APPENDIX G

FutureFuel Four-Factor Documentation

Division of Environmental Quality

Office of Air Quality

Contents

APPENDIX G-1

FutureFuel Information Collection Request (ICR)

Division of Environmental Quality

Office of Air Quality

January 8, 2020

Philip Antici
Manager, HSES
FutureFuel Chemical Company (FutureFuel)

Sent via Electronic Mail

RE: Regional Haze Four-Factor Analysis; Information Collection Request; AFIN 32-00036

Dear Mr. Antici:

The Arkansas Department of Energy and Environment, Division of Environmental Quality (DEQ) hereby requests that FutureFuel submit the information described in Section II no later than 90 days from the date of this letter.

I. BACKGROUND

DEQ must develop a Regional Haze Program state implementation plan (SIP) that demonstrates reasonable progress toward achieving natural visibility conditions in Arkansas Class I areas during the period between 2018 and 2028, which is referred to as Planning Period II. The SIP must also address emissions from within the state that may impair visibility in Class I areas in other states. The Regional Haze Program uses an iterative planning process lead by the states with the ultimate goal of remedying existing and preventing future visibility impairment from anthropogenic sources of air pollution by 2064.

For the Planning Period II SIP, DEQ must develop a long-term strategy for reducing emissions of key pollutants and sources impacting visibility at Class I areas to make "reasonable" progress toward the goal of no anthropogenic visibility impairment by 2064. The Regional Haze Rule provides four factors by which a state must consider potential control measures for the long-term strategy. The factors are the cost of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of existing sources that contribute to visibility impairment.

The key pollutants from anthropogenic sources impairing visibility at Arkansas Class I areas are ammonium sulfate and ammonium nitrate.[1] Ammonium sulfate is formed by chemical reactions between ammonia and sulfur dioxide (SO_2) in the atmosphere. Ammonium nitrate is formed by chemical reactions between ammonia and nitrogen oxides (NOx) in the atmosphere. EPA modeling projects that these two pollutants will continue to be the key pollutants contributing to visibility impairment at Arkansas Class I areas in 2028.[2]

The states in the Central States Air Resources Agencies (CENSARA) organization, which includes Arkansas, contracted with Ramboll US Corporation (Ramboll) to produce a study examining the impact of stationary sources of NOx and SO_2 on each Class I area in the central region of the United States. For each Class I area, the study took into account light extinction-weighted wind trajectory residence times, 2016 sulfur dioxide and nitrogen oxides facility emissions, and distance from sources of nitrogen oxides and sulfur dioxide to Class I Areas. The study produced an area of influence (AOI) for each Class I area, which shows the geographic areas with a high probability of contributing to anthropogenic visibility impairment.

Based on the results of the AOI study, DEQ has identified FutureFuel as a source of visibility impacting pollutant emissions that DEQ should evaluate for potential emission reduction measures during Planning Period II.

II. INFORMATION REQUESTED FOR POTENTIAL EMISSION REDUCTION STRATEGIES

DEQ requests that FutureFuel provide information about potential emission reduction strategies for SO_2 and NOx emissions from the FutureFuel facility. At a minimum, FutureFuel should include the following potential strategies for the emission units that emit the majority of the SO_2 and NOx from FutureFuel, identified by DEQ as SN:6M01-01 three coal-fired boilers:

- SO_2 (ranked from highest control efficiency to lowest)
    - Fuel switching from subbituminous coal to natural gas (Typical SO_2 control efficiency $\approx$ 99.9%)[3]
    - Wet Gas Scrubber[4] (Typical SO_2 control efficiency for industrial coal-fired boilers $\approx$ 90–99%)

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[1] http://vista.cira.colostate.edu/Improve/improve-data/

[2] https://www.epa.gov/visibility/visibility-guidance-documents

[3] From EPA Menu of Control Measures: "Fuel substitution involves replacing the current fuel with a fuel which emits less of a given pollutant when burned. For many older boilers, fuel switching is an especially attractive option because the capital investment is usually small when compared to that of control devices. Cost effectiveness varies depending on the ranks of the old and new fuels and is estimated based on the emission factors."

[4] From EPA Menu of Control Measures: "Wet scrubbing techniques are used to control both particulate and SO2 emissions. Wet scrubbing processes used to control SO2 are generally termed flue-gas desulfurization (FGD) processes. FGD utilizes gas absorption technology, the selective transfer of materials from a gas to a contacting liquid, to remove SO2 in the waste gas. Caustic, crushed limestone, or lime are used as scrubbing agents. Cost estimates are from the OTC / LADCO Workgroup (OTC / LADCO Control Cost Subgroup), for a 66% capacity factor at 8760 hour/year, and are based on a methodology similar to EPA's methodology provided in the EPA

- Spray Dryer Absorber[5] (Typical SO_2 control efficiency for industrial coal-fired boilers ≈ 90–95%)
- In-Duct Dry Sorbent Injection[6] (Typical SO_2 control efficiency for industrial coal-fired boilers ≈ 40%)
- Fuel Switching to lower sulfur coal (Typical control efficiency proportionate to the % decrease in sulfur content)

- NOx (ranked from typical highest control efficiency to lowest)
  - Selective Catalytic Reduction[7] (Typical NOx control efficiency for industrial coal-fired boilers ≈ 80%)
  - Low NOx Burner[8] (Typical NOx control efficiency for industrial coal-fired boilers ≈ 50%)
  - Selective Non-Catalytic Reduction[9] (Typical NOx control efficiency for industrial coal-fired boilers ≈ 40%)

The list above is not comprehensive. FutureFuel may provide information about strategies in addition to those listed above.

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document "Alternative Control Techniques Document – NOx Emissions from Industrial/Commercial/Institutional (ICI) Boilers"'.

[5] From EPA Menu of Control Measures: "Spray dryer absorption (SDA) systems spray lime slurry into an absorption tower where SO2 is absorbed by the slurry, forming CaSO3/CaSO4. The liquid-to-gas ratio is such that the water evaporates before the droplets reach the bottom of the tower. The dry solids are carried out with the gas and collected with a fabric filter or ESP. When used to specifically control SO2, the term dry flue-gas desulfurization (dry FGD) may also be used. Cost estimates are from the OTC / LADCO Workgroup (OTC / LADCO Control Cost Subgroup), for a 66% capacity factor at 8760 hour/year, and are based on a methodology similar to EPA's methodology provided in the EPA document "Alternative Control Techniques Document – NOx Emissions from Industrial/Commercial/Institutional (ICI) Boilers"'.

[6] From EPA Menu of Control Measures: "As opposed to spray dryer absorption, in duct sorbent injection technology does not require a dedicated reactor and instead uses the existing boiler and duct system as the "reactor," and several configurations are possible based on the temperature window desired. DSI technologies include calcium (lime) and sodium (trona) reagents and are currently being tested or demonstrated within the ICI boiler sector."

[7] From EPA Menu of Control Measures: "This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to coal ICI boilers with NOx emissions greater than 10 tons per year."

[8] From EPA Menu of Control Measures: "This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to coal/wall fired ICI boilers and Petroleum coke fired ICI boilers with uncontrolled NOx emissions greater than 10 tons per year. Cost estimates are from the OTC / LADCO Workgroup (OTC / LADCO Control Cost Subgroup), for a single burner (for a 66% capacity factor at 8760 hours/year), and are based on a methodology similar to EPA's methodology provided in the EPA document "Alternative Control Techniques Document – NOx Emissions from Industrial/Commercial/Institutional (ICI) Boilers"'.

[9] From EPA Menu of Control Measures: "This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to coal IC boilers with uncontrolled NOx emissions greater than 10 tons per year."

For each emission reduction strategy, FutureFuel should assess whether the strategy is technically feasible.[10] If a strategy is not technically feasible, FutureFuel should provide a robust explanation about why the strategy is not technically feasible.

For each technically feasible emission reduction strategy, FutureFuel should provide the following information for SO_2 and/or NOx:

- Control effectiveness (Percentage NOx and/or SO_2 reduced) estimates specific to FutureFuel's emission units in terms of actual emissions
- Emission reductions that would be achieved by implementation of the strategy:
  - Baseline actual emission rate in lb/hr or lb/MMBTU (maximum monthly value in the period between 2017–2019)
  - Control rate in lb/hr or lb/MMBTU (units should match baseline actual emission rate)
  - Resulting annual emission reductions (tons/year)
- Time necessary to implement the strategy with an explanation justifying the time needed
  - A reasonable time period is one in which the source comes "into compliance in an efficient manner without unusual amounts of overtime, above-market wages and prices, or premium charges for expedited delivery of control equipment."[11]
  - The time during which the source begins taking steps to come into compliance is assumed to begin upon EPA approval of the SIP, which is projected to be no later than January 31, 2023 based on deadlines for the SIP submission and EPA action on the SIP.[12]
- Remaining useful life
  - Remaining useful life of an emission unit should be based on an enforceable shutdown date. Otherwise, the remaining useful life should be the full period of the useful life for the control technology evaluated
  - The EPA Pollution Control Cost Manual[13] provides guidance on typical values for the useful life of various emission control systems
- Energy and non-air quality environmental impacts

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[10] From 40 CFR Appendix Y to Part 51 "Control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions, or (2) the technology could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: 'availability' and 'applicability.' As explained in more detail below, a technology is considered 'available' if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is 'applicable' if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible."

[11] https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period

[12] The deadline for submission of this state implementation plan is July 31, 2021. EPA's deadlines for timely action on a SIP submittal are as follows: six months for determining whether a SIP is complete and one year from determining that a SIP is complete to take final action on the SIP.

[13] https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

- Specify any energy and non-air environmental impacts, such as the generation of wastes for disposal, impacts on other environmental media, etc.
- Factor any costs associated with energy and non-air environmental impacts into the cost of implementing the strategy, including without limitation:
  - Permitting costs if other regulatory requirements are triggered by the strategy
  - Costs associated with compliance with any other regulatory requirements triggered by the strategy
  - Cost of waste disposal for wastes generated by proposed control systems
  - Changes associated with alternative disposal methods for chemical waste currently burned in coal-fired boilers

- Cost of implementing the strategy
  - Use the EPA Pollution Control Cost Control Cost Manual[14] overnight methodology to quantify the following cost metrics:
    - Capital costs
    - Annual operating and maintenance costs
    - Annualized costs
  - The amortization period should be based on the time between when the strategy could reasonably be in place and the remaining useful life of the emission unit or emission control system, whichever is less.[15]

III. CONCLUSION

Thank you for your timely response to this information request. This information is necessary for DEQ to prepare a technically and legally robust state implementation plan consistent with the Regional Haze Rule. Please respond with the requested information by April 7, 2020. If you have any questions, please contact Tricia Treece (treecep@adeq.state.ar.us) of my staff.

Sincerely,

William K. Montgomery
Interim Associate Director
Office of Air Quality
Division of Environmental Quality
Arkansas Department of Energy and Environment

[14] https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[15] Amortization start date is equal to the time necessary for compliance for the strategy added to January 31, 2023 (Deadline for timely EPA action on a SIP submitted on July 31, 2021).

CC:

Thomas Floyd, FutureFuel Chemical Company

Lynn Cornelius, FutureFuel Chemical Company

Farah Robbins, FutureFuel Chemical Company

APPENDIX G-2

FutureFuel ICR Response

Division of Environmental Quality

Office of Air Quality

APPENDIX G-2: FUTUREFUEL COST ICR RESPONSE

REGIONAL HAZE EVALUATION

Revision 0

Pursuant to

DEQ Information Collection Request dated January 8, 2020

AFIN 32-00036

FutureFuel Chemical Company
P.O. Box 2357
Batesville, AR 72503
ARD089234884

April 7, 2020

EXECUTIVE SUMMARY

FutureFuel Chemical Company (FFCC) owns and operates an organic chemical manufacturing plant located southeast of Batesville, Arkansas. As part of plant operations, FFCC (EPA ID# ARD089234884) operates two natural gas boilers, three coal-fired boilers, one waste incinerator, one regenerative thermal oxidizer, two thermal oxidizers, and a flare. FFCC is currently operating these units under its Arkansas Division of Environmental Quality (DEQ) Title V Permit (1085-AOP-R14).

On January 8, 2020, FFCC (AFIN 32-00036) received an "Information Collection Request" from the DEQ asking for information about potential emission reduction strategies for SO_2 and NO_x emissions from the FutureFuel facility. DEQ seeks to develop a Regional Haze State Implementation Plan (SIP) that demonstrates reasonable progress toward achieving natural visibility conditions by remedying existing and preventing future visibility impairment from anthropogenic sources of air pollution by 2064. FFCC believes information provided in this transmittal may be useful as DEQ develops a step-wise approach to the achieving the 2064 goal.

The request stated, at a minimum, that FFCC should include the following potential strategies for the emission units that emit the majority of the SO_2 and NO_x from FFCC, identified by the DEQ as SN:6M01-01 three coal-fired boilers:

- SO_2 Reduction Strategies
  - Fuel Switching from coal to natural gas
  - Wet Gas Scrubber
  - Spray Dryer Absorber
  - In-Duct Dry Sorbent Injection
  - Fuel Switching to a lower sulfur coal

- NO_x Reduction Strategies
  - Selective Catalytic Reduction
  - Selective Non-Catalytic Reduction
  - Low NOx Burner

FFCC and the DEQ concur that the three coal-fired boilers emit the majority of SO_2 and NOx emissions at FFCC, and this submittal will evaluate feasibility and costs associated with implementing the above strategies on FFCC's coal-fired boilers. However, it should be noted that previous DEQ modeling results indicates the coal boilers at FFCC, "do not cause or contribute to visibility impairment at the following Class I wilderness areas in Arkansas: Caney Creek and Upper Buffalo." (BART modeling results, Attachment C.) For this reason, FFCC believes it is not prudent to make more than minimal control steps in this period, Planning Period II.

This evaluation relates to the second planning period of development of a state implementation plan (SIP) to address regional haze. The DEQ plans to use the information provided in this evaluation to conduct a four-factor analysis and determine if there are emission control options at FFCC's coal-fired boilers that, if implemented, could be used to attain reasonable progress toward the state's visibility goals.

FFCC completed an evaluation on fifteen (15) different strategies. Three (3) of these strategies were determined to be technically infeasible. Twelve (12) of these strategies were technically feasible and were assessed to determine 1) control effectiveness, 2) emission reduction, 3) time necessary to implement, 4) remaining useful life, 5) energy and non-environmental impacts, and 6) the cost of implementation.

Table ES-1 below provides a summary of the three technologies that were not technically feasible. More information is provided in Section 4.0.

Table ES-1 - Summary of Technically Infeasible Strategies

Emission Reduction Strategy	Rationale
Installation of a Low-NOx Burner on the CFBs	There are no available or applicable Low-NOx burner systems designed for stoker style boilers.
Installation of a Sodium Hydroxide Wet Scrubber on the CFBs	Wet Scrubbing is a viable option, but the use of Sodium Hydroxide scrubbing is not technically feasible to due to NPDES permit limitations.
Use of a Low-Sulfur Coal from a nearby Power Plant at the CFBs	The local supply of low-sulfur coal is not usable at FFCC's stoker style boilers due to the heating value being too low (< 11,000 Btu/lb) and the fusion temperature being two low (< 2,550°F fluid fusion temp)

Table ES-2 on the next page provides a summary of the emissions reduction and costs of the twelve technologies that were determined to be technically feasible.

Table ES-2 – Summary of Feasible Strategies by Annual Cost

Emission Reduction Strategy	Emission Reduction		Baseline Emissions Before Control (ton/yr)	Emission Reduction by Strategy (ton/yr)	Capital and Indirect Investment (Millions)	Annualized Capital and Indirect Costs	Annual Operating and Maintenance Costs	Strategy Annual Cost	Cost per Ton Reduced ($/ton)
	SO2	NOx							
Fuel Switch to 2.5% Sulfur Coal	17%	0%	2,884	490	$0.0	$0.0	$1,149,137	$1,149,137	$2,345
Fuel Switch to 2% Sulfur Coal	33%	0%	2,884	952	$0.0	$0	$1,995,030	$1,995,030	$2,096
Selective Non-Catalytic Reduction	0%	40%	332	133	$23.8	$2,252,744	$413,695	$2,666,469	$20,049
Fuel Switch to 1.5% Sulfur Coal	50%	0%	2,884	1,442	$0.0	$0	$4,232,823	$4,232,823	$2,935
Selective Catalytic Reduction	0%	80%	332	266	$46.1	$4,166,872	$541,053	$4,708,925	$17,703
Fuel Switch to Natural Gas - Retrofit 1 CFB	33%	30%	3,216	1,061	$6.3	$903,388	$10,931,976	$11,835,364	$11,155
Close and Replace 1-CFB with Natural Gas	33%	30%	3,216	1,061	$8.2	$1,205,117	$10,931,976	$12,137,153	$11,439
Dry Sorbent Injection	40%	0%	2,884	1,154	$61.9	$9,892,986	$921,467	$10,814,453	$9,371
Spray Dry Absorption	92%	0%	2,884	2,653	$67.7	$11,568,303	$2,058,925	$13,627,228	$5,137
Wet Scrubber - Lime Slurry	94%	0%	2,884	2,711	$79.4	$14,194,554	$3,043,215	$17,237,769	$6,358
Fuel Switch to Natural Gas - Retrofit 3 CFBs	99%	90%	3,216	3,154	$12.9	$1,922,044	$30,597,829	$32,519,873	$10,311
Close and Replace 3-CFBs with Natural Gas	99%	90%	3,216	3,154	$13.6	$2,043,919	$30,597,829	$32,641,748	$10,349

DEQ presented modeling results indicating that FFCC contributes a minimal amount to haze in Class I Wilderness Areas. Previous DEQ BART models (Attachment C-1.1) indicated there was no contribution to visibility impairment in Arkansas Class I Wilderness Areas. For this reason, FFCC believes it is not prudent to make more than minimal control steps in this period, Planning Period II.

End of Executive Summary

TABLE OF CONTENTS

TABLE OF CONTENTS, continued

LIST OF ATTACHMENTS

LIST OF ATTACHMENTS, *continued*

1.0 INTRODUCTION

FutureFuel Chemical Company (FFCC) owns and operates an organic chemical manufacturing plant located southeast of Batesville, Arkansas. As part of plant operations, FFCC (EPA ID# ARD089234884) operates two natural gas boilers, three coal-fired boilers, one waste incinerator, one regenerative thermal oxidizer, two thermal oxidizers, and a flare. FFCC is currently operating these units under its Arkansas Division of Environmental Quality (DEQ) Title V Permit (1085-AOP-R14).

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- SO_2 Reduction Strategies
  - Fuel Switching from coal to natural gas
  - Wet Gas Scrubber
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  - In-Duct Dry Sorbent Injection
  - Fuel Switching to a lower sulfur coal

- NO_x Reduction Strategies
  - Selective Catalytic Reduction
  - Selective Non-Catalytic Reduction
  - Low NOx Burner

FFCC and the DEQ concur that the three coal-fired boilers emit the majority of SO_2 and NOx emissions at FFCC, and this submittal will evaluate feasibility and costs associated with implementing the above strategies on FFCC's coal-fired boilers. However, it should be noted that previous DEQ modeling results indicates the coal boilers at FFCC "do not cause or contribute to visibility impairment at the following Class I wilderness areas in Arkansas: Caney Creek and Upper Buffalo." (BART modeling results, Attachment C.) For this reason, FFCC believes it is not prudent to make more than minimal control steps in this period, Planning Period II.

The DEQ plans to use the information provided in this evaluation to conduct a four-factor analysis and determine if there are emission control options at FFCC's coal-fired boilers that, if implemented, could be used to attain reasonable progress toward the state's visibility goals.

1.1 FFCC Regional Haze Emission Reduction Strategy

The balance of this introduction provides an overview of the FFCC Regional Haze Emission Reduction Strategy, including the following:

- FFCC Facility Information
- DEQ Regional Haze Information Request
- FFCC Emissions Summary
- Description of the Coal-Fired Boilers
- Regional Haze Evaluation Objective and Layout

1.2 FFCC Facility Information and Contacts

Facility Information

Name:	FutureFuel Chemical Company
Address:	2800 Gap Road Batesville, Arkansas 72501
Phone:	(870) 698-3000
EPA ID:	ARD089234884
AFIN:	32-00036
Title V Permit:	1085-AOP-R14
RCRA Permit:	11H-RN2

Facility Contacts

Contact:	Thomas L Floyd	Contact:	Philip Antici
Title:	Assoc. Environmental Biologist	Title:	HSES Manager
Address:	P.O. Box 2357 Batesville, AR 72503	Address:	P.O. Box 2357 Batesville, AR 72503
Phone:	(870) 698-5577	Phone:	(870) 698-5358
Email:	thomasfloyd@ffcmail.com	Email:	philipantici@ffcmail.com

1.3 DEQ REGIONAL HAZE INFORMATION REQUEST

The request stated, at a minimum, that FFCC should include the following potential strategies for the emission units that emit the majority of the SO_2 and NO_x from FFCC, identified by the DEQ as SN:6M01-01 three coal-fired boilers:

- SO_2 Reduction Strategies
    - Fuel Switching from coal to natural gas
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- NO_x Reduction Strategies
    - Selective Catalytic Reduction
    - Selective Non-Catalytic Reduction
    - Low NO_x Burner

FFCC and the DEQ concur that the three coal-fired boilers emit the majority of SO_2 and NO_x emissions at FFCC, and this submittal will evaluate feasibility and costs associated with implementing the above strategies on FFCC's coal-fired boilers.

1.4 FFCC Emissions Summary

FFCC has several emission points of NO_x and SO_2. However, as noted earlier, the Coal-Fired Boilers generate the vast majority of those emissions. Below is a list of units' onsite with the potential to emit NO_x and/or SO_2:

- Three Coal-Fired Boilers
- One Incinerator
- Two Natural Gas Boilers
- One Regenerative Thermal Oxidizer (RTO)
- Two Thermal Oxidizers (TO-1 & TO-2)
- One Flare

Table 1.0 below, list these units and their annual emissions per year. They are listed in order of ton/yr of total SO_2 and NO_x.

Table 1.0 – FFCC Emissions Summary

Unit Description	Unit #	[1]SO_2 (ton/yr)	% of Total SO_2	[1]NO_x (ton/yr)	% of Total NO_x	SO_2 & NO_x (ton/yr)	% Total Emissions
Coal-Fired Boilers	6M01-01	2,884	99	332	71	3216	95
Incinerator	6M03-05	26	1	48	12	74	2
Natural Gas Boiler #4	6M06-01	<1	0	28	6	28	1
Natural Boiler #5	6M07-01	<1	0	39	9	39	1
RTO	5N09-01	1	0	10	2	11	<1
TO-1	5N09-02	<1	0	<1	0	<1	<1
TO-2	5N09-03	<1	0	<1	0	<1	<1
Flare	5N03-54	<1	0	2	0	2	<1

[1]*Note: Baseline actual emission rate in ton/yr based on maximum monthly value in the period between 2017-2019,*

Table 1.0 above illustrates the following points of emphasis:

- 95% of all SO_2 and NO_x emissions are emitted from the coal-fired boilers. They emit over 99% of all SO_2, and 71% of all NO_x. This validates that emission reduction strategies on the coal-fired boilers will have the most significant impact.

- Approximately 86% of all SO_2 and NO_x emissions are in the form of SO_2, leaving the remaining 14% as NO_x. This substantiates that emission reduction strategies that reduce SO_2 will have the most significant impact.

This evaluation will focus on Emission Reduction Strategies that involve the coal-fired boilers. For purposes of this evaluation, the coal-fired boilers will also be referred to as by the acronym "CFB" if referring to one coal-fired boiler or "CFBs" when referring to more than one coal-fired boiler.

1.5 Description of the Coal-Fired Boilers

FFCC operates three coal-fired boilers (Nos. 1, 2, and 3) at its Batesville, Arkansas Plant. The CFBs consist of 4 primary process systems: (1) primary fuel and waste feed system, (2) boiler system, (3) air pollution control system (APCS), and (4) ash handling system.

<u>Primary Fuel and Waste Feed Systems</u>

Stoker coal is the primary fuel used to maintain the boilers at a steady state. Coal is fed to the boilers on a continuous basis (i.e., 24 hours/day, 7 days/week) to maintain the desired steam demand.

The coal is delivered by bulk transport. The coal is unloaded into track-hoppers and conveyed on a belt conveyor system up to three separate coal bunkers inside the building that houses the boilers. The coal is gravity fed via the coal chute from the bunkers into the boilers. The coal is mechanically spread onto a traveling grate once it enters the boilers. The grate slowly moves the burning bed of coal across the boiler.

The liquid waste burned in the boilers is usually supplied from one of eleven permitted hazardous waste storage tanks. Waste can also be fed directly to the boiler from containers or a 90-day accumulation tank. FFCC can burn wastes that are potentially incompatible with the waste stored in tanks directly from containers.

Each boiler has one waste liquid injection nozzle located above the coal fuel bed. The liquid waste is injected into the boiler firebox through this steam-atomizing nozzle. Each waste liquid injection nozzle is also equipped with a separate fan/blower to provide combustion air to the nozzle in order to facilitate combustion. However, the nozzle does not act as a stand-alone burner. The primary source of heat needed to sustain a stable flame in the boiler firebox is the burning coal fuel bed.

The boilers could also burn non-hazardous solid waste and alternative fuels. These are fed directly to the boilers via special handling systems. Non-hazardous wastes handled in these direct systems include biological sludge from FFCC's wastewater treatment plant.

Combustion Process

The three coal-fired boilers are a Model MKB units built by E. Keeler Co. in 1976. The boilers are water tube type units with firebox dimensions that are approximately 11 feet wide by 19 feet long by 45 feet tall. The boilers are rated for 50,000 pound per hour steam but have design criteria that specify a maximum steam production surge of 57,500 pounds per hour.

An induced draft fan provides the motive force to transport the combustion gas toward the cold end of the boilers where it will exit to the ESPs at temperatures between 350 and 520 °F. The combustion gas flow rate is expected to range between 15,000 to 25,000 standard cubic feet per minute (scfm).

Air Pollution Control System

The electrostatic precipitators (ESP) remove the suspended material, principally fly ash, from the boiler flue gas. Each of the three ESPs contains three (3) sections demonstrated to treat flue gases to a basis at or below 68 milligrams per dry standard cubic meter (mg/dscm). ESP performance is maintained by ensuring that adequate power, measured in kilowatts (KW), is supplied to each section.

Ash Handling System

Bottom ash falls from the boiler into a collection hopper and the ESPs discharge fly ash into a separate hopper. The ash is then hydraulically conveyed to an ash management area.

Waste to be treated

FFCC produces a variety of specialty chemicals used by numerous industries, including biofuel, photographic, agricultural, and other manufacturing organizations. FFCC has explored and continues to look for additional ways to recover and reuse as much of its wastes as is practicable, especially the solvent wastes. FFCC is currently burning wastes, which cannot be recovered for useful benefit, in the coal-fired boilers. These wastes not only assist in producing steam, they also reduce the amount of coal combustion necessary to maintain steam production.

FFCC's liquid wastes typically consist of RCRA-listed or characteristic wastes containing constituents listed in 40 Code of Federal Regulation (CFR) 261 Appendix VIII. FFCC does not generate any waste materials that are designated as F020, F021, F022, F023, F026, or F027 wastes (dioxin waste codes).

1.6 Regional Haze Evaluation Objective and Layout

The overall objective of this Regional Haze Evaluation is to provide the DEQ with the information requested in a letter dated January 8, 2020.

This evaluation will focus on the coal-fired boilers and provide information on the following areas:

- Potential Emission Reduction Strategies (Section 2)
- Emission Reduction Strategy Evaluation Objectives (Section 3)
- Technically Infeasible Emission Reduction Strategies (Section 4)
- Technically Feasible Emission Reduction Strategies (Section 5)
- Summary of the Emission Reduction Strategies (Section 6)

2.0 POTENTIAL EMISSION REDUCTION STRATEGIES

The DEQ request stated, at a minimum, that FFCC should include the following potential strategies for the emission units that emit the majority of the SO_2 and NO_x from FFCC, identified by DEQ as SN:6M01-01 three coal-fired boilers:

- SO_2 Reduction Strategies
  - Fuel Switching from coal to natural gas
  - Wet Gas Scrubber
  - Spray Dryer Absorber
  - In-Duct Dry Sorbent Injection
  - Fuel Switching to a lower sulfur coal

- NO_x Reduction Strategies
  - Selective Catalytic Reduction
  - Selective Non-Catalytic Reduction
  - Low NO_x Burner

Each one of these strategies will be evaluated to determine if they are technically feasible options for FFCC's coal-fired boilers. Those strategies that are feasible will be evaluated in detail to determine the reduction in emissions, as well as, the cost of implementing that strategy. For any strategies that are determine to be infeasible, FFCC will document as to why but will not conduct a detailed evaluation of that strategy.

3.0 EMISSION REDUCTION STRATEGY EVALUATION

Each potential Emission Reduction Strategy (ERS) will be evaluated for technical feasibility and, if feasible, then FFCC will evaluate and provide the following information in Section 5:

- Control effectiveness (percentage of NO_x and/or SO_2 reduced)

- Emission reductions comparing the following:
  - Baseline actual emission rate in ton/yr for the period between 2017 and 2019
  - Controlled emission rate in ton/yr
  - Resulting annual emission reductions in tons/yr

- Time necessary to implement the strategy
  - A reasonable time period is one in which the source comes "into compliance in an efficient manner without unusual overtime, above-market wages and prices, or premium charges for expedited delivery of equipment."

- Remaining useful life
  - Remaining useful life of an emission unit will be the remaining useful life of the control technology as found in the EPA Pollution Control Cost Manual.
  - In cases where this is not applicable FFCC will estimate the life of the strategy.

- Energy and non-air quality environmental impacts
  - Associated permitting costs, waste disposal costs, and compliance costs, etc.

- Cost of Implementing the Strategy that involves:
  - Capital and Non-Reoccurring costs
  - Annual Operating and Maintenance Costs
  - Total Annual Costs
  - Annual Cost per ton of emissions reduced

4.0 TECHNICALLY INFEASIBLE EMISSION REDUCTION STRATEGIES

There were three emission reduction strategies that the agency requested FFCC evaluate that were deemed technically infeasible to implement on the CFBs.

- Installation of a Low NO_x Burner,
- Installation of a Wet Scrubber using Sodium Hydroxide, and
- Use of Low Sulfur Coal from a nearby Power Plant.

4.1 Installation of a Low NO_x Burner

FFCC's coal-fired boilers are E. Keeler water tube boilers fed by a spreader-stoker traveling grate system designed by the Detroit Stoker Company. The coal is mechanically spread onto a traveling grate once it enters the boiler's firebox, and then the grate slowly moves the burning bed of coal across the firebox where the combusted bottom ash drops off into a hopper for removal.

There are currently no low-NO_x burner systems for a spreader-stoker traveling grate coal-fired boiler. Therefore no systems have been installed and operated successfully for this type of system. Since no system is available or applicable, FFCC deems this strategy infeasible.

4.2 Installation of a Wet Scrubber using Sodium Hydroxide (NaOH)

FFCC considered installing a wet scrubbing system that would use NaOH to scrub the SO_2 gases from the exit gas. FFCC currently uses NaOH to scrub acid gases at its on-site incinerator. However, upon evaluation the amount of base needed to neutralize the SO_2 from burning coal created an enormous amount of salts. The amount of salt in the scrubber blowdown would exhaust the limits FFCC currently has in its NPDES permit. Since there is no practical method of removing the salts from the scrubber solution, FFCC deemed this strategy infeasible.

4.3 Use of Lower Sulfur Coal from a Nearby Power Plant

There is a nearby power plant that uses coal which contains significantly less sulfur than the coal used in FFCC's coal-fired boilers. This coal has sulfur content near 0.5% sulfur as compared to FFCC's current sulfur specification of 3% sulfur.

As noted earlier, FFCC's boiler is an E. Keeler, spreader-stoker, traveling grate water tube boiler. This is a completely different style boiler than the one used at the local power plant, which as a pulverized coal feed system.

A spreader stoker boiler uses stoker grade coal because it must set on the traveling gate bed until combusted and since the ash from a spreader stoker is about 90% bottom ash, the ash then needs to readily fall off the grate once it is combusted.

The pulverized coal boiler pulverizes the coal and basically blows it into the combustion zone. Pulverizing the coal allows the use of coal with a lower heating value than that of a spreader stoker system, and since the ash is typically 90% fly ash, the fusion temperature of the coal is insignificant.

FFCC's system is designed for coal with a heating value of at least 11,100 Btu/lb (as received). The coal specification supplied to us by the local power plant indicated the heating value was less than 9,000 Btu/lb (as received). The minimum fluid fusion temperature of the coal used at FFCC must be at least 2,550 deg F. The coal used by the local power plant has a fluid fusion temperature at around 2,234 deg F. There are other significant differences but these two specifications alone make the coal at the local power plant technically infeasible for FFCC's CFBs.

FFCC has located some coal supplies that contain a lower concentration of sulfur than the coal currently under contract, and these coal supplies are identified and evaluated in the Section 5.0.

5.0 TECHNICALLY FEASIBLE EMISSION REDUCTION STRATEGIES

FFCC completed an evaluation on twelve (12) different emission reduction strategies that were technically feasible to implement at the coal-fired boilers (CFBs). Four (4) of these strategies involved reduction of both SO_2 and NO_x emissions, six (6) of these strategies involved only reducing SO_2 emissions, and two (2) of these strategies only involved reducing NOx emissions.

5.1 Fuel Switch from Coal to Natural Gas (Close and Replace All CFBs)

FFCC evaluated closing all CFBs and removing them from service. This would require FFCC to replace the 150k lb/hr steam production with non-coal fueled boilers and ship all waste fuels off-site for treatment. The replacement of steam would require a minimum of two 75k lb/hr steam natural gas boilers (150k lb/hr steam combined).

5.1.1 Control Effectiveness

Since 95% of all SO_2 and NO_x emissions come from the three coal-fired boilers, this option would reduce total SO_2 and NO_x emissions from the plant by about 92-94%. Shutting down the CFBs would result in a control effectiveness of 100%, but the replacement combustion units would add between 30 – 50 tons/yr of NO_x so the emission reduction would be around 98%.

5.1.2 Emission Reductions

The CFBs baseline calculated emissions were 3,216 tons/year of combined SO_2 and NO_x. Replacing them with natural gas boilers would reduce the CFB emissions by about 98%, which would be 3,154 tons/year. Since the total emissions for the facility are approximately 3,375 tons/year, the reduction would be equal to about a 93% reduction in total emissions. See Table 5.1-A below for an emission reduction summary for this strategy.

Table 5.1-A - Replace All CFBs Emission Reduction Summary

Emission Reduction Strategy	Emission Reduction (%)		CFBs Baseline Emissions (ton/yr)	CFB Emission Reduction (ton/yr)	CFB Emission Reduction (%)	Facility Baseline Emission (ton/yr)	Facility Emission Reduction (%)
	SO_2	NO_x					
Close All CFBs and replace with Natural Gas Units	99%	90%	3,216	3,154	98%	3,375	93%

5.1.3 Time Necessary to Implement Strategy

It is estimated that it would take 2 ½ years to transition the steam demand from coal-fired boilers to natural gas boilers, as well as, prepare logistically for shipping waste off-site. This would involve about a year to study, design the system, and get DEQ approval for construction and implementation. Then it would take a year for vendors to evaluate the system, be selected, build the equipment, and then deliver the equipment needed to construct the system. Finally it would take 6 months for construction, checkout and training before it was up and running. See Attachment A-1.1 for a chart of this timeline.

5.1.4 Remaining Useful Life

There is no enforceable shutdown of these units and there is no documented useful life for the replacement boilers in the EPA Cost Manual. For purposes of this evaluation FFCC chose to use a 30-year useful life even though well maintained units could last beyond that time frame.

5.1.5 Energy and Non-Environmental Impacts

The most significant Energy and Non-Environmental impacts with this strategy would be the loss of FFCC's ability to burn waste for energy recovery as permitted by regulation. This cost would fluctuate based on business conditions and other factors, but FFCC estimated an annual cost of over $25 million dollars in off-site waste disposal alone. However, FFCC placed this cost under "Annual Operating Costs" since it would be reoccurring for the life of the facility. See Attachment B-1.1 for a more detailed explanation of energy and non-environmental impacts.

5.1.6 Cost of Implementing the Strategy

The cost of implementing this strategy is summarized below in Table 5.1-B. FFCC estimates the total capital and indirect cost to close the coal-fired boilers and install replacement gas-fired boilers to be just over $13.6 million dollars. These costs were depreciated over 30 years and that equates to annualized capital and indirect cost of $2,043,919 per year. The annual operating and maintenance cost is mostly waste disposal, and is estimated to be $30,597,829 per year. The actual annual cost associated with this strategy comes to $32,641,748 per year. That annual cost can be divided by the 3,154 ton/year emission reduction to bring the cost per ton reduced to $10,349. See Attachment B-1.1 for a more detailed explanation of costs.

Table 5.1-B - Replace All CFBs Cost Summary

Emission Reduction Strategy	CFB Emission Reduction (ton/yr)	Capital and Indirect Costs	Annualized Capital and Indirect Costs	Annual Operating and Maintenance Costs	Strategy Annual Costs	Cost Per Ton Reduced
Close All CFBs and replace with Natural Gas Units	3,154	$13,621,485	$2,043,919	$30,597,829	$32,641748	10,349

5.2 Fuel Switch from Coal to Natural Gas (Close and Replace one CFB)

FFCC evaluated closing just one CFB and removing it from service. This would require FFCC to replace the 50k lb/hr steam production with a natural gas boiler and ship the waste fuels it would typically burn for energy recovery off-site for treatment. The replacement of steam would done with one 75 KPPH steam natural gas boiler.

5.2.1 Control Effectiveness

Since 95% of all SO_2 and NO_x emissions come from the three coal-fired boilers, replacing one boiler would reduce the total SO_2 and NO_x emissions from the plant by about 31-32%. Shutting down one CFB would result in no emissions from that unit but the replacement natural gas boiler would add between 10 – 17 tons/yr of NO_x.

5.2.2 Emission Reductions

The CFBs baseline calculated emissions were 3,216 tons/year of combined SO_2 and NOx. Replacing one CFB with a natural gas boiler would reduce those CFB emissions by about 33%, which would be 1,061 tons/year. Since the total emissions for the facility are approximately 3,375 tons/year, the reduction would be equal to about a 31% reduction in total emissions. See Table 5.2-A below for an emission reduction summary for this strategy.

Table 5.2-A - Replace One CFBs Emission Reduction Summary

Emission Reduction Strategy	Emission Reduction (%)		CFBs Baseline Emissions (ton/yr)	CFB Emission Reduction (ton/yr)	CFB Emission Reduction (%)	Facility Baseline Emission (ton/yr)	Facility Emission Reduction (%)
	SO_2	NO_x					
Close One CFB and replace with Natural Gas Unit	33%	30%	3,216	1,061	33%	3,375	31%

5.2.3 Time Necessary to Implement Strategy

It is estimated that it would take 2 years to transition the steam demand from coal-fired boilers to natural gas boilers, as well as, prepare logistically for shipping waste off-site. This would involve about a year to study, design the system, and get DEQ approval for construction and implementation. Then it would take six months for vendors to evaluate the system, be selected, build the equipment, and then deliver the equipment need to construct the system. Finally it would take 6 months for construction, checkout and training before it was up and running. See Attachment A-1.2 for a chart of this timeline.

5.2.4 Remaining Useful Life

There is no enforceable shutdown of this unit and there is no documented useful life for a replacement boiler in the EPA Cost Manual. For purposes of this evaluation FFCC chose to use a 30-year useful life even though a well maintained unit could last beyond that time frame.

5.2.5 Energy and Non-Environmental Impacts

The most significant Energy and Non-Environmental impacts with this strategy would be the loss of FFCC's ability to burn waste for energy recovery in that one permitted boiler. This cost would fluctuate based on business conditions and other factors, but FFCC estimated an annual cost of over $8.4 million dollars in off-site waste disposal. However, FFCC placed this cost under "Annual Operating Costs" since it would be reoccurring for the life of the facility. See Attachment B-1.2 for a more detailed explanation of energy and non-environmental impacts.

5.2.6 Cost of Implementing the Strategy

The cost of implementing this strategy is summarized below in Table 5.2-B. FFCC estimates the total capital and indirect cost to close one coal-fired boiler and install a replacement gas-fired boiler to be just over $8.2 million dollars. These costs were depreciated over 30 years and that equates to annualized capital and indirect cost of $1,205,117 per year. The annual operating and maintenance cost is mostly waste disposal, and is estimated to be $10,931,976 per year. The actual annual cost associated with this strategy comes to $12,137,153 per year. That annual cost can be divided by the 1,061 ton/year emission reduction to bring the cost per ton reduced to $11,439. See Attachment B-1.2 for a more detailed explanation of costs.

Table 5.2-B - Replace One CFB Cost Summary

Emission Reduction Strategy	CFB Emission Reduction (ton/yr)	Capital and Indirect Costs	Annualized Capital and Indirect Costs	Annual Operating and Maintenance Costs	Strategy Annual Costs	Cost Per Ton Reduced
Close One CFB and replace with Natural Gas Unit	1,061	$8,248,162	$1,205,117	$10,931,976	$12,137,153	$11,439

5.3 Fuel Switch from Coal to Natural Gas (Retrofit All CFBs)

FFCC evaluated retrofitting all CFBs to natural gas boilers. This would require FFCC to redesign and modify each boiler's coal fuel system to a natural gas fuel system. Each boiler would be designed to produce 50 KPPH steam using natural gas. This design would change the dynamics so significantly that it would require a significant physical modification to the entire boiler system.

5.3.1 Control Effectiveness

Since 95% of all SO_2 and NO_x emissions come from the three coal-fired boilers, this option would reduce total SO_2 and NO_x emissions from the plant by about 92 - 94%. Retrofitting the CFBs to natural gas would result in significant control effectiveness, but the replacement natural gas burner would add between 30 – 50 tons/yr of NO_x so the emission reduction would be around 98%.

5.3.2 Emission Reductions

The CFBs baseline calculated emissions were 3,216 tons/year of combined SO_2 and NO_x. Redesigning them to burn natural gas boilers would reduce the current emissions by about 98%, which would be 3,154 tons/year. Since the total emissions for the facility are approximately 3,375 tons/year, the reduction would be equal to about a 93% reduction in total emissions. See Table 5.3-A below for an emission reduction summary for this strategy.

Table 5.3-A - Retrofit All CFBs Emission Reduction Summary

Emission Reduction Strategy	Emission Reduction (%)		CFBs Baseline Emissions (ton/yr)	CFB Emission Reduction (ton/yr)	CFB Emission Reduction (%)	Facility Baseline Emission (ton/yr)	Facility Emission Reduction (%)
	SO_2	NO_x					
Retrofit all CFBs with Natural Gas Units	99%	90%	3,216	3,154	98%	3,375	93%

5.3.3 Time Necessary to Implement Strategy

It is estimated that it would take 4 years to retrofit the coal-fired boilers to natural gas boilers, as well as, prepare logistically for shipping waste off-site. This would involve about a year to study, design the system, and get DEQ approval for construction and implementation. Then it would take a year for each Boiler to demolish the old feed system, install a new natural gas system, optimize the combustion criteria, check out the equipment, train operators, and then start up the modified unit. See Attachment A-1.3 for a chart of this timeline.

5.3.4 Remaining Useful Life

There is no enforceable shutdown of these units and there is no documented useful life for the retrofitted boilers in the EPA Cost Manual. For purposes of this evaluation FFCC chose to use a 30-year useful life even though well maintained units could last beyond that time frame.

5.3.5 Energy and Non-Environmental Impacts

The most significant Energy and Non-Environmental impacts with this strategy would be the loss of FFCC's ability to burn waste for energy recovery as permitted by regulation. This cost would fluctuate based on business conditions and other factors, but FFCC estimated an annual cost of over $25 million dollars in off-site waste disposal alone. However, FFCC placed this cost under "Annual Operating Costs" since it would be reoccurring for the life of the facility. See Attachment B-1.3 for a more detailed explanation of energy and non-environmental impacts.

5.3.6 Cost of Implementing the Strategy

The cost of implementing this strategy is summarized below in Table 5.3-B. FFCC estimates the total capital and indirect cost to retrofit the coal-fired boilers into natural gas-fired boilers would be just around $12.9 million dollars. These costs were depreciated over 30 years and that equates to annualized capital and indirect cost of $1,922,044 year. The annual operating and maintenance cost is mostly waste disposal and is estimated to be $30,597,829 per year. The actual annual cost associated with this strategy comes to $32,519,873 per year. That annual cost can be divided by the 3,154 ton/year emission reduction to bring the cost per ton reduced to $10,311. See Attachment B-1.3 for a more detailed explanation of costs.

Table 5.3-B - Retrofit All CFBs Cost Summary

Emission Reduction Strategy	CFB Emission Reduction (ton/yr)	Capital and Indirect Costs	Annualized Capital and Indirect Costs	Annual Operating and Maintenance Costs	Strategy Annual Costs	Cost Per Ton Reduced
Retrofit all CFBs with Natural Gas Units	3,154	$12,912,725	$1,922,044	$30,597,829	$32,519,873	$10,311

5.4 Fuel Switch from Coal to Natural Gas (Retrofit One CFB)

FFCC evaluated retrofitting just one CFB to a natural gas boiler. This would require FFCC to redesign and modify one boiler's coal fuel system to a natural gas fuel system. The boiler would be designed to produce 50 KPPH steam using natural gas. This design would change the dynamics significantly and would require a significant physical modification to the entire boiler system.

5.4.1 Control Effectiveness

Since 95% of all SO_2 and NO_x emissions come from the three coal-fired boilers, retrofitting one boiler to natural gas would reduce the total SO_2 and NO_x emissions from the plant by about 31-32%. Retrofitting one coal-fired boiler burner to natural gas would result in significant control effectiveness, but the replacement natural gas burner would add between 10 – 17 tons/yr of NO_x.

5.4.2 Emission Reductions

The CFBs baseline calculated emissions were 3,216 tons/year of combined SO_2 and NO_x. Retrofitting one CFB to burn natural gas would reduce those emissions by about 33%, which would be 1,061 tons/year. Since the total emissions for the facility are approximately 3,375 tons/year, the reduction would be equal to about a 31% reduction in total emissions. See Table 5.4-A below for an emission reduction summary for this strategy.

Table 5.4-A – Retrofit One CFBs Emission Reduction Summary

Emission Reduction Strategy	Emission Reduction (%)		CFBs Baseline Emissions (ton/yr)	CFB Emission Reduction (ton/yr)	CFB Emission Reduction (%)	Facility Baseline Emission (ton/yr)	Facility Emission Reduction (%)
	SO_2	NO_x					
Retrofit One CFB with a Natural Gas Unit	33%	30%	3,216	1,061	33%	3,375	31%

5.4.3 Time Necessary to Implement Strategy

It is estimated that it would take 2 years to retrofit the coal-fired boiler to natural gas boiler, as well as, prepare logistically for shipping waste off-site. This would involve about a year to study, design the system, and get DEQ approval for construction and implementation. Then it would take a year to demolish the old feed system, install a new natural gas system, optimize the combustion criteria, check out the equipment, train operators, and then start up the modified unit. See Attachment A-1.4 for a chart of this timeline.

5.4.4 Remaining Useful Life

There is no enforceable shutdown of this unit and there is no documented useful life for a retrofitted boiler in the EPA Cost Manual. For purposes of this evaluation, FFCC chose to use a 30-year useful life even though a well maintained unit could last beyond that time frame.

5.4.5 Energy and Non-Environmental Impacts

The most significant Energy and Non-Environmental impact with this strategy would be the loss of FFCC's ability to burn waste for energy recovery in retrofitted boiler. This cost would fluctuate based on business conditions and other factors, but FFCC estimated an annual cost of over $8.4 million dollars in off-site waste disposal. However, FFCC placed this cost under "Annual Operating Costs" since it would be reoccurring for the life of the facility. See Attachment B-1.4 for a more detailed explanation of energy and non-environmental impacts.

5.4.6 Cost of Implementing the Strategy

The cost of implementing this strategy is summarized below in Table 5.4-B. FFCC estimates the total capital and indirect cost to retrofit one coal-fired boiler to burn natural gas would be just under $6.3 million dollars. These costs were depreciated over 30 years and that equates to annualized capital and indirect cost of $903,388 per year. The annual operating and maintenance cost is mostly waste disposal and is estimated to be $10,931,976 per year. The actual annual cost associated with this strategy comes to $11,835,364 per year. That annual cost can be divided by the 1,061 ton/year emission reduction to bring the cost per ton reduced to $11,155. See Attachment B-1.4 for a more detailed explanation of costs.

Table 5.4-B - Retrofit One CFB Cost Summary

Emission Reduction Strategy	CFB Emission Reduction (ton/yr)	Capital and Indirect Costs	Annualized Capital and Indirect Costs	Annual Operating and Maintenance Costs	Strategy Annual Costs	Cost Per Ton Reduced
Retrofit One CFB with a Natural Gas Unit	1,061	$6,267,742	$903,388	$10,931,976	$11,835,364	$11,155

5.5 SO_2 Control Technology – Wet Gas Scrubber

FFCC evaluated installing wet gas scrubbers on its three-coal fired boilers to the mitigate SO_2 emissions. This would require at least two wet gas scrubbers, although three would be more desirable. FFCC conducted this analysis based on the installation of two lime-slurry wet gas scrubbers operating independently.

5.5.1 Control Effectiveness

99% of all SO_2 emissions come from the three coal-fired boilers. This strategy would reduce total SO_2 emissions from the facility by about 93%. The reduction of SO_2 emission from the CFBs would be about 94%, which demonstrates that wet gas scrubbing is a very effective method of controlling SO_2 emissions.

5.5.2 Emission Reductions

The CFBs baseline calculated emissions were 2,884 tons/year of SO_2. The addition of a lime slurry wet scrubber would reduce the current emissions by about 94%, which would be 2,711 tons/year. Since the total emissions for the facility are approximately 2,911 tons/year, the reduction would be equal to about a 93% reduction in total emissions. See Table 5.5-A below for an emission reduction summary for this strategy.

Table 5.5-A – Install Wet Scrubber Emission Reduction Summary

Emission Reduction Strategy	Emission Reduction (%)		CFBs Baseline Emissions (ton/yr)	CFB Emission Reduction (ton/yr)	CFB Emission Reduction (%)	Facility Baseline Emission (ton/yr)	Facility Emission Reduction (%)
	SO_2	NO_x					
Wet Scrubber – Lime Slurry	94%	0%	2,884	2,711	94%	2,911	93%

5.5.3 Time Necessary to Implement Strategy

It is estimated that it would take 6 years to install two lime-slurry wet scrubbers on the back end of the three coal-fired boilers. Since all three boilers share one common stack, this would require FFCC to shutdown all three CFB's during the 6-month installation period. The lime-slurry system would be new to our facility and would require equipment and operations to which FFCC is currently not familiar. Basically, the time frame involves designing the two systems, DEQ review and approval, selection of vendors and equipment, purchasing components, demolishing or moving at least one existing building to make room for the scrubbers, installing the equipment, checkout of the equipment, operator training, and start-up. See Attachment A-1.5 for a chart of this timeline.

5.5.4 Remaining Useful Life

The EPA Cost Manual indicates that the useful life of a Wet Scrubber is approximately 15-years. For purposes of this evaluation, FFCC will use a 15-year useful life to establish the annualized capital and indirect costs.

5.5.5 Energy and Non-Environmental Impacts

The most significant Energy and Non-Environmental impacts with this strategy would come from the need to shut down the coal-fired boiler to install the system. This would require the rental of portable gas boilers and the need to ship waste off-site during the downtime. Once the unit is installed, there would be significant cost with disposing of the spent lime slurry from the scrubbing system as well. See Attachment B-1.5 for a more detailed explanation of energy and non-environmental impacts.

5.5.6 Cost of Implementing the Strategy

The cost of implementing this strategy is summarized below in Table 5.5-B. FFCC estimates the total capital and indirect cost to purchase and install a lime slurry wet scrubber would be just over $79.4 million dollars. These costs were depreciated over 15 years and that equates to annualized capital and indirect cost of $14,194,554 per year. The annual operating and maintenance cost is estimated to be $3,043,215 per year. The actual annual cost associated with this strategy comes to $17,237,769 per year. That annual cost can be divided by the 2,711 ton/year SO2 emission reduction to bring the cost per ton reduced to $6,358. See Attachment B-1.5 for a more detailed explanation of costs.

Table 5.5-B – Install Wet Scrubber Cost Summary

Emission Reduction Strategy	CFB Emission Reduction (ton/yr)	Capital and Indirect Costs	Annualized Capital and Indirect Costs	Annual Operating and Maintenance Costs	Strategy Annual Costs	Cost Per Ton Reduced
Wet Scrubber – Lime Slurry	2,711	$79,442,824	$14,194,554	$3,043,215	$17,237,769	$6,358

5.6 SO_2 Control Technology – Spray Dry Absorber

FFCC evaluated installing a spray dry absorber on the back end of its coal-fired boilers to the mitigate SO_2 emissions. This system is designed to use lime to transform SO_2 into a stable and dry powdery material that can easily be handled. Although FFCC would prefer to install a spray dry absorber for each coal-fired boiler, FFCC has decided to base this evaluation on the installation of only two spray dry absorbers in order to minimize the costs.

5.6.1 Control Effectiveness

99% of all SO_2 emissions come from the three coal-fired boilers. This strategy would reduce total SO_2 emissions from the CFBs by about 92%. The reduction of SO_2 emission from the entire facility would be about 91%. Spray Dry Absorber has been used in many applications and is prove to be a very effective method of controlling SO_2, among other emissions.

5.6.2 Emission Reductions

The CFBs baseline calculated emissions were 2,884 tons/year of SO_2. The addition of a spray dry absorber would reduce the current emissions by about 92%, which would be 2,653 tons/year. Since the total emissions for the facility are approximately 2,911 tons/year, the reduction would be equal to about a 91% reduction in total emissions. See Table 5.6-A below for an emission reduction summary for this strategy.

Table 5.6-A – Install Spray Dry Absorber Emission Reduction Summary

Emission Reduction Strategy	Emission Reduction (%)		CFBs Baseline Emissions (ton/yr)	CFB Emission Reduction (ton/yr)	CFB Emission Reduction (%)	Facility Baseline Emission (ton/yr)	Facility Emission Reduction (%)
	SO_2	NO_x					
Spray Dry Absorber	92%	0%	2,884	2,653	92%	2,911	91%

5.6.3 Time Necessary to Implement

It is estimated that it would take 4 years to install two spray dry absorbers on the back end of the three coal-fired boilers. Since all three boilers share one common stack, this would require FFCC to shut down all three CFBs during the installation period. The spray dry absorber system would be new to our facility and would require equipment and operations to which FFCC is currently not familiar. Basically, the time frame involves designing the two systems, DEQ review and approval, selection of vendors and equipment, purchasing components, demolishing or moving at least one existing building to make room for the scrubbers, installing the equipment, checkout of the equipment, operator training, and start-up. See Attachment A-1.6 for a chart of this timeline.

5.6.4 Remaining Useful Life

The EPA Cost Manual indicates that the useful life of a Spray Dry Absorbing system is approximately 15 years. For purposes of this evaluation FFCC will use a 15-year useful life to establish the annualized capital and indirect costs.

5.6.5 Energy and Non-Environmental Impacts

The most significant Energy and Non-Environmental impacts with this strategy would come from the need to shut down the coal-fired boiler to install the system. This would require the rental of portable gas boilers and the need to ship waste off-site during the downtime. Once the unit is installed, there would be some cost for managing the spent sorbent. See Attachment B-1.6 for a more detailed explanation of energy and non-environmental impacts.

5.6.6 Cost of Implementing the Strategy

The cost of implementing this strategy is summarized below in Table 5.6-B below. FFCC estimates the total capital and indirect cost to purchase and install a spray dry absorber system would be just over $67.7 million dollars. These costs were depreciated over 15 years and that equates to annualized capital and indirect cost of $11,568,303 per year. The annual operating and maintenance cost is estimated to be $2,058,925 per year. The actual annual cost associated with this strategy comes to $13,627,228 per year. That annual cost can be divided by the 2,711 ton/year SO_2 emission reduction to bring the cost per ton reduced to $5,137. See Attachment B-1.6 for a more detailed explanation of costs.

Table 5.6-B - Install Spray Dry Absorber Cost Summary

Emission Reduction Strategy	CFB Emission Reduction (ton/yr)	Capital and Indirect Costs	Annualized Capital and Indirect Costs	Annual Operating and Maintenance Costs	Strategy Annual Costs	Cost Per Ton Reduced
Wet Scrubber – Lime Slurry	2,711	$64,776,915	$11,568,303	$2,058,925	$13,627,228	$5,137

5.7 SO_2 Control Technology – Dry Sorbent Injection

FFCC evaluated installing a dry sorbent injection on its coal-fired boilers to the mitigate SO_2 emissions. This system is designed to inject hydrated lime into the boilers system to neutralize SO_2, which is then removed by other pollution control equipment. Although FFCC would prefer to install a dry sorbent injection system for each coal-fired boiler, FFCC has decided to base this evaluation on the installation of only two dry sorbent injection systems in order to minimize the costs.

5.7.1 Control Effectiveness

99% of all SO_2 emissions come from the three coal-fired boilers. This strategy would reduce total SO_2 emissions from the CFBs by about 40%. The reduction of SO_2 emissions from the entire facility would be about 39%. Dry sorbent injection systems have been used in various coal combustion units and have proven to be a fairly effective method of controlling SO_2 in pulverized coal boilers; however FFCC's coal-fired boilers are spreader-stoker boilers and that limits the removal efficiency.

5.7.2 Emission Reductions

The CFBs baseline calculated emissions were 2,884 tons/year of SO_2. The addition of a spray dry absorber would reduce the current emissions by about 40%, which would be 1,154 tons/year. Since the total emissions for the facility are approximately 2,911 tons/year, the reduction would be just under a 40% reduction in total SO_2 emissions. See Table 5.7-A below for an emission reduction summary for this strategy.

Table 5.7-A – Install Dry Sorbent Injection Emission Reduction Summary

Emission Reduction Strategy	Emission Reduction (%)		CFBs Baseline Emissions (ton/yr)	CFB Emission Reduction (ton/yr)	CFB Emission Reduction (%)	Facility Baseline Emission (ton/yr)	Facility Emission Reduction (%)
	SO_2	NO_x					
Dry Sorbent Injection	40%	0%	2,884	1,154	40%	2,911	40%

5.7.3 Time Necessary to Implement Strategy

It is estimated that it would take 3 years to install two dry sorbent injection systems on the three coal-fired boilers. Since all three boilers share one common stack, this would require FFCC to shut down all three CFBs during the installation period. The spray dry absorber system would be new to our facility and would require equipment and operations to which FFCC is currently not familiar. Basically, the time frame involves designing the two systems, DEQ review and approval, selection of vendors and equipment, purchasing components, demolishing or moving at least one existing building to make room for the scrubbers, installing the equipment, checkout of the equipment, operator training, and start-up. See Attachment A-1.7 for a chart of this timeline.

5.7.4 Remaining Useful Life

The EPA Cost Manual indicates that the useful life of a dry sorbent injection system is approximately 15 years. For purposes of this evaluation FFCC will use a 15-year useful life to establish the annualized capital and indirect costs.

5.7.5 Energy and Non-Environmental Impacts

The most significant Energy and Non-Environmental impacts with this strategy would come from the need to shut down the coal fired boiler to install the system. This would require the rental of portable gas boilers and the need to ship waste off-site during the downtime. Once the unit is installed, there would be some cost for managing the spent sorbent. See Attachment B-1.7 for a more detailed explanation of energy and non-environmental impacts.

5.7.6 Cost of Implementing the Strategy

The cost of implementing this strategy is summarized below in Table 5.7-B below. FFCC estimates the total capital and indirect cost to purchase and install a spray dry absorber system would be just under $61.9 million dollars. These costs were depreciated over 15 years and that equates to annualized capital and indirect cost of $9,892,986 per year. The annual operating and maintenance cost is estimated to be $921,467 per year. The actual annual cost associated with this strategy comes to $10,814,453 per year. That annual cost can be divided by the 1,154 ton/year SO_2 emission reduction to bring the cost per ton reduced to $9,371. See Attachment B-1.7 for a more detailed explanation of costs.

Table 5.7-B – Install Dry Sorbent Injection Cost Summary

Emission Reduction Strategy	CFB Emission Reduction (ton/yr)	Capital and Indirect Costs	Annualized Capital and Indirect Costs	Annual Operating and Maintenance Costs	Strategy Annual Costs	Cost Per Ton Reduced
Dry Sorbent Injection	1,154	$61,894,695	$9,892,986	$921,467	$10,814,453	$9,371

5.8 Fuel Switch to Lower Sulfur Coal (2.5% Sulfur)

FFCC evaluated the use of lower sulfur coal. The current FFCC coal specification is 3% sulfur. This strategy involves the purchase and use of 2.5% sulfur coal. The science to this strategy is the less sulfur present in the combustion zone, the less sulfur is oxidized into SO_2.

5.8.1 Control Effectiveness

99% of all SO_2 emissions come from the three coal-fired boilers. This strategy involves introducing almost 17% less sulfur into the combustion zone, which based on the stoichiometry would produce about 17% less SO2. A 17% reduction of SO_2 emissions from the coal-fired boilers would also equate to about a 17% reduction for the entire facility.

5.8.2 Emission Reductions

The CFBs baseline calculated emissions were 2,884 tons/year of SO_2 using 3% sulfur specification coal. The use of 2.5% sulfur specification coal would result in an SO_2 reduction of about 17%, which would be about 490 tons/year. Since the total emissions for the facility are approximately 2,911 tons/year, the reduction would be just under a 17% reduction in total SO_2 emissions. See Table 5.8-A below for an emission reduction summary for this strategy.

Table 5.8-A – Lower Sulfur Coal (2.5%) Emission Reduction Summary

Emission Reduction Strategy	Emission Reduction (%)		CFBs Baseline Emissions (ton/yr)	CFB Emission Reduction (ton/yr)	CFB Emission Reduction (%)	Facility Baseline Emission (ton/yr)	Facility Emission Reduction (%)
	SO_2	NO_x					
Fuel Switch to 2.5% Sulfur Coal	17%	0%	2,884	490	17%	2,911	17%

5.8.3 Time Necessary to Implement Strategy

It is estimated that it would take less than one year to implement this strategy. There would be some time required to work through the current coal stock pile, and there might be some time required to complete any existing purchase agreements. However, FFCC does not anticipate any necessary equipment or operational changes to implement this strategy. Since this strategy is fairly seamless, FFCC did not see the need to prepare timeline for this strategy.

5.8.4 Remaining Useful Life

There is no enforceable shutdown of these units, so for purposes of this evaluation, FFCC will use a 30-year useful life even though well maintained boilers should last beyond that time frame.

5.8.5 Energy and Non-Environmental Impacts

The only significant Energy and Non-Environmental impacts with this strategy would involve a change in the coal heating value or fusion temperature. However, such a change would make the coal unusable in FFCC's application and thus there would need to be a specification to ensure those requirements are met on any lower sulfur coal.

5.8.6 Cost of Implementing the Strategy

The cost of implementing this strategy is summarized below in Table 5.8-B. FFCC does not anticipate any capital or indirect cost to purchase 2.5% sulfur specification coal, so there would be no annualized capital and indirect cost from this strategy. The annual operating and maintenance cost would be the cost difference of the lower sulfur coal and the associated tax. This annual operating cost is estimated to be $1,149,137 per year, which would be equal to the actual annual cost. By dividing the annual cost by the 490 ton/year reduction of SO_2 emissions, the cost per ton reduced would be $2,345. See Attachment B-1.8 for a more detailed explanation of costs.

Table 5.8-B – Lower Sulfur Coal (2.5%) Cost Summary

Emission Reduction Strategy	CFB Emission Reduction (ton/yr)	Capital and Indirect Costs	Annualized Capital and Indirect Costs	Annual Operating and Maintenance Costs	Strategy Annual Costs	Cost Per Ton Reduced
Fuel Switch to 2.5% Sulfur Coal	490	$0	$0	$1,149,137	$1,149,137	$2,345

5.9 Fuel Switch to Lower Sulfur Coal (2.0% Sulfur)

FFCC evaluated the use of lower sulfur coal. The current FFCC coal specification is 3% sulfur. This strategy involves the purchase and use of 2.0% sulfur coal. The science to this strategy is the less sulfur present in the combustion zone, the less sulfur is oxidized into SO_2.

5.9.1 Control Effectiveness

99% of all SO_2 emissions come from the three coal-fired boilers. This strategy involves introducing almost 33% less sulfur into the combustion zone, which based on the stoichiometry would produce about 33% less SO_2. A 33% reduction of SO_2 emissions from the coal-fired boilers would also equate to about a 33% reduction for the entire facility.

5.9.2 Emission Reductions

The CFBs baseline calculated emissions were 2,884 tons/year of SO_2 using 3% sulfur specification coal. The use of 2.0% sulfur specification coal would result in an SO_2 reduction of about 33%, which would be about 952 tons/year. Since the total emissions for the facility are approximately 2,911 tons/year, the reduction would be just under a 33% reduction in total SO_2 emissions. See Table 5.9-A below for an emission reduction summary for this strategy.

Table 5.9-A – Lower Sulfur Coal (2.0%) Emission Reduction Summary

Emission Reduction Strategy	Emission Reduction (%)		CFBs Baseline Emissions (ton/yr)	CFB Emission Reduction (ton/yr)	CFB Emission Reduction (%)	Facility Baseline Emission (ton/yr)	Facility Emission Reduction (%)
	SO_2	NO_x					
Fuel Switch to 2.0% Sulfur Coal	33%	0%	2,884	952	33%	2,911	33%

5.9.3 Time Necessary to Implement Strategy

It is estimated that it would take less than one year to implement this strategy. There would be some time required to work through the current coal stock pile, and there might be some time required to complete any existing purchase agreements. However, FFCC does not anticipate any necessary equipment or operational changes to implement this strategy. Since this strategy is fairly seamless, FFCC did not see the need to prepare timeline for this strategy.

5.9.4 Remaining Useful Life

There is no enforceable shutdown of these units, so for purposes of this evaluation, FFCC will use a 30-year useful life even though well maintained boilers should last beyond that time frame.

5.9.5 Energy and Non-Environmental Impacts

The only significant Energy and Non-Environmental impacts with this strategy would involve a change in the coal heating value or fusion temperature. However, such a change would make the coal unusable in FFCC's application and thus there would need to be a specification to ensure those requirements are met on any lower sulfur coal.

5.9.6 Cost of Implementing the Strategy

The cost of implementing this strategy is summarized below in Table 5.9-B. FFCC does not anticipate any capital or indirect cost to purchase 2.0% sulfur specification coal, so there would be no annualized capital and indirect cost from this strategy. The annual operating and maintenance cost would be the cost difference of the lower sulfur coal and its associated tax. This annual operating cost is estimated to be $1,995,030 per year, which would be the same as the actual annual cost. By dividing the annual cost by the 952 ton/year reduction of SO_2 emissions, the cost per ton reduced would be $2,096. See Attachment B-1.9 for a more detailed explanation of costs.

Table 5.9-B – Lower Sulfur Coal (2.0%) Cost Summary

Emission Reduction Strategy	CFB Emission Reduction (ton/yr)	Capital and Indirect Costs	Annualized Capital and Indirect Costs	Annual Operating and Maintenance Costs	Strategy Annual Costs	Cost Per Ton Reduced
Fuel Switch to 2.0% Sulfur Coal	952	$0	$0	$1,995,030	$1,995,030	$2,096

5.10 Fuel Switch to Lower Sulfur Coal (1.5% Sulfur)

FFCC evaluated the use of lower sulfur coal. The current FFCC coal specification is 3% sulfur. This strategy involves the purchase and use of 1.5% sulfur coal. The science to this strategy is the less sulfur present in the combustion zone, the less sulfur is oxidized into SO_2.

5.10.1 Control Effectiveness

99% of all SO_2 emissions come from the three coal-fired boilers. This strategy involves introducing 50% less sulfur into the combustion zone, which based on the stoichiometry would produce about 50% less SO_2. A 50% reduction of SO_2 emissions from the coal-fired boilers would equate to just under a 50% reduction for the entire facility.

5.10.2 Emission Reductions

The CFBs baseline calculated emissions were 2,884 tons/year of SO_2 using 3% sulfur specification coal. The use of 1.5% sulfur specification coal would result in an SO_2 reduction of about 50%, which would be about 1,442 tons/year. Since the total emissions for the facility are approximately 2,911 tons/year, the reduction would be just under a 50% reduction in total SO_2 emissions. See Table 5.9-A below for an emission reduction summary for this strategy.

Table 5.10-A – Lower Sulfur Coal (1.5%) Emission Reduction Summary

Emission Reduction Strategy	Emission Reduction (%)		CFBs Baseline Emissions (ton/yr)	CFB Emission Reduction (ton/yr)	CFB Emission Reduction (%)	Facility Baseline Emission (ton/yr)	Facility Emission Reduction (%)
	SO_2	NO_x					
Fuel Switch to 1.5% Sulfur Coal	50%	0%	2,884	1,442	50%	2,911	50%

5.10.3 Time Necessary to Implement Strategy

It is estimated that it would take less than one year to implement this strategy. There would be some time required to work through the current coal stock pile, and there might be some time required to complete any existing purchase agreements. However, FFCC does not anticipate any necessary equipment or operational changes to implement this strategy. Since this strategy is fairly seamless, FFCC did not see the need to prepare timeline for this strategy.

5.10.4 Remaining Useful Life

There is no enforceable shutdown of these units, so for purposes of this evaluation, FFCC will use a 30-year useful life even though well maintained boilers should last beyond that time frame.

5.10.5 Energy and Non-Environmental Impacts

The only significant Energy and Non-Environmental impacts with this strategy would involve a change in the coal heating value or fusion temperature. However, such a change would make the coal unusable in FFCC's application and thus there would need to be a specification to ensure those requirements are met on any lower sulfur coal.

5.10.6 Cost of Implementing the Strategy

The cost of implementing this strategy is summarized below in Table 5.10-B. FFCC does not anticipate any capital or indirect cost to purchase 1.5% sulfur specification coal, so there would be no annualized capital and indirect cost from this strategy. The annual operating and maintenance cost would be the cost difference of the lower sulfur coal and its associated tax. This annual operating cost is estimated to be $4,232,823 per year, which would be the same as the actual annual cost. By dividing the annual cost by the 1,442 ton/year reduction of SO_2 emissions, the cost per ton reduced would be $2,935. See Attachment B-1.10 for a more detailed explanation of costs.

Table 5.10-B – Lower Sulfur Coal (1.5%) Cost Summary

Emission Reduction Strategy	CFB Emission Reduction (ton/yr)	Capital and Indirect Costs	Annualized Capital and Indirect Costs	Annual Operating and Maintenance Costs	Strategy Annual Costs	Cost Per Ton Reduced
Fuel Switch to 1.5% Sulfur Coal	1,442	$0	$0	$4,232,823	$4,232,823	$2,935

5.11 NO_x Control Technology – Selective Catalytic Reduction

FFCC evaluated installing two selective catalytic reduction (SCR) systems for the three coal-fired boilers to mitigate NO_x emissions. This system is designed to react boiler combustion gases with urea in the presence of a catalyst in order to reduce NO_x into nitrogen and water vapor. Each boiler would be equipped with SCR downstream of the combustion zone and ESP. The design would require an air heater just before the SCR to ensure reduction temperatures are optimal.

5.11.1 Control Effectiveness

71% of all NO_x emissions come from the three coal-fired boilers. This strategy would reduce total NO_x emissions from the CFBs by about 80%. The reduction of NO_x emissions from the entire facility would be about 57%. Selective Catalytic Reduction is one of the most effective systems to reduce NO_x from combustion gases. They have been used efficiently in combustion units for various design and sizes.

5.11.2 Emission Reductions

The CFBs baseline calculated emissions were 332 tons/year of NO_x. The addition of an SCR would reduce the current emissions by about 80%, which would be 266 tons/year. Since the total emissions for the facility are approximately 464 tons/year, the reduction would be about 57% in total NO_x emissions. See Table 5.11-A below for an emission reduction summary for this strategy.

Table 5.11-A – Install SCR Emission Reduction Summary

Emission Reduction Strategy	Emission Reduction (%)		CFBs Baseline Emissions (ton/yr)	CFB Emission Reduction (ton/yr)	CFB Emission Reduction (%)	Facility Baseline Emission (ton/yr)	Facility Emission Reduction (%)
	SO_2	NO_x					
Selective Catalytic Reduction	0%	80%	332	266	80%	464	57%

5.11.3 Time Necessary to Implement Strategy

It is estimated that it would take 4 years to install two SCRs on the three coal-fired boilers. This would involve about a year to study, design the system, and get DEQ approval for construction and implementation. Then it would take a year for each Boiler to select the vendors and equipment, purchase components, demolish an existing building to make room for the SCRs, install the equipment, checkout of the equipment, operator training, and start-up. See Attachment A-1.11 for a chart of this timeline.

5.11.4 Remaining Useful Life

The EPA Cost Manual indicates that the useful life of an SCR is approximately 22-years for an industrial boiler. For purposes of this evaluation FFCC will use a 22-year useful life to establish the annualized capital and indirect costs. The EPA Cost Manual states that the life of an industrial SCR is less than the life of an SCR on an electrical generating facility which is typically 30 years.

5.11.5 Energy and Non-Environmental Impacts

The most significant Energy and Non-Environmental impacts with this strategy would come from the need to shut down the coal-fired boilers to install the system. This would require the rental of portable gas boilers and the need to ship waste off-site during the downtime. See Attachment B-1.11 for a more detailed explanation of energy and non-environmental impacts.

5.11.6 Cost of Implementing the Strategy

The cost of implementing this strategy is summarized below in Table 5.11-B. FFCC estimates the total capital and indirect cost to purchase and install a SCR system would be just over $46 million dollars. These costs were depreciated over 22 years and that equates to annualized capital and indirect cost of $4,167,872 per year. The annual operating and maintenance cost is estimated to be $541,053 per year. The actual annual cost associated with this strategy comes to $4,708,925 per year. That annual cost can be divided by the 266 ton/year NO_x emission reduction to bring the cost per ton reduced to $17,703. See Attachment B-1.11 for a more detailed explanation of costs.

Table 5.11-B – Install SCR Cost Summary

Emission Reduction Strategy	CFB Emission Reduction (ton/yr)	Capital and Indirect Costs	Annualized Capital and Indirect Costs	Annual Operating and Maintenance Costs	Strategy Annual Costs	Cost Per Ton Reduced
Selective Catalytic Reduction	266	$46,056,653	$4,167,872	$541,053	$4,708,925	$17,703

5.12 NOx Control Technology – Selective Non-Catalytic Reduction

FFCC evaluated installing two selective non-catalytic reduction (SNCR) systems for the three coal-fired boilers to mitigate NO_x emissions. This system is designed to react the boiler combustion gases with urea at high temperatures in order to reduce NO_x into nitrogen and water vapor without using a catalyst. Each boiler would be equipped with SNCR close to the combustion zone. The design would require an air heater just before the SNCR to ensure reduction temperatures are optimal.

5.12.1 Control Effectiveness

71% of all NO_x emissions come from the three coal-fired boilers. This strategy would reduce total NO_x emissions from the CFBs by about 40%. The reduction of NO_x emissions from the entire facility would be right at 29%. Selective Non-Catalytic Reduction is one of the most cost effective systems to reduce NO_x from combustion gases. They have been used efficiently in combustion units for various design and sizes.

5.12.2 Emission Reductions

The CFBs baseline calculated emissions were 332 tons/year of NO_x. The addition of an SNCR would reduce the current emissions by about 40%, which would be 133 tons/year. Since the total emissions for the facility are approximately 464 tons/year, the reduction would come to about 29% in total NO_x emissions. See Table 5.12-A below for an emission reduction summary for this strategy.

Table 5.12-A – Install SNCR Emission Reduction Summary

Emission Reduction Strategy	Emission Reduction (%)		CFBs Baseline Emissions (ton/yr)	CFB Emission Reduction (ton/yr)	CFB Emission Reduction (%)	Facility Baseline Emission (ton/yr)	Facility Emission Reduction (%)
	SO_2	NO_x					
Selective Non-Catalytic Reduction	0%	40%	332	133	40%	464	29%

5.12.3 Time Necessary to Implement Strategy

It is estimated that it would take 4 years to install SNCRs on the three coal-fired boilers. This would involve about a year to study, design the system, and get DEQ approval for construction and implementation. Then it would take a year for each Boiler to select the vendors and equipment, purchase components, demolish or move existing equipment to make room for the SNCR, install the equipment, checkout of the equipment, operator training, and start-up. See Attachment A-1.12 for a chart of this timeline.

5.12.4 Remaining Useful Life

The EPA Cost Manual indicates that the useful life of an SNCR for industrial boilers is approximately 15-25 years. For purposes of this evaluation FFCC will use a 20-year useful life to establish the annualized capital and indirect costs.

5.12.5 Energy and Non-Environmental Impacts

The most significant Energy and Non-Environmental impacts with this strategy would come from the need to shut down each coal-fired boiler to install the system. This would require the rental of portable gas boilers and the need to ship the waste that boiler would have burned off-site during the downtime. See Attachment B-1.12 for a more detailed explanation of energy and non-environmental impacts.

5.12.6 Cost of Implementing the Strategy

The cost of implementing this strategy is summarized below in Table 5.12-B. FFCC estimates the total capital and indirect cost to purchase and install a SNCR system would be just under $23.8 million dollars. These costs were depreciated over 20 years and that equates to annualized capital and indirect cost of $2,252,744 per year. The annual operating and maintenance cost is estimated to be $413,695 per year. The actual annual cost associated with this strategy comes to $2,666,469 per year. That annual cost can be divided by the 133 ton/year NO_x emission reduction to bring the cost per ton reduced to $20,049. See Attachment B-1.12 for a more detailed explanation of costs.

Table 5.12-B Table 5.11-B – Install SNCR Cost Summary

Emission Reduction Strategy	CFB Emission Reduction (ton/yr)	Capital and Indirect Costs	Annualized Capital and Indirect Costs	Annual Operating and Maintenance Costs	Strategy Annual Costs	Cost Per Ton Reduced
Selective Non-Catalytic Reduction	133	$23,794,387	$2,252,744	$413,695	$2,666,469	$20,049

6.0 SUMMARY OF REGIONAL HAZE EVALUATION

Each strategy discussed in sections 4.0 and 5.0 are summarized in this section in the form of tables. This allows the DEQ to see the over performance and impact of each strategy. These same tables were provided in the Executive Summary. Finally, there is a summary of the basis of this evaluation and the sources used to obtain all costs, data, and timelines.

6.1 Summary of Technically Infeasible Strategies

The strategies in Table 6.1-A below were determined to be technically infeasible.

Table 6.1-A - Summary of Technically Infeasible Strategies

Emission Reduction Strategy	Rationale
Installation of a Low-NO_x Burner on the CFBs	There are no available or applicable Low-NO_x burner systems designed for stoker style boilers.
Installation of a Sodium Hydroxide Wet Scrubber on the CFBs	Wet Scrubbing is a viable option, but the use of Sodium Hydroxide scrubbing is not technically feasible to due to NPDES permit limitations.
Use of a Low-Sulfur Coal from a nearby Power Plant at the CFBs	The local supply of low-sulfur coal is not usable at FFCC's stoker style boilers due to the heating value being too low (< 11,000 Btu/lb) and the fusion temperature being two low (< 2,550°F fluid fusion temp)

6.2 Summary of Technically Feasible Strategies

The strategies in Table 6.2-A and Table 6.2-B below were determined to be technically feasible. The tables contain the same information but they are sorted by different cost perspectives.

Table 6.2-A – Summary of Feasible Strategies by Annual Cost

Emission Reduction Strategy	Emission Reduction		Baseline Emissions Before Control (ton/yr)	Emission Reduction by Strategy (ton/yr)	Capital and Indirect Investment (Millions)	Annualized Capital and Indirect Costs	Annual Operating and Maintenance Costs	Strategy Annual Cost	Cost per Ton Reduced ($/ton)
	SO_2	NO_x							
Fuel Switch to 2.5% Sulfur Coal	17%	0%	2,884	490	$0.0	$0.0	$1,149,137	$1,149,137	$2,345
Fuel Switch to 2% Sulfur Coal	33%	0%	2,884	952	$0.0	$0	$1,995,030	$1,995,030	$2,096
Fuel Switch to 1.5% Sulfur Coal	50%	0%	2,884	1,442	$0.0	$0	$4,232,823	$4,232,823	$2,935
Selective Non-Catalytic Reduction	0%	40%	332	133	$23.8	$2,252,744	$413,695	$2,666,469	$20,049
Selective Catalytic Reduction	0%	80%	332	266	$46.1	$4,167,872	$541,053	$4,708,925	$17,703
Fuel Switch to Natural Gas - Retrofit 1 CFB	33%	30%	3,216	1,061	$6.3	$903,388	$10,931,976	$11,835,364	$11,155
Close and Replace 1-CFB with Natural Gas	33%	30%	3,216	1,061	$8.2	$1,205,117	$10,931,976	$12,137,153	$11,439
Dry Sorbent Injection	40%	0%	2,884	1,154	$61.9	$9,892,986	$921,467	$10,814,453	$9,371
Spray Dry Absorption	92%	0%	2,884	2,653	$67.7	$11,568,303	$2,058,925	$13,627,228	$5,137
Fuel Switch to Natural Gas - Retrofit 3 CFBs	99%	90%	3,216	3,154	$12.9	$1,922,044	$30,597,829	$32,519,873	$10,310
Close and Replace 3-CFBs with Natural Gas	99%	90%	3,216	3,154	$13.6	$2,043,919	$30,597,829	$32,641,748	$10,349
Wet Scrubber - Lime Slurry	94%	0%	2,884	2,711	$79.4	$14,194,554	$3,043,215	$17,237,769	$6,358

Table 6.2-B – Summary of Feasible Strategies by Cost per Ton Reduced

Emission Reduction Strategy	Emission Reduction		Baseline Emissions Before Control (ton/yr)	Emission Reduction by Strategy (ton/yr)	Capital and Indirect Investment (Millions)	Annualized Capital and Indirect Costs	Annual Operating and Maintenance Costs	Strategy Annual Cost	Cost per Ton Reduced ($/ton)
	SO_2	NO_x							
Fuel Switch to 2% Sulfur Coal	33%	0%	2,884	952	$0.0	$0	$1,995,030	$1,995,030	$2,096
Fuel Switch to 2.5% Sulfur Coal	17%	0%	2,884	490	$0.0	$0.0	$1,149,137	$1,149,137	$2,345
Fuel Switch to 1.5% Sulfur Coal	50%	0%	2,884	1,442	$0.0	$0	$4,232,823	$4,232,823	$2,935
Spray Dry Absorption	92%	0%	2,884	2,653	$67.7	$11,568,303	$20,589,925	$13,627,228	$5,137
Wet Scrubber - Lime Slurry	94%	0%	2,884	2,711	$79.4	$14,194,554	$3,043,215	$17,237,769	$6,358
Dry Sorbent Injection	40%	0%	2,884	1,154	$61.9	$9,892,986	$921,467	$10,814,453	$9,371
Fuel Switch to Natural Gas - Retrofit 3 CFBs	99%	90%	3,216	3,154	$12.9	$1,922,044	$30,597,829	$32,519,873	$10,311
Close and Replace 3-CFBs with Natural Gas	99%	90%	3,216	3,154	$13.6	$2,043,919	$30,597,829	$32,641,748	$10,349
Fuel Switch to Natural Gas - Retrofit 1 CFB	33%	30%	3,216	1,061	$6.3	$903,388	$10,931,976	$11,835,364	$11,155
Close and Replace 1-CFB with Natural Gas	33%	30%	3,216	1,061	$8.2	$1,205,117	$10,931,976	$12,137,153	$11,439
Selective Catalytic Reduction	0%	80%	332	266	$46.1	$4,167,872	$541,053	$4,708,925	$17,703
Selective Non-Catalytic Reduction	0%	40%	332	133	$23.8	$2,252,744	$413,695	$2,666,469	$20,049

6.3 Summary of FFCC's Approach to the Regional Haze Evaluation

This evaluation was prepared using internal and external information. FFCC's internal Construction and Engineering Department, Health, Safety, Environmental, and Security Department, Accounting Department, and Process Engineering Department all provided input. The information they provided was based on process knowledge and historical experience involving similar systems and projects.

FFCC personnel also obtained information from external sources such as the EPA, DEQ, the internet, and third-party vendor and/or consultants. Much of the information provided by third party vendors and consultants was provided under a request that it not be shared or made public without written consent.

All strategies were evaluated at the conceptual design level and based on budgetary estimates and proposals. FFCC added the 30% contingency, recommended in the EPA cost manual, but believes these costs could fluctuate as much as 50% in actual installation. Nevertheless, FFCC believes this information to be representative estimates of the actual costs necessary to implement technically feasible strategies.

DEQ presented modeling results indicating that FFCC contributes a minimal amount to haze in Class I Wilderness Areas. Previous DEQ BART models (Attachment C-1.1) indicated there was no contribution to visibility impairment in Arkansas Class I Wilderness Areas. For this reason, FFCC believes it is not prudent to make more than minimal control steps in this period, Planning Period II.

Attachment A

Emission Reduction Strategy Timelines

Revision 0

Pursuant to

DEQ Information Collection Request dated January 8, 2020

AFIN 32-00036

FutureFuel Chemical Company
P.O. Box 2357
Batesville, AR 72503
ARD089234884

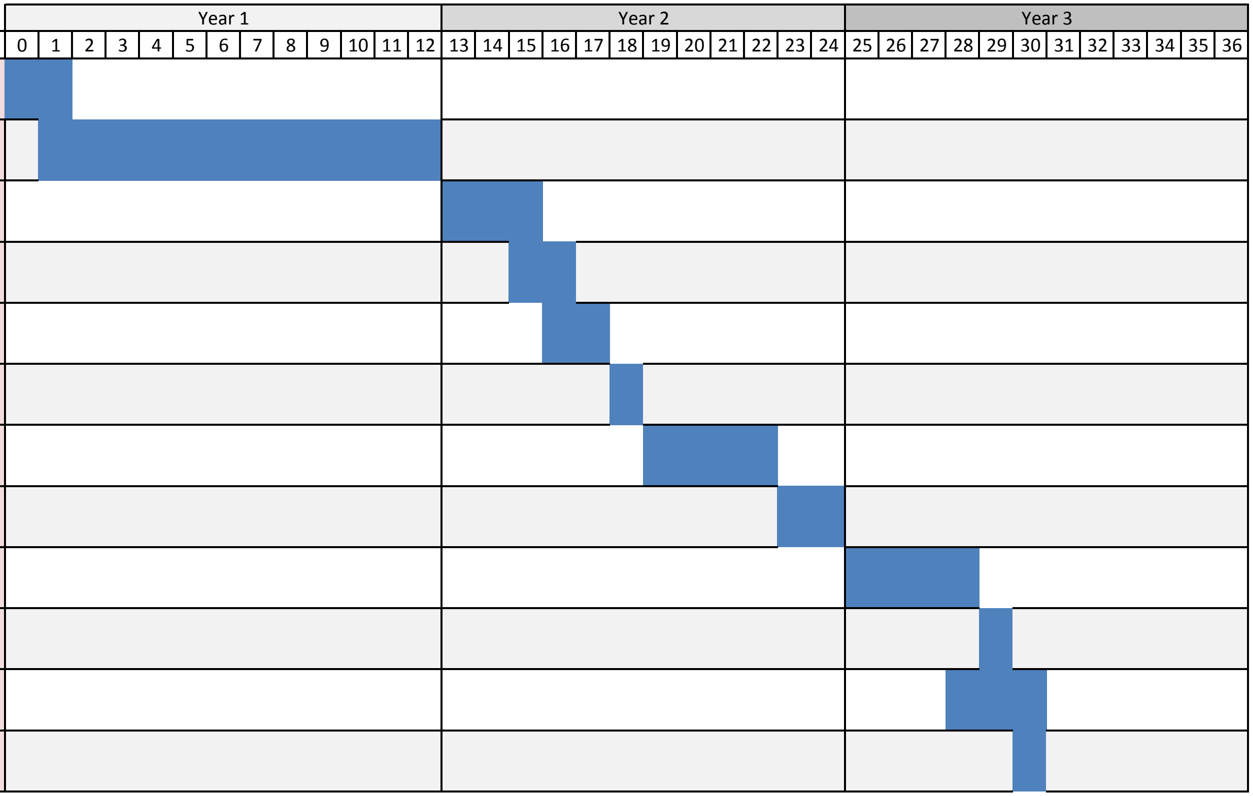
April 7, 2020

Attachment A-1.1

Fuel Switch Shut Down 3 Coal Boilers and Install Natural Gas Boilers

Time to Start-Up: 30 Months

Step	Task	Start	Duration	End
1	**Feasibility Study**	0	1	1
2	**ADEQ Review**	1	12	12
3	**Engineering Design**	13	3	15
4	**Capital Cost Estimate**	15	2	16
5	**Vendor Quotes**	16	2	17
6	**Selection of Equipment**	18	1	18
7	**Vendor Fulfillment**	19	4	22
8	**Equipment Delivery**	23	2	24
9	**FFCC Construction**	25	4	28
10	**Equipment Checkout**	29	1	29
11	**Operator Training**	28	3	30
12	**Start-Up**	30	0	30



Attachment A-1.2

Fuel Switch Shut Down 1 Coal Boiler and Install Natural Gas Boiler

Time to Start-Up: 24 Months

Step	Task	Start	Duration	End
1	Feasibility Study	0	1	1
2	ADEQ Review	1	12	12
3	Engineering Design	13	1	13
4	Capital Cost Estimate	13	1	14
5	Vendor Quotes	14	1	15
6	Selection of Equipment	15	1	16
7	Vendor Fulfillment	16	4	20
8	Equipment Delivery	20	2	22
9	FFCC Construction	19	4	23
10	Equipment Checkout	23	1	24
11	Operator Training	23	1	24
12	Start-Up	30	0	24

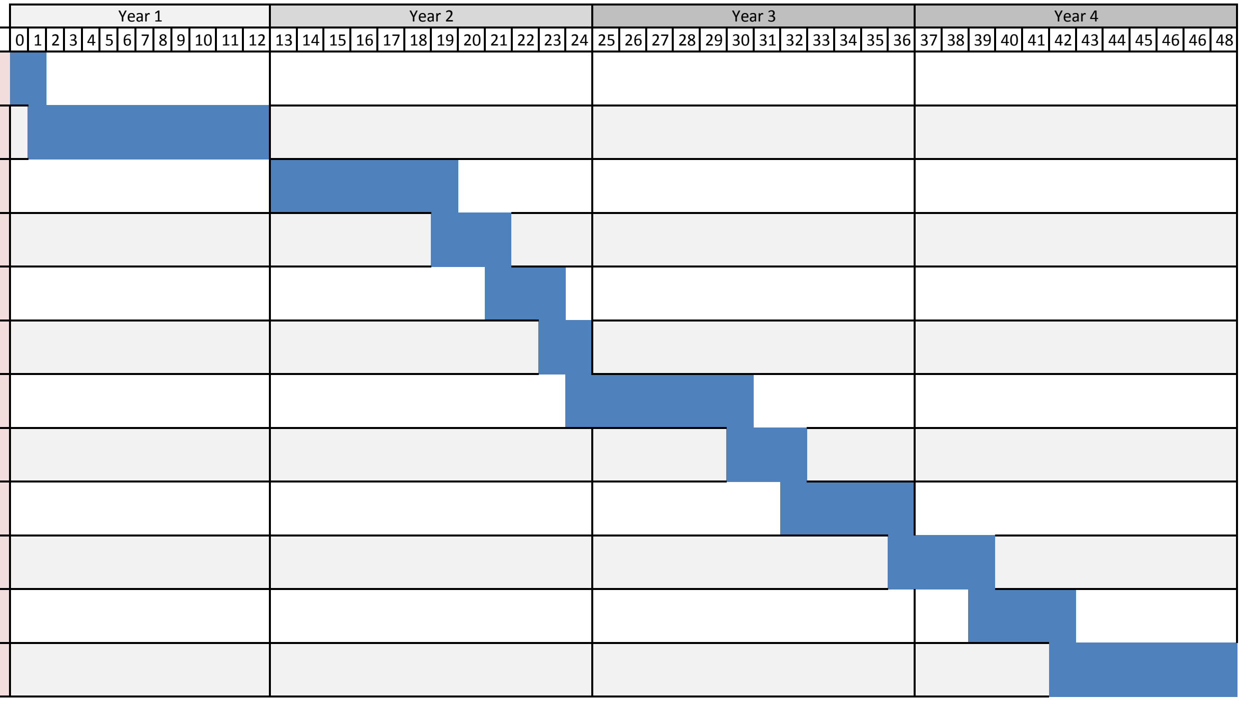
Year 1													Year 2											
0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24

Attachment A-1.3

Fuel Switch Convert 3 Coal Boilers to Natural Gas

Time to Start-Up: 42 Months

Step	Task	Start	Duration	End
1	**Feasibility Study**	0	1	1
2	**ADEQ Review**	1	12	12
3	**Engineering Design**	13	6	19
4	**Capital Cost Estimate**	19	2	21
5	**Vendor Quotes**	21	2	23
6	**Selection of Equipment**	23	1	24
7	**Vendor Fulfillment**	24	6	30
8	**Equipment Delivery**	30	2	32
9	**FFCC Construction**	32	6	38
10	**Equipment Checkout**	36	3	39
11	**Operator Training**	39	4	42
12	**Start-Up**	42	5	48

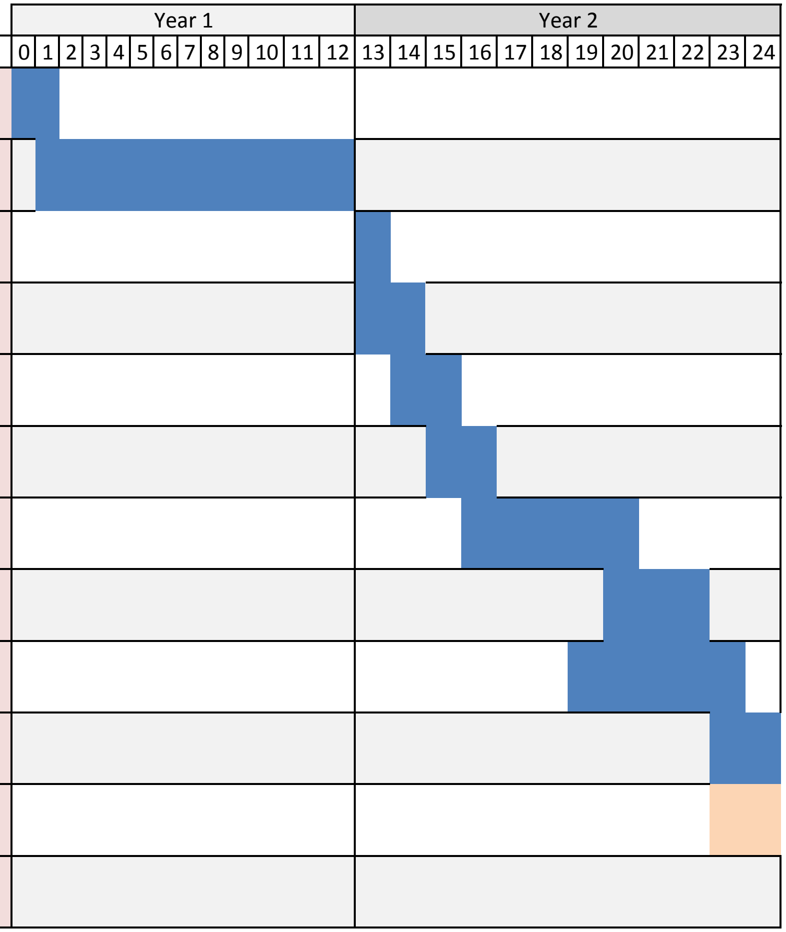


Attachment A-1.4

Fuel Switch Convert 1 Coal Boiler to Natural Gas

Time to Start-Up: 24 Months

Step	Task	Start	Duration	End
1	**Feasibility Study**	0	1	1
2	**ADEQ Review**	1	12	12
3	**Engineering Design**	13	1	13
4	**Capital Cost Estimate**	13	1	14
5	**Vendor Quotes**	14	1	15
6	**Selection of Equipment**	15	1	16
7	**Vendor Fulfillment**	16	4	20
8	**Equipment Delivery**	20	2	22
9	**FFCC Construction**	19	4	23
10	**Equipment Checkout**	23	1	24
11	**Operator Training**	23	1	24
12	**Start-Up**	30	0	24

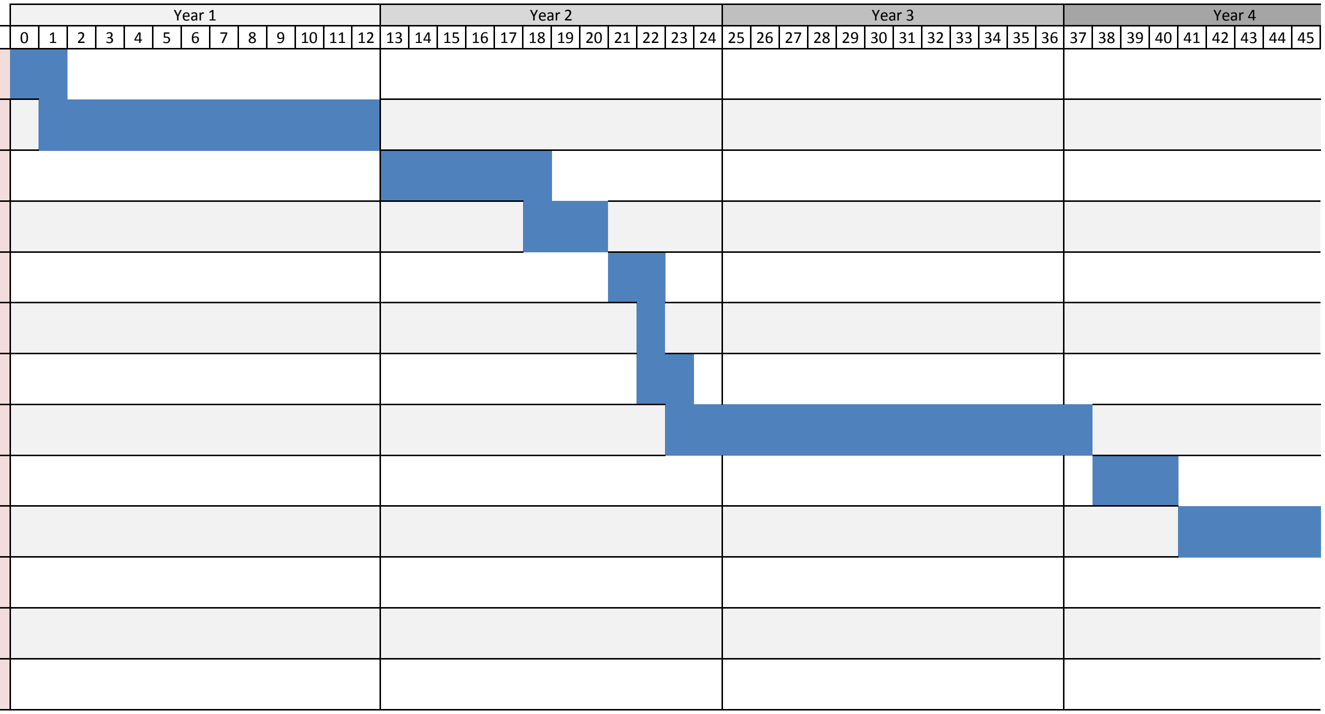


Attachment A-1.5

Wet Gas Scrubbers - Lime Slurry

Time to Start-Up: 72 Months

Step	**Task**	**Start**	**Duration**	**End**
1	**Feasibility Study**	0	1	1
2	**ADEQ Review**	1	12	12
3	**Engineering Design**	13	6	18
4	**Capital Cost Estimate**	18	3	20
5	**Vendor Quotes**	21	2	22
6	**Selection of Equipment**	22	1	22
7	**Demolition or Relocation of Existing Structures**	22	2	23
8	**Vendor Fulfillment**	23	15	37
9	**Equipment Delivery**	38	3	40
10	**FFCC Construction**	41	30	70
11	**Equipment Checkout**	71	1	71
12	**Operator Training**	70	3	72
13	**Start-Up**	72	0	72



Attachment A-1.5

Wet Gas Scrubbers - Lime Slurry

Time to Start-Up: 72 Months

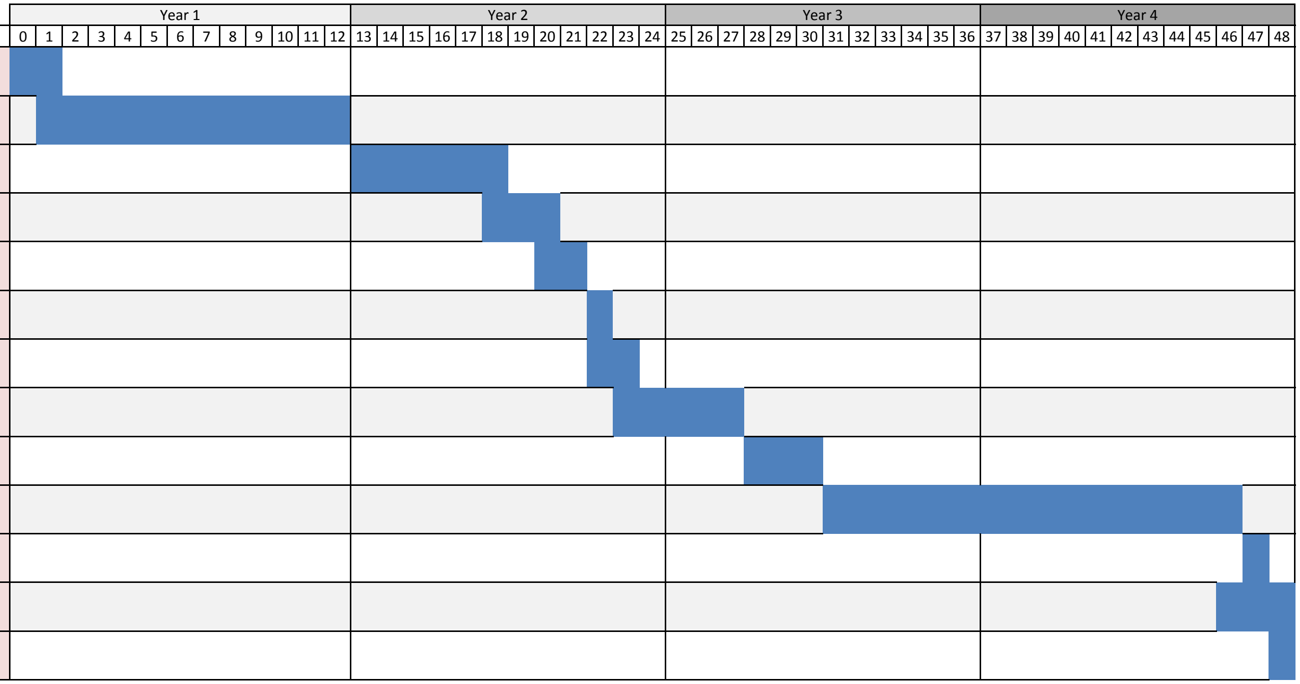
								Year 5												Year 6											
Step	**Task**	**Start**	**Duration**	**End**	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60	61	62	63	64	65	66	67	68	69	70	71	72
1	**Feasibility Study**	0	1	1																											
2	**ADEQ Review**	1	12	12																											
3	**Engineering Design**	13	6	18																											
4	**Capital Cost Estimate**	18	3	20																											
5	**Vendor Quotes**	21	2	22																											
6	**Selection of Equipment**	22	1	22																											
7	**Demolition or Relocation of Existing Structures**	22	2	23																											
8	**Vendor Fulfillment**	23	15	37																											
9	**Equipment Delivery**	38	3	40																											
10	**FFCC Construction**	41	30	70																											
11	**Equipment Checkout**	71	1	71																											
12	**Operator Training**	70	3	72																											
13	**Start-Up**	72	0	72																											

Attachment A-1.6

Spray Dry Absorption

Time to Start-Up: 48 Months

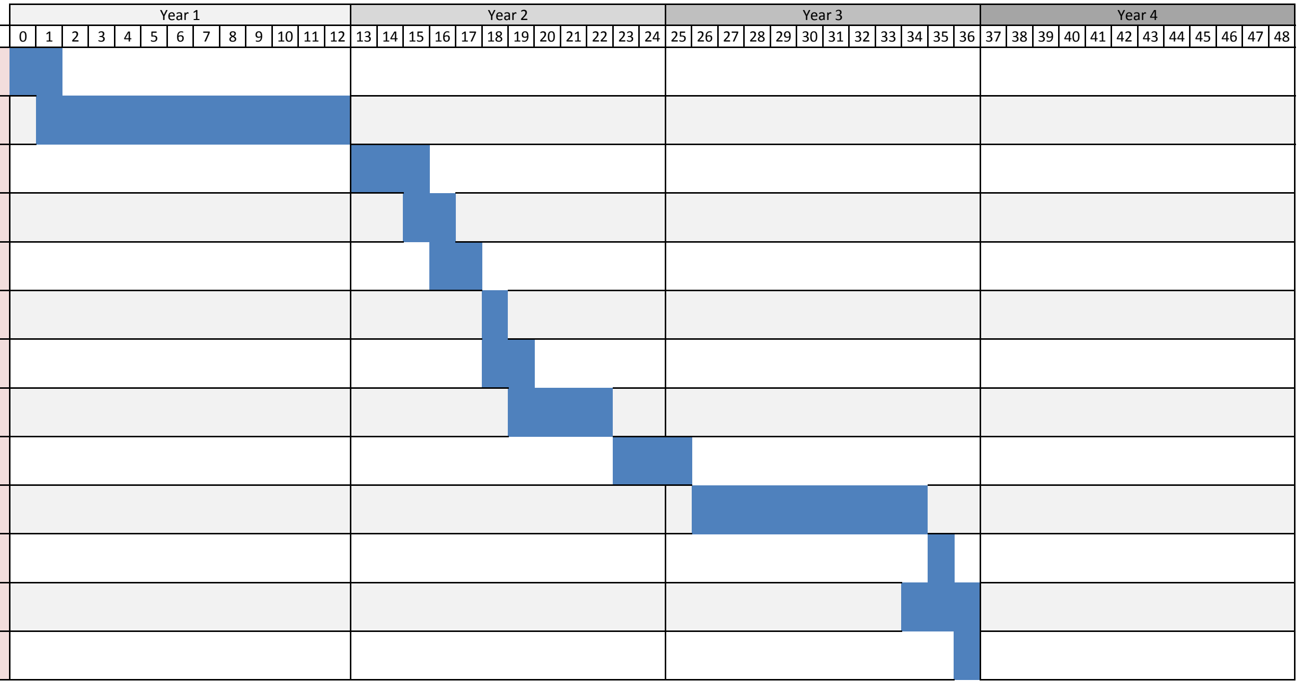
Step	Task	Start	Duration	End
1	**Feasibility Study**	0	1	1
2	**ADEQ Review**	1	12	12
3	**Engineering Design**	13	6	18
4	**Capital Cost Estimate**	18	3	20
5	**Vendor Quotes**	20	2	21
6	**Selection of Equipment**	22	1	22
7	**Demolition or Relocation of Existing Structures**	22	2	23
8	**Vendor Fulfillment**	23	5	27
9	**Equipment Delivery**	28	3	30
10	**FFCC Construction**	31	16	46
11	**Equipment Checkout**	47	1	47
12	**Operator Training**	46	3	48
13	**Start-Up**	48	0	48



Attachment A-1.7
Dry Sorbent Injection

Time to Start-Up: 36 Months

Step	Task	Start	Duration	End
1	Feasibility Study	0	1	1
2	ADEQ Review	1	12	12
3	Engineering Design	13	3	15
4	Capital Cost Estimate	15	2	16
5	Vendor Quotes	16	2	17
6	Selection of Equipment	18	1	18
7	Demolition or Relocation of Existing Structures	18	2	19
8	Vendor Fulfillment	19	4	22
9	Equipment Delivery	23	3	25
10	FFCC Construction	26	9	34
11	Equipment Checkout	35	1	35
12	Operator Training	34	3	36
13	Start-Up	36	0	36



ATTACHMENT A-1.8

RESERVED

ATTACHMENT A-1.9

RESERVED

ATTACHMENT A-1.10

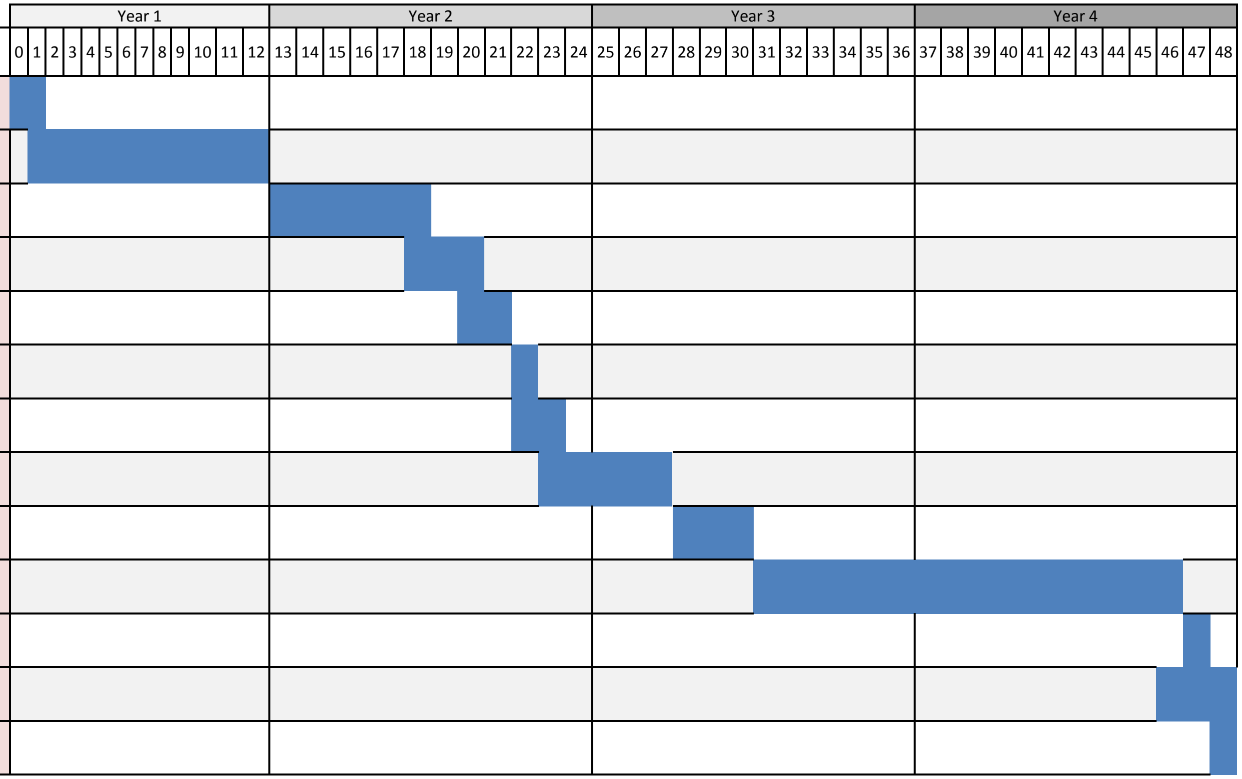
RESERVED

Attachment A-1.11

Selective Catalytic Reduction

Time to Start-Up: 48 Months

Step	Task	Start	Duration	End
1	Feasibility Study	0	1	1
2	ADEQ Review	1	12	12
3	Engineering Design	13	6	18
4	Capital Cost Estimate	18	3	20
5	Vendor Quotes	20	2	21
6	Selection of Equipment	22	1	22
7	Demolition or Relocation of	22	2	23
8	Vendor Fulfillment	23	5	27
9	Equipment Delivery	28	3	30
10	FFCC Construction	31	16	46
11	Equipment Checkout	47	1	47
12	Operator Training	46	3	48
13	Start-Up	48	0	48

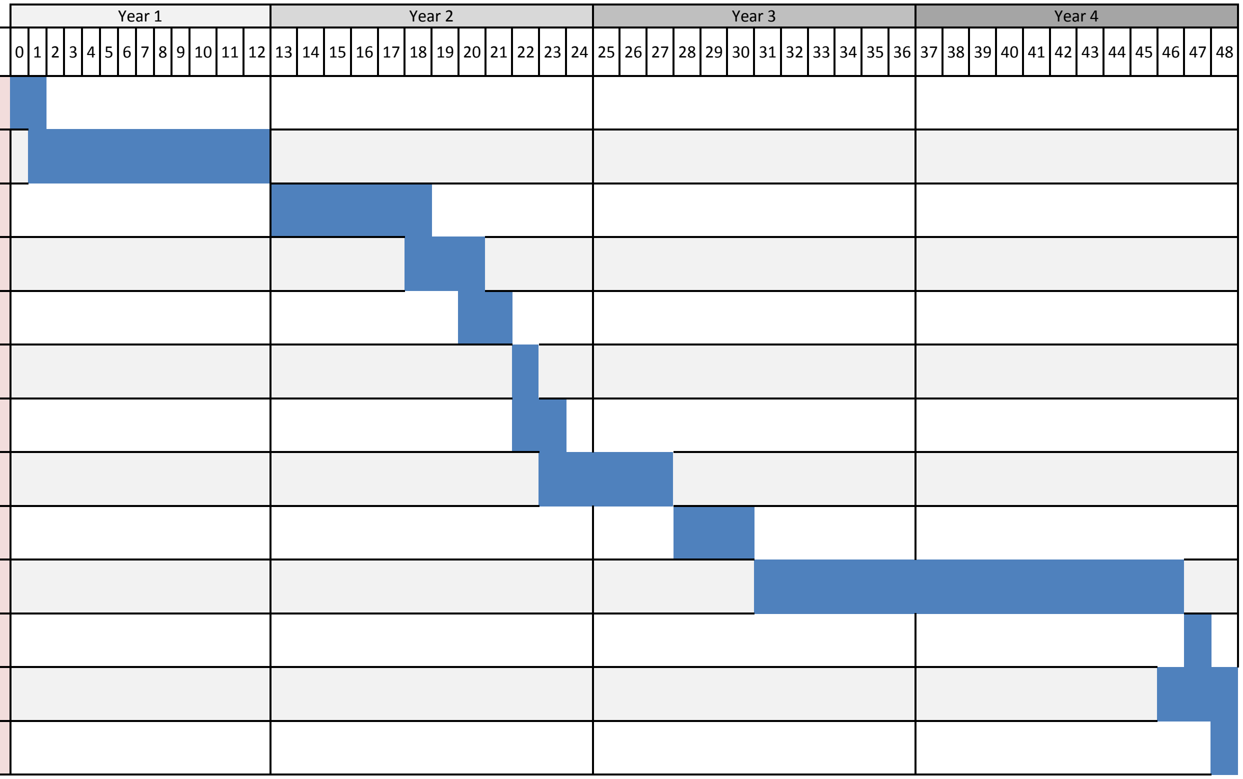


Attachment A-1.12

Selective Non-catalytic Reduction

Time to Start-Up: 48 Months

Step	Task	Start	Duration	End
1	Feasibility Study	0	1	1
2	ADEQ Review	1	12	12
3	Engineering Design	13	6	18
4	Capital Cost Estimate	18	3	20
5	Vendor Quotes	20	2	21
6	Selection of Equipment	22	1	22
7	Demolition or Relocation of Existing Structures	22	2	23
8	Vendor Fulfillment	23	5	27
9	Equipment Delivery	28	3	30
10	FFCC Construction	31	16	46
11	Equipment Checkout	47	1	47
12	Operator Training	46	3	48
13	Start-Up	48	0	48



Attachment B

Emission Reduction Strategy Cost Analysis

Revision 0

Pursuant to

DEQ Information Collection Request dated January 8, 2020

AFIN 32-00036

FutureFuel Chemical Company
P.O. Box 2357
Batesville, AR 72503
ARD089234884

April 7, 2020

Attachment B-1.1

FFCC SO_2/NO_x Emission Reduction Strategy
Fuel Switch - Replace All Coal Boilers with Natural Gas

Cost Item		Cost Estimate	Reference
Capital Costs			
Two 75 KPPH, 600 PSIG, Gas-Fired Water Tube Boilers	=	$3,000,000	- Budgetary Quote B&W - $1.5 mm each
Civil	=	$900,000	- Equipment configuration per FFCC proposed general Layout
Piping	=	$1,620,000	
Eletrical and Instrument	=	$1,620,000	- Costs based on similar existing facilities & equipment quotes
Engineering	=	$690,000	
Project Management	=	$270,000	- Estimate Resources FFCC & Vendors
30% Contigency	=	$2,430,000	- 30% Contingency from EPA Manual
Total Capitaal Costs	=	$10,530,000	
Energy and Non-Environmental Capital Costs			
Start-Up Training	=	$30,000	
Plant Shutdown for Tie-ins	=	$2,899,000	
Boiler Hazardous Waste Closure Costs	=	$162,485	RCRA 2020 Closure Cost
Total Energy and Non-Environmental Capital Costs	=	$3,091,485	
Annual Operating and Maintenance Costs			
Natural Gas Costs	=	$4,086,385	Similar Onsite Unit
Electrical Costs	=	$407,735	Similar Onsite Unit
Maintenance Costs	=	$111,585	Similar Onsite Unit
Operating And Support Labor Costs	=	$251,776	Similar Onsite Unit
Permitting and Compliance Costs	=	$8,642	Similar Onsite Unit
Offsite Liquid Waste Disposal Costs	=	$25,396,988	Based on known offsite disposal costs
Offsite Dewatered Sludge Disposal Costs	=	$205,086	Based on known offsite disposal costs
Offsite Disposal Support Labor Costs	=	$129,632	Logistical offsite labor cost estimate
Total Annual Operting and Maintenace Costs	=	$30,597,829	
Indirect Annual costs			
Overhead	=	$218,016	Cost Control Manual
Administrative Charges	=	$364,005	Cost Control Manual
Property Tax	=	$182,003	Cost Control Manual
Insurance	=	$182,003	Cost Control Manual
Capital Recovery	=	$1,097,892	Cost Control Manual
Total Annual Indirect Costs	=	$2,043,919	
Total Strategy Annual Costs			
Annual Operting and Maintenace Costs	=	$30,597,829	
Annual Indirect Costs	=	$2,043,919	
Total Strategy Annual Costs	=	$32,641,748	
Cost per Ton of SO2 Reduced			
Total Uncontrolled SO2 and NOx Emissions (ton/yr)	=	3216	Based on maximum monthly value, annualized for years 2017- 2019
Total Controlled SO2 and NOx Emissions (ton/yr)	=	62	
Total SO2 and NOx Emission Reduction (ton/yr)	=	3154	
Emission Reduction , $/Ton Reduced	**=**	**$10,349**	

Attachment B-1.2

FFCC SO_2/NO_x Emission Reduction Strategy
Fuel Switch - Replace One Coal Boiler with Natural Gas

Cost Item		Cost Estimate	Reference
Capital Costs			
One 75 KPPH, 600 PSIG, Gas-Fired Water Tube Boilers	=	$1,500,000	- Proprietary Quote from Vendor
Civil	=	$450,000	- Equipment configuration per FFCC proposed general Layout
Piping	=	$810,000	
Eletrical and Instrument	=	$810,000	- Costs based on similar existing facilities & equipment quotes
Engineering	=	$345,000	
Project Management	=	$135,000	- Estimate Resources FFCC & Vendors
30% Contigency	=	$1,215,000	- 30% Contingency from EPA Manual
Total Capitaal Costs	=	$5,265,000	

Energy and Non-Environmental Capital Costs			
Start-Up Training	=	$30,000	
Plant Shutdown for Tie-ins	=	$2,899,000	
Boiler Hazardous Waste Closure Costs	=	$54,162	RCRA 2020 Closure Cost
Total Energy and Non-Environmental Capital Costs	=	$2,983,162	

Annual Operating and Maintenance Costs			
Natural Gas Costs	=	$1,916,532	Similar Onsite Unit
Electrical Costs	=	$152,901	Similar Onsite Unit
Maintenance Costs	=	$42,173	Similar Onsite Unit
Operating And Support Labor Costs	=	$251,776	Similar Onsite Unit
Permitting and Compliance Costs	=	$8,642	Similar Onsite Unit
Offsite Liquid Waste Disposal Costs	=	$8,465,663	Based on known offsite disposal costs
Offsite Dewatered Sludge Disposal Costs	=	$68,363	Based on known offsite disposal costs
Offsite Disposal Support Labor Costs	=	$25,926	Logistical offsite labor support
Total Annual Operting and Maintenace Costs	=	$10,931,976	

Indirect Annual costs			
Overhead	=	$176,370	Cost Control Manual
Administrative Charges	=	$182,003	Cost Control Manual
Property Tax	=	$91,001	Cost Control Manual
Insurance	=	$91,001	Cost Control Manual
Capital Recovery	=	$664,802	Cost Control Manual
Total Annual Indirect Costs	=	$1,205,177	

Total Strategy Annual Costs			
Annual Operting and Maintenace Costs	=	$10,931,976	
Annual Indirect Costs	=	$1,205,177	
Total Strategy Annual Costs	=	$12,137,153	

Cost per Ton of SO2 Reduced			
Total Uncontrolled SO2 and NOx Emissions (ton/yr)	=	3216	Based on maximum monthly value, annualized for years 2017- 2019
Total Controlled SO2 and NOx Emissions (ton/yr)	=	2155	
Total SO2 and NOx Emission Reduction (ton/yr)	=	1061	
Emission Reduction , $/Ton Reduced	**=**	**$11,439**	

Attachment B-1.3

FFCC SO_2/NO_x Emission Reduction Strategy
Fuel Switch - Retrofit 3-Coal Boilers to Natural Gas

Cost Item		Cost Estimate	Reference
Capital Costs			
Three 50 KPPH Steam Conversion Gas Boiler	=	$1,232,100	
Mechanical Installation of Gas Boilers	=	$2,171,700	Vender-D Budgetary Proposal
Electrical and Instruments	=	$812,100	
Thermal Modeling	=	$153,900	
Boiler Tube and Refractory Replacement	=	$3,135,000	Vendor-P Budgetary Proposal
Project Management	=	$50,000	- Estimate Resources FFCC
30% Contigency	=	$2,266,440	- 30% Contingency from EPA Manual
Total Capital Costs	=	$9,821,240	
Energy and Non-Environmental Capital Costs			
Start-Up Training	=	$30,000	
Plant Shutdown for Tie-ins	=	$2,899,000	
Boiler Hazardous Waste Closure Costs	=	$162,485	RCRA 2020 Closure Cost
Total Energy and Non-Environmental Capital Costs	=	$3,091,485	
Annual Operating and Maintenance Costs			
Natural Gas Costs	=	$4,086,385	Similar Onsite Unit
Electrical Costs	=	$407,735	Similar Onsite Unit
Maintenance Costs	=	$111,585	Similar Onsite Unit
Operating And Support Labor Costs	=	$251,776	Similar Onsite Unit
Permitting and Compliance Costs	=	$8,642	Similar Onsite Unit
Offsite Liquid Waste Disposal Costs	=	$25,396,988	Based on known offsite disposal costs
Offsite Dewatered Sludge Disposal Costs	=	$205,086	Based on known offsite disposal costs
Offsite Disposal Support Labor Costs	=	$129,632	Logistical offsite labor support
Total Annual Operting and Maintenace Costs	=	$30,597,829	
Indirect Annual costs			
Overhead	=	$218,016	Cost Control Manual
Administrative Charges	=	$331,630	Cost Control Manual
Property Tax	=	$165,816	Cost Control Manual
Insurance	=	$165,816	Cost Control Manual
Capital Recovery	=	$1,040,766	Cost Control Manual
Total Annual Indirect Costs	=	$1,922,044	
Total Strategy Annual Costs			
Annual Operting and Maintenace Costs	=	$30,597,829	
Annual Indirect Costs	=	$1,922,044	
Total Strategy Annual Costs	=	$32,519,873	
Cost per Ton of SO2 Reduced			
Total Uncontrolled SO2 and NOx Emissions (ton/yr)	=	3216	Based on maximum monthly value, annualized for years 2017- 2019
Total Controlled SO2 and NOx Emissions (ton/yr)	=	62	
Total SO2 and NOx Emission Reduction (ton/yr)	=	3154	
Emission Reduction , $/Ton Reduced	**=**	**$10,311**	

Attachment B-1.4

FFCC SO_2/NO_x Emission Reduction Strategy

Fuel Switch - Retrofit One Coal Boiler to Natural Gas

Cost Item		Cost Estimate	Reference
Capital Costs			
One 50 KPPH Steam Conversion Gas Boiler	=	$410,700	Vender-D Budgetary Proposal
Mechanical Installation of Gas Boiler	=	$723,900	
Electrical and Instruments	=	$270,700	
Thermal Modeling	=	$51,300	
Boiler Tube and Refractory Replacement	=	$1,045,000	Vendor-P Budgetary Proposal
Project Management	=	$25,000	- Estimate Resources FFCC
30% Contigency	=	$757,980	- 30% Contingency from EPA Manual
Total Capitaal Costs	=	$3,284,580	
Energy and Non-Environmental Capital Costs			
Start-Up Training	=	$30,000	
Plant Shutdown for Tie-ins	=	$2,899,000	
Boiler Hazardous Waste Closure Costs	=	$54,162	RCRA 2020 Closure Cost
Total Energy and Non-Environmental Capital Costs	=	$2,983,162	
Annual Operating and Maintenance Costs			
Natural Gas Costs	=	$1,916,532	Similar Onsite Unit
Electrical Costs	=	$152,901	Similar Onsite Unit
Maintenance Costs	=	$42,173	Similar Onsite Unit
Operating And Support Labor Costs	=	$251,776	Similar Onsite Unit
Permitting and Compliance Costs	=	$8,642	Similar Onsite Unit
Offsite Liquid Waste Disposal Costs	=	$8,465,663	Based on known offsite disposal costs
Offsite Dewatered Sludge Disposal Costs	=	$68,363	Based on known offsite disposal costs
Offsite Disposal Support Labor Costs	=	$25,926	Logistical offsite labor support
Total Annual Operting and Maintenace Costs	=	$10,931,976	
Indirect Annual costs			
Overhead	=	$176,370	Cost Control Manual
Administrative Charges	=	$110,918	Cost Control Manual
Property Tax	=	$55,460	Cost Control Manual
Insurance	=	$55,460	Cost Control Manual
Capital Recovery	=	$505,180	Cost Control Manual
Total Annual Indirect Costs	=	$903,388	
Total Strategy Annual Costs			
Annual Operting and Maintenace Costs	=	$10,931,976	
Annual Indirect Costs	=	$903,388	
Total Strategy Annual Costs	=	$11,835,364	
Cost per Ton of SO2 Reduced			
Total Uncontrolled SO2 and NOx Emissions (ton/yr)	=	3216	Based on maximum monthly value, annualized for years 2017- 2019
Total Controlled SO2 and NOx Emissions (ton/yr)	=	2155	
Total SO2 and NOx Emission Reduction (ton/yr)	=	1061	
Emission Reduction , $/Ton Reduced	**=**	**$11,155**	

Attachment B-1.5

FFCC SO_2 Emission Reduction Strategy
Wet Scrubber

Cost Item		Cost Estimate	Reference
Capital Costs			
Equipment Base Absorber Island Cost	=	$8,524,883	IPM Model
Base Module Reagent Preparation	=	$4,833,436	IPM Model
Base Waste Handing Cost.	=	$3,344,731	IPM Model
Balance of cost including booster fans, ductwork, piping, etc.	=	$15,405,909	IPM Model
Engineering and construction management	=	$3,185,896	IPM Model
Contractor profit and fees	=	$3,185,896	IPM Model
Labor Adjustment	=	$3,185,896	IPM Model
Owner's Costs	=	$2,070,832	IPM Model
Allowaance for Funds used during Construction	=	$4,348,748	IPM Model
Demo old control room	=	$1,000,000	FFC Estimate
Line from scrubber to WWT	=	$700,000	FFC Estimate
Tank, Sulfuric Acid Line, pH Control	=	$1,000,000	FFC Estimate
30% Contigency	=	$15,235,868	IPM Model
Total Capital Costs	=	$66,022,096	
Energy and Non-Air Quality Environmental Costs			
Boiler Rental During Tie-ins	=	$3,740,000	Vendor Quotes
Plant Shutdown for Tie-ins	=	$2,899,000	
Off Site Disposal During Tie-ins	=	$6,781,728	Vendor Quotes
Total Energy and Non-Environmental Capital Costs	=	$13,420,728	
Annual Operating and Maintenance Costs			
Fixed Additional Operating Labor Costs	=	$2,166,649	IPM Model
Fixed Additional Maintenance labor and materials	=	$448,041	IPM Model
Additional Adminstrative labor Costs	=	$70,376	IPM Model
Variable Sorbant Cost	=	$6,742	IPM Model
Variable Cost Waste Disposal of Sorbant	=	$332,983	IPM Model
Variable Cost of Additional Power, Makeup water and Sulfuric Acid	=	$18,424	IPM Model
Total Annual Operting and Maintenace Costs	=	$3,043,215	
Indirect Annual Costs			
Overhead	=	$1,611,040	IPM Model
Adminstrative Charges	=	$1,910,346	IPM Model
Property Tax	=	$955,173	IPM Model
Insurance	=	$995,173	IPM Model
Capital Recovery	=	$8,722,822	IPM Model
Total Annual Indirect Costs	=	$14,194,554	
Total Strategy Annual Costs			
Annual Operting and Maintenace Costs	=	$3,043,215	
Annual Indirect Costs	=	$14,194,554	
Total Strategy Annual Costs	=	$17,237,769	
Cost per Ton of SO_2 Removed			
Total Uncontrolled SO_2 Emissions, Tons/yr	=	2,884	Maxium monthly
SO_2 Removal Efficiency, %	=	94	value in period
Total SO_2 Removed, Tons/yr	=	2,711	2017-2019 annualized
SO_2 Effectiveness, $/Ton SO_2 Removed	=	$6,358	

Attachement B-1.6

FFCC SO_2 Emission Reduction Strategy
Spray Dry Absorber

Cost Item		Cost Estimate	Reference
<u>Capital Costs</u>			
Equipment Base Module Absorber Island Cost	=	$8,614,265	IPM Model
Base Module reagent preparation and waste handling	=	$6,358,937	IPM Model
Base Module balance of costs including booster fans piping ductwork etc.	=	$12,239,675	IPM Model
Labor Adjustments	=	$2,696,287	IPM Model
Engineering and construction management	=	$2,696,287	IPM Model
Contractor profit and fees	=	$2,696,287	IPM Model
Owner's Cost	=	$1,752,587	IPM Model
Allowaance for Funds used during Construction	=	$3,680,433	IPM Model
Demo old control room	=	$1,000,000	FFC Estimate
30% Contigency	=	$12,520,428	IPM Model
Total Capital Costs	=	$54,255,187	
<u>Energy and Non-Air Quality Environmental Costs</u>			
Boiler Rental During Tie-ins	=	$3,740,000	Vendor Quotes
Plant Shutdown for Tie-ins	=	$2,899,000	
Off Site Disposal During Tie-ins	=	$6,781,728	Vendor Quotes
Total Energy and Non-Environmental Capital Costs	=	$13,420,728	
<u>Annual Operating and Maintenance Costs</u>			
Fixed Additional Operating Labor Costs	=	$1,444,433	IPM Model
Fixed Additional Maintenance labor and materials	=	$173,063	IPM Model
Additional Adminstrative labor Costs	=	$45,410	IPM Model
Variable Sorbant Cost	=	$6,763	IPM Model
Variable Cost Waste Disposal of Sorbant	=	$379,506	IPM Model
Variable Cost Additional Power and Make Up Water	=	$9,750	IPM Model
Total Annual Operting and Maintenace Costs	=	$2,058,925	
<u>Indirect Annual Costs</u>			
Overhead	=	$997,744	IPM Model
Adminstrative Charges	=	$1,569,872	IPM Model
Property Tax	=	$784,936	IPM Model
Insurance	=	$784,936	IPM Model
Capital Recovery	=	$7,430,815	IPM Model
Total Annual Indirect Costs	=	$11,568,303	
<u>Total Strategy Annual Costs</u>			
Annual Operting and Maintenace Costs	=	$2,058,925	
Annual Indirect Costs	=	$11,568,303	
Total Strategy Annual Costs	=	$13,627,228	
<u>Cost per Ton of SO_2 Removed</u>			
Total Uncontrolled SO_2 Emissions, Tons/yr	=	2,884	Maxium monthly value
SO_2 Removal Efficiency, %	=	92	in period
Total SO_2 Removed, Tons/yr	=	2,653	2017-2019 annualized
SO_2 Effectiveness, $/Ton SO_2 Removed	=	$5,137	

Attachment B-1.7

FFCC SO_2 Emission Reduction Strategy
Dry Sorbant Injection

Cost Item		Cost Estimate	Reference
Capital Costs			
Equipment Base DSI Module from unloading to injection	=	$26,651,221	IPM Model
Labor adjustment	=	$2,640,122	IPM Model
Contractor proffit and fees	=	$2,640,122	IPM Model
Owner's costs (owner's engineering, management, and procurement)	=	$1,716,079	IPM Model
Engineering	=	$2,640,122	IPM Model
Demo old control room	=	$1,000,000	FFC Estimate
30% Contigency	=	$11,186,300	IPM Model
Total Capital Costs	=	$48,473,967	
Energy and Non-Air Quality Environmental Costs			
Boiler Rental During Tie-ins	=	$3,740,000	Vendor Quotes
Plant Shutdown for Tie-ins	=	$2,899,000	
Off Site Disposal During Tie-ins	=	$6,781,728	Vendor Quotes
Total Energy and Non-Environmental Capital Costs	=	$13,420,728	
Annual Operating and Maintenance Costs			
Fixed Additional Operating Labor Costs	=	$361,108	IPM Model
Fixed Additional Maintenance labor and materials	=	$112,972	IPM Model
Additional Adminstrative labor Costs	=	$12,189	IPM Model
Variable Sorbant Cost	=	$18,206	IPM Model
Variable Cost Waste Disposal of Sorbant	=	$397,132	IPM Model
Variable Cost Additional Power	=	$19,860	IPM Model
Total Annual Operting and Maintenace Costs	=	$921,467	
Indirect Annual Costs			
Overhead	=	$291,762	IPM Model
Adminstrative Charges	=	$1,402,592	IPM Model
Property Tax	=	$701,297	IPM Model
Insurance	=	$701,297	IPM Model
Capital Recovery	=	$6,796,038	IPM Model
Total Annual Indirect Costs	=	$9,892,986	
Total Strategy Annual Costs			
Annual Operting and Maintenace Costs	=	$921,467	
Annual Indirect Costs	=	$9,892,986	
Total Strategy Annual Costs	=	$10,814,453	
Cost per Ton of SO_2 Removed			
Total Uncontrolled SO_2 Emissions, Tons/yr	=	2,884	period
SO_2 Removal Efficiency, %	=	40	2017-2019 annualized
Total SO_2 Removed, Tons/yr	=	1,154	
SO_2 Effectiveness, $/Ton SO_2 Removed	=	$9,371	

Attachment B-1.8

FFCC SO_2 Emission Reduction Strategy
Fuel Switch - Lower Sulfur Coal (2.5%)

Cost Item		Cost Estimate	Reference
Capital Costs			
Total Capitaal Costs	=	$0	Do not anticipate any capital costs
Energy and Non-Environmental Capital Costs			
Total Energy and Non-Environmental Capital Costs	=	$0	Do not anticipate any front end costs
Annual Operating and Maintenance Costs			
Cost Increase for 2.5% coal	=	$1,064,016	Coal Increase Cost
Coal Usage Tax	=	$85,121	Coal Usage Tax
Total Annual Operting and Maintenace Costs	=	$1,149,137	
Indirect Annual costs			
Total Annual Indirect Costs	=	$0	
SO2 Emission Summary			
Total Uncontrolled SO2 and NOx Emissions (ton/yr)	=	2884	Based on maximum monthly value, annualized for years 2017- 2019
Total Controlled SO2 and NOx Emissions (ton/yr)	=	2394	
Total SO2 and NOx Emission Reduction (ton/yr)	=	490	
Cost per Ton of SO2 Reduced			
Total Annual Costs	=	$1,149,137	
Total SO2 Emission Reduction (ton/yr)	=	490	
SO2 Emission Reduction , $/Ton Reduced	**=**	**$2,345**	

Attachment B-1.9

FFCC SO_2 Emission Reduction Strategy

Fuel Switch - Lower Sulfur Coal (2.0%)

Cost Item		Cost Estimate	Reference
Capital Costs			
Total Capitaal Costs	=	$0	Do not anticipate any capital costs
Energy and Non-Environmental Capital Costs			
Total Energy and Non-Environmental Capital Costs	=	$0	Do not anticipate any front end costs
Annual Operating and Maintenance Costs			
Cost Increase for 2.0% coal	=	$1,847,250	Coal Increase Cost
Coal Usage Tax	=	$147,780	Coal Usage Tax
Total Annual Operting and Maintenace Costs	=	$1,995,030	
Indirect Annual costs			
Total Annual Indirect Costs	=	$0	
SO2 Emission Summary			
Total Uncontrolled SO2 and NOx Emissions (ton/yr)	=	2884	Based on maximum monthly value, annualized for years 2017- 2019
Total Controlled SO2 and NOx Emissions (ton/yr)	=	1932	
Total SO2 and NOx Emission Reduction (ton/yr)	=	952	
Cost per Ton of SO2 Reduced			
Total Annual Costs	=	$1,995,030	
Total SO2 Emission Reduction (ton/yr)	=	952	
SO2 Emission Reduction , $/Ton Reduced	**=**	**$2,096**	

Attachment B-1.10

FFCC SO_2 Emission Reduction Strategy
Fuel Switch - Lower Sulfur Coal (1.5%)

Cost Item		Cost Estimate	Reference
Capital Costs			
Total Capitaal Costs	=	$0	Do not anticipate any capital costs
Energy and Non-Environmental Capital Costs			
Total Energy and Non-Environmental Capital Costs	=	$0	Do not anticipate any front end costs
Annual Operating and Maintenance Costs			
Cost Increase for 1.5% coal	=	$3,919,281	Coal Increase Cost
Cost Increase for 1.5% coal	=	$313,542	Coal Usage Tax
Total Annual Operting and Maintenace Costs	=	$4,232,823	
Indirect Annual costs			
Total Annual Indirect Costs	=	$0	
SO2 Emission Summary			
Total Uncontrolled SO2 and NOx Emissions (ton/yr)	=	2884	Based on maximum monthly value, annualized for years 2017- 2019
Total Controlled SO2 and NOx Emissions (ton/yr)	=	1442	
Total SO2 and NOx Emission Reduction (ton/yr)	=	1442	
Cost per Ton of SO2 Reduced			
Total Annual Costs	=	$4,232,823	
Total SO2 Emission Reduction (ton/yr)	=	1442	
SO2 Emission Reduction , $/Ton Reduced	**=**	**$2,935**	

Attachment B-1.11

FFCC NO_x Emission Reduction Strategy
Selective Catalytic Reduction

Cost Item		Cost Estimate	Reference
Capital Costs			
Capital for SCR	=	$11,696,397	Cost Control Manual
Reagent Preparation Cost	=	$5,105,005	Cost Control Manual
Air Pre-Heater Cost	=	$2,031,974	Cost Control Manual
Balance of Plant Costs	=	$5,271,181	Cost Control Manual
Demo old control room	=	$1,000,000	FFC Estimate
30% Contigency	=	$7,531,367	Cost Control Manual
Total Capital Costs	=	$32,635,925	

Energy and Non-Air Quality Environmental Costs			
Boiler Rental During Tie-ins	=	$3,740,000	Vendor Quotes
Plant Shutdown for Tie-ins	=	$2,899,000	
Off Site Disposal During Tie-ins	=	$6,781,728	Vendor Quotes
Total Energy and Non-Environmental Capital Costs	=	$13,420,728	

Annual Operating and Maintenance Costs			
Maintenance Cost	=	$239,320	Cost Control Manual
Reagent Cost	=	$216,051	Cost Control Manual
Electricity Cost	=	$66,018	Cost Control Manual
Catalyst Replacement Cost	=	$19,664	Cost Control Manual
Total Annual Operting and Maintenace Costs	=	$541,053	

Indirect Annual Costs			
Adminstrative Charges	=	$4,351	Cost Control Manual
Capital Recovery	=	$4,163,521	Cost Control Manual
Total Annual Indirect Costs	=	$4,167,872	

Total Strategy Annual Costs			
Annual Operting and Maintenace Costs	=	$541,053	
Annual Indirect Costs	=	$4,167,872	
Total Strategy Annual Costs	=	$4,708,925	

Cost per Ton of SO_2 Removed			
Total Uncontrolled NOx Emissions, Tons/yr	=	332	Maxium monthly
NOx Removal Efficiency, %	=	80	value in period
Total NOx Removed, Tons/yr	=	266	2017-2019 annualized
NOx Effectiveness, $/Ton NOx Removed	=	$17,703	

Attachment B-1.12

FFCC NO_x Emission Reduction Strategy
Selective Non-Catalytic Reduction

Cost Item		Cost Estimate	Reference
Capital Costs			
Capital for SCR	=	$2,352,725	Cost Control Manual
Air Pre-Heater Cost	=	$1,956,098	Cost Control Manual
Balance of Plant Costs	=	$2,670,915	Cost Control Manual
Demo old control room	=	$1,000,000	FFC Estimate
30% Contigency	=	$2,393,921	Cost Control Manual
Total Capital Costs	=	$10,373,659	

Energy and Non-Air Quality Environmental Costs			
Boiler Rental During Tie-ins	=	$3,740,000	Vendor Quotes
Plant Shutdown for Tie-ins	=	$2,899,000	
Off Site Disposal During Tie-ins	=	$6,781,728	Vendor Quotes
Total Energy and Non-Environmental Capital Costs	=	$13,420,728	

Annual Operating and Maintenance Costs			
Maintenance Cost	=	$219,462	Cost Control Manual
Reagent Cost	=	$189,948	Cost Control Manual
Electricity Cost	=	$2,845	Cost Control Manual
Water, Additiona Fuel, Additional Ash Cost	=	$1,440	Cost Control Manual
Total Annual Operting and Maintenace Costs	=	$413,695	

Indirect Annual Costs			
Adminstrative Charges	=	$6,584	Cost Control Manual
Capital Recovery	=	$2,246,190	Cost Control Manual
Total Annual Indirect Costs	=	$2,252,774	

Total Strategy Annual Costs			
Annual Operting and Maintenace Costs	=	$413,695	
Annual Indirect Costs	=	$2,252,774	
Total Strategy Annual Costs	=	$2,666,469	

Cost per Ton of SO_2 Removed			
Total Uncontrolled NOx Emissions, Tons/yr	=	332	period
NOx Removal Efficiency, %	=	40	2017-2019 annualized
Total NOx Removed, Tons/yr	=	133	
NOx Effectiveness, $/Ton NOx Removed	=	$20,049	

Attachment C

Emission Reduction Strategy
Other Information

Revision 0

Pursuant to

DEQ Information Collection Request dated January 8, 2020

AFIN 32-00036

FutureFuel Chemical Company
P.O. Box 2357
Batesville, AR 72503
ARD089234884

April 7, 2020

ADEQ
ARKANSAS
Department of Environmental Quality

April 14, 2008

Mr. Mike Collins
FutureFuel Chemical Company
P.O. Box 2357
Batesville, AR 72503

Re: Best Available Retrofit Technology (BART) modeling results

Dear Mr. Collins:

This letter is to notify you that ADEQ's BART determination modeling results indicate your facility's unit 6M01-01 is not subject-to-BART. According to the data, emissions from your unit do not cause nor contribute to visibility impairment at the following Class I wilderness areas in Arkansas: Caney Creek and Upper Buffalo.

Sincerely,

Mary Pettyjohn

Mary Pettyjohn
Senior Epidemiologist

ARKANSAS DEPARTMENT OF ENVIRONMENTAL QUALITY
5301 NORTHSHORE DRIVE / NORTH LITTLE ROCK / ARKANSAS 72118-5317 / TELEPHONE 501-682-0744 / FAX 501-682-0880
www.adeq.state.ar.us

APPENDIX G-3

Follow-up Consultation: FutureFuel Revised Cost and Cost-Effectiveness

Division of Environmental Quality

Office of Air Quality

Treece, Tricia

From: Antici, Philip <philipantici@ffcmail.com>
Sent: Thursday, July 23, 2020 12:28 PM
To: Treece, Tricia
Cc: Cornelius, Lynn; ThomasFloyd@ffcmail.com; Clark, David; Montgomery, William; Bill Campbell
Subject: Re: FutureFuel Regional Haze Evaluation Follow-Up

Tricia,

Thank you for the opportunity to review the revised cost and cost-effectiveness values and to provide supplemental information. The information below is provided per your request. Please let me know if we can provide additional information to aid in your analysis.

Best Regards,

Philip

DEQ requires additional technical justification and/or information for the following:

- With respect to section 4.2, please provide the following additional information:
  - The specific NPDES limit(s) that would be exhausted;

    The sulfate limit of 70,000 lb/day.

    The estimated amount by which a wet scrubber using sodium hydroxide would exhaust these limits; and

    The wet scrubber is estimated to add 43,000 lb/day sulfate to the outfall. Currently the outfall contains between 16,500 and 30,000 lb/day. The addition of 43K lb/day to the 30K lb/day would exceed our limit and cause a violation.

  - The legal and/or technical reasons why the NPDES limits could not be revised via a permit amendment to accommodate use of a wet scrubber using NaOH.

The sulfate limit in our permit is based on Technology-Based Effluent Limitations (TBELs). We are not aware of a legal or technical reason that we could not obtain a higher sulfate limit based on Water Quality-Based Effluent Limitations (WQBELs). This is not a self imposed limit, it was a constraint given to FFCC by the ADEQ.
There might need to be some bio-monitoring work done at sulfate levels above 70K, but as long as there is no environmental impact and the ADEQ Water Division agrees, limits could be potentially increased.

- Please provide additional information with respect to why coals with a lower sulfur content than 1.5% are not technically feasible for FutureFuel's coal-fired boilers.

  - Explain why a minimum heating value of 11,000 Btu/lb is necessary to ensure that ash can readily fall of the grate once combusted;

    Although minimum Btu value (Bituminous coal, 10,500 - 15,500 Btu/lb) is recommended for stoker boilers, fusion temperature is the key parameter associated with coal ash sticking on boiler structures. According to Keeler Boilers and Detroit Stoker vendor data, the fusion temperature must be above 2550°F to manage "clinkers" or caking. A fusion temperature above 2720°F is recommended by the manufacturer of our boilers.

  - Explain why lower sulfur content fuels from Powder River Basin and Uinta Basin are not feasible.

    Powder River Basin coal has an ash fusion temperature below the minimums required by Keeler, especially the softening and fluid temperatures. The typical Btu content of coal from Powder River mines is near 8,500 Btu/lb, below the recommended stoker boiler range. FutureFuel unsuccessfully attempted to burn Powder River basin coal, resulting in caking, clinker formation and damage to the tubes and grate.

    On average, sulfur content and calorific values of coal from the Uinta basin meet stoker boiler specifications, but the mean and median fusion temperatures of coal from the Uinta basin are typically 200°F below the minimum recommended fusion temperature for our stoker boilers. Also, FutureFuel's coal trucking fleet would require a significant expansion and upgrade to make the 42 hour round trip. Finally, FutureFuel also does not have the infrastructure or resources to handle large coal trains. Closer low-sulfur coal mines were considered over the distant Uinta basin.

- Attachments B-1.8, 1.9, and 1.10

  - Please clarify whether the cost increase for the lower sulfur coal in each attachment reflects the incremental increase in cost of the lower sulfur coal above current costs for coal (including transportation)

- The transportation cost for lower sulfur coal from Broker A did not change, therefore only coal was taxed. Transportation costs associated with Broker B did increase. The table below was adjusted to remove the tax on transportation. The annual cost per year came down about 1.5% to $2,679,500.

o Could you please specify the percentage used for the coal usage tax and whether this was applied to the total cost increase or to the increase of coals less any transportation cost changes?

- 8% coal usage tax was applied to the total cost increase, not including transportation as noted above.

o Can you please cite the source from which you obtained the estimate for the cost increase for lower sulfur coal? (vendor estimates, EIA coal markets data, etc.) Please specify the incremental cost per ton for using the lower sulfur coal.

- The table shown below includes contract quotes from two major coal brokers. The brokers represent numerous mines.

Coal Supply	Sulfur (%)	Current Cost/ton	Cost/ton Increase over Current	Annual Max Usage	Coal Tonnage Cost per Year	8% Coal Usage Tax	Annual Cost per Year
Broker A	2.5	CBI	$13.68	50,000	$684,000	$54,720	$738,720
Broker A	2	CBI	$23.75	50,000	$1,187,500	$95,000	$1,282,500
Broker B	1.5	CBI	$50.39	50,000	$2,519,500	$160,000	$2,679,500

Notes:

CBI = Confidential Business Information

Broker A and Broker B are Coal Brokers who have supplied the quotes used in this evaluation

Broker B's usage tax was adjusted to ensure only the coal usage increase was taxed

- Attachments B-1.1, 1.2, 1.3, 1.4

o Please specify whether the electrical costs, maintenance costs, operating and support labor costs, and permitting and compliance costs are the amount by which these costs would increase above what these items currently cost using coal.

- FutureFuel agrees these costs need to be adjusted to reflect only cost increases above the current cost using coal. We feel it is appropriate to remove the cost associated with electrical, maintenance, operating and support labor, permitting and compliance.

End of Response

On Mon, Jul 20, 2020 at 2:44 PM Treece, Tricia <treecep@adeq.state.ar.us> wrote:

Philip,

We have now completed a thorough review of the cost information provided in the Regional Haze Evaluation Version 0 Pursuant to DEQ Information Collection Request dated January 8, 2020. Based on our review, each of the cost analyses require revision to ensure consistency with EPA guidance. DEQ has calculated, based on the information provided and EPA guidance, revised cost and cost-effectiveness values. See attached spreadsheet for an explanation of changes and DEQ's calculations. We are providing you the opportunity to review these calculation revisions and provide us additional information if site-specific considerations warrant changes to the control-cost methodology assumptions.

In addition, DEQ requires additional technical justification and/or information for the following:

- With respect to section 4.2, please provide the following additional information:
    - The specific NPDES limit(s) that would be exhausted;
    - The estimated amount by which a wet scrubber using sodium hydroxide would exhaust these limits; and
    - The legal and/or technical reasons why the NPDES limits could not be revised via a permit amendment to accommodate use of a wet scrubber using NaOH.
- Please provide additional information with respect to why coals with a lower sulfur content than 1.5% are not technically feasible for FutureFuel's coal-fired boilers.
    - Explain why a minimum heating value of 11,000 Btu/lb is necessary to ensure that ash can readily fall of the grate once combusted;
    - Explain why lower sulfur content fuels from Powder River Basin and Uinta Basin are not feasible.
- Attachments B-1.8, 1.9, and 1.10
    - Please clarify whether the cost increase for the lower sulfur coal in each attachment reflects the incremental increase in cost of the lower sulfur coal above current costs for coal (including transportation)

- Could you please specify the percentage used for the coal usage tax and whether this was applied to the total cost increase or to the increase of coals less any transportation cost changes?

- Can you please cite the source from which you obtained the estimate for the cost increase for lower sulfur coal? (vendor estimates, EIA coal markets data, etc.) Please specify the incremental cost per ton for using the lower sulfur coal.

- Attachments B-1.1, 1.2, 1.3, 1.4

    - Please specify whether the electrical costs, maintenance costs, operating and support labor costs, and permitting and compliance costs are the amount by which these costs would increase above what these items currently cost using coal.

Please provide a response to each of these items and any feedback you may have on the revised control strategy cost calculations by COB 7/24/20. We would also be happy to set up a call with you to address any questions you may have.

Tricia Treece | SIP/Planning Supervisor

Division of Environmental Quality | **Office of Air Quality**
Policy and Planning Branch

5301 Northshore Drive | North Little Rock, AR 72118

t: 501.682.0055 | e: treecep@adeq.state.ar.us

ARKANSAS ENERGY & ENVIRONMENT

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Philip Antici
Manager, HSES
FutureFuel Chemical Co.
(870) 698-5358
(870) 307-2158 mobile
philipantici@ffcmail.com

APPENDIX G-4

FutureFuel Cost Calculations

(see spreadsheet of the same name)

Division of Environmental Quality

Office of Air Quality

APPENDIX G-5

FutureFuel Baseline Heat Input and SO_2 Emissions

(see spreadsheet of the same name)

Division of Environmental Quality

Office of Air Quality

APPENDIX G-6

FutureFuel Draft Administrative Agreement

Division of Environmental Quality

Office of Air Quality

ARKANSAS DEPARTMENT OF ENERGY AND ENVIRONMENT

DIVISION ENVIRONMENTAL QUALITY

In the Matter of:

LIS No. ________

FutureFuel Chemical Company
2800 Gap Road
Batesville, AR 72501
AFIN No. 32-00036

ADMINISTRATIVE ORDER

This Administrative Order (AO) is issued pursuant to the authority delegated under the federal Clean Air Act, 42 U.S.C. § 7401 *et seq*., and the federal regulations issued thereunder. In addition, this AO is issued pursuant to the authority of the Arkansas Water and Air Pollution Control Act, Act 472 of 1949, as amended, codified at Ark Code Ann. § 8-4-101 *et seq*., including Ark. Code Ann. § 8-4-311.

The issues herein having been settled by agreement of FutureFuel Chemical Company (FutureFuel) and the Division of Environmental Quality[1] (DEQ), it is hereby stipulated that the following STATEMENT OF BASIS and ORDER AND AGREEMENT be entered. DEQ and FutureFuel hereby agree to the entry of this AO in order to satisfy second planning period requirements associated with the Regional Haze Rule, 40 C.F.R. Part 51 Subpart P.

STATEMENT OF BASIS

1. FutureFuel owns and operates a chemical manufacturing facility that is located in Batesville, Independence County, Arkansas.

2. On July 1, 1999, the United States Environmental Protection Agency (U.S. EPA) published regulations to address visibility impairment in the nation's Class I areas. 64 Fed. Reg. 35714. These regulations were amended on July 6, 2005 (70 Fed. Reg. 39156), October 13, 2005 (71 Fed. Reg. 60631), June 7, 2012 (77 Fed Reg. 33656), and January 10, 2017 (82 Fed. Reg. 3124). Collectively, these regulations are commonly known as the "Regional Haze Rule," codified at 40 C.F.R. §§ 51.300–51.309.

[1] Pursuant to Act 910 of 2019, the Arkansas Transformation and Efficiencies Act, the former Arkansas Department of Environmental Quality is now the Division of Environmental Quality in the Department of Energy and Environment.

3. Two Class I areas in Arkansas are covered by the Regional Haze Rule: Caney Creek Wilderness Area (Caney Creek) and the Upper Buffalo Wilderness Area (Upper Buffalo).

4. To meet the requirements of the Regional Haze Rule, each State must submit a State Implementation Plan (SIP) implementing the requirements of the Regional Haze Rule to the U.S. EPA for approval. *Id*. Each State must submit a revised SIP in 2021 and every ten years thereafter that includes a long-term strategy to "address regional haze visibility impairment for each mandatory Class I Federal area within the State and for each mandatory Class I Federal area located outside that State that may be affected by emissions from the State." 40 C.F.R. §51.308(f)(2).

5. In developing the long-term strategy for each SIP revision, each State "must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the cost of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment," collectively referred to as the four-factors. 40 C.F.R. §51.308(f)(2)(i).

6. DEQ identified the following emission unit operated by FutureFuel as reasonably anticipated to contribute to visibility impairment at Upper Buffalo and Hercules Glades Wilderness Area: SN:6M01-01 three coal-fired boilers.

7. On January 8, 2020, DEQ issued an information collection request (ICR) to FutureFuel soliciting information about potential control strategies for reducing emissions from SN:6M01-01.

8. On April 7, 2020, FutureFuel provided information to DEQ pursuant to the ICR.

9. Based on the information provided by FutureFuel and consideration of the four factors, DEQ determined that switching from coal with three percent sulfur content by weight to coal that has two percent sulfur content in the three coal-fired boilers (SN:6M01-01) satisfies Regional Haze Rule requirements for FutureFuel for the second planning period (2021–2028).

10. DEQ considers the requirements set forth in the ORDER AND AGREEMENT to be "applicable requirements" within the meaning of Title V of the Clean Air Act. The addition of these applicable requirements necessitates the reopening of the permit for FutureFuel in order to incorporate the applicable requirements. 40 C.F.R. § 70.7(f)(1)(i).

ORDER AND AGREEMENT

WHEREFORE, without any admission by FutureFuel of the factual and legal allegations contained herein, DEQ and FutureFuel do hereby stipulate and agree as follows:

1. FutureFuel shall comply with all requirements set forth in this Order and Agreement.

2. No later than one year after the effective date of EPA approval of this AO, FutureFuel shall comply with an emission rate of 3.9 pounds of sulfur dioxide per million British thermal units for SN:6M01-01. This limit is based on a rolling 30-operating-day average.

3. Compliance with Paragraph 2 shall be demonstrated based on fuel usage records and feed stream analysis.
   a. For the purposes of determining the sulfur dioxide emission rate agreed upon in this AO, it shall be assumed that all sulfur entering the boilers, either through sludge, liquid fuel, or coal is emitted as sulfur dioxide.
   b. For the purposes of determining the sulfur dioxide emission rate agreed upon in this AO, a "day" shall be considered from 12 A.M. one calendar day to 12 A.M. the following calendar day.
   c. For each day the three coal-fired boilers (SN:6M01-01) are operated, FutureFuel shall record the amount, types, sulfur content, and heat content of coal, biosludge, and liquids fed to the three coal-fired boilers (SN:6M01-01).
   d. For each day the three coal-fired boilers (SN:6M01-01) are operated, FutureFuel shall calculate the daily sulfur dioxide emission rate by summing the pounds of sulfur fed to the three coal-fired boilers (SN:6M01-01), multiplying the total sulfur by a sulfur dioxide conversion factor of 1.997, and then dividing the calculated sulfur dioxide emissions by the sum of heat content from fuels burned (in million British thermal units).
   e. The 30-operating day average shall be calculated as the arithmetic average of 30 consecutive daily sulfur dioxide emission rate values.

4. FutureFuel shall keep records showing compliance with this AO. All records required under this AO must be maintained by FutureFuel for at least 5 years and shall be made available to representatives of DEQ and EPA upon request.

5. A violation of this AO shall be considered unlawful under Ark. Code Ann § 8-4-217 and subject to the penalties set forth in Ark. Code Ann § 8-4-103 in the same manner as a violation of a permit issued by DEQ.

6. FutureFuel shall submit a permit modification application to DEQ to incorporate the applicable requirements of this AO such that the permit reopening is completed no later than eighteen (18) months after the effective date of this AO.

7. Prior to the execution of any agreement for the transfer of ownership or operation of the FutureFuel facility, FutureFuel shall provide notice of and a copy of this AO to the proposed transferee. Transfer of ownership or operation of any portion of the FutureFuel facility shall not relieve FutureFuel of its obligation to ensure that the terms of the AO are implemented unless, at least 30 days prior to such transfer, FutureFuel provides written notice of the prospective transfer to EPA Region 6 and DEQ, and the prospective transferee executes an AO with DEQ prior to the effective date of the transfer providing for continued compliance with the terms set forth in the AO. The Notice of Transfer shall clearly identify the parties responsible for any existing violations of this AO. Any attempt to transfer

ownership or operation of the FutureFuel facility without complying with this Paragraph constitutes a violation of this AO.

8. Nothing contained in this AO shall relieve FutureFuel of any obligations imposed by any other applicable local, state, or federal laws, nor, except as specifically provided herein, shall this AO be deemed in any way to relieve FutureFuel of responsibilities contained in the permit.

9. If federal legislation or a federal court takes action on the Arkansas Regional Haze SIP revision or Regional Haze Rule resulting in a stay of compliance requirements of the AO including deadlines or the alteration of other federal regional haze requirements, in whole or in part, then the AO shall be enforceable only to the extent it is federally enforceable.

10. If any provision or requirement of this AO is disapproved by EPA, all provisions or requirements shall be rendered inoperative.

11. This AO is effective upon execution by the Chief Administrator for Environment.

12. By virtue of the signature appearing below, the individual represents that he or she is either an Officer or authorized representative of FutureFuel.

SO ORDERED THIS _____ DAY OF __________, 2022.

____
Julie Linck
Chief Administrator, Environment

APPROVED AS TO FORM AND CONTENT:

FutureFuel Chemical Company

BY:__________________________(Signature)

______________________________(Typed or printed name)

TITLE: _______________________

DATE: _______________________