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INTEGRATED DRY NO_x /SO_2 EMISSIONS CONTROL SYSTEM

Final Report, Volume 1: Public Design

Clean Coal Technology Projects
Pittsburgh Energy Technology Center (PETC)

DOE Contract Number DE-FC22-91PC90550

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ABSTRACT

The U.S. Department of Energy (DOE)/Pittsburgh Energy Technology Center (PETC) and the Public Service Company of Colorado (PSCo) signed the cooperative agreement for the Integrated Dry NO_x/SO_2 Emissions Control System in March 1991. This project integrates various combinations of five existing and emerging technologies onto a 100 MWe, down-fired, load-following unit that burns pulverized coal. The project is expected to achieve up to 70% reductions in both oxides of nitrogen (NO_x) and sulfur dioxide (SO_2) emissions.

Various combinations of low-NO_x burners (LNBs), overfire air (OFA) ports, selective non-catalytic reduction (SNCR), dry sorbent injection (DSI) using both calcium- and sodium-based reagents, and flue-gas humidification are expected to integrate synergistically and control both NO_x and SO_2 emissions better than if each technology were used alone. For instance, ammonia emissions from the SNCR system are expected to reduce NO_2 emissions and allow the DSI system (sodium-based reagents) to achieve higher removals of SO_2.

Unlike tangentially or wall-fired units, down-fired units require substantial modification to their pressure parts to retrofit LNBs and OFA ports, substantially increasing the cost of retrofit. Conversely, the retrofitting of SNCR, DSI, or humidification systems does not require any major boiler modifications and are easily retrofitted to all boiler types. However, existing furnace geometry and flue-gas temperatures can limit their placement and effectiveness. In particular, SNCR requires injecting the SNCR chemicals into the furnace where the temperature is within a very narrow temperature range.

Project construction was completed in August 1992. Except for a 10-day test using high-sulfur coal, testing is expected to end in June 1994 and the final report is expected to be issued in November 1994. The project is expected to cost $27.4 million.

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LIST OF ABBREVIATIONS

B&W	Babcock & Wilcox
BZHRR	Burner zone heat release rate (Btu/h–ft^2)
CCT-III	Third Round of the DOE Clean Coal Technology Program
CEM	continuous emission monitor
DCS	Distributive control system
DOE	United States Department of Energy
DRB-XCL®	Dual-range burner, axially-controlled low-NO$_x$
DSI	Dry sorbent injection (also called duct sorbent injection)
EPRI	Electric Power Research Institute
ESP	Electrostatic precipitator
FERCo	Fossil Energy Research Corporation
FGD	Flue-gas desulfurization
FGR	Flue-gas recirculation
HVT	High-velocity thermocouple
ID fan	Induced-draft fan
LCP	Local control panel
LNB	Low-NO$_x$ burners
MCC	Motor control center
NSPS	New Source Performance Standards
NSR	Normalized stoichiometric ratio
OFA	Overfire air
PETC	Pittsburgh Energy Technology Center
PLC	Programmable logic controller
PSCo	Public Service Company of Colorado
SNCR	Selective noncatalytic reduction (also called urea injection)
UBC	Unburned carbon
UCC	United Conveyor Corporation

LIST OF UNITS

acfm	actual cubic feet per minute
Btu	British thermal unit. Heat required to raise 1 lb of water at 60°F 1 °F.
Btu/lb	British thermal units per pound of fuel
Btu/h	British thermal unit per hour
Btu/ft^3	British thermal units per cubic foot of gas
ft	feet
ft^2	square feet
ft^3/h	cubic feet per hour
ft^3/min	cubic feet per minute
gal	gallons
gal/min	gallons per minute
grains/dSCF	grains per dry standard cubic foot
Hz	Hertz (cycles per second)
icfm	inlet cubic feet per minute
inH$_2$Og	inches water (gauge)
inHg	inches of mercury (pressure)
kW	kilowatt (1,000 watts)
kW-h	kilowatt hour
lb/MMBtu	pounds per million British thermal unit
lb/h	pounds per hour
lbm/h	pound-mass per hour
MCFH	1,000 cubic feet per hour
MMBtu/h	1,000,000 British thermal units per hour
MMBtu	1,000,000 British thermal heat units
mole/h	moles per hour
MWe	megawatts (electric)
ppm	parts per million
ppmv	parts per million by volume

ppmw	parts per million by weight
psig	pounds per square inch (gauge)
scfm	standard cubic feet per minute (at 1 atmosphere and 60 °F)
t/h	tons per hour
V	Volts
VAC	Volts, alternating current
vol%	percent content by volume
wt%	percent content by weight
°F	degrees Fahrenheit
μm	micrometer (10^{-6} meters)

GLOSSARY

acoustic pyrometry	An instrument used to measure high temperatures in gases that is based on measuring the speed of sound.
agglomeration	Groups of fine dust particles clinging together to form a larger particle.
air staging	A technique used to reduce the amount of air available in the initial stages of combustion to limit NO_x formation. This may be accomplished by burner design or by using overfire air.
air heater	A heat transfer device used to heat air. At Arapahoe Unit 4, the hot flue-gas preheats the combustion air before it enters the boiler.
air-to-cloth ratio	Ratio of the flue-gas flowrate (acfm) to the area of the bag filters (ft^2). This ratio indicates the relative size of an FFDC.
air-to-liquid ratio	Ratio of the injected urea solution (liquid) and atomizing air.
aqueous ammonia	A liquid solution of water and ammonia. Usually with ammonia concentration less than 30%. NH_4OH
ammonia	NH_3
amidogen	NH_2
ammonia slip	The excess ammonia emitted by a unit because of the injection of urea or ammonia into the furnace for SNCR.
ash	The incombustible solid matter in a fuel.
atomizer	Nozzle that reduces a liquid to a very fine spray.
baghouse	See **FFDC**.
baseload station	A generating station that is normally operated to produce load for a system's base load. Therefore, the station runs at virtually constant full load.
bulk furnace residence time	Computed by dividing the volume of the furnace (the space between the burners and the leading convective surface) by the total flowrate of the flue gas. Represents the amount of time the fuel has to burn completely.

char	The product of coal devolatization. It consists of unburned carbon, a small amount of hydrocarbons (high molecular weight), and ash.
CO	Carbon monoxide.
CO_2	Carbon dioxide.
coal reactivity	A qualitative measure of a coal's propensity to burn rapidly. Measured by the coal's content of volatile matter and FC/VM.
combustion air	The air used to burn the coal. Consists of the primary, secondary, and overfire air.
cyanic (or isocyanic) acid	HNCO
direct-fired unit	Unit that pulverizes coal in proportion to load and conveys it directly to the burners.
down-fired unit (or boiler)	A furnace in which the burners are arranged so that the air and fuel flow down through the roof into the boiler. Also called vertical-fired, roof-fired, or top-fired.
downcomer	A tube in the water wall system of a boiler in which the fluid flows downward.
dry sorbent injection (DSI)	Injection of dry calcium- or sodium-based reagents into the economizer or furnace duct to remove SO_2 from the flue gas.
economizer	Heat recovery device used to transfer heat from the products of combustion (the flue gas) to the feedwater.
electrostatic precipitator (ESP)	Device that collects dust, mist, or fumes from a gas stream by placing an electrical charge on the particle and collecting it on an electrode.
endothermic reaction	Reaction that absorbs heat.
excess O_2	Used to determine the amount of combustion air above that required for stoichiometric combustion of the fuel.
exhauster	Fan connected to the outlet of a pulverizer that pulls primary air through the pulverizer.
exothermic reaction	Reaction that releases heat.
free moisture	Water that is not chemical bound to the product.
FC/VM ratio	Ratio of fixed carbon to volatile matter in coal. Measure of a coal's reactivity.

FFDC	Fabric filter dust collector. Used to remove ash particles from a unit's flue gas.
fixed carbon	Carbonaceous residue less the ash remaining in a test container after the volatile matter has been driven off in a proximate analysis.
flame scanner (detector)	Device that indicates if a flame is present.
flue gas	Gaseous products of combustion in the flue to the stack.
flyash	Fine particles of ash carried by the products of combustion out of the boiler.
fuel staging	The introduction of fuel into the combustion air in steps.
fuel NO_x	NO_x produced by combination of the nitrogen released from the fuel and oxygen.
H_2O	Water.
H_2S	Hydrogen sulfide.
HNCO	Cyanic or isocyanic acid.
ignitor	Small gas or oil burner used to ignite a larger fuel stream.
intertube burners	Burners located between the waterwall tubes of a boiler.
lance	Pipe that injects f fluid stream into a boiler or duct.
lignite coal	Consolidated coal of low classification according to rank: less than 8,300 Btu (moist).
load-following station	A generating unit operated at various points to follow an automatic demand signal.
loss on ignition (LOI)	Test used to determine an approximation of the amount of unburned carbon in the flyash. Generally provides a slightly higher measurement than direct carbon measurement.
makeup water	Water added to the boiler to compensate for water lost through exhaust, blowdown, leakage, etc.
momentum ratios	A ratio of mass and velocity that indicates jet penetration.
N_2	Molecular nitrogen
N_2O	Nitrous oxide (commonly called "laughing gas").

nahcolite	Mineral name for naturally occurring sodium bicarbonate.
New Source Performance Standards (NSPS)	A 1971 federal law regulating the emissions of generating units.
NH_2	amidogen
NH_3	Ammonia
NO	Nitric oxide
NO_2	Nitrogen dioxide
NO_x	oxides of nitrogen, the combined total of NO and NO_2.
normalized stoichiometric ratio (NSR)	The molar ratio of reagent used to that theoretically required to remove all of the desired species. The ratio is normalized by dividing by the number moles of reagent required to remove one mole of species. Theoretically, an NSR of 1 removes 100% of a desired species.
NO_x Ports®	B&W's tradename for their OFA ports.
O_2	Molecular oxygen.
overfire air (OFA)	A NO_x control technology that diverts part of the secondary air and injects it through ports downstream of the primary combustion zone. This diversion reduces the oxygen available for NO_x formation in the main combustion zone.
oxidation, oxidizes	The combining of a chemical with oxygen.
pitot-tube	Device used to measure the flow of a gas by comparing the static and velocity pressures.
primary air	In direct-fired units, air passed through the pulverizer to dry and convey the coal to the burners.
proximate analysis	Analysis of a solid fuel that determines its moisture, volatile matter, fixed carbon, and ash content as a percent of its total weight.
reducing atmosphere	Atmosphere with little or no oxygen.
reduction	Removal of oxygen from a chemical compound.
register	Apparatus used in a burner to regulate the direction and amount of flow and spin for combustion.
Reynolds number	Represents the turbulence of a flowing fluid.
roof-fired unit	See **down-fired unit (or boiler)**.

scrubber	An apparatus that removes solids or selective gas species from gases by entrainment in water with subsequent chemical reaction.
secondary air	Includes all air for combustion except primary air.
slag	Molten or fused refuse.
sliding air-damper	Regulates flow of combustion air.
SO_2	Sulfur dioxide.
sodium sesquicarbonate	Dry sodium-based reagent used to remove SO_2 from flue gas. $(NaHCO_3 \bullet Na_2CO_3 \bullet 2H_2O)$
sodium bicarbonate	Dry sodium-based reagent used to remove SO_2 from flue gas. $(NaHCO_3)$
sootblower	Mechanical device that uses steam or air to clean heat absorbing surfaces.
stack	Vertical conduit that, due to the difference in densities between the internal and external gases, causes a draft at its base.
stoichiometric ratio	Ratio of actual combustion air used to that theoretically required for 100% combustion of the coal. A stoichiometric ratio greater than one indicates a lean fuel (oxygen rich) condition. A stoichiometric ratio less than one indicates a fuel-rich (oxygen lean) condition.
sub-bituminous coal	A general coal classification defined by ASTM D388. A lower rank coal with higher heating value from 8,300 to 11,500 Btu per lb and relatively high moisture from 15 to 30%.
swirl	Rate of fuel/air mixing.
tangential-fired unit	A method of firing in which the burners are arranged so that the center lines of the burners are tangential to an imaginary circle in the furnace.
thermal NO_x	NO_x formed through high-temperature oxidation of the nitrogen found in the combustion air.
top-fired unit	See **down-fired unit (or boiler)**.
trona	Mineral name for naturally occurring sodium sesquicarbonate.
ultimate analysis	Chemical analysis of a solid, liquid, or gaseous fuel. For coal, it determines the content of carbon, hydrogen, sulfur, nitrogen, oxygen, and ash.

unburned carbon (UBC)	An indicator of combustible losses. The amount of unburned carbon in the flyash.
urea	$(NH_2)_2CO$
utilization	Ratio of the actual removal rate of a chemical to the NSR. Indicates the theoretical effectiveness of a chemical reaction. For example, a utilization of 40% means that 60% of an injected reagent remained unreacted.
vertical-firing	See **down-fired unit (or boiler)**.
wall-fired unit	A method of firing in which the burners are arranged on the wall(s) of the furnace to fire horizontally.
windbox	A plenum chamber around a burner or a port that maintains air pressure to properly distribute and discharge the air.

EXECUTIVE SUMMARY

The overall goal of this program is to achieve up to 70% reductions in the emissions of NO_x and SO_2 through the integration of existing and emerging technologies while minimizing capital expenditures and limiting waste production to dry solids that can be handled with conventional ash removal equipment. This report presents the detailed process design of the system. Volume 2 of the final report will present the results and economics of the system and will include any process design updates.

Project Background and History

In September 1988, Congress allocated funds for CCT-III to demonstrate technologies that can be implemented on existing facilities. In March 1991, the DOE and PSCo signed the cooperative agreement for the Integrated Dry NO_x/SO_2 Emissions Control System as part of CCT-III. PSCo, the DOE, and the Electric Power Research Institute (EPRI) sponsor the $27 million program.

PSCo is conducting the Integrated Dry NO_x/SO_2 Emissions Control System project on Unit 4 at its Arapahoe Steam Electric Generating Station (5,300 feet above sea level) located in Denver, CO. Arapahoe Unit 4 is a down-fired, 100-MWe unit (name plate) designed to burn pulverized coal (Colorado lignite) or natural gas that came on line in 1955. PSCo uses Arapahoe Unit 4 as a load-following station. The unit's normal capacity factor is 50 to 60%.

Project Technologies

The Integrated Dry NO_x/SO_2 Emissions Control System uses various combinations of five major control technologies to control the emissions of both NO_x and SO_2. To control NO_x emissions, the integrated system uses low-NO_x burners (LNB), overfire air (OFA) ports, and selective noncatalytic reduction (SNCR). To control SO_2 emissions, the integrated system uses dry-sorbent injection (DSI) with and without flue-gas humidification. (Figure 1-1 on page 1-4 shows a simplified block flow diagram of the integrated system.)

B&W DRB-XCL® Low-NO_x Burners

The low-NOx Burners (LNBs) are Babcock & Wilcox (B&W) Dual Register Burner-Axially Controlled Low-NO_x (DRB-XCL®) burners. They use air and fuel staging within the burner to reduce the formation of NO_x. They can also balance the distribution of fuel and air to each burner to optimize combustion efficiency and NO_x reduction. On wall fired-boilers, these burners have achieved NO_x reductions of 35 to 70% from uncontrolled baseline levels.

Retrofitting a down-fired boiler for low-NO_x burners requires more outage time, a larger capital investment, and is much more complicated than it is for a wall-fired boiler. Also, down-fired boilers require substantial modifications in order to install the modified burners. These modifications greatly increase the capital cost of installing LNBs on this type of generating unit.

Overfire Air (OFA) (NO_x) Ports

The Integrated Dry NO_x/SO_2 Emissions Control System uses B&W Dual-Zone NO_x Ports®. OFA ports use air staging over a larger volume of the furnace than LNBs, diverting part of the combustion air from the primary combustion zone to a zone downstream of the burner. This diversion creates a slightly fuel-rich environment that inhibits the formation of NO_x. B&W Dual-Zone NO_x Ports® incorporate a central (inner) zone and an outer zone to provide adequate mixing across the entire furnace.

Unlike wall-fired boilers, adding OFA ports to down-fired boilers involves more than a simple extension of the windbox. Instead, installing OFA ports into a down-fired boiler requires new ductwork to carry the OFA to the OFA ports. This additional ductwork must fit the existing unit and significantly increases the capital cost of installing OFA ports. When used with pulverized coal, OFA ports can increase slagging and corrosion in the furnace and decrease combustion efficiency.

Selective Non-Catalytic Reduction (SNCR) (Urea and Ammonia Injection)

SNCR systems inject either urea or ammonia (anhydrous or aqueous) into the flue gas at a point where its temperature is between 1,600 and 2,100 °F. In this temperature range and in the presence of oxygen (O_2), the injected chemical releases NH_2 which selectively reacts with NO to form harmless N_2 and H_2O. This reaction reduces NO_x emissions, but increases N_2O and NH_3 emissions.

Small changes in flue-gas temperature at a system's injection points can significantly affect the performance of an SNCR system. When the boiler load is changed, the flue-gas temperature for a particular injection location also changes. For this reason, multiple levels of injection are usually required to provide good NO_x removal over a range of boiler load conditions. Coal-fired units retrofitted with SNCR systems have achieved NO_x reductions ranging from below 20% to above 80%.

Dry Sorbent Injection (DSI)

DSI systems inject dry reagents (calcium- or sodium-based) into the flue gas. Calcium reagents are injected into the flue-gas duct at a point where the flue gas is about 1,000 °F (usually before the economizer). Sodium- or calcium-based reagents (for lower SO_2 removal rates than economizer injection) are injected between the air heater and the particulate control device. Through a series of complex reactions, the reagents react with the gaseous SO_2 in the flue gas to form a calcium- or sodium-based solid that can be removed by the particulate control device.

DSI systems are simple, use existing ductwork, and have low capital costs. They produce a dry, solid product that can be handled by conventional flyash systems, but the use of DSI increases the amount of flyash and adds soluble compounds to it. Because of the increase in flyash, existing flyash handling equipment may be inadequate. Because of the soluble compounds, the flyash cannot be slurried or sold as a concrete additive.

Flue-Gas Humidification

The flue-gas humidification system injects water into the flue-gas between the air heater and the particulate control device to enhance the effectiveness of the calcium-based reagent injected by the DSI system. Increasing the humidity of the flue gas does not change the SO_2 removal chemistry of the calcium-based reagents, but it does improve their reactivity. Flue-gas humidification is not expected to increase significantly the effectiveness of sodium-based reagents. Depending on the type of reagent, the rate of injection, furnace geometry, and other operating conditions, the use of flue-gas humidification and DSI with calcium-based reagents has achieved SO_2 removal rates from 20% to 50%.

Operationally, it is important to prevent unevaporated water from reaching the duct walls, obstructions in the duct, or the particulate control device. Increasing the humidification of the flue gas improves SO_2 removal, but also increases the risks of localized-wetting problems. So, the optimum operating point for the humidification system is a compromise between operation and performance.

Integrated Emissions Control System

The various combinations of emission control technologies are expected to integrate synergistically, for example:

- Combining LNBs and OFA will allow the burners and ports to be adjusted to work together and produce less NO_x.
- With lower levels of NO_x, both the SNCR and DSI systems are expected to achieve higher NO_x and SO_2 removal.

- The SNCR's ammonia emissions are expected to react with NO_2 allowing greater performance from the SNCR and DSI systems.

Major Conclusions From Design and Construction Effort

In general, the design and construction of the project was very successful. The system has required only limited modifications during the operation and testing phase of the project. Preliminary indications are that the integrated system works very well and will easily meet the project performance goals.

Project's Status

Most of the retrofitting was completed in August 1992. Currently, DSI with sodium-based reagents and an integrated system (SNCR and DSI) are being tested. Testing is expected to end in June 1995 (except for a 10-day test of high-sulfur coal) and the final report is expected to be issued in November 1995. (Figure 1-2 on page 1-6 summarizes the overall schedule of the program.)

Project's Cost

The design, procurement, and installation of the Integrated Dry NO_x/SO_2 Emissions Control System is expected to cost \$20.9 million. An additional \$6.5 million is budgeted for the operating and testing of the system, bringing the total cost of the program to \$27.4 million, including overheads. Except for a \$934,000 change in the scope of work requested by the DOE for air toxics testing, the project is within the original approved budget.

1.0 PROJECT OVERVIEW

1.1 Purpose of Public Design Report

The purpose of this public design report is to consolidate all design and cost information on the Integrated Dry NO_x/SO_2 Emissions Control System project after the completion of its construction and startup. Modifications to the original design that are completed during the operating phase of this project will be contained in the Final Report, Volume 2. This report also contains an overview of this project, its key design features and data, and its potential commercialization.

1.2 Brief Description of Project

The overall goal of this program is to achieve up to 70% reductions in the emissions of NO_x and SO_2 through the integration of existing and emerging technologies while minimizing capital expenditures and limiting waste production to dry solids that can be handled with conventional ash removal equipment. This program plans primarily to burn low-sulfur coal (0.4% sulfur), but it also plans a short-term test of high-sulfur coal (2.5% sulfur). This section briefly describes the history, sponsors, technologies, vendors, performance requirements, process flow, location, test program, and schedule of the project. Sections 2 through 7 describes the technologies in more detail.

1.2.1 History

In September 1988, Congress allocated funds for the third Clean Coal Technology demonstration program (CCT-III) to demonstrate technologies that can be implemented on existing facilities. The United States Department of Energy (DOE) then solicited proposals to demonstrate technologies capable of reducing the emissions of oxides of nitrogen (NO_x) and sulfur dioxide (SO_2). In response to the DOE solicitation, the Public Service Company of Colorado (PSCo) proposed the Integrated Dry NO_x/SO_2 Emissions Control System. The DOE selected this system for funding as part of CCT-III. The DOE and PSCo signed the final Cooperative Agreement in March 1991.

1.2.2 Sponsors

PSCo, the DOE, and the Electric Power Research Institute (EPRI) sponsor the Integrated Dry NO_x/SO_2 Emissions Control System program.

1.2.3 Technologies Employed

The Integrated Dry NO_x/SO_2 Emissions Control System uses various combinations of five major control technologies to form integrated systems to control the emissions of both NO_x and SO_2. To control NO_x emissions, the integrated system uses low-NO_x burners (LNB), overfire air (OFA) ports, and selective noncatalytic reduction (SNCR). To control SO_2 emissions, the integrated system uses dry-sorbent injection (DSI) with and without flue-gas humidification.

1.2.4 Technology Vendors

PSCo is the project manager for the Integrated Dry NO_x/SO_2 Emissions Control System program, and is responsible for all aspects of project performance. PSCo engineered and installed the DSI system, installed the SNCR system, engineered and installed the modifications to the flyash system, and installed much of the balance of plant systems. PSCo also provided the host site, trained the operators, selected site construction services, startup services and maintenance, and is assisting in the testing program. The following companies also contribute to the project:

- **Babcock and Wilcox (B&W)** was responsible for the engineering, procurement, fabrication, installation, and shop testing of the low-NO_x burners, OFA ports, flue-gas humidification equipment, and associated controls. B&W is also assisting in the test program, and will provide for commercialization of the technology.

- **NOELL, Inc.** was responsible for the engineering, procurement, and fabrication of the SNCR system.

- **Fossil Energy Research Corporation (FERCo)** is conducting the test program.

- **Western Research Institute (WRI)** is characterizing the waste materials and recommending options for their disposal.

- **Colorado School of Mines** is conducting research in the areas of bench-scale chemical kinetics for the NO_2 formation reaction with DSI while injecting sodium-based reagents.

- **Stone & Webster Engineering Corporation** is assisting PSCo with the engineering efforts.

- **Cyprus Coal** and **Amax Coal** are supplying coal for the project.

- **Coastal Chem, Inc.** is providing urea for the SNCR system.

1.2.5 Project Block Flow Diagram

Figure 1-1 shows a simplified block flow diagram of the integrated system.

1.2.6 Project Location

PSCo is conducting the Integrated Dry NO_x/SO_2 Emissions Control System project at its Arapahoe Steam Electric Generating Station located in Denver, CO. The generating station includes 4 coal-fired steam electric generating units with a total generating capacity of 232 MWe (nameplate). The demonstration system has been installed on Unit 4. The burners are mounted vertically on the boiler roof. Elevation of the site is 5,300 feet above sea level.

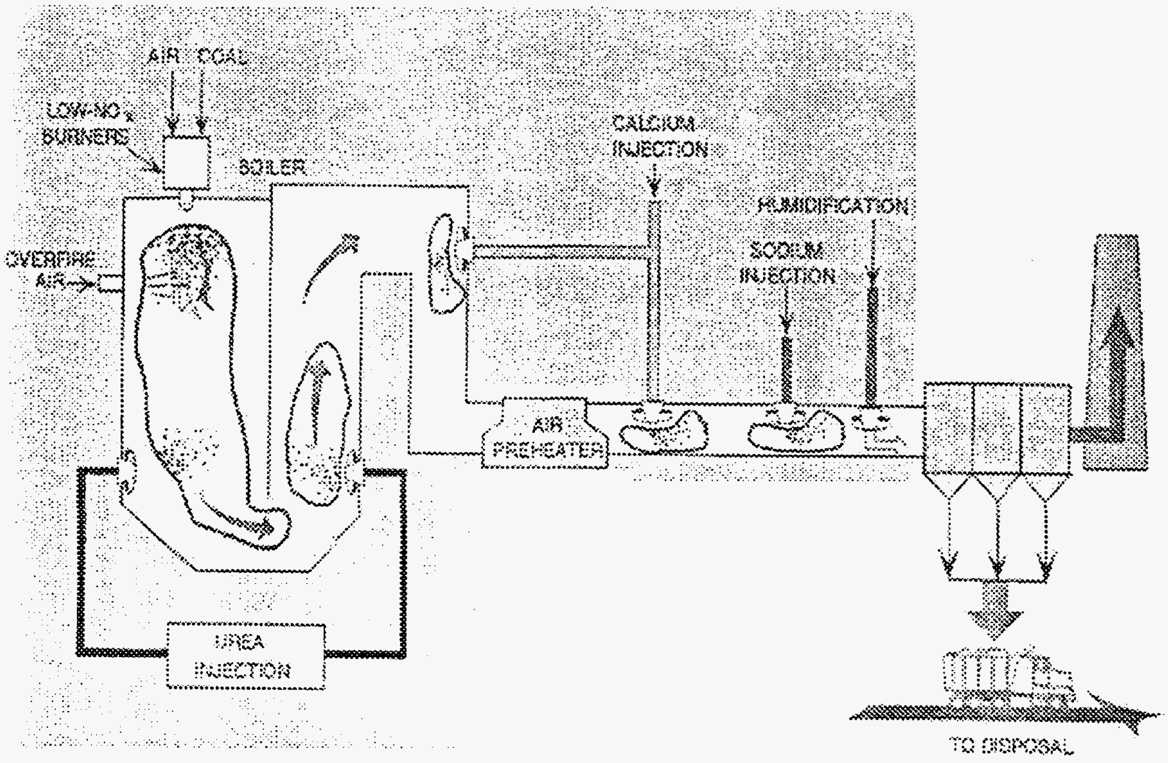


Figure 1-1: Block Flow Diagram of Integrated Dry NO$_x$/SO$_2$ Emission Control System

1.2.7 Summary of Planned Test Program

Because of the number of technologies this project integrates, the test program has been divided into the following test activities:

- **Baseline tests of the original combustion system:** Provides the basis for comparing the performance of the individual technologies and that of the integrated system.
- **Baseline combustion system/SNCR:** Tests the performance of SNCR (urea and ammonia injection) with the original combustion system.

- **LNB/OFA:** Identifies the optimum operating conditions and settings for the burners and the OFA ports. Assesses the combined performance of the low-NO_x burners and the OFA ports.

- **LNB/OFA/SNCR:** Tests the NO_x reduction potential of the combined low-NO_x combustion system and SNCR.

- **LNB/OFA/DSI (calcium-based reagents):** Tests the injection of calcium-based reagents into the economizer and into the duct with flue-gas humidification during the operation of the low-NO_x burners and the OFA ports.

- **LNB/OFA/DSI (sodium-based reagents):** Tests the SO_2 removal performance of sodium-based reagents in the DSI system.

- **Integrated systems:** Tests the NO_x and SO_2 reduction potential of the integrated system using LNB, OFA, SNCR, and DSI (calcium- or sodium-based reagents) on low- and high-sulfur coals.

In addition to investigating the emissions of NO_x and SO_2, the test program will investigate the emissions of air toxics. Baseline levels for the emissions of air toxics were obtained during the testing of the low-NO_x combustion system. Three additional tests were also performed during each of the urea, calcium, and sodium injection tests to determine the potential of these pollution control technologies for removing air toxics.

1.2.8 Overall Schedule for Project

Figure 1-2 summarizes the status of the program as of the draft date of this report.

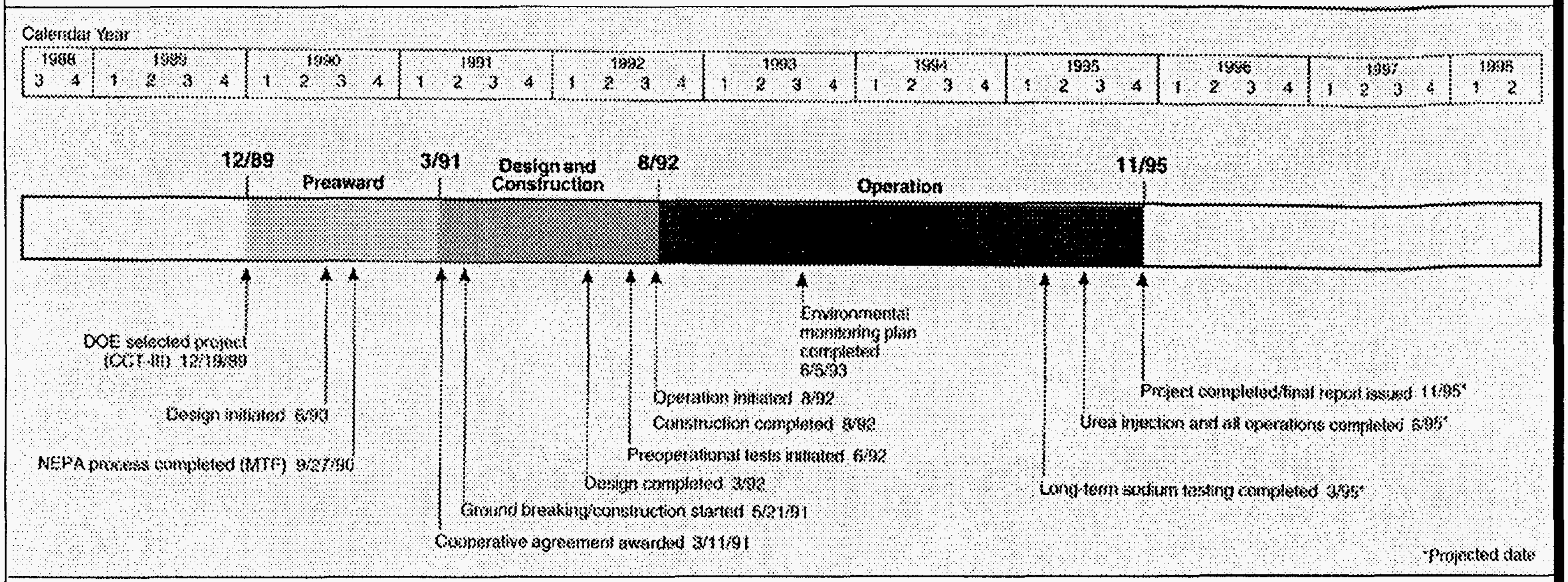


Figure 1-2: Overall Project Schedule

1.3 Objectives of Project

The Integrated Dry NO_x/SO_2 Emissions Control System demonstrates the **first**:

- Integration of low-NO_x burners, OFA ports, SNCR, DSI, and flue-gas humidification into a single emission control system.
- Application of low-NO_x burners to a down-fired pulverized-coal boiler.
- Application of OFA ports to a pulverized-coal, down-fired boiler.
- Use of an SNCR system on a coal-fired utility boiler in the U.S.
- Combined use of DSI and SNCR.

The emissions reduction goal of the project is to demonstrate up to 70% reductions in both NO_x and SO_2.

1.4 Significance of Project

The extensive testing program for the integrated system addresses the performance of each individual system (except low-NO_x burners and OFA ports which always operate together) as well as various combinations of the systems. If successful, this program will establish an alternative technology to the use of wet or dry flue-gas desulfurization (FGD) for SO_2 emissions control and SCR processes for NO_x emissions control.

The Integrated Dry NO_x/SO_2 Emissions Control System program will demonstrate, at utility scale, new integrated combustion and flue-gas cleanup technologies for the removal of potential acid-rain causing emissions. This project is directed particularly at down-fired units, but its results will also be applicable to other types of units.

Currently, down-fired units represent a market without any demonstrated low-cost NO_x and SO_2 removal systems. Consequently, the commercialization of the technology requires a comprehensive data base to demonstrate the emission control, performance enhancements, reliability, and cost effectiveness of the technology.

1.4.1 Commercialization

If successful, this demonstration project will establish that the combinations of technologies used by the Integrated Dry NO_x/SO_2 Emissions Control System are effective, reliable, and economic approaches to the control of the two major pollutants associated with acid rain. The technology has the potential to penetrate not only the pre-NSPS down-fired and wall-fired wet-bottom utility-boiler market, but the pre-NSPS dry-bottom wall-fired utility-boiler and the industrial boiler markets as well.

The Integrated Dry NO_x/SO_2 Emissions Control System has many advantages for commercialization. Either the entire integrated emissions control system or its parts:

- Can be retrofitted to most utility and industrial coal-fire units with modest capital investment and downtime. It is mainly applicable to older, small- to mid-size units.
- Is a lower capital-cost alternative to conventional wet flue-gas desulfurization processes. It also requires substantially lower space allowing for easy retrofitting.
- Can be applied to a wide range of coals.
- Has low cost (estimated): $190 per kW for a 100MWe unit burning a low sulfur coal

The Integrated Dry NO_x/SO_2 Emissions Control System has many features expected to increase the project's potential for commercialization. The integrated emission control system:

- Uses proven, commercially available equipment.
- Simultaneously removes up to 70% of NO_x and SO_2.
- Has low to moderate capital and operating costs.
- Can use sodium- or calcium-based reagents depending on cost and disposal requirements.
- Forms dry, free flowing, non-toxic reaction products that are removed by downstream particulate-removal systems and disposed of with the rest of the flyash. The existing dry ash removal system can be used.
- Requires minimum space to aid retrofitting.

Commercialization also requires the means of transferring the information gained by this program directly to industry. Therefore, applicable project information (non-proprietary) will be made available to the utility industry and to other potential users of the technology. EPRI is particularly suited to disseminating the information generated by this project.

1.4.2 Level of Technical and Commercial Risk Reduction

Although there is already some experience with the individual technologies of the Integrated Dry NO_x/SO_2 Emissions Control System, the effectiveness of the entire system has not been demonstrated. The generally conservative utility industry is the main market for the demonstrated technology. The system's potential customers must be able to demonstrate to their regulating agencies that their planned environmental equipment is proven and economical. Therefore, the commercialization of this technology requires a demonstration on a full-scale generating unit to prove that it is an effective and economical method for controlling NO_x and SO_2 emissions.

1.4.3 Known Concerns to be Met by Project

It is anticipated that the integrated control system will reduce both NO_x and SO_2 emissions by up to 70% at costs lower than other technologies now available. However, there are technical concerns with some of the technologies. For example, an undesirable side effect of sodium-based DSI at high levels of SO_2 removal is the oxidation of nitric oxide (NO) to nitrogen dioxide (NO_2) that results in the colorization of the exhaust plume. Pilot-scale testing, sponsored by EPRI, has shown that ammonia (NH_3) can suppress the net conversion of NO to NO_2. Therefore, when SNCR and DSI (using sodium-based reagents) are integrated, the byproduct NH_3 from the SNCR system is expected to suppress the net conversion of NO to NO_2 in the DSI system. It is also expected that this reaction will reduce the excess NH_3 emissions (ammonia slip) produced by SNCR.

The project will investigate the difficulties of installing low-NO_x burners, OFA ports, and SNCR on a down-fired boiler burning pulverized coal.

1.5 DOE's Role in Project

The DOE overviews the management of the Integrated Dry NO_x/SO_2 Emissions Control program and provides 50% of its financing. In addition, the DOE:

- Is responsible for monitoring all aspects of the project and for granting or denying approvals based on the Cooperative agreement.
- Provides technical advice.
- Reviews technical reports.
- Publishes the technical data and test conclusions for the public's use.

1.5.1 Management Plan

Figure 1-3 shows the organization chart of the demonstration program for the Integrated Dry NO_x/SO_2 Emissions System.

As overall manager, PSCo is responsible for all aspects of project performance including budget, scheduling, and contracting for the required scope of work. PSCo has assigned a Project Engineer to control the project and manage the detailed technical work. Although the project will use various PSCo engineering and support personnel to help complete the work, PSCo contracted much of the work to companies with experience and knowledge in the various technologies. This team of an experienced project manager and core of experienced professionals has brought the project through its design and construction phases on time and budget.

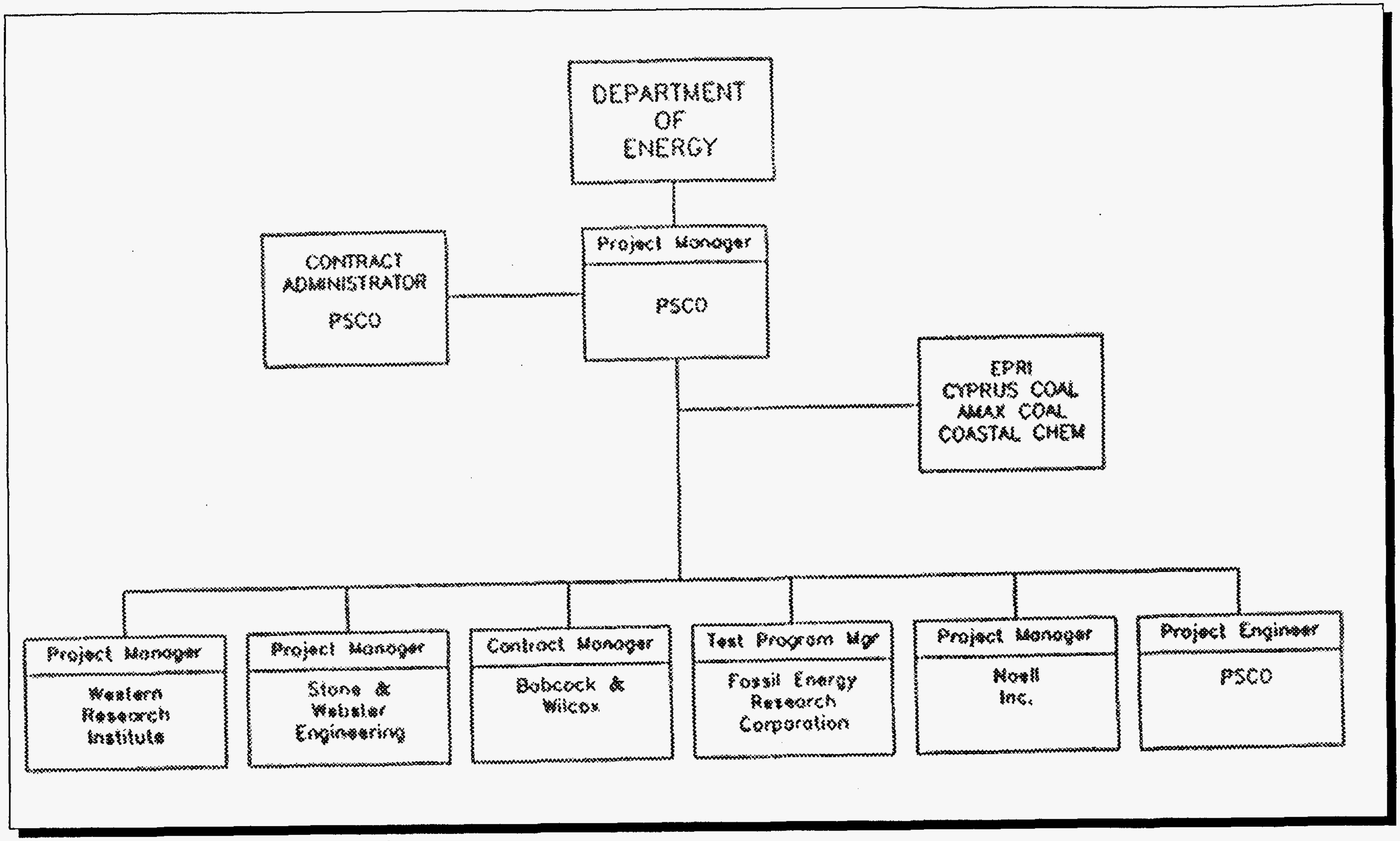


Figure 1–3: Project Organization Chart

2.0 TECHNOLOGY DESCRIPTION

2.1 Brief Description of Technology Used

To control NO_x and SO_2 emissions, the Integrated Dry NO_x/SO_2 Emissions Control System integrates various combinations of the five following technologies:

- Low-NO_x burners.
- OFA ports.
- SNCR (urea and ammonia injection).
- DSI (calcium- and sodium-based reagents).
- Flue-gas humidification (with DSI and calcium-based reagents).

2.1.1 Low-NO_x Burners

The Integrated Dry NO_x/SO_2 Emissions Control System uses Babcock & Wilcox (B&W) Dual Register Burner-Axially Controlled Low-NO_x (DRB-XCL®) burners to reduce NO_x emissions.

2.1.1.1 Low-NO_x Burner Process Chemistry

The oxidation of nitrogen (N_2) from two sources forms most of the NO_x in flue gases: (1) atmospheric nitrogen that dissociates and oxidizes at flame temperatures forms "thermal NO_x" and (2) fuel-bound nitrogen that is organically bonded to the fuel forms "fuel NO_x". While burning pulverized coal, fuel NO_x is the primary source (as much as 80%) of NO_x emissions, although thermal NO_x is also a significant contributor. While burning natural gas, thermal NO_x is the primary source of NO_x emissions.

2.1.1.2 Low-NO_x Burner Technology

The B&W DRB-XCL® burner uses air and fuel staging to reduce the formation of NO_x. Further, it is designed so that the amount of combustion air can be measured and regulated to balance the distribution of fuel and air to each burner. This balance is important for optimizing combustion efficiency and NO_x reduction.

Air staging is the withholding of a portion of the total combustion air from the initial combustion zone. The withheld air is then mixed with incomplete products of combustion following the consumption of oxygen in the initial burning stage.

Fuel staging is the introduction of fuel in stages. In conjunction with air staging, the design of the DRB-XCL® burner accelerates the combustion of the fuel immediately after it leaves the burner, but in an oxygen-lean (fuel-rich) zone. The devolatization of the coal in a fuel-rich environment creates hydrocarbon radicals that can reduce some of the NO to N_2.

2.1.1.3 Advantages/Limitations of Low-NO_x Burner

The use of DRB-XCL® burners on wall fired-boilers has achieved NO_x reductions of 35 to 70% from uncontrolled baseline levels. However, because the burner is designed for wall-fired applications, it requires modification for use in down-fired units like Arapahoe Unit 4. Also, down-fired boilers require substantial modifications in order to install the modified burners. These modifications greatly increase the capital cost of installing lox-NO_x burners on this type of generating unit.

2.1.2 OFA (NO_x) Ports

In addition to B&W DRB-XCL® burners, the Integrated Dry NO_x/SO_2 Emissions Control System uses B&W Dual-Zone NO_x Ports® to reduce NO_x emissions.

2.1.2.1 OFA Port Chemistry

OFA ports (also called NO_x ports) use air staging to control the mixing process over a larger volume of the furnace. OFA ports divert part of the combustion air from the primary combustion zone to a zone downstream of the burner so that initial combustion occurs in a nearly stoichiometric or slightly fuel-rich environment. The diverted air is introduced downstream of the primary combustion zone through the OFA ports.

2.1.2.2 OFA Port Technology

Typically, conventional single-jet OFA ports are not capable of providing adequate mixing across an entire furnace. The B&W Dual-Zone NO_x Ports®, however, incorporate a central (inner) zone and an outer zone to provide adequate mixing across the entire furnace. The inner zone produces a high-velocity jet of air that penetrates across the entire furnace. The outer zone diverts and disperses the air in the area of the furnace near the NO_x ports. Also, the ability to measure and regulate the flow of air to the burners and the OFA ports throughout a boiler's load range improves the performance of OFA ports.

2.1.2.3 Advantages/Limitations of OFA Ports

Unlike wall-fired boilers, adding OFA ports to down-fired boilers involves more than a simple extension of the windbox. Instead, installing OFA ports into a down-fired boiler requires new ductwork to carry the OFA to the OFA ports. This additional ductwork significantly increases the capital cost of installing OFA ports on down-fired boilers.

When used with pulverized coal, OFA ports can increase slagging and corrosion in the furnace and decrease combustion efficiency. Corrosion from hydrogen sulfide (H_2S) is a concern with higher-sulfur coals (particularly those with more than 2 lb/MMBtu). Protective coatings of aluminum or stainless steel can reduce the potential for corrosion, but substoichiometric burning of high-sulfur coal is not recommended. Also, because of the potential formation of wet or plastic slag, OFA ports are not suitable for high- and severe-slagging bituminous coals.

2.1.3 SNCR (Urea and Ammonia Injection)

To further control NO_x emissions, the Integrated Dry NO_x/SO_2 Emissions Control System uses an SNCR system designed by NOELL, Inc.

2.1.3.1 SNCR Chemistry

This process injects either urea or ammonia (anhydrous or aqueous) into the flue gas at a point where its temperature is between 1,600 to 2,100 °F. In this temperature range and in the presence of oxygen (O_2), the injected chemical releases NH_2 which selectively reacts with NO to form harmless N_2 and H_2O and reduce NO_x emissions.

2.1.3.2 SNCR Technology

Generally, a liquid solution of urea is injected through atomizers into the boiler. The atomizing medium can be either air or steam. The urea and any additives are stored as a liquid and pumped through the injection atomizers. At Arapahoe Unit 4, a system has also been installed to convert catalytically the urea solution to an aqueous ammonium compound for low-load conditions.

2.1.3.3 Advantages/Limitations of SNCR

The performance of an SNCR system depends greatly on a unit's furnace geometry, fuel, and other factors. Coal-fired units retrofitted with SNCR systems have achieved NO_x reductions ranging from below 20% to above 80%. While maintaining acceptable levels of reagent consumption and ammonia slip, SNCR systems generally achieve NO_x reductions of 30 to 50%. However, retrofitting SNCR systems to large utility units where the proper temperature for SNCR occurs in the convection pass cavities is more challenging and may limit NO_x reductions to 20 to 40%.

SNCR systems are very sensitive to the changes in flue-gas temperatures caused by changes in load, coals, sootblowing, and other operating conditions. Small changes in flue-gas temperature at a system's injection points can significantly affect the performance of an SNCR system.

2.1.4 DSI

The Integrated Dry NO_x/SO_2 Emissions Control System uses a dry-sorbent injection (DSI) system to reduce SO_2 emissions.

2.1.4.1 DSI Chemistry

The calcium- and sodium-based reagents are injected into the flue gas dry. Through a series of complex reactions, the reagents react with the gaseous SO_2 in the flue gas to form a calcium- or sodium-based solid that can be removed by the particulate control device (fabric-filter dust controller or electrostatic particulate device).

2.1.4.2 DSI Technology

DSI systems include equipment for storing, conveying, pulverizing and injecting sodium- or calcium-based reagents into the flue-gas ductwork. Calcium reagents are injected into the flue gas duct at a point where the flue gas is about 1,000 °F (usually just before the economizer and the air heater). Calcium reagents may also be injected between the air heater and the particulate control device, but for lower SO_2 removal rates. Sodium reagents are generally injected into the flue gas between the air heater and the particulate control device.

2.1.4.3 Advantages/Limitations of DSI

DSI is a simple system that uses existing ductwork. Therefore, it has low capital costs and is easily retrofitted to existing units. On some systems, DSI using sodium-based reagents has also been shown to provide an additional 5 to 20% of NO_x removal.

DSI produces a dry solid product that can be handled by conventional flyash systems, but the use of DSI increases the amount of flyash and adds soluble compounds to it. For example, because of its DSI system, the Integrated Dry NO_x/SO_2 Emissions Control System creates approximately 25% more waste with low-sulfur coal. Because of the soluble compounds, the flyash from the test program will be collected dry instead of slurried to ash ponds. Also, due to the solubility of the sodium compounds added, the ash is not appropriate for use as a concrete additive and thus cannot be sold.

2.1.5 Flue-Gas Humidification

The Integrated Dry NO_x/SO_2 Emissions Control System uses flue-gas humidification to enhance the effectiveness of the calcium-based reagent injected by the DSI system.

2.1.5.1 Flue-Gas Humidification Chemistry

Flue-gas humidification systems inject water into the flue-gas downstream of the air heater and upstream of the particulate control device. Increasing the humidity of the flue gas does not change the SO_2 removal chemistry of the calcium-based reagents, but it does improve their reactivity. Flue-gas humidification is not expected to significantly increase the effectiveness of sodium-based reagents.

2.1.5.2 Flue-Gas Humidification Technology

Flue-gas humidification systems inject water into the flue-gas between the sorbent-injection grid and the fabric filter dust collector (FFDC) or the electrostatic precipitator (ESP). Generally, dual-fluid nozzles are used to inject large quantities of high-pressure air to atomize the injected water and ensure its complete evaporation before it enters the particle control device.

2.1.5.3 Advantages/Limitations of Flue-Gas Humidification

Depending on the type of sorbent, the rate of injection, furnace geometry, and other operating conditions, the use of flue-gas humidification and DSI with calcium-based reagents has achieved SO_2 removal rates from 20% to 50%.

Humidification also lowers the pressure drop across, and increases the effective collection area of, the particulate control device, particularly FFDCs. The injected water evaporates and cools the flue gas. This cooling reduces the volumetric flow rate of the flue gas and increases both its relative and absolute humidities. Decreasing the volumetric flowrate and increasing the humidity of the flue gas improves the performance of the particulate control device. However, if liquid water reaches the FFDC, the water could damage it. Flue-gas humidification has also been used to increase the effectiveness of ESPs.

2.1.6 Integrated Emissions Control System

The combined technologies of the Integrated Dry NO_x/SO_2 Emissions Control System are expected to integrate synergistically and control NO_x and SO_2 emissions better than if each technology were used alone. The following sections describe the synergistic interaction of the technologies.

2.1.6.1 Integration of Low-NO_x Burners and OFA Ports

Both low-NO_x burners and OFA reduce the formation of NO_x by controlling the fuel/air mixing process. While low-NO_x burners use air and fuel staging to control the mixing of the fuel and air near the burner, OFA ports control the process over a larger volume of the furnace. OFA ports extend the zones produced by the burner to fill more volume of the furnace. This allows the burners and ports to be adjusted to work together and produce less NO_x.

Under short-term, controlled test conditions, the first combined use of B&W's DRB-XCL® burners and Dual-Zone NO_x ports on a wall-fired unit burning coal in Japan reduced NO_x emissions 65 to 70% from uncontrolled levels.

2.1.6.2 Integration of SNCR and DSI

Although sodium-based DSI systems reduce the emissions of SO_2, some applications have caused NO to convert to NO_2. Because NO_2 is a reddish-brown gas, the formation of NO_2 can cause a visible plume to form as the flue gas exits the stack.

It is expected that the combination of urea injection and sodium-based DSI will improve the performance of both systems. Previous pilot-scale tests have shown that ammonia reduces the formation of NO_2 in sodium-based DSI systems. The ammonia emissions are also reduced due to a reaction with the NO_2.

2.1.6.3 Integration of Low-NO_x Combustion System and SNCR

Low-NO_x burners and OFA ports reduce the NO_x produced by combustion. This reduction enhances the effectiveness of the SNCR system. With a lower initial level of NO_x, an SNCR system requires less urea and is expected to create less excess ammonia.

2.1.6.4 Integration of Low-NO_x Combustion System and DSI

Most of the NO_x produced by combustion is NO and less than 5% is NO_2. The low-NO_x combustion system produces less of both NO and NO_2. Since the low-NO_x combustion system greatly reduces the NO baseline, the DSI system will have less NO to convert to NO_2. With a lower NO_2 baseline, the DSI system will be able to form more NO_2 before a visible plume appears. Therefore, the integration of the low-NO_x combustion system with DSI will allow the DSI system to achieve higher rates of SO_2 removal.

2.1.7 Proprietary Information

The Integrated Dry NO_x/SO_2 Emissions Control System does not use any significant proprietary information. However, the U.S. Patent Office issued patent number 5,165,903 for the integration of the sodium-based DSI and urea-based SNCR systems on November 24,1992.

2.2 Overall Block Flow Diagram

Figure 1-1 shows a block flow diagram for the integrated system. Section 4.0 contains block flow diagrams and material and energy balances for the individual and integrated systems.

3.0 PROCESS DESIGN CRITERIA

Arapahoe Unit 4 is a down-fired, 100-MWe unit (name plate) designed to burn pulverized coal (Colorado lignite) or natural gas. It came on line in 1955 and is the largest generating unit at Arapahoe Station. PSCo uses Arapahoe Unit 4 as a load-following station, so it can experience large and rapid load swings. The unit generally operates at high use factors. The unit's normal capacity factor is 50 to 60%.

Currently, Arapahoe Unit 4 mainly burns two low-sulfur (0.4% sulfur) bituminous coals mined in Colorado: Cyprus Yampa Valley and Empire Energy Coals. A third coal (2.5% sulfur) mined in Illinois and designated as Delta No. 6 will be used during the testing phase of the project to evaluate the emission control technologies on a high-sulfur coal. Proximate and ultimate analyses for the low-sulfur coals are shown in Section 3.1.2. Although Arapahoe Unit 4 can use natural gas to run at full load, natural gas is used only occasionally to provide load when pulverizers or other equipment are out of service.

3.1 Base Data for Design/Retrofit of Project

The information and the data in the following sections was used as a basis for designing the Integrated Dry NO_x/SO_2 Emissions Control System and its retrofit to Arapahoe Unit 4. The following tables summarize the base design and operating information used to design and retrofit the integrated system to Arapahoe Unit 4. Table 3-1 lists the ambient conditions. Table 3-2 summarizes the information on the unit. Table 3-3 summarizes the information on the particulate control device. Table 3-4 summarizes the information on the pulverizers.

Ambient Conditions	
Elevation	5,300 ft
Atmospheric pressure	12.2 psi
Air temperature range	-20 to 110 °F
Average temperature	60 °F

Table 3-1: Ambient Conditions

Arapahoe Unit 4		
Capacity	Maximum	112.5 MWe
	Name plate	100 MWe
	# of burners	12
Heat Transfer	Heat release rate	14,700 Btu/ft^3 of furnace volume
	Area of heat surface	15,744 ft^2
Steam	Total flowrate	1,004,400 lb/h
	Temperature	1,005 °F
	Pressure	1,530 psig
Flue Gas	Design duct gas velocity	3,600 ft/min
	Air heater exit/FFDC inlet temperature	290 °F
	Flowrate	1,236,000 lb/h
	Base NO_x emissions (full load)	840 ppm at 3% O_2 (1.15 lb/MMBtu)
	Base SO_2 emissions (full load)	350 ppm at 3% O_2 (0.66 lb/MMBtu)

Table 3-2: Design and Operating Information on Arapahoe Unit 4

Particulate Control Device	
Vendor/type	Ecolaire FFDC
Flyash particulate removal rate	99.99%
Number of compartments	12
Bags per compartment	252
Design air-to-cloth ratio	2.0
Outlet dust loading	0.007 grains/dSCF
Date installed	1980

Table 3-3: **Base Design and Operating Information on Arapahoe Unit 4's Particulate Control Device**

Pulverizers	
Vendor/Type	Riley Stoker Atrita Series 550 Duplex Pulverizers
Quantity	4
Flowrate of primary air per pulverizer	46,000 lb/h
Coal fineness	99%-US standard 50 mesh 70%-US standard 200 mesh
Date installed	1955 (original to plant)

Table 3-4: **Base Data on Arapahoe Unit 4's Pulverizers**

3.1.1 Design Coals

The following tables list the ultimate and proximate analyses of the coal used in designing and retrofitting the integrated emission control system. Table 3-5 lists the proximate analysis and Table 3-6 lists the ultimate analysis for Cyprus Yampa coal. Table 3-7 lists the proximate analysis and Table 3-8 lists the ultimate analysis for Empire Energy coal.

Property	As Received
Moisture	10.6%
Ash	9.6%
Volatile matter	34.1%
Fixed carbon	45.4%
FC/VM	1.33
Heating value	11,050 Btu/lb

Table 3-5: **Proximate Analysis of Cyprus Yampa Coal**

Property	As Received
Moisture	10.6%
Carbon	62.8%
Hydrogen	4.5%
Nitrogen	1.6%
Chlorine	negligible
Sulfur	0.4%
Ash	9.6%
Oxygen (difference)	10.5%

Table 3-6: **Ultimate Analysis of Cyprus Yampa Coal**

Property	As Received
Moisture	13.2%
Ash	8.0%
Volatile matter	33.8%
Fixed carbon	45.0%
FC/VM	1.33
Heating value	10,600 Btu/lb

Table 3-7: Proximate Analysis of Empire Energy Coal

Property	As Received
Moisture	13.2%
Carbon	61.5%
Hydrogen	4.5%
Nitrogen	1.3%
Chlorine	negligible
Sulfur (average)	0.4%
Ash (average)	8.0%
Oxygen (difference)	11.1%

Table 3-8: Ultimate Analysis of Empire Energy Coal

3.1.2 Pulverizers

Arapahoe Unit 4 has four Riley Stoker Model Atrita Series 550 duplex pulverizers. These are the original mills supplied with the boiler unit. Although normal procedure is to operate all four mills, Arapahoe Unit 4 can maintain design load with only three mills in operation.

Previous performance testing has shown that 99% of the coal produced by the pulverizers can pass through a U.S. Standard 50 mesh screen and that 70% of the coal produced by the pulverizers can pass through a U.S. Standard 200 mesh screen. Each pulverizer was designed for a primary airflow of 46,000 lb/h. The original Riley pulverizers were not modified, but new variable-speed feeder drives were added to provide a more consistent feed of coal to the pulverizers as part of this project.

3.1.3 Particulate Control Device

The existing Ecolaire Fabric Filter Dust Collector (FFDC) that was installed in 1980 will continue to remove the flyash from the flue gas. The FFDC removes greater than 99.9% of the flyash particulates and will remain essentially unaffected by the project.

3.1.4 Injected Materials

The following tables list the properties of the materials injected by the integrated emissions control system. Table 3-9 lists the product specifications for the urea injected by the SNCR system.

Urea (as Received)	
Urea content	65 wt%
Biuret (maximum)	1.0 wt%
Iron (maximum)	2 ppmw
Color	10 APHA units
Turbidity	10
Free ammonia (maximum)	0.3 wt%
Salt out temperature	115 °F (approximate)
Specific gravity	1.168 at 130 °F (9.74 lb/gal) 1.165 at 140 °F (9.72 lb/gal) 1.162 at 150 °F (9.69 lb/gal)
Viscosity at 120 °F	1.07 cP
Specific heat	0.68 Btu/lb-°F
Minimum shipping temperature	140 °F

Table 3-9: Product Specifications for Urea (Coastal Chemical)

Hydrated Lime	
Calcium oxide as CaO	68.32%
Magnesium oxide as MgO	1.43%
Silica as SiO_2	0.54%
Aluminum oxide as AL_2O_3	0.43%
Iron oxide as Fe_2O_3	0.19%
Carbon dioxide as CO_2	3.37%
Free H_2O	0.43%

Table 3-10: Hydrated Lime

Sodium Sesquicarbonate-Solvey Minerals T-200		
Composition	Na_2CO_3	45.8%
	$NaHCO_3$	36.3%
	Available Na	29.8%
	Free moisture	0.01%
	H_2O insolubles	2.3%
	NaCl	0.1%
Size/Density	Bulk density	49 lb/ft^3
	−200 U.S. mesh	67.0%
	−140, +200 U.S. mesh	10.2%
	−100, +140 U.S. mesh	17.5%
	−70, +100 U.S. mesh	2.3%
	−50, +70 U.S. mesh	0%

Table 3-11: Sodium Sesquicarbonate

Sodium Bicarbonate-Natec Flue Gas Desulfurization Grade		
Composition	$NaHCO_3$	99.5%
	Available Na	27.2%
	Free moisture	0.0%
Size/Density	Bulk density	64 lb/ft^3
	−325 U.S. mesh	25 %
	−200 U.S. mesh	52%
	−100 U.S. mesh	76%

Table 3-12: Sodium Bicarbonate

3.2 Design Criteria for Low-NO_x Burners

Characteristically, pulverized-coal-fired generating plants with intertube down-fired burners emit high levels of NO_x. The combination of low-NO_x DRB-XCL® burners with B&W Dual-Zone NO_x Ports® is an advanced technology available for the combustion control of NO_x. In wall-fired boilers, operating experience has shown that converting to B&W DRB-XCL® burners can reduce NO_x emissions by up to 50%. Combining low-NO_x burners and OFA ports is expected to reduce NO_x emissions by up to 70%.

3.2.1 Chemistry of Low-NO_x Burners

The oxidation of nitrogen (N_2) from two sources forms most of the NO_x in flue gases: (1) atmospheric nitrogen (forms "thermal" NO_x) and (2) fuel-bound nitrogen (forms "fuel" NO_x). While burning pulverized coal, fuel NO_x is the primary source of NO_x emissions, although thermal NO_x is also a significant contributor. While burning natural gas, thermal NO_x is the primary source of NO_x emissions.

Coal burns in two stages: (1) devolatization and (2) char burnout. Typically, about 0.5 to 2.0% of a coal's content is nitrogen bound in its organic matter. When burned, coal releases this nitrogen as a free radical that can then combine with oxygen in the air to form NO_x. It is estimated that 60 to 90% of the fuel NO_x forms during devolatilization.

The availability of oxygen during devolatilization promotes the formation of the released nitrogen to NO_x. Therefore, the most effective means of inhibiting the formation of fuel NO_x is to limit the availability of oxygen during devolatilization. Instead of the released nitrogen radicals combining with oxygen, they combine with each other to form N_2. To maintain a high level of combustion efficiency, the remaining air is added later in the process (during char burnout).

Studies have shown that decreasing the temperature as well as the concentrations of N_2 and O_2 at the flame-front inhibits the formation of thermal NO_x. Diverting combustion air away from the flame-front lowers the O_2 concentrations (creates a fuel-rich environment) and the temperature at the flame-front, thus inhibiting the formation of thermal NO_x.

In contrast, the production of fuel NO_x, is relatively unaffected by temperature. Studies indicate that the primary factor in the production of fuel NO_x is the availability of oxygen to react with the fuel-bound nitrogen compounds when they are converted to gases. Gaseous nitrogen compounds produced from coal are fairly unstable and form N_2 in a fuel-rich environment.

3.2.2 Operation of Low-NO_x Burners

The physical design of the DRB-XCL® burner promotes air-staging and fuel-staging. The coal nozzle is centrally located in the burner in an arrangement that carefully limits the interaction of air and fuel in the base of the flame. Dual air-zones with multi-stage swirl-vanes regulate the introduction of secondary air to the fuel.

Figure 3-1 shows the B&W DRB-XCL® low-NO_x burner. This burner uses two air zones. A separate register controls the mix of air and fuel for each air zone. The conical diffuser and flame stabilizing ring in the nozzle combine to improve flame stabilization, stage the burning of the fuel, and reduce NO_x emissions. The adjustable inner vanes stabilize ignition at the nozzle tip. The adjustable outer vanes control the mixing of the secondary air into the flame.

The coal piping supplies pulverized coal and primary air from the pulverizers to their respective burners. Secondary air is gradually introduced to the products of combustion further along the flame to complete combustion. This staged combustion reduces the flame intensity and, therefore, minimizes NO_x formation.

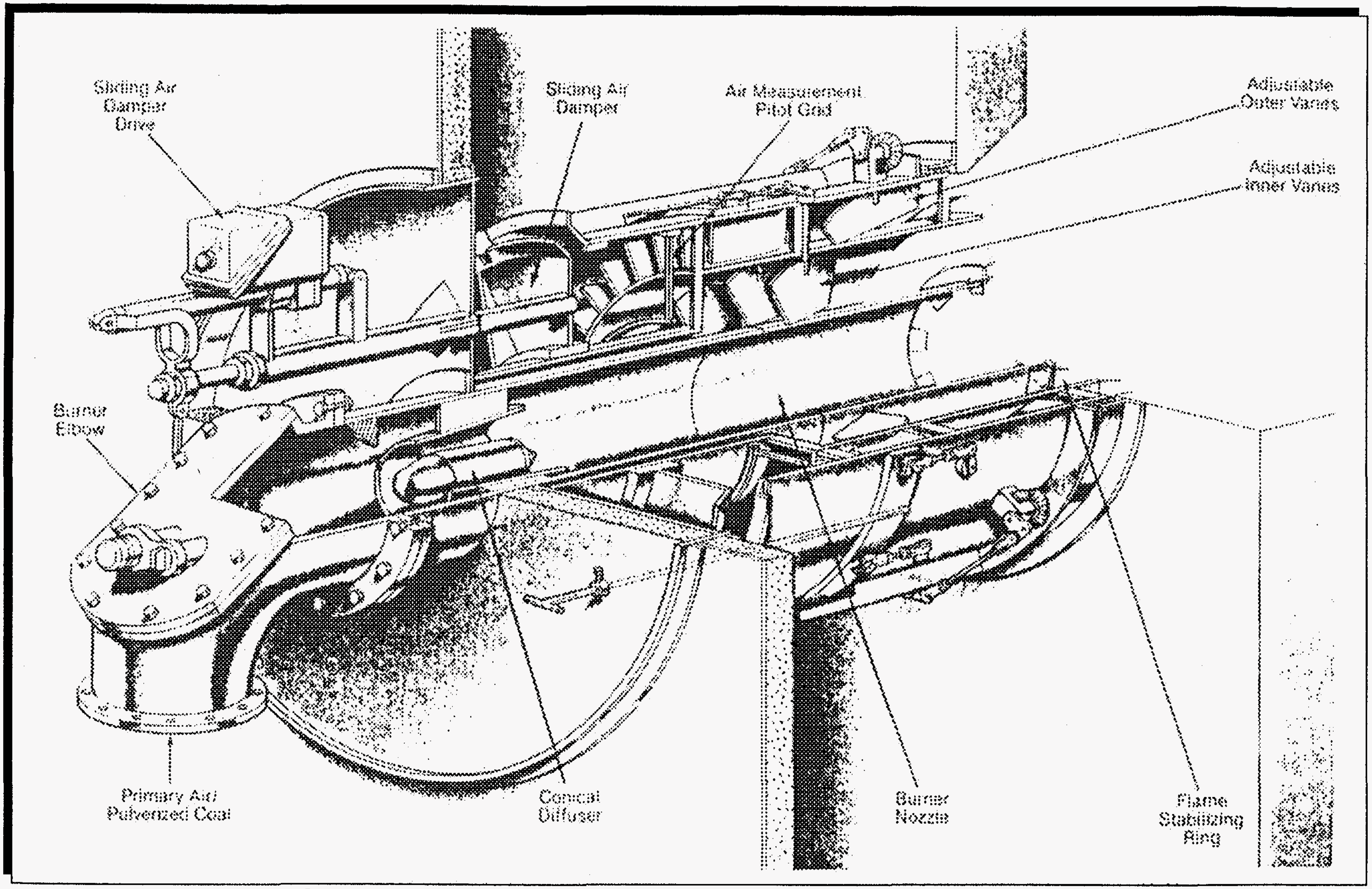


Figure 3–1: B&W DRB-XCL® Low-NO_x Burner (Source: B&W)

The design of the DRB-XCL® burner allows the airflow and air turbulence to each burner to be independently controlled. The flow of secondary air to each burner is controlled by positioning an adjustable sliding air-damper at the entrance to the air sleeves. To adjust the mixing of the fuel and air, Adjustable spin vanes located in the inner and outer air-zones impart swirl. An airflow measurement device located in the air sleeve upstream of the spin vanes indicates the relative airflow through each burner and facilitates the balancing of the airflow.

Figure 3-2 shows a schematic of the four combustion zones created by the B&W DRB-XCL® burner. The burner generates rapid heating and high temperatures in the fuel-rich core of the flame (Zone A). These conditions cause more of the coal to burn as volatile matter and release more nitrogen (leaving less in the char). The limited amount of oxygen in the flame core produces reducing species and minimizes the formation of NO_x. The reducing species propagate into the flame (Zone C) to further decrease NO_x emissions. Finally, the char oxidizes (burns) at lower temperatures and oxygen concentrations in Zone D than in the other zones.

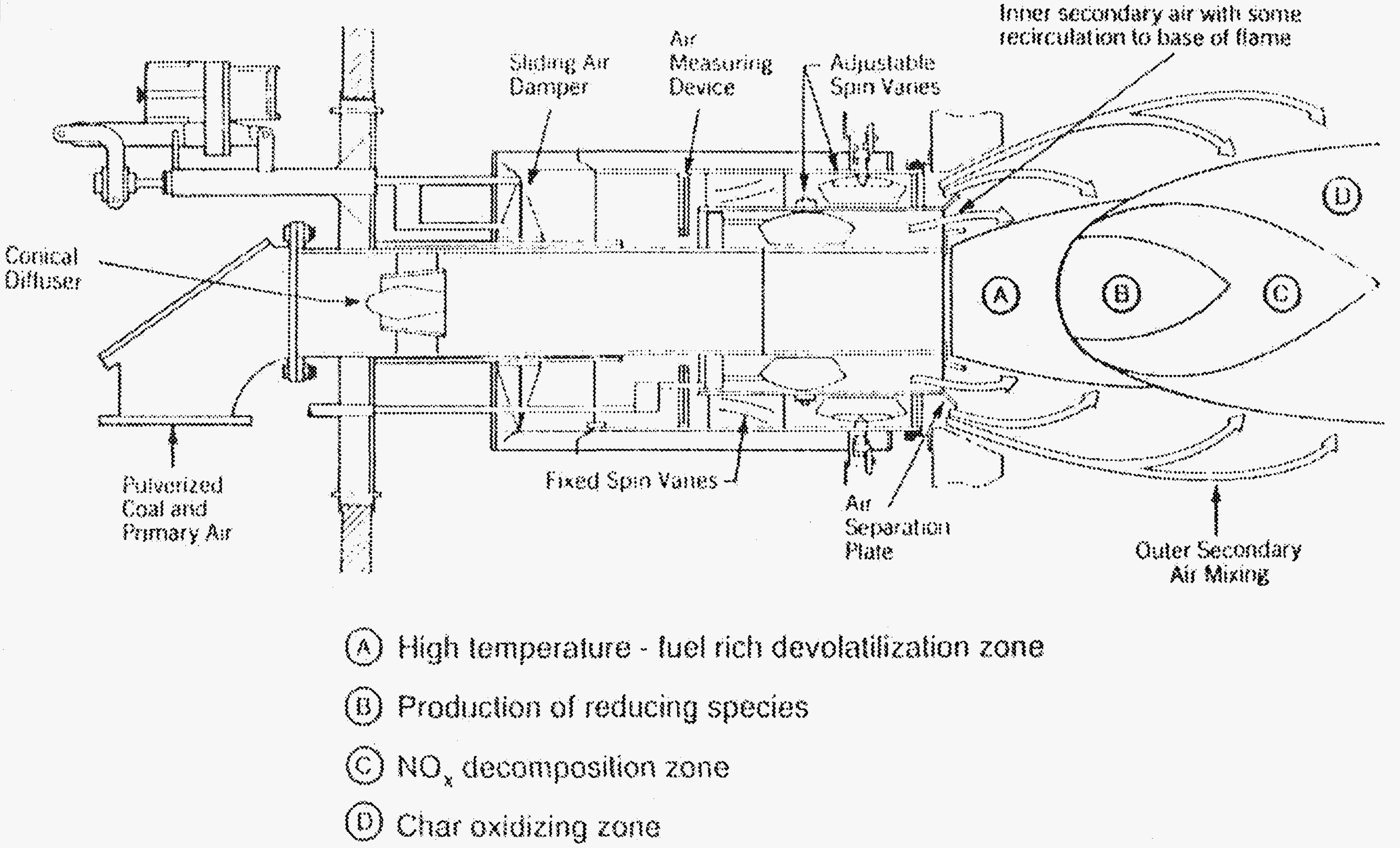


Figure 3-2: B&W Low-NO_x Burner Combustion Zones (Source: B&W)

3.2.3 Difficulty of Retrofitting DRB-XCL® Burners to Down-Fired Boilers

Retrofitting a top-fired boiler for low-NO_x burners requires more outage time, a larger capital investment, and is much more complicated than it is for a wall-fired boiler. Installing low-NO_x burners into a top-fired boiler requires the:

- Modification of the burner for vertical operation.
- Replacement of all roof tubes.
- Modification of secondary air supply ductwork.
- Removal of a large amount of asbestos containing material.
- Replacement of the windbox.
- Rerouting of coal and gas piping.
- Major modification of the control system.

B&W DRB-XCL® burners are designed to be fired horizontally. To avoid mechanical problems, these burners require modifications for down-firing. For instance, sliding dampers that were designed to operate horizontally, would have to be lifted and overcome their own weight when oriented vertically for down-firing. Improper operation of these dampers would result in problems with combustion operation.

3.2.4 Summary of Design Criteria

Low-NO_x burners are generally designed to:

- Accommodate plug-in installation to minimize or avoid changes to pressure parts.
- Minimize increases in differential pressure between the windbox and furnace to accommodate existing fan capacities and avoid upgrading or replacing fans.
- Maintain or improve boiler performance (maintain heat absorption profiles).

Table 3-13 summarizes the design criteria for low-NO_x burners.

Subsystem	Variable
Boiler Configuration/Geometry	Boiler heat release rate Number of burners
Coal and Air	Total airflow Velocity of primary air Coal-to-air ratio Coal fineness Uniformity of coal distribution Nitrogen content of coal FC/VM ratio Slagging characteristics Sulfur content of coal
Baseline Emissions	Excess O_2 UBC CO NO_x SO_2

Table 3-13: Design Criteria for Installing Low-NO_x Burners In Down-Fired Boilers

3.3 OFA Port Design Criteria

Generally, conventional single-jet OFA ports are not capable of adequately mixing the air and fuel across an entire furnace. The B&W Dual-Zone NO_x Ports®, however, incorporate a central zone and a separate outer zone.

Figure 3-3 shows front- and side-views of a B&W Dual-Zone NO_x Port®. The central zone produces a jet of air with sufficient axial momentum to reach across the furnace. The outer zone diverts and disperses air to the region near the waterwall. This two-stage injection provides faster mixing and a more equal distribution of air in the furnace, which reduces the emissions of CO and promotes the burnout of solid carbon.

The central zone has a manual air-control disk for flow control. The manually adjustable sliding damper controls the airflow to the inner zone to provide sufficient mixing across the entire furnace. The outer zone incorporates manually adjustable spin-vanes for swirl control. These adjustable spin vanes in the outer zone improve mixing near the furnace walls. In addition, each B&W Dual-Zone NO_x® Port has an airflow measurement device in each air zone for balancing the distribution of the OFA flow.

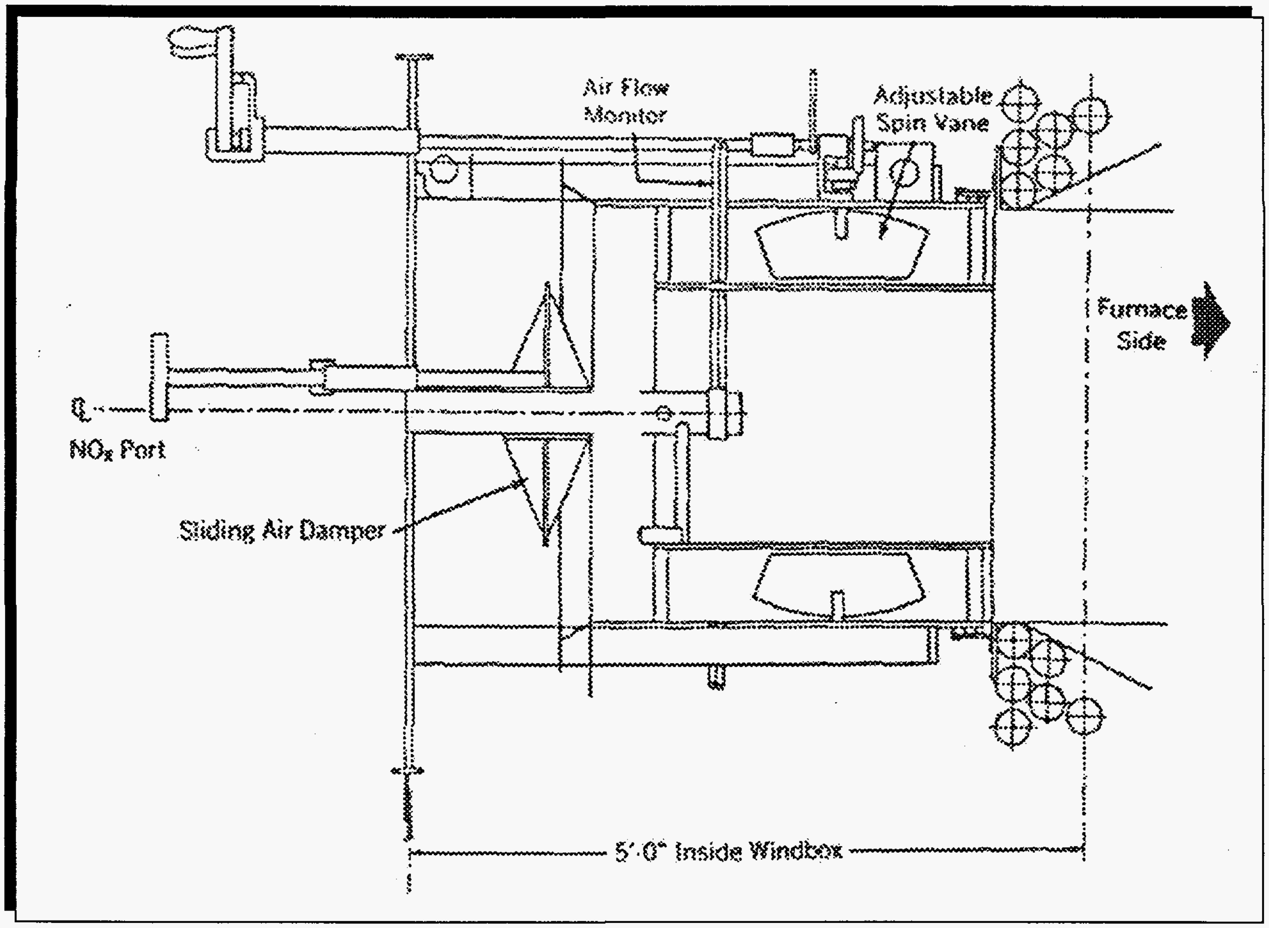


Figure 3-3: B&W Dual-Zone NO_x Port® (Source B&W)

3.3.1 Process Chemistry

A typical pulverized coal system operates at 15 to 20% excess air (above stoichiometric). Reducing the flow of air to the burners (even to below stoichiometric) decreases the formation of NO_x. The greater the reduction in airflow to the burners, the greater the reduction in NO_x. However, as the airflow to the burners is decreased, the system requires larger amounts and better mixing of OFA to complete combustion. At some point, depending on the system, the OFA system cannot complete the combustion of the coal so that further reducing the air to the burners increases unburned carbon loss, slagging, and corrosion.

3.3.2 Design Approach

The effectiveness of an OFA installation depends primarily on the following:

- **Placement of OFA ports**: The available upper furnace residence time, the available physical space for installation, and potential structural impediments (for example, sootblowers, steam headers, downcomers, and observation doors) determine the optimum placement of the OFA ports for a specific unit.
- **Coal properties**: A coal's reactivity (VM or FC/VM) as it affects UBC and slagging, and its corrosion potential are the most important properties that affect the performance of OFA ports. Relatively reactive coals and coals with low potentials for slagging and corrosion can use higher amounts of OFA.
- **OFA flow penetration**: Adequately mixing the OFA and the flue gas requires sufficient penetration of the OFA into the flue gas. The penetration of the OFA depends on the location, number and design of the OFA ports, and the available pressure for the OFA.
- **Other factors**: The configuration of the existing windbox and secondary air ducts, furnace stoichiometry, heat absorption patterns, and other factors can affect the effectiveness of OFA ports.

The design process for OFA ports varies from application to application and from vendor to vendor. Generally, OFA ports are designed to achieve good OFA penetration and mixing as quickly as possible. Other design goals include:

- Separating the supply of OFA from the main windbox so that the OFA can be operated independently from the air requirements of the windbox.
- Independently controlling the quantity and jet velocity of the OFA to optimize its mixing with the flue gas.
- Placing the OFA ports to ensure adequate residence times and to promote good mixing of the OFA and the flue gas.

3.3.2.1 Bulk Furnace Residence Time

The bulk furnace residence time is the most important design criterion in determining the feasibility and effectiveness of retrofitting OFA ports to a boiler. The bulk furnace residence time is the time the flue gas takes to travel from the burners to the leading convective surface. It is calculated by dividing the volume of the furnace between the burners and the leading convective surface by the flowrate of the flue gas.

The bulk-furnace-residence time must be long enough to mix completely the OFA and the flue gas and to complete the combustion process. Site-specific factors that affect the length of the required bulk-furnace-residence time include the following:

- Type and fineness of the coal.
- Degree of staging (percent of air diverted for OFA).
- Furnace geometry.
- Configuration of the burners (wall-, down-, or tangential-fired).
- Uniformity of the air and coal distribution in the burner zone.

The bulk-furnace-residence time is the sum of two components:

t_1: The time the flue gas takes to travel from the burners to the OFA ports. This is the time available for the fuel to burn in a low-oxygen environment. Longer times minimize the formation of NO_x.

t_2: The time the flue gas takes to travel from the OFA ports to the exit of the furnace. This is the time available for the fuel to complete combustion. Longer times minimize CO emissions and UBC.

3.3.2.2 OFA Penetration

The penetration of OFA into the flue gas depends primarily on two factors: the injection momentum of the OFA and the placement of the OFA ports. Injection momentum depends on the pressure of the secondary air and the design of the OFA ports. Dual-zone ports, such as the B&W Dual Zone NO_x Ports®, use two zones to achieve good penetration and mixing. Design and control of the air supplied for OFA depends on the quantity of OFA, FD fan capacity, and the design of each boiler and its supporting structures.

One parameter used to measure the penetration of OFA into a furnace is the ratio of the velocity of the injected OFA and the velocity of the flue gas. Higher ratios result in better mixes, but high OFA velocities may require modifications to the fan system.

3.3.2.3 Summary

Numerical modeling is an emerging technology that facilitates the integrating of low-NO_x burners and OFA ports. Computer programs can provide detailed model information about mixing effectiveness throughout a furnace as well as be used to optimize OFA port size and placement, burner swirl orientation, and furnace geometry. Table 3–14 summarizes the design criteria for OFA ports.

MAJOR CRITERIA	VARIABLE
OFA Port Location (Bulk Furnace Residence Time)	Residence time for substoichiometric combustion (t_1) Residence time for carbon burnout (t_2) Distribution of air and coal Furnace geometry Potential structural impediments
Properties of Coal	Slagging potential Coal fineness Corrosion potential
Mixing/Penetration	Port location Number Design (number of zones, etc.) Injection velocity of OFA Flue gas velocity Percent of total air for OFA

Table 3-14: Design Criteria for Installing OFA Ports in Down-Fired Boilers

3.4 SNCR Design Criteria

SNCR is a class of processes designed to reduce NO_x emissions from fossil-fuel combustion systems. SNCR processes involve the injection of a nitrogen-containing chemical (Primarily urea or NH_3) into the combustion products at a point where there temperature is between 1,600 and 2,100 °F. In this temperature range and in the presence of oxygen (O_2), the SNCR chemical reacts selectively with NO to form N_2 and H_2O. At too high of a temperature, the injected chemical reacts directly with the O_2 to form more NO_x. At too low of a temperature, the injected chemical does not react with the NO, resulting in excessive emissions of ammonia (NH_3) which is normally referred to as ammonia slip.

3.4.1 Process Chemistry

The injection of urea into the boiler provides SNCR of NO_x. The following equation (3-1) describes the overall reaction:

$$(NH_2)_2CO + 2NO + \frac{1}{2}O_2 \rightarrow 2N_2 + CO_2 + 2H_2O \qquad (3\text{-}1)$$

Figure 3-4 compares the vaporization of aqueous ammonium (NH_4OH) and urea when injected into hot flue gas. Aqueous ammonia vaporizes directly into NH_3 and H_2O. This release of NH_3 occurs until the injected drop is entirely evaporated. In contrast, the urea remains in the aqueous phase until enough water evaporates for the urea to approach saturation in the injected droplet. Then, it is thought, that the urea decomposes into NH_3 and cyanic (or isocyanic) acid (HNCO). The ammonia deNOx reaction begins immediately as the ammonia vapor is released while the urea droplet must evaporate before the deNOx reaction begins.

Figure 3-5 shows the decomposition of the injected chemicals once they have evaporated. From the injected ammonia, the gaseous NH_3 decomposes into amidogen (NH_2) which then

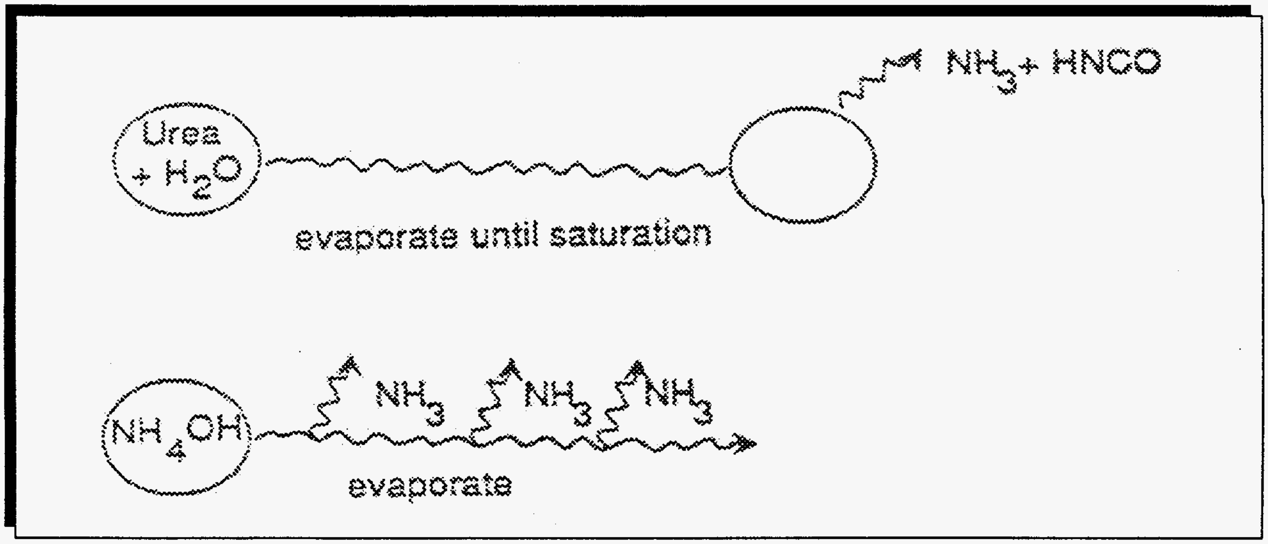


Figure 3-4: SNCR Chemical Vaporization Processes

reacts with NO to form N_2 and H_2O. From the injected urea, the NH_3 reacts as it did with the injected ammonia and the HCNO reacts with hydrogen or with a hydroxyl radical (OH). If it reacts with hydrogen, it follows a reaction path to reduce NO. If the HCNO reacts with OH, it follows a reaction path to create N_2O. Depending on temperature and residence time, the N_2O either decomposes further to N_2 or is emitted as a byproduct of the SNCR process.

3.4.2 Optimum Temperature Location

Urea and ammonia each have their own optimum temperature "window" for NO_x reduction. Figure 3-6 conceptually shows an example of such a window. Above the optimum temperature window, the injected chemical reacts with O_2 to form additional NO_x and reduce the NO_x removal efficiency of the system. Below the optimum temperature window, the injected chemical does not react with the NO resulting in an increased emission of ammonia called "ammonia slip." Chemical additives can be injected with urea to widen the optimum temperature window and minimize the emission of ammonia.

This narrow temperature window is the primary complication in the design of SNCR injection technology. When the boiler load is changed, the flue-gas temperature for a

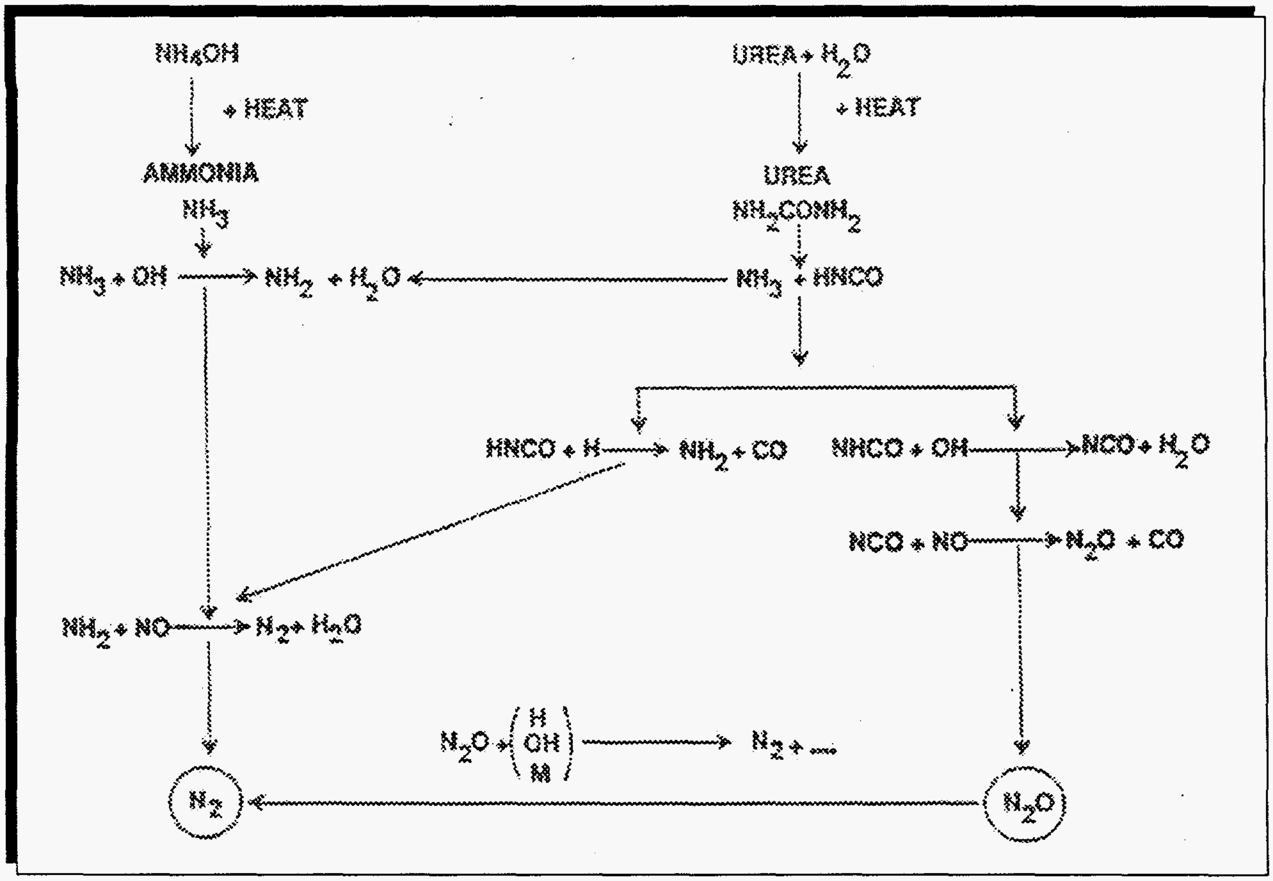


Figure 3-5: Major SNCR Chemical Paths for Urea and Ammonia

particular injection location also changes. For this reason, multiple levels of injection are usually required to provide good NO_x removal over a range of boiler load conditions.

Pilot-scale tests have shown that the optimum temperature for ammonia is 1,750 °F and for urea is 1,850 °F. It is not certain if the difference in these temperatures is due to differences in the decomposition of the chemicals and the release of reactive nitrogen compounds or to basic differences in the chemical reaction paths. Figure 3-7 graphs the differences between urea's and ammonia's optimum temperature ranges for NO_x reduction.

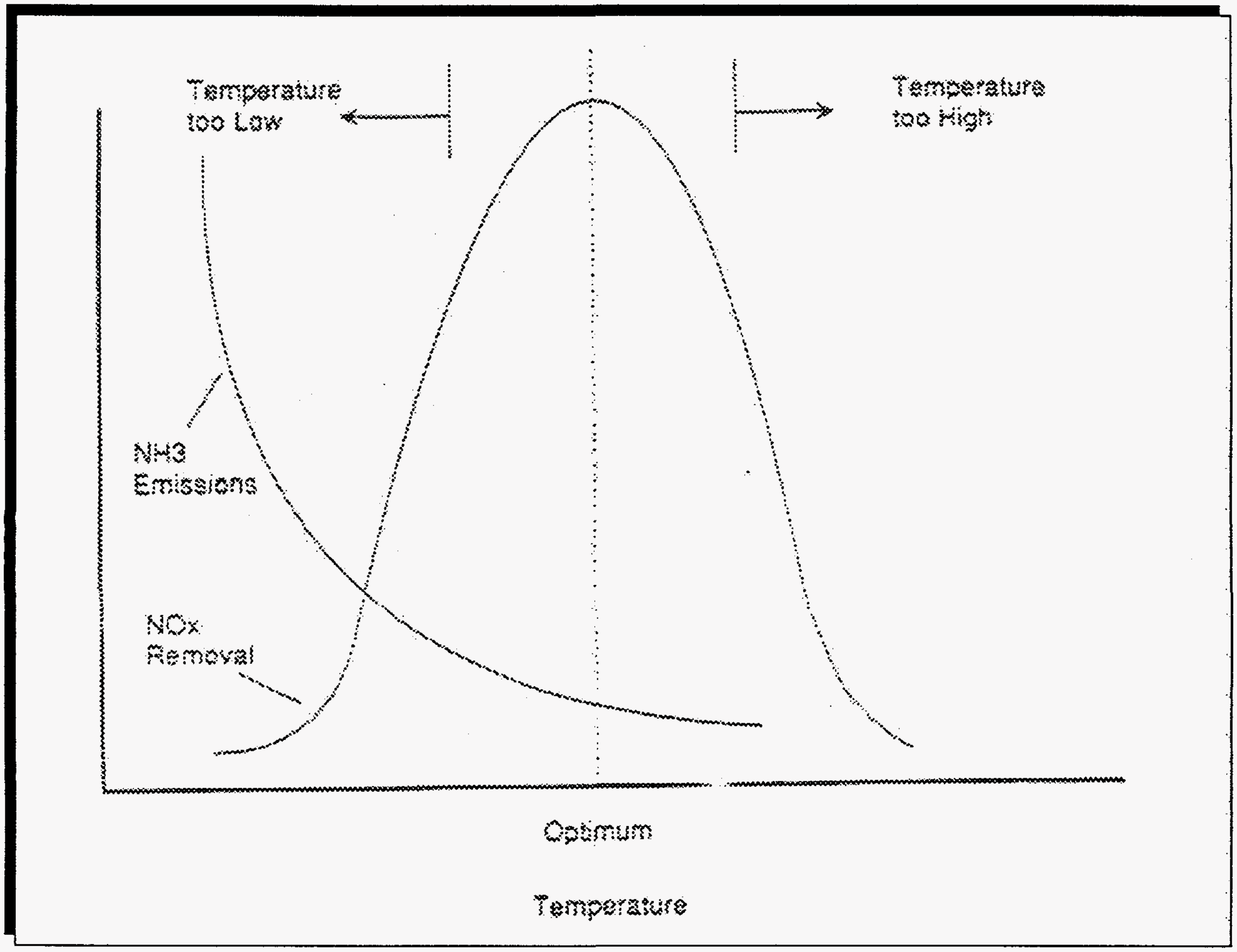


Figure 3-6: Conceptual Temperature Window for SNCR Process

3.4.3 Urea Concentration

The efficiency of the urea injection process depends on a number of process and operating variables. During the testing program, these variables will be optimized. The key process variables are as follows:

- Stoichiometric ratio: moles urea/moles NO.
- Initial concentration of NO (ppm).
- Concentration of injected urea (wt% urea).
- Air-to-liquid ratio at injectors (lb/lb).

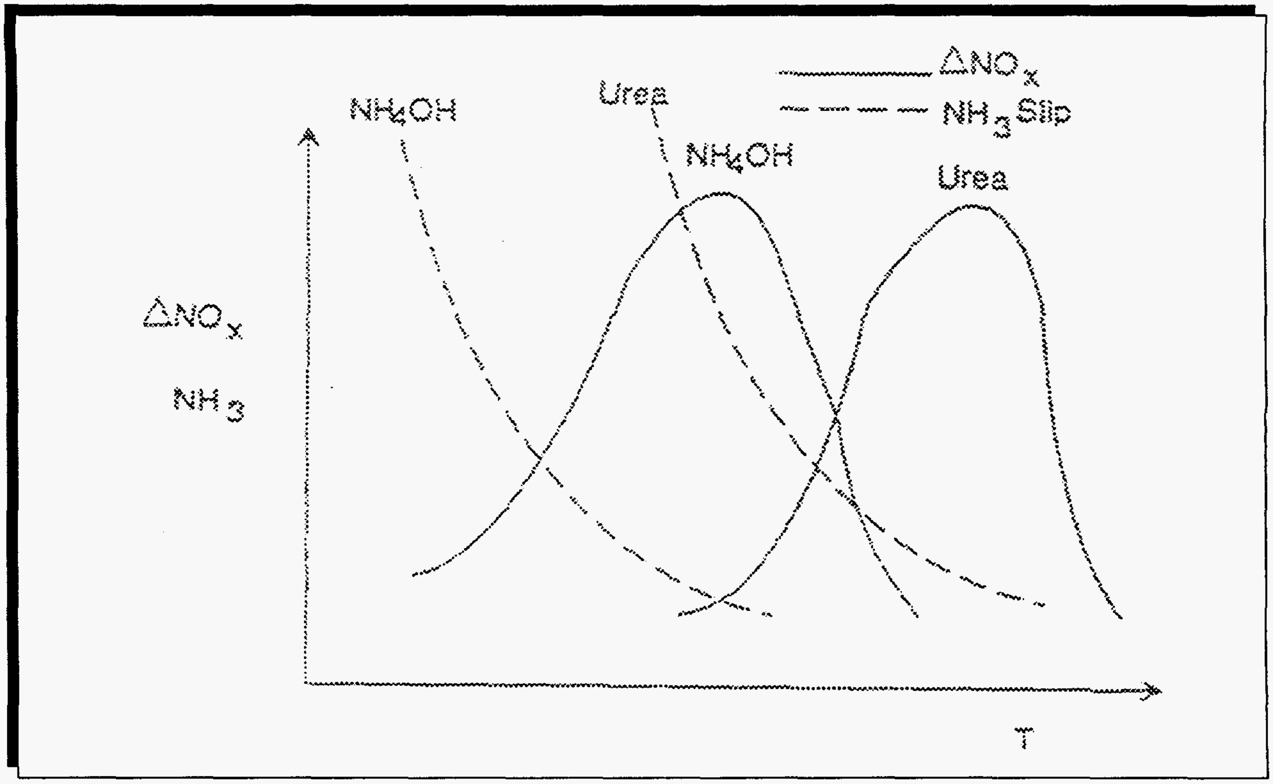


Figure 3-7: Comparison of Optimum Temperatures for SNCR Chemicals

The stoichiometric ratio is the most important process variable because the urea utilization rate is a key factor in process economics. A balance exists between NO$_x$ reduction and urea utilization. It is important to define an optimum balance between these two parameters. A low stoichiometric ratio improves urea utilization (due to the presence of excess NO), but it also results in lower reductions of NO. A high stoichiometric ratio reduces urea utilization (due to the presence of excess urea), but it also results in higher NO reduction.

The initial concentration of NO may also affect the urea injection process. At high initial levels of NO, large amounts of urea must be injected into the boiler to remove significant amounts of NO. In addition, injecting lots of urea may lead to large amounts of unreacted urea that may convert to ammonia and become a new emission source. With a lower initial concentration of NO (reduced by the use of low-NO$_x$ burners, for instance), a smaller amount of urea is required, resulting in less unreacted urea. The planned testing will help to clarify these concerns.

The concentration of the injected urea also affects the reduction of NO. A more dilute solution requires more time to evaporate the dilution water prior to the pyrolysis of the urea and, therefore, the urea travels farther down the boiler before pyrolysis begins. This lowers the effective temperature of the urea reaction and can be used to widen urea's effective temperature window.

3.4.4 Operating Variables

Operating variables can also influence the temperatures of the combustion gas at the location of a particular injector or nozzle. The key variables are:

- Boiler load.
- Burner firing pattern.
- Combustion gas recirculation patterns.
- Excess oxygen in the combustion gas.
- Cleanliness of the boiler.

Before the detailed design of an SNCR system can be completed, the basic temperature and velocity flow patterns of the flue gas must be defined. Both on-site and laboratory tests were used to define these patterns. The on-site tests used acoustic pyrometry and high-velocity thermocouples (HVT) to measure the temperatures of the flue-gas at different operating conditions. The laboratory used a scale model of the Arapahoe Unit 4 boiler to perform cold-flow testing to determine the velocity profile and optimize the injection mixing.

Table 3–15 summarizes the design criteria for the support systems of an SNCR system. Table 3–16 summarizes the design criteria for the injection locations and atomization/mixing systems of an SNCR system.

SUBSYSTEM	MAJOR CRITERIA	CONCERNS/LIMITATIONS
Storage	Concentration of urea (as delivered)	Temperature, Distance from source
	Concentration of stored urea	Temperature, Tank Size, Insulation
	Capacity	Days supply required
	Dilution	Quality of water supply
	Heating	Crystallization temperatures of stored and injected urea solutions
Water softening	Water quality	Hardness Chlorides
Piping	Joining method	Minimize threaded connections by welding
	Materials	No copper alloys Stainless steel

Table 3–15: Summary of Design Criteria for SNCR (Support Systems)

SUBSYSTEM	MAJOR CRITERIA	CONCERNS/LIMITATIONS
Injection	Flue-gas temperature distribution (temperature map)	1,600 to 2,100 °F
	Furnace-wall penetration	Minimize, Asbestos concerns
	Residence time	Flue-gas velocity Furnace geometry
	Flue gas flow distribution	Existence and location of recirculation zones
	Boiler load	Base load Load following Low-load levels may require extra sets of injectors
Atomization/Mixing	Urea flowrate	Initial NO concentration Stoichiometric ratio Allowable ammonia slip Ammonia contamination of ash
	Atomization air flowrate	2% of total boiler flowrate, maximum Urea droplet size Mixing
	Total injection flowrate (urea and air)	Concentration of dilute urea Flue gas temperature at injection location Injection pressure
	Ammonia conversion system	Catalyst type Catalyst operating temperature Catalyst residence time
	Number of injectors Injector diameter Angle of injection	Flue gas density Jet (air and liquid) density Injection-air velocity Injection-liquid velocity

Table 3-16: Summary of Design Criteria for SNCR System (Injection and Atomization/Mixing)

3.5 DSI Design Criteria

The chemistry of using calcium- and sodium-based reagents to scrub SO_2 consists of a series of complex reactions. The following sections briefly summarize these reactions for the injection of the calcium-based reagent (hydrated lime) into the economizer and for the injection of the sodium reagents into the duct. The reaction of calcium-based reagents injected into the duct is described with flue gas humidification in section 3.6.1.

3.5.1 Economizer Injection of Calcium-Based Reagents

The DSI system was designed to inject hydrated lime into an area of the boiler where the flue gas is approximately 1,000 °F. Generally, this location is just before the economizer, but is commonly referred to as "economizer injection."

3.5.1.1 Hydrated Lime and SO_2 Reactions for Economizer Injection

Very few studies have investigated the chemical path hydrated lime follows to capture SO_2, so it is not well understood. One of these studies, by Bortz, Roman, Yang, and Offen, has shown that hydrated lime's SO_2 capture depends on several competing reactions. Of these reactions, those that occur fast enough to be significant include the four reactions below:

$$Ca(OH)_2+SO_2 \rightarrow CaSO_3+H_2O \tag{3-2}$$

$$Ca(OH)_2+CO_2 \rightarrow CaCO_3+H_2O \tag{3-3}$$

$$Ca(OH)_2 \rightarrow CaO+H_2O \tag{3-4}$$

$$CaCO_3+SO_2 \rightarrow CaSO_3+CO_2 \tag{3-5}$$

3.5.2 Sodium-Based Reagents

The DSI system uses one of two sodium-based reagents: sodium bicarbonate (called nahcolite when naturally occurring) or sodium sesquicarbonate (called trona when naturally occurring). The injected reagent decomposes into soda ash (Na_2CO_3). The soda ash then reacts with the SO_2 in both the flue-gas duct and in the FFDC. Although it appears that it would be more efficient to inject soda ash directly, tests have shown that it is not effective at removing SO_2. It may be that directly injecting soda ash is not effective because it has much less surface area than the soda ash formed by the decomposition of the reagent.

3.5.2.1 Sodium Bicarbonate ($NaHCO_3$)

The decomposition of sodium bicarbonate into soda ash is complex and not well understood. The following equations show the generally accepted overall reactions for the decomposition of sodium bicarbonate (3-2), (3-4), (3-6) into soda ash and its subsequent reaction with SO_2 (3-3), (3-5), (3-7):

$$2NaHCO_3 \rightarrow Na_2CO_3 + H_2O + CO_2 \tag{3-6}$$

$$Na_2CO_3 + SO_2 + \frac{1}{2}O_2 \rightarrow Na_2SO_4 + CO_2 \tag{3-7}$$

Test have shown that the endothermic decomposition of sodium bicarbonate to sodium carbonate depends on the temperature of the flue gas. Reducing the reaction temperature to below 300 °F reduces the decomposition rate of the sodium bicarbonate, the utilization of the reagent, and the SO_2 removal rate.

3.5.2.2 Sodium Sesquicarbonate ($Na_2CO_3 \bullet NaHCO_3 \bullet 2H_2O$)

The decomposition of sodium sesquicarbonate into soda ash is complex and not well understood. The following equations show the generally accepted overall equations for the decomposition of sodium sesquicarbonate into soda ash (3–8) and its subsequent reaction with SO2 (3–9):

$$2(Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O) \rightarrow 3Na_2CO_3 + CO_2 + 5H_2O \qquad (3\text{–}8)$$

$$Na_2CO_3 + SO_2 + \frac{1}{2}O_2 \rightarrow Na_2SO_4 + CO_2 \qquad (3\text{–}9)$$

Previous testing has shown that at temperatures above 300 °F, sodium sesquicarbonate removes SO2 less efficiently than sodium bicarbonate. However, sodium sesquicarbonate is not as temperature sensitive as sodium bicarbonate, and, depending on residence times, it is more effective for flue-gas temperatures from 220 to 300 °F.

3.5.3 Theoretical Operation

Theoretically, two moles of sodium or one mole of calcium must be injected to remove one mole of SO2. Since these reactions are not completely efficient, normalized stoichiometric ratio (NSR) and utilization are commonly calculated to describe the effectiveness of a injected reagent at removing SO2.

3.5.3.1 NSR

The following equations define NSR for sodium- (3–10), (3–11) and calcium-based (3–11) reagents:

$$NSR_{Na} = \frac{moles\ Na}{2\ moles\ SO_2} = \frac{\frac{lb\ reagent}{h} \times \frac{1\ mole\ Na}{23\ lb\ Na} \times \%Na}{2 \times \frac{lb\ SO_2}{MMBtu} \times \frac{tons\ coal}{h} \times \frac{Btu}{lb\ coal} \times \frac{2{,}000\ lb}{ton} \times \frac{1\ MMBtu}{10^6 Btu} \times \frac{1\ mole\ SO_2}{64\ lb\ SO^2}} \qquad (3\text{–}10)$$

$$NSR_{Ca} = \frac{moles\ Ca}{1\ mole\ SO_2} = \frac{\frac{lb\ reagent}{h} \times \frac{1\ mole\ Ca}{23\ lb\ Ca} \times \%Ca}{2 \times \frac{lb\ SO_2}{MMBtu} \times \frac{tons\ coal}{h} \times \frac{Btu}{lb\ coal} \times \frac{2{,}000\ lb}{ton} \times \frac{1\ MMBtu}{10^6 Btu} \times \frac{1\ mole\ SO_2}{64\ lb\ SO^2}} \qquad (3\text{–}11)$$

Theoretically, based on these definitions, injecting reagent at an NSR of 1 will achieve a 100% SO_2 removal rate. However, since some reagent does not react with the SO_2, the utilization of the injected chemical must also be calculated.

3.5.3.2 Utilization

The following equation (3–12) defines utilization:

$$Utilization = \frac{\%SO_2\ removal}{NSR} \qquad (3\text{–}12)$$

Based on this definition, if all the injected reagent reacts with SO_2, then the utilization is 100% (even if the NSR is less than 1). For DSI, the utilization is expected to be about 40 to 70%. The following conditions affect utilization:

- Reagent Type (sodium bicarbonate or sodium sesquicarbonate)
- Temperature of flue-gas.
- Size of reagent particle.
- Purity of reagent.
- Amount of SO_2 in duct.
- Type of particulate control device: FFDC or ESP.

Table 3-17 summarizes the criteria for designing the reagent injection system of a DSI system. Table 3-18 summarizes the criteria for design the storage, transport, and pulverizing systems of a DSI system.

Subsystem	Major Criteria	Applicable Ranges/Limitations
Injection Location	Economizer	Flue-gas temperature
	Duct	Duct geometry
Reagent Type	Hydrated lime	Reagent supply/availability
	Sodium sesquicarbonate	Delivered cost
	Sodium Bicarbonate	Flue-gas temperature
	Nahcolite	Waste disposal
		Type of existing particulate control device
		Effectiveness of particulate control device
Reagent Injection	Flowrate	Initial SO_2 concentration
		Desired SO_2 removal rate (up to 70%)
		Initial NO_x concentration (sodium-based reagents only)
		NO_2 generated by DSI (sodium-based reagents only)
		Reagent type
	Mixing	Number of injectors
		Flue-gas velocity
		Flue-gas temperature
		Temperature of injected reagent
		Injection velocity
		Duct or boiler geometry

Table 3-17: Design Criteria for DSI System (Injection and Reagents)

Subsystem	Major Criteria	Applicable Ranges/Limitations
Delivery	Transportation	Available roads, rail lines, etc. Rail car Truck
	Unloading requirements	Existing facilities Shipment size Unloading rate Unloading equipment
Storage	Capacity	Day or bulk storage
	Silos	Concrete or steel Mass flow or funnel flow Material of construction
Reagent Feed/Transport	Conveying	Pneumatic Velocity: 3,000 to 5,000 ft/min Pressure Reagent/conveying air ratio
	Feeder	Volumetric or loss-in-weight Minimum/maximum reagent flowrate
	Airlock	Minimum air leakage Reagent abrasiveness
Pulverizer	Feedrate	Reagent type Design SO_2 removal rate
	Inlet reagent size (feed)	Reagent type
	Outlet reagent size (ground)	Flue-gas velocity Flue-gas temperature Residence time for injected reagent Smallest economically achievable size ($\approx$20 μm)
	Mill type	Attrition or ball mill

Table 3-18: Design Criteria for DSI System (Storage, Transport, and Pulverizing)

3.6 Flue-Gas Humidification Design Criteria

3.6.1 Process Chemistry

The following equations show the reaction of the hydrated lime with the sulfur oxides to form calcium sulfate (3-13) and calcium sulfite (3-14).

$$Ca(OH)_2+SO_2+\frac{1}{2}O_2+H_2O \rightarrow CaSO_4+2H_2O \qquad (3\text{-}13)$$

$$2Ca(OH)_2+2SO_2 \rightarrow 2CaSO_3\bullet\frac{1}{2}H_2O+H_2O \qquad (3\text{-}14)$$

Because temperatures at the outlet of the air heater (≈300 °F) are not favorable for these gas-solid reactions, calcium reagents capture SO_2 more efficiently if they occur in liquid water. Figure 3-8 shows the generalized results of studies that have been conducted to determine the level of SO_2 removal that can be achieved with flue-gas humidification with calcium-based reagents. These tests were performed using hydrated lime at a stoichiometric ratio of 2.4, and an inlet SO_2 concentration of 1,200 ppm.

3.6.2 Limits on Approach to Saturation Temperature

As the flue-gas temperature (T) approaches its adiabatic-saturation-temperature (T_{sat}), SO_2 capture increases. However, as the approach temperature of the flue gas ($T_{AS} = T-T_{sat}$) becomes small, incomplete mixing limits the flue-gas temperature's approach to its saturation temperature. This incomplete mixing of the flue gas causes localized areas of complete saturation. So, as the flue-gas temperature (T) approaches T_{sat} and T_{AS} approaches zero, the areas of complete saturation may deposit liquid water and solids onto the ductwall or carry liquid water into the fabric filter. For duct humidification, the generally accepted practical limit for T_{AS} is approximately 20 °F or about 50% relative humidity. With an FFDC, a

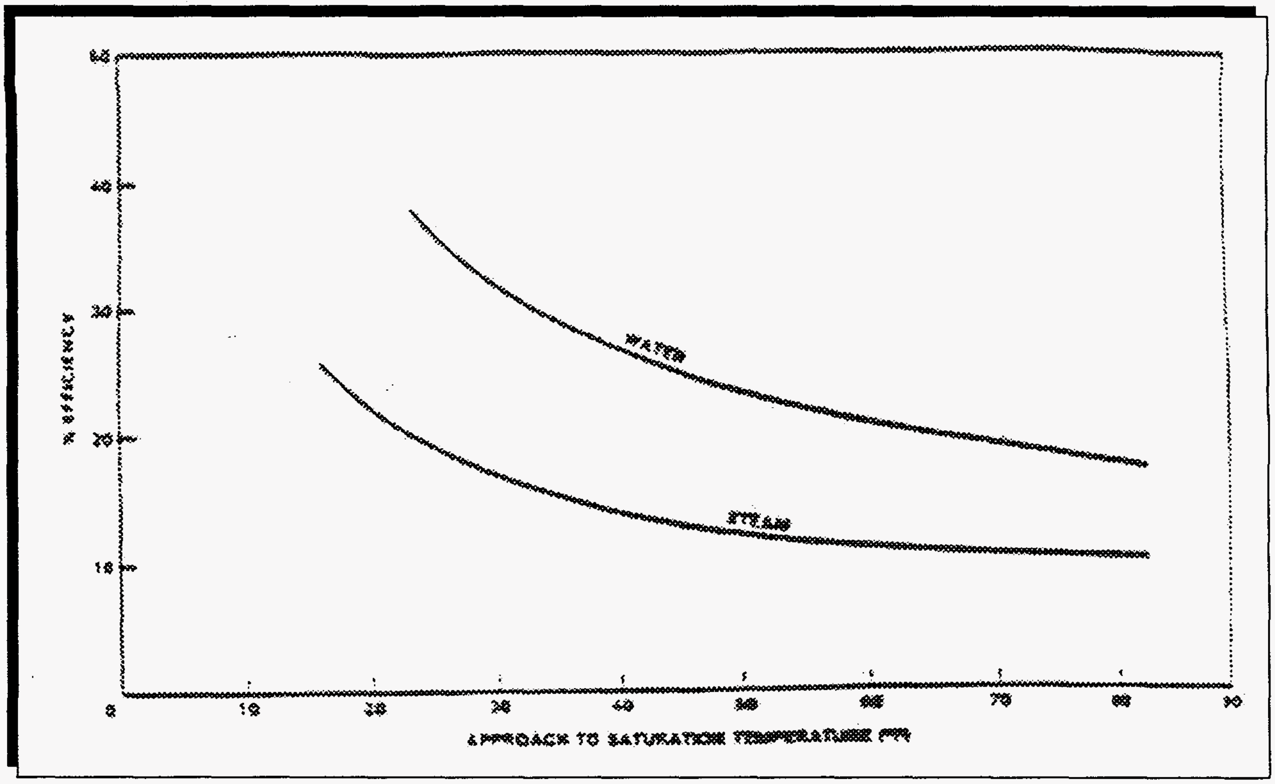


Figure 3-8: Effect of Humidification on SO_2 Capture by Calcium-Based Reagents

more practical T_{AS} is closer to 40 °F because of the high risk of wetting the bag-filters and the expensive possibility of replacing them.

3.6.3 Atomization

Operationally, it is important to prevent unevaporated water from reaching the duct walls, particulate-collection device, turning vanes, or other obstructions in the duct. To assure the complete evaporation of the injected water, it must be atomized to very small diameters and distributed evenly in the duct. Dual-fluid atomizers are preferable for in-duct humidification because they:

- Can be mounted in both horizontal and vertical ducts.
- Produce a fine spray.
- Can be directed to spray downstream and away from duct walls.

- Can be mounted on common headers (lances) and arranged for even distribution and mixing.
- They inject the atomizing air at high velocity to promote the mixing of the water and the flue gas by entrainment.

3.6.4 Particulate Collection Efficiency

It is generally accepted that flue-gas humidification improves the efficiency of ESPs by agglomerating particles, decreasing ash resistivity, and by increasing the effective size of the ESP. Little work has been done with FFDCs and flue-gas humidification, but FFDCs are very efficient particulate control devices, so the use of flue-gas humidification is not expected to significantly improve the efficiency of Arapahoe Unit 4's FFDC.

3.6.4.1 Effective Size of Particulate Collector

Flue-gas humidification decreases the temperature and, therefore, the volume of the flue gas. This reduction may improve the effectiveness of the particulate-collection device by increasing its effective collection area. For example, if the flowrate of flue gas is 400,000 acfm at 260 °F and the humidification system injects water and atomizing air to obtain a T_{AS} of 40 °F, the gas cools to 150 °F and the flow reduces to approximately 340,000 acfm (calculated at outlet). This is a 15% decrease in volumetric flow and, therefore, a 15% increase in the effective collection area of the FFDC or ESP. In addition, the pressure drop for an FFDC is proportional to its volumetric flow. So, a 15% decrease in volumetric flow corresponds to more than a 15% decrease in pressure drop across the baghouse and a possible reduction in the energy consumed by the ID fan.

3.6.4.2 Particle Agglomeration and Ash Resistivity

As the water droplets enter the flue gas, they impact with the flyash and sorbent particles. Flue-gas humidification improves particle agglomeration by two possible mechanisms:

- The impacting water droplets either form a film on the surface of the particles or they absorb the particle. The droplet then evaporates and forces the particles together to form a larger particle.
- The increase in the flue-gas humidity causes water to condense on the surface of the particles and increases the moisture content of the particle. The increased moisture content improves the cohesion of the particles and decreases its resistivity. Lower ash resistivity (also caused by lowering the temperature of the ash) improves the effectiveness of ESPs.

3.6.5 Summary

The optimum operating point for the humidification system is a compromise between operation and performance. While a low approach to saturation temperature for increased SO_2 capture is desirable, localized-wetting problems require larger approach temperatures. Table 3-19 summarizes the design criteria for flue-gas humidification.

SUBSYSTEM	MAJOR CRITERIA	CONCERNS/LIMITATIONS
Injection Location	Duct geometry	Residence time Uniformity of flue-gas flow
Water Spray Rate	Flue gas temperature (exiting air heater) Initial water content Inlet adiabatic saturation temperature	
	Approach to saturation temperature (T_{AS})	Particulate control device Practical limit: 20 °F Safe/conservative: ~40 °F
Atomization/Mixing	Type of injectors	Desired droplet diameter
	Injector orientation	With flue-gas flow
	Air flow	Air-to-water ratio (≈0.2 to 0.3) Air pressure
Piping	Materials	Non-rusting Stainless steel

Table 3-19: Design Criteria for Flue-Gas Humidification System

4.0 DETAILED PROCESS DESIGN

4.1 Plot Plan and Plant Layout Drawing

Figure 4–1 shows a plot plan and layout and Figure 4–2 shows an elevation view of the Arapahoe Unit 4 boiler. Downstream of the burners, the flue-gas flows down the furnace and then turns upward to flow through the convective sections on the boiler backpass. After reaching the burner-level elevation, the flue-gas passes through the horizontal duct and is then directed downward through a tubular air-heater. After leaving the air heater, the flue gas passes through a reverse-air baghouse to control its particulate emissions. Induced-draft (ID) fans are positioned downstream of the baghouse and deliver the flue gas into a common stack for Units 3 and 4.

4.1.1 Low-NO$_x$ Burners

4.1.1.1 Original Burner Configuration

The design of the original intertube-burners is not comparable to that of the more common wall-fired burners. The original furnace configuration was a down-fired system that employed 12 intertube burners located on the roof and arranged in 1 row across the width of the furnace.

Each burner consisted of a rectangular coal/primary-air duct split into 20 nozzles arranged in a 4-by-5 rectangle that injected the coal/air mixture evenly across the furnace roof. A secondary-air windbox surrounded each burner and allowed air to flow around each of the coal nozzles resulting in a checkerboard pattern of coal/primary-air and secondary-air streams. The burners had no provision to control the mixing rate of the fuel and secondary air.

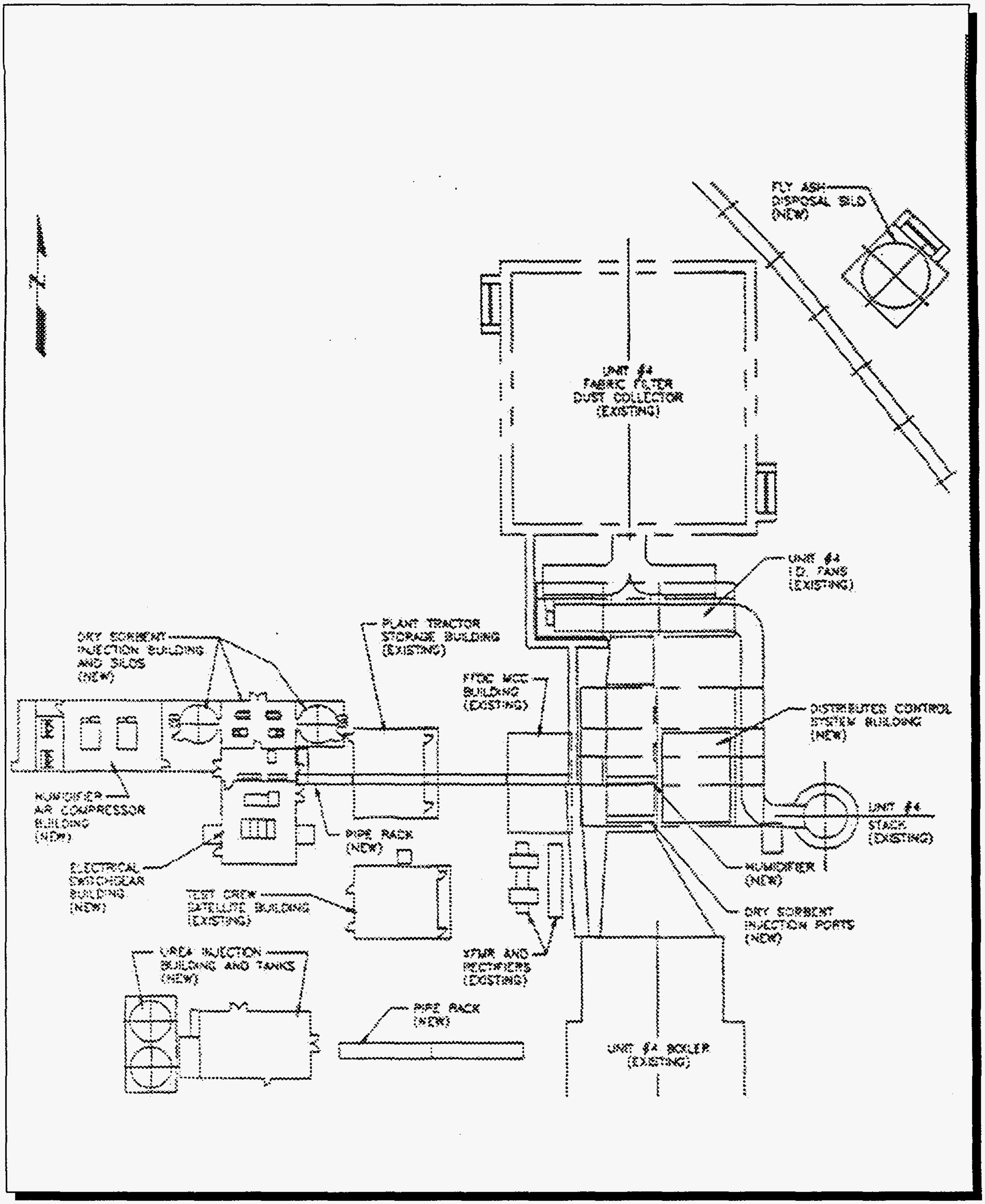


Figure 4–1: Plot Plan and Layout of Arapahoe Unit 4

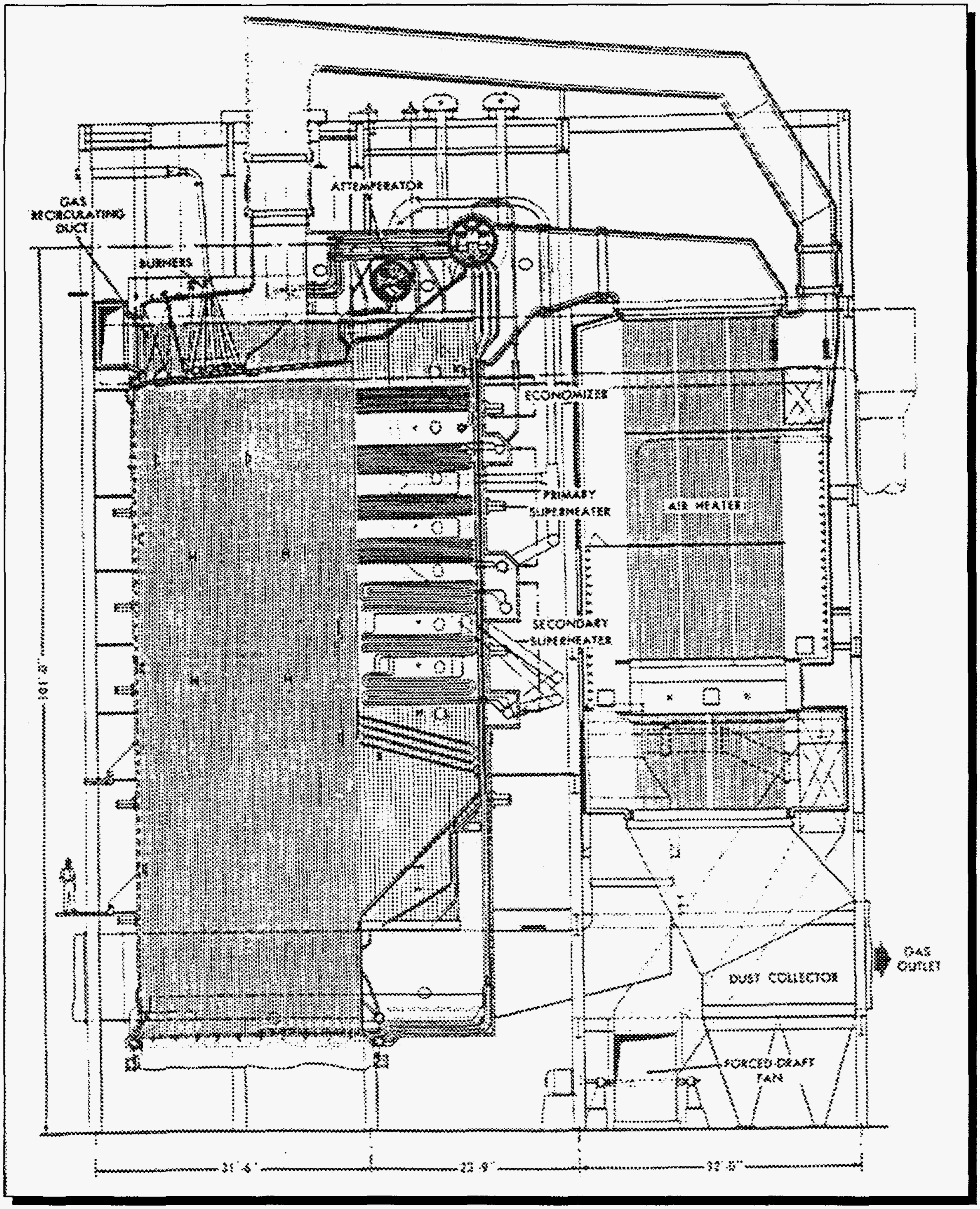


Figure 4–2: Elevation View of Arapahoe Unit 4

Figure 4–3 shows a photo of the unmodified boiler roof. The coal/primary air enters through the oval opening and the secondary air entered through the rectangular opening. The perforated nozzle is a gas burner.

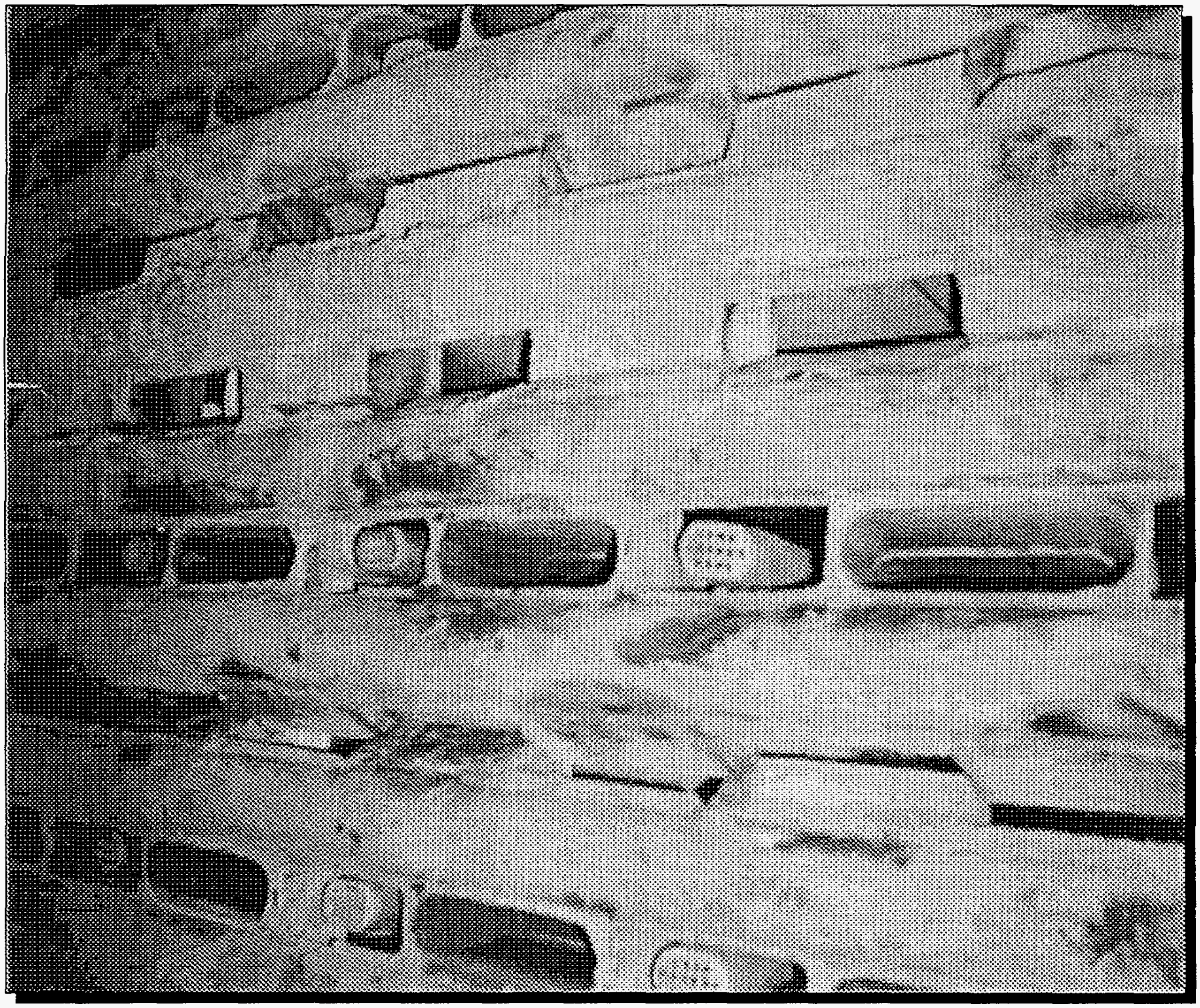


Figure 4–3: Photo of Unmodified Boiler Roof

Figure 4–4 shows the original firing configuration and the distribution of coal from the four mills. The burners were numbered 1 through 12 from west to east. Each of the four attrition mills supplied primary air and coal to three of the burners. The coal piping from each mill supplied two burners in one furnace-half and one burner in the other half. The secondary-air ducts were positioned behind the burners and included a secondary-air damper for each burner. When a single burner was removed from service, the secondary-air flow was also stopped by closing the associated secondary-air damper. The dampers were manually controlled at the burner deck and were intended only for on/off duty. The secondary-air-feeder-duct and windbox has been modified to accommodate the new burners and burner arrangement.

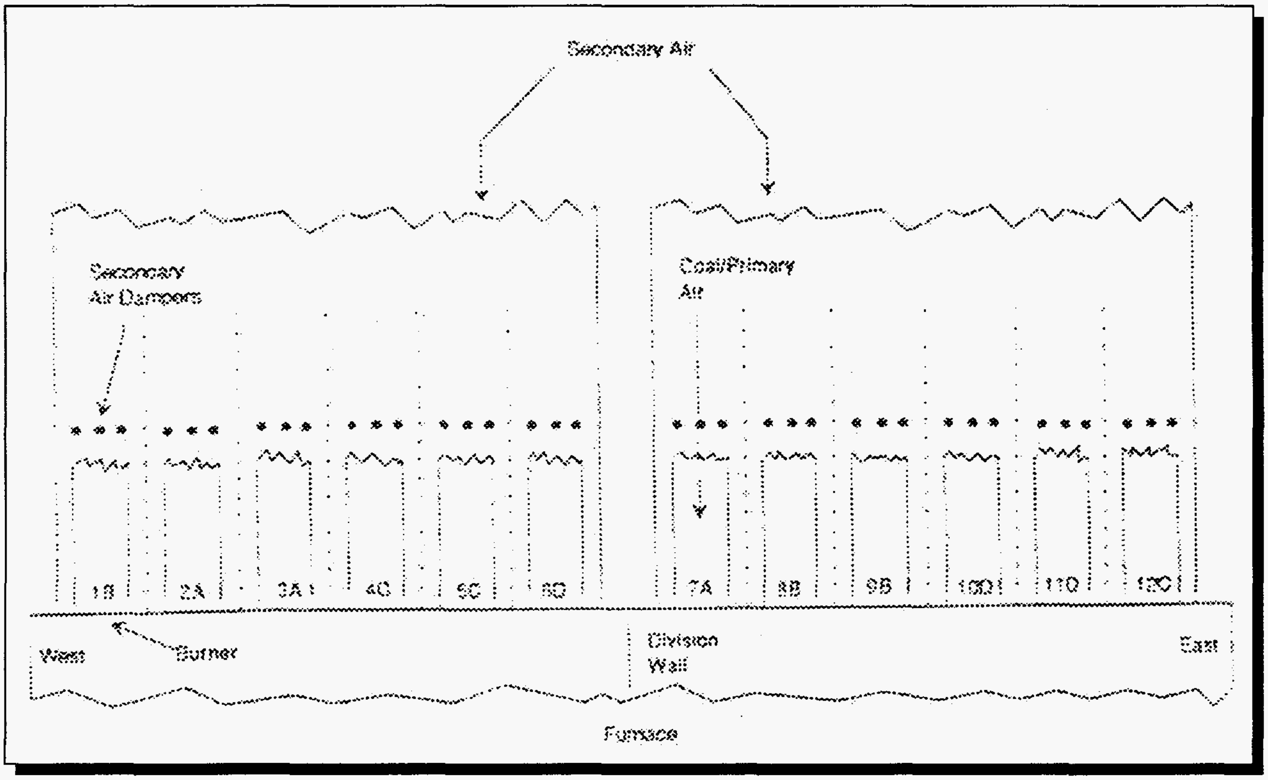


Figure 4-4: **Original Burner Firing Configuration and Coal Distribution Arrangement at Arapahoe Unit 4**

4.1.1.2 Retrofit

The retrofitting of the top-fired combustion system at Arapahoe Unit 4 was much more involved than if it had been a normal wall- or tangential-fired unit. The old intertube burners required only small openings in the roof tubes. The modifications to Arapahoe Unit 4 required the removal of everything from the boiler-roof-tubes to the roof of the boiler enclosure, including the windbox, the coal and gas piping, and the secondary-air-supply duct.

To accommodate the new burners, new roof tubes were welded in place. The new burners were placed in four rows of three burners, as shown in Figure 4–5. The boiler has a full division wall that separates the furnace into two, approximately square, sections. The limited space available for the placement of the burners was a major problem. The outer edges of the burners on each side of the division wall are located only inches apart. Figure 4–6 shows a photo of modifications being made to the furnace roof for the installation of a new burner. Figure 4–7 shows a photo of the new burners installed in the roof of Arapahoe Unit 4's furnace.

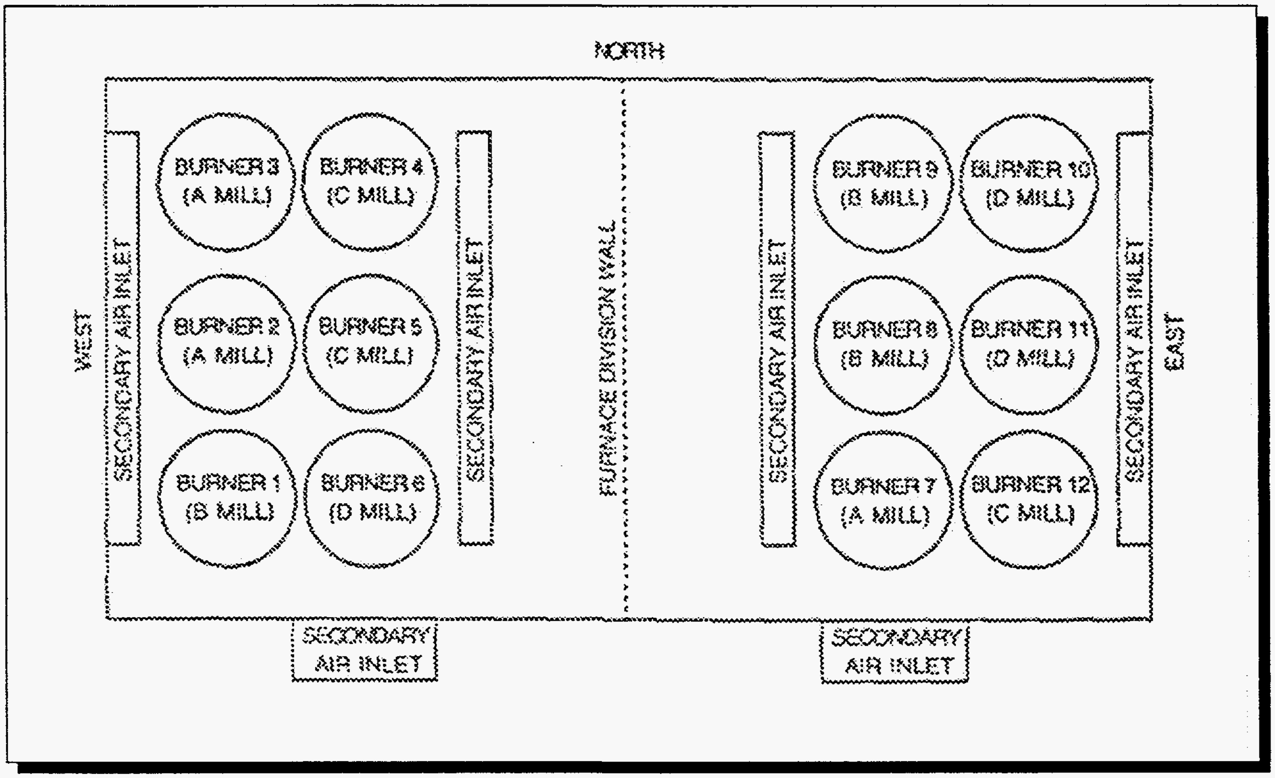


Figure 4–5: Plan View of Burner Arrangement After Retrofit

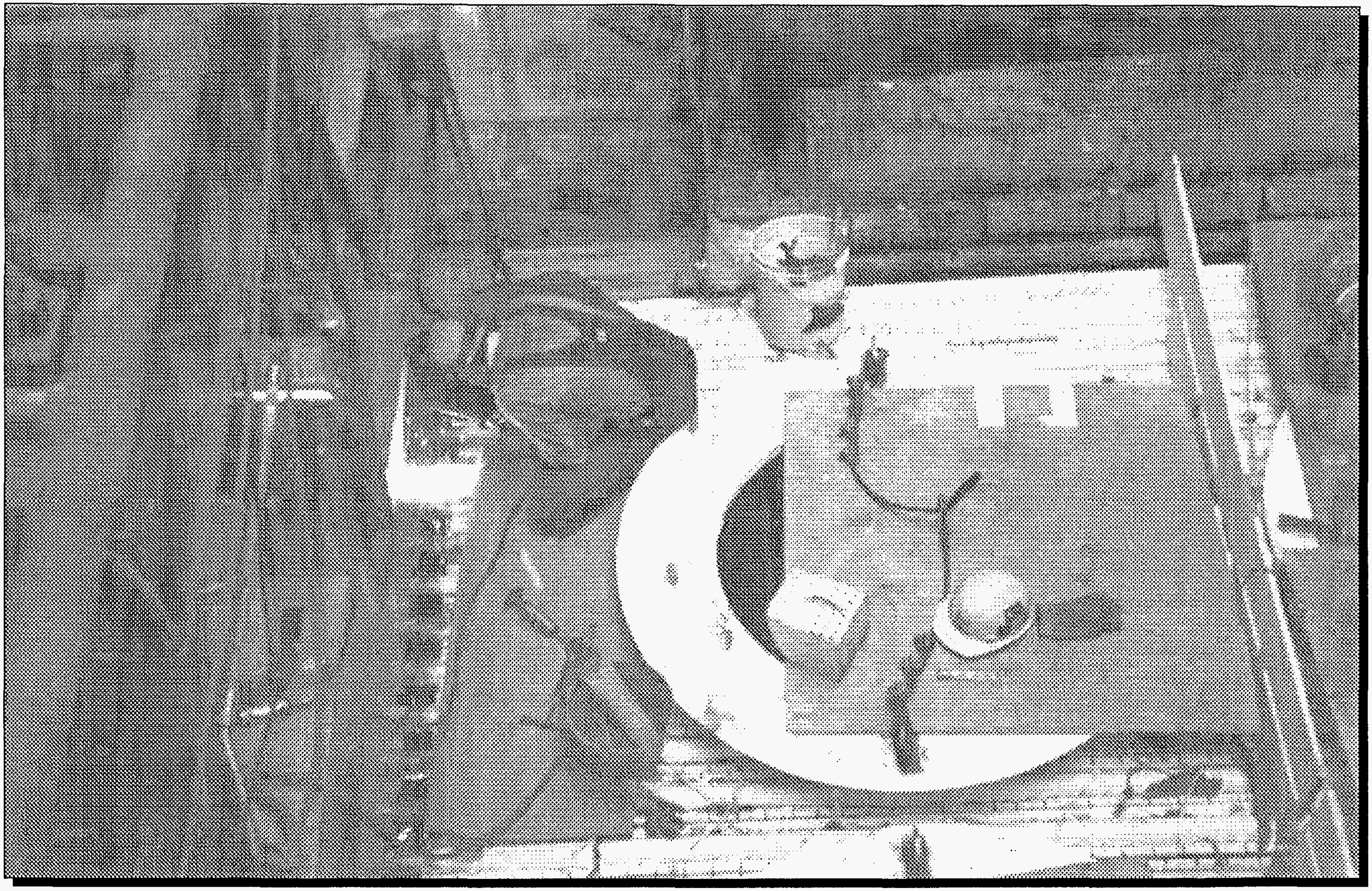


Figure 4-6: Photo of Furnace Being Modified (Looking Down onto Top of Furnace Roof)

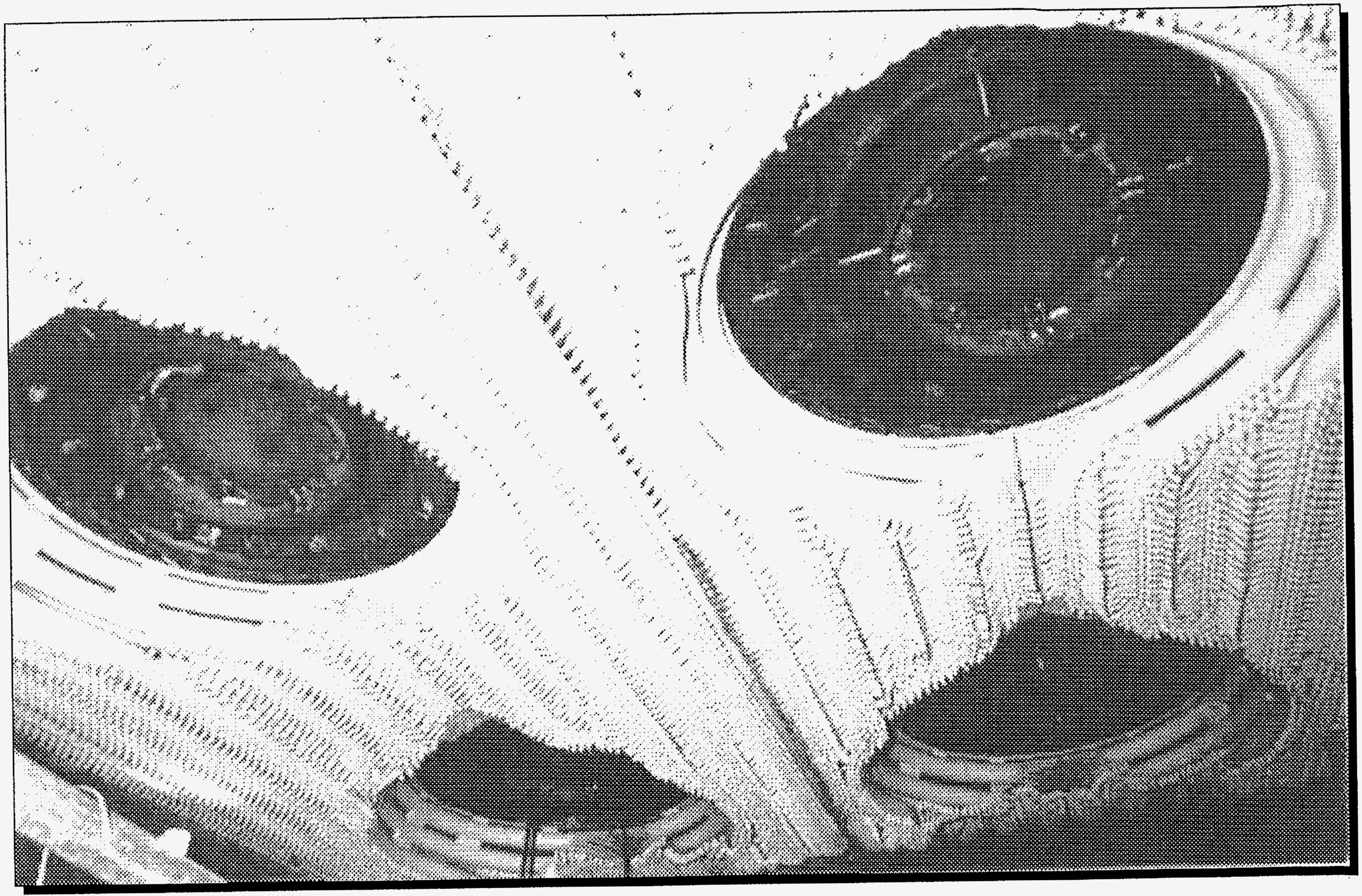


Figure 4-7: Photo of New Burners

As shown in Figure 4–2 , the secondary-air duct originally entered the windbox at the rear (south side) of the furnace roof. Since the new burners required significantly more roof area than the intertube burners, and there were now four burners where the secondary air duct was originally located, providing secondary air to the windbox was a challenge.

As shown in Figure 4–8, four "pantleg" ducts were added to transport and introduce the secondary air. However, because of limited space, these ducts could not be made large enough to carry all of the secondary air, so additional ductwork was required. The boiler at Arapahoe Unit 4 was originally designed to use flue-gas recirculation (FGR) to control the steam temperature. However, the FGR system was no longer in use, so two abandoned FGR ducts that entered the front (south) wall of the windbox were used to provide the balance of the secondary air.

The secondary air feeder duct and windbox were modified to accommodate the new burners and burner arrangement. In addition to the NO_x port assemblies, new ductwork and windboxes were also installed for the NO_x ports. New boiler-tube panels have also been installed to accommodate the throats of the NO_x ports.

4.1.2 OFA Ports

The OFA ports are located in a small windbox on each side of the furnace. Figure 4–9 shows the location of the OFA ports in a side view of the upper furnace. New ductwork was added to direct secondary air from the boiler roof to the sidewalls (see Figure 4–8). Each of the ducts that supply OFA to the windboxes contains an opposed-blade-louver-damper to control the flow of OFA, and a pitot-tube grid with a flow straightener to measure the total flow of OFA to each side of the furnace. Originally, two sootblowers were located on each side of the furnace at the location chosen for the OFA ports. Because of this, the sootblowers were lengthened to accommodate the depth of the new windboxes and relocated slightly.

4.1.3 SNCR

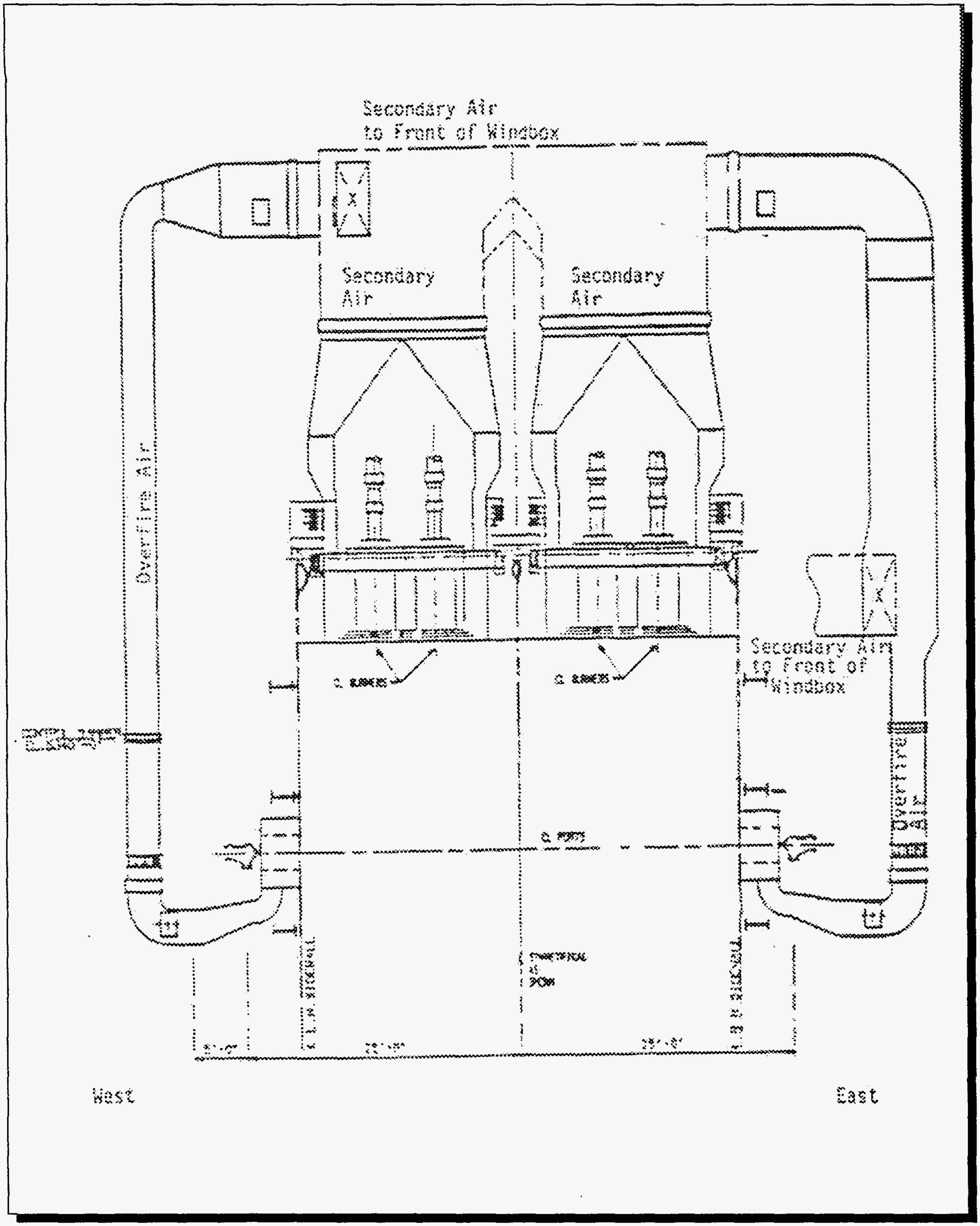


Figure 4-8: Front Sectional View of Upper Furnace (Looking North)

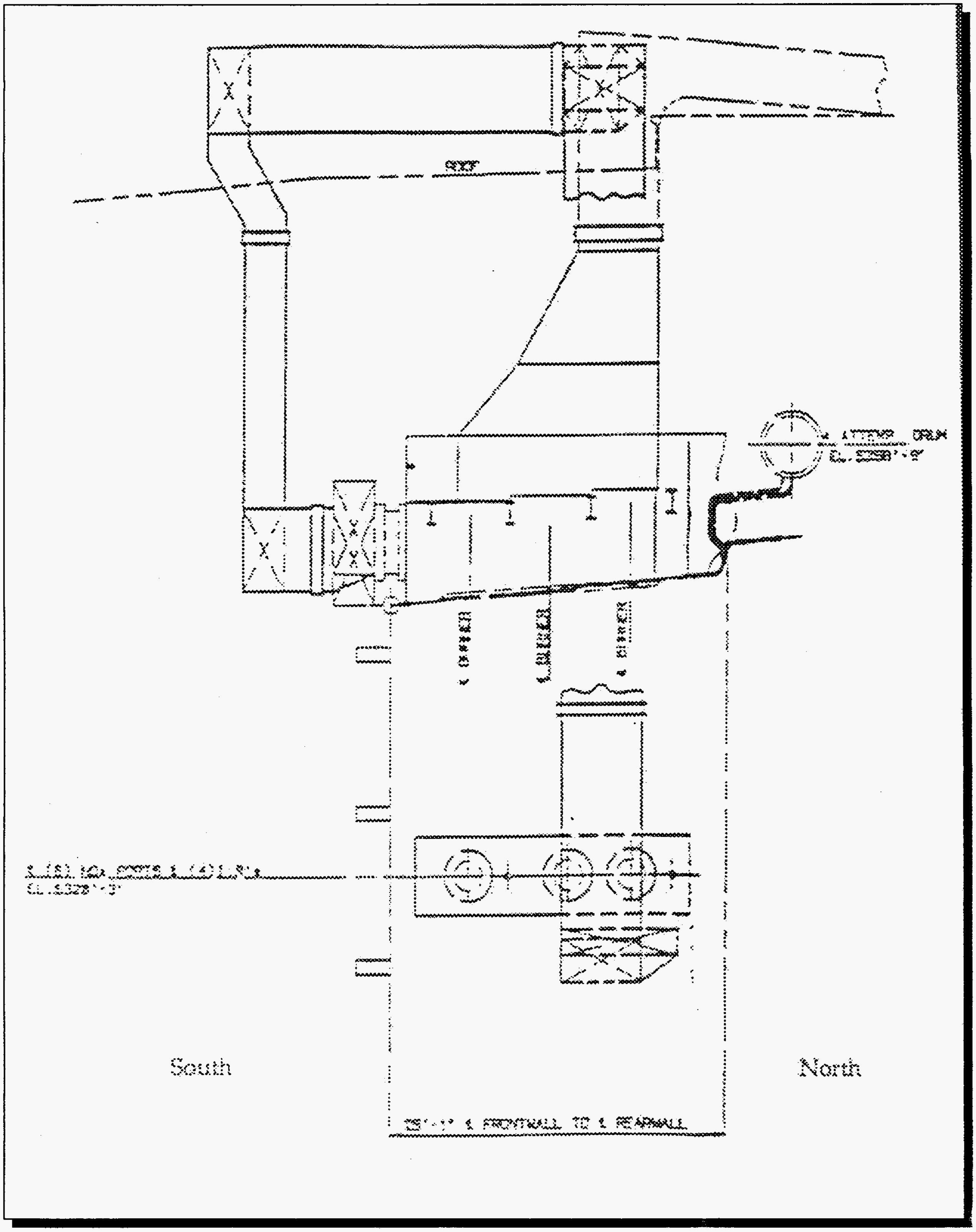


Figure 4-9: **Side-Section View of Upper Furnace (Looking West)**

Figure 4–10 shows the plot plan and layout of the SNCR system. Table 4–1 lists the equipment names and numbers.

Equipment Number	Equipment Name	Equipment Number	Equipment Name
T-1 T-2	Urea storage tank	C-1	Atomization compressor
P-3 P-4	Urea circulation pump	V-1	Quench vessel
H-1 H-2	Urea heater	P-1 P-2	Quench pump
F-1 F-1	Urea filter	PF-1	Purge fan
P-5 P-6	Urea injection pump	WS-1	Water softener skid

Table 4–1: Equipment Numbers and Names for SNCR System

The majority of the equipment for the SNCR system is installed in a newly erected building west of Arapahoe Unit 4. The building is divided into an equipment section and a control room section. The equipment section houses the water softening skid, the quench skid, the water filter skid, the circulation heater skid, the purge air fan, the pump skid, and a turbo air compressor. The control room section houses the motor control center (MCC), the PLC and the control panel.

Outside the building there are two 20,000-gal. urea storage tanks, the inlet filters for the purge air fan, the turbo air compressor, the lube-oil cooler, and the blow-off silencer for the turbo air compressor.

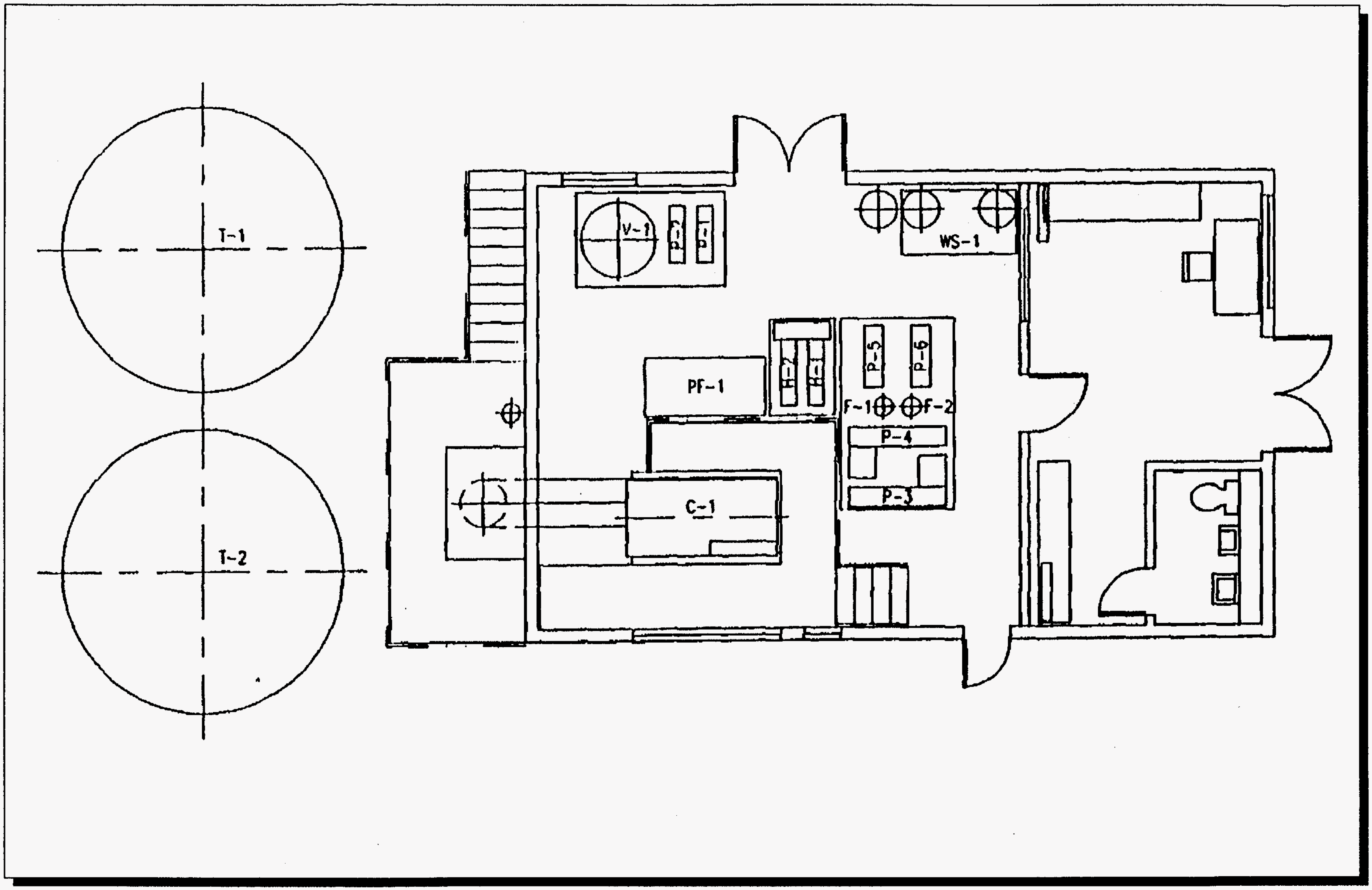


Figure 4-10: Plot Plan and Layout of SNCR System

4.1.4 DSI

Figure 4–11 shows the layout of the building that houses the equipment for the DSI system. Figure 4–12 shows a photo of the equipment room for the DSI system. On the left are the two pneumatic conveying blowers (B-4A and B-4B) and on the right are the two reagent pulverizers (P-4A and P-4B).

4.1.5 Flue-Gas Humidification

Figure 4–13 shows the layout and plot plan of the flue-gas humidification lances and thermocouples. The humidification lances are approximately 100 feet from the entrance of the FFDC. At the design duct velocity of 3,600 ft/min, this distance provides a residence time of about 1.6 seconds. At a more normal duct velocity of 2,500 ft/min, the residence time is about 2.4 seconds.

A 12-point thermocouple grid is used to measure the average flue-gas temperature. Figure 4–13 shows both the new and old locations for the thermocouples. The original grid was too close to the humidification system and experienced wetting which caused incorrect temperature measurements. Moving the location of the thermocouple grid downstream increased the evaporation time before measurement, minimized the wetting problem, and improved the accuracy of the temperature measurements.

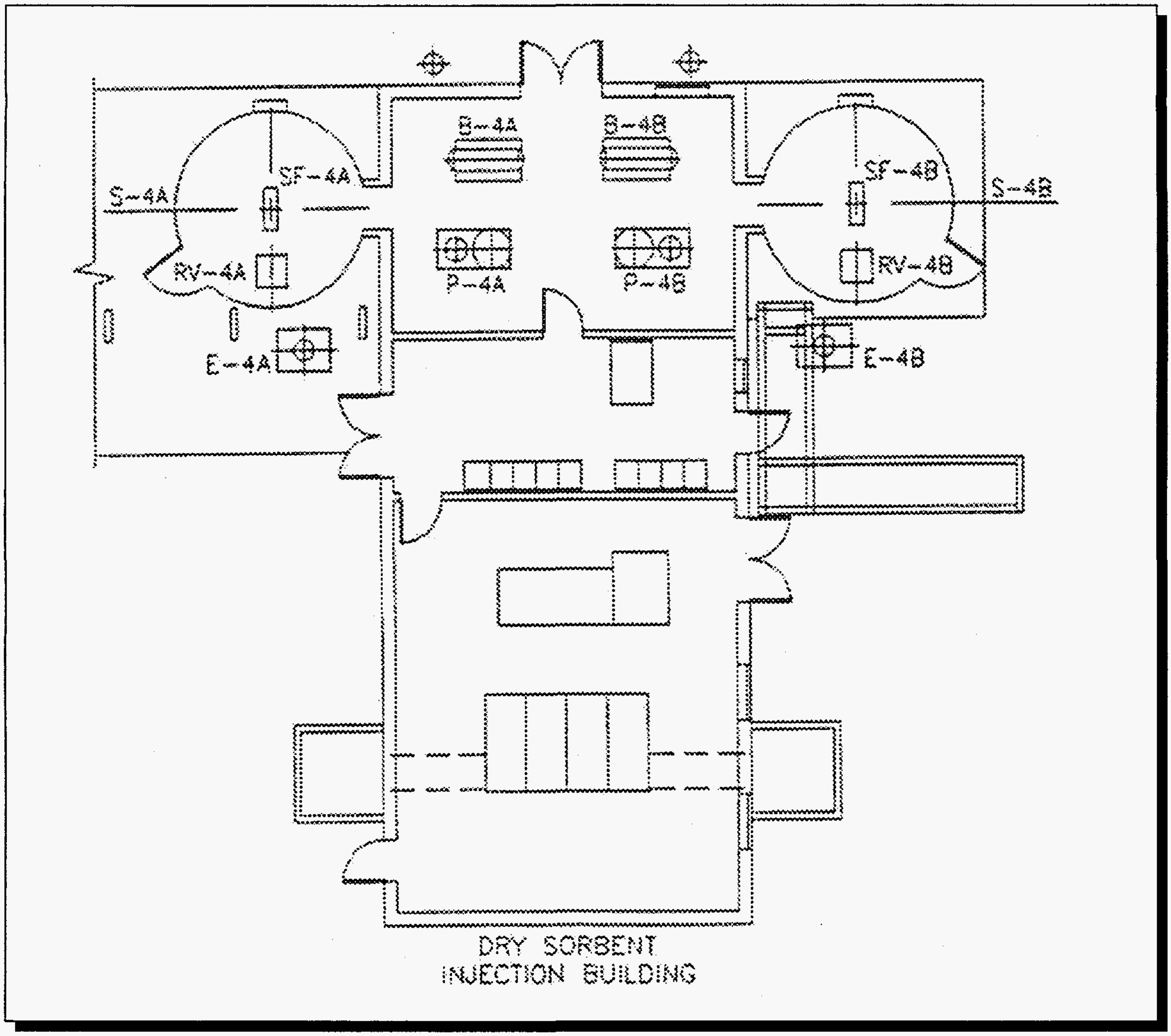


Figure 4-11: Layout of DSI System Building

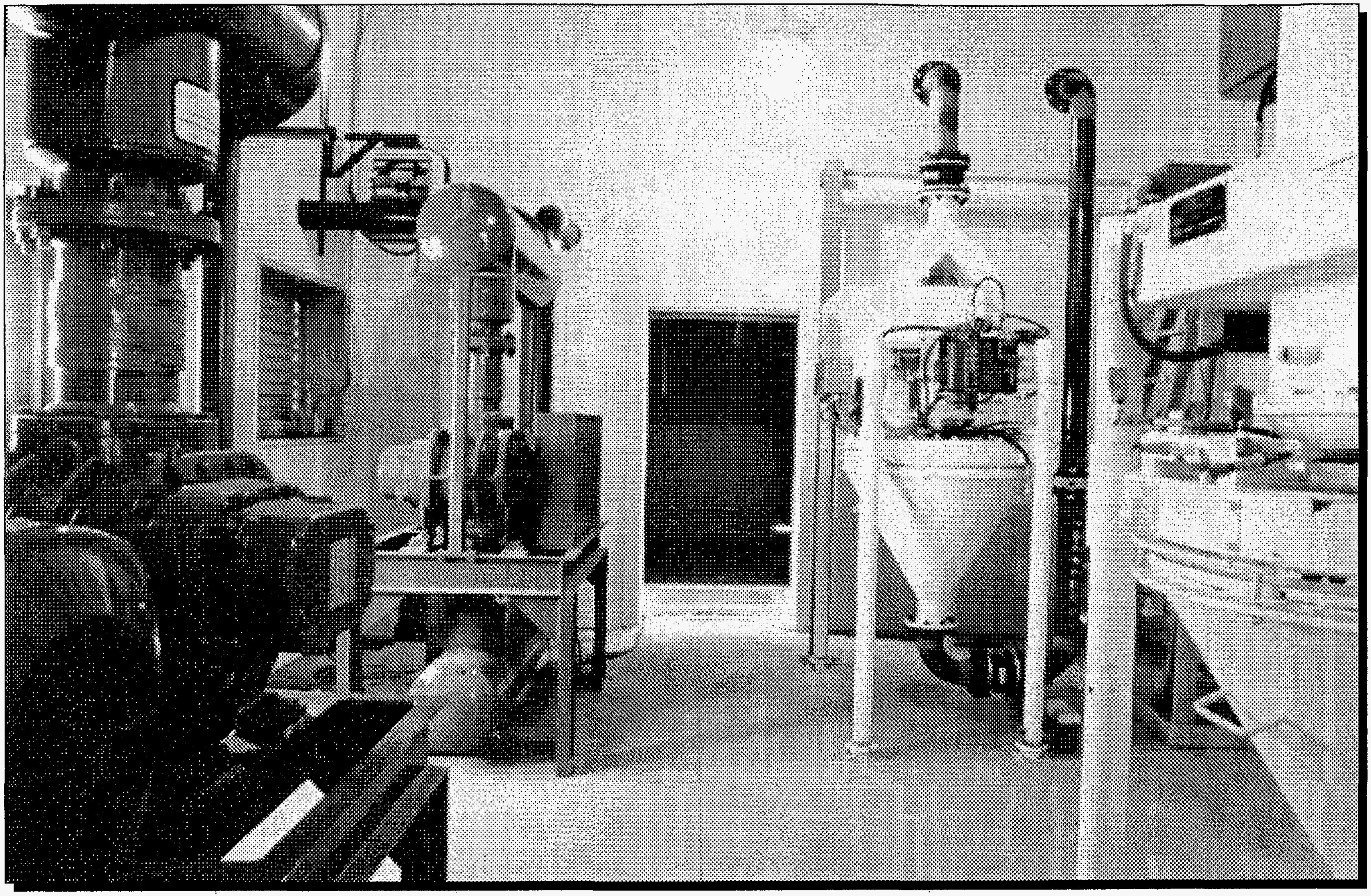


Figure 4–12: Photo of Equipment Room for DSI System

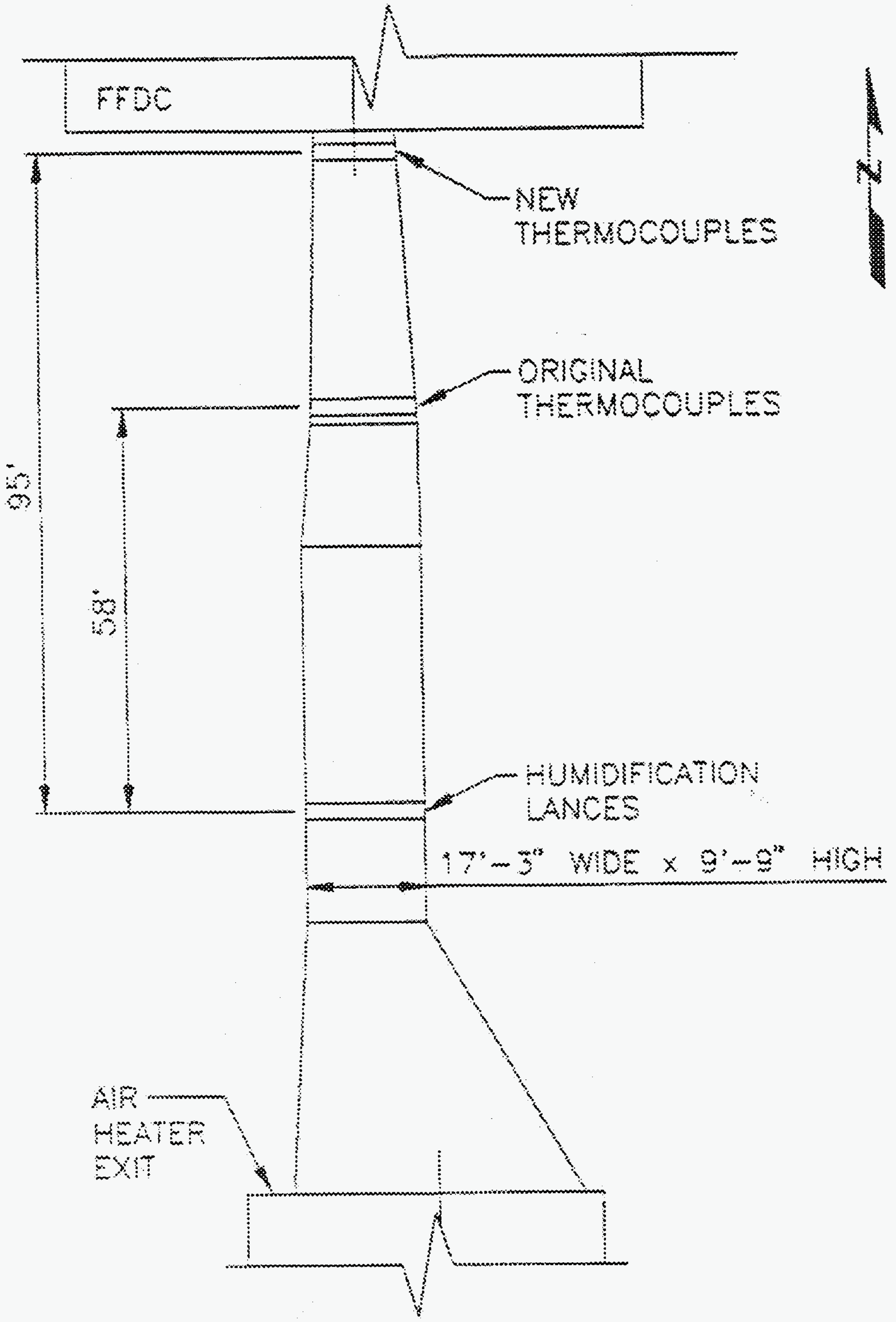


Figure 4–13: Plant Layout of Flue-Gas Humidification System

4.2 Low-NO_x Burners

4.2.1 Equipment

The following sections describe some of the equipment that was retrofitted to Arapahoe Unit 4 to complement the new low-NO_x burners.

4.2.1.1 Ignitors

The original burner ignitors were replaced with new, Class 1 natural gas fired ignitors that are compatible with the DRB-XCL® low-NO_x burners. The ignitors are used before firing any main fuel, prior to a normal shutdown, and during any condition that requires flame stabilization.

4.2.1.2 Scanners

Each burner also has two flame scanners (commercially available) supplied by COEN, Inc.: (1) an infrared scanner to detect the coal flame and (2) an ultraviolet scanner to detect both the gas ignitor and the main gas flame. The scanners send input signals to a flame safety system that interacts with the burner management system to assure safe and proper operation during startup, shutdown, and normal operation.

4.2.2 Process/Operation

The coal piping supplies pulverized coal and primary air from the pulverizer to its respective burners. Secondary air is gradually introduced to the products of combustion further along the flame to complete combustion. This staged combustion reduces the flame intensity and, therefore, minimizes NO_x formation.

The forced draft (FD) fan provides secondary air to the air heater, which preheats it. The main secondary-air-flow meters then measure the total flow of the preheated secondary-air to the plenum. The plenum then distributes the preheated secondary-air to the burner windbox and NO_x port windbox.

4.2.3 Adjustment of Burners

The following sections describe the use of the sliding damper and the spin vanes.

4.2.3.1 Sliding Damper

An electric-linear-actuator is used to adjust the sliding damper. The control system allows for three disk positions: cool, light, and normal. These positions have the following functions:

- The cool position is used while a burner is out of service. It provides a minimum amount of cooling air to ensure only that the temperature of the burner metals do not exceed their design limits of 1,300 °F.
- The light position is used to provide slightly more air while the ignitors are firing natural gas.
- The normal position is used while the burners are firing either coal or natural gas.

Limit switches in the actuator are used to adjust the three disk positions. If imbalances in secondary air occur between the burners, the flow of secondary air can be individually adjusted at each burner. During startup of the burners, it was discovered that actuator operation and coasting of the sliding damper made minor adjustments to the limit switches. While some balancing of the secondary air is possible, the desired level of control cannot be obtained. Designers of future installations should consider using infinite positioning with analog signals instead of limit switches.

4.2.3.2 Inner-Zone Spin Vanes

The area between the outer diameter of the coal nozzle and the sleeve separating the inner and outer zones forms the inner-air-zone. The inner-air-zone is equipped with a set of externally adjustable vanes for use in optimizing combustion. When the DRB-XCL® burners are started for the first time, the spin vanes are set at 45° open. During startup operation, it was determined that the optimum spin setting for Arapahoe Unit 4 25° open.

4.2.3.3 Outer-Zone Spin Vanes

The area between the inner sleeve and the main burner barrel form the outer-air-zone of the burner. The outer-air-zone is equipped with two stages of vanes. The first stage of vanes are stationary and improve the peripheral distribution of air entering this zone. The second stage of vanes are externally adjustable from the burner front and are used to further optimize combustion.

When DRB-XCL® burners are first started, the adjustable vanes are set at approximately 60° open. After initial operation, it was determined that setting these vanes to 25° open obtained optimum combustion for Arapahoe Unit 4.

All secondary air enters past the sliding-air-damper located at the entrance to the inner- and outer-air zones. This damper allows the airflow to each burner to be controlled independently. A reverse-pitot-tube array indicates the relative airflow entering these two zones.

4.2.3.4 Burner Cooling

When a burner is out of service, a small amount of secondary air continues to be fed to the burner to cool it and prevent it from overheating. The operator sets the sliding-air-damper to the cool position. Thermocouples are used to periodically monitor the temperatures of the burners to determine the proper cool position.

The thermocouples are sheathed with stainless steel and welded to the outer-air-sleeve of the burner (near the furnace-wall tubes). To protect the thermocouple leads from damage during operation or maintenance, they are housed in conduit routed out of the windbox through the coverplate.

The temperature indicator for the thermocouples is in a central location at the burner front. The maximum allowable temperature readings on the thermocouples under any operating condition is 1,300 °F. The thermocouples are not connected to the DCS.

Each pitot-tube-assembly provides a 30-point-flow-measurement-grid for each burner. A magnetic differential-pressure gauge is placed across the impact and suction manifolds. The pitot grids indicate the relative flow at each burner to help balance the distribution of the secondary airflow. This indicated airflow is not used or incorporated into the automatic control system.

4.2.4 Gas Firing

Although coal is the main fuel used, natural gas is used occasionally to provide load when pulverizers or other equipment are out of service. A gas ring-header was located at the tip of each burner to maintain the capability of firing 100% natural gas.

Natural gas is supplied to the ring header of each burner. The header is located inside the windbox with the inlet pipe extending through the windbox casing for accessibility. Gas is distributed from the ring header to 18 gas-elements that extend into the outer-air-zone of the burner, as shown in Figure 4-14.

Figure 4-15 shows the design-gas-pressures required at the burner manifold to fire natural gas. When used with the gas-ring-header arrangement, the DRB-XCL® burner does not provide internal air and fuel staging when it burns natural gas. Thus, when firing natural gas, these burners are not expected to reduce NO_x emissions significantly from that of the

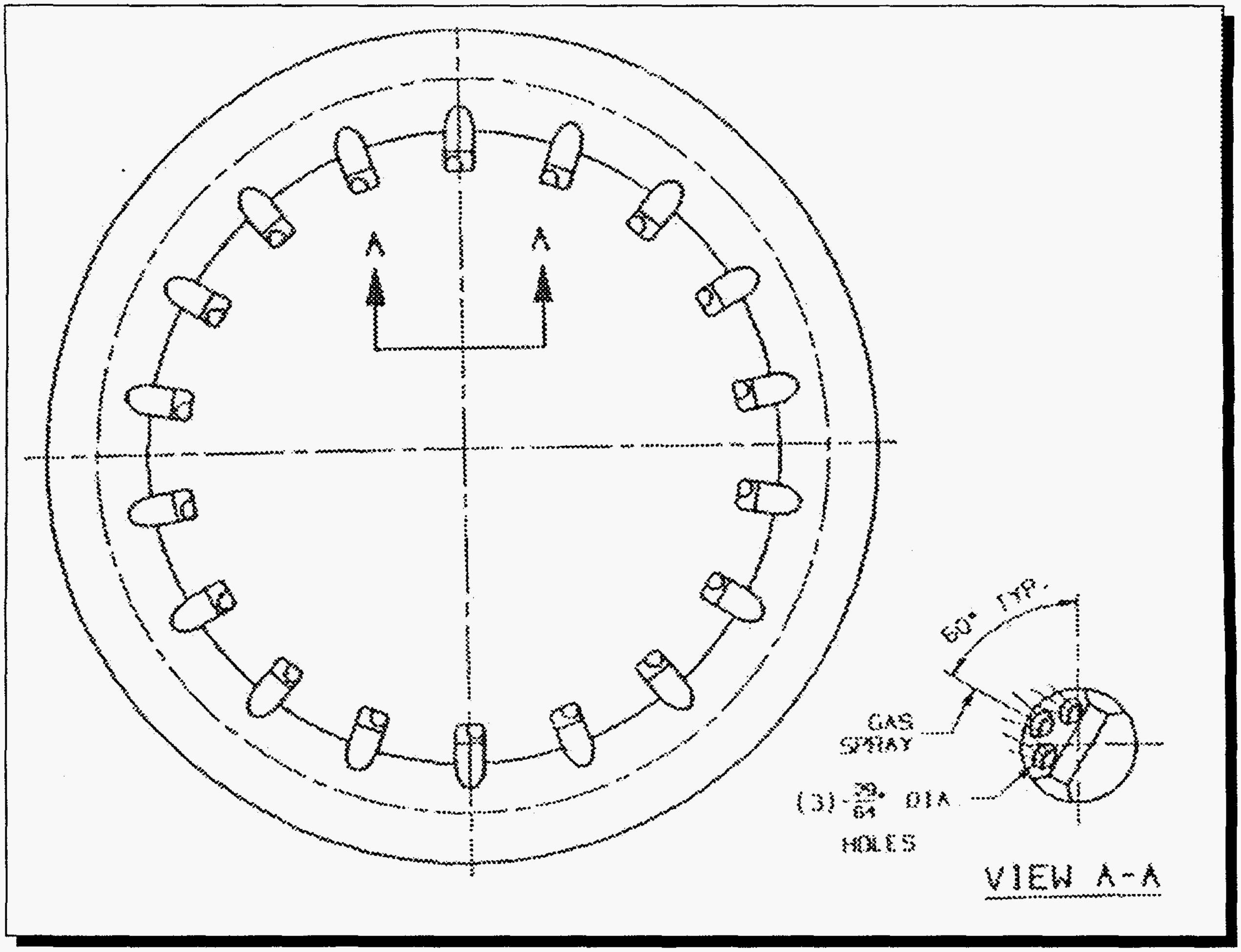


Figure 4–14: Radial Gas Elements

original burners. However, OFA (covered in other sections) is very effective with gaseous fuels and is expected to reduce NO_x emissions produced by burning natural gas by up to 50%.

4.2.5 Process Flow Diagrams

Since Arapahoe Unit 4 is not designed to operate without OFA, the process flow diagrams for the low-NO_x burners are incorporated into those of the OFA ports shown in Section 4.3.2.

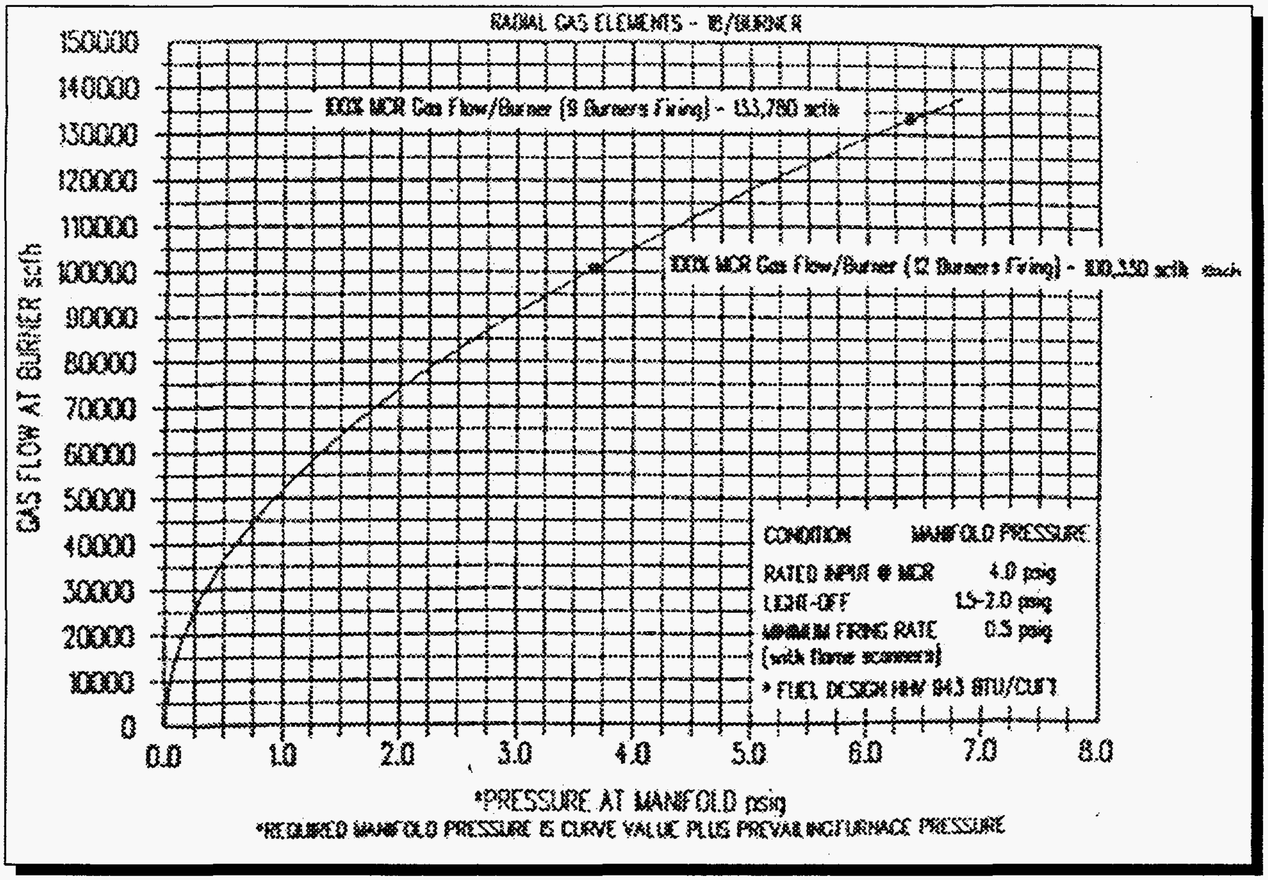


Figure 4-15: **Gas Flow at Burner versus Manifold Pressure**

4.2.6 Material Balances

Since Arapahoe Unit 4 is not designed to operate without OFA, the material balance for the low-NO_x burners is incorporated into the material balance for the OFA ports shown in Section 4.3.3.

4.2.7 Energy Balances

Since Arapahoe Unit 4 is not designed to operate without OFA, the energy balance is described in the section covering OFA ports, Section 4.3.4.

4.2.8 P&ID

Figure 4-16 shows a simplified P&ID of a single low-NO_x burner installed at Arapahoe Unit 4.

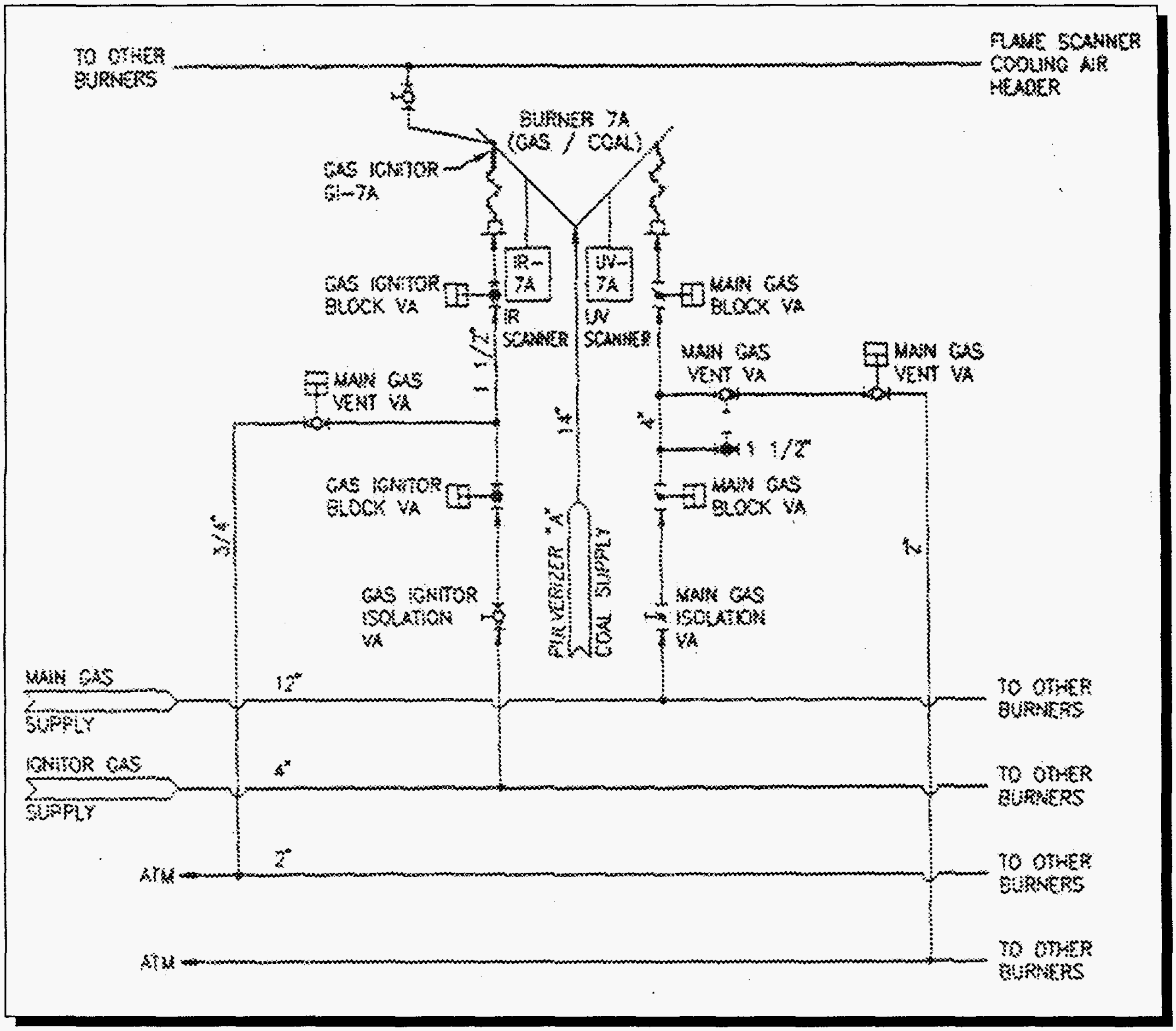


Figure 4-16: P&ID of a Low-NO_x Burner

4.3 OFA Ports

In addition to the low-NO_x burners, an overfire air (OFA) system (or in this case, an "underfire" air system because of the down-fired configuration) was also retrofitted to the boiler of Arapahoe Unit 4. B&W Dual-Zone NO_x Ports® were installed about 20 feet below the boiler roof: 3 ports to the east side and 3 ports to the west side of the boiler. In addition to the NO_x port assemblies, new ductwork, boiler-tube panels, and windboxes have also been installed for the NO_x ports.

B&W performed a numerical modeling study to determine the optimum size and location for the ports. The OFA ports were designed to inject through the furnace sidewalls up to 25% of the total secondary air.

4.3.1 Operation/Process

The NO_x ports are located in a very hot zone of the furnace and are exposed to a significant amount of radiant heat. Providing sufficient cooling air is very important to the protection of the NO_x ports. Two thermocouples mounted on each port monitor locally the temperatures of the inner- and outer-air-zones. Keeping the temperatures of the ports below their design metal temperature of 1,300 °F requires injecting approximately 10% of the combustion air. During some short-term testing, the OFA was reduced to levels that caused the metal temperature to rise to 1,700 °F. This high-temperature operation did not damage the NO_x ports, but B&W still recommended the 1,300 °F limit for long-term operation.

The initial NO_x-port-spin-vane position is 45° open. The initial position of the inner-air-zone-damper should be 30° open. During startup operations, the optimum setting was found to be 100% open for both dampers.

4.3.2 Process Flow Diagram

Figure 4–17 shows the process flow diagram for the low-NO_x combustion system (low-NO_x burners and OFA ports).

4.3.3 Material Balances

Table 4–2 shows the mass balance (lbm/h) and Table 4–3 shows the flow and composition (wt% and vol%) for the low-NO_x combustion system (LNBs and OFA ports). The material balances assume that Arapahoe Unit 4 is operating at its nameplate output of 100 MWe and that 25% of the secondary air is diverted to the OFA ports. They also neglect air leakage from the boiler or air heater since these are very difficult to determine accurately.

4.3.4 Energy Balances

Testing has shown that the low-NO_x combustion system does not produce more unburned carbon than the original system. So, as long as steam temperatures can be maintained, the low-NO_x combustion system is not expected to increase losses or change the efficiency of the boiler. At loads of 100 MWe or more, Arapahoe Unit 4 does not have a problem maintaining steam temperature, but at loads below 100 MWe, testing has shown that the airflow (excess O_2) must be increased slightly from that of the unmodified boiler to maintain steam temperatures. So at 100 MWe, even though the new combustion system changed the heat transfer characteristics of the boiler slightly, there is no change in boiler efficiency. However, at loads below 100 MWe, the excess O_2 must be increased. For example, to maintain steam temperatures at 60 MWe (the lowest load at which the unit is normally regulated) the excess O_2 must be increased from 4 at full load to 6% at 60 MWe. At 60 MWe, this slight increase in excess O_2 increases stack losses by about 4.9 MMBtu/h and decreases the overall efficiency of the unit by 0.76%.

The energy balances for the other systems use the operating conditions of the low-NO_x combustion system described by the material balances in Section 4.3.3 (100 MWe, 25% OFA, and 0.40% sulfur coal) as a baseline. The effects of the additional systems on the unit's efficiency is shown by the change in fuel flow from this base case.

4.3.5 P&ID for OFA Ports

Figure 4-18 shows a simplified P&ID for the OFA ports. The equipment numbers on the P&ID correspond to those on the equipment lists in Section 4.10.

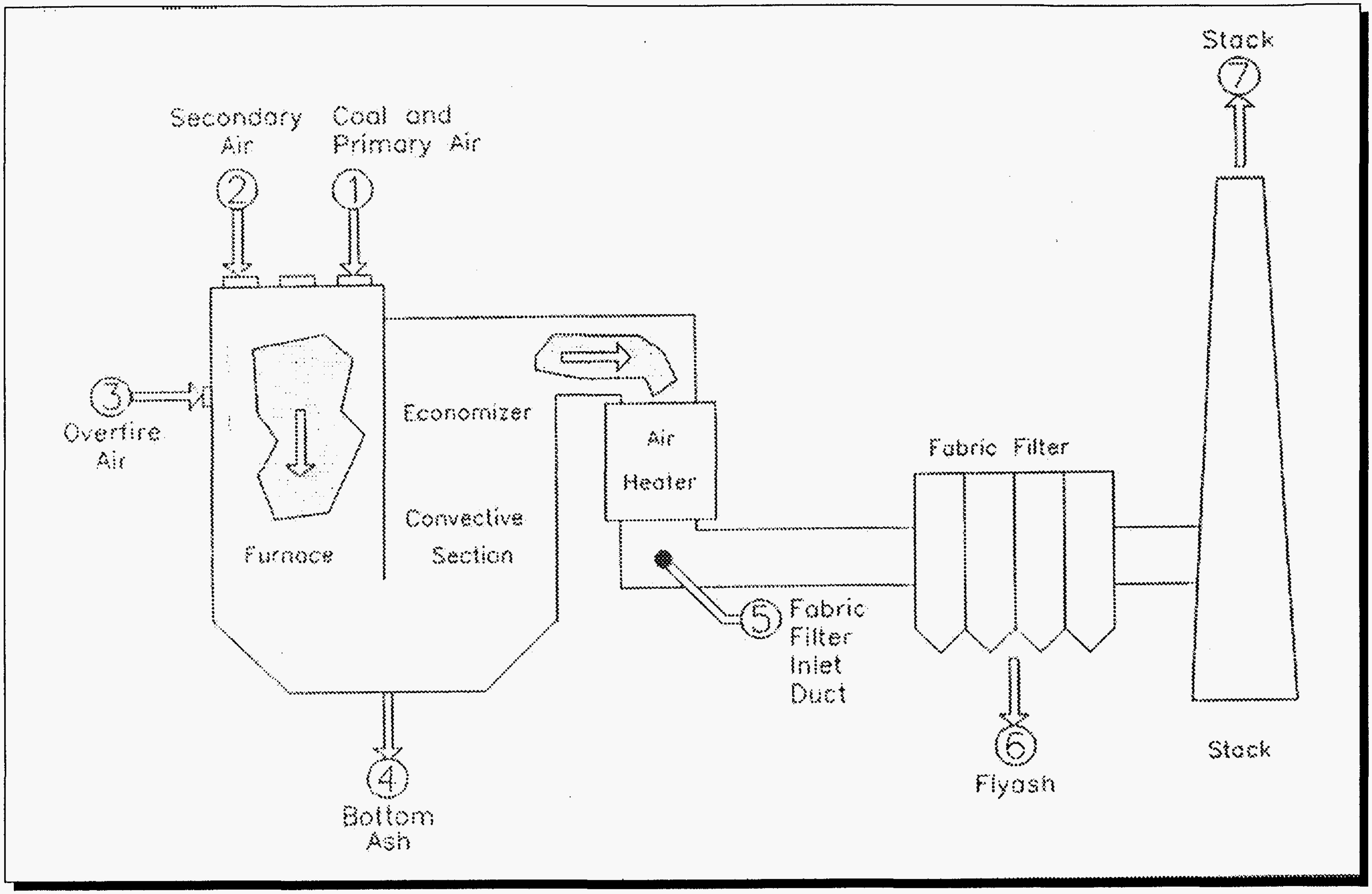


Figure 4-17: Process Flow of Low-NO_x Combustion System

Material		MW	1-Coal/ Primary Air	2-Secondary Air	3-OFA	4-Bottom Ash	5-FFDC Inlet Duct	6-Flyash	7-Stack
Solids (lbm/h)	C	12	59,106	--	--	22	202	202	--
	H_2	2	4,235	--	--	--	--	0	--
	N_2	28	1,508	--	--	--	--	0	--
	O_2	32	9,882	--	--	--	--	0	--
	S	32	376	--	--	0	3	3	--
	Na	23	61			15	46	46	
	Ca	40	61			15	46	46	
	NH_3	17	--			--	--	0	
	Inerts[1]	N/A	8,913	--	--	2,228	6,685	6,682	3
	H_2O	18	9,976	--	--	--	--	--	--
	Total Solids		+94,118	--	--	-2,280	(6,982)	-6,979	-3
Gases[2] (lbm/h)	Temperature		300 °F	600 °F	600 °F	--	260 °F	--	250 °F
	Pressure		1,772 lb/ft^2	1,767 lb/ft^2	1,767 lb/ft^2	--	1,705 lb/ft^2	--	1,762 lb/ft^2
	N_2	28	140,760	390,990	177,251	--	710,378	--	710,378
	O_2	32	42,504	118,064	53,523	--	32,567	--	32,567
	H_2O	18	736	2,044	927	--	51,798	--	51,798
	CO_2	44	--	--	--	--	215,854	--	215,854
	CO	28	--	--	--	--	30	--	30
	SO_2	64	--	--	--	--	746	--	746
	NH_3	17	--	--	--	--	0		0
	N_2O	44	--	--	--	--	0		0
	NO	30	--	--	--	--	277	--	277
	NO_2	46	--	--	--	--	5	--	5
	Total Gases		+184,000	+511,098	+231,701	--	(1,011,655)	--	-1,011,655
Total In	1,020,917		+278,118	+511,098	+231,701		(=1,018,637)		
Total Out	-1,020,917					-2,280		-6,979	-1,011,658

Note: "+" indicates flow into the system, "-" indicates flow out of system, "(=)" indicates an intermediate balance point.

1. Assumes that the oxides in the ash remain constant.
2. Assumes no leakage of air into the boiler, air heater, or FFDC.

Table 4-2: Mass Balance for Low-NO_x Burners and OFA Ports (Load=100 MWe, OFA=25%, 0.40% Sulfur Coal)

Material		MW	1-Coal/Primary Air		2-Secondary Air		3-OFA		4-Bottom Ash		5-FFDC Inlet Duct		6-Flyash		7-Stack	
Solids (wt%)	C	12	62.8		--		--		1.0		2.9		2.9		--	
	H_2	2	4.5		--		--		--		--		--		--	
	N_2	28	1.6		--		--		--		--		0.0		--	
	O_2	32	10.5		--		--		--		0.0		0.0		--	
	S	32	0.4		--		--		0.0		0.0		0.0		--	
	Na	23	0.1		--		--		0.7		0.7		0.7		--	
	Ca	40	0.1		--		--		0.7		0.7		0.7		--	
	NH_3	17	--		--		--		--		--		0		--	
	Inerts[1]	N/A	9.5		--		--		97.6		95.7		95.7		100	
	H_2O	18	10.5		--		--		--		--		--		--	
	Total		100%		--		--		100%		100%		100%		100%	
Gases[2]	Temperature		300 °F		600 °F		600 °F		--		260 °F		--		250 °F	
	Pressure		1,772 lb/ft^2		1,767 lb/ft^2		1,767 lb/ft^2		--		1,705 lb/ft^2		--		1,762 lb/ft^2	
		MW	acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%
	N_2	28	55,507	78.6	215,677	78.6	97,775	78.6	--	--	275,917	74.2	--	--	263,245	74.2
	O_2	32	14,666	20.8	56,985	20.8	25,834	20.8	--	--	11,068	3.0	--	--	10,560	3.0
	H_2O	18	451	0.6	1,754	0.6	795	0.6	--	--	31,296	8.4	--	--	29,859	8.4
	CO_2	44	--	--	--	--	--	--	--	--	53,352	14.3	--	--	50,902	14.3
	CO	28	--	--	--	--	--	--	--	--	12	31 ppmv	--	--	11	31 ppmv
	SO_2	64	--	--	--	--	--	--	--	--	127	341 ppmv	--	--	121	341 ppmv
	NH_3	17	--	--	--	--	--	--	--	--	0	0	--	--	0	0
	N_2O	44	--	--	--	--	--	--	--	--	0	0	--	--	0	0
	NO	30	--	--	--	--	--	--	--	--	100	270 ppmv	--	--	96	270 ppmv
	NO_2	46	--	--	--	--	--	--	--	--	1	3 ppmv	--	--	1	3 ppmv
	Total		70,624	100%	274,416	100%	124,404	100%	--	--	371,873	100%	--	--	354,795	100%

1. Assumes mineral oxides in ash remain constant.
2. Assumes no air leakage in the boiler, air heater, or FFDC.

Table 4-3: Flow and Composition for Low-NO_x Burners and OFA Ports (Load = 100 MWe, OFA = 25%, 0.40% Sulfur Coal)

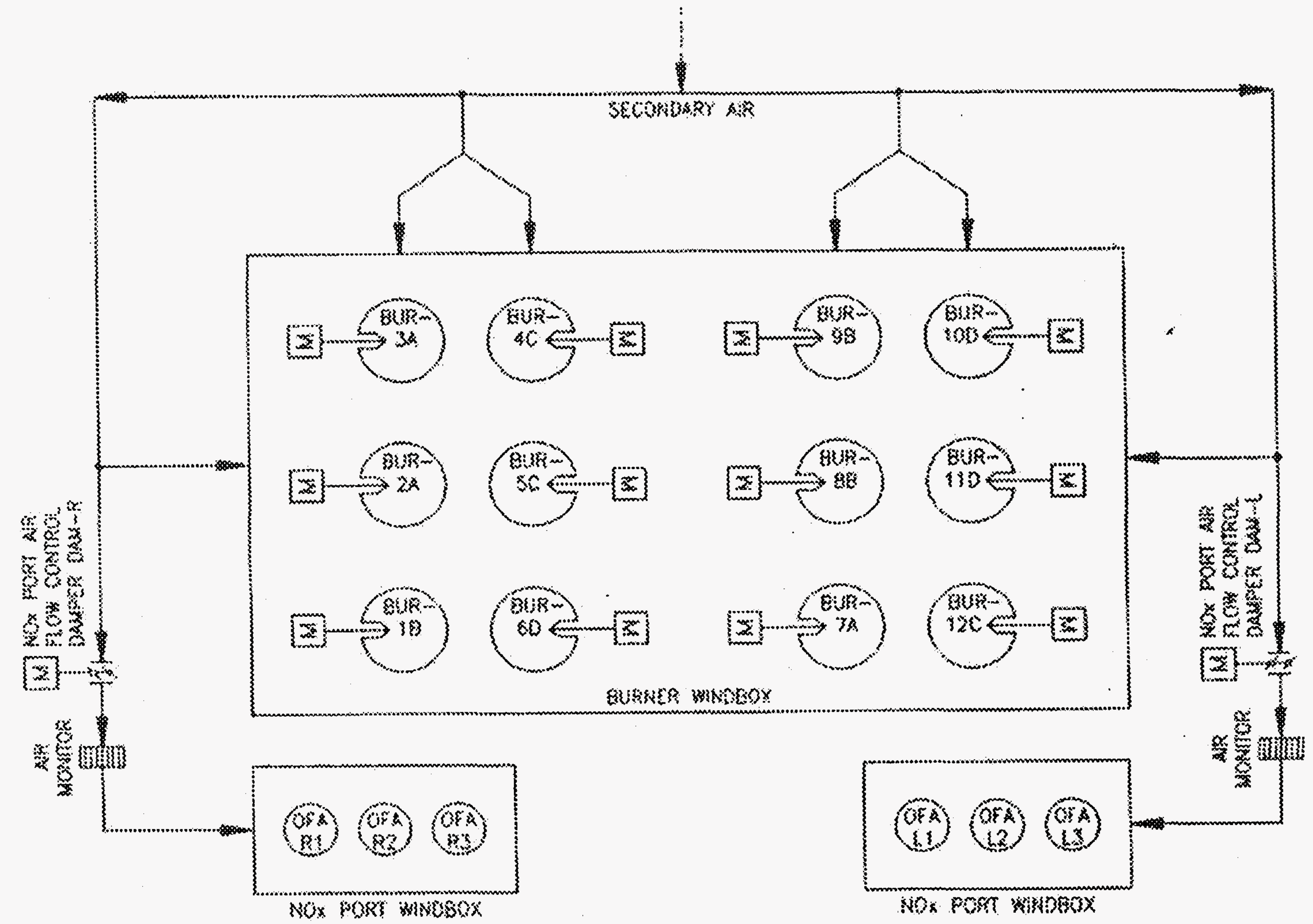


Figure 4-18: Simplified P&ID for OFA Ports

4.4 SNCR

The SNCR injection system (designed by NOELL, Inc.) is designed to mix the flue gases and the reducing agent to a high degree and in a short residence time. The system can be divided into the following subsystems:

- Urea-recirculation loop: Stores and heats the base urea solution.
- Injection: diverts a small slipstream of urea from the recirculation loop is filtered, diluted it with softened water, and pumps it at high pressure (100 to 1,000 psig) to the atomizers.
- Ammonia conversion (If in use): converts urea into ammonia compounds for injection during low-load conditions.
- Atomization: atomizes and distributes the urea or ammonia compounds evenly into the boiler through the injection lances.

4.4.1 Urea Recirculation

The urea-recirculation loop stores and heats the base urea solution. Urea is received as a 65 wt% aqueous solution and is stored in one of two 20,000-gal tanks. To prevent the 65 wt% urea from crystallizing, it must be stored above 115 °F.

The urea recirculation pump continuously circulates the solution. The recirculation lines are insulated and include electric in-line heaters. At Arapahoe Unit 4, a 200-gal/min-pump (with another pump on standby) circulates the urea solution through an electric heater. To prevent the urea from crystallizing, the recirculation system is designed to keep the urea solution at 150 °F.

During the baseline testing of the SNCR system, it was found that maintaining a 65 wt% solution of urea above 115 °F caused ammonia to vaporize so that a slight odor could be detected on some days. However, diluting the 65 wt% urea to 37.5 wt% after it was delivered solved this problem, and saved the costs of recirculating and heating it. As shown in Figure 4-19, the crystallization temperature for 37.5 wt% urea is only 21 °F.

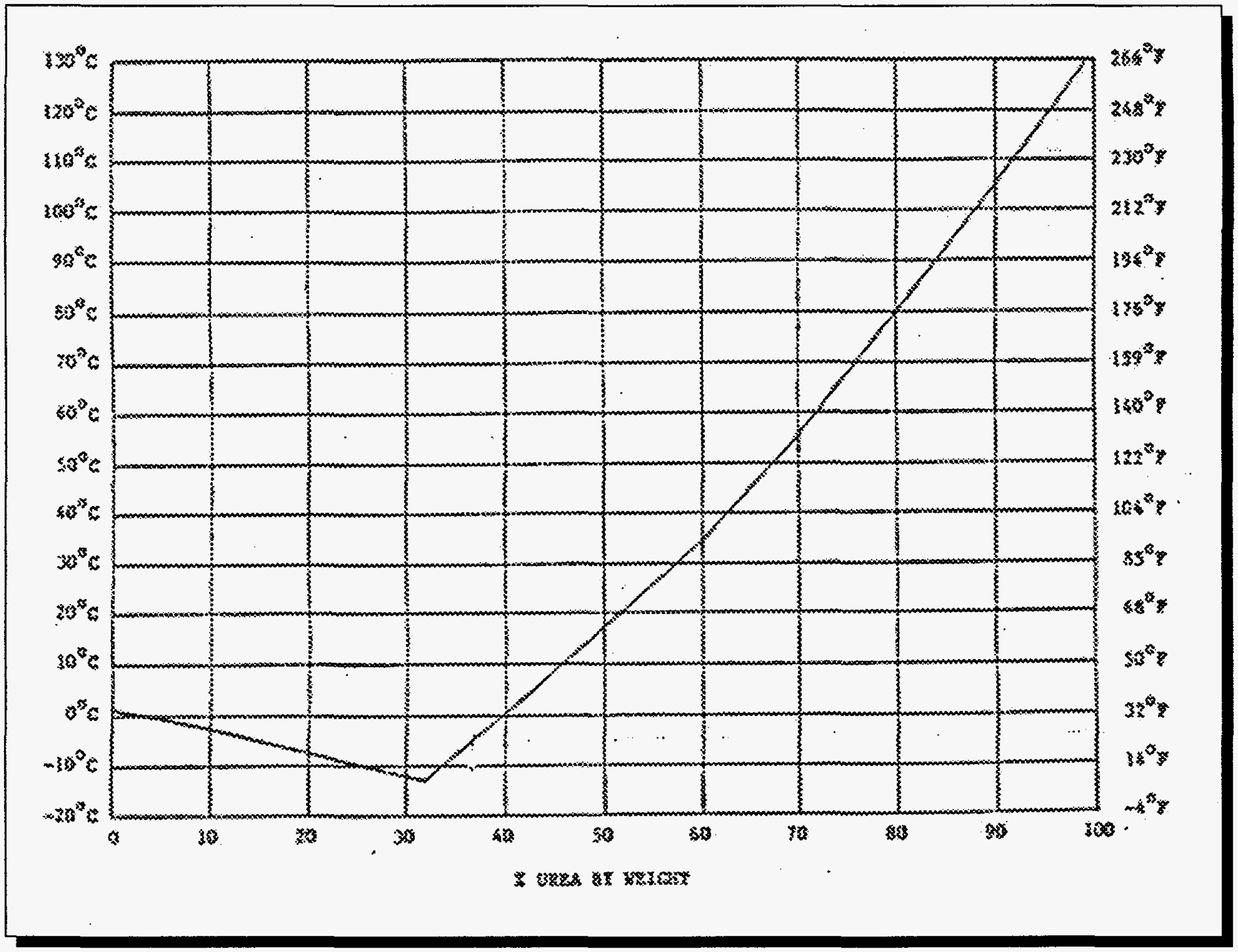


Figure 4-19: **Crystallization (Fog) Temperatures of Aqueous Urea Solutions (Source: Wycon Chemical Co.)**

4.4.2 Injection System

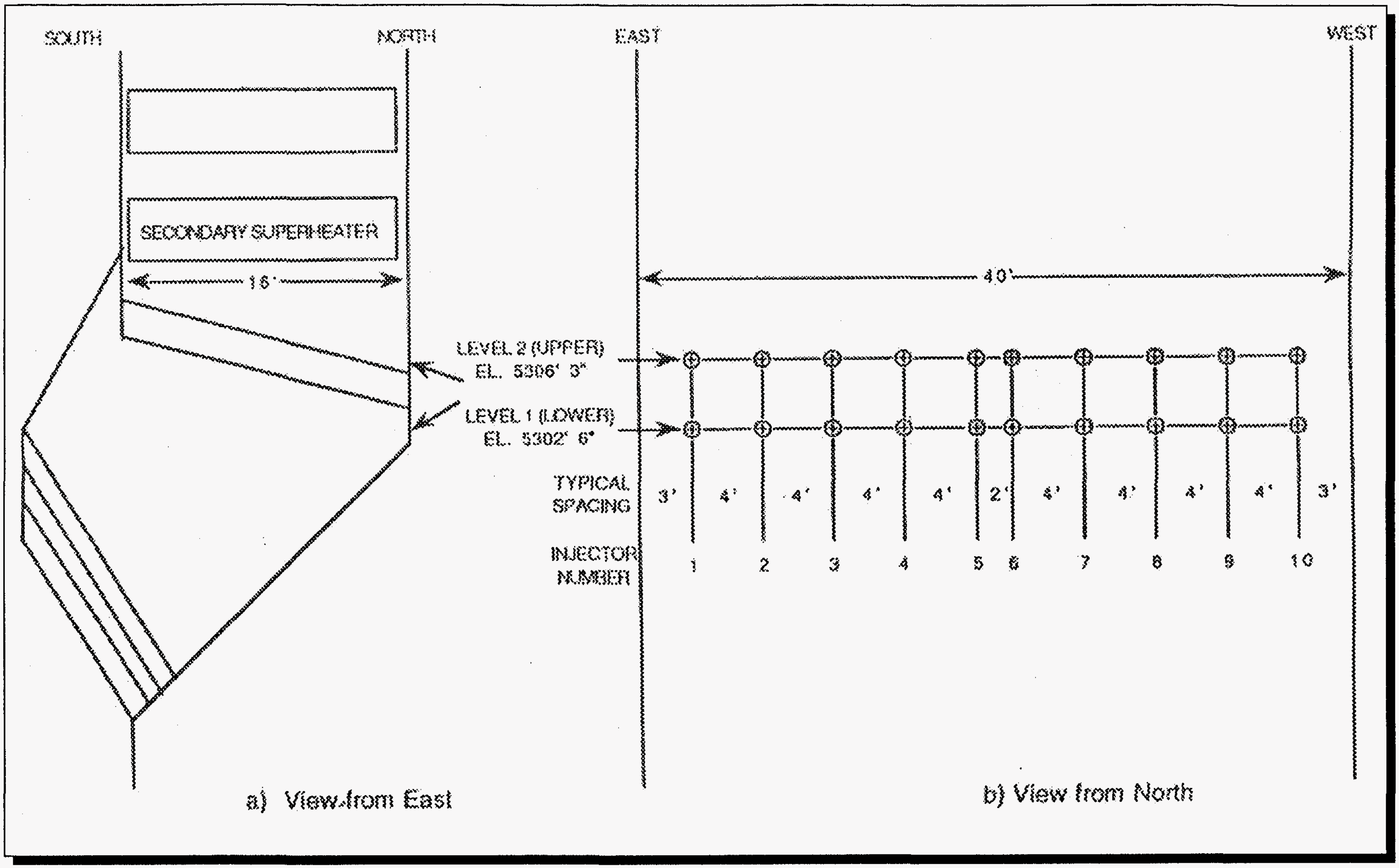
The urea system installed at Arapahoe Unit 4 is based on a high-energy injection system that uses air compressed to medium pressure to help atomize the urea. The injection system diverts a small slipstream of urea from the recirculation loop, filters it, dilutes it with softened water to 10 wt% urea, and then pumps the diluted urea at high pressure (100 to 1,000 psig) to the atomizers.

The system at Arapahoe Unit 4 uses one of 2 positive-displacement pumps (100%-capacity) to supply the urea solution to the header and subsequently to the pre-selected set of injection nozzles. A variable-speed motor drives each pump and varies the flow from 2.0 to 10.5 gal/min of diluted urea. The liquid transfer lines are insulated and heat traced to 50 °F to prevent the urea from crystallizing.

The ability to vary the total flow allows some control over the effective-gas-injection-temperature. Increasing the liquid flowrate compensates for flue-gas temperatures that are too high by evaporating and cooling the flue-gas. Conversely, decreasing the liquid flowrate can compensate for flue-gas temperatures that are too low by not significantly lowering its temperature by evaporation.

Several parameters are used to control the urea flowrate. The feedforward control of the urea flowrate is based on boiler load. The feedback control of the urea flowrate is based on the levels of NH_3 at the stack. The feedback control can adjust the urea control valve (FV-1063) to increase or decrease by 30% the urea flowrate established by the boiler load.

The Arapahoe Unit 4 boiler has 2 rows of 10 wall-mounted injectors, one immediately downstream (level 1) and one immediately upstream (level 2) of the second set of screen tubes. Figure 4–20 shows the location of the SNCR injectors. Figure 4–21 shows the tubing that supplies the urea to the lances as the tubes enter the furnace wall. The level-1 tubes are directed 45° down from horizontal so that they inject directly counter to the flow of the flue gas. The level-2 injectors point 15° above horizontal.



a) View from East

b) View from North

Figure 4–20: Arapahoe Unit 4 SNCR Injection Nozzle Location

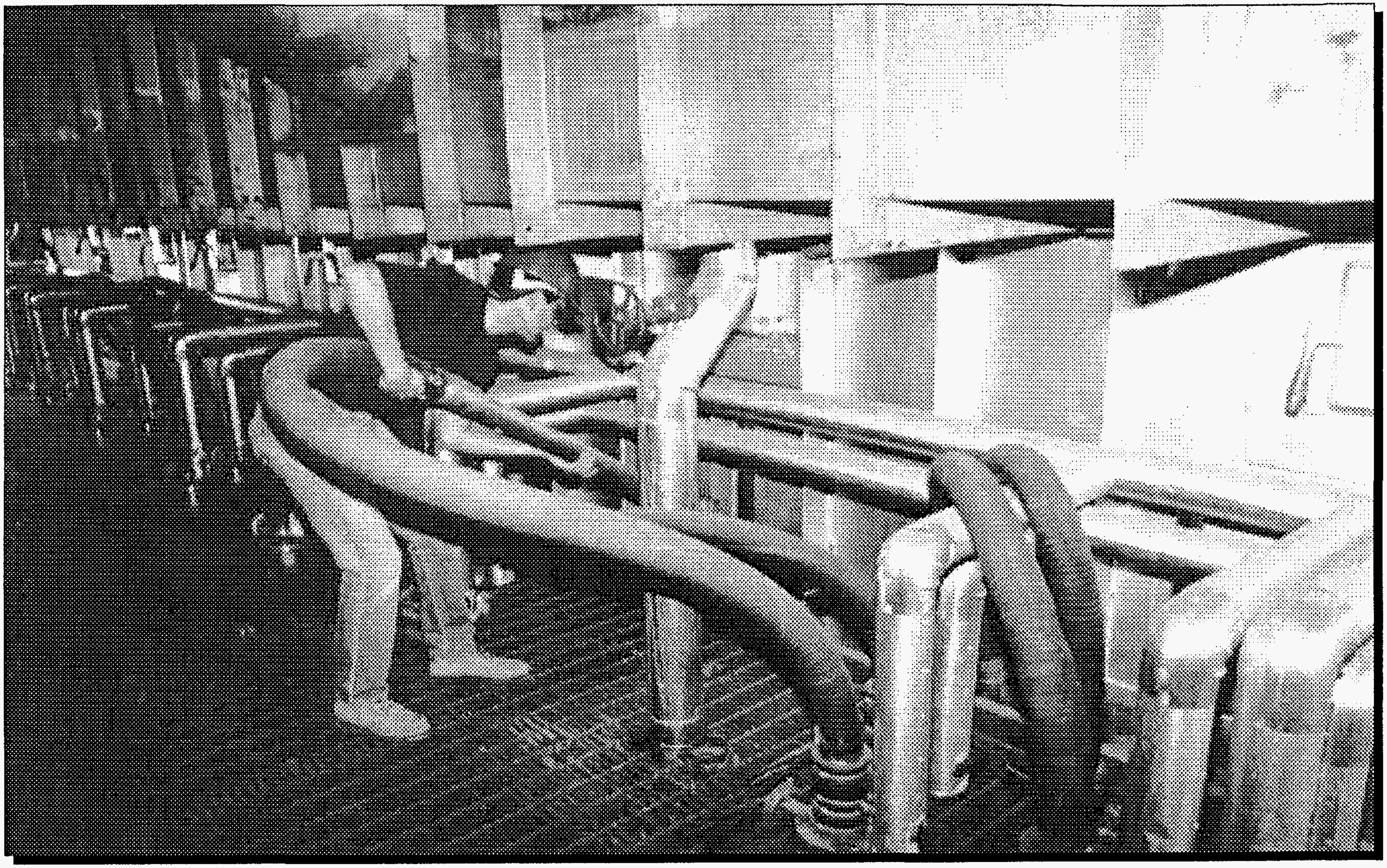


Figure 4-21: Photo of Urea Tubing Entering the Furnace Wall

The SNCR system at Arapahoe Unit 4 was designed with two levels of injectors to allow the system to operate effectively over a wider load range. The upper level of injectors was for higher loads (80 to 100 MWe) and the lower level of injectors was designed for lower loads (below 80 MWe). However, initial testing showed that the urea injected through the upper level of injectors was ineffective over the entire load range because either flue-gas temperatures were too low or the residence times were too short.

Purge air injected through injectors while they are not in use, cools the lances and keeps them free of ash build up. The purge air fan draws ambient air through a filter and silencer. The fan feeds it through the air lines, up to the air header, and then through the injection lances not in service. During short periods when neither set of injectors is in use, the purge-air fan supplies cooling air to both sets of injectors. For extended shutdown periods, the injectors can be removed and the purge-air fan can be shutdown.

4.4.3 Ammonia Converter

The ammonia converter was added after the original SNCR test program on the original burners found that urea was not very effective at removing NO_x at low-load levels. A short test showed that aqueous ammonia reacted more quickly, at a lower temperature in the boiler, and was utilized more effectively than urea. Although ammonia is more effective, for safety reasons it is more desirable to store urea than ammonia. In addition, the storage tanks were originally not designed to store liquid ammonia and were vented.

To solve this dilemma, NOELL, Inc. suggested an on-line conversion system that converts urea into ammonia compounds. This system first heats the urea and then passes it over a proprietary catalyst to convert it to ammonia-based compounds. By bypassing the ammonia conversion system, the operator may select either urea or ammonia injection.

4.4.4 Atomization

The SNCR system at Arapahoe Unit 4 uses NOELL, Inc.'s proprietary dual-fluid injection nozzles to distribute the urea or ammonia compounds evenly into the boiler. A centrifugal compressor (K-1) supplies a large volume (up to 9,000 scfm) of medium pressure (4 to 12 psig) air to the injection nozzles.

The compressor pulls air through the inlet silencer/filter and discharges it to the quench vessel. The hot, compressed air (up to 300 °F) is cooled in the quench vessel by spraying water into the air stream. The water evaporates and cools the air. Makeup water is supplied by the water softener, which softens the water and supplies it to the quench vessel.

The quench vessel discharges the air to the proper air header selected automatically by the control system. The compressed air flows from the selected air header to the injectors, where the air and the urea solution are injected into the flue gas.

The air helps atomize the injected solution to mix rapidly with the flue gas. Variable-inlet-guide-vanes and a variable-diffuser assembly control the volume of air supplied and automatically delivers a preset discharge pressure.

The quantity of atomization air is changed to adjust the size of the droplet. To ensure proper atomization of the urea solution, the designed system can inject the atomization air at velocities up to the speed of sound.

4.4.5 Design of SNCR Injection Lances

The installation of the low-NO_x combustion system was not expected to change significantly the temperature distribution in the boiler, so temperature measurements and cold-flow modeling of the original combustion system were used to determine the location and configuration of the injection lances.

4.4.5.1 Temperature Measurements

Acoustic and suction pyrometry (HVT) measurements of the flue-gas temperatures indicated that the general vicinity of the north ports provided the temperatures necessary for urea injection over the load range. It was determined that Arapahoe Unit 4 required two levels of wall-mounted injector assemblies. Figure 4-22 shows the placement of the injectors.

The upper level of injectors was designed for boiler loads ranging from 70% to 100%. The lower level of injectors was designed for boiler loads ranging from about 40% to 70%. The SNCR system was not designed for boiler loads below 40%. Both rows of injectors are installed running across the north wall of the convective section at roughly the same elevation as the north ports. One row of injectors is at exactly the same elevation as the north ports, essentially parallel to the screen tubes, and pointed upward slightly. The other row of injectors is below the screen tubes, parallel to the bottom of the convective section, and pointed downward slightly.

4.4.5.2 Cold-Flow Modeling

Once the injection locations were determined, cold-flow modeling was used to design the injection system. Maximizing NO_x removal rates and minimizing ammonia slip requires good mixing and distribution of the SNCR chemical and the flue gas. A 1:10 model of Arapahoe Unit 4 was used to examine the bulk flow patterns and to optimize the configuration of the injectors. Figure 4-23 shows the bulk flow patterns of the model.

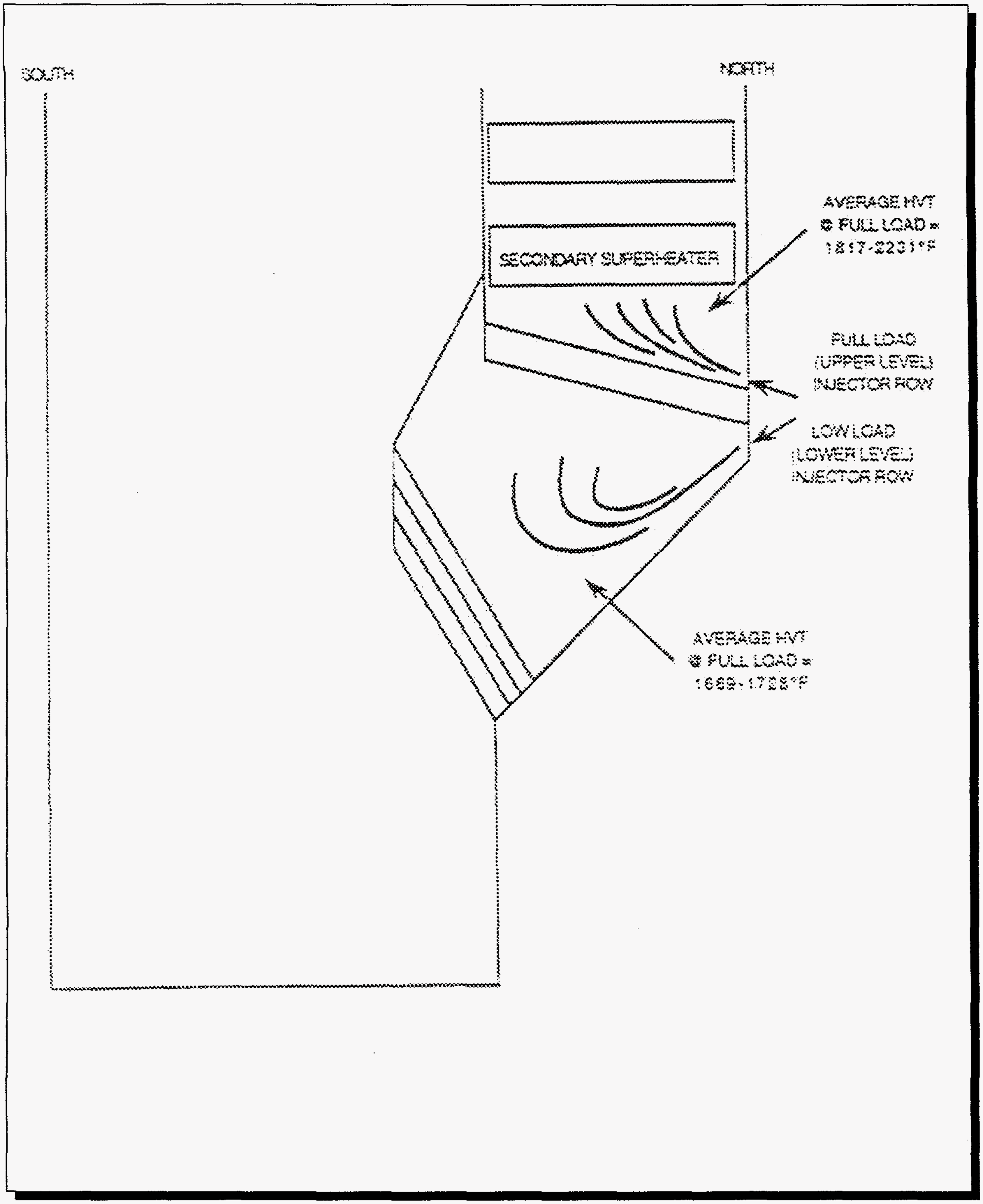


Figure 4–22: Injector Placement Scenario Based on Flue-Gas Temperature Measurements

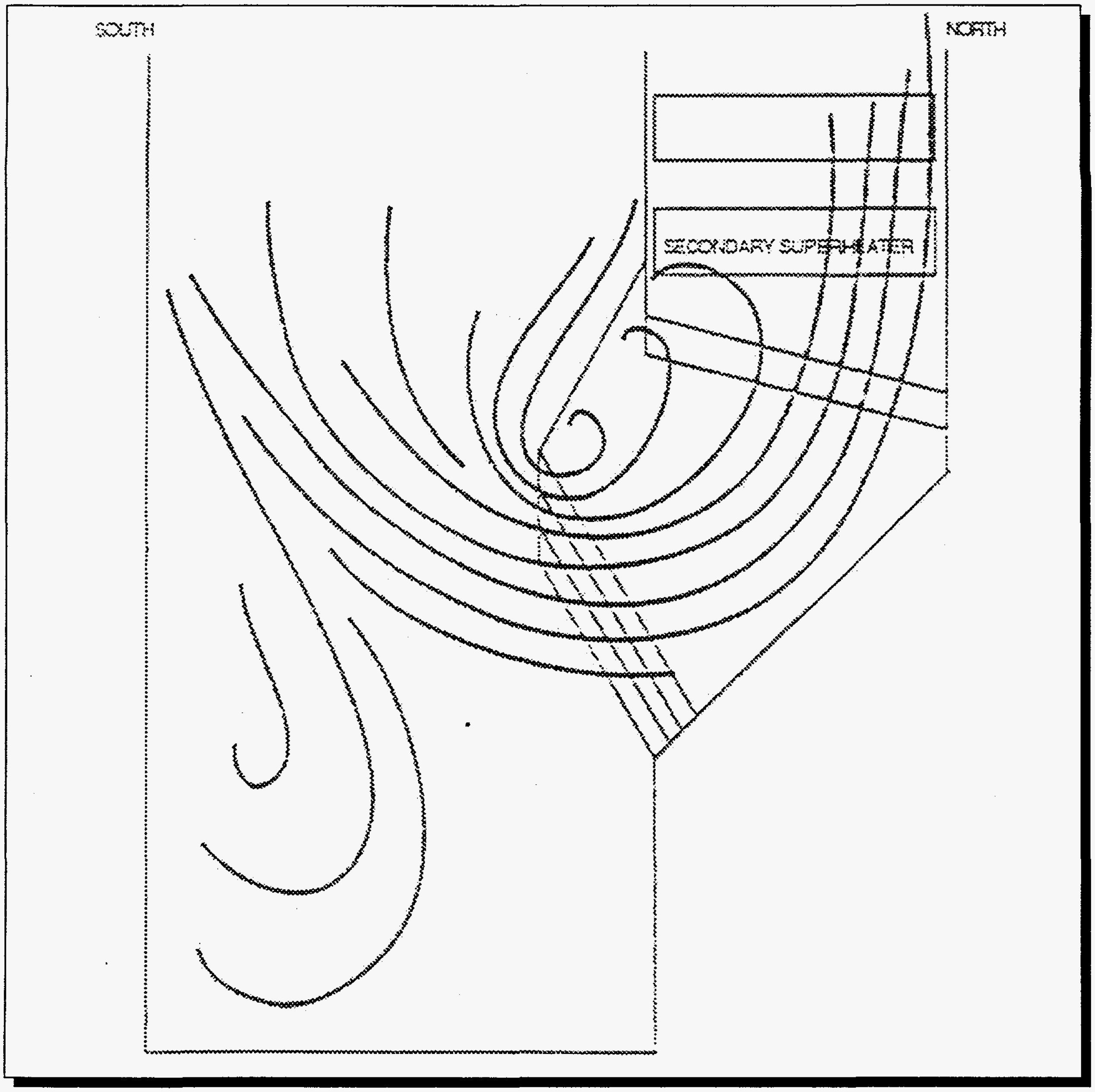


Figure 4–23: Overall Bulk-Flow Patterns

Optimizing the configuration of the injector requires determining the number of injectors, the injection angle, the injection diameter, and the amount of mixing air. Previous design experience had shown that an injection flowrate of 2% of the total flowrate of the boiler at full load provided high levels of mixing, but does not result in excessive power costs for the compressor. Modeling showed that 10 injectors gave the best combination of jet penetration and lateral dispersion.

4.4.5.3 Configuration of Injectors

The flue-gas temperature measurements and the cold-flow modeling tests resulted in the following:

- The vicinity near the north ports provides the temperatures necessary for effective reactions of the SNCR chemicals.

- Optimizing these reactions over the entire load range requires two rows of injectors: an upper level for high loads and a lower level for lower loads.

- At full load, the following configuration produced optimum mixing:
  - Ten injectors, evenly spaced.
  - A full-scale injector diameter of 1.61 inches.
  - An injector angle of +15° ±5°.

- At low load, the following configuration produced optimum mixing:
  - Ten injectors, evenly spaced.
  - A full-scale injector diameter of 1.08 inches.
  - An injector angle of -45° ±5° (direct counterflow).

4.4.6 Local Control of SNCR System

A programmable logic controller (PLC) controls the SNCR system. The PLC is operated with an IBM-compatible computer and controls most functions of the system. Three local-control panels (LCP) control the functions not controlled by the PLC: the centrifugal compressor, the circulation heaters, and the water softening skid. However, the LCPs receive main commands from and exchange information with the PLC. Also, the valves of some of the redundant equipment (urea recirculation pump, quench pump, filter-inlet and -outlet valves) must be manually preselected.

From the PLC, the SNCR system can be operated manually, or automatically. Under automatic control, feed-forward and feedback functions control the flowrate of urea. The feed forward function uses a boiler-load signal. The feedback control uses either a stack-NO_x or a stack-NH_3 signal and can vary the urea flowrate by plus or minus 30%.

4.4.7 Process Flow Diagram

Figure 4–24 shows a simplified flow diagram of the SNCR system at Arapahoe Unit 4.

4.4.8 Material Balances

This section shows the material balances for the SNCR system calculated at the same operating conditions as the low-NO_x combustion system: load=100 MWe, OFA=25%, and 0.40% sulfur coal. Table 4–5 and Table 4–6 show the mass balance (lbm/h) and Table 4–7 and Table 4–8 show the flows and stream compositions for the SNCR system. The material balances were calculated for injecting urea at an NSR of 0.87 and a NO_x removal rate of 43%.

4.4.9 Energy Balances

SNCR has the following four effects on the energy balance of the unit:

- The chemical reaction that reduces NO to N_2, H_2O, and other products is exothermic, so it adds energy to the flue gas that the unit absorbs.
- The evaporation of the injected water requires energy from the flue gas.
- The heating of the atomization air absorbs energy from the flue gas.
- The operation of the SNCR equipment requires 283 kW of energy.

Table 4–4 summarizes the energy loss caused by these effects. The total net energy loss is 6.2 MMBtu/h or a 0.52% efficiency loss for the unit. The mass balances in Section 4.4.8 show the additional fuel required to maintain an output of 100 MWe with SNCR operating.

Energy Source	Energy Loss (Btu/h)
Urea reaction	-1,985,608
Water evaporation	3,059,575
Atomization air	551,001
Auxiliary power	4,568,168
Net loss	6,193,136

Table 4–4: Summary of SNCR Energy Losses and Gains

4.4.10 P&ID for SNCR System

Figure 4–25 shows a simplified P&ID of the SNCR system at Arapahoe Unit 4. The equipment numbers on the P&ID correspond to the equipment numbers shown in the equipment lists in Section 4.10.

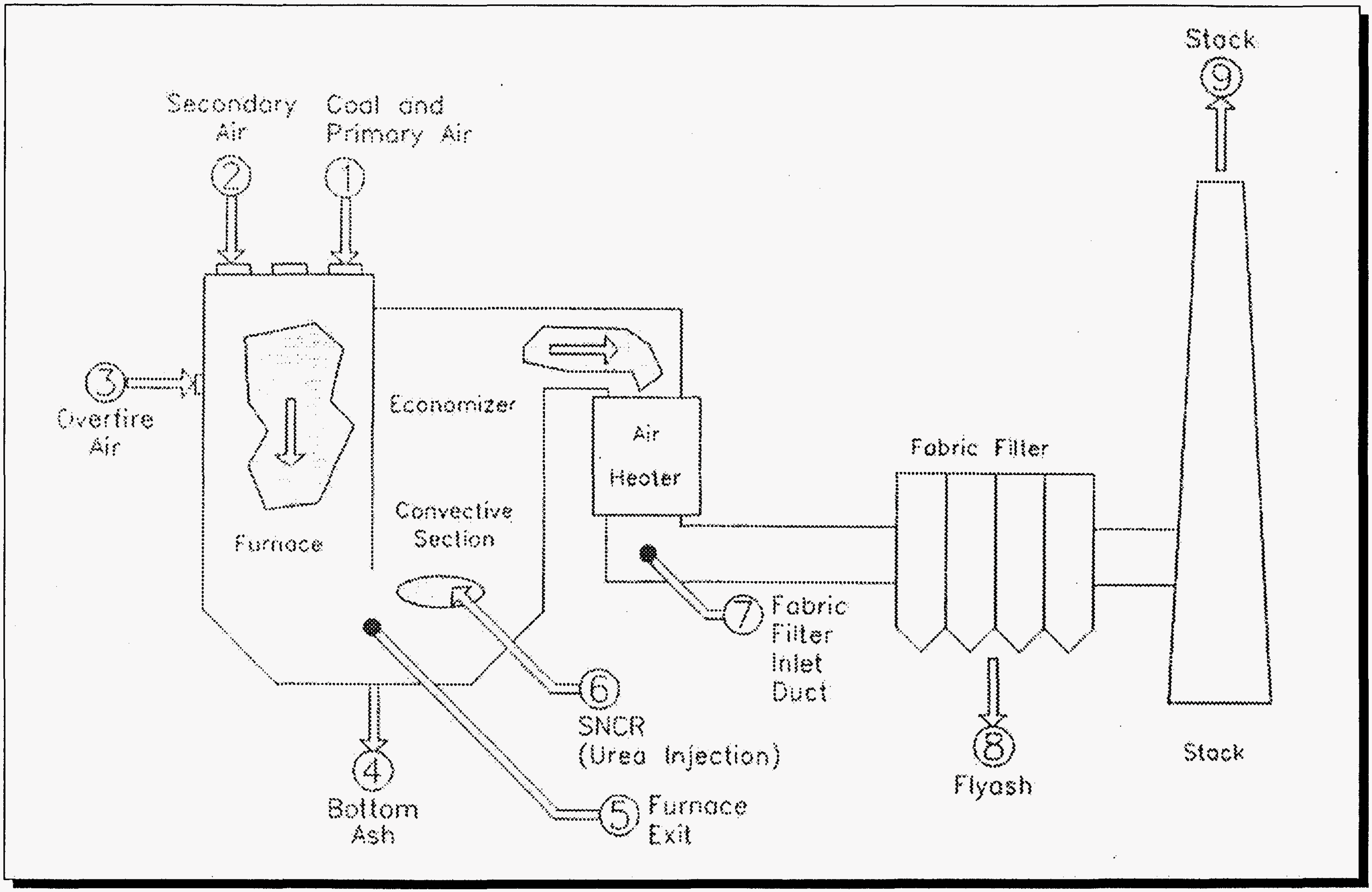


Figure 4-24: Process Flow Diagram of SNCR System at Arapahoe Unit 4

Material		MW	1-Coal/ Primary Air	2-Secondary Air	3-OFA	4-Bottom Ash	5-Furnace Exit
Solids (lbm/h)	C	12	59,366	--	--	23	203
	H_2	2	4,254	--	--	--	--
	N_2	28	1,513	--	--	--	--
	O_2	32	9,926	--	--	--	--
	S	32	378	--	--	0	3
	Na	23	61	--	--	15	46
	Ca	40	61	--	--	15	46
	NH_3	17	--	--	--	--	--
	Inerts[1]	N/A	8,953	--	--	2,238	6,715
	H_2O	18	10,020	--	--	--	--
	Total Solids		+94,532	--	--	-2,291	(=7,013)
Gases[2] (lbm/h)	Temperature		300 °F	600 °F	600 °F	--	1,850 °F
	Pressure		1,772 lb/ft^2	1,767 lb/ft^2	1,767 lb/ft^2	--	1,746 lb/ft^2
	N_2	28	140,760	393,342	178,035	--	713,519
	O_2	32	42,504	118,774	53,759	--	32,971
	H_2O	18	736	2,057	931	--	52,030
	CO_2	44	--	--	--	--	216,094
	CO	28	--	--	--	--	479
	SO_2	64	--	--	--	--	750
	NH_3	17	--	--	--	--	0
	N_2O	44	--	--	--	--	0
	NO	30	--	--	--	--	278
	NO_2	46	--	--	--	--	5
	Total Gases		+184,000	+514,173	+232,725	--	(=1,016,126)
Liquids (lbm/h)	Temperature		--	--	--	--	--
	Pressure		--	--	--	--	--
	Urea[3]	60	--	--	--	--	--
	H_2O	18	--	--	--	--	--
	N_2	28	--	--	--	--	--
	H_2	2	--	--	--	--	--
	C	12	--	--	--	--	--
	O_2	32	--	--	--	--	--
	Total Liquids		--	--	--	--	--
Total (lbm/h)	In		+278,532	+514,173	+232,725		(=1,023,139)
	Out					-2,291	

Note: "+" indicates flow into the system, "-" indicates flow out of system, "(=)" indicates an intermediate balance point.

1. Assumes mineral oxides in ash remain constant.
2. Assumes no leakage of air into boiler, air heater, or FFDC.
3. Shown for information only, not included in totals.

Table 4-5: Mass Balance (to Furnace Exit) for SNCR System (Urea at NSR=0.87, NO_x Removal=43%, Load=100 MWe, OFA=25%, 0.40% Sulfur Coal)

6-SNCR (Urea Injection)	7-FFDC Inlet Duct	8-Flyash[2]	9-Stack	MW	Material	
--	203	203	--	12	C	Solids (lbm/h)
--	--	0	--	2	H_2	
--	--	0	--	28	N_2	
--	0	0	--	32	O_2	
--	3	3	--	32	S	
--	46	46	--	23	Na	
--	46	46	--	40	Ca	
--	--	0	--	17	NH_3	
--	6,715	6,712	3	N/A	Inerts[1]	
--	--	--	--	18	H_2O	
--	(=7,013)	-7,010	-3	Total Solids		
130 °F	260 °F	--	250 °F	Temperature		Gases (lbm/h)
1,746 lb/ft^2	1,705 lb/ft^2	--	1,762 lb/ft^2	Pressure		
13,426	727,190	--	727,190	28	N_2	
4,054	36,437	--	36,437	32	O_2	
108	55,075	--	55,075	18	H_2O	
--	217,154	--	217,154	44	CO_2	
--	30	--	30	28	CO	
--	750	--	750	64	SO_2	
--	6	--	6	17	NH_3	
--	49	--	49	44	N_2O	
--	158	--	158	30	NO	
--	5	--	5	46	NO_2	
+17,588	(=1,036,854)	--	-1,036,854	Total Gases		
60 °F	--	--	--	Temperature		Liquids (lbm/h)
1,746 lb/ft^2	--	--	--	Pressure		
484	--	--	--	60	Urea[3]	
2,657	--	--	--	18	H_2O	
226	--	--	--	28	N_2	
32	--	--	--	2	H_2	
97	--	--	--	12	C	
129	--	--	--	32	O_2	
+3,140	--	--	--	Total Liquids		
+20,728	(=1,043,867)			+1,046,158	Total In	
		-7,010	-1,036,857	-1,046,158	Total Out	

Note: "+" indicates flow into the system, "-" indicates flow out of system, "(=)" indicates an intermediate balance point.

1. Assumes mineral oxides in ash remain constant.
2. Assumes no leakage of air into boiler, air heater, or FFDC.
3. Shown for information only, not included in totals.

Table 4-6: Mass Balance (from Furnace Exit) for SNCR System (Urea at NSR=0.87, NO_x Removal=43%, Load=100 MWe, OFA=25%, 0.40% Sulfur Coal)

Material		MW	1-Coal/ Primary Air		2-Secondary Air		3-OFA		4-Bottom Ash		5-Furnace Exit	
Solids (wt%)	C	12	62.8		--		--		1.0		2.9	
	H_2	2	4.5		--		--		--		--	
	N_2	28	1.6		--		--		--		--	
	O_2	32	10.5		--		--		--		--	
	S	32	0.4		--		--		0.0		0.0	
	Na	23	0.1		--		--		0.7		0.7	
	Ca	40	0.1		--		--		0.7		0.7	
	NH_3	17	--		--		--		--		--	
	Inerts[1]	N/A	9.5		--		--		97.6		95.7	
	H_2O	18	10.5		--		--		--		--	
	Total		100%		--		--		100%		100%	
Gases[2]	Temperature		300 °F		600 °F		600 °F		--		1,850 °F	
	Pressure		1,772 lb/ft^2		1,767 lb/ft^2		1,767 lb/ft^2		--		1,746 lb/ft^2	
		MW	acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%
	N_2	28	55,507	78.6	216,974	78.6	98,207	78.6	--	--	867,951	74.2
	O_2	32	14,666	20.8	57,328	20.8	25,948	20.8	--	--	35,094	3.0
	H_2O	18	451	0.6	1,765	0.6	799	0.6	--	--	98,453	8.4
	CO_2	44	--	--	--	--	--	--	--	--	167,277	14.3
	CO	28	--	--	--	--	--	--	--	--	583	598 ppmv
	SO_2	64	--	--	--	--	--	--	--	--	399	341 ppmv
	NH_3	17	--	--	--	--	--	--	--	--	0	0
	N_2O	44	--	--	--	--	--	--	--	--	0	0
	NO	30	--	--	--	--	--	--	--	--	316	270 ppmv
	NO_2	46	--	--	--	--	--	--	--	--	4	3 ppmv
	Total		70,624	100%	276,067	100%	124,954	100%	--	--	1,170,077	100%
Liquids	Temperature		--	--	--	--	--	--	--	--	--	--
	Pressure		--	--	--	--	--	--	--	--	--	--
	gal/min	wt%	gal/min	wt%	gal/min	wt%	gal/min	wt%	gal/min	wt%	gal/min	wt%
	Urea	60	--	--	--	--	--	--	--	--	--	--
	H_2O	18	--	--	--	--	--	--	--	--	--	--
	N_2	28	--	--	--	--	--	--	--	--	--	--
	H_2	2	--	--	--	--	--	--	--	--	--	--
	C	12	--	--	--	--	--	--	--	--	--	--
	O_2	32	--	--	--	--	--	--	--	--	--	--
	Total		--	--	--	--	--	--	--	--	--	--

1. Assumes mineral oxides in ash remain constant.
2. Assumes no air leakage in the boiler, air heater, or FFDC.

Table 4-7: Flow and Composition (to Furnace Exit) for SNCR System (Urea at NSR=0.87, NO_x Removal=43%, Load=100 MWe, OFA=25%, 0.40% Sulfur Coal)

6-SNCR (Urea Injection)		7-FFDC Inlet Duct		8-Flyash		9-Stack		MW	Material	
--		2.9		2.9		--		12	C	Solids (wt%)
--		--		--		--		2	H_2	
--		--		0.0		--		28	N_2	
--		0		0.0		--		32	O_2	
--		0		0.0		--		32	S	
--		0.7		0.7		--		23	Na	
--		0.7		0.7		--		40	Ca	
--		--		43 ppmw		--		17	NH_3	
--		95.7		95.7		100		N/A	Inert[1]	
--		--		--		--		18	H_2O	
--		100%		100%		100%		Total		
130 °F		260 °F		--		250 °F		Temperature		Gases[2]
1,746 lb/ft^2		1,705 lb/ft^2		--		1,762 lb/ft^2		Pressure		
acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%	MW		
4,171	78.3	282,447	73.9	--	--	269,474	73.9	28	N_2	
1,102	20.7	12,383	3.2	--	--	11,815	3.2	32	O_2	
52	1.0	33,276	8.7	--	--	31,748	8.7	18	H_2O	
--	--	53,674	14.1	--	--	51,209	14.1	44	CO_2	
--	--	12	31 ppmv	--	--	11	31 ppmv	28	CO	
--	--	127	334 ppmv	--	--	122	334 ppmv	64	SO_2	
--	--	4	10 ppmv	--	--	3	10 ppmv	17	NH_3	
--	--	12	32 ppmv	--	--	12	32 ppmv	44	N_2O	
--	--	57	150 ppmv	--	--	55	150 ppmv	30	NO	
--	--	1	3 ppmv	--	--	1	3 ppmv	46	NO_2	
5,325	100%	381,993	100%	--	--	364,450	100%	Total		
60 °F		--		--		--		Temperature		Liquids
1,746 lb/ft^2		--		--		--		Pressure		
gal/min	wt%	gal/min	wt%	gal/min	wt%	gal/min	wt%	MW		
0.7	--	--	--	--	--	--	--	60	Urea	
5.3	84.6	--	--	--	--	--	--	18	H_2O	
--	7.2	--	--	--	--	--	--	28	N_2	
--	1.0	--	--	--	--	--	--	2	H_2	
--	3.1	--	--	--	--	--	--	12	C	
--	4.1	--	--	--	--	--	--	32	O_2	
6	100%	--	--	--	--	--	--	Total		

1. Assumes mineral oxides in ash remain constant.
2. Assumes no air leakage in the boiler, air heater, or FFDC.

Table 4-8: Flow and Composition (from Furnace Exit) for SNCR System (Urea at NSR=0.87, NO_x Removal=43%, Load=100 MWe, OFA=25%, 0.40% Sulfur Coal)

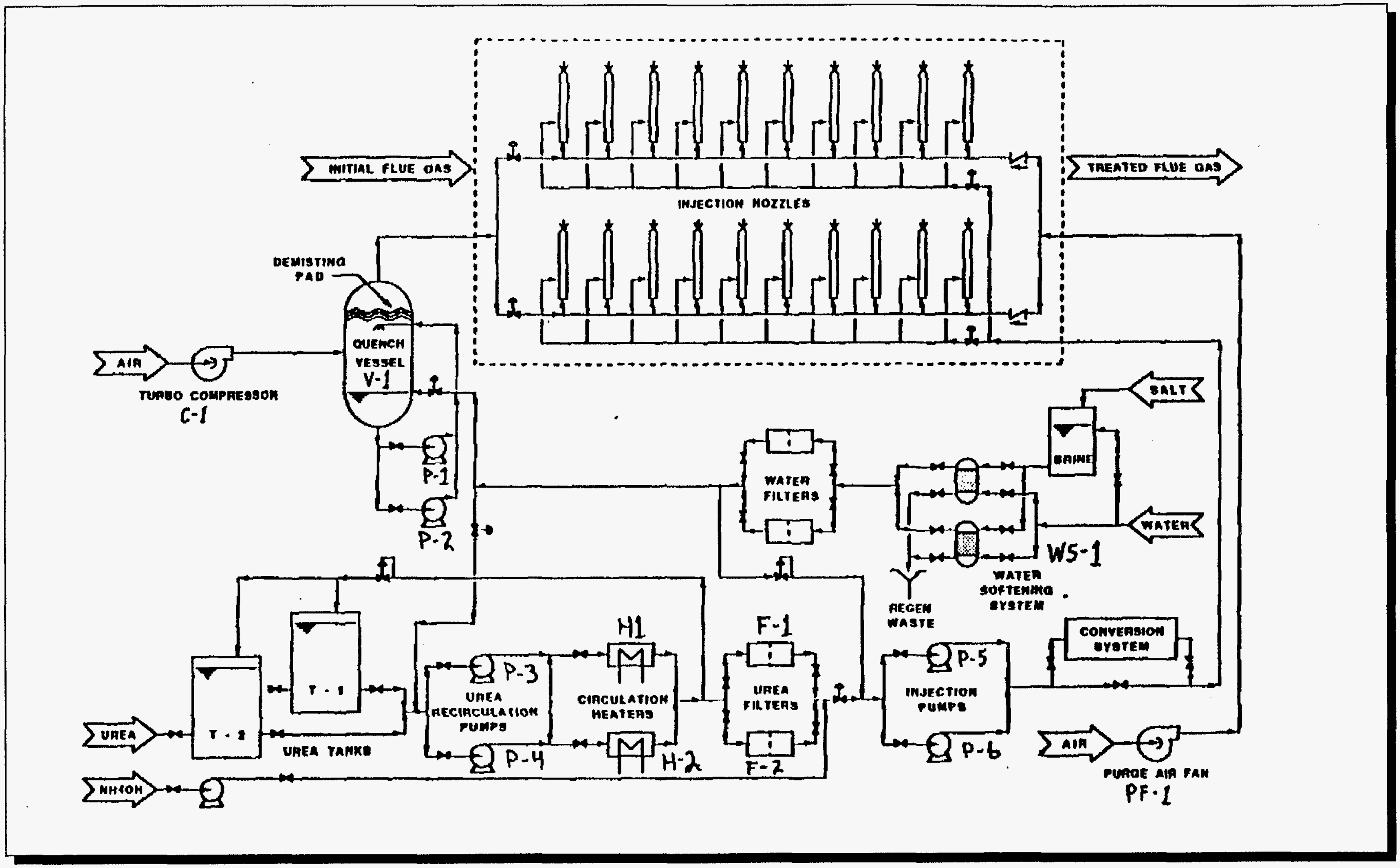


Figure 4–25: Simplified P&ID of SNCR System at Arapahoe Unit 4

4.5 DSI

The following section describes the DSI system dividing it into the four following subsystems:

- Storage
- Transport
- Pulverizing
- Injection

4.5.1 Storage

Storage for the sodium- or calcium-based reagents consists of two 150-ton silos. Trucks deliver the reagents in granular form. Each truck holds approximately 25 tons and is equipped with blowers to fill the silos pneumatically.

A magnetic grate located at the top of the silo catches any large or ferrous pieces of material. Vent filters located on each silo separate the reagent from the conveying air. The silo vent filters are cleaned periodically with a pulse of compressed air. The cleaning cycle can be initiated manually or automatically based on a pre-determined high differential pressure across the vent filter. The cleaning cycle opens each of five solenoid valves to blow a pulse of air back through the filters. Each vent filter is equipped with 25 polyester felt bags with a design-air-to-cloth-ratio of approximately 3.5.

Each silo hopper is constructed of polished stainless steel and has steep angles (70°) to facilitate mass flow of reagent from the silo. To promote reagent flow when blockages occur, each silo is equipped with two vibrators. An ultrasonic level indicator measures the height of reagent in the silo.

4.5.2 Transport

A screw feeder and rotary airlock discharge the reagent into the pneumatic conveying system. A variable-speed motor drives the screw feeder. The airlock provides a pressure boundary between the storage silo and the screw feeder, which are at atmospheric pressure, and the conveying pipeline at approximately 9 psig. Any air leakage is sent back to the silo through the bin vent filter.

The screw feeder can be controlled automatically by the distributed control system (DCS) or manually. In automatic mode, the feeders are controlled as a function of the desired percent SO_2 removal. The DCS also uses feedback from the continuous emission monitors (CEM) to maintain the required feedrate of reagent. If unacceptable emissions of NO_2 exist, a second control loop is used. This loop limits the SO_2 removal to the maximum that can be obtained without generating a visible plume of NO_2 at the stack.

A positive-displacement blower driven by a 40-HP motor supplies the transport air for the pneumatic conveying system. Each blower has a capacity of 660 ft^3/min at 9 psig. The blowers are sized to transport the reagent through the entire piping system, including the pulverizers. The blowers are equipped with inlet and outlet silencers, an inlet filter, a pressure-relief valve, expansion joints, and instrumentation. A fan-driven air-to-air heat exchanger cools the conveying air to below 105 °F. The transport piping uses both 4-inch and 5-inch schedule 40 carbon steel. The transport air conveys the reagent to the pulverizers and then to the injection piping in the flue-gas duct.

4.5.3 Pulverizing

The granulated reagents are pulverized before they are injected into the flue-gas stream. Figure 4-26 shows the pulverizer. It is manufactured by Entoleter and is a rugged, compact machine that includes a body, motor, rotor, liner, and discharge hopper.

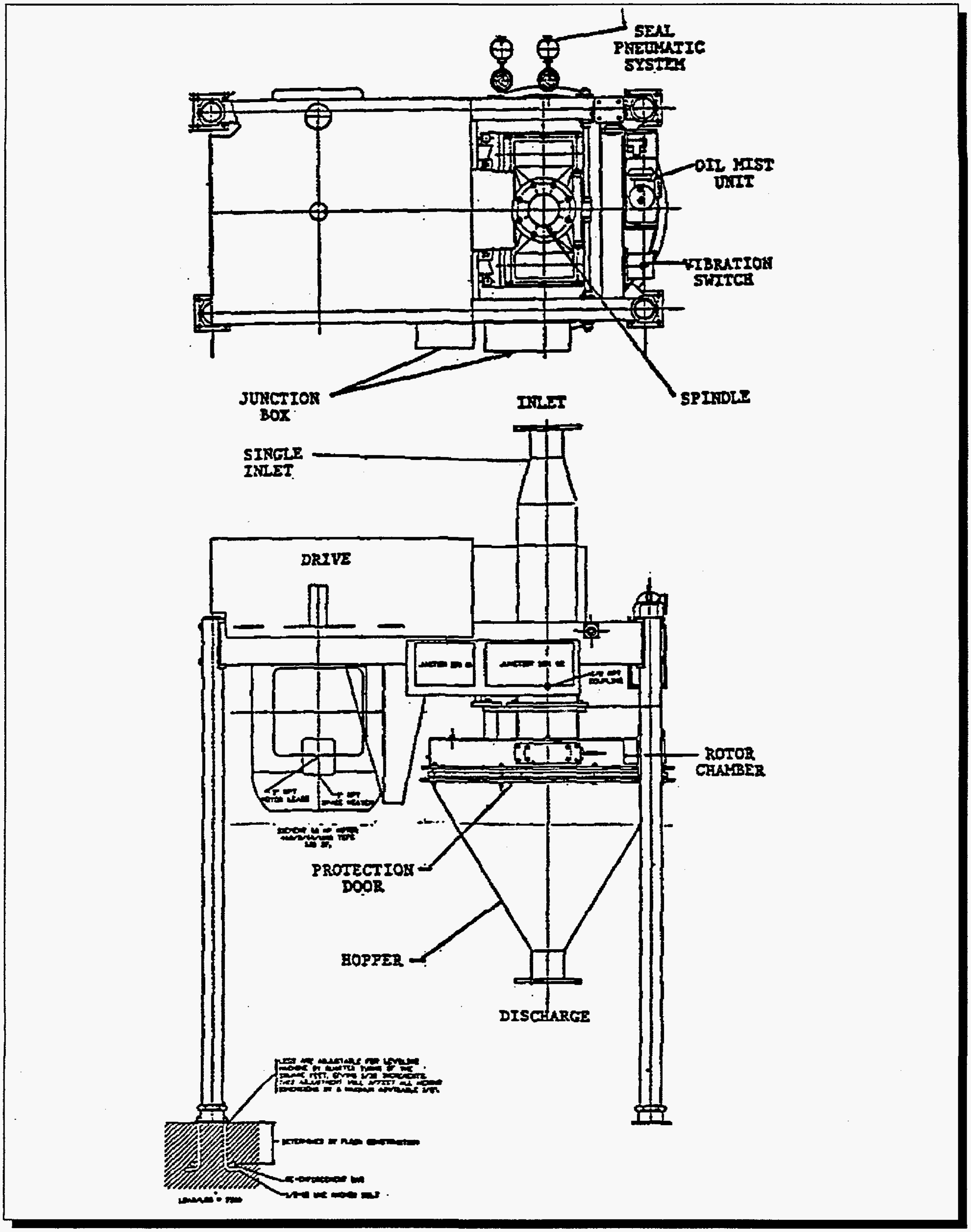


Figure 4–26: Entoleter Pulverizer

The body consists of two feed-chutes and a distributor ring. An air seal around the shaft of the drive spindle deters leakage of the pulverized reagent. An oil-mist lubrication system continuously feeds a flow of oil to the spindle bearings to lubricate and protect them. The pulverizer body is lined with a facing made of tungsten carbide to provide abrasion resistance.

The pulverizer uses centrifugal impact to reduce the size of the reagent particles. Reagent fed into either feed chute travels to the center of the rotor chamber. The high-speed rotor accelerates the reagent radially toward the outer periphery of the rotor. The rotor evenly distributes the reagent particles against the stator-impactor-ring. The reagent particles strike impactors on the rotor and the impact pulverizes the reagent. Reagent pulverized by impacting the rotor falls to the hopper, is pneumatically conveyed to a splitter box, and injected into flue gas.

Over a feed range of 0.25 to 2 t/h, each pulverizer is designed to grind the reagents (hydrated lime, sodium bicarbonate, or sodium sesquicarbonate) so that approximately 90% of if it will pass through a 400 US standard mesh sieve. A 60-HP motor drives each pulverizer. However, the DSI system is also designed to bypass the pulverizers while injecting hydrated lime since additional pulverizing is not expected to increase its utilization.

4.5.4 Injection

The DSI system can inject reagent either into the economizer or into the flue-gas duct between the air heater and the FFDC.

4.5.4.1 Duct Injection

Figure 4–27 shows an elevation view of the splitter box and injection grid for the DSI system. Figure 4–28 shows a photo of the two splitter boxes located on top of the flue-gas duct. Each splitter is connected to one of the parallel DSI systems and separates the flow into six carbon steel (2-inch diameter) pipes. The injection nozzles enter the duct and are evenly distributed to form a matrix of injection locations.

Although the DSI system is designed to obtain up to a 70% SO_2 removal rate with only one of the parallel systems injecting sodium-based reagents, using both systems results in a more uniform distribution of reagent in the duct. Testing will be conducted to determine if operating both systems provides better SO_2 removal efficiency.

4.5.4.2 Economizer Injection

For economizer injection, the piping of each DSI system is routed to opposite sides of the boiler. Each splitter separates the main reagent flow into four carbon steel pipes (2-1/2 inch diameter). The injectors are located on the sides of the boiler, as shown in Figure 4–29.

Testing determined that the optimum flue-gas temperatures occur in the center of the secondary superheat section of the boiler. The boiler at the superheater is rectangular in cross-section so that the distance from the front of the boiler to the back is shorter than it is from side to side. Therefore, the optimum location for the lances for minimizing the distance the nozzle jets have to penetrate is on the front and back walls.

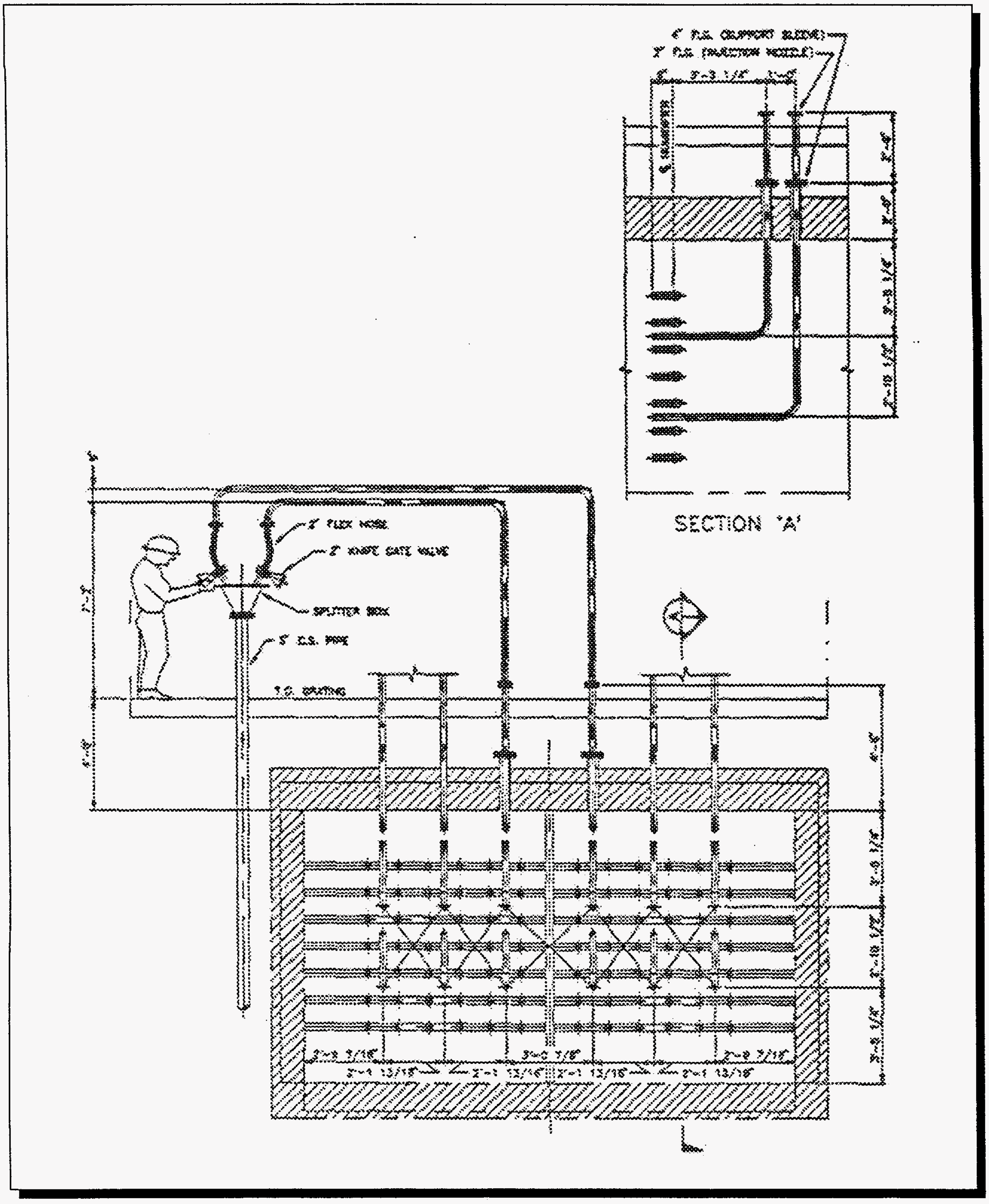


Figure 4–27: Elevation View of Splitter Box and Injection Grid for DSI System

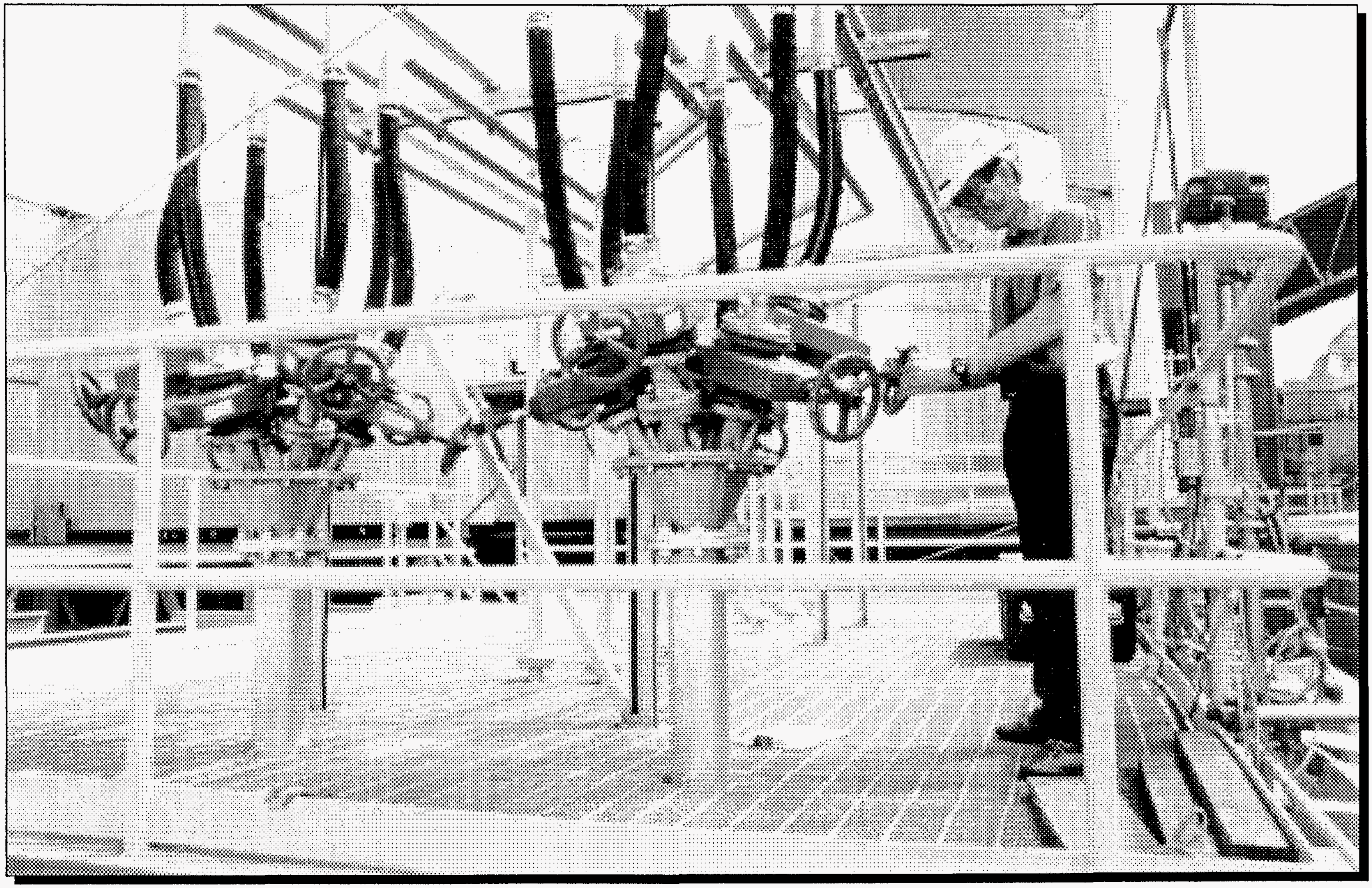


Figure 4–28: Photo of Splitter Boxes Located on Top of the FFDC Inlet Duct

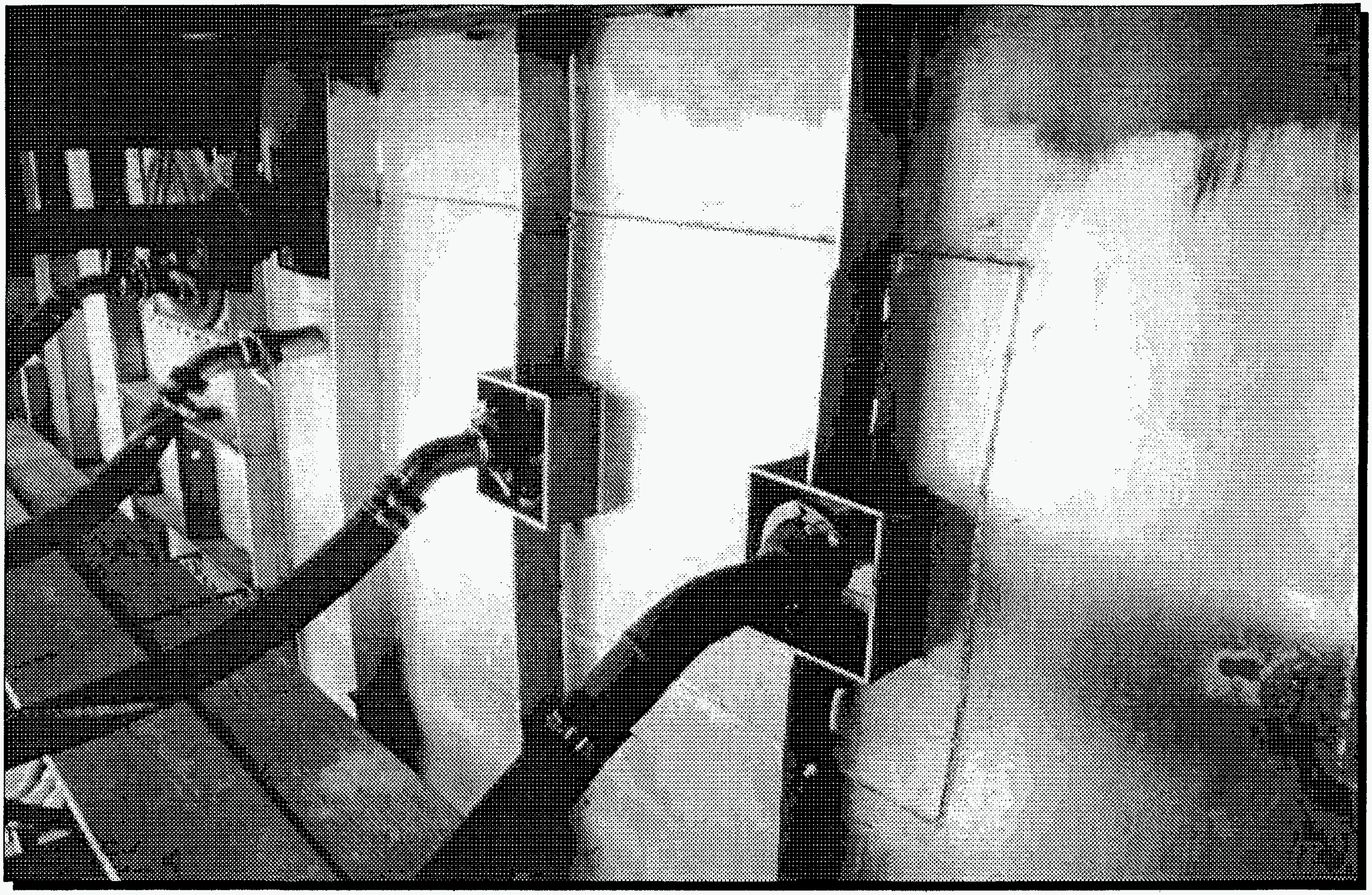


Figure 4–29: Photo of DSI Piping and Lances Entering the Side of the Boiler.

Unfortunately, the superheat tubing blocks the back wall and limits the injection location to through the sidewalls only. Since the boiler is 40 feet from side to side at this location, each nozzle must achieve about 13 feet of penetration to obtain a reasonably uniform distribution of the reagent. Instead of injecting at a location with a different temperature, it was decided to compromise and proceed with the sidewall injection in the superheater (although referred to as economizer injection) even though it was not expected to distribute the reagent uniformly.

4.5.5 Process Flow Diagrams

Figure 4-30 shows the process flow diagram for the DSI system injecting sodium sesquicarbonate into the FFDC inlet duct. Figure 4-31 shows the process flow diagram for the DSI system injecting hydrated lime into the economizer.

4.5.6 Material Balances

This section shows the material balances for the DSI system calculated at the same operating conditions as the low-NO_x combustion system: load=100 MWe, OFA=25%, and 0.40% sulfur coal. Table 4-9 shows the mass balance and Table 4-10 shows the mass flows and stream concentrations for the duct injection of sodium sesquicarbonate at an NSR of 1.75 and a 70% SO_2 removal rate. Table 4-11 shows the mass balance and Table 4-12 shows the mass flows for the economizer injection of hydrated lime at an NSR of 2.0 and a SO_2 removal rate of 15%.

4.5.7 Energy Balances

Since any energy remaining in the flue-gas after it passes through the air heater is lost, the DSI system does not significantly affect the efficiency of Arapahoe Unit 4. When the DSI system injects sodium-based reagents, it uses approximately 72.5 kW resulting in a 0.07% loss in unit efficiency. When the DSI injects hydrated lime, it uses 25.0 kW resulting is a

0.025% loss in unit efficiency. The material balances in Section 4.5.6 show this efficiency loss in an increase in fuel flow from the base case of the low-NO_x combustion system.

4.5.8 P&ID for DSI System

Figure 4-32 shows a simplified P&ID of the DSI system installed at Arapahoe Unit 4. The equipment numbers in the P&ID correspond to the equipment numbers in the equipment list (Section 4.10).

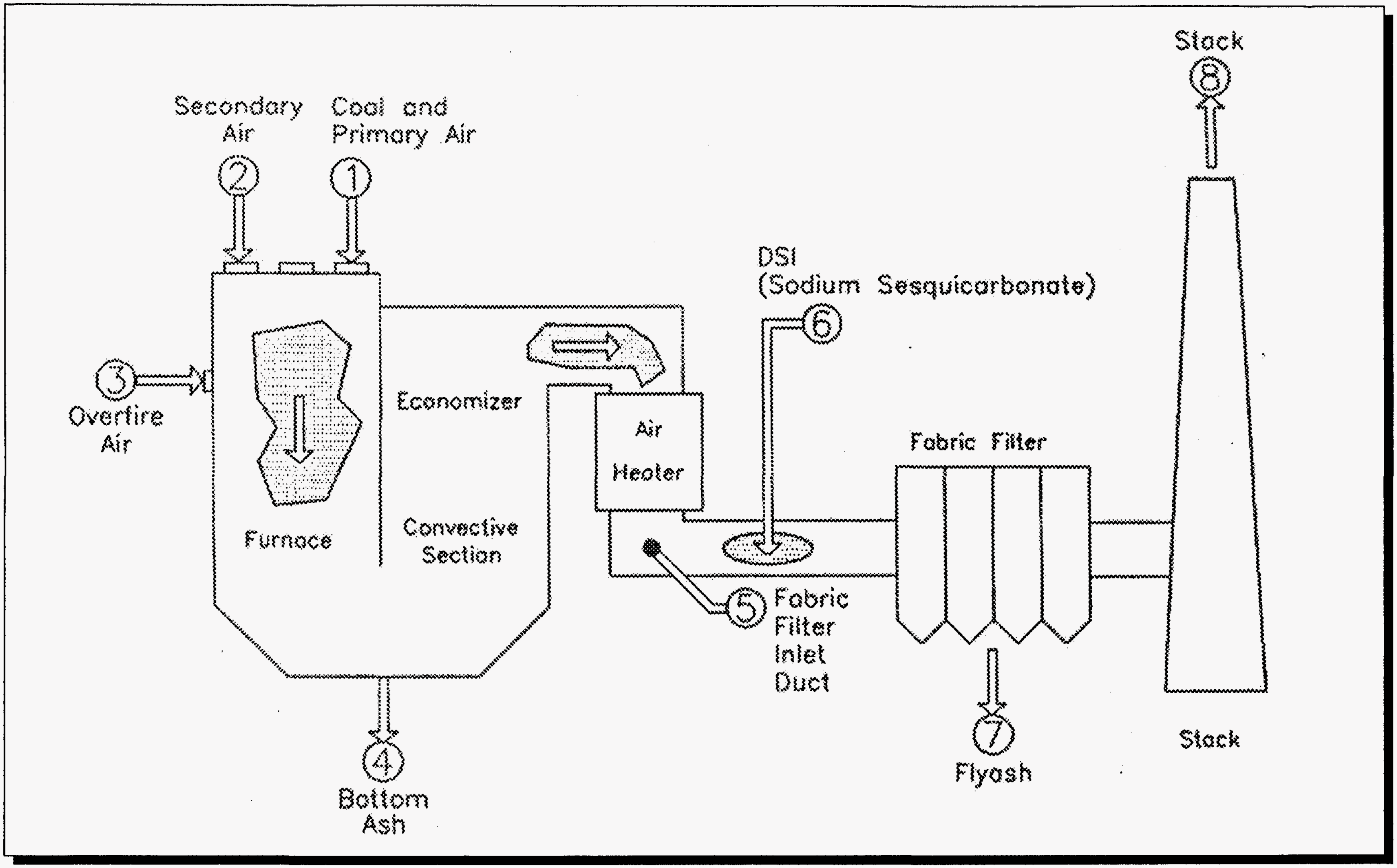


Figure 4–30: Process Flow Diagram for DSI System at Arapahoe Unit 4 (Duct Injection of Sodium Sesquicarbonate)

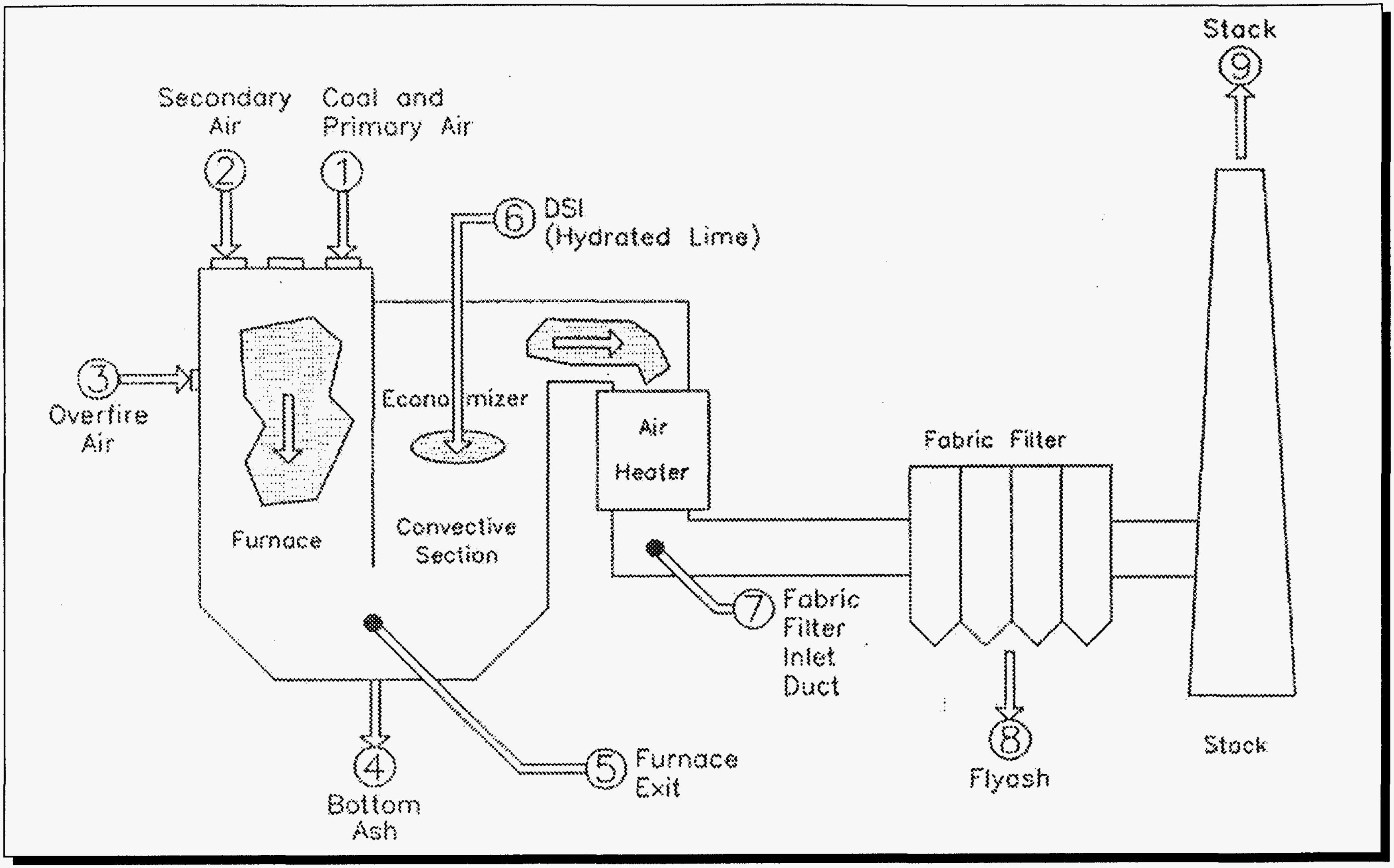


Figure 4–31: Process Flow Diagram for DSI System at Arapahoe Unit 4 (Economizer Injection of Hydrated Lime)

Material		MW	1-Coal/ Primary Air	2-Secondary Air	3-OFA	4-Bottom Ash	5-FFDC Inlet Duct	6-DSI	7-Flyash	8-Stack
Solids (lbm/h)	C	12	59,147	--	--	22	202	328	345	--
	H_2	2	4,238	--	--	--	--	68	0	--
	N_2	28	1,507	--	--	--	--	--	10	--
	O_2	32	9,889	--	--	--	0	1,747	1,130	--
	S	32	377	--	--	0	3	--	265	--
	Na	23	61			15	46	941	987	--
	Ca	40	61			15	46	0	46	--
	NH_3	17	--			--	--	--	0	--
	Inerts[1]	N/A	8,920	--	--	2,230	6,690	95	6,782	3
	H_2O	18	9,984	--	--	--	--	--	--	--
	Total Solids		+94,184	--	--	-2,282	(=6,987)	+3,179	-9,565	-3
Gases[2] (lbm/h)	Temperature		300 °F	600 °F	600 °F	--	260 °F	120 °F	--	250 °F
	Pressure		1,772 lb/ft^2	1,767 lb/ft^2	1,767 lb/ft^2	--	1,705 lb/ft^2	1,705 lb/ft^2	--	1,762 lb/ft^2
	N_2	28	140,710	391,348	177,370	--	710,855	1,532	--	712,389
	O_2	32	42,504	118,172	53,559	--	32,584	463	--	32,888
	H_2O	18	736	2,046	927	--	51,834	8	--	52,456
	CO_2	44	--	--	--	--	216,004	--	--	216,679
	CO	28	--	--	--	--	30	--	--	30
	SO_2	64	--	--	--	--	748	--	--	224
	NH_3	17	--	--	--	--	0	--		0
	N_2O	44	--	--	--	--	0	--		0
	NO	30	--	--	--	--	277	--	--	235
	NO_2	46	--	--	--	--	5	--	--	37
	Total Gases		+184,000	+511,566	+231,856	--	(=1,012,337)	+2,003	--	-1,014,938
Total In	+1,026,788		+278,184	+511,566	+231,856		(=1,019,324)	5,182		
Total Out	-1,026,788					-2,282			-9,565	-1,014,941

Note: "+" indicates flow into system, "-" indicates flow out of system, "(=)" indicates intermediate balance.

1. Assumes that the oxides in the ash remain constant.
2. Assumes no leakage of air into the boiler, air heater, or FFDC.

Table 4-9: Mass Balance for DSI (Sodium Sesquicarbonate, NSR=1.75, Duct Injection, SO_2 Removal=70%, Load=100 MWe, OFA=25%, 0.40% Sulfur Coal)

Material		MW	1-Coal/ Primary Air		2-Secondary Air		3-OFA		4-Bottom Ash		5-FFDC Inlet Duct		6-DSI		7-Flyash		8-Stack	
Solids (wt%)	C	12	62.8		--		--		1.0		2.9		10.3		3.6		--	
	H_2	2	4.5		--		--		--		--		2.1		--		--	
	N_2	28	1.6		--		--		--		--		--		0.1		--	
	O_2	32	10.5		--		--		--		0.0		54.9		11.9		--	
	S	32	0.4		--		--		0.0		0.0		--		2.8		--	
	Na	23	0.1		--		--		0.7		0.7		29.6		10.3		--	
	Ca	40	0.1		--		--		0.7		0.7		0.0		0.5		--	
	NH_3	17	--		--		--		--		--		--		0		--	
	Inerts[1]	N/A	9.5		--		--		97.6		95.7		3.0		70.9		100	
	H_2O	18	10.5		--		--		--		--		--		--		--	
	Total		100%		--		--		100%		100%		100%		100%		100%	
Gases[2]	Temperature		300 °F		600 °F		600 °F		--		260 °F		120 °F		--		250 °F	
	Pressure		1,772 lb/ft^2		1,767 lb/ft^2		1,767 lb/ft^2		--		1,705 lb/ft^2		1,705 lb/ft^2		--		1,762 lb/ft^2	
		MW	acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%
	N_2	28	55,507	78.6	215,874	78.6	97,841	78.6	--	--	276,102	74.1	480	78.6	--	--	274,839	74.4
	O_2	32	14,666	20.8	57,037	20.8	25,851	20.8	--	--	11,074	3.0	126	20.8	--	--	13,395	3.6
	H_2O	18	451	0.6	1,756	0.6	795	0.6	--	--	31,318	8.5	4	0.6	--	--	30,293	8.1
	CO_2	44	--	--	--	--	--	--	--	--	53,389	14.3	--	--	--	--	51,061	13.8
	CO	28	--	--	--	--	--	--	--	--	12	31 ppmv	--	--	--	--	11	30 ppmv
	SO_2	64	--	--	--	--	--	--	--	--	127	342 ppmv	--	--	--	--	36	328 ppmv
	NH_3	17	--	--	--	--	--	--	--	--	0	0	--	--	--	--	0	0
	N_2O	44	--	--	--	--	--	--	--	--	0	0	--	--	--	--	0	0
	NO	30	--	--	--	--	--	--	--	--	100	270 ppmv	--	--	--	--	81	260 ppmv
	NO_2	46	--	--	--	--	--	--	--	--	1	3 ppmv	--	--	--	--	8	3 ppmv
	Total		70,624	100%	274,667	100%	124,487	100%	--	--	372,123	100%	610	100%	--	--	369,724	100%

1. Assumes mineral oxides in ash remain constant.
2. Assumes no air leakage in the boiler, air heater, or FFDC.

Table 4-10: Flow and Composition for DSI (Sodium Sesquicarbonate, NSR = 1.75, Duct Injection, SO_2 Removal = 70%, Load = 100 MWe, OFA = 25%, 0.40% Sulfur Coal)

Material		MW	1-Coal/ Primary Air	2-Secondary Air	3-OFA	4-Bottom Ash	5-Furnace Exit	6-DSI	7-FFDC Inlet Duct	8-Flyash	9-Stack
Solids (lbm/h)	C	12	59,121	--	--	22	202	--	462	462	--
	H_2	2	4,236	--	--	--	--	47	--	0	--
	N_2	28	1,506	--	--	--	--	--	--	0	--
	O_2	32	9,885	--	--	--	--	748	1,122	1,122	--
	S	32	377	--	--	0	3	--	59	59	--
	Na	23	61	--	--	15	46	--	46	46	--
	Ca	40	61	--	--	15	46	935	981	981	--
	NH_3	17	--	--	--	--	--	--	--	0	--
	Inerts[1]	N/A	8,916	--	--	2,229	6,687	194	6,881	6,878	3
	H_2O	18	9,978	--	--	--	--	--	--	--	--
	Total Solids		+94,141	--	--	-2,281	(=6,984)	+1,924	(=9,551)	-9,548	-3
Gases[2] (lbm/h)	Temperature		300 °F	600 °F	600 °F	--	1,850 °F	120 °F	260 °F	--	250 °F
	Pressure		1,772 lb/ft²	1,767 lb/ft²	1,767 lb/ft²	--	1,746 lb/ft²	1,746 lb/ft²	1,705 lb/ft²	--	1,762 lb/ft²
	N_2	28	140,760	391,144	177,302	--	710,580	1,532	712,112	--	712,112
	O_2	32	42,504	118,110	53,538	--	32,839	463	33,045	--	33,045
	H_2O	18	736	2,045	927	--	51,811	8	52,240	--	52,240
	CO_2	44	--	--	--	--	215,203	--	214,957	--	214,957
	CO	28	--	--	--	--	479	--	30	--	30
	SO_2	64	--	--	--	--	748	--	636	--	636
	NH_3	17	--	--	--	--	0	--	0	--	0
	N_2O	44	--	--	--	--	0	--	0	--	0
	NO	30	--	--	--	--	277	--	277	--	277
	NO_2	46	--	--	--	--	5	--	5	--	5
	Total Gases		+184,000	+511,299	+231,767	--	+1,011,942	+2,003	(1,013,302)	--	-1,013,302
Total In	+1,025,134		+278,141	+511,299	+231,767		(=1,018,926)	+3,927	(=1,022,853)		
Total Out	-1,025,134					-2,281				-9,548	-1,013,305

Note: +" indicates flow into the system, "-" indicates flow out of system, "(=)" indicates an intermediate balance point.

1. Assumes that the oxides in the ash remain constant.
2. Assumes no leakage of air into the boiler, air heater, or FFDC.

Table 4-11: Mass Balance for DSI (Hydrated Lime, Economizer Injection, NSR=2.0, NO_x Removal=15%, Load=100 MWe, OFA=25%, 0.40% Sulfur Coal)

Material		MW	1-Coal/ Primary Air		2-Secondary Air		3-OFA		4-Bottom Ash		5-Furnace Exit		6-DSI		7-FFDC Inlet Duct		8-Flyash		9-Stack	
Solids (wt%)	C	12	62.8		--		--		1.0		2.9		--		2.9		3.6		--	
	H_2	2	4.5		--		--		--		--		2.4		--		--		--	
	N_2	28	1.6		--		--		--		--		--		--		0.1		--	
	O_2	32	10.5		--		--		--		--		38.9		0.0		11.8		--	
	S	32	0.4		--		--		0.0		0.0		--		0.0		2.8		--	
	Na	23	0.1		--		--		0.7		0.7		--		0.7		10.3		--	
	Ca	40	0.1		--		--		0.7		0.7		48.6		0.7		0.5		--	
	NH_3	17	--		--		--		--		--		--		--		0		--	
	Inert[1]	N/A	9.5		--		--		97.6		95.7		10.1		95.8		70.9		100	
	H_2O	18	10.5		--		--		--		--		--		--		--		--	
	Total		100%		--		--		100%		100%		100%		100%		100%		100%	
Gases[2]	Temp.		300 °F		600 °F		600 °F		--		120 °F		120°F		260 °F		--		250 °F	
	Pressure		1,772 lb/ft^2		1,767 lb/ft^2		1,767 lb/ft^2		--		1,705 lb/ft^2		1,746 lb/ft^2		1,705 lb/ft^2		--		1,762 lb/ft^2	
		MW	acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%[3]	acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%
	N_2	28	55,507	78.6	215,762	78.6	97,803	78.6	--	--	864,375	74.2	468	78.6	276,590	74.2	--	--	263,888	74.2
	O_2	32	14,666	20.8	57,008	20.8	25,841	20.8	--	--	34,963	3.0	124	20.8	11,231	3.0	--	--	10,715	3.0
	H_2O	18	451	0.6	1,755	0.6	795	0.6	--	--	98,039	8.4	4	0.6	31,563	8.5	--	--	30,113	8.5
	CO_2	44	--	--	--	--	--	--	--	--	166,588	14.3	--	--	53,131	14.3	--	--	50,691	14.3
	CO	28	--	--	--	--	--	--	--	--	583	500ppm	--	--	12	31ppm	--	--	11	31ppm
	SO_2	64	--	--	--	--	--	--	--	--	398	342ppm	--	--	108	290ppm	--	--	103	290ppm
	NH_3	17	--	--	--	--	--	--	--	--	0	--	--	--	0	0	--	--	0	0
	N_2O	44	--	--	--	--	--	--	--	--	0	--	--	--	0	0	--	--	0	0
	NO	30	--	--	--	--	--	--	--	--	314	270ppm	--	--	100	269ppm	--	--	96	269ppm
	NO_2	46	--	--	--	--	--	--	--	--	4	3ppm	--	--	1	3ppm	--	--	1	3ppm
	Total		70,624	100%	274,525	100%	124,439	100%	--	--	1,165,254	100%	596	100%	386,377	100%	--	--	369,724	100%

1. Assumes mineral oxides in ash remain constant.
2. Assumes no air leakage in the boiler, air heater, or FFDC.

Table 4-12: Flow and Composition for DSI (Hydrated Lime, Economizer Injection, NSR=2.0, NO_x Removal=15%, Load=100 MWe, OFA=25%, 0.40% Sulfur Coal)

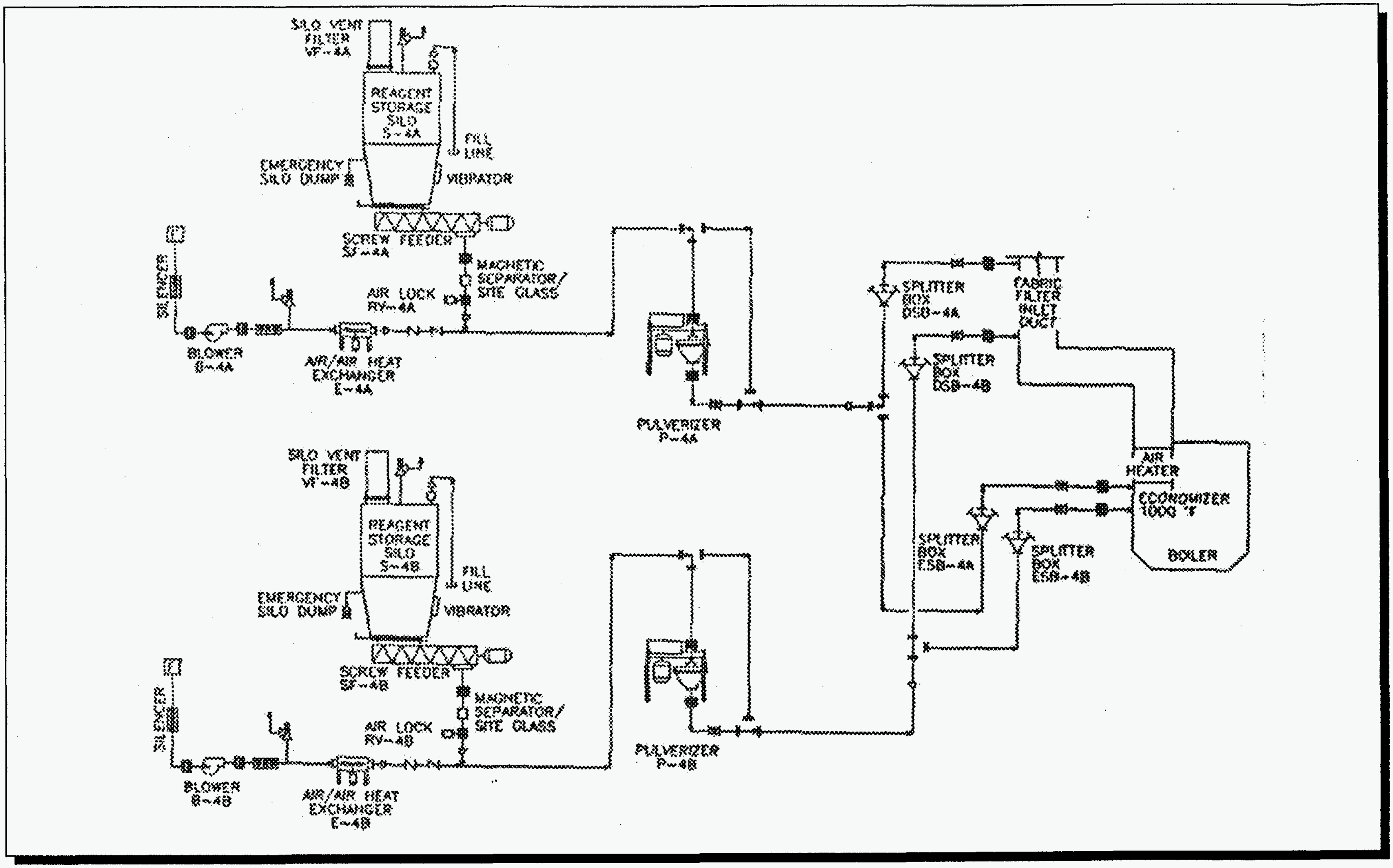


Figure 4-32: Simplified P&ID of DSI System at Arapahoe Unit 4

4.6 Flue-Gas Humidification

The flue-gas humidification system consists of a:

- Water supply system.
- Compressed air (atomizing air) system.
- Injection lances.
- Shield air system.

4.6.1 Water Supply System

The water system consists of a variable-speed pump, a strainer and a block valve. The variable-speed pump supplies city water to the system. The water passes through a strainer which removes particles which could plug the lances. Redundant strainers are provided so that on-line cleaning can be performed. A high differential pressure alarm provides indication of when cleaning should be performed.

The flue-gas temperature is monitored by 12 temperature-sensing elements in the flue-gas duct. The water flowrate may be controlled manually by establishing a flowrate setpoint or automatically by establishing a flue-gas temperature downstream of the humidifier.

4.6.2 Atomizing Air System

The atomizing air system uses two compressors, which operate together. Each air compressor can produce 2,200 scfm at 150 psig. After investigating various alternatives, it was decided that rotary screw compressors were the most economical type of compressor for this system. The DCS and a pressure-control valve control the pressure of the atomizing air. Air pressure can be set manually or can be automatically controlled by establishing a setpoint above the operating water pressure.

To evenly distribute the atomization-air in the duct, the differential pressure across each lance must be equal. Four control valves located on an air-header system allow the airflow to each of the lances to be controlled. These control valves compensate for the larger flow of water to the lances at the bottom of the duct due to greater static head at these locations. The four control valves can be positioned manually by observing pressure differentials across the lances or automatically by establishing a differential setpoint across the lances.

4.6.3 Injection Lances

The Arapahoe Unit 4's FFDC inlet duct is unique. When the unit's ESP was replaced with an FFDC in 1980, about 100 feet of straight duct was added. This long straight duct was an obvious place to locate the humidification system, so a temperature traverse was performed at the air heater exit to determine the uniformity of the temperatures across the duct. Although some differences in temperature were found, they were not expected to cause any problems and the air heater exit was chosen as the location for the humidification injection lances. Figure 4-33 shows a photo of the humidification piping and lances entering the side of the FFDC inlet duct.

Once the location was chosen, B&W designed the lances based on the experience they gained at Ohio-Edison's Edgewater station. Using general operating conditions for Arapahoe Unit 4 and a desired approach temperature (T_{AS}) of 45 °F, B&W predicted that the system required an injection flowrate of 78.9 gal/min.

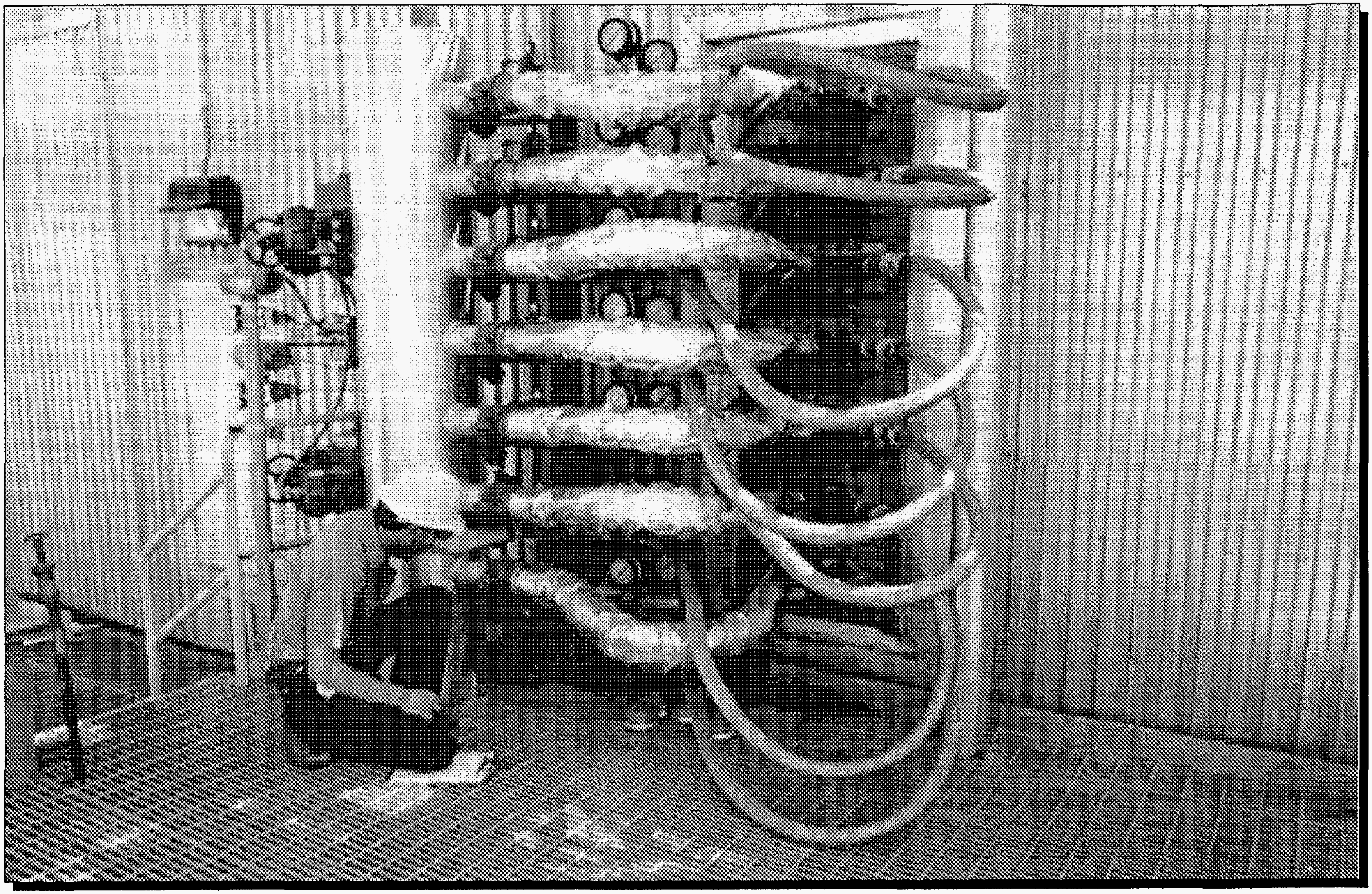


Figure 4-33: Photo of Humidification Piping and Lances Entering Side of FFDC Inlet Duct.

B&W has found that as a general rule of thumb, that each I-Jet nozzle can atomize about 1 gal/min of water. Therefore, it was determined that this system required 84 I-Jet nozzles on 14 injection lances. Each lance has 6 dual-fluid atomizers. Previous experience showed that locating the nozzles 2 feet from the duct walls would be sufficient to prevent wall-wetting and the buildup of solids. Figure 4-34 shows a photo of the DSI and humidification grid. Figure 4-35 shows a photo of the humidification lances in operation.

B&W has developed a significant well of performance data for their I-Jet lances at their Alliance, OH Research Center. Based on this data, they developed a proprietary computer program to predict the evaporation of the injected water. At the operating conditions used to determine the injection flowrate, the computer program predicted that 99.8% of the injected water would evaporate before it entered the FFDC.

4.6.4 Shield Air System

Shield air is also supplied to the lances to help prevent the deposition of solids by the flue gas. A rapper is provided for the system to help remove ash that may collect on the lances.

4.6.5 Process Flow Diagram

Figure 4-36 shows the flow of the flue-gas humidification system at Arapahoe Unit 4.

4.6.6 Material Balances

This section shows the material balances for the flue-gas humidification system calculated at the same operating conditions as the low-NO_x combustion system: load=100 MWe, OFA=25%, and 0.40% sulfur coal. Table 4-13 and Table 4-14 show the mass balance and Table 4-15 and Table 4-16 show the mass flows and stream composition for the duct injection of hydrated lime at an NSR of 2.0, an approach temperature of 40 °F, and an 25% SO_2 removal rate.

4.6.7 Energy Balance

The humidification and calcium injection systems require a significant amount of electric energy (about 1,109 kW) to operate. Since any energy remaining in the flue-gas after it passes through the air heater is lost, the endothermic evaporation reactions do not affect the overall unit efficiency of Arapahoe Unit 4. So, a thermodynamic energy balance is not useful for calculating unit efficiency loss. However, the energy required to run the DSI and humidification equipment corresponds to 11.6 MMBtu/h, or a 1.11% efficiency loss.

While a thermodynamic energy balance of the humidification system is not useful for determining unit efficiency, it is useful for calculating the water flowrate required to obtain a given approach to saturation temperature (T_{AS}). Initial testing showed that precisely measuring the water at the injection inlet and performing an energy balance was the most accurate method for determining an actual T_{AS}. The final temperature of the flue gas can be determined by assuming adiabatic conditions and using the first law of thermodynamics to perform an energy balance. However, these calculations are complex and require many iterations to solve, so they are best solved by using a computer. The data contained in the mass balances shown in Section 4.6.6 were used to determine T_{AS}.

4.6.8 Simplified P&ID for Flue-Gas Humidification System

Figure 4-37 shows a simplified P&ID for the flue-gas humidification system. The equipment numbers on the P&ID correspond to the equipment numbers shown on the equipment list in Section 4.10.

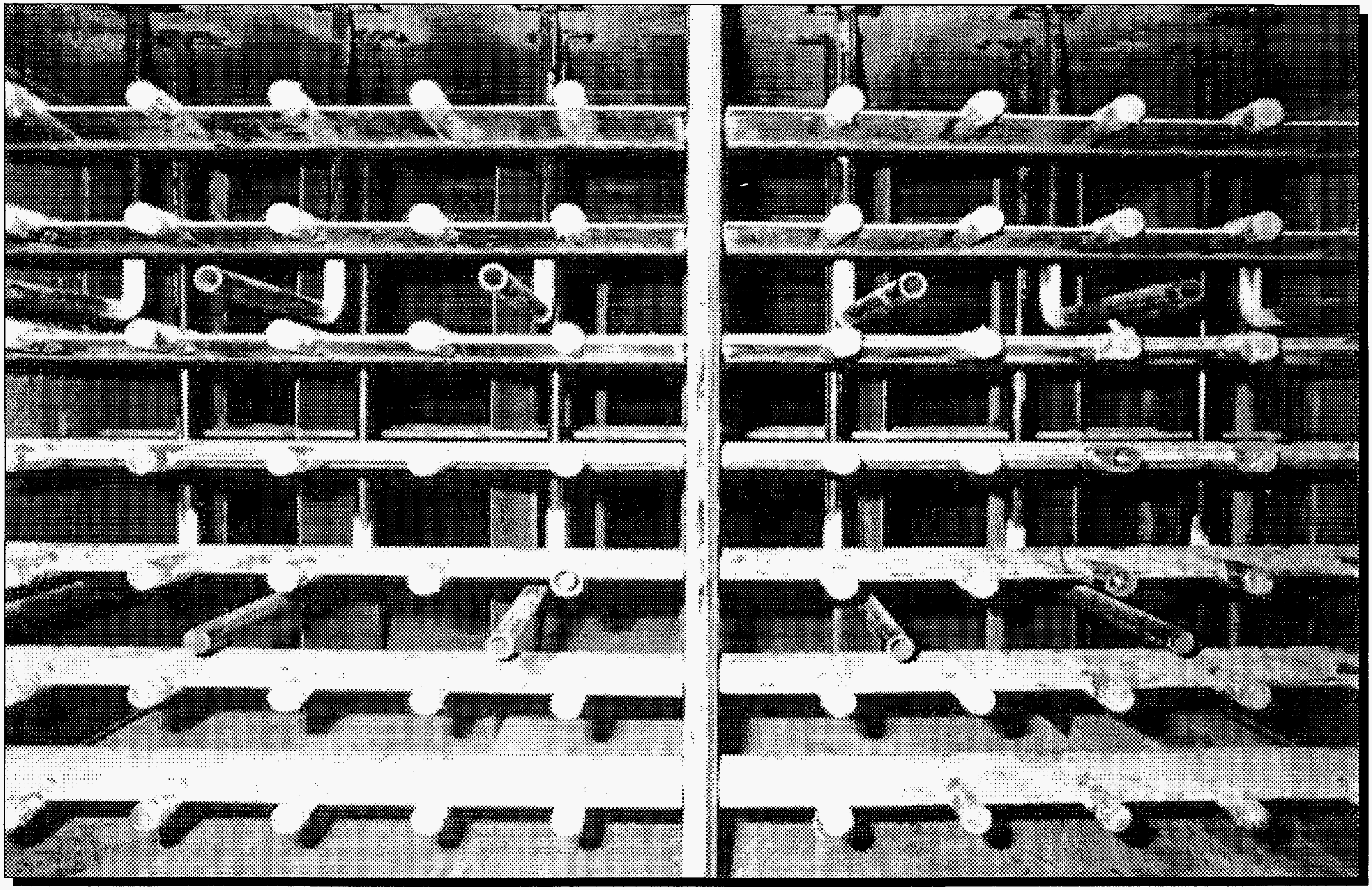


Figure 4–34: Photo of DSI and Humidification Lances at Air Heater Exit

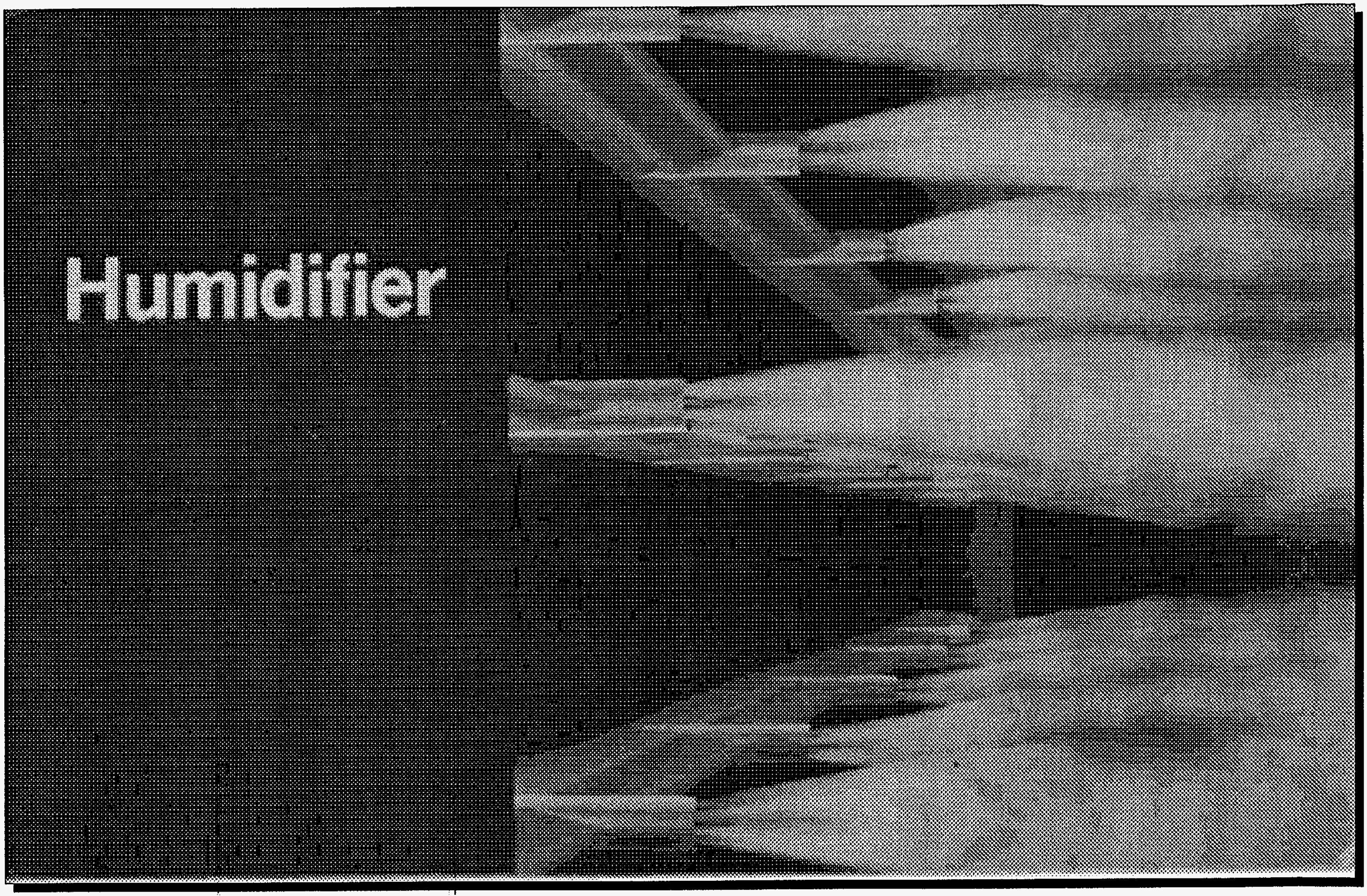


Figure 4-35: Photo of Humidification Lances in Operation

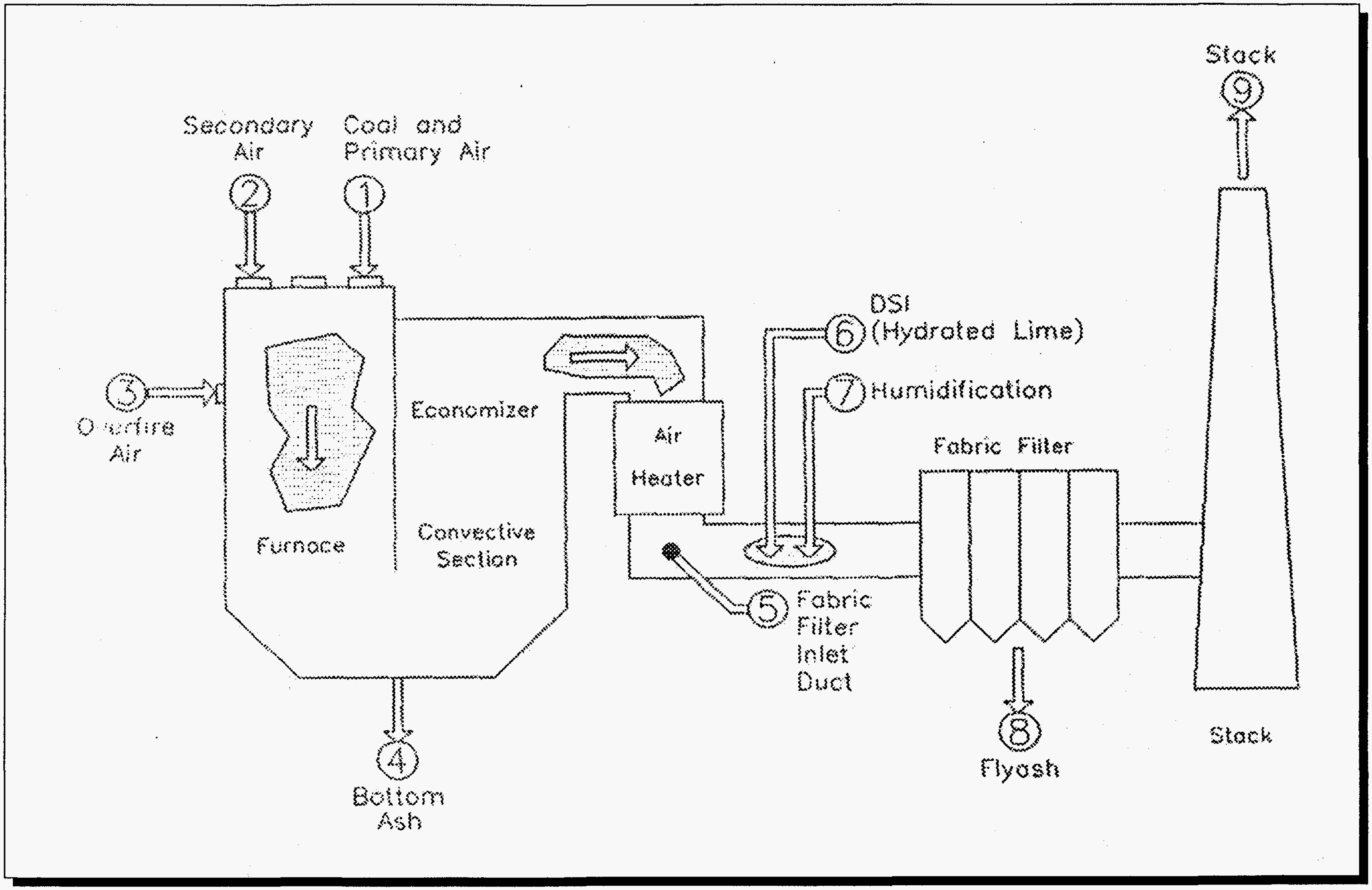


Figure 4-36: Block Flow Diagram for Flue-Gas Humidification System

Material		MW	1-Coal/ Primary Air	2-Secondary Air	3-OFA	4-Bottom Ash	5-FFDC Inlet Duct
Solids (lbm/h)	C	12	59,777	--	--	23	204
	H_2	2	4,283	--	--	--	--
	N_2	28	1,522	--	--	--	--
	O_2	32	9,995	--	--	--	--
	S	32	381	--	--	0	3
	Na	23	62	--	--	16	46
	Ca	40	62	--	--	16	46
	NH_3	17	--	--	--	--	--
	Inerts[1]	N/A	9,014	--	--	2,254	6,760
	H_2O	18	10,090	--	--	--	--
	Total Solids		+95,186	--	--	-2,309	(=7,059)
Gases[2] (lbm/h)	Temperature		300 °F	600 °F	600 °F	--	260 °F
	Pressure		1,772 lb/ft^2	1,767 lb/ft^2	1,767 lb/ft^2	--	1,705 lb/ft^2
	N_2	28	140,760	397,023	179,262	--	718,435
	O_2	32	42,504	119,886	54,130	--	32,937
	H_2O	18	736	2,076	937	--	52,386
	CO_2	44	--	--	--	--	218,303
	CO	28	--	--	--	--	30
	SO_2	64	--	--	--	--	756
	NH_3	17	--	--	--	--	0
	N_2O	44	--	--	--	--	0
	NO	30	--	--	--	--	280
	NO_2	46	--	--	--	--	5
	Total Gases		+184,000	+518,985	+234,329	--	(=1,023,132)
Liquids (lbm/h)	Temperature		--	--	--	--	--
	Pressure		--	--	--	--	--
	Urea	60	--	--	--	--	--
	H_2O	18	--	--	--	--	--
	N_2	28	--	--	--	--	--
	H_2	2	--	--	--	--	--
	C	12	--	--	--	--	--
	O_2	32	--	--	--	--	--
	Total Liquids		--	--	--	--	--
Total (lbm/h)	In		+279,186	+518,985	+234,329		(=1,030,191)
	Out					-2,309	

Note: "+" indicates flow into system, "-" indicates flowout of system, "(=)" indcates intermediate balance point.

1. Assumes mineral oxides in ash remain constant.
2. Assumes no leakage of air into boiler, air heater, or FFDC.

Table 4-13: Mass Balance (to FFDC Inlet Duct) for DSI and Humidification (Load=100 MWe, OFA=25%, 0.40% Sulfur Coal, Hydrated Lime, NSR=2.0, T_{AS}=40 °F, SO_2 Removal=25%)

6-DSI (Hydrated Lime)	7-Humidification	9-Flyash[2]	10-Stack	MW	Material	
0	--	204	--	12	C	Solids (lbm/h)
47	--	50	--	2	H_2	
--	--	0	--	28	N_2	
756	--	926	--	32	O_2	
--	--	116	--	32	S	
945	--	46	--	23	Na	
--	-	991	--	40	Ca	
287	--	0	--	17	NH_3	
--	--	7,044	3	N/A	Inerts[1]	
--	--	--	--	18	H_2O	
+2,035	--	-9,378	-3	Total Solids		
120 °F	150 °F	--	155 °F	Temperature		Gases (lbm/h)
1,705 lb/ft^2	1,705 lb/ft^2	--	1,762 lb/ft^2	Pressure		
1,533	11,305	--	731,273	28	N_2	
463	3,414	--	36,779	32	O_2	
8	59	--	76,679	18	H_2O	
--	--	--	218,303	44	CO_2	
--	--	--	30	28	CO	
--	--	--	529	64	SO_2	
--	--	--	0	17	NH_3	
--	--	--	0	44	N_2O	
--	--	--	280	30	NO	
--	--	--	5	46	NO_2	
+2,003	+14,778	--	-1,063,878	Total Gases		
--	65 °F	--	--	Temperature		Liquids (lbm/h)
--	1,705 lb/ft^2	--	--	Pressure		
--	--	--	--	60	Urea	
--	24,251	--	--	18	H_2O	
--	--	--	--	28	N_2	
--	--	--	--	2	H_2	
--	--	--	--	12	C	
--	--	--	--	32	O_2	
--	24,251	--	--	Total Liquids		
+4,039	+39,029	-9,378	-1,063,881	+1,103,146 -1,103,145	Total In Total Out	

Note: "+" indicates flow into system, "-" indicates flowout of system, "(=)" indcates intermediate balance point.

1. Assumes mineral oxides in ash remain constant.
2. Assumes no leakage of air into boiler, air heater, or FFDC.

Table 4-14: Mass Balance (from FFDC Inlet Duct) for DSI and Humidification (Load = 100 MWe, OFA = 25%, 0.40% Sulfur Coal, Hydrated Lime, NSR = 2.0, T_{AS} = 40 °F, SO_2 Removal = 25%)

Material		MW	1-Coal/ Primary Air		2-Secondary Air		3-OFA		4-Bottom Ash		5-FFDC Inlet Duct	
Solids (wt%)	C	12	62.8		--		--		1.0		2.9	
	H_2	2	4.5		--		--		--		--	
	N_2	28	1.6		--		--		--		--	
	O_2	32	10.5		--		--		--		--	
	S	32	0.4		--		--		0.0		0.0	
	Na	23	0.1		--		--		0.7		0.7	
	Ca	40	0.1		--		--		0.7		0.7	
	NH_3	17	--		--		--		--		--	
	Inerts[1]	N/A	9.5		--		--		97.6		95.7	
	H_2O	18	10.5		--		--		--		--	
	Total		100%		--		--		100%		100%	
Gases[2]	Temperature		300 °F		600 °F		600 °F		--		260 °F	
	Pressure		1,772 lb/ft^2		1,767 lb/ft^2		1,767 lb/ft^2		--		1,705 lb/ft^2	
		MW	acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%
	N_2	28	55,507	78.6	219,005	78.6	98,884	78.6	--	--	873,931	74.2
	O_2	32	14,666	20.8	57,865	20.8	26,127	20.8	--	--	35,331	3.0
	H_2O	18	451	0.6	1,781	0.6	804	0.6	--	--	99,127	8.4
	CO_2	44	--	--	--	--	--	--	--	--	168,441	14.3
	CO	28	--	--	--	--	--	--	--	--	583	495 ppmv
	SO_2	64	--	--	--	--	--	--	--	--	402	342 ppmv
	NH_3	17	--	--	--	--	--	--	--	--	0	0
	N_2O	44	--	--	--	--	--	--	--	--	0	0
	NO	30	--	--	--	--	--	--	--	--	318	270 ppmv
	NO_2	46	--	--	--	--	--	--	--	--	4	3 ppmv
	Total		70,624	100%	278,651	100%	125,815	100%	--	--	1,178,137	100%
Liquids	Temperature		--	--	--	--	--	--	--	--	--	--
	Pressure		--	--	--	--	--	--	--	--	--	--
	gal/min	wt%	gal/min	wt%	gal/min	wt%	gal/min	wt%	gal/min	wt%	gal/min	wt%
	Urea	60	--	--	--	--	--	--	--	--	--	--
	H_2O	18	--	--	--	--	--	--	--	--	--	--
	N_2	28	--	--	--	--	--	--	--	--	--	--
	H_2	2	--	--	--	--	--	--	--	--	--	--
	C	12	--	--	--	--	--	--	--	--	--	--
	O_2	32	--	--	--	--	--	--	--	--	--	--
	Total		--	--	--	--	--	--	--	--	--	--

1. Assumes mineral oxides in ash remain constant.
2. Assumes no air leakage in the boiler, air heater, or FFDC.

Table 4-15: Flow and Composition (to FFDC Inlet Duct) for DSI and Humidification (Load = 100 MWe, OFA = 25%, 0.40% Sulfur Coal, Hydrated Lime, NSR = 2.0, T_{AS} = 40 °F, SO_2 Removal = 25%)

6-DSI (Hydrated Lime)		7-Humidification		8-Flyash		10-Stack		MW	Material	
0.0		--		2.2		--		12	C	Solids (wt%)
2.3		--		0.5		--		2	H_2	
--		--		0.0		--		28	N_2	
37.2		--		9.9		--		32	O_2	
--		--		1.2		--		32	S	
0.0		--		0.5		--		23	Na	
46.4		--		10.6		--		40	Ca	
--		--		0		--		17	NH_3	
14.1		--		75.1		100		N/A	Inert[1]	
--		--		--		--		18	H_2O	
100%		--		100%		100%		Total		
120 °F		150 °F		--		250 °F		Temperature		Gases[2]
1,705 lb/ft^2		1,705 lb/ft^2		--		1,762 lb/ft^2		Pressure		
acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%	MW		
480	78.6	3,720	78.6	--	--	234,729	71.5	28	N_2	
127	20.8	983	20.8	--	--	10,330	3.1	32	O_2	
4	0.6	30	0.6	--	--	38,287	11.7	18	H_2O	
--	--	--	-	--	--	44,592	13.6	44	CO_2	
--	--	--	--	--	--	10	29 ppmv	28	CO	
--	--	--	--	--	--	74	227 ppmv	64	SO_2	
--	--	--	--	--	--	0	0	17	NH_3	
--	--	--	--	--	--	0	0	44	N_2O	
--	--	--	--	--	--	84	256 ppmv	30	NO	
--	--	--	--	--	--	1	3 ppmv	46	NO_2	
611	100%	4,733	100%	--	--	328,107	100%	Total		
--		65 °F		--		--		Temperature		Liquids
--		1,705 lb/ft^2		--		--		Pressure		
gal/min	wt%	gal/min	wt%	gal/min	wt%	gal/min	wt%	MW		
--	--	--	--	--	--	--	--	60	Urea	
--	--	49	100%	--	--	--	--	18	H_2O	
--	--	--	--	--	--	--	--	28	N_2	
--	--	--	--	--	--	--	--	2	H_2	
--	--	--	--	--	--	--	--	12	C	
--	--	--	--	--	--	--	--	32	O_2	
--	--	49	100%	--	--	--	--	Total		

1. Assumes mineral oxides in ash remain constant.
2. Assumes no air leakage in the boiler, air heater, or FFDC.

Table 4-16: Flow and Composition (from FFDC Inlet duct) for DSI and Humidification (Load = 100 MWe, OFA = 25%, 0.40% Sulfur Coal, Hydrated Lime, NSR = 2.0, T_{AS} = 40 °F, SO_2 Removal = 25%)

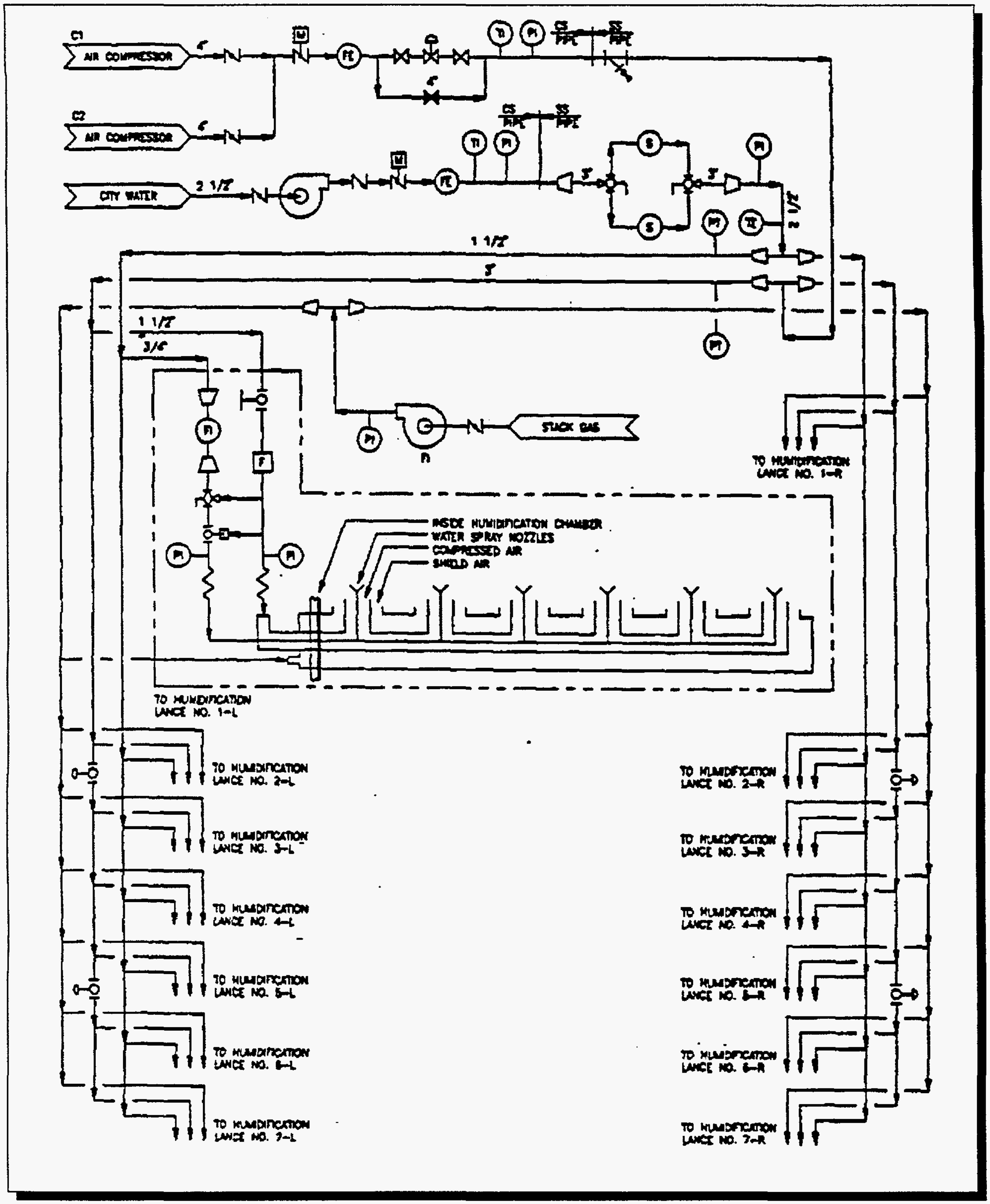


Figure 4–37: Simplified P&ID of Flue-Gas Humidification System

4.7 Integrated System

The integrated system consists of the low-NO_x burners, OFA ports, SNCR system, and the DSI system injecting sodium-based reagents.

4.7.1 Process Flow Diagram

Figure 4–38 (page 4–86) shows the process flow of the integration of the low-NO_x burners, OFA ports, SNCR system, and DSI system to control NO_x and SO_2 emissions.

4.7.2 Material Balance

Table 4–17 and Table 4–18 show the mass balance (lbm/h) and Table 4–19 and Table 4–20 show the mass flows and stream compositions for the integrated system shown in Figure 4–38.

Material		MW	1-Coal/ Primary Air	2-Secondary Air	3-OFA	4-Bottom Ash	5-Furnace Exit
Solids (lbm/h)	C	12	59,408	--	--	23	203
	H_2	2	4,257	--	--	--	--
	N_2	28	1,514	--	--	--	--
	O_2	32	9,933	--	--	--	--
	S	32	378	--	--	0	3
	Na	23	61	--	--	15	46
	Ca	40	61	--	--	15	46
	NH_3	17	--	--	--	--	--
	Inerts[1]	N/A	8,959	--	--	2,240	6,719
	H_2O	18	10,027	--	--	--	--
	Total Solids		+94,598	--	--	-2,293	(=7,017)
Gases[2] (lbm/h)	Temperature		300 °F	600 °F	600 °F	--	1,850 °F
	Pressure		1,772 lb/ft^2	1,767 lb/ft^2	1,767 lb/ft^2	--	1,746 lb/ft^2
	N_2	28	140,760	393,700	178,153	--	713,996
	O_2	32	42,504	118,882	53,795	--	32,986
	H_2O	18	736	2,059	932	--	52,067
	CO_2	44	--	--	--	--	216,248
	CO	28	--	--	--	--	479
	SO_2	64	--	--	--	--	750
	NH_3	17	--	--	--	--	0
	N_2O	44	--	--	--	--	0
	NO	30	--	--	--	--	278
	NO_2	46	--	--	--	--	5
	Total Gases		+184,000	+514,641	+232,880	--	(=1,016,809)
Liquids (lbm/h)	Temperature		--	--	--	--	--
	Pressure		--	--	--	--	--
	Urea[3]	60	--	--	--	--	--
	H_2O	18	--	--	--	--	--
	N_2	28	--	--	--	--	--
	H_2	2	--	--	--	--	--
	C	12	--	--	--	--	--
	O_2	32	--	--	--	--	--
	Total Liquids		--	--	--	--	--
Total (lbm/h)	In		+278,598	+514,641	+232,880		(=1,023,826)
	Out					-2,293	

Note: "+" indicates flow into system, "-" indicates flow out of system, "(=)" indicates intermediate balance point.

1. Assumes mineral oxides in ash remain constant.
2. Assumes no leakage of air into boiler, air heater, or FFDC.
3. Shown for information only, not included in total.

Table 4-17: Mass Balance (to Furnace Exit) for Integrated System (Load = 100 MWe, OFA = 25%, 0.40% Sulfur Coal, Sodium Sesquicarbonate at NSR = 2.0, SO_2 Removal = 70%, Urea at NSR = 0.87, NO_x Removal = 43%)

6-SNCR	7-FFDC Inlet Duct	8-DSI	9-Flyash[2]	10-Stack	MW	Material	
--	203	328	344	--	12	C	Solids (lbm/h)
--	--	68	0	--	2	H_2	
--	--	--	13	--	28	N_2	
--	0	1,751	1,138	--	32	O_2	
--	3	--	266	--	32	S	
--	46	944	990	--	23	Na	
--	46	0	46	--	40	Ca	
--	--	--	0	--	17	NH_3	
--	6,719	96	6,812	3	N/A	Inerts[1]	
--	--	--	--	--	18	H_2O	
--	(=7,017)	+3,187	-9,609	-3	Total Solids		
130 °F	260 °F	120 °F	--	250 °F	Temperature		Gases (lbm/h)
1,746 lb/ft^2	1,705 lb/ft^2	1,705 lb/ft^2	--	1,762 lb/ft^2	Pressure		
13,426	727,668	1,533	--	729,201	28	N_2	
4,054	36,453	463	--	36,751	32	O_2	
108	55,109	8	--	55,739	18	H_2O	
--	217,309	--	--	217,991	44	CO_2	
--	30	--	--	30	28	CO	
--	750	--	--	225	64	SO_2	
--	6	--	--	1	17	NH_3	
--	49	--	--	49	44	N_2O	
--	158	--	--	134	30	NO	
--	5	--	--	12	46	NO_2	
+17,588	(=1,037,537)	+2,004	--	-1,040,133	Total Gases		
60 °F	--	--	--	--	Temperature		Liquids (lbm/h)
1,746 lb/ft^2	--	--	--	--	Pressure		
484	--	--	--	--	60	Urea[3]	
2,656	--	--	--	--	18	H_2O	
226	--	--	--	--	28	N_2	
32	--	--	--	--	2	H_2	
97	--	--	--	--	12	C	
129	--	--	--	--	32	O_2	
+3,140	--	--	--	--	Total Liquids		
+20,728	(=1,044,554)	+5,191			+1,052,038	Total In	
			-9,609	-1,040,136	-1,052,038	Total Out	

Note: "+" indicates flow into system, "-" indicates flow out of system, "(=)" indicates intermediate balance point.

1. Assumes mineral oxides in ash remain constant.
2. Assumes no leakage of air into boiler, air heater, or FFDC.
3. Shown for information only, not included in total.

Table 4-18: Mass Balance (from Furnace Exit) for Integrated System (Load = 100 MWe, OFA = 25%, 0.40% Sulfur Coal, Sodium Sesquicarbonate at NSR = 2.0, SO_2 Removal = 70%, Urea at NSR = 0.87, NO_x Removal = 43%)

Material		MW	1-Coal/ Primary Air		2-Secondary Air		3-OFA		4-Bottom Ash		5-Furnace Exit	
Solids (wt%)	C	12	62.8		--		--		1.0		2.9	
	H_2	2	4.5		--		--		--		--	
	N_2	28	1.6		--		--		--		--	
	O_2	32	10.5		--		--		--		--	
	S	32	0.4		--		--		0.0		0.0	
	Na	23	0.1		--		--		0.7		0.7	
	Ca	40	0.1		--		--		0.7		0.7	
	NH_3	17	--		--		--		--		--	
	Inerts[1]	N/A	9.5		--		--		97.6		95.7	
	H_2O	18	10.5		--		--		--		--	
	Total		100%		--		--		100%		100%	
Gases[2]	Temperature		300 °F		600 °F		600 °F		--		1,850 °F	
	Pressure		1,772 lb/ft^2		1,767 lb/ft^2		1,767 lb/ft^2		--		1,746 lb/ft^2	
		MW	acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%
	N_2	28	55,507	78.6	217,171	78.6	98,272	78.6	--	--	868,531	74.2
	O_2	32	14,666	20.8	57,380	20.8	25,965	20.8	--	--	35,110	3.0
	H_2O	18	451	0.6	1,767	0.6	800	0.6	--	--	98,521	8.4
	CO_2	44	--	--	--	--	--	--	--	--	167,397	14.3
	CO	28	--	--	--	--	--	--	--	--	583	498 ppmv
	SO_2	64	--	--	--	--	--	--	--	--	399	341 ppmv
	NH_3	17	--	--	--	--	--	--	--	--	0	0
	N_2O	44	--	--	--	--	--	--	--	--	0	0
	NO	30	--	--	--	--	--	--	--	--	316	270 ppmv
	NO_2	46	--	--	--	--	--	--	--	--	4	3 ppmv
	Total		70,624	100%	276,318	100%	125,037	100%	--	--	1,170,861	100%
Liquids	Temperature		--	--	--	--	--	--	--	--	--	--
	Pressure		--	--	--	--	--	--	--	--	--	--
	gal/min	wt%	gal/min	wt%	gal/min	wt%	gal/min	wt%	gal/min	wt%	gal/min	wt%
	Urea	60	--	--	--	--	--	--	--	--	--	--
	H_2O	18	--	--	--	--	--	--	--	--	--	--
	N_2	28	--	--	--	--	--	--	--	--	--	--
	H_2	2	--	--	--	--	--	--	--	--	--	--
	C	12	--	--	--	--	--	--	--	--	--	--
	O_2	32	--	--	--	--	--	--	--	--	--	--
	Total		--	--	--	--	--	--	--	--	--	--

1. Assumes mineral oxides in ash remain constant.
2. Assumes no air leakage in the boiler, air heater, or FFDC.

Table 4-19: Flow and Composition (to Furnace Exit) for Integrated System (Load = 100 MWe, OFA = 25%, 0.40% Sulfur Coal, Sodium Sesquicarbonate at NSR = 2.0, SO_2 Removal = 70%, Urea at NSR = 0.87, NO_x Removal = 43%)

6-SNCR		7-FFDC Inlet Duct		8-DSI		9-Flyash		10-Stack		MW	Material	
--		2.9		10.3		3.6		--		12	C	Solids (wt%)
--		--		2.1		--		--		2	H_2	
--		--		--		0.1		--		28	N_2	
--		0		55.0		11.8		--		32	O_2	
--		0		--		2.8		--		32	S	
--		0.7		29.6		10.3		--		23	Na	
--		0.7		0		0.5		--		40	Ca	
--		0.7		--		31 ppmw		--		17	NH_3	
--		--		3.0		70.9		100		N/A	Inert[1]	
--		95.7		--		--		--		18	H_2O	
--		100%		100%		100%		100%		Total		
130 °F		260 °F		120 °F		--		250 °F		Temperature		Gases[2]
1,746 lb/ft²		1,705 lb/ft²		1,705 lb/ft²		--		1,762 lb/ft²		Pressure		
acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%	acfm	vol%	MW		
4,172	78.3	282,633	73.9	479	78.6	--	--	270,220	73.9	28	N_2	
1,102	20.7	12,389	3.2	127	20.8	--	--	11,916	3.3	32	O_2	
52	1.0	33,296	8.7	4	0.6	--	--	32,131	8.8	18	H_2O	
--	--	53,712	14.1	--	--	--	--	51,406	14.0	44	CO_2	
--	--	12	30 ppmv	--	--	--	--	11	30 ppmv	28	CO	
--	--	127	333 ppmv	--	--	--	--	36	100 ppmv	64	SO_2	
--	--	4	10 ppmv	--	--	--	--	1	2 ppmv	17	NH_3	
--	--	12	32 ppmv	--	--	--	--	12	32 ppmv	44	N_2O	
--	--	57	150 ppmv	--	--	--	--	46	127 ppmv	30	NO	
--	--	1	3 ppmv	--	--	--	--	3	7 ppmv	46	NO_2	
5,326	100%	382,243	100%	610	100%	--	--	365,782	100%	Total		
60 °F		--		--		--		--		Temperature		Liquids
1,746 lb/ft²		--		--		--		--		Pressure		
gal/min	wt%	gal/min	wt%	gal/min	wt%	gal/min	wt%	gal/min	wt%	MW		
0.7	--	--	--	--	--	--	--	--	--	60	Urea	
5.3	84.6	--	--	--	--	--	--	--	--	18	H_2O	
--	7.2	--	--	--	--	--	--	--	--	28	N_2	
--	1.0	--	--	--	--	--	--	--	--	2	H_2	
--	3.1	--	--	--	--	--	--	--	--	12	C	
--	4.1	--	--	--	--	--	--	--	--	32	O_2	
6	100%	--	--	--	--	--	--	--	--	Total		

1. Assumes mineral oxides in ash remain constant.
2. Assumes no air leakage in the boiler, air heater, or FFDC.

Table 4-20: Flow and Composition (from Furnace Exit) for Integrated System (Load = 100 MWe, OFA = 25%, 0.40% Sulfur Coal, Sodium Sesquicarbonate at NSR = 2.0, SO_2 Removal = 70%, Urea at NSR = 0.87, NO_x Removal = 43%)

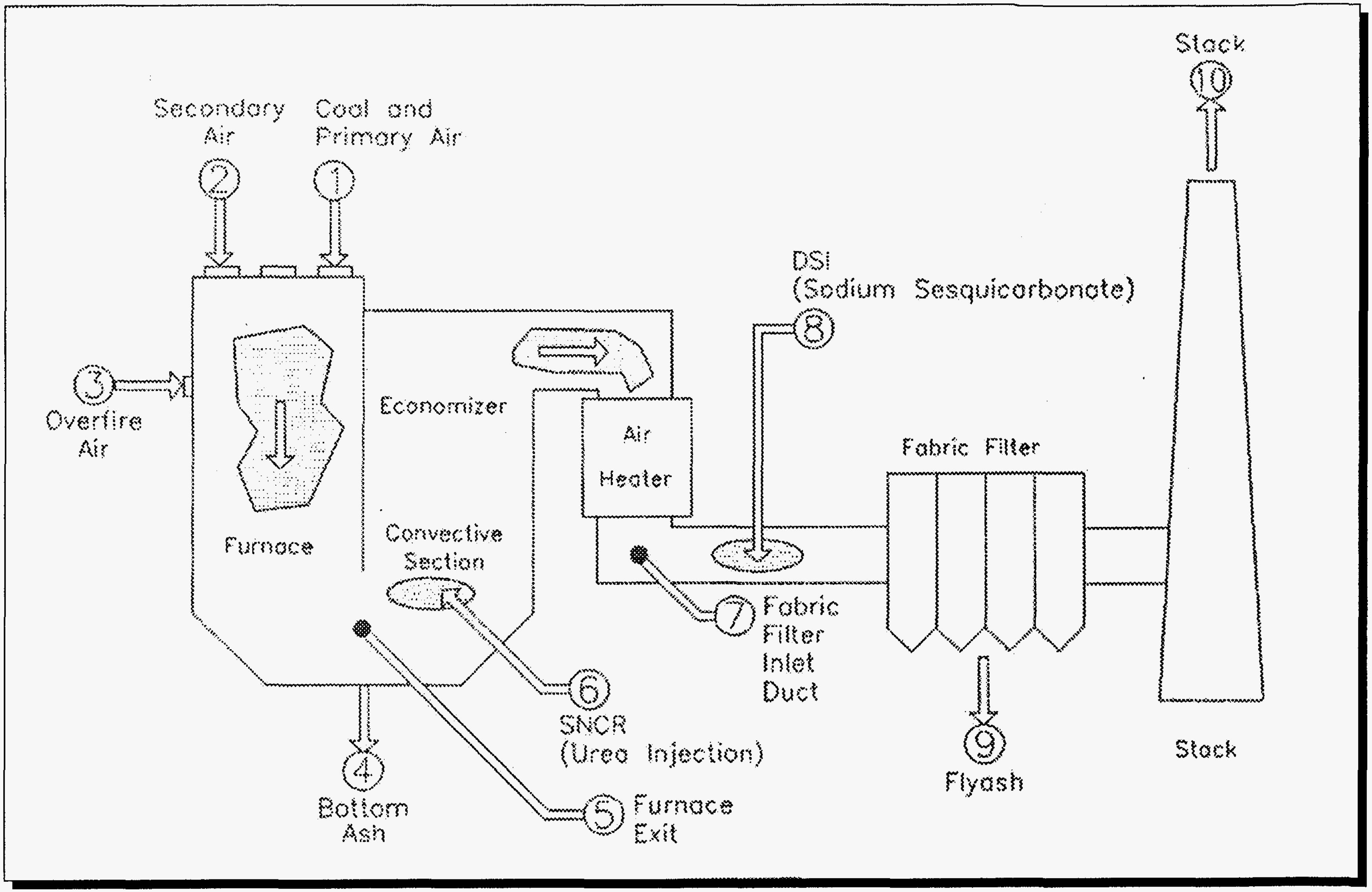


Figure 4-38: Process Flow for Integrated System

4.8 Balance of Plant

The balance of the plant includes the continuous emissions monitor (CEM), the distributive control system (DCS), and the new flyash system.

4.8.1 Continuous Emissions Monitor (CEM)

The Integrated Dry NO_x/SO_2 Emissions Control System incorporates a CEM. The monitor utilizes extractive sampling for either hot/wet or cold/dry sample measurements. The hot/wet sampling system can maintain sample temperatures as high as 480 °F for measuring reactive gases. The hot/wet sampling system maintains these elevated temperatures throughout the entire system including the analyzer. This system provides measurement of reactive gases such as ammonia (NH_3) that cannot survive cold sample conditioning equipment. The CEM measures SO_2, NO, NO_2, N_2O, O_2, CO, CO_2, H_2O and NH_3.

The CEM utilizes an infrared (IR) bench to provide continuous analysis of all eight gases. Under computer control, it uses either the gas-filter correlation or single-beam dual-wavelength techniques. A programmable logic controller (PLC) provides all analyzer and system controls. All control system functions and ranges are completely field programmable. Since infrared is not a suitable technique for measuring oxygen, a zirconium oxide analyzer is used to monitor this gas.

The CEM has four sample locations: one at the boiler-outlet, two at the FFDC-inlet, and one at the FFDC outlet. A 12-point grid is located at the outlet of the boiler. This non-heated sample grid will be used to determine the distribution of the sampled gases throughout the duct. Since the sample lines for this location are not heated, it can measure only for SO_2, NO, CO, and O_2. A single-point-heated-probe sample may also be taken at the inlet of the FFDC. All the gases are not thoroughly mixed at this location, but the sample allows the measurement of all eight gases. Six non-heated sample lines are also located at the FFDC-inlet to determine the distribution of SO_2, NO, CO, and O_2. A single-point-heated-sample point is also located at the inlet of the FFDC. A second single-point-heated-sample point is located at the outlet of the FFDC.

4.8.2 Flyash Removal System

Prior to the installation of the emissions control project, flyash and bottom ash were slurried to the ash pond. Periodically, the ash pond was dredged and the ash was taken to a landfill.

4.8.2.1 Flyash from Test Program

The Integrated Dry NO_x/SO_2 Emissions Control System creates approximately 25% more ash (because of its DSI system) and adds soluble compounds to the flyash from Arapahoe Unit 4. Therefore, the flyash from the test program will be collected dry and disposed of in a landfill. However, the bottom ash will continue to be slurried to the ash ponds.

4.8.2.2 Process/Operation of New Flyash System

The additional controls required to operate the dry ash collection system were added to the existing PLC and control panel for the original system. Normally the system is operated to transfer the flyash from the FFDC hoppers to the dry ash silo. If equipment problems occur preventing normal operation, the system may be adjusted to convey the ash to the storage ponds. When the DSI system is in operation, flyash is also transferred to the dry storage system. The ash is then loaded into covered trucks for disposal at approved/permitted solid waste disposal facilities.

4.8.2.3 Process Flow Diagram

Figure 4-39 shows a flow diagram of the new flyash collection system. The pneumatic flyash transport system utilizes a hydroveyor exhauster. This device is a water-powered venturi-exhauster that uses high-pressure water to create airflow through the conveying system. The ash/air mixture is conveyed dry to either the flyash storage-silo or directly to the exhauster. When conveying to the flyash silo, the ash/air mixture is transported to the filter/separator mounted on the flyash-storage silo. The ash from the filter/separator is collected in the filter/separator transfer hopper, which is a double-valve air-lock-type device. The ash is periodically dumped into the flyash-storage silo.

The clean transport air exits the filter/separator and flows to the hydroveyor. The flyash-storage silo is unloaded by either a twin-paddle mixer or a telescoping spout. Fluidizing stones in the floor of the silo aerate the flyash and assist its flow out of the silo. A blower supplies fluidizing air and another blower is on standby.

When conveying directly to the hydroveyor exhauster, dry flyash is combined with the motive water that powers the exhauster and is discharged into an air separator which removes air from the mixture and vents it to the atmosphere. The remaining ash-water slurry is discharged to the ash ponds.

Only one intake and one branch line are open at a time. The system sequences from ash-intake to ash-intake as the FFDC hoppers are emptied. The PLC controls the opening and closing of the intakes and proper positioning of the gates. The flyash may be removed from the storage silo either wet or dry using the twin-paddle mixer/unloader or the telescoping spout. The mixer is used for wet unloading and the telescoping spout is used for dry unloading.

During the dry unloading of flyash, dusting would be a hazard and a nuisance. A vent fan creates a negative pressure in the chute and transports the fugitive dust back to the storage silo. A bin-vent filter on the silo vents the silo and removing associated dust.

Ash may also be removed from the storage silo using the twin-paddle mixer/unloader. Ash flows from the discharge hopper, through the ash-feed valve, and enters the body of the unloader. In the unloader, the ash is sprayed with approximately 20% by weight water to condition the ash and minimize dust emissions. The conditioned ash is then discharged through a chute to disposal vehicles.

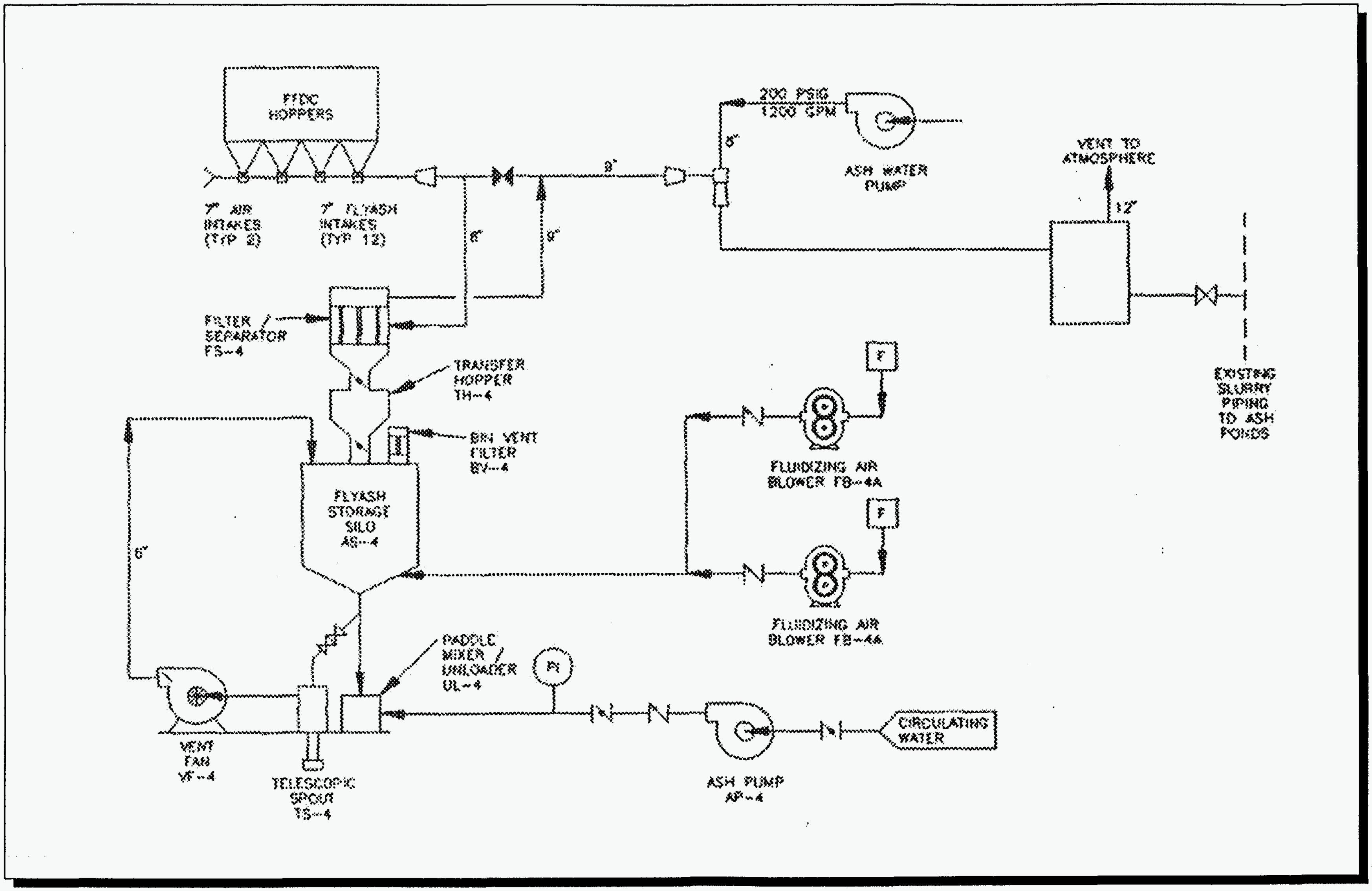


Figure 4-39: Flow Diagram of New Flyash Removal/Storage System

4.8.3 Distributed Control System

Originally, a Bailey pneumatic control system controlled the operation of Arapahoe Unit 4. The burners were operated manually and had limited controls. Because of the complexity of the Integrated Dry NO_x/SO_2 Emissions Control System, a new distributed control system (DCS) was added to Arapahoe Unit 4 to control the modified boiler and the added pollution control equipment. The DCS:

- Controls the entire boiler including its fans, dampers, flows, fuel-gas regulators, flame scanners, ignitors, flame safety system, and sootblowing.
- Controls all of the auxiliary equipment (pulverizers, feeds, pump, control valves, etc.)
- Controls the DSI system.
- Controls the humidification system.
- Gathers and processes data from the CEMs.

Since the DCS allows better control of the equipment than the original control system, it controls the fuel and air more efficiently during the rapid load swings that can occur with automatic control under load following. A high degree of automation is necessary to keep the project at peak efficiency during all modes of operation. Widely varying operating conditions will occur due to the cycling operation of the plant, and the number of different coals utilized for the testing phase of this project. In addition, other variables such as different reagents, boiler cleanliness, and excess air quantity will further add to the varying nature of operating conditions.

4.8.3.1 Burner Management System

Stone & Webster Engineering Corporation programmed the burner management portion of the Integrated Dry NO_x/SO_2 Emissions Control System. The burner-management system is designed to place a burner in or out of service safely. It includes interlocks and permissives to prevent unsafe operation of the boiler.

The burners are divided into four groups that correspond to the four pulverizers. Each burner group consists of three burners and can be operated in a supervised manual mode where the operator performs all of the start and stop functions. However, the system does not allow the operator to initiate any function until all of its required permissives are satisfied. The burner-management system controls the following subsystems and equipment:

- Purge protection system.
- Boiler trip system.
- Ignitor system.
- Main gas system.
- Pulverizer and coal feeder.
- Combustion air systems.
- Flame monitors.

The new burner-management system includes both infrared and ultraviolet flame scanners as well as automated controls for most of the boiler functions. In order to be able to start the boiler safely from the control room, the ignitors and the main natural gas systems were modified for the automatic control of the vent valves and the main fuel-valves.

4.8.3.2 Local Control

The DCS allows the whole plant to be controlled and monitored from a central location, but individual plant areas may also be controlled and monitored at remote locations. At the central location, the operator accesses system through four CRT displays with integral keyboards.

The DCS' hardware cabinets are located on the north side of the Arapahoe Unit 4's control room in the house-power room. The cabinets contain local and network highway interfaces, process controllers, I/O signal conditioning hardware, and prefabricated interconnecting cables.

The existing main control room was modified to accommodate the new DCS console. The DCS console is arranged in front of the existing control panel for Arapahoe Unit 4 and includes:

- Four CRTs with integral keyboards.
- Alarm and utility printer.
- System tape drives.
- An engineering work station.

The DCS software is configured specifically for the control functions of Arapahoe Unit 4. An operator may control the DCS from either of the stations located in the central control room. The DCS was designed so that the failure of a single system-component does not render the system inoperable. A non-interruptable power supply powers the DCS.

4.9 Waste Streams

The Integrated Dry NO_x/SO_2 Emissions Control system does not create any additional waste streams. However, portions of the system will slightly affect all of its waste streams. Coal-fired utility boilers produce three major waste streams: bottom ash, flyash, and stack gas. The most dramatic and positive effect of the system will be on the stack gas. The system is expected to reduce both SO_2 and NO_x emissions by up to 70%. However, the additional equipment and reagents used by the system will increase or slightly change the composition of some of its waste streams.

4.9.1 Low-NO_x Combustion System

The addition of the low-NO_x burners and the OFA ports is not expected to change the composition of any waste streams. However, it is possible that the amount of unburned carbon in the flyash will increase slightly and that CO emissions will increase slightly at the stack. Since the low-NO_x combustion system is not expected to affect significantly the boiler's efficiency, and thus its coal flow, the low-NO_x burners and OFA ports are expected to generate the same amount of ash. The mass balances in Section 4.2.6 detail the composition of the low-NO_x combustion system's expected waste streams.

4.9.2 SNCR

Three effects of urea injection are expected to modify slightly all three of the boiler's waste streams. First, operating the injection system requires additional electric energy and slightly decreases boiler efficiency. Thus additional coal must be used to maintain an equivalent load. The higher coal flow increases all waste streams slightly. Second, the NO_x removal chemistry of the SNCR system generates NH_3 and N_2O emissions. These wastes exit through the stack. Third, flyash collected by the FFDC will absorb a portion of the NH_3 emissions in the fluegas. The absorbed NH_3 contaminates the flyash removed from the FFDC. The mass balances in Section 4.4.4 detail the compositions of the waste streams. These waste streams may be directly compared to the material balance of the low-NO_x combustion system in Section 4.2.6 (the base case) which shows equivalent unit operation without SNCR injection.

4.9.3 DSI

Three effects of the DSI system will also modify all three of the boiler's waste streams. First, the DSI equipment requires additional electric energy which increases coal usage and thus increases all three waste streams. Second, the DSI system modifies the composition of the flue gas leaving the stack. In addition to removing SO_2 and NO, the DSI system slightly increases the NO_2 and CO_2 emissions. Third, the injection of the reagent into either the economizer or the duct increases the amount and changes the composition of the solid waste collected with by the FFDC.

Of these changes, the change in the composition of the waste stream collected by the FFDC affects the disposal of waste the most. The chemical reaction that converts the SO_2 in the flue gas into a solid sulfate or sulfite compound also changes the composition of the flyash waste stream. As both sodium and calcium-based sulfate/sulfites are soluble, precautions must be used for disposal. At Arapahoe 4 the FFDC waste stream was originally disposed of in an on-site pond. When the pond became full, it was dredged and the waste was trucked to a local landfill. Sluicing of DSI waste is not acceptable due to the possibility of leaching sodium, calcium, and sulfur compounds. As part of the project, a new dry ash storage silo was installed. All wastes are now collected and disposed of dry. The wastes must be disposed of in a properly permitted landfill.

Regulations vary by state, but Colorado requires a lined landfill and ground monitoring wells to inspect and ensure no leaching is occurring. As part of this project, a significant amount of waste characterization is planned to determine what, if any, effect these soluble wastes have on both clay and plastic liners. The results of this study will be reported in Volume 2 of the final report.

Section 4.5.6 contains material balances for both calcium-based economizer injection and sodium-based duct injection. These balances show both the change in composition of the waste streams and their change in volume. The net effect of DSI waste streams may be determined by comparing the material balances of the low-NO_x combustion system in Section 4.2.6 (the base case) with the DSI material balances.

4.9.4 Flue-Gas Humidification

When operated by itself, flue-Gas humidification does not significantly change any of the waste streams, except for slightly increasing the water emissions from the stack. However, the humidification system is installed to be operated with the duct injection of calcium-based DSI reagents. The combination of these systems provides similar changes to the waste streams as described in Section 4.9.3. In addition to the changes described in Section 4.9.3, injecting and atomizing the humidification water requires additional power, slightly increasing the coal flow. The waste stream composition for the flue-gas humidification system is shown in the material balances in Section 4.6.6 and may also be compared to the low-NO_x combustion system.

4.9.5 Integrated System

The integrated system is just the combination of the three systems previously described: low-NO_x combustion, SNCR, and DSI with sodium-based reagents. Except for two stack gases, the associated changes in the waste streams are just a combination of those associated with the individual systems. The systems are expected to integrate synergistically and slightly reduce both NO_2 and NH_3 emissions. The material balances in Section 4.7.2 details the waste streams of the integrated system. These material balances may also be compared with those of the low-NO_x combustion system.

4.10 Equipment List

The following tables list the significant items in the Integrated Dry NO_x/SO_2 Emissions Control System.

Equipment Number	Item	Quantity	Manufacturer/ Vendor	Model	Size/Capacity	Characteristics/ Materials
BUR-1B, 2A, 3A, 4C, 5C, 6D, 7A, 8B, 9B, 10D, 11D, 12C	Burner	12	Babcock & Wilcox	DRB-XCL®	Coal: 91.3 MMBtu/h Gas: 100,330 ft^3/h Coal flow: 8,370 lb/h Gas pressure: 4 psig	Modified for vertical operation Design coal: 10,904 Btu/lb Design gas: 943 Btu/ft^3
GI-1B, 2A, 3A, 4C, 5C, 6D, 7A, 8B, 9B, 10D, 11D, 12C	Gas Lighter (Ignitor)	12	Babcock & Wilcox		10.6 MCFH 10 MMBtu/h Gas pressure: 13 psig	High Capacity Retractable
IR-1B, 2A, 3A, 4C, 5C, 6D, 7A, 8B, 9B, 10D, 11D, 12C	IR Scanner	12	Coen	IR 7000 Series		Monitors coal firing
UV-1B, 2A, 3A, 4C, 5C, 6D, 7A, 8B, 9B, 10D, 11D, 12C	UV Scanner	12	Coen	UV 7000 Series		Monitors natural gas firing
M-1B, 2A, 3A, 4C, 5C, 6D, 7A, 8B, 9B, 10D, 11D, 12C	Sliding disk actuator	12	Jordan	LA-2510	12 in. stroke 1,600 lb thrust 460VAC, 60 Hz, 3-phase	NEMA 4 Enclosure
DAM-R, DAM-L	OFA damper actuator	2	Beck®	Group II Electronic Drive		
OFA-R1, R2, R3, L1, L2, L3	OFA Ports	6	Babcock & Wilcox			Dual-zone

Table 4-21: Equipment List for Low-NO_x Combustion System

Equip. Number	Item	Quantity		Manufacturer	Model	Size/Capacity	Characteristics/ Materials
		Opn[1]	S/B[2]				
T-1 T-2	Urea storage tank	1	1	Eaton Metal	Custom	20,000 gal Height: 18.5 ft Dia: 14 ft	Epoxy coated 2 in. fiberglass insulation Design temp: 160 °F
P-3 P-4	Urea circulation pump	1	1	Wilfley	A 10–6	220 gal/min, 60 psig 15 hp	Centrifugal Sealless Single-stage
H1 H2	Urea heater	1	1	Gaumer Co., Inc.	67SF1ZN40M4 J C6SF1ZN4M4J	30 kW 460 V 3-phase	Electrical immersion
F-1 F-2	Urea filter	1	1	Cuno	CT 102	5 μm	Cellulose
P-5 P-6	Urea injection pump	1	1	Kerr Machine Co.	KM 3250	10.5 gal/min, 900 psi, (1,000 psig max.) 15 hp	Reciprocating

1. Quantity in operation.
2. Quantity on standby.

Table 4–22: Equipment List for SNCR System (Urea Storage and Injection)

Equip. Number	Item	Quantity		Manufacturer	Model	Size/Capacity	Characteristics/ Materials
		Opn[1]	S/B[2]				
C-1	Atomization compressor	1	--	Turblex	KA226V-GA250	9,400 scfm, 13.3 psig 750 hp	Centrifugal Single-stage
	Compressor motor	1		Siemens		700 hp 4,160V	Type: RG Frame: 588US
V-1	Quench vessel	1	--	Alaskan Copper	Custom	650 gal	SS 304
P-1 P-2	Quench pump	1	1	Worthington	D1012	30 gal/min, 50 psig, (100%)	Centrifugal
	Pump motor	1	1	General Electric	E 9939	3 hp 460V, 3-phase	Type KS
PF-1	Urea purge air fan	1	--	Fan Engineering	M-14IE	3,000 scfm, 29 inH$_2$Og	
	Purge fan motor	1	--	General Electric		40 hp 460V, 3-phase	Frame: 324TS Type KS 2-pole
WS-1	Water softener skid	1	--	Kisco	TDV 2460 1-1/2	28 gal/min, 65 gal/min (max) 2 resin vessels 9 ft^3 resin/vessel	Resin: Purolite C–100 1 vessel operating 1 vessel regenerating
Level 1	Injection lances	10	--	Noell	Custom	Length: 35 in.	Dual fluid
Level 2	Injection lances	10	--	Noell	Custom	Length: 20-3/4 in.	Dual fluid

1: Quantity in operation.

2: Quantity on standby.

Table 4–23: Equipment List for SNCR System (Atomization)

Item Number	Item	Quantity*	Manufacturer	Model	Size/Capacity	Characteristics/ Materials
S-4A, 4B	Reagent Storage Silo	2	Coors Brewing Co.	Custom	150 t	Stainless steel (T–304) hopper Mass flow
VF-4A, 4B	Silo Vent Filter	2	Chicago Conveyor	440-40-138	183 ft^2	Pulse jet
SF-4A, 4B	Reagent Screw Feeder	2	Schloss	6SF6	55 ft^3/h 1 hp	Variable diameter
B-4A, 4B	Pneumatic conveying blower	2	Sutorbilt	7ML	660 icfm, 9 psig 40 hp	Rotary lobe
E-4A, 4B	Conveying heat exchanger	2	Xchanger	AA1000	100,000 Btu/h	Air-to-air
P-4A, 4B	Reagent pulverizer	2	Entoleter	Series 30	2 t/h (90%-400 mesh) 60 hp	Attrition-type mill
ESB-4A, 4B	Splitter box (Economizer injection)	2	Fuller	Custom	Inlet: 5 in Outlet id: 2-1/2 in # of outlets: 4	
DSP-4A, 4B	Splitter box (duct injection)	2	Fuller	Custom	Inlet id: 5 in Outlet id: 2 in # of outlets: 6	
RV-4A, 4B	Rotary Airlock	2	Fuller	150	0.23 ft^3/rev 1 hp	High-differential pressure design

*There are two duplicate DSI systems at Arapahoe Unit 4. These systems can be operated separately or together.

Table 4–24: Equipment List for DSI System

Item Number	Item	Number*	Manufacturer	Model	Size/Capacity	Materials/ Characteristics
I-6R, I-6L	Humidification lances	14	Babcock & Wilcox	I-Jet	6 nozzles per lance 1 gal/min per nozzle 6 gal/min per lance	Ceramic inserts Hot gas application
P-1	Water pump	1	Ingersoll-Rand	HC	120 gpm, 200 psig 15 hp	Variable-speed drive
C1, C2	Atomization air compressor	2	Ingersoll-Rand	2200 HH	1,642 scfm, 150 psig 700 hp	4,000 volts
F1	Shield Air Fan	1	New York Blower	20-LS	4,500 ft^3/min, 4 inH_2Og 10 hp	

*No backup or standby equipment.

Table 4–25: **Equipment List for Flue-Gas Humidification System**

Equipment Number	Item	Quantity	Manufacturer/ Vendor	Model	Size/ Capacity	Characteristics/ Materials
AS-4	Flyash storage silo	1	United Conveyor Corp. (UCC)	Custom	id: 25 ft height: 45 ft	Steel Flat-bottomed
FS-4	Flyash filter/separator	1	UCC	Custom	Max. dust size: 3 μm 18 scfm cloth area: 727 ft^2 20 inHg vacuum	max temp: 275 °F
TH-4	Transfer hopper	1	UCC	Drawing number: 5-3206-108-9		
BV-4	Bin vent filter	1	Industrial Accessories Co.	96BVT-A2-36:60S	36 bags 466 ft^2	Reverse pulse Fabric filter
UL-4	Mixer/unloader	1	UCC	1535/45	60 t/h 15 hp drive	Twin paddles (abrasion resistant steel) Water requirements: 25-50 gal/min
TS-4	Telescopic spout	1	UCC	Custom		
FB-4A, 4B	Fluidizing air blowers	1	Sutorbilt	7HVL	350 ft^3/min @ 10 psi 40 hp	
VF-4	Bin vent fan	1	Clarage	6CI.CW	780 ft^3/min at 6.5 WG static 1.75 Bhp at 3,515 r/m	
AP-4	Ash pump	1	Ingersoll-Rand	HC:2-1/2 x 1-1/2 x 12	75 gal/min @ 63 psi 7-1/2 hp	Centrifugal
CEM-1	Continuous emission monitor (CEM)	1	Altech	ASC-219	SO_2, NO, NO_2, N_2O, NH_3, O_2, H_2O, CO_2, CO	Infrared analysis Dual-point switching Hot/wet
DCS-1	Distributive control system	1	Westinghouse	WDPF	9DPU	

Table 4-26: Equipment List for Balance of Plant

5.0 ESTIMATED CAPITAL COSTS

This section summarizes the capital costs for each of the systems of the Integrated Dry NO_x/SO_2 Emissions Control System.

- Costs for individual equipment items are given when they are available. Some systems were built on a fixed-price basis and costs for individual equipment items are not available.

- The cost of installation is not available for most equipment items, so the cost of installing each system is included. This cost includes civil, mechanical, and electrical engineering costs as well as some minor purchases.

- The capital costs do not include home office engineering or general and administrative costs, but they do include labor overheads.

The design, procurement, and installation of the Integrated Dry NO_x/SO_2 Emissions Control System is expected to cost \$20.9 million. An additional \$6.5 million is budgeted for the operating and testing of the system, bringing the total cost of the program to \$27.4 million, including overheads. Except for a \$934,000 change in the scope of work requested by the DOE for air toxics testing, the project is within the original approved budget.

Item Number	Item	Unit Purchase Price	Freight ($/unit)	Installation ($/unit)	Total Unit Cost ($/unit)	Quantity	Total Cost	Year
BUR-1B, 2A, 3A, 4C, 5C, 6D, 7A, 8B, 9B, 10D, 11D, 12D	Burner	$42,900			$42,900	12	$514,800	91
GI-1B, 2A, 3A, 4C, 5C, 6D, 7A, 8B, 9B, 10D, 11D, 12D	Gas lighter (ignitor)	$3,100			$3,100	12	$37,200	91
IR-1B, 2A, 3A, 4C, 5C, 6D, 7A, 8B, 9B, 10D, 11D, 12D	IR scanner	$3,400*			$3,400	12	$40,800	91
UV-1B, 2A, 3A, 4C, 5C, 6D, 7A, 8B, 9B, 10D, 11D, 12D	UV scanner	$3,400*			$3,400	12	$40,800	91
M-1B, 2A, 3A, 4C, 5C, 6D, 7A, 8B, 9B, 10D, 11D, 12D	Sliding disk actuator	$2,000			$2,000	12	$24,000	91
DAM-R, DAM-L	OFA damper actuator	$6,200			$6,200	2	$12,400	91
OFA-R1, R2, R3, L1, L2, L3	OFA ports	$12,100			$12,100	6	$72,600	91
--	Other Equipment						$1,217,400	91
Total design/engineering							$1,053,000	91
Total procurement							$1,960,000	91
Total installation							$2,903,000	91
Total capital costs for low-NO_x combustion system							**$5,916,000**	91

* Includes blower, cables, and cabinets.

Table 5-1: Summary of Capital Costs for Low-NO_x Burners and OFA Ports

Item Number	Item	Unit Purchase Price	Freight ($/unit)	Installation ($/unit)	Total Unit Cost ($/unit)	Quantity	Total Cost	Year
T-1, T-2	Urea storage tank	N/A				2		91
P-3, P-4	Urea circulation pump	N/A				2		91
H-1, H-2	Urea heater	N/A				2		91
F-1, F-2	Urea filter	N/A				2		91
P-5, P-6	Urea injection pump	N/A				2		91
C-1	Atomization compressor	N/A				1		91
V-1	Quench vessel	N/A				1		91
P-1, P-2	Quench pump	N/A				2		91
PF-1	Purge fan	N/A				1		91
WS-1	Water softener skid	N/A				1		91
Level 1	Injection lances	N/A				10		91
Level 2	Injection lances	N/A				10		91
	NH_3 conversion system	$100,828		$36,000*	136,828	1	136,828	91
	Other equipment						$1,181,172	91
Total design/engineering							$536,000	91
Total procurement							$1,318,000	91
Total installation							$711,000	91
Total capital costs for SNCR system							**$2,565,000**	**91**

*Includes startup costs only

Table 5-2: Summary of Capital Costs for SNCR System

Item Number	Item	Unit Purchase Price	Freight ($/unit)	Installation ($/unit)	Total Unit Cost ($/unit)	Quantity	Total Cost	Year
S-4A, 4B	Reagent storage silo	$104,480			$104,480	2	$208,960	91
VF-4A, 4B	Silo vent filter	$3,850	$193		$4,043	2	$8,086	91
SF-4A, 4B	Reagent screw feeder	$5,525			$5,525	2	$11,050	91
B-4A, 4B E-4A, 4B	Pneumatic conveying blower and conveying heat exchanger	$13,104			$13,104	2	$26,208	91
P-4A, 4B	Reagent pulverizer	$65,533			$65,533	2	$131,066	91
ESB-4A, 4B	Splitter box (economizer)	$7,616			$7,616	2	15,232	91
DSB-4A, 4B	Splitter box (duct)	$7,616			$7,616	2	15,232	91
RV-4A, 4B	Rotary airlock	$9,340			$9,340	2	$18,680	91
--	Other Equipment						$335,950	91
	Total design/engineering						$199,000	91
	Total procurement						$740,000	91
	Total installation						$541,000	91
	Total capital costs for DSI system						**$1,480,000**	**91**

Table 5-3: Summary of Capital Costs for DSI System

Item Number	Item	Unit Purchase Price	Freight ($/unit)	Installation ($/unit)	Total Unit Cost ($/unit)	Quantity	Total Cost	Year
I-6R, I-6L	Humidification lances	$13,600			13,600	14	$190,400	91
P-1	Water pump	$3,115			$3,115	1	$3,115	91
C-1, C-2	Atomization air compressor	$80,560	$930		$81,490	2	$162,980	91
F-1	Shield air fan	$2,321	$134		$2,455	1	$2,455	91
--	Other equipment						$424,050	91
Total design/engineering							$330,000	91
Total procurement							$783,000	91
Total installation							$470,000	91
Total capital costs for flue-gas humidification system							**$1,583,000**	**91**

Table 5-4: Summary of Capital Costs for Flue-Gas Humidification System

Item	Item	Unit Purchase Price	Freight ($/unit)	Installation ($/unit)	Design/ Engineering	Total Unit Cost ($/unit)	Qua	Total Cost	Yr
AS-4	Flyash storage silo	N/A					1		91
FS-4	Flyash filter/separator	N/A					1		91
TH-4	Transfer hopper	N/A					1		91
TH-4	Bin vent filter	N/A					1		91
UL-4	Flyash mixer/unloader	N/A					1		91
TS-4	Flyash telescopic spout	N/A					1		91
FB-4A, 4B	Fluidizing air blower	N/A					1		91
VF-4	Bin vent fan	N/A					1		91
AP-4	Ash pump	N/A					1		91
Total Flyash (UCC)		$631,000		$756,000	$113,000	$1,500,000	1	1,500,000	91
DCS-1	Distributive control system	$1,100,000		$588,000	$567,000	$2,255,000	1	2,255,000	91
CEM-1	Continuous emission monitor	$254,000		$27,000	$16,000	$297,000	1	297,000	91

Table 5-5: Summary of Capital Costs for Balance of Plant

6.0 ESTIMATED OPERATING COSTS

6.1 Fixed Operating and Maintenance Costs

None of the emission control systems require the hiring of full-time operators. It is assumed that an existing operator can maintain the system while on regular rounds. However, the increased time for the rounds is estimated and used to calculate a labor expense. Since there are no new operator functions, no operator costs are assumed for the low-NO_x combustion system .

6.2 Variable Operating Costs

Variable cost includes those items that are directly proportional to the run time of the system. For example, they include the cost of reagents, water, waste disposal, and auxiliary power. In these tables it is assumed that the SNCR system is operated to obtain 40% NO_x removal, DSI system is operated to obtained 70% SO_2 removal when using sodium reagent and 50% SO_2 removal when using lime reagent.

6.3 Summary of Estimated Operating Costs

The following tables summarize the estimated operating costs of the various systems of the Integrated Dry NO_x/SO_2 Emissions Control System. The costs are based on 1992 dollars. The costs of operating various combinations of systems can be determined by adding the costs of the individual systems.

ANNUAL FIXED OPERATING COSTS		
Expense		**Estimated Annual Cost ($/yr)**
Operator-hours per day	0	
Number of operating days per year	365	
Operator pay rate per hour	$29.95	
	Total operating labor	$0
	Maintenance labor	$4,680
	Maintenance materials	$24,000
	Administrative and support labor	$7,170
	Total annual fixed O&M costs	**$35,850**

VARIABLE OPERATING COSTS				
Commodity	**Unit**	**Unit Cost ($/unit)**	**Quantity (# of units/hour)**	**Cost ($/hour)**
Auxiliary power	kWh	0.0242	1.2	$0.03
			Total variable operating costs	$0.03

Total planned operating hours for demonstration	16,664 hours

Table 6-1: Summary of Estimated Annual Operating Costs for Low-NO$_x$ Burners and OFA Ports

ANNUAL FIXED OPERATING COSTS		
Expense		**Estimated Annual Cost ($/yr)**
Operator-hours per day	2	
Number of operating days per year	365	
Operator pay rate per hour	$29.95	
	Total operating labor	$21,353
	Maintenance labor	$14,040
	Maintenance materials	$18,000
	Administrative and support labor	$13,348
	Total annual fixed O&M costs	**$66,741**

VARIABLE OPERATING COSTS				
Commodity	**Unit**	**Unit Cost ($/unit)**	**Quantity (# of units/hour)**	**Cost ($/hour)**
Reagent	ton	180	0.241	$43.38
Water	acre-ft	165	0.000921	$0.15
Auxiliary power	kWh	0.0242	283	$6.85
			Total variable operating costs	$50.38

Total planned operating hours for demonstration	1,120 hours

Table 6-2: Summary of Estimated Annual Operating Costs for SNCR System

ANNUAL FIXED OPERATING COSTS

Expense		Estimated Annual Cost ($/yr)
Operator-hours per day	2	
Number of operating days per year	365	
Operator pay rate per hour	$29.95	
Total operating labor		$21,353
Maintenance labor		$11,700
Maintenance materials		$17,900
Administrative and support labor		$12,738
Total annual fixed O&M costs		**$63,691**

VARIABLE OPERATING COSTS

Commodity	Unit	Unit Cost ($/unit)	Quantity (# of units/hour)	Cost ($/hour)
Reagent	ton	82	1.723	$141.29
Waste disposal	ton	8.30	1.723	$14.31
Auxiliary power	kWh	0.0242	72.5	$1.75
Total variable operating costs				$157.35

Total planned operating hours for demonstration	800 hours

Table 6-3: **Summary of Estimated Annual Operating Costs for DSI System (Duct Injection of Sodium Sesquicarbonate)**

ANNUAL FIXED OPERATING COSTS		
Expense		Estimated Annual Cost ($/yr)
Operator-hours per day	1.4	
Number of operating days per year	365	
Operator pay rate per hour	$29.95	
	Total operating labor	$14,947
	Maintenance labor	$7,020
	Maintenance materials	$4,900
	Administrative and support labor	$6,717
	Total annual fixed O&M costs	**$33,584**

VARIABLE OPERATING COSTS				
Commodity	**Unit**	**Unit Cost ($/unit)**	**Quantity (# of units/hour)**	**Cost ($/hour)**
Reagent	ton	95	1.138	$108.10
Waste disposal	ton	8.30	1.138	$9.45
Auxiliary power	kWh	0.0242	25.01	$0.61
			Total variable operating costs	$118.16

Total planned operating hours for demonstration	480 hours

Table 6-4: **Summary of Estimated Annual Operating Costs for DSI System (Economizer Injection of Hydrated Lime)**

ANNUAL FIXED OPERATING COSTS		
Expense		Estimated Annual Cost ($/yr)
Operator-hours per day	1.4	
Number of operating days per year	365	
Operator pay rate per hour	$29.95	
Total operating labor		$14,947
Maintenance labor		$9,360
Maintenance materials		$13,900
Administrative and support labor		$9,551
Total annual fixed O&M costs		**$47,758**

VARIABLE OPERATING COSTS				
Commodity	**Unit**	**Unit Cost ($/unit)**	**Quantity (# of units/hour)**	**Cost ($/hour)**
Reagent	ton	95	1.138	$108.10
Water	acre-ft	165	0.009023	$1.49
Waste disposal	ton	8.30	1.138	$9.45
Auxiliary power	kWh	0.0242	1109.01	$26.84
Total variable operating costs				$145.88

Total planned operating hours for demonstration	640 hours

Table 6-5: **Summary of Estimated Annual Operating Costs for DSI and Flue-Gas Humidification Systems (Duct Injection of Hydrated Lime)**

7.0 COMMERCIAL APPLICATIONS

The entire Integrated Dry NO_x/SO_2 Emissions Control System, each individual technology, and/or other combinations of the technologies are applicable to most utility and industrial coal-fired units. Compared with conventional wet scrubber or SCR technologies, this program's emissions control technologies:

- Are lower capital-cost alternatives.
- Are lower maintenance cost alternatives.
- Can be retrofitted with modest capital investment and downtime.
- Require substantially less space.
- Can be applied to units of any size, but are mostly applicable to small- to mid-sized units.
- Can reduce NO_x emissions by up to 70%.
- Can reduce SO_2 emissions by up to 70%.
- Produce a dry, solid waste product.
- Can handle all coal types, especially low- to mid-sulfur coals.

The most difficult situations to retrofit are down-fired and wet-bottom boilers. These boilers emit high levels of NO_x ranging from 1.2 to more than 2 lb NO_x/MMBtu. Currently, there is no low-cost, proven technology for reducing NO_x emissions on down-fired or wet-bottom boilers.

There are about 6,410 MWe (65 units) of down-fired-boiler capacity still operating in the U.S. Of this capacity, 45 units are coal-fired, 15 units are oil-fired, and 5 units are gas-fired. In addition, there are about 4,000 MWe of wall-fired, wet-bottom boilers that could use a variation of the Integrated Dry NO_x/SO_2 Emission Control System with the low-NO_x burners. Overall, the primary market for this emission control system is about 10,000 MWe in 94 units.

In addition, there is a secondary market of 42,000 to 72,000 MWe. Pre-NSPS boilers burning coals that produce more than 1.2 lb SO_2/MMBtu and using electrostatic precipitators (ESPs) or FFDCs that can accommodate incremental loading will be able to use the SO_2 emission control portion and, possibly, the NO_x emission control portion of the integrated process.

7.1 Low-NO_x Burners

B&W DRB-XCL® Low-NO_x Burners are a state-of-the-art and commercially available technology. However, they are configured for wall-mounted, horizontal firing. Modifying and installing these burners in a down-fired furnace will add to B&W's extensive experience with low-NO_x burners in wall-fired furnaces.

7.2 OFA Ports

B&W Dual Zone NO_x Ports® are a significant improvement over simpler designs of OFA ports and are commercially available for all boiler types. The use of these ports for the first time on a down-fired unit are a significant achievement that increases their commercial potential.

7.3 SNCR

Currently, several vendors offer urea-based SNCR systems. Noell's Arapahoe Unit 4 installation was the first demonstration on a U.S. utility coal-fired boiler. The successful demonstration of this vendor's system at this site will also help other vendors by providing data that SNCR can be successfully and economically retrofitted to older boilers.

7.4 DSI

Currently, only one vendor specifically markets sodium-based DSI systems to the utility market. While sodium-based DSI systems can successfully operate on many units, they are most marketable to units that use low-sulfur (<1%) Western fuels. The majority of the units that use these fuels currently meet the mandatory SO_2 emissions limit of 1.2 lb/MMBtu required by the 1990 Clean Air Act Amendments. However, some stations are looking for an economical technology for older units with lower capacity factors that require only small percentages of SO_2 reduction. Sodium-based DSI technology is an exceptional choice for these units and the additional data generated during this demonstration will improve the commercial potential of these systems.

7.5 Flue-Gas Humidification

Calcium-based DSI systems have a large market and may be successfully used on higher sulfur coal units. Calcium-based duct injection requires a humidification system to obtain reasonable levels of SO_2 removal. Full scale demonstration of this technology has been limited and the Arapahoe Unit 4 demonstration will provide the data necessary to commercialize this technology. Commercialization will depend on the ability of the technology to obtain SO_2 removals above 30 to 40%. The technology will be most applicable to older units that operate at low capacity factors and do not require high levels of SO_2 removal.

7.6 Integrated System

Arapahoe Unit 4 is the first integration of both sodium-based DSI and urea-based SNCR. The integration of these two technologies provides a synergistic effect that improves both technologies. PSCo has patented the integration of these technologies. Upon successful demonstration of this integration, PSCo intends to license third parties to market and install this technology. The technology is applicable to all unit types, but the major market is expected to be older units that fire a low-sulfur (<1%) coal and require both SO_2 and NO_x reduction. While this is not a large market, the significant savings that are possible over competing technologies will provide a niche market that can be filled by this technology.

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