, solid waste generated, wastewater discharged, acid deposition, nitrogen deposition, and climate impacts (e.g., generation and mitigation of greenhouse gas emissions).

In general, the data needed to estimate these energy and other non-air pollution impacts were obtained from the cost studies which were evaluated under Factor 1. These analyses generally quantify electricity requirements, steam requirements, increased fuel requirements, and other impacts as part of the analysis of annual operation and maintenance costs.

Costs of disposal of solid waste or otherwise complying with regulations associated with waste streams were included under the cost estimates developed under Factor 1, and were evaluated as to whether they could be cost-prohibitive or otherwise negatively affect the facility. Energy needs and non-air quality impacts of identified control technologies were aggregated to estimate the energy impacts for the specified industry sectors. However, indirect energy impacts were not considered, such as the different energy requirements to produce a given amount of coal versus the energy required to produce an equivalent amount of natural gas.

Table 2-1 Summary of Energy and Environmental Impacts Evaluated Under Factor 3

Energy Impacts
Electricity requirement for control equipment and associated fans
Steam required
Fuel required
Environmental Impacts
Waste generated
Wastewater generated
Additional carbon dioxide (CO_2) produced
Reduced acid deposition
Reduced nitrogen deposition
Benefits from reductions in $PM_{2.5}$ and ozone, where available
Impacts Not Included
Impacts of control measures on boiler efficiency
Energy required to produce lower sulfate fuels
Secondary environmental impacts to produce additional energy (except CO_2) produced

2.4 Factor 4 – Remaining Equipment Life

Factor 4 accounts for the impact of the remaining equipment life on the cost of control. Such an impact will occur when the remaining expected life of a particular emission source is less than the lifetime of the pollution control device (such as a scrubber) that is being considered. In this case, the capital cost of the pollution control device can only be amortized for the remaining lifetime of the emission source. Thus, if a scrubber with a service life of 15 years is being evaluated for a boiler with an expected remaining life of 10 years, the shortened amortization schedule will increase the annual cost of the scrubber.

The ages of major pieces of equipment were determined where possible, and compared with the service life of pollution control equipment. The impact of a limited useful life on the amortization period for control equipment was then evaluated, along with the impact on annualized cost-effectiveness.

2.5 References for Section 2

1. WRAP (2008), *Emissions Data Management System*, Western Regional Air Partnership, Denver, CO, http://www.wrapedms.org/app_main_dashboard.asp.

2. E.H. Pechan & Associates (2005), *AirControlNET, Version 4.1 - Documentation Report*, U.S. EPA, RTP, NC, http://www.epa.gov/ttnecas1/AirControlNET.htm.

3. *Coal Utility Environmental Cost (CUECost) Model Version 1.0*, U.S. EPA, RTP, NC, http://www.epa.gov/ttn/catc/products.html.

4. MRPO (2006), *Interim White Papers-- Midwest RPO Candidate Control Measures*, Midwest Regional Planning Organization and Lake Michigan Air Directors Consortium, Des Plaines, IL, www.ladco.org/reports/control/white_papers/.

5. NACAA (formerly STAPPA and ALAPCO) (2006), *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, National Association of Clean Air Agencies, www.4cleanair.org/ PM25Menu-Final.pdf.

6 EPA (2007), *Guidance for Setting Reasonable Progress Goals under the Regional Haze Program*, http://www.epa.gov/ttncaaa1/t1/memoranda/reasonable_progress_guid071307.pdf.

7. EPA (2002), *EPA Air Pollution Control Cost Manual, 6th ed.*, EPA/452/B-02-001, U.S. EPA, Office of Air Quality Planning and Standards, RTP, NC, Section 5 - SO_2 and Acid Gas Controls, pp 1-30 through 1-42, http://www.epa.gov/ttncatc1/products.html#cccinfo.

3. Petroleum Refineries

Four-factor analyses have been conducted for selected emission sources at three New Mexico petroleum refineries. The following facilities and emission sources have been evaluated:

- Navajo Refining Co., Artesia Refinery – Fluid Catalytic Cracking Unit (FCCU) #1, catalyst regeneration and process heater
- Western Refining Southwest, Bloomfield Refinery – FCCU #1, catalyst regeneration and process heater
- Western Refining Southwest, Gallup Refinery – CO Boiler Unit #1

Table 3-1 summarizes the emission control measures that have already been applied to the selected emission sources, the baseline levels of emissions with these current controls, and potential additional control measures that could be adopted to further reduce emissions. The table also gives the estimated control efficiency and annual emission reduction for each potential future control measure.

Baseline SO_2 emissions from the Navajo Artesia refinery FCCU regenerator were derived from the permit concentration limit listed in the EPA RACT/BACT/LAER Clearinghouse (RBLC).[1] The Navajo Artesia refinery permit listed in the RBLC database was issued on March 5, 2002. Other baseline emissions of NO_X and SO_2 for the refineries are based on the WRAP 2002 emissions inventory, and data received from the New Mexico Environment Department.[2,3] Emissions of $PM_{2.5}$ and PM_{10} were obtained from the 2002 U.S. EPA NEI. Emissions of EC and OC were estimated using mass fraction factors from EPA's SPECIATE database.[4] EC and OC are estimated to comprise 0.07% and 0.014% of PM_{10} emissions from catalytic cracking units, respectively. PM_{10} emissions from the carbon monoxide (CO) boiler were assumed to have a composition similar to natural gas combustion emissions, about 38.4% EC and 24.7% OC. It should be noted that the emission estimates were not verified by the New Mexico Environment Department and therefore may not reflect the actual emissions from the facility.

In catalytic cracking, the heavier fractions of crude petroleum are treated with a catalyst which breaks the petroleum molecules into lighter compounds. The catalyst is continuously cycled between the cracking and a separate regeneration reactor in order to burn off coke build-up. Since the catalyst coke contains relatively high levels of sulfur, the combustion products from this coke are an important source of SO_2 emissions. The catalyst regenerator also emits NO_X and PM, including material abraded from the catalyst (catalyst fines).

Table 3-1. Control Options for Selected Petroleum Refinery Operations in New Mexico

Company	Source	Pollutant	Existing control measures	Baseline emissions		Potential additional control measures	Estimated control efficiency (%)	Potential emission reduction (tons/year)	References
				ppm	tons/yr				
Navajo Refining Company, Artesia Refinery	FCCU regen-erator (Unit 22)	NO_X	NO_X reduction catalyst and low-NO_X combustion promoters	123	153	Optimization of NO_X reduction catalyst	47 - 59	72 - 90	8,9
						SCR	67 - 84	103 - 129	9,11
		SO_2	Wet scrubber	25	43	None identified			
		PM_{10}, $PM_{2.5}$, EC, OC	Wet scrubber		not avail-able	None identified			
	FCCU heater	NO_X	None identified		4.0	LNB	40	1.6	17,18
						ULNB	75 - 85	3 - 3.4	8,17,18
						LNB and FGR	48	1.9	17,18
						SNCR	60	2.4	8,17,18
						SCR	70 - 90	2.8 - 3.6	8,17,18
						LNB and SCR	70 - 90	2.8 - 3.6	8,17,18
		SO_2	Sulfur recovery		0.15				
		PM_{10}, $PM_{2.5}$, EC, OC	None identified		not avail-able				
Western Refining Southwest, Bloomfield Refinery	FCCU regen-erator (A-201)	NO_X	None identified	262	57	Catalyst additives for NO_X reduction	75 - 81	43 - 46	8,9
						LoTOx^{TM}	85	49	8,11
						SNCR	40 - 80	23 - 46	8,9
						SCR	85 - 92	49 - 53	9,11
		SO_2	None identified	1,223	371	Catalyst additives for SO_2 absorbtion	98	364	8,9
						Desulfurization of catalytic cracker feed	98	364	9,15
						Wet scrubbing	98	364	8,12,17
		PM_{10}, $PM_{2.5}$, EC, OC	ESP		0.90	None identified			
	FCCU heater (H-202)	NO_X	None identified		6.1	LNB	40	2.4	17,18
						ULNB	75 - 85	4.6 - 5.2	8,17,18
						LNB and FGR	48	2.9	17,18
						SNCR	60	3.7	8,17,18
						SCR	70 - 90	4.3 - 5.5	8,17,18
						LNB and SCR	70 - 90	4.3 - 5.5	8,17,18
		SO_2	Sulfur recovery		0.84	None identified			
		PM_{10}, $PM_{2.5}$, EC, OC	None identified		0.15	None identified			
Western Refining Southwest, Gallup Refinery	CO Boiler, Unit 10	NO_X	None identified		65.1	LNB with OFA	30 - 50	20 - 33	19,20,21,22
						LNB, OFA, and FGR	30 - 50	20 - 33	19,20,21,22
						SNCR	30 - 75	20 - 49	19,20,21,22
						SCR	40 - 90	26 - 59	19,20,21,22
		SO_2	None identified		703.5	DSI	50 - 90	352 - 633	20,23
						SDA	80 - 90	563 - 633	20,23
						FGD	80 - 90	563 - 633	20,23
		PM_{10}			21.4				
		$PM_{2.5}$			21.4				
		EC			7.3				
		OC			5.1				

The Navajo Artesia refinery FCCU has a capacity of 27,000 barrels per day (bbl/day), and the Western Refining Southwest Bloomfield refinery FCCU has a capacity of 7,200 bbl/day.[3,5] The Western Refining Gallup refinery FCCU has a capacity of 8,500 bbl/day. (It is not being analyzed under this effort.)

The SO_2 concentration in the Artesia FCCU regenerator exhaust is limited by permit conditions to 25 parts per million (ppm), which is achieved by a wet scrubber.[1] The SO_2 permit limit was imposed after the 2002 baseline year, but for the purposes of this analysis, the wet scrubber system will be included as the baseline control. The NO_X emissions from the FCCU regenerator are also limited to 34.9 lb/hr, or about 153 tons/year.[3] This emission rate is estimated to correspond to an exhaust NO_X concentration of about 123 ppm, and is achieved by the use of NO_X absorption catalyst and low-NO_X combustion promoters.[3] Based on reported stack gas flow rates and emissions data, the concentrations of NO_X and SO_2 in the Bloomfield FCCU regenerator exhaust are about 262 ppm and 1,223 ppm respectively.[2]

The EPA RBLC includes a number of Best Available Control Technology (BACT) and Prevention of Significant Deterioration (PSD) determinations and case-specific determinations for the FCCU regenerator exhaust stream, which are based on the application of synthetic catalytic reduction (SCR).[1] The RBLC does not list any Reasonably Achievable Control Technology (RACT) determinations for this category. Permit limits for the SCR installations range from 20 to 40 ppm on an annual average basis. Some refineries have used catalyst additives to reduce NO_X emissions in the FCCU regenerator exhaust to 50 to 65 ppm.[6,7] One refinery in Japan has also used selective noncatalytic reduction (SNCR).[8,9] In addition, the LoTOx™ process has been developed to control NO_X emissions in the catalytic cracking regenerator offgas. In this system, ozone is injected into the offgas to convert the nitrogen oxide (NO) and nitrogen dioxide (NO_2) which comprise NO_X into more highly oxidized forms of nitrogen such as dinitrogen pentoxide (N_2O_5). These more highly oxygenated compounds are more soluble in water, and are removed from the offgas stream in a wet scrubber. The ozone also reacts with particulate compounds in the exhaust stream, therefore there is no ozone slip from the system.[10] This system has been reported to reduce NO_X emissions to under 10 parts per million by volume (ppmv).[8,11,12,]

A menu of control options developed by NACAA identifies a regenerator offgas concentration of 25 ppm, on an annual average basis, as well-controlled for SO_2.[8] In addition, the EPA RBLC shows an offgas SO_2 concentration of 25 ppm for a number of recent BACT/PSD determinations.[1] Refineries have achieved the 25 ppm level by wet scrubbing, which can reduce SO_2 emissions by 95% to over 99%.[1,8,13] Some refineries have achieved the 25 ppm level by using an SO_2 adsorption catalyst, which is added to the catalytic cracking catalyst.[6] The catalyst additive adsorbs sulfur oxide compounds produced in the catalyst regenerator. These compounds are then converted to H_2S in the catalytic cracking reactor, and exit this reactor with the cracked hydrocarbon stream. The H_2S is eventually removed from the hydrocarbon stream in an amine treatment process, and then recovered in the sulfur recovery process.[14] SO_2 emissions from the FCCU regenerator can also be controlled by desulfurization of the oil feed stream to the FCCU.[7,15] Particulate matter emissions from the FCCU regenerators can be controlled by wet scrubbing or by electrostatic precipitation (ESP).[8,16]

Based on the RBLC determinations and the NACAA report, the Artesia FCCU exhaust would be considered to be well controlled for SO_2, with an emission concentration of 25 ppm. The wet scrubber used to control SO_2 for the Artesia regenerator also provides control of particulate emissions. Artesia also uses NO_X absorption catalyst and low-NO_X combustion promoters to reduce NO_X emissions to less than 123 ppm, as stated in the RBLC determination for this facility. It is possible that this emission rate could be further reduced by testing different NO_X catalyst addition rates. As noted above, some refineries in another state have used catalyst additives to reduce NO_X emissions in the FCCU regenerator exhaust to 50 to 65 ppm.[6,7] These concentrations represent an emission reduction of 47 to 59% from the concentration currently achieved in the Artesia regenerator. These lower emission levels were achieved by testing different types and usage rates of NO_X reduction catalysts, in order to identify the formula for the best NO_X control.[6,7] The EPA RBLC shows a number of BACT determinations for NO_X from FCCU regenerators based on SCR.[1] These SCR installations have achieved exhaust concentrations of 20 to 40 ppm, which would represent a reduction of 67 to 84% from the emission level currently achieved for the Artesia FCCU regenerator.

The Western Refining Bloomfield refinery FCCU regenerator is well controlled for particulate matter, with an ESP. No baseline controls have been identified for NO_X or SO_2 from the regenerator vent. As discussed above, a number of options are available for reducing NO_X and SO_2.

Various options are available to reduce NO_X emissions from process heaters. Combustion modifications including low-NO_X burners (LNB), ultralow-NO_X burners (ULNB), and flue gas recirculation (FGR) reduce the formation of NO_X.[17] In addition, flue gases from the process heaters can be treated with SCR or SNCR to reduce NO_X emissions. These post-combustion controls can be used either alone or in conjunction with combustion controls.[18] The RBLC lists a number of BACT/PSD determinations for refinery process heaters. These are based on the use of ULNB or LNB, with emission limitations ranging from 0.3 lb/MMBTU to 0.1 lb/MMBtu.

The Gallup Refinery uses a CO boiler to combust CO and volatile organic compound (VOC) off-gases produced by the refinery. The steam generated by the boiler is used as process steam at the refinery. The CO boiler is uncontrolled and has NO_X and SO_2 emissions of 65.1 tons/yr and 703.5 ton/yr, as reported in the NEI database. NO_X emissions from a CO boilers can be controlled using a variety of combustion modifications including overfire air (OFA), LNB, FGR, and combinations of these technologies.[19,20,21,22,23] Add-on control systems such as SCR and SNCR can also be used to reduce NO_X emissions from boilers.[8] In SCR, the flue gas is treated with a small quantity of ammonia (NH_3) in a catalyst bed. The ammonia reacts with NO_X to produce nitrogen gas (N_2). Alternatively, urea [$(NH_3)_2CO$] can be added instead of ammonia. In this case, the urea decomposes to produce ammonia, which reacts with NO_X. SNCR also involves the addition of ammonia or urea to reduce NO_X, but without a catalyst. SNCR is less efficient at reducing NO_X than SCR, but is also generally less expensive. SNCR can also be used in situations where flue gas contaminants would poison the SCR catalyst.

It must be noted that SCR and SNCR for controlling NO_X require injection of ammonia (NH_3), urea [$(NH_3)_2CO$], or other nitrogen compounds into the exhaust stream. These chemicals react with NO_X to chemically convert the pollutant to elemental nitrogen (N_2). However, the use of these chemicals generally results in ammonia emissions, termed ammonia slip.

Emissions of SO_2 can be reduced by using duct sorbent injection (DSI), spray dryer absorber (SDA), or flue gas desulfurization (FGD). DSI uses dry limestone to react with the SO_2 in the flue gas. The reacted limestone is then collected in a particulate control device, The SDA process is similar to the DSI process, except that a limestone slurry is injected into the flue gas where it reacts with the SO_2 and is removed in a particulate control device. FGD involves the flue being passed through a vessel where it is contacted with an alkaline solution which reacts with the flue gas SO_2 to form a sulfate particulate. The sulfate particulate is removed in the system and the used alkaline solution is recycled through the process.

3.1 Factor 1 – Costs

Table 3-2 provides cost estimates for the emission control options which have been identified for the New Mexico refineries. For each option, the table gives an estimate of the capital cost to install the necessary equipment, and the total annual cost of control, including the amortized cost associated with the capital equipment cost. The table also shows the estimated cost effectiveness for each control measure, in terms of the cost per ton of emission reduction.

3.2 Factor 2 – Time Necessary for Compliance

Once the regional haze control strategy is formulated for New Mexico, up to 2 years will be needed for the state to develop the necessary rules to implement the strategy. We have estimated that sources may then require up to a year to procure the necessary capital to purchase control equipment. The Institute of Clean Air Companies (ICAC) has estimated that approximately 13 months is required to design, fabricate, and install SCR or SNCR technology for NO_X control.[24] However, the time necessary will depend on the type and size of the unit being controlled. For instance, state regulators' experience indicates that closer to 18 months is required to install this technology.[25] In the CAIR analysis, EPA estimated that approximately 30 months is required to design, build, and install SO_2 scrubbing technology for a single emission source.[26] The analysis also estimated that up to an additional 12 months may be required for staging the installation process if multiple sources are to be controlled at a single facility.

Table 3-2. Estimated Costs of Control for Selected Petroleum Refinery Operations in New Mexico

Company	Source	Control Technology	Pollutant controlled	Estimated control efficiency (%)	Potential emission reduction (tons/year)	Estimated capital cost ($1000)	Estimated annual cost (1000 $/year)	Cost effectiveness ($/ton)	Refer-ences
Navajo Refining Company, Artesia Refinery	FCCU regen-erator (Unit 22)	Optimization of NO_X reduction catalyst	NO_X	47 - 59	72 - 90	not available			8,9
		SCR	NO_X	67 - 84	103 - 129	not avail.	260 - 320	2,500	9,11
	FCCU heater	LNB	NO_X	40	1.6	76	8.1	5,100	17,18
		ULNB	NO_X	75 - 85	3 - 3.4	131	13	3,800 - 4,400	8,17,18
		LNB and FGR	NO_X	48	1.9	161	17	9,000	17,18
		SNCR	NO_X	60	2.4	221	24	10,100	8,17,18
		SCR[a]	NO_X	70 - 90	2.8 - 3.6	483	56	15,600 - 20,100	8,17,18
		LNB and SCR	NO_X	70 - 90	2.8 - 3.6	553	63	17,600 - 22,600	8,17,18
Western Refining Southwest, Bloomfield Refinery	FCCU regen-erator (A-201)	Catalyst additives for NO_X reduction	NO_X	75 - 81	43 - 46	not available			8,9
		LoTOx™	NO_X	85	49	not avail.	80 - 100	1,700 - 2,000	8,11
		SNCR	NO_X	40 - 80	23 - 46	not avail.	60 - 120	2,500	8,9
		SCR	NO_X	85 - 92	49 - 53	not avail.	120 - 130	2,500	9,11
		Catalyst additives for SO_2 absorbtion	SO_2	98	364	not available			8,9
		Desulfurization of catalytic cracker feed	SO_2	98	364	not available			9,15
		Wet scrubbing	SO_2	98	364	not avail.	180 - 660	1,500 - 1,800	8,17,12
	FCCU heater	LNB	NO_X	40	2.4	117	12	5,200	17,18
		ULNB	NO_X	75 - 85	4.6 - 5.2	199	20	3,800 - 4,300	8,17,18
		LNB and FGR	NO_X	48	2.9	245	26	9,000	17,18
		SNCR	NO_X	60	3.7	337	37	9,900	8,17,18
		SCR[a]	NO_X	70 - 90	4.3 - 5.5	736	86	15,600 - 20,000	8,17,18
		LNB and SCR	NO_X	70 - 90	4.3 - 5.5	843	97	17,600 - 22,500	8,17,18
Western Refining Southwest, Gallup Refinery	CO Boiler, Unit 10	LNB with OFA	NO_X	30 - 50	20 - 33	0.5 - 0.7	80 - 110	2,500 - 5,600	19
		LNB, OFA, and FGR	NO_X	30 - 50	20 - 33	0.8 - 1.0	125 - 170	3,800 - 8,700	19
		SNCR	NO_X	30 - 75	20 - 49	0.5 - 0.7	320 - 440	6,600 - 22,500	19
		SCR	NO_X	40 - 90	26 - 59	1.5 - 2.0	400 - 600	6,800 - 10,200	19
		DSI	SO_2	50 - 90	352 - 633	1.5 - 2.0	720 - 970	1,100 - 3,400	20
		SDA	SO_2	80 - 90	563 - 633	1.5 - 2.0	1380 - 1860	2,200 - 3,300	20
		FGD	SO_2	80 - 90	563 - 633	1.5 - 2.0	1150 - 1560	1,800 - 2,800	20

[b] SCR cost estimates for process heaters apply to mechanical draft heaters. Natural draft heaters would have to be converted to mechanical draft for installation of SCR. This would increase both the capital and annualized costs of control by about 10%.

Based on these figures, the total time required achieve emission reductions for the FCCUs would be up to 6½ years. This includes 2 years for regulatory development, 1 year for capital acquisition, and 2½ years for designing, building and installing a scrubber, if this option is selected. If catalyst additives are used, time will be required to select and test the appropriate additives, and to determine the optimum feed rate for the additive.

The time to achieve emission reductions for the CO boiler would be up to 5½ years. This includes 2 years for regulatory development, 1 year for capital acquisition, and 1½ years for designing, building and installing NO_X controls.

3.3 Factor 3 – Energy and Other Impacts

Table 3-3 shows the estimated energy and non-air pollution impacts of control measures for sources at the New Mexico refineries. The table shows the additional fuel, electricity, and steam requirements resulting required to operate the control equipment; and the additional solid waste would be produced. CO_2 emissions associated with the generation of the additional electricity and steam are also estimated in the table.

The use of catalyst additives for the FCCU or desulfurization of the FCCU feed stream involve process modifications which are tailored to each specific refinery. Therefore, it was not possible to quantify the energy and non-air pollution impacts of these modifications within the time limitations of this project. However, process modifications to desulfurize the FCCU feed stream would generally require increases in catalytic hydrotreatment processing. These modifications may increase the generation of spent catalyst, which would need to be treated as a solid waste or a hazardous waste. Catalyst additives for reducing NO_X and SO_2 emissions from fluid catalytic cracking units are likely to result in increased generation of spent catalyst, which would have to be disposed as hazardous waste. These catalyst additives may also result in increases in fuel consumption.

A LoTOx^{TM} scrubbing system or wet scrubbing system applied to the fluidized catalytic cracking unit would require electricity to operate fans and other auxiliary equipment, and would produce a wastewater stream which would require treatment. In addition, sludge from the scrubber would require disposal as solid waste. SCR and SNCR systems would also require electricity for fans, and SCR systems would produce additional solid waste because of spent catalyst disposal.

3.4 Factor 4 – Remaining Equipment Life

Information was not available on the age of the FCCU processes or the CO boiler. However, industrial processes often refurbished to extend their lifetimes. Therefore, the remaining lifetime of most equipment is expected to be longer than the projected lifetime of pollution control technologies which have been analyzed for these sources.

Table 3-3. Energy and Non-Air Pollution Impacts of Control for Selected Petroleum Refinery Operations in New Mexico

						Energy and non-air pollution impacts (per ton of emission reduced)				
Company	**Source**	**Control Technology**	**Pollutant controlled**	**Potential emission reduction (tons/year)**	**Additional fuel requirement (%)**	**Electricity requirement (kW-hr)**	**Steam requirement (tons steam)**	**Solid waste produced (tons waste)**	**Wastewater produced (1000 gallons)**	**Additional CO_2 emitted (tons)**
Navajo Refining Company, Artesia Refinery	FCCU regenerator (Unit 21)	Optimization of NOX reduction catalyst	NO_X	72 - 90				~0.03		
		SCR	NO_X	103 - 129		8,400		0.073		8.4
	FCCU heater	LNB	NO_X	1.6	a					
		ULNB	NO_X	3 - 3.4	a					
		LNB and FGR	NO_X	1.9		3,300				3.3
		SNCR	NO_X	2.4	0.16	460				3.2
		SCR	NO_X	2.8 - 3.6		8,400		0.073		8.4
		LNB and SCR	NO_X	2.8 - 3.6		8,400		0.073		8.4
Western Refining Southwest, Bloomfield Refinery	FCCU regenerator (A-201)	Catalyst additives for NO_X reduction	NO_X	43 - 46				~0.03		
		LoTOx™	NO_X	49.0		1,100		1.9	3.7	1.6
		SNCR	NO_X	23 - 46		460				3.2
		SCR	NO_X	49 - 53		8,400		0.073		8.4
		Catalyst additives for SO_2 absorbtion	SO_2	364				0.03		
		Desulfurization of catalytic cracker feed	SO_2	364	3			<0.03		0.5
		Wet scrubbing	SO_2	364		1,100	3.1		3.7	2.6
	FCCU heater	LNB	NO_X	2.4	a					
		ULNB	NO_X	4.6 - 5.2	a					
		LNB and FGR	NO_X	2.9		3,300				3.3
		SNCR	NO_X	3.7	0.16	460				3.2
		SCR	NO_X	4.3 - 5.5		8,400		0.073		8.4
		LNB and SCR	NO_X	4.3 - 5.5		8,400		0.073		8.4
Western Refining Southwest, Gallup Refinery	CO Boiler, Unit 1	LNB with OFA	NO_X	20 - 33	a					
		LNB, OFA, and FGR	NO_X	20 - 33		3,300				3.3
		SNCR	NO_X	20 - 49	0.16	460				3.2
		SCR	NO_X	26 - 59		8,400		0.073		8.4
		DSI	SO_2	352 - 633		1,207		6.7	84	1.2
		SDA	SO_2	563 - 633		836		8.0	67	0.8
		FGD	SO_2	563 - 633		2,387		7.0	148	2.4

NOTES:

A blank indicates no impact is expected.

a - The measure is expected to improve fuel efficiency.

If the remaining life of an emission source is less than the projected lifetime of a pollution control device, then the capital cost of the control device would have to be amortized over a shorter period of time, corresponding to the remaining lifetime of the emission source. This would cause an increase in the amortized capital cost of the pollution control option, and a corresponding increase in the total annual cost of control. This increased cost can be quantified as follows:

$$A_1 = A_0 + C \times \frac{1-(1+r)^{-m}}{1-(1+r)^{-n}}$$

where:

A_1 = the annual cost of control for the shorter equipment lifetime ($)
A_0 = the original annual cost estimate ($)
C = the capital cost of installing the control equipment ($)
r = the interest rate (0.07)
m = the expected remaining life of the emission source (years)
n = the projected lifetime of the pollution control equipment

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