Gas Cofiring Evaluation on a Tangential PC-Fired Boiler

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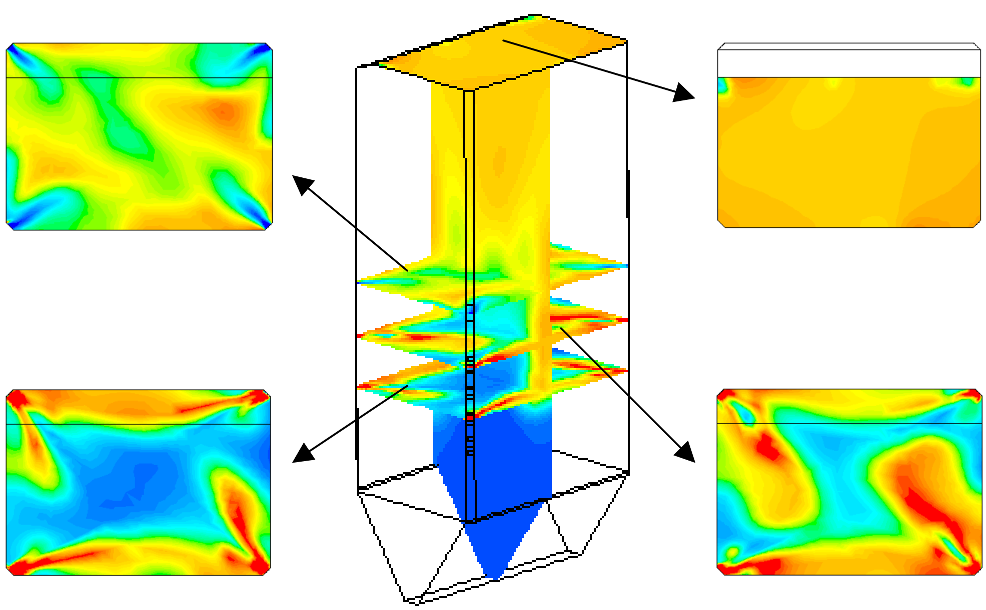

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Technology Review, December 2000

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ABSTRACT

In response to potential Title I NOx emission limitations of 0.15 lb/MBtu (64.5 mg/MJ), Dynegy Midwest Generation's (DMG) Vermilion Station desired to explore the potential effectiveness of gas cofiring through existing coal and gas burner configurations. This report summarizes the results of a test and modeling program that was implemented to evaluate the achievable NOx emission reductions on a nominal 102 MW tangential design coal-fired boiler having 100% natural gas capability. DMG owns similar units where high compliance costs bring about the need for attractive zero to low capital cost options. The central focus of the gas cofiring project incorporated field testing efforts, in parallel with numerical modeling evaluations, to provide an assessment of the NOx reduction capability. Initial field tests focused on assessing baseline operations (e.g., primary air to coal ratios, coal pipe balance, mill performance, and overfire air operation) with the goal of better defining baseline coal-fired NOx emission levels that are achievable with current equipment. Subsequent tests with natural gas cofiring were directed toward defining the achievable NOx emission reductions as a function of natural gas heat input with the current burner configurations. Baseline NOx emission levels were reduced from levels of nominally 0.32 lb/MBtu to 0.28 lb/MBtu (138 to 120 mg/MJ) through simple operational adjustments. Additional reductions are anticipated through incorporation of recommended maintenance on the mills to reduce the primary air to coal ratio. Gas cofiring through the current gas burner configurations in the uppermost (CD) auxiliary air ports exhibited limited success in achieving further reductions. Incorporation of this information into an economic evaluation indicated that the cost effectiveness of gas cofiring with the existing burner configuration was on the order of $18,000 per ton NOx removed, assuming a $2/MBtu fuel cost differential. This could be reduced to $4,200 to $4,700/ton if additional separation of the gas and overfire air ports were incorporated. However, tuning the coal delivery and combustion system offer the most effective approach.

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1
EXECUTIVE SUMMARY

1.1 Project Objectives

The central objective of the project was to develop a cost effective approach for reducing NOx emissions as close to 0.15 lb/MBtu (64.5 mg/MJ) as practical on Vermilion Unit 2, while using existing overfire air (OFA) and gas burner hardware, and not adversely affecting unit operability and reliability. Design lessons learned from the application of successful concepts on Unit 2, could then be applied to Unit 1 so as to minimize the NOx emissions from these units at the greatest possible cost effectiveness. Tasks to be performed through the project included:

1. Perform baseline tests prior to initiation of gas cofiring tests to assess changes in NOx emissions resultant from mill maintenance to reduce tramp air in-leakage.
2. Identify incremental NOx reduction that is achievable with existing gas burner hardware as a function of gas cofiring heat input.
3. Examine potential differences in NOx reduction performance as a function of the gas cofiring elevation.
4. Document changes in superheat and reheat steam temperatures, and ash Loss-of-Ignition (LOI), resultant from the use of natural gas at full load.
5. Determine whether percentage NOx reductions are consistent over the load range (70% - 100% MCR) based on the optimal gas cofiring configuration identified under full load operation.
6. Develop and implement a furnace numerical model using Computational Fluid Dynamics (CFD) to investigate additional concepts for NOx reduction not possible during field testing.

1.2 Field Test Results

A summary of results from both the baseline testing conducted in February-March 2000, and the gas cofiring testing conducted in May 2000 is provided in Table ES-1. Conclusions drawn from these tests include:

- As found operation at full load of 102 MW NOx emissions were found to be on the order of 220 ppm, dry @ 3% O_2 (ppmd), with ash LOI collected at the Electrostatic Precipitation (ESP) inlet of 4.3%. Adjustments to secondary air damper settings, as well as reductions in the primary air to coal ratios, resulted in full load NOx emissions of nominally 190 ppmd (0.29 lb/MBtu), for a nominal 14% reduction from as found emission levels. Ash LOI samples collected at the ESP inlet were found to have been reduced to levels less than 2.0%, attributable to mill adjustments identified during the baseline testing.

- As found operation at an intermediate load of 70 MW with four mills yielded NOx emissions of 348 ppmd and ash LOI on the order of 1.0%. Air biasing was able to reduce NOx emissions 30% without changes in the ash LOI levels.

- Intermediate load operation of 70 MW with three mills yielded as found NOx emissions of 295 ppmd. Baseline testing in April reduced the NOx emissions 30% to 200 ppmd through increased air biasing. Further testing in May reduced NOx emissions an additional 20% to 160 ppmd through reduced primary air to coal ratio operation. Ash LOI levels for all intermediate load tests were at 1.0% or less.

- Use of existing natural gas burners located within auxiliary air ports, in combination with OFA, only provided an incremental 5% NOx reduction with 8% heat input as natural gas. Although a zero capital approach, with a fuel price differential of $2/MBtu, the existing approach only provided a cost effectiveness of $18,000 per ton NOx removed.

- Modifying the Overfire Air (OFA) and gas injection location is projected to exhibit a cost effectiveness of nominally $4,300 per ton NOx removed. Efforts at achieving additional reductions through mill performance and combustion optimization should be pursued to define lower limits of existing operation.

1.3 Numerical Model Results

In concurrence with the field tests effort, ten CFD simulations, based on a full load condition of 102MW, were completed. The main objective included investigation of optimizing primary and secondary air flows, gas cofiring, and ultimately minor furnace modifications to create an extended reducing zone in the upper furnace. Table ES-2 summarizes the effect on NOx from applying these concepts through the CFD simulations. Based on these results, the following conclusions could be drawn:

- Improving primary air to fuel mass ratios (1.8 to 2.0) can gain up to a 12% reduction in NOx emissions. This could be achieved by optimizing primary air control hence increasing pulverizer efficiency (through improved particle fineness).
- Improved control over the primary air to coal mass ratio in combination with staging n the lower furnace to levels of 0.80 would reduce NOx emissions over the primary load range to levels between 0.20 - 0.25 lb/MBtu (86 - 107.5 mg/MJ).
- Further NOx reductions (up to 9%) could result from increasing flue gas residence time under reducing conditions. This simulation was carried out by moving the SOFA ports 10 feet higher than their current location thereby creating an extended reducing zone.
- One CFD simulation suggest that pulverized coal reburn has the potential to reduce NOx by at least 24% based on current operating conditions. Further investigation into the potential of this approach under optimized conditions was not carried out, but is highly recommended based on the projected NOx reduction cost effectiveness.

Day	Task start/end Time	Test	Test Conditions	Load (MWg)	Gas (scfm)	Mills In Serv	Boiler O2 (%)	Avg LOI (%)	Avg NOx (ppmd)
Baseline Tests									
2/28/00	0800 - 1700		Full Load Baseline Mill Test	103.6	0	4	2.38	2.45	
2/29/00	8:00 - 9:00	1	Full Load Baseline Emissions	101.8	0	4	1.95	4.31	226
2/29/00	12:00 - 14:00	2	Reduced Mill Air	102.5	0	4	1.90		222
2/29/00	14:00 - 15:30	3	Air Bias	102.3	0	4	1.60	3.09	213
2/29/00	15:45 - 16:30	4	Increased Bias	102.0	0	4	1.50		187
2/29/00	16:45 - 17:30	5	Increased Bias	104.0	0	4	1.50	2.87	191
3/1/00	08:00 - 11:30		Full Load FEGT/O2 Test	100.8	0	4	1.45		
3/1/00	12:00 - 14:00	6	Intermediate Load Baseline - 4 Mills	71.0	0	4	3.60	1.03	348
3/1/00	15:00 - 16:00	7	Air Bias - 4 Mills	71.5	0	4	2.80	0.91	235
3/2/00	09:00 - 10:30	8	Intermediate Load Baseline - 3 Mills	70.0	0	3	3.30	0.94	295
3/2/00	12:00 - 13:00	9	Air Bias - 3 Mills	70.0	0	3	3.20	0.82	203
Gas Cofiring Tests									
5/23/00	11:00 - 12:30	1	Full Load Baseline	101.6	0	4	1.97	1.41	189
5/23/00	14:10 - 15:10	2	Gas Cofiring C/D Level ; two corners	104.0	1,024	4	1.35	2.00	200
5/23/00	17:00 - 17:30	3	Gas Cofiring A/B Level ; three corners	104.8	1,505	4	1.51		204
5/24/00	10:10 - 11:00	4	Gas Cofiring C/D Level ; four corners	106.4	6,628	4	1.09	3.55	189
5/24/00	13:00 - 13:50	5	Gas Cofiring C/D Level ; four corners	105.8	5,979	3	1.01	3.42	164
5/24/00	14:00 - 14:30	6	Gas Cofiring C/D Level ; four corners	105.8	5,887	3	1.03		151
5/24/00	15:45 - 16:30	7	Gas Cofiring C/D Level ; four corners	105.8	3,110	3	1.37	3.27	169
5/25/00	23:45 - 00:45	8	Intermediate Load Gas Cofiring	65.0	2,996	3	3.30	0.80	149
5/25/00	01:30 - 02:00	9	Intermediate Load Gas Cofiring	69.0	1,969	3	3.44		146
5/25/00	02:30 - 03:10	10	Intermediate Load Gas Cofiring	68.7	1,092	3	3.55		152
5/25/00	03:30 - 04:20	11	Intermediate Load Baseline	65.2	0	3	3.48	0.77	163

Table ES-1
Summary of Baseline OFA and Gas Cofiring NOx Emission and Ash LOI Results

Item	Concept	Approach	Reference* (ppmd)	Modification Result** (ppmd)	ΔNOx	Cases or Tests Compared†
1	Effect of optimizing PA/F ratio	CFD: Reduce current condition from range of 2.5-2.8 to 2.0	240	212	-12%	3, 4
2a	Effect of Primary Zone Stoichiometry	OFA Field Test: Staging PZS from 0.81-> 0.75 (Feb. 2000)	226	190	-16%	1, 5
2b		CFD: Ultimate Staging PZS decreased from 0.81 -> 0.65 (must evaluate corrosion potential)	245	176	-28%	1, 2
2c		CFD: Revised burner fluid mechanics, PZS increased from 0.81 -> 0.87	212	260	+23%	4, 5
3	Effect of increasing Residence Time	CFD: move SOFA ports 10 ft. higher	245	195	-20%	1, 6
4a	Effect of Gas Cofiring	CFD: direct comparison to baseline	240	166	-31%	3, 9
4b		Gas Cofiring Field test: 15% gas heat input (May 2000)	183	159	-13%	1, 7
5	Effect of Pulverized Coal Reburn	CFD: Fire PC through existing SOFA ports	240	183	-24%	3, 10
6a	Combinations	CFD: move SOFA ports 10 ft higher + optimize PA/F ratios	240	192	-20%	3, 8
6b		CFD: net gain in NOx reduction from moving SOFA ports	212	192	-9%	4, 8
6c		CFD: Moved SOFA ports + optimized PA/F ratios + PZS inc. 0.81 -> 0.88	231	260	+13%	5, 7

* The reference value is not necessarily the CFD baseline as comparisons are made so that only one parameter is varied

** This is the result of applying the modification described in the approach column.

† Field tests and simulations are not mutually compared

Table ES-2
Summary of Conclusions Drawn From Comparative Analysis of CFD Simulations.

1.4 Recommendations

A screening level assessment of the associated economics for implementing different NOx reduction approaches indicate that combustion modifications provide the best cost effectiveness in achieving incremental NOx reductions (Section 6). Minimal cost modifications that could consistently achieve NOx emission levels over the load range include:

- Maintenance of mills to minimize tramp air inleakage, in combination with changes in primary air control curves to limit air to coal mass ratios to values of nominally 1.8. It should be noted, that with 50% of the coal moisture driven off during the pulverization process within the mill, the air to coal mass ratio increases to 2.0.

- Increased staging of the lower furnace can result in further NOx reductions, although numerical modeling projects increases in Unburned Carbon (UBC) to levels over 10%. In addition, the potential for increased water wall wastage from coal sulfur should be taken into account.

- Significant reductions in NOx emissions can be made over the load range by maintaining a consistent level of staging and primary air to coal mass ratios, subject to constraints imposed by mill coal drying and coal pipe transport velocity requirements.

- The limited residence time between the windbox and Separated Overfire Air (SOFA) ports constrains the NOx reduction effectiveness of the existing OFA ports, as well as the results obtained from gas cofiring. An assessment of upper furnace plug flow residence time indicates that there is sufficient space to increase the SOFA port separation. Based on numerical modeling, increases in the SOFA separation can lead to 10% - 20% additional NOx reductions, assuming similar levels of staging, while not adversely impacting UBC or CO emissions. Increases in the SOFA air capacity would enable further NOx reduction capability, albeit further increases would need to be tempered by water wall wastage evaluations.

- The use of natural gas for trimming NOx does not appear to provide NOx reduction cost efficiencies less than $18,000 per ton NOx removed. The use of existing natural gas burner locations result in the rapid combustion of a large fraction of gas that is introduced due to the close proximity of combustion air. An assessment of a gas reburn geometry similar to that implemented at Greenidge Station (100 MW corner fired boiler), indicates that the potential exists to improve the cost effectiveness to nominally $4,300 per ton NOx removed, based on a 30% NOx reduction to 0.20 lb NOx/MBtu (86 mg/MJ), at 8% heat input as natural gas, and assuming a $2/MBtu fuel cost differential.

2 INTRODUCTION

2.1 Background

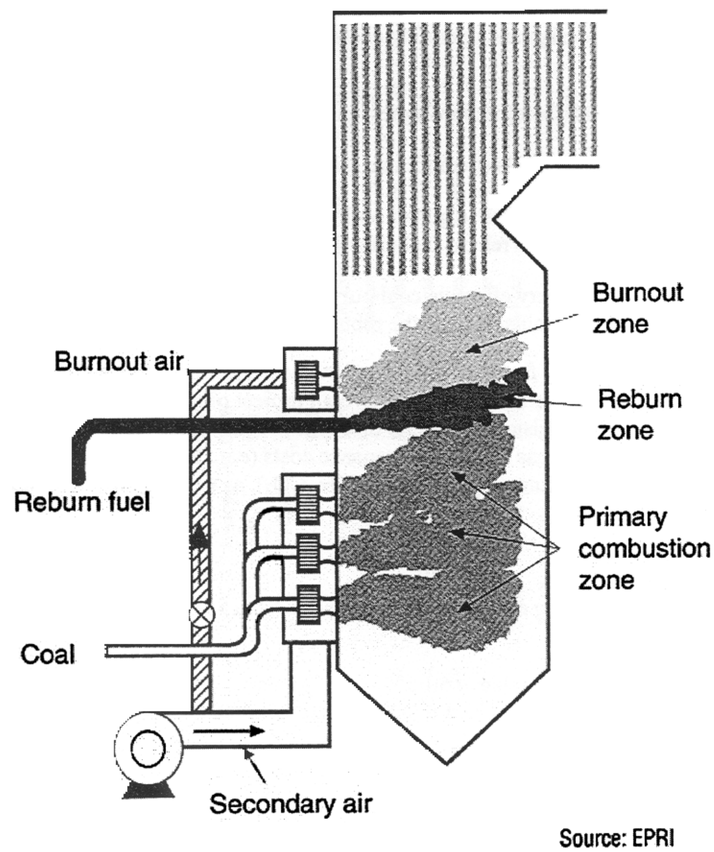
A basic knowledge of NOx formation is beneficial to understanding how NOx control technologies affect emissions. NOx is collectively comprised of two compounds: nitric oxide (NO) and nitrogen dioxide (NO_2). NO is the predominant compound found in NOx at the stack and typically accounts for 95% to 98% of the total NOx emitted from fossil fuel-fired boilers. The combustion process involves three main sources of NOx: (1) fuel NOx, which refers to the conversion of chemically bound nitrogen in the fuel, (2) thermal NOx, which refers to the high temperature reaction of nitrogen and oxygen in the combustion air, and (3) prompt NOx, which refers of the rapid formation of NOx in the flame front due to reactions between hydrocarbons and atmospheric nitrogen. Because most of the baseline NOx is formed via fuel and thermal related reactions, control techniques typically concentrate on reducing these forms of NOx.

Fuel NOx generally arises from the oxidation of organically bound nitrogen compounds associated with coal. Only a fraction of the fuel nitrogen is converted to NOx, with the conversion rate decreasing as the nitrogen content increases. Bituminous and subbituminous coals within the continental United States exhibit a relatively narrow range of fuel nitrogen levels, typically between 1.0% to 1.7%. Relatively insensitive to flame temperature, the most significant property affecting fuel nitrogen conversion is the availability of oxygen to react with the fuel nitrogen compounds in their gaseous state. Thus, the principal control measure for fuel nitrogen conversion is staged combustion in which a fuel rich zone is initially created to limit fuel nitrogen oxidation to nitric oxide. After reduction of the fuel nitrogen species to molecular nitrogen, the balance of the combustion air can then be added.

Thermal NOx is dependent upon the reaction temperature, local fuel and oxygen stoichiometry, and residence time at the peak reaction temperature. During combustion, high temperatures dissociate nitrogen and oxygen in the air, leading to the formation of NOx according to a set of reactions referred to as the extended Zeldovich mechanism. NOx formation increases exponentially with temperature, becoming significant above 2800°F (1538°C). Thus, formation of thermal NOx is best controlled by reducing the temperature, and less importantly, reducing the concentration of available oxygen, and/or the residence time at the peak temperature.

Reburning can be accomplished by injecting coal, oil, natural gas, and potentially other fuels, above the primary combustion zone within the furnace to create a reducing zone (reburn zone). A schematic of the reburn process is depicted in Figure 2.1. In conventional reburn, the reburn fuel typically accounts for 10-20 percent of the boiler's total fuel heat input. To ensure a reducing atmosphere in the reburn zone, the fuel is added with insufficient air to fully complete combustion. Additional OFA, or burnout air, is added to burn the remaining fuel prior to the gases exiting the furnace.

Figure 2.1
Conventional Reburn System Process Schematic, (TR-102906, 1993)



The potentially attractive Fuel Lean Gas Reburn (FLGR) process was developed by the Gas Research Institute (GRI) and Energy Systems Associates (ESA) with the objective of minimizing capital and operating costs for a system with a NOx-reduction capability of about 40%. Key features of FLGR include:

- Lower amount of reburn gas (5-8% of total heat input)
- Injection of gas into the furnace through numerous gas jets that use their natural turbulence to create fuel-rich "eddies"
- No need for overfire air, because overall lean furnace conditions are maintained

At two full-scale demonstrations of FLGR, nominal 40% NOx reductions were achieved. CO emissions were the main factor limiting the NOx reduction capability, suggesting that optimization of the gas injectors will be key to improved performance. EPRI reports TR-102906 (1993) and TR-102906-Addendum (1997) provide a good overview of reburning technology. Good sources for recent technical papers include the Proceedings of the 1998 American Power Conference, and The Institute of Clean Air Companies (ICAC) Forum '98.

2.2 Acronyms and Abbreviations

The following acronyms and abbreviations are used throughout this report:

CEGRIT	Automatic Flyash Sampler
CFD	Computational Fluid Dynamics
FGR	Flue Gas Recirculation
FLGR	Fuel Lean Gas Reburn
HVT	High Velocity Thermocouple
kg/s	kilogram per second
kJ/kg	kiloJoule per kilogram
kPa	kiloPascals
kWh	kilowatt hour
lb/MBtu	Pounds per Million Btu
LOI	Loss-on-Ignition (used in reference to ash laboratory test)
mg/MJ	milligram per Million Jule
OOS	Out-of-Service
PA	Primary Air
PA/F	Primary Air to Fuel Mass Ratio
PC	Pulverized Coal

ppm	Parts per Million, volumetric basis
ppmd	Parts per Million, volumetric basis normalized to 3% excess O_2
PZS	Primary Zone Stoichiometry
SA	Secondary Air
scfm	Standard Cubic Feet per Min
SOFA	Separated Overfire Air
SR	Stoichiometric Ratio
UBC	Unburned Carbon (used in reference to CFD predictions of unburned carbon alone)

3
UNIT DESCRIPTION

Vermilion Unit 2 is a balanced draft tangentially fired boiler capable of a maximum continuous output of nominally 102 MWnet. The unit is designed to provide 740,000 lb/hr (93.24 kg/s) steam at 1,650 psig (11,376 kPa) with 1,005°F (541°C) design superheat and reheat temperatures. The unit is not equipped with flue gas recirculation (FGR), but does have spray attemperation available for steam temperature control. Due to difficulties in maintaining reheat steam temperatures, however, spray attemperation is rarely required. The furnace cross-section measures nominally 34 feet (10.36 m) wide and 24 feet (7.32 m) deep. There are four elevations of burners fed by four No. 633 Raymond Bowl Mills. Each intermediate auxiliary air compartment is also equipped with two Tampella gas spuds, twenty-four in total, that allow attainment of full load on natural gas.

In order to comply with a Title IV emissions averaging plan, the unit was retrofitted with NEI/ICL low NOx burners and overfire air (OFA) in 1994. Designed and built in 1956, the unit exhibits above average upper furnace residence time, with 42.5 feet (12.95 m) between the top burner elevation and the furnace nose. Individual ducts from each corner of the windbox feed each of the separated OFA ports. Each port is nominally 8 feet (2.44 m) above the top of the windbox, thereby limiting the plug flow residence time within the reducing zone to nominally 350 milliseconds. Based on a furnace exit gas temperature at full load of 2,200°F (1204°C), the plug flow upper furnace residence time is on the order of 1.60 seconds. It should be noted that a high velocity thermocouple (HVT) traverse across a line of site near the nose of the furnace exhibited an average temperature of 2,190°F (1199°C). Based on NEI design specifications, the maximum OFA flow is rated at 227,250 lb/hr (28.63 kg/s) through dual 1.15 square foot (0.1068 m^2) cross-sectional area SOFA nozzles in each corner. The system was designed to achieve a NOx emission guarantee of 0.40 lb/MBtu (172 mg/MJ), with stack CO emissions less than 150 ppmd, and LOI levels less than 4%.

Figure 3.1 depicts the corner fired furnace and the burner ports arrangement. Note that coal elevations are labeled from A-D from lowest to highest. Auxiliary air ports are labeled AB, BC, and CD to denote its location between the nearest coal elevation. For example, Aux air AB lies between coal nozzles A and B. AA and DD ports provide the offset air at the lowest and highest points of the burner box respectively.

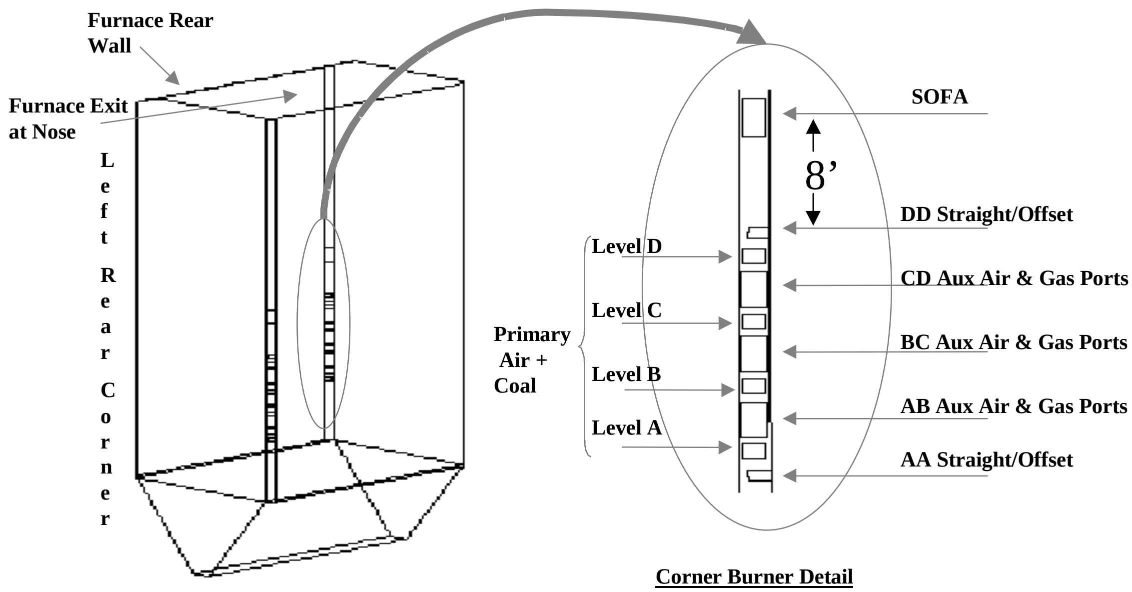


Figure 3.1
Burner Detail for Vermilion Unit 2

An analysis of the fourth quarter 1999 CEMS common stack data during periods when Unit 1 was not operating, indicate that the average Unit 2 NOx emissions are nominally 0.35 lb/MBtu (151 mg/MJ). As shown in Table 3.1, the full load NOx emissions range from a value of nominally 0.30 lb/MBtu (129 mg/MJ) at full load, to values in excess of 0.5 lb/MBtu (215 mg/MJ) at low load. The increased NOx emissions at low load result from the need to increase the excess oxygen levels to maintain steam temperatures. Data from testing also indicates that the primary air to coal ratio increases significantly on this unit as the load is reduced.

The station coal supply is delivered to the plant from a local Illinois mine. An average coal analysis from the four days of testing is provided in Table 3.2. The coal is partially washed and blended with mine run to maintain a 12% maximum ash content. LOI samples reportedly run less than 2% by weight based on samples obtained at the economizer outlet with a CEGRIT sampler.

Table 3.1
Vermilion Unit 2 CEMS NOx Data

Low End Load (MWg)	High End Load (MWg)	Mid-Point Load (MWg)	Operating Time (Hrs)	Average NOx (lb/MBtu)
0.0	11.2	5.6	0	
11.2	22.4	16.8	2	0.80
22.4	33.6	28.0	11	0.60
33.6	44.8	39.2	34	0.49
44.8	56.0	50.4	14	0.43
56.0	67.2	61.6	35	0.38
67.2	78.4	72.8	267	0.35
78.4	89.6	84.0	119	0.32
89.6	100.8	95.2	58	0.30
100.8	112.0	106.4	26	0.28
			566	

The ESP on the unit is undersized due to its 1974 vintage design for high sulfur coal and current use of a washed medium sulfur coal. There is no flue gas conditioning on the unit, which typically operates at 18% opacity at minimum load and 25% opacity at full load. The station has a common stack with a 30% opacity permit limit based on a 6-minute average. Ash from the ESP is ponded. It should be noted, however, that the ESP has been recently rebuilt with significant improvement on opacity performance expected.

Table 3.2
Vermilion Unit 2 Average Coal Analysis for As-Received Illinois Bituminous Coal

Parameter	Value
Heating Value (Btu/lb)	10,671 (24,830 kJ/kg)
Total Moisture	14.98%
Total Ash	11.04%
Volatile Matter	30.94%
Sulfur	2.01%
Nitrogen	1.24%
Stoichiometric Air/Fuel Ratio	8.09 lb air / lb coal

4
FIELD TESTING

4.1 Approach for OFA Tests

The first phase of the project was directed toward establishing a tuned baseline set of data under overfire air (OFA) operation. These efforts were comprised of the following three tasks (1) site visit, (2) test plan preparation, and (3) field test. The site visit was conducted in late January 2000 to assess current equipment condition and unit operation. Physical port access on the unit was also documented to determine the feasibility of potential measurements to be collected during the field test portion of the task. As no dirty air coal flow tests had ever been conducted on this unit, two-inch ball valves were recommended to be added on each coal pipe at the turbine deck elevation to enable coal balance and primary air/coal ratio determinations. A test matrix was prepared to define the current operating limits of the unit under staged operation with OFA with respect to steam temperature and/or unburned carbon levels. The test plan was carried out during the week of February 28, 2000.

The general approach for the testing was two fold. The first objective was to document current mill operation and performance based on coal pipe sampling tests under full load operation. The second objective was to ascertain additional NOx reductions that could be achieved through increased air biasing, while monitoring the economizer outlet LOI and Carbon Monoxide (CO) levels. As the NOx emissions were observed to increase markedly at reduced loads, a series of tests were also set up to explore the NOx reduction potential over the intermediate load range through increased air biasing.

4.2 OFA Test Results

A summary of the NOx emission and ash LOI results obtained at the ESP inlet are provided in Table 4.1. To assist in the interpretation of the results, a summary of the windbox damper positions by elevation are provided in Table 4.2. It should be noted that due to the common stack, unit specific emissions data were not collected on February 28, as the focus of the test crew was on the collection of the coal pipe data.

Table 4.1
Summary of NOx Emissions and LOI Results

Day	Task start/ end Times	TEST #	Condition	Load %MCR	Mills in Service	Excess Oxygen	LOI %			NOx ppm @ 3% O2, dry		
							West	East	Avg.	West	East	Avg.
2/28/00	0800 - 1700		Baseline Mill Test	100	4	Normal			2.45			
2/29/00	8:00 - 9:00	1	Baseline Emissions	100	4	Normal	4.19	4.42	4.31	230	222	226
2/29/00	12:00 - 14:00	2	Reduced Mill Air	100	4	Normal				232	211	222
2/29/00	14:00 - 15:30	3	Air Bias	100	4	Normal	2.65	3.52	3.09	220	206	213
2/29/00	15:45 - 16:30	4	Increased Bias	100	4	Normal				201	172	187
2/29/00	16:45 - 17:30	5	Increased Bias	100	4	Normal	2.65	3.08	2.87	188	194	191
3/1/00	08:00 - 11:30		Full Load	100	4	Normal						
3/1/20	12:00 - 14:00	6	Baseline	70	4	Normal	1.09	0.97	1.03	351	344	348
3/1/00	15:00 - 16:00	7	Air Bias	70	4	Normal	0.87	0.95	0.91	232	237	235
3/2/00	09:00 - 10:30	8	Baseline	70	3	Normal	1.03	0.84	0.94	301	288	295
3/2/00	12:00 - 13:00	9	Air Bias	70	3	Normal	0.81	0.83	0.82	206	200	203

Table 4.2
Damper Settings during Field Tests

Date Time Condition Test	28-Feb 12:00 Baseline Mill Tests	29-Feb 8:30 Baseline Emissions 1	29-Feb 13:20 Reduced Prim Air 2	29-Feb 15:00 Full Load Bias 1 3	29-Feb 16:15 Full Load Bias 2 4	29-Feb 17:00 Full Load Bias 3 5	01-Mar 9:00 Int Load 4 Mill Base 6	01-Mar 12:40 Int Load Air Bias 7	02-Mar 9:30 Int Load 3 Mill Base 8	02-Mar 12:50 Int Load Air Bias 9
SOFA A	100	100	100	100	100	100	100	100	100	100
SOFA B	90	90	90	90	90	90	90	90	90	90
DD	32	21	32	37	25	44	21	76	30	89
D	48	46	24	24	20	20	44	10	41	11
CD	32	20	32	36	25	25	22	11	21	18
C	45	46	27	26	23	23	41	13	41	14
BC	35	24	36	40	29	28	24	14	25	20
B	47	46	26	26	21	20	44	12	43	12
AB	33	21	33	22	25	25	21	11	43	16
A	40	39	24	24	18	18	42	10	3	4
AA	33	22	32	24	27	26	23	12	5	3
WB/Furn	2.0	2.8	2.4	2.4	2.8	2.8	2.4	1.8	1.5	1.5

4.2.1 Coal Pipe Tests

A detailed overview of the coal pipe tests conducted by Innovative Combustion has been included in Appendix A. The scope of the coal pipe tests was to perform baseline isokinetic coal sampling to ascertain pulverizer airflow, fuel balance, dirty air balance as well as to collect representative coal samples for fineness analysis. Additional dirty air traverses were also conducted at reduced exhauster damper openings to evaluate unit operation with reduced pulverizer airflow. In summary, full load air to fuel mass ratios were found to range between 2.6 – 3.0 pounds of air per pound of coal. Optimum and design primary airflow on deep bowl mills is 1.8 pounds air per pound coal at the pulverizer inlet, which translates to nominally 2.0 pounds of air per pound of coal in the burner lines with partial coal moisture vaporization in the mill.

The pulverizer airflow was reduced from normal operating conditions by closing the exhauster dampers on 2A and 2B pulverizers. The reduction in pulverizer primary airflow that could be achieved was limited by mechanical stops on the exhauster dampers. As a consequence of the physical stop limitation, primary airflow could only be reduced by nominally 10%, with burner line air to fuel ratios being in the range of 2.5 – 2.6 pounds of air per pound of coal. These excessive primary air flow rates constrained the achievable NOx reductions with combustion modifications, as the increased oxygen partial pressure in the near burner zone tends to increase the fuel nitrogen conversion to NOx as the coal devolatilizes.

4.2.2 Baseline As-found Emissions

Full load NOx emissions of 226 ppmd were measured at the ESP inlet under as-found operating conditions. As noted in Table 4.2, however, there was some variability in the auxiliary air damper set points between shifts. The auxiliary air dampers were closed nominally 10%, to 25% open for Test 1, relative to the 35% open recorded during the mill tests the previous day. This point is made as the baseline value against which other measurements will be compared already reflects some degree of staging. Baseline LOI values were on the order of 4.3% based on isokinetic sampling at the ESP inlet and 2.4% from samples obtained at the economizer outlet with the CEGRIT sampler. In furnace CO measurements were obtained with a single HVT traverse through a boiler view port a few feet from the boiler nose. These measurements ranged from 60-122 ppmd, as compared to zero CO levels measured downstream at the ESP inlet.

4.2.3 Full Load Emission Tests

Initial tests focused on documenting the impact of the increased primary air flow on NOx emissions. Test 2 minimized the primary airflow, with the mills placed in manual operation by having the exhauster dampers closed against the physical stops. As indicated in Table 4.1, insufficient reductions in primary air were not achievable due to the constraints imposed by the physical stops. NOx emissions were only marginally reduced on the order of 2%. In Test 3, the secondary air windbox compartment dampers were closed from a nominal 45% open position to 24% open. As noted in Table 4.1, this reduction in primary and secondary air was not of sufficient quantity to significantly affect the NOx emissions, with 213 ppmd being measured, representing only a nominal 6% reduction.

Subsequent tests (Tests 4 and 5) increased the lower furnace staging through further reductions in the lower furnace auxiliary air damper settings, and increases in the DD auxiliary air damper at the top of the windbox (reference Figure 3.1). These tests resulted in NOx emission reductions on the order of 16% (190 ppmd). No significant changes in the ash LOI were observed, with measurements yielding values between 2.9% - 3.1%. No CO emissions were detected providing further indication that complete burnout was being achieved within the furnace.

4.2.4 Intermediate Load Emission Tests

As the NOx emissions were observed to increase at reduced loads (i.e., 70% maximum continuous rating (MCR)), and the unit has historically spent almost 50% of its operating time at this load interval, additional testing focused on the achievable NOx reduction at this operating load. In addition, dirty air burner line tests were conducted to document the air to coal mass ratios at 70% of MCR. Measurements indicated that mill operation at reduced loads results in the primary air flow being essentially unchanged. As the coal flow is reduced with four mill operation, the primary air to coal mass ratio results in values exceeding four to one. Tests 6 through 9 explored the impact of these high primary air to coal ratios on NOx emissions by operating the unit at identical loads, but with four mills in operation in Tests 6 and 7, and three mills in operation in Tests 8 and 9. As indicated in Table 4.1, the baseline NOx emissions were reduced by 15%, from 348 ppmd in Test 6, to 295 ppmd in Test 8. The reduced coal throughput of the mills in Test 6 yielded ash LOI values of nominally 1%. Although the coal throughput was comparable to full load conditions with three-mill operation in Test 8, ash LOI values were also only on the order of 1%.

Increased staged operation of the unit in Tests 7 and 9 was implemented through reductions in all of the auxiliary and fuel air dampers to nominally 15% open, with the exception of DD auxiliary air, which was opened to 75% - 90%. Resultant NOx emissions under both three and four mill operation were reduced nominally 30% relative to their respective baselines. No changes were observed in the ash LOI samples obtained, with both tests exhibiting values comparable to intermediate load baseline of less than 1%. CO emissions were also negligible, indicative of complete burnout occurring within the furnace.

4.3 Approach for Gas Cofiring Tests

For the second phase of the project, a test plan (see Appendix B) was prepared with the objective of addressing the following list of questions/issues regarding the application of gas cofiring on Vermilion Unit 2:

- Under normal full load staged operation, identify the incremental NOx reduction that is achievable as a function of the level of gas heat input (three tests over a range of gas heat inputs from nominally 2.5% - 7.5%).

- Identify any incremental differences in NOx reduction as a function of the gas cofiring elevation (AB, BC, or CD).

- Document any changes in superheat and reheat steam temperatures, as well as ash LOI content, that result from the use of natural gas at full load based on steam temperatures collected from the DCS, and particulate samples collected at the ESP inlet.

- Document percentage NOx reductions over the load range (70% - 100% MCR) based on the optimal gas cofiring configuration identified under full load operation and compare to baseline operation in order to define a NOx reduction cost effectiveness in $/ton NOx removed.

As indicated in Table 4.3, the first test was directed toward re-establishing the full load baseline staged operation of the unit with improved primary air/coal ratios. The reduced primary air flow rates were achieved through the use of weights on the barometric air damper arms.

The second and third tests investigated potential differences in the effectiveness of gas cofiring based on the gas injection elevation. Test 2 introduced nominally 7.5% of the full load heat input as natural gas at C/D aux air port elevation (see Figure 3.1), while Test 3 replicated this test with natural gas introduction at the lower A/B aux air port.

A shift in test focus was made when little NOx reduction was realized from these initial tests due to rapid mixing between the natural gas introduced through spuds located in the auxiliary air ports and surrounding combustion air. Test 4 maximized staging in the vicinity of the natural gas introduction, as well as the level of natural gas heat input, in an effort to ascertain NOx reduction potential at extreme levels of gas use. Tests 5 – 7 removed Mill D from service, while maintaining full load with natural gas heat input. The tests explored the potential benefit of increasing the residence time within the reducing zone, horizontal tilts, and the effectiveness at a test condition that minimized gas use while maintaining full load operation. Finally, Tests 8 – 11 documented staged intermediate load operations over a range of natural gas heat inputs in comparison to baseline operation.

4.4 Test Results

4.4.1 Mill Primary Air Curves

In order to exert tighter control over the primary air to coal ratios, dirty air velocity data from the mill tests conducted by Innovative Combustion Technologies (ICT) in early May 2000 were curve fitted against the mill discharge pressure. A summary of the curve fitted data is provided in Appendix A (Figures A-1.1 through A-1.4. The general philosophy adopted for each test was directed toward minimizing the primary airflow rate while maintaining the bulk coal pipe velocity above the settling velocity. Primary air through the tempering air damper was minimized through installation of weights on the damper arm. In general, the mill primary air to coal mass ratios at full load ranged between 1.7 – 2.2. Reduced mill loading due to natural gas cofiring, or intermediate load operation, resulted in increased mass ratios on the order of 2.3 – 3.1, due to the inability to eliminate tramp air in-leakage and reduce primary air further. It should be noted that there was insufficient time and manpower to implement all of the maintenance action items identified by ICT during the mill tests in early May 2000. It is anticipated that completion of these maintenance activities would provide additional NOx reductions than those realized at the intermediate load tests.

Test	Condition	Load (MWg)	Mills In Serv	Gas (scfm)	Blr O_2 (%)	LOI (%)			NOx (ppmd, 3% O_2, dry)		
						L-West	R-East	Average	L-West	R-East	Average
1	Full Load Baseline	101.6	4	0	1.97	1.35	1.46	1.41	183	194	189
2	Gas Cofiring C/D Level ; two corners	104.0	4	1,024	1.35	1.93	2.07	2.00	191	209	200
3	Gas Cofiring A/B Level ; three corners	104.8	4	1,505	1.51				196	212	204
4	Gas Cofiring C/D Level ; four corners	106.4	4	6,628	1.09	3.18	3.91	3.55	184	193	189
5	Gas Cofiring C/D Level ; four corners	105.8	3	5,979	1.01	3.56	3.27	3.42	158	170	164
6	Gas Cofiring C/D Level ; four corners	105.8	3	5,887	1.03				140	162	151
7	Gas Cofiring C/D Level ; four corners	105.8	3	3,110	1.37	3.35	3.19	3.27	159	179	169
8	Min Load Gas Cofiring	65.0	3	2,996	3.30	0.79	0.80	0.80	143	154	149
9	Min Load Gas Cofiring	69.0	3	1,969	3.44				142	150	146
10	Min Load Gas Cofiring	68.7	3	1,092	3.55				148	156	152
11	Min Load Baseline	65.2	3	0	3.48	0.83	0.70	0.77	159	166	163

Table 4.3
Summary of NOx Emissions and Ash LOI Results Obtained at the ESP Inlet during the Second Field Test Campaign

4.4.2 Full Load Baseline Results

A summary of the NOx emissions and ash LOI results obtained at the ESP inlet is provided in Table 4.3. To assist in the interpretation of the results, a summary of the windbox damper positions by elevation for each test is also provided in Table 4.4. A staged baseline test with primary air to coal ratios reduced to nominally 2 pounds air per pound coal resulted in NOx emissions of 189 ppmd. This result confirms the full load NOx levels achieved on February 29, 2000 during Tests 4 and 5. By reference, NOx levels of this magnitude correspond to roughly 0.28 lb/MBtu (120 mg/MJ) for this particular fuel.

Lower furnace stoichiometries were estimated to range between 80% - 90% of theoretical air (Appendix C). Additions of natural gas through spuds located at the C/D and A/B auxiliary air port elevations (Tests 2 and 3, respectively), while maintaining similar baseline secondary air damper positions, were not successful in achieving further reductions in NOx emission levels, and in practice, actually increased NOx emissions by 5% - 7.5%. In spite of the lower furnace being overall reducing, however, a review of the estimated secondary air flows through the C/D auxiliary air port (Appendix C), indicated that 93,500 lb/hr (11.78 kg/s) combustion air was being introduced to the boiler with the damper closed from 45% to 31% open. Based on a stoichiometric air requirement for the natural gas of 17 lb air/lb fuel, the local stoichiometry with the natural gas was 0.50. Thus, as much as one-half of the natural gas was immediately combusted upon introduction into the furnace, thereby reducing the hydrocarbon concentration available to reduce NOx via reburning. In addition, the near burner combustion of the natural gas appears to have increased local temperatures, promoting the formation of added thermal NOx. As a result, subsequent tests (Tests 4 through 7) focused on minimizing air introduced in the vicinity of the gas spuds, as well as maximizing the residence time within the reducing zone.

Table 4.4
Summary of Damper Positions for May Tests

Date Test	23-May 1	23-May 2	23-May 3	24-May 4	24-May 5	24-May 6	24-May 7	25-May 8	25-May 9	25-May 10	25-May 11
SOFA B	77	77	77	90	96	96	96	96	96	96	96
SOFA A	99	99	99	99	99	99	99	98	98	98	98
DD	99	99	99	4	5	5	5	1	1	1	1
D	22	22	22	21	6	6	6	3	3	3	3
CD	31	31	31	10	10	10	7	2	2	2	2
C	23	23	23	23	24	24	24	8	8	8	8
BC	34	34	34	60	62	62	53	29	29	29	29
B	23	23	23	21	22	22	22	9	9	9	9
AB	31	31	31	57	58	58	49	28	28	28	28
A	21	21	21	21	20	20	19	9	9	9	9
AA	33	33	33	100	100	100	100	29	29	29	29
WB/Furn	4.0	4.0	4.0	2.9	2.9	2.9	3.3	2.7	2.5	2.6	2.6

Test 4 reduced the CD auxiliary air damper from 31% open to 10% open, while increasing AA, AB, and BC auxiliary air dampers to maintain a windbox/furnace differential pressure of around

3 inches water column (747 Pa), while maintaining the burner zone exit furnace stoichiometry at a nominal level of 0.8. Although NOx levels were reduced from those achieved with gas cofiring in Tests 2 and 3, it only achieved a similar NOx level as that achieved in Test 1 under baseline operating conditions.

An alternate approach was applied in Test 5 to reduce the primary air/coal ratios, and to further maximize the flue gas residence time within the reducing zone upstream of the introduction of the OFA into the furnace. The principal change was to remove D mill from service, while maintaining load with the natural gas cofiring. In addition, the D level fuel air dampers were closed from 21% open to 6%. In practice, this approach reduced the amount of air introduced in the vicinity of the natural gas from 200,000 lb/hr (25.2 kg/s) in Test 2 and 130,000 lb/hr (16.38kg/s) in Test 4, to 92,000 lb/hr (11.59 kg/s) in Test 5. The NOx emission levels were correspondingly reduced 13% relative to baseline levels in Test 1 (189 ppmd).

An increase in the burner tilts during this test to control reheat steam temperatures prompted an investigation of the impact of tilts on mixing between the natural gas within the reducing zone and the OFA. Test 6 maintained similar operating conditions with the exception of a change in burner tilts from +15 degrees to horizontal. It should be noted that the left front (LF) tilt control became inoperable, and was locked at +11 degrees throughout Tests 3 through 11. The increased residence time achieved between the upper windbox flows and the OFA streams through use of horizontal tilts reduced NOx emission levels 8% from those achieved in Test 5 (164 ppmd), or 20% below baseline levels in Test 1. An investigation of the superheat (SH) and reheat (RH) steam temperatures did not show an appreciable change, albeit the duration of the test was only on the order of 1-1/2 hours.

As these 20% NOx emission levels were achieved with 5,900 scfm (2,784 dm^3/s) of natural gas, an additional test was performed to explore the sensitivity of the NOx reductions to the percent heat input as natural gas. Test 7 reduced the natural gas flow rate to 3,100 scfm (1,463 dm^3/s), while holding all other operating conditions constant. NOx emission levels increased from 151 to 169 ppmd, representing a nominal 12% increase. As shown in Figure 4.1, the reduction in NOx emissions as a function of heat input of natural gas is a linear relationship, with reductions occurring at a rate of nominally 1 ppmd per percent natural gas.

4.4.3 Intermediate Load Baseline Results

The balance of tests (Tests 8 – 11) focused on an assessment of the gas cofiring at intermediate load. As above, the effectiveness was evaluated over a range of natural gas firing rates. Burner tilts were set in manual at +6 degrees, which matched the SOFA tilt setting. A positive setting that did not result in an intersecting trajectory with the SOFA was selected so as to minimize impacts on SH and RH temperatures. Damper settings were constant throughout the tests, with DD, D, and CD windbox dampers essentially closed, fuel air dampers for operating mills A, B, and C closed to nominal 9% open, and BC, AB, and AA auxiliary air dampers closed to 29% open. SOFA dampers were opened 100%. With the exception of the last test, a similar NOx reduction effectiveness was observed as that achieved at full load (Figure 4.2). NOx levels were observed to increase, however, at the maximum natural gas heat input levels of 26%. A review of the local air flow rates surrounding the CD auxiliary air location where the natural gas is introduced indicated the air flow rates to be essentially constant at 60,000 lb/hr (7.56 kg/s). As increases in natural gas levels would further reduce the local stoichiometry, the NOx should not increase as a result of the available combustion air in this vicinity. Further investigations of the panel data indicate that increases in the gas flow rate naturally result in a decrease in the required coal heat input to maintain a given load. Although the primary air was partially modulated as a function of the changes in coal mass flow rates, the primary air to coal ratio was found to have increased nominally 25% at the peak natural gas heat input. The change in primary air to coal ratio was only 15% for the tests at full load that varied natural gas heat input. Thus, one interpretation of the data is that the effectiveness of increased natural gas cofiring at intermediate load was offset through increased coal fuel nitrogen conversion due to increased primary air to coal ratios beyond the 2.0 – 2.4 range.

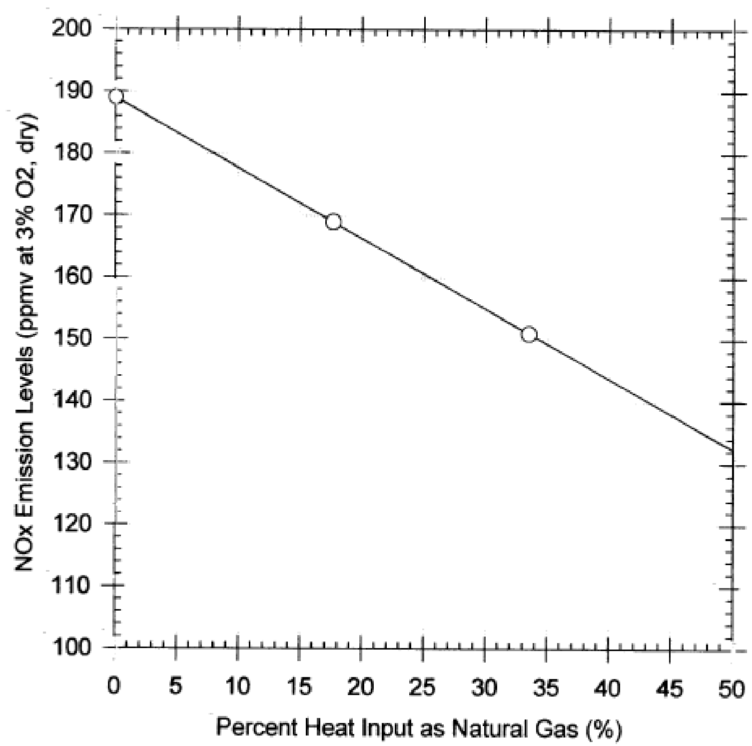


Figure 4.1
Full Load Gas-Cofiring NOx Emissions

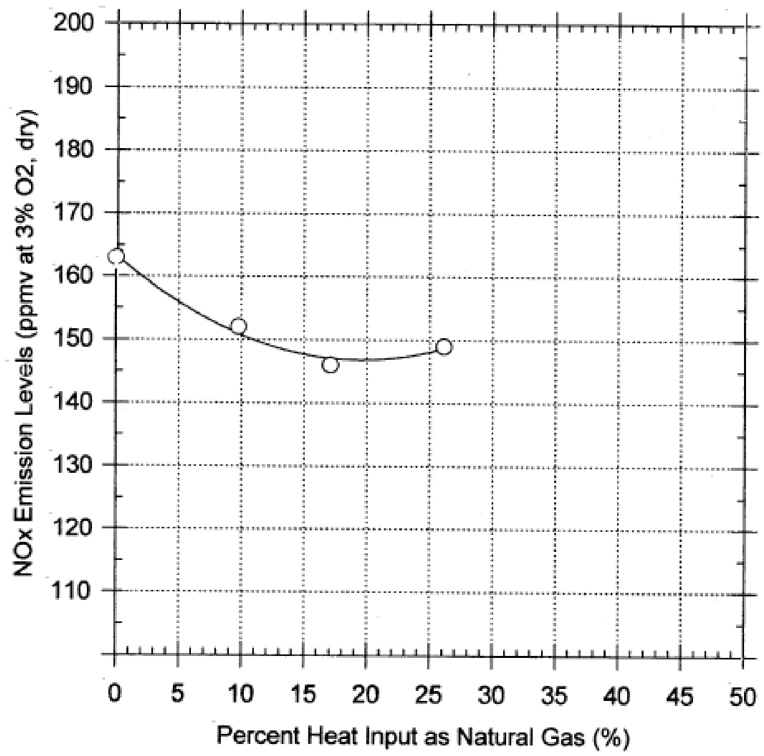


Figure 4.2
Intermediate Load Gas Cofiring NOx Emissions

5
FURNACE MODEL SIMULATION

5.0 Approach

In conjunction with the field test evaluation of Vermilion Unit 2, simulation of the furnace combustion was conducted through the use of a commercial Computational Fluid Dynamics (CFD) code. All simulations were carried out at the EPRI, Palo Alto facilities in collaboration with Airflow Sciences, Inc. The first phase of this study involved the development of a three-dimensional (3-D) furnace numerical model using the FLUENT CFD code. The second phase validated the model using as-found furnace conditions collected during the baseline field tests. The next phase of the project comprised of multiple parametric studies including:

- Effect of optimizing primary air/fuel ratio
- Effect of lowering primary zone stoichiometry (PZS)
- Effect of increased residence time through increased elevation of the SOFA ports
- Evaluation of gas cofiring using existing hardware
- Evaluation of firing pulverized coal to create a reburn zone

A systematic approach to analyze the effects of varying an individual parameter was adopted as simultaneously changing more than one parameter made interpretation difficult. As such, a total of ten case runs were carried out using a HP Kayak XU workstation operating under the Windows NT 4.0 platform. Detailed analyses are presented in Section 5.2.

Table 5.1 presents a brief description of each case along with NOx, carbon monoxide (CO), Unburned Carbon (UBC) and Furnace Exit Gas Temperature (FEGT). NOx, CO, and FEGT predictions were computed within the model by integrating (area weighed average) the horizontal plane at the furnace exit (the end of the computational domain). UBC predictions were obtained from the discrete phase model (particles) mass and energy balance report. It should be noted that the CFD model predicts the exact amount of unburned carbon that remains on the particles whereas LOI field tests incorporate unburned carbon plus other volatiles. All gas phase concentrations reported used units of parts per million on a volume basis, dry corrected to 3% O_2 (ppmd).

NO.	ID	PZS	FS	Primary Air/Fuel Ratio	NOx Reburn Model	Conditions	Purpose	NOx* ppmd	CO* ppmd	UBC %	FEGT °F
1	Baseline	0.81	1.12	2.5-2.8	N	As-found conditions	Model Validation.	245	815	6	2241
2	Maximum Staging	0.65	1.10	2.1-2.3	N	Reduced PA/F ratio and reduced BZSR	Effect of Deep Staging	176	2240	10	2235
3	Baseline with NOx reburn enabled	0.81	1.10	2.5-2.8	Y	As found conditions	Effect of NOx reburn chemistry model	240	320	2	2087
4	Optimized PA/F ratio	0.81	1.10	2.0	Y	Case 3 with lower PA/F ratio	Effect of optimizing PA/F	212	16	3	2050
5	SA Velocities	0.87	1.10	2.0	Y	SA velocities match PA.	Effect of SA velocity modification.	260	369	4	2055
6	Elevated SOFA	0.81	1.12	2.5-2.8	N	As-found except moved SOFA ports 10 ft higher than original location	Effect of increasing residence time Note No NOx reburn chemistry.	195	1220	11	2166
7	Elevated SOFA with OPA/F	0.88	1.10	2.0	Y	SA velocities match PA..	Same as case 5.	231	709	12	2125
8	Elevated SOFA with OPA/F	0.81	1.10	2.0	Y	Case 4 with PZS=0.81	Best case scenario with OPA/F.	192	10	6	2161
9	Gas Cofiring	0.73	1.10	2.0-2.1	Y	Inject gas at CD elev.	Effect of gas reburn using existing HW.	166	1143	20	2289
10	Pulverized Coal Reburn	0.95/0.82	1.10	2.5-2.8	Y	PC injection through lower SOFA location.	Effect of PC Reburn	183	3345	13	2262

PZS=primary zone stoichiometry; FS = furnace stoichiometry; PA/F = primary air to fuel ratio; *NOx & CO @ 3% O_2

Table 5.1
Summary of CFD Cases for Vermilion Unit 2

5.1 Model Description

The three-dimensional CFD model was generated from plant drawings and direct hardware measurements. Based on these resources, it was determined that the computational domain would extend from the bottom of the ash pit hopper to the narrowest flow region at the furnace nose. Figure 5.1 depicts the furnace model boundaries, fuel/air inlets and the horizontal exit plane at the nose of the furnace. Once finalized, the model included 400,000 independent cell volumes. The burner region, from just below level A through the SOFA ports, accounted for nearly 75% of the total cell volumes.

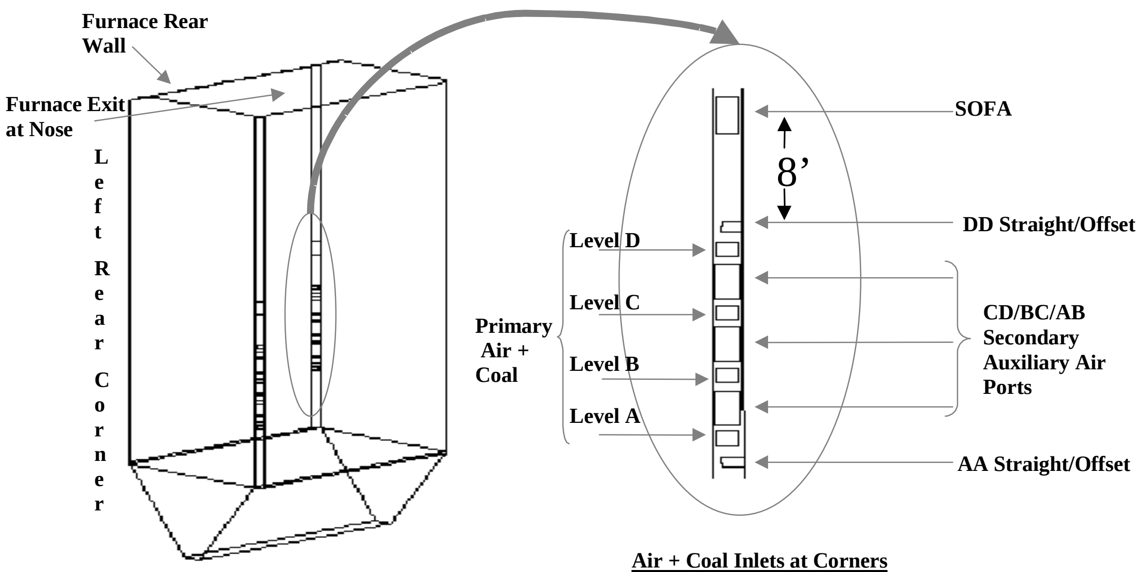


Figure 5.1
Furnace Model with Burner Detail

In order to maintain consistency in results between cases, each case was run with identical computational grids. Aside from minor modifications to the boundary inlets for the gas cofiring case and the modified SOFA and PC reburn cases; no changes to the original 400,000 cell mesh were performed.

5.1.1 Commercial Code Description

The FLUENT commercial code utilizes a cell-volume based technique to transform the governing equations, of mass, energy and momentum, to algebraic equations that can be solved numerically. The segregated solver solution to the system of equations is carried out by integrating the governing equations at each cell volume. This iterative scheme is repeated until the system yields a converged solution based on the boundary conditions supplied by the user.

5.1.1.1 Combustion Model

In general, the code uses a Reynolds-Averaged Navier-Stokes (RANS) scheme for resolving the turbulent velocity field. In this study, a standard κ–ε turbulence model along with a Semi-Implicit Method for Pressure-Linked Equations (SIMPLE) velocity coupling algorithm were used. The energy transport equation was solved using conjugate heat transfer and multi-directional radiative heat flux.

For turbulent diffusion flames, such as those produced within utility boilers, the turbulent mixing is the limiting rate for the reaction progress. As such, a mixture fraction/PDF (probability density function) approach was chosen as the most appropriate modeling technique. The basis for the mixture fraction modeling approach is that under a certain set of simplifying assumptions the instantaneous thermochemical state of the fluid is related to a conserved scalar quantity known as the mixture fraction:

$$f = \frac{Z_{\kappa} - Z_{\kappa,O}}{Z_{\kappa,F} - Z_{\kappa,O}}$$

where Z_κ is the element mass fraction for some element κ. The subscript O refers to the value at the oxidizing stream inlets and subscript F refers to the value at the fuel stream inlets. Transport equations for individual species are not solved but derived from the predicted mixture fraction distribution. The reacting system is treated using chemical equilibrium calculations and physical properties defined in the FLUENT database. Turbulence-chemistry interaction is accounted for by using a fast equilibrium PDF. This particular approach avoids the specification of numerous complex reaction mechanisms but it requires additional computation time when compared to other models (i.e., finite rate).

5.1.1.2 Handling of Fuel Particles

Solid fuel trajectories are handled by a discrete phase model based on a random walk approach. Integration of a force balance between the gas and solid phases at each cell volume determines the effect that each other exhort on the mean flow field. The particle reaction behavior includes rate expressions for its two combustible portions. In the first stage, the particle volatiles are consumed via a two competing Arrheneous rate scheme. After the volatiles are consumed, an oxygen diffusion/kinetic rate based char oxidation model is enabled. Without exception, the code tracks the particle fate from the injection point until its consumption or departure from the computational domain.

5.1.1.3 NOx predictions

Because NOx concentrations generated in combustion systems are relatively small, NOx chemistry has negligible influence on the predicted temperature and flow field. As a result, NOx concentrations are derived from a converged combustion solution through a post-processing step. The three submodels enabled for this application included thermal NOx, fuel NOx, and NOx destruction through reactions with hydrocarbons or reburn. Thermal NOx is modeled through an extended Zeldovich mechanism. Fuel NOx formation is derived from fuel bound nitrogen (N) distributed between the volatiles and char of the coal. The mechanism for the fuel NOx assumes that volatile N converts to HCN then to NO whereas all char N converts directly to NO. The reburn model reactions were enabled for the temperature range of 2420°F < T < 3320°F (1327°C < T < 1826°C).

5.1.2 Input Conditions

Parameters used to define the boundary conditions were obtained from test data collected by EPRI and Innovative Combustion personnel. This data included:

- Coal analysis from field samples (Section 2)
- Burner coal and air flow distribution as determined from dirty air tests (Appendix A)
- Secondary air distribution as calculated through windbox damper settings (Appendix D)
- Furnace exit gas temperature from full load HVT tests at the furnace nose (Appendix B)
- Flue gas composition from field testing at the economizer outlet (Appendix B)

Fuel chemistry and fuel/air distribution were determined through analysis of laboratory data and from DCS output files. Coal chemical composition was derived from average values of five coal samples obtained during the March tests. These averaged parameters were presented in Table 3.2.

Mass distribution of the primary and secondary airflow into the computational domain was controlled through 23 independent, inlet boundary conditions located at each boiler corner (92 total). This airflow distribution was derived from damper position settings obtained from DCS and analog data collected during the site tests. Secondary air flows to each windbox compartment were calculated as a function of the nozzle outlet flow area and damper position. Detailed air distribution flow tables for each simulation are shown in Appendix D.

In a similar fashion to the gas phase inlets, coal flow input to the domain was controlled by four injection levels at each furnace corner. For all the cases, each of the coal injections used a Rosin-Rammler distribution generated from the coal fineness tests. As indicated by the coal particle size analyses from each of the four mills (Figure 5.1.2), B mill yielded poor performance as compared to the other mills. From Figure 5.1.2, it can be observed that a mean average diameter of 60 microns for mills A, C and D and 92 microns for mill B was achieved. This discrepancy in mill performance was included in cases 1, 2, 3, 6 and 10. All subsequent case studies assumed a uniform particle size distribution for each mill. Coal mass flow distributions were determined from dirty air measurements.

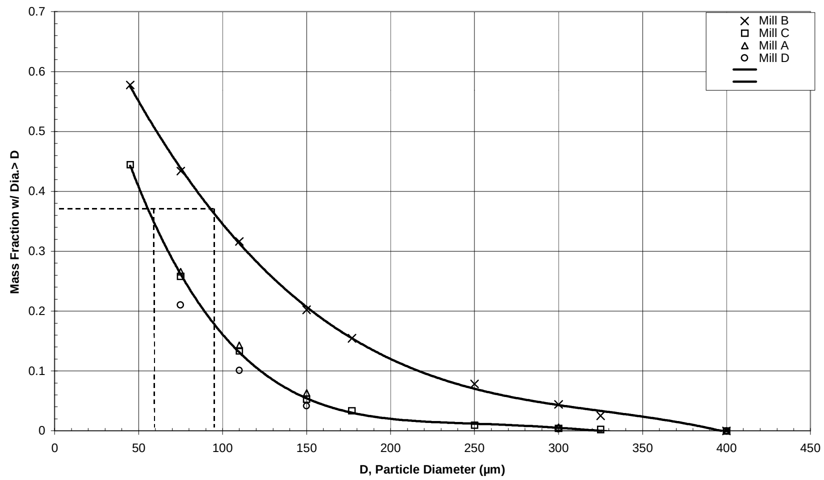


Figure 5.1.2
Particle Size Distribution Determined from Coal Samples for All Four Mills

5.1.3 Model Assumptions

In addition to the previous inputs, other assumptions and generalizations were made to facilitate the convergence of the case to a steady-state solution. These assumptions, although partially supported by the collected field data, are also frequently used for CFD modeling purposes:

1. Furnace wall temperature was assumed constant at the saturation temperature and operating pressure of the steam. (Nominally ~ 650°F (343°C)).
2. Primary air temperature was set to 150°F (66°C) (at the nozzle tip) as reported by DCS data.
3. Secondary air temperature was set to its indicated value of 530°F (277°C).
4. A relative coal distribution from each mill to its four pipes was estimated from dirty air coal tests and used as a guideline for all case runs.
5. A single HVT test, conducted at the nose elevation (exit of the computational domain), indicated a rough average of 2,200°F (1,204°C) at full load during baseline operation. Note that this was only a linear average of a single traverse test.
6. Burner tilt elevation angles were assumed horizontal, or 0° with respect to the normal.
7. Burner and SOFA yaw angles were set as determined from plant drawings (Appendix D, Figure D-1).
8. Kinetic parameters are coal specific. Due to the lack of coal kinetic experimental data for the reaction rates of volatile matter and char oxidation, literature values for a similar coal were used.

5.2 Baseline Model Results

The following sections present the results for the baseline case studies conducted. The first section compares the predicted values versus field test data. In addition, the sensitivity of the

NOx reburn chemistry model was also tested. Subsequent sections present results for the two parametric studies of interest. The first study analyzed the effect of optimizing the primary air to fuel ratio (PA/F) to a level of 2.0. The second study analyzed the effect of Primary Zone Stoichiometry (PZS) on NOx predictions.

5.2.1 Model Validation

The predictions obtained from any numerical model are only as credible as the experimental data with which they are validated. For this reason, Cases 1 and 3 simulated full load as-found conditions used during the field tests. These cases served to validate the numerical model predictions through the data collected. Table 5.2.1 compares baseline field tests with the respective model predictions:

Table 5.2.1
Predicted and Field-test Data Comparisons for As-found Conditions

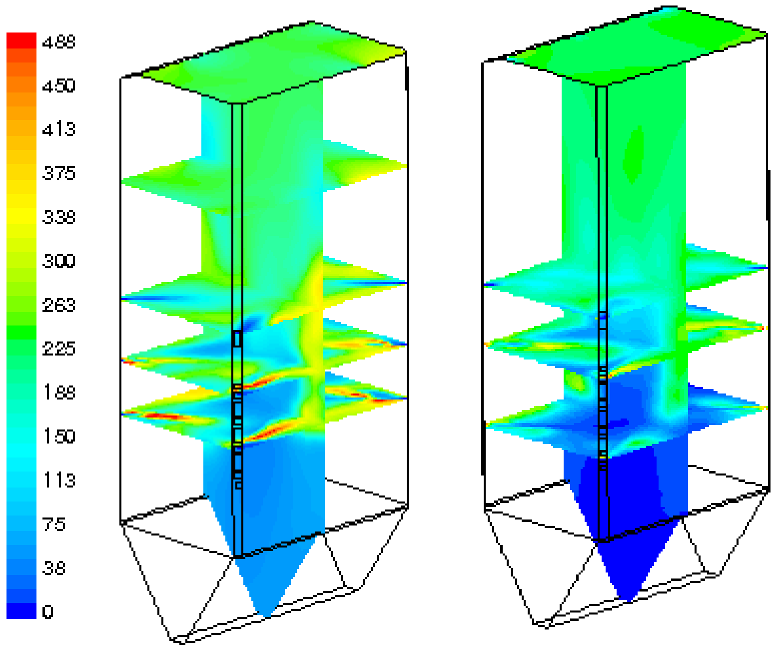
	Case 1†	Case 3†	Field Test
FEGT	2240°F (1227°C)	2087°F (1142°C)	2190°F † (1199°C)
Excess O_2%	3.1	3.3	1.9†, 2.3*
CO ppmd	815	320	75†
NOx, ppmd	245	240	230†, 226*
UBC, %	6	2	2*

† At furnace exit near nose (HVT traverse).

* At economizer outlet

As can be seen from the table, predictions for temperature, excess oxygen, and UBC fell within an acceptable range of measured field test values. Although the CO concentrations predicted by the model exceed those measured by the HVT traverse, it should be noted that the model relies upon equilibrium chemistry for predicting CO concentrations, which tends to overpredict by several hundred ppm. In addition, CO burnout continues throughout the convective cavity, thus making predicted levels at the furnace nose not representative of actual expected emission levels at the economizer outlet. Indeed, physical measurements performed during the field tests at the economizer outlet seldom indicated values greater than 10 – 20 ppmd.

For NOx concentration, direct quantitative predictions are not feasible from commercial CFD codes but direct trends between similar case studies have been successfully proven. Because of this, the predictions for the baseline case were determined by adjusting fuel NOx parameters to yield an acceptable prediction in accordance with the field-test NOx measurements. Subsequently, these settings were used for all other case runs.



CASE 1 -Without NOx Reburn
245 ppm @ 3% O_2

CASE 3 - With NOx reburn
240 ppm @ 3% O_2

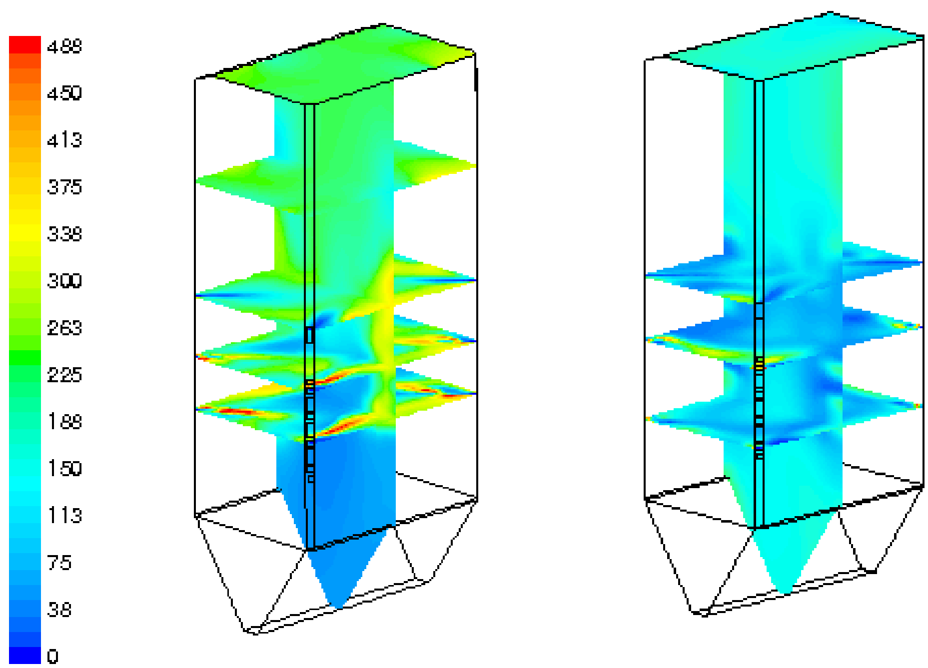
Figure 5.2.1.1
Effect of NOx Reburn Model on Baseline Cases

5.2.1.1 Effect of NOx Reburn Chemistry Model

It was determined through the course of the study, that a reburn chemistry model for the destruction of NOx under reducing conditions should be enabled for the gas cofiring case. Furthermore, since some degree of staging was present during normal plant operation, it was decided to include the NOx reburn model on all subsequent model runs, as well as to assess any impact it may have on NOx emission predictions from the baseline case. A sensitivity study was conducted to determine the effect of this model under normal operating conditions. The results obtained yielded only a 2% improvement over the initial predictions for the baseline (245 ppmd without reburn model in Case 1, and 240 ppmd with the reburn model in Case 3). NOx profiles from each of these cases are illustrated in Figure 5.2.1.1, where the principal effect of incorporation of the reburn model can be seen in the near burner zone. In summary, at least for this particular case, the NOx reburn chemistry model did not effect a significant change in predicted NOx emissions. Nonetheless, all other cases employed the NOx reburn model, with the exception of Case 6, which was run to provide a direct comparison to Case 1.

5.2.2 Effect of Reducing Furnace Stoichiometry and Excess Air - Cases 1 and 2

In order to establish a lower limit of anticipated NOx reduction potential, Case 2 was set up to investigate the effects of deep staging for maximum NOx reduction. In Case 2, all of the windbox dampers were set to 15% open. As a result, the PZS was reduced to 0.65 prior to the SOFA inlets. In addition to a reduced PZS, primary air was reduced by 15% based on field estimates of mill in-leakage. As a result, the PA/F ranged from 2.1-2.3 lb air/ lb fuel. All of these modifications maintained an overall furnace SR of 1.10. A direct comparison of NOx formation levels relative to baseline operations as represented in Case 1 is provided in Figure 5.2.2. Deeper staging effected a 28% NOx reduction from baseline operation, while predicting modest increases in UBC. CO levels were also predicted to increase at the furnace exit, as one might expect, but continued burnout through the convective pass suggest that these levels would not be problematic. However, deep staging of this magnitude is not recommended for Vermilion Unit 2 without further evaluation of potential waterwall corrosion and adoption of measures to prevent waterwall wastage (such as spray coatings, tube cladding, etc.). See EPRI Report No.TR-111155, October 1998.



CASE 1 - BASELINE
SR=1.12

CASE 2 MAX STAGED
SR=1.10

Figure 5.2.2
Comparison of NOx Predictions from Deep Staging, NOx ppmd

5.2.3 Effect of Primary Air Sensitivity – Cases 3 and 4

As discussed in sections Section 4.2.1, the PA/F ratio for this unit was found to be higher than the optimal range of 1.8 to 2.0 lb. air/lb. fuel. Case 4 investigated the effect of reducing the PA/F ratio to a more optimal range of 2.0, while keeping the overall furnace stoichiometry constant at 1.10. NOx emission contours as compared against baseline operating conditions in Case 3 are provided in Figure 5.2.3. Overall, the NOx concentration contours indicated an increase in fuel NOx near the burners but a nominal 12% decrease in NOx at the furnace nose. No significant change was predicted in UBC levels of nominally 2% - 3%, and CO levels were reduced from 320 ppm under baseline operation to 16 ppm with reduced PA/F ratios. Temperature predictions at the furnace nose remained within 1% of the baseline.

5.2.4 Effect of Primary Zone Stoichiometry(PZS) – Cases 3 and 5

Case 5 investigated the effect of increasing the PZS just enough to reduce the high shear strain created in the flow by large velocity differences between the PA to SA nozzles. It was thought that by making these velocities closer together, the reduction in shear strain would decrease the mixing between streams and enable a longer fuel core to remain rich. However, increasing SA velocities from approximately 65 ft/s to 84-88 ft/s resulted in a PZS increase from 0.81 to 0.87 (Cases 3 and 5, respectively). As before, overall furnace stoichiometry remained constant at 1.10 thereby reducing the SOFA air flow by 18% to account for the air increase in the primary zone. Figure 5.2.3 (c) depicts the NOx concentration profile for case 5 which simulated these higher SA velocity conditions. In comparison to Figures 5.2.3(a) and 5.2.3(b), NOx levels actually increased throughout the primary zone and into the upper furnace region. In contrast to Section 5.2.2, this approach did not yield a reduction in NOx concentration at the furnace exit. Rather, NOx levels increased by 8% from Case 3 predictions. CO and temperature levels changed only slightly. These case studies confirmed the predominant effect on NOx by the PZS, and the second order effect of increased air entrainment by the coal/air jet.

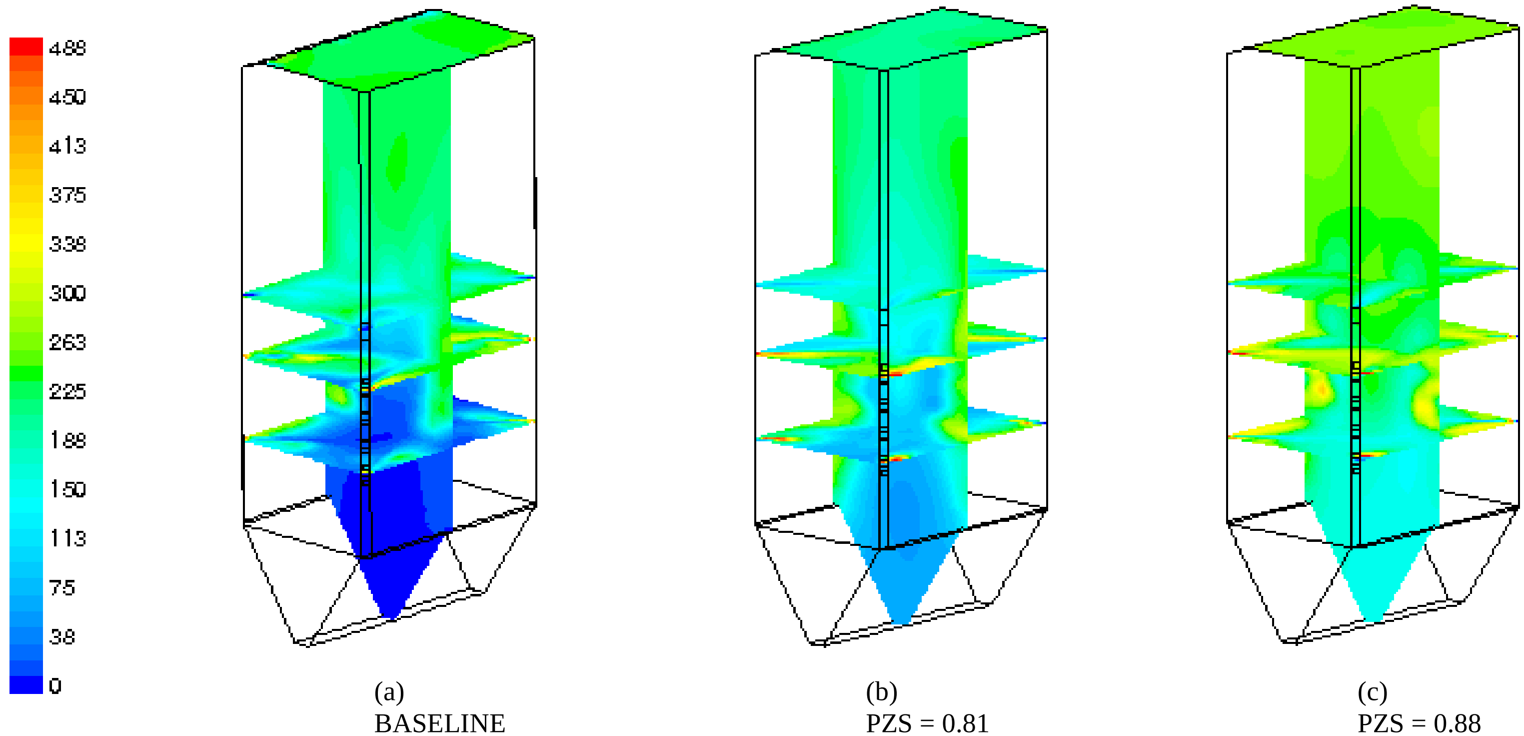


Figure 5.2.3
Isometric furnace model views for comparison of predictions for primary air optimization and primary zone stoichiometry case studies, (a) case 3, (b) case 4, and (c) case 5, NOx ppmd

5.3 Elevated SOFA Results

Another set of parametric studies investigated the effect of extending the current reducing zone to provide additional residence time for NOx reductions. To achieve this, the model geometry was altered by closing the existing SOFA ports and relocating them 10 feet (3.04 m) above their original location. Figure 5.3 depicts the modification to the SOFA ports location. As detailed in the following sections, the effects of primary zone stoichiometry and PA/F ratio reduction were investigated with the Elevated SOFA (ESOFA) configuration.

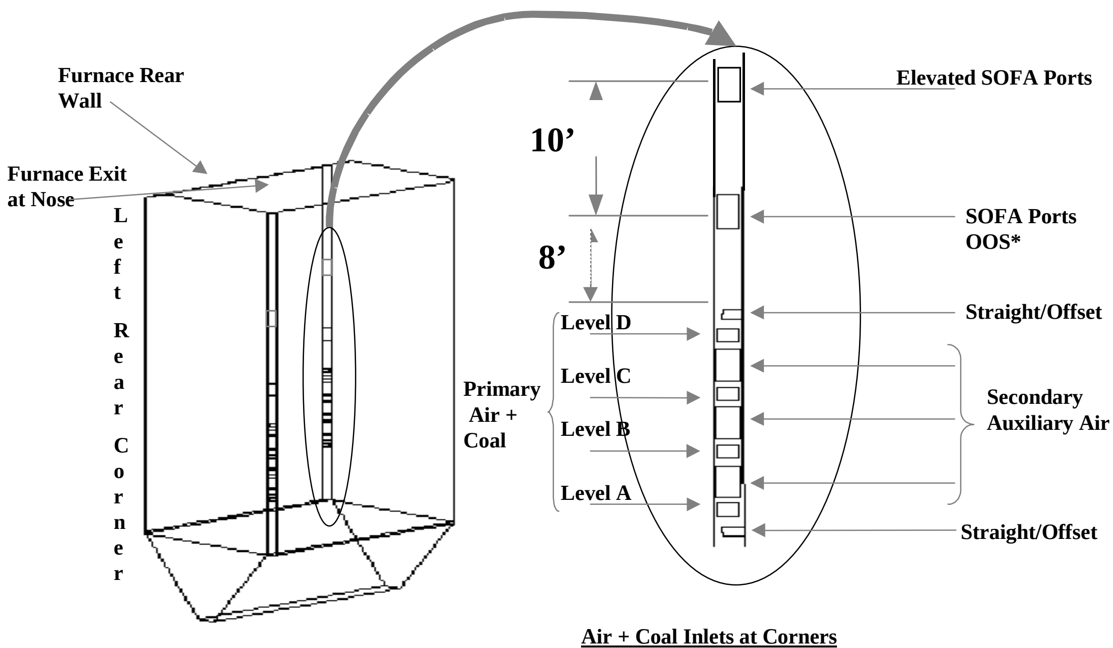


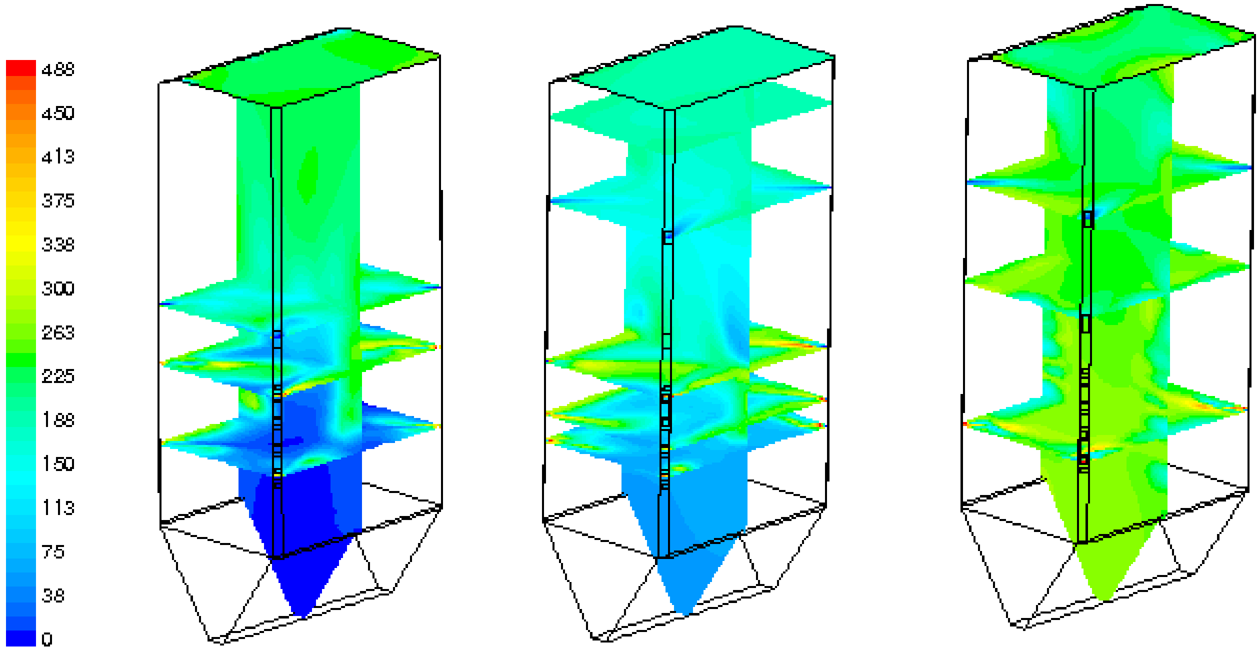
Figure 5.3
Modifications to Furnace Model for Elevated SOFA Cases (*later re-modified to accommodate coal input, see Section 5.5)

5.3.1 Effect of Primary Zone Stoichiometry – Cases 7 and 8

Modeling Case 7 represents a PZS of 0.88 with a setup similar in nature to Case 5, with the exception of the increased SOFA port separation from the burners. Modeling Case 8 reduces the PZS further to 0.81, while holding all other conditions constant. The comparison between model Cases 7 and 8 supported previous trends seen for Cases 5 and 4, in which the lower PZS yielded the least NOx. Case 7, with a PZS of 0.88 and PA/F ratio of 2.0, predicted NOx emission levels on the order of 231 ppmd, UBC levels of 12% and CO levels at the furnace exit of approximately 700 ppm. Alternatively, Case 8, with a PZS of 0.81 and PA/F ratio of 2.0, predicted NOx emission levels of nominally 192 ppm, UBC levels of 6%, and CO levels at the furnace exit of only 10 ppm. Table 5.3.1 presents a summary of the effects on NOx differential derived from comparing CFD case runs. It can be seen on this table that Cases 5 and 4 yielded NOx reductions of 18% when the PZS was reduced from 0.87 to 0.81. In a similar trend, cases run with the extended SOFA separation (Cases 7 and 8) predicted NOx reductions of 17%, albeit with increased levels of UBC (refer to Table 5 for UBC levels). A comparison of the NOx contours for the baseline case and the two ESOFA cases is shown in Figure 5.3.1.

Case No.	Description	PA/F Ratio	PZS	NOx ppmd	ΔNOx	Compared to
3	Baseline	2.5-2.8	0.81	240	-	-
4	OPA/F	2.0	0.81	212	-12% -18%	Case 3 Case 5
5	OPA/F	2.0	0.87	260	+8%	Case 3
7	ESOFA	2.0	0.88	231	-4% +9% -11%	Case 3 Case 4 Case 5
8	ESOFA	2.0	0.81	192	-20% -9% -17%	Case 3 Case 4 Case 7

Table 5.3.1
Summary of NOx differentials obtained from CFD case comparisons.



(a) Case 3 Baseline PZS=0.81

(b) Case 8 Optimized PA/F PZS=0.81

(c) Case 7 Optimized PA/F PZS=0.88

Figure 5.3.1
NOx Concentrations Showing the Effect of Primary Zone Stoichiometry and Increased Reducing Zone, (ppmd).

5.3.2 Effect of Primary Zone Residence Time – Cases 1 and 6, 4 and 8

Two distinct approaches were adopted to analyzing the effect of increased reducing zone residence time on NOx. In the first comparison, Case 1 conditions were entered into the modified geometry SOFA model to generate Case 6. This included all as-found furnace conditions, including the higher than optimal PA/F ratio of 2.5 – 2.8. As such, this approach allowed a direct comparison of the effect of extending the reducing environment, while holding all other operating conditions constant. In this instance, the predicted NOx reduction for Case 6 was 20% of the baseline emission levels predicted in Case 1. CO levels increased only slightly to 1220 ppm.

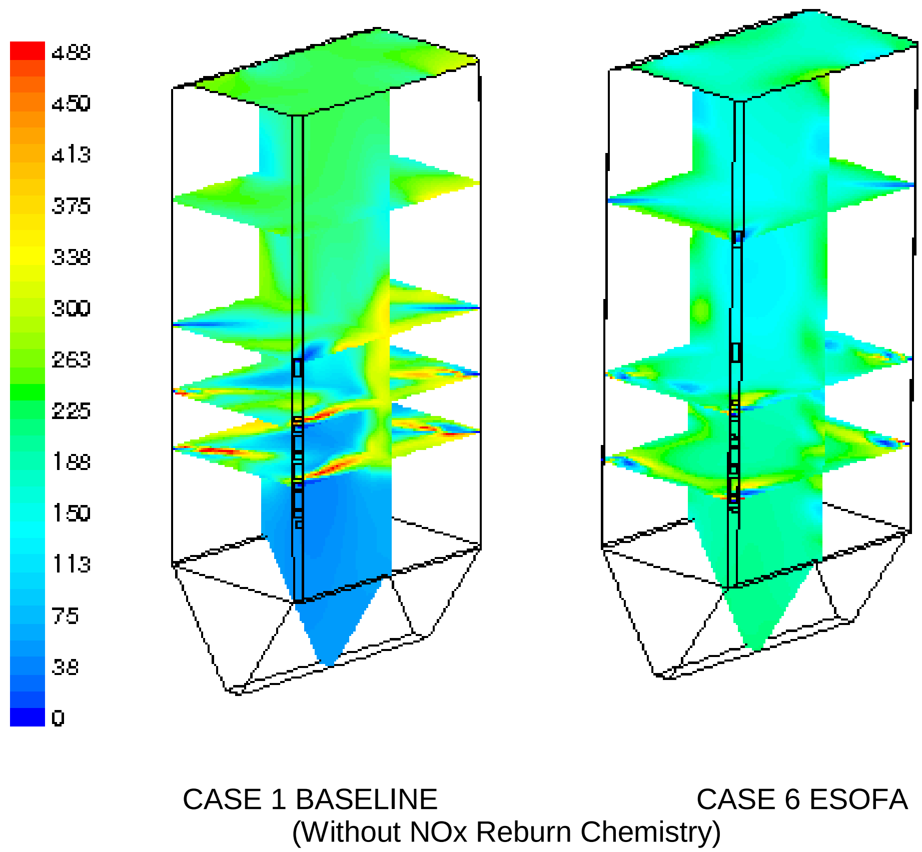


Figure 5.3.2a
Effect of Increased Residence Time on Models with As-found Conditions

In the second assessment PA/F ratios were optimized in combination with increased residence time between the burners and SOFA ports. Toward this end, operating conditions from Case 4, (e.g., PA/F ratio of 2.0 and PZS of 0.81) were rerun with extended SOFA separation to generate Case 8. As indicated previously in Table 5.3.1, NOx predictions for Cases 8 and 3 yielded an overall ΔNOx of 20%. UBC predictions doubled from 3% to 6%, while CO emissions were essentially unchanged at levels under 20 ppm. A summary of the NOx contours for these cases is provided in Figure 5.3.2 (b). Based on these assessments, improvements in the PA/F ratio to levels more commensurate with design specifications appear to provide 60% of the total NOx reductions achieved when both optimal PA/F and elevated SOFA ports are implemented (e.g., Cases 1 – Baseline, Case 4 – Reduced PA/F ratio, and Case 8 – Reduced PA/F ratio and elevated SOFA).

5.3.3 Summary of CFD Cases 1 through 8

In Summary, there appears to be several paths to achieve roughly 20% NOx reduction. As noted earlier, Cases 1 to 6 (for increased SOFA separation only) also yielded 20% NOx reduction without changing the PA/F ratio. Changing the PA/F alone (as in Case 4) yielded 12% NOx reduction but in combination with the increased SOFA separation again yielded 20%. Therefore, the increased separation of the SOFA ports alone, at a low PA/F ratio (Cases 4 and 8), yielded 9 percentage points of additional reduction. Based on these numerical model predictions, it appears that increasing the SOFA separation can achieve significant NOx reductions, albeit at the expense of increased UBC levels. Should mill maintenance be able to control the primary air to coal mass ratios over the load range, these NOx emission levels are predicted to be attainable with no impact on UBC.

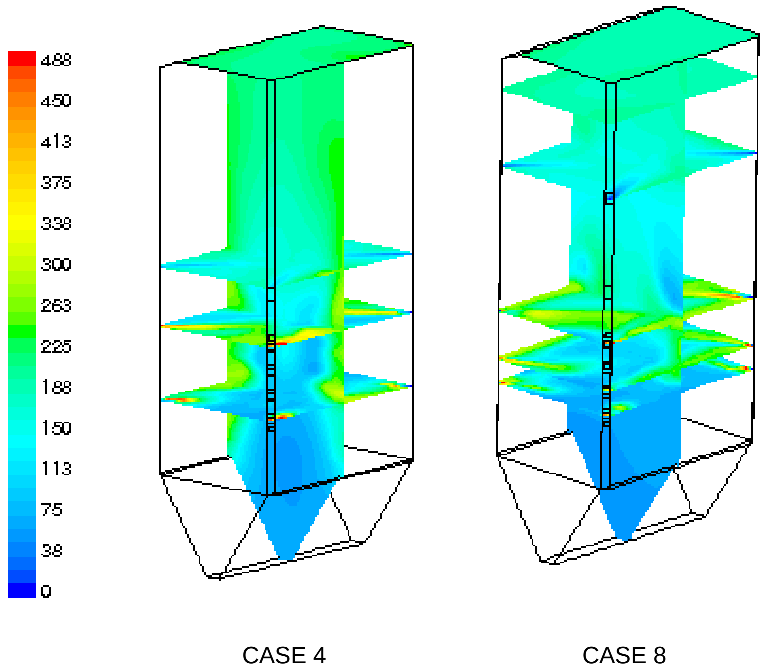


Figure 5.3.2b
Effect of Residence Time via Increasing Reducing Zone on NOx Reduction

5.4 Gas Cofiring Results

One of the main objectives of the project involved the potential to reduce NOx emissions by simultaneously burning natural gas with pulverized coal. In concurrence with the second field testing campaign of May 2000, CFD simulation of the boiler was carried-out to gain additional insights into this potential NOx reduction approach. To investigate the effects of gas cofiring, the model domain was modified to include gas inlets at each of the auxiliary air ports located between the coal levels A through D. In total, six gas inlets were located at each corner.

5.4.1 Gas Cofiring Validation

The addition of a second fuel increased the complexity of the numerical model with a resultant increase in the computational time required to arrive at a converged solution. Current code capabilities prevented the use of multiple computer processors to speed up the numerical calculations. Limited to use of a single processor, computational times were more than quintupled when compared to the previous single fuel cases.

	Case 3	Field Test 7*
FEGT	2289°F (1254°C)	Not available
Excess O_2%	1.3	1.4
CO ppmd @ 3%O_2	1143	Not available
NOx, ppmd @ 3% O_2	166	169
UBC/LOI, %	20	3*

*all field tests measurements at economizer outlet

Table 5.4.1
Summary of Gas Cofiring Predictions and Field Data

Data from the gas cofiring Field Test 7, which was performed on May 24, was used to validate boundary conditions for the initial gas cofiring model case. In this operating scenario, coal elevation D remained out of service, while natural gas was introduced just below this location at the CD auxiliary air ports. Heat input from the gas was estimated at 16% of total heat input to the furnace (i.e., 3,110 scfm), or about 9% fuel input by weight. The lower furnace stoichiometry was calculated to be on the order of 0.73, with the completion air provided through the SOFA ports bringing the overall stoichiometry up to 1.10 at the furnace exit.

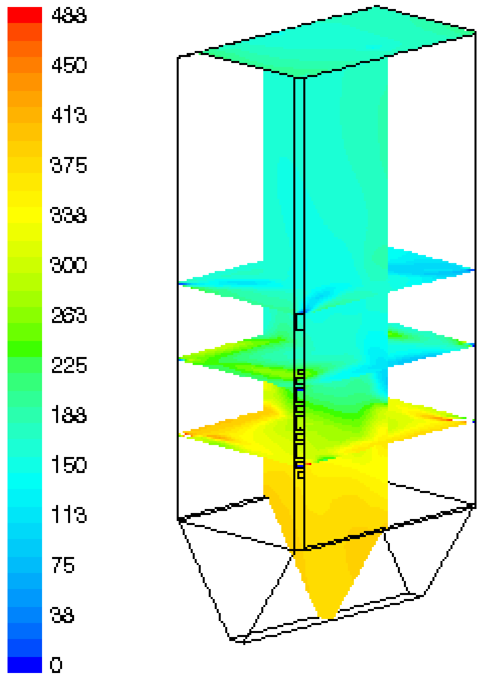
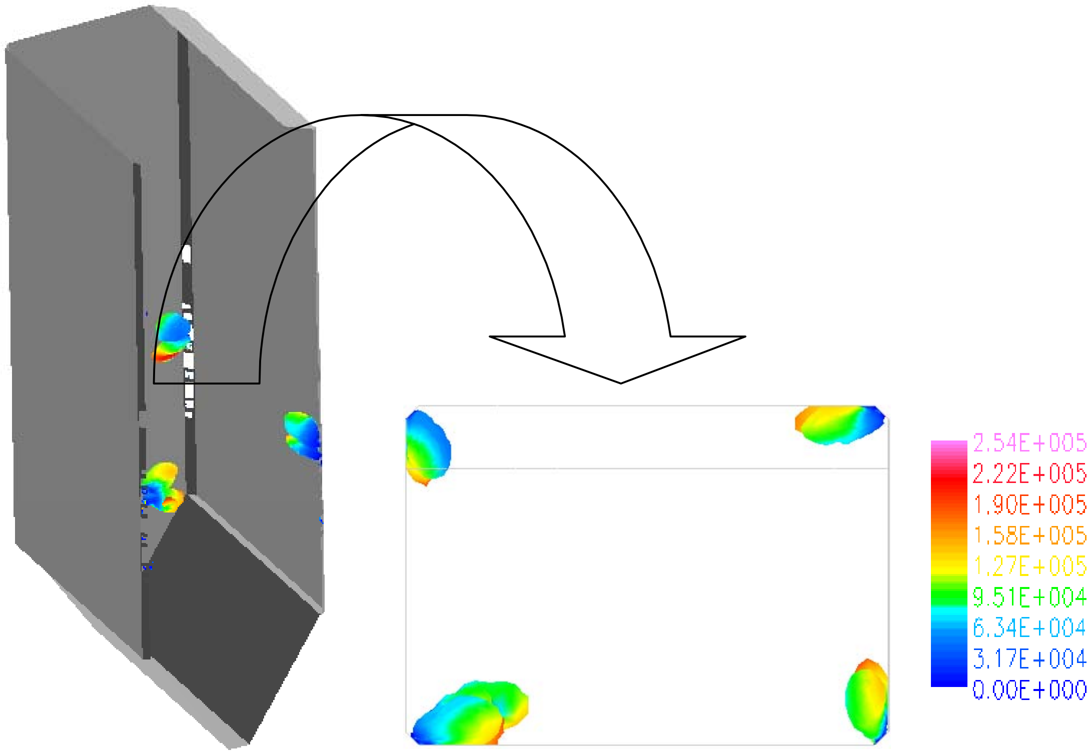


Figure 5.4.1
Predicted NOx Contours for Model Case 9 (ppmd)

NOx predictions were found to be in good agreement with those measured at the economizer outlet of the unit. An overview of the NOx contours throughout the furnace, as predicted by the numerical model, are shown in Figure. 5.4.1. In sum, a comparison of the predicted NOx levels to the original CFD baseline case (Case 3 with PA/F ratio of 2.5 - 2.8) suggest the potential for a 30% NOx reduction. When compared against a baseline case with a comparable PA/F ratio (Case 4), however, the predicted NOx reduction potential from gas cofiring is reduced to 20%. Interestingly, the gas cofiring field test resulted in NOx emission levels of nominally 169 ppmd, while the numerical model predicted levels of 166 ppmd. Optimization of the furnace operation, however, was able to lower the furnace baseline NOx levels to 189 ppmd (Table 4.3, Test 1), with gas cofiring only providing an additional 12% NOx reduction. Although the UBC was predicted to increase to levels of 20%, field test results never exceeded 4%. In addition, CO concentrations at the furnace exit were predicted to increase from nominally 320 ppmd to 1,140 ppmd. CO measurements at the economizer outlet, however, never experienced CO levels greater than 10-20 ppm.



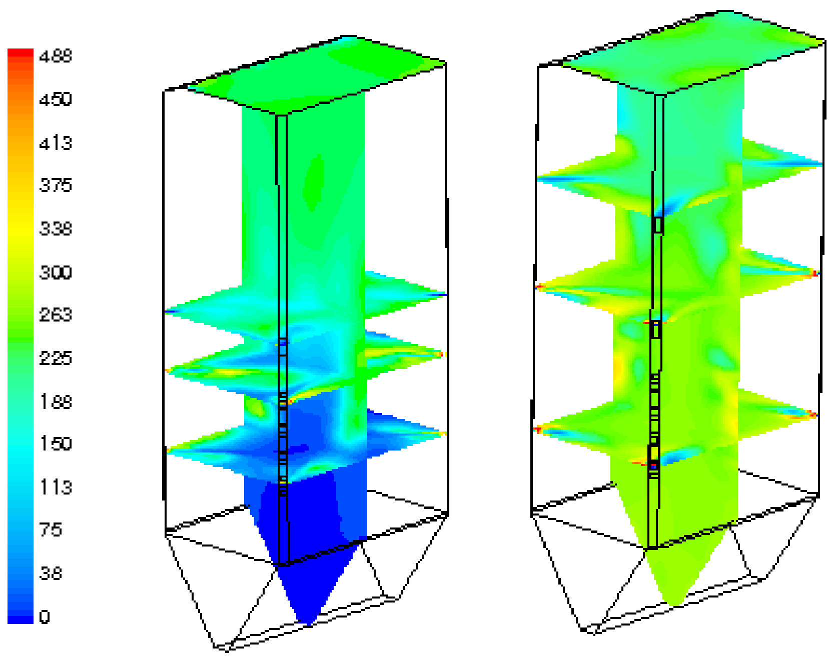
(a) (b)

Figure 5.4.2
Extent of natural gas penetration into furnace. (a) isometric of furnace with right wall cutaway. (b) This is a top view of CD plane. Note: CO concentration contours (ppmd) at a constant CH_4 mole fraction of 1e-6.

One possible explanation for the low effectiveness of the cofiring effort could be attributed to the excessive secondary air present near the vicinity of the gas injection ports. Supportive evidence of this inference could be observed in a planar view of the upper CD elevation. Figure 5.4.2(a) presents a cutaway view of the furnace with the right wall removed. The contours of CO concentration shown, in ppmd, correspond to cells in the computational domain where the mole fraction of methane (CH_4) is equivalent to 10^{-6}. This CH_4 value was arbitrarily chosen as an indicator that, for practical purposes, represents a region where most of the natural gas was consumed. A top view of the upper gas inlet, Figure 5.4.2(b), suggests that the bulk of the gas is consumed rapidly without mixing at the center of the furnace.

5.5 Pulverized Coal Reburn Results

In light of the results from the gas reburn tests, another approach was investigated using the modified SOFA CFD model. Case 10 modeled the effect of reburning using pulverized coal. As in the gas cofiring case, coal elevation D was left out of service while the “old” existing SOFA ports, located 8 feet above the burner zone, were modified to accommodate the coal injection. In order to directly compare the effect of the reburning scheme, baseline as-found conditions of PA/F ratio (2.5-2.8) were assumed at all inlets. A stoichiometry of 0.95 was estimated prior to the reburn zone with only three coal elevations in service. As such, one quarter of the coal input was injected at the reburn ports thereby decreasing stoichiometry to 0.82 prior to the elevated SOFA inlets.



(a)
CASE 3 BASELINE

(b)
CASE 10 PC REBURN

Figure 5.5.1
Comparison of NOx Predictions between the Baseline and Pulverized Coal Reburn Case Study, ppmd.

Because this case run used baseline operating conditions with a higher PA/F ratio, as well as a higher burner zone stoichiometry, direct comparison to other CFD case runs was limited to the Baseline Case 3. Comparison of the predicted NOx levels suggests that a 23% NOx reduction from PC cofiring is feasible, relative to baseline operating levels. NOx concentration contours within the furnace are shown in Figure 5.5.1. It should be noted, however, that the NOx differential associated with the PC reburn case is only 14% relative to the optimized PA/F (Case 4). Thus, optimization of the PA/F ratio and lower furnace stoichiometry will provide a large fraction of the NOx emission reductions predicted to be achievable from incorporation of a pulverized coal reburn approach.

6
ECONOMIC ASSESSMENT

In order to be able to compare the gas cofiring option on Vermilion Unit 2 with existing hardware against alternative approaches, a NOx reduction cost effectiveness was computed on the basis of a $2/MBtu fuel differential cost between natural gas and coal. Baseline NOx emissions were reduced nominally 18% to reflect improvements from reductions in the primary air to coal ratios, as well as increased staging of the lower furnace. An assumed baseline NOx versus load curve is shown in Table 6, with percent operating time over each load interval based upon fourth quarter 1999 CEMS data. Using a gas cofiring effectiveness of 1.1 ppmd reduction in NOx per percent natural gas heat input, a level of 8% natural gas heat input with the existing burner geometry would result in a nominal 6% NOx reduction. The cost effectiveness associated with this specific application of gas cofiring with the existing burner geometry (i.e., zero capital cost) is on the order of $18,000/ton NOx removed. The cost stems exclusively from the gas/coal fuel differential cost penalty of $2/MBtu, which is estimated to amount to $435,000 over the ozone season, using a 65% capacity factor. When combined with the limited NOx reduction effectiveness of the approach given the current gas burner and OFA arrangement, the cost effectiveness is rapidly diminished.

Table 6
Estimated Load Average NOx Emissions with Optimized Primary Air /Coal Ratio and OFA Operation on Vermilion Unit 2

Low End Load (MWg)	High End Load (MWg)	Mid-Point Load (MWg)	NOx (lb/MBtu)	Average NOx (lb/MBtu)	Percent Op Time (%)
0.0	11.2	5.6		0.000	0.00%
11.2	22.4	16.8	0.50	0.002	0.35%
22.4	33.6	28.0	0.50	0.010	1.94%
33.6	44.8	39.2	0.45	0.027	6.01%
44.8	56.0	50.4	0.40	0.010	2.47%
56.0	67.2	61.6	0.30	0.019	6.18%
67.2	78.4	72.8	0.25	0.118	47.17%
78.4	89.6	84.0	0.27	0.057	21.02%
89.6	100.8	95.2	0.29	0.030	10.25%
100.8	112.0	106.4	0.29	0.013	4.59%
				0.285	100.00%

6.1 Modified OFA and Gas Reburn

For purposes of comparison, the cost effectiveness of changing existing boiler hardware to increase the upper furnace residence time was also investigated from a screening level approach. Two limitations of the gas cofiring approach evaluated was the limited residence time available within the reducing zone, as well as the gas burners being located within close proximity to the introduction of the secondary combustion air. A scenario was evaluated whereby the OFA separation from the windbox was increased from nominally 8 feet (2.43 m) to 18 feet (5.48 m), and the introduction of the natural gas was moved from the auxiliary air ports to a level near where the existing OFA ports are located. This approach would follow the gas reburn geometry applied at Greenidge Station, a tangentially designed boiler of similar capacity and age as Vermilion Unit 2.

The cost effectiveness of such an approach is based upon achieving NOx emission levels of 0.20 lb/MBtu (86 mg/MJ) at a natural gas heat input of 8%. Capital costs for the boiler modifications are estimated to be on the order of $500,000 - $1,000,000. Using a 12% capital cost recovery factor, $2/MBtu fuel cost differential, and assuming an overall NOx reduction of 30% from baseline levels with OFA, the cost effectiveness is calculated to range between $4,200/ton to $4,700/ton NOx removed. As above, the fuel cost differential during the ozone season with 8% heat input is on the order of $435,000, which represents close to 90% of the total levelized cost. The projected increase in NOx reduction efficiencies from hardware modifications, however, improve the overall cost effectiveness of the approach.

6.2 PC Reburn

Assuming that a similar level of NOx reduction performance (e.g., 0.20 lb/MBtu) could be achieved through adoption of PC reburn, the cost effectiveness could be improved to $900 – 1,200/ton NOx removed. These estimates assume a capital cost retrofit budget of $750,000 - $1,000,000, and annual incremental O&M costs incurred during the ozone season of nominally $10,000 - $25,000. The principal cost savings over the fuel lean gas reburn approach stem from the elimination of the fuel differential cost penalty. It should be noted, however, that limitations to the NOx reduction potential could arise from unacceptable increases in either the UBC or CO levels at the economizer outlet. Increases in UBC could impact the collection efficiency of the ESP.

6.3 SNCR Trim

An SNCR trim approach is based upon a simplified SNCR injection system that operates with a single level of injectors and is targeted to reduce NOx over a load range with the greatest frequency of operation. Using cost estimates from EPRI's HYBRID software for Vermilion Unit 2, a urea system operating with less than 5 ppm ammonia slip could reduce NOx by nominally 30%, bringing the overall NOx emissions down to a level below 0.20 lb/MBtu. The cost effectiveness of this approach, based on a capital cost estimate ranging between $500,000 to $750,000, and annual operating and maintenance costs of $100,000, would be on the order of $1,350/ton to $1,600/ton NOx removed.

7 CONCLUSIONS AND RECOMMENDATIONS

7.1 Conclusions

The results of the field test and numerical modeling efforts suggest that potential NOx reductions can be achieved at Vermilion Unit 2 without the implementation of high capital cost modifications. In summary, the results of the field testing and numerical model analyses suggest that:

- Improving primary air to fuel ratios can gain up to a 12% reduction in NOx emissions. As suggested by item 1 in table 7, this could be achieved by optimizing primary air control hence increasing pulverizer efficiency (through improved particle fineness) on Mill B. The primary goal of these modifications is to yield a 1.8 to 2.0 lb air/lb fuel mass ratio.
- Primary Zone Stoichiometry has a significant impact on NOx formation. As found through field testing, staging of the primary burner zone could potentially reduce NOx emissions from current levels by up to 16% at full load, and by over 50% at intermediate load. Based on field test and modeling results (items 2a-2c, Table 7), improved control over the primary air to coal mass ratio in combination with staging n the lower furnace to levels of 0.80 would reduce NOx emissions over the primary load range to levels less than 0.25 lb/MBtu (107.5 mg/MJ).
- As shown in item 6b from Table 7, CFD modeling predictions suggests that after optimizing PA/F ratios, an additional 9% NOx reduction could result from increasing flue gas residence time under reducing conditions. This simulation was carried out by moving the SOFA ports 10 feet higher than their current location thereby creating an extended reducing zone.
- Gas cofiring using the existing hardware provides some limited NOx reduction improvement (<10% at full load), but at gas use levels that are not economically competitive.
- Results of one CFD simulation (item1, Table 7) suggest that pulverized coal reburn has the potential to reduce NOx by at least 24% based on current operating conditions. Further investigation into the potential of this approach under optimized conditions was not carried out, but is highly recommended based on the projected NOx reduction cost effectiveness.

Item	Concept	Approach	Reference* (ppmd)	Modification Result** (ppmd)	ΔNOx	Cases or Tests Compared†
1	Effect of optimizing PA/F ratio	CFD: Reduce current condition from range of 2.5-2.8 to 2.0	240	212	-12%	3, 4
2a	Effect of Primary Zone Stoichiometry	Field Test: Staging PZS from 0.81-> 0.75 (Feb. 2000)	226	190	-16%	1, 5
2b		CFD: Ultimate Staging PZS decreased from 0.81 -> 0.65 (must evaluate corrosion potential)	245	176	-28%	1, 2
2c		CFD: Revised burner fluid mechanics, PZS increased from 0.81 -> 0.87	212	260	+23%	4, 5
3	Effect of increasing Residence Time	CFD: move SOFA ports 10 ft. higher	245	195	-20%	1, 6
4a	Effect of Gas Cofiring	CFD: direct comparison to baseline	240	166	-31%	3, 9
4b		Field test: 15% gas heat input (May 2000)	183	159	-13%	1, 7
5	Effect of Pulverized Coal Reburn	CFD: Fire PC through existing SOFA ports	240	183	-24%	3, 10
6a	Combinations	CFD: move SOFA ports 10 ft higher + optimize PA/F ratios	240	192	-20%	3, 8
6b		CFD: net gain in NOx reduction from moving SOFA ports	212	192	-9%	4, 8
6c		CFD: Moved SOFA ports + optimized PA/F ratios + PZS inc. 0.81 -> 0.88	231	260	+13%	5, 7

* The reference value is not necessarily the CFD baseline as comparisons are made so that only one parameter is varied

** This is the result of applying the modification described in the approach column.

† Field tests and simulations are not mutually compared

Table 7
Summary of Investigated Effects and their Impacts on NOx Reduction

7.2 Recommendations

The use of natural gas for NOx reduction, even with zero capital costs, do not appear to be economically competitive. Current burner hardware configurations introduce the natural gas in the vicinity of the auxiliary air ports, which results in the immediate combustion of a large fraction of the natural gas, reducing its effectiveness for achieving NOx reductions. Field tests and numerical modeling investigations suggest, however, that significant improvements in NOx emissions can be obtained through (1) optimization of the primary air to coal mass ratios over the load range, (2) increasing the separation (i.e., residence time) between the top burner elevation and the OFA ports, and (3) increased staging within the lower furnace. Due to the relatively large upper furnace residence time available within Vermilion Unit 2, these approaches appear to provide the capability to achieve and maintain NOx emission levels below 0.25 lb/MBtu (107.5 mg/MJ) while not incurring any additional operating costs from reagents and fuel cost differentials. The increased separation between the burner windbox and SOFA ports would also enhance the potential for pulverized coal reburn. Should NOx emissions approaching 0.15 lb/MBtu be required, the above combustion modifications could also be combined with a variable cost oriented technology such as SNCR trim. As noted in Section 6, limitations in the achievable NOx reductions from combustion modifications alone appear to be around 0.20 – 0.25 lb/MBtu (86-107.5 mg/MJ). Thus, reductions beyond these levels would likely require more extensive hardware modifications, or the incorporation of a low cost post combustion control technology.

8 REFERENCES

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A
Mill Performance Tests

Primary Air Flow Curves as a Function of Mill Discharge Pressure

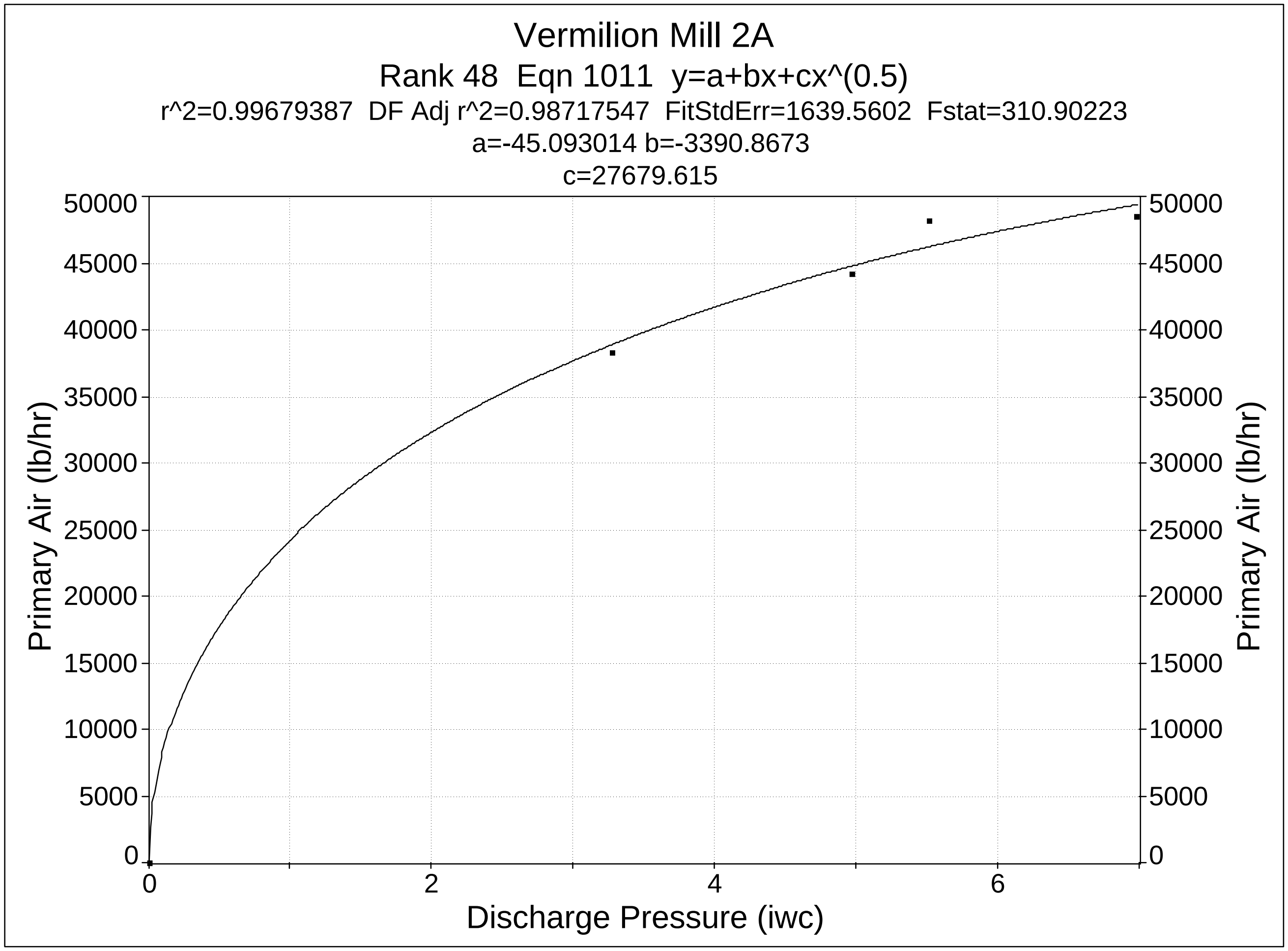


Figure A-1.1. Relationship between primary air mass flow rate and discharge pressure for Vermilion Mill 2A (Section 4.4.1)

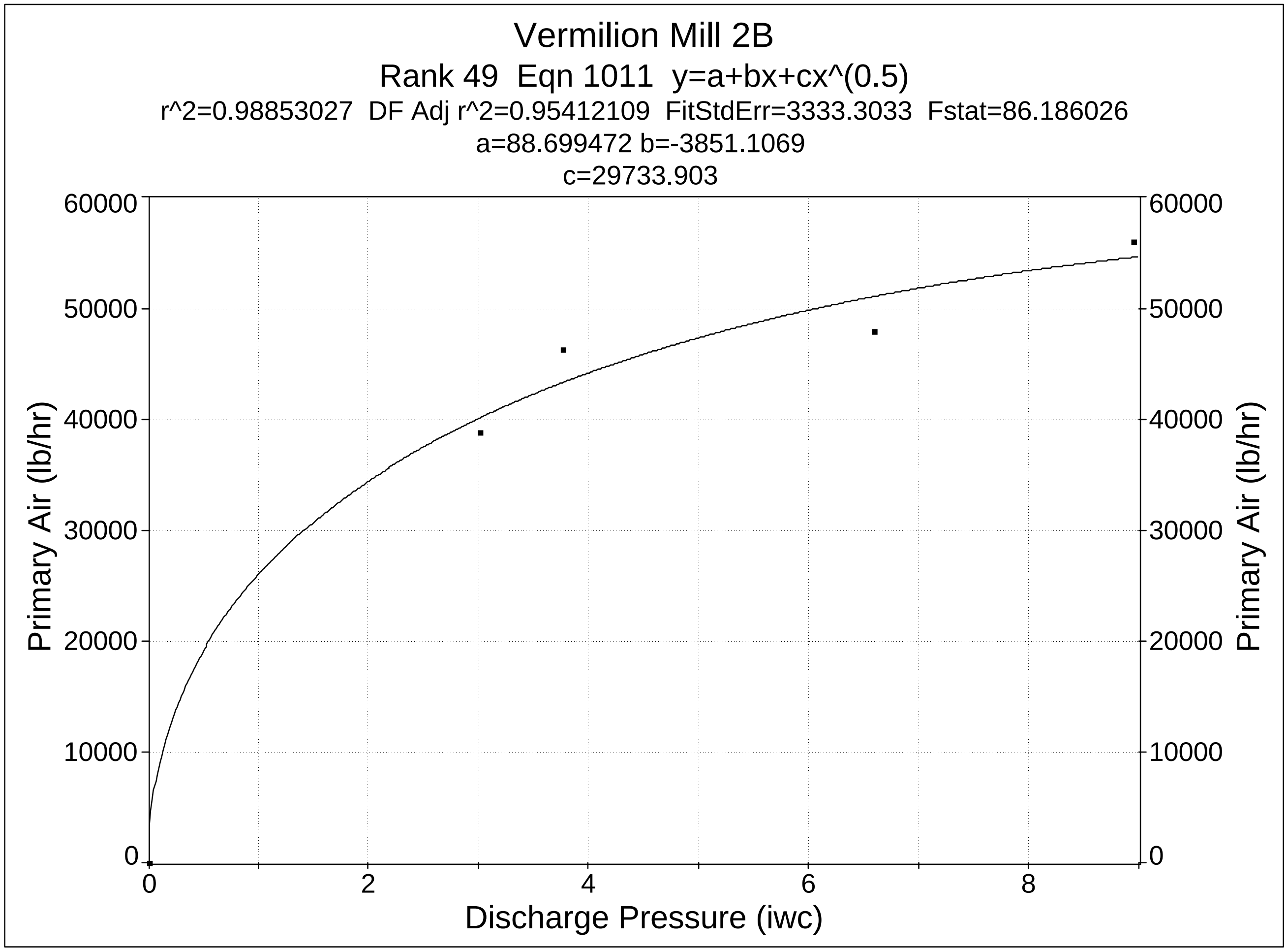


Figure A-1.2. Relationship between primary air mass flow rate and discharge pressure for Vermilion Mill 2B (Section 4.4.1)

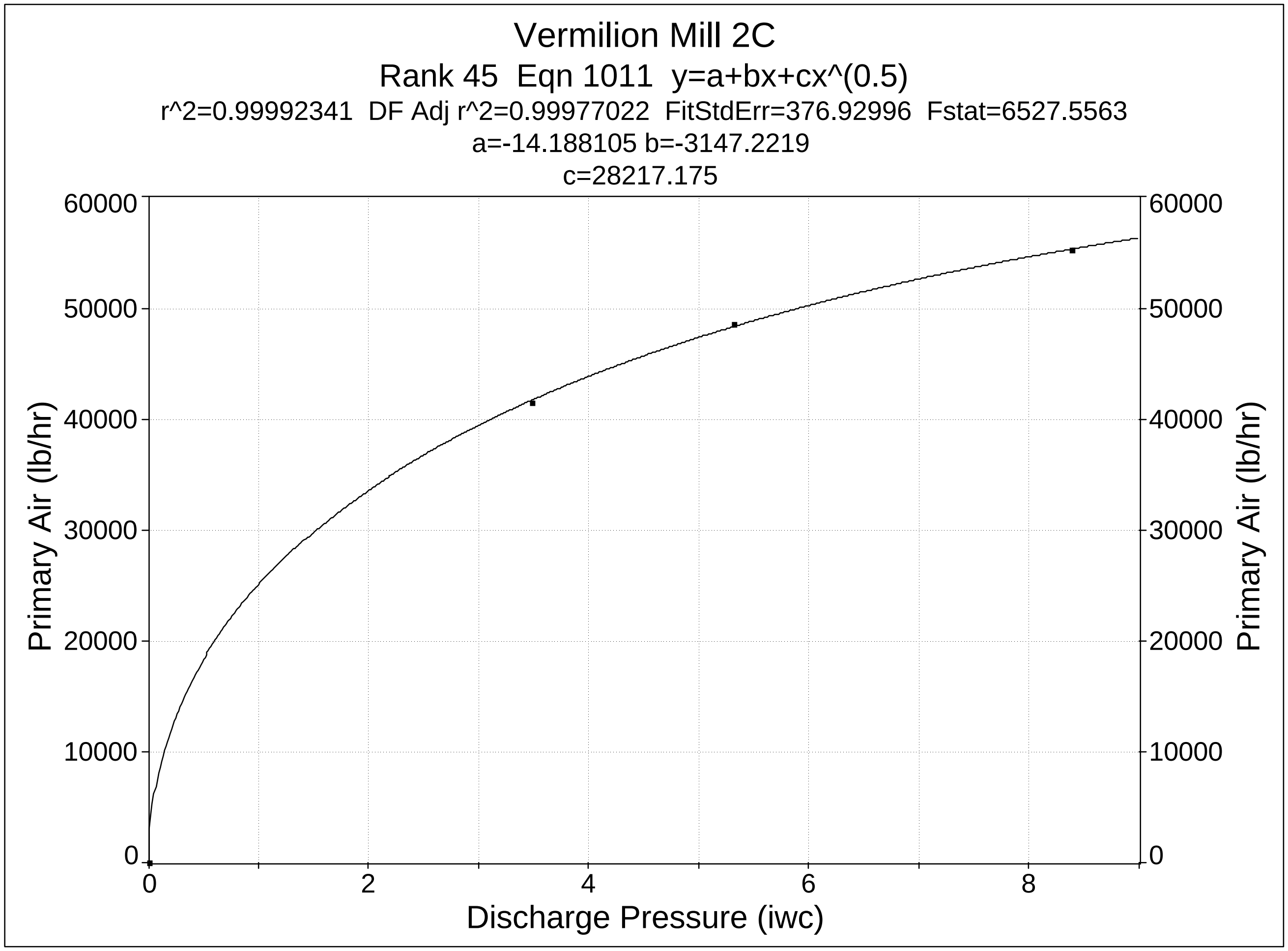


Figure A-1.3. Relationship between primary air mass flow rate and discharge pressure for Vermilion Mill 2C (Section 4.4.1)

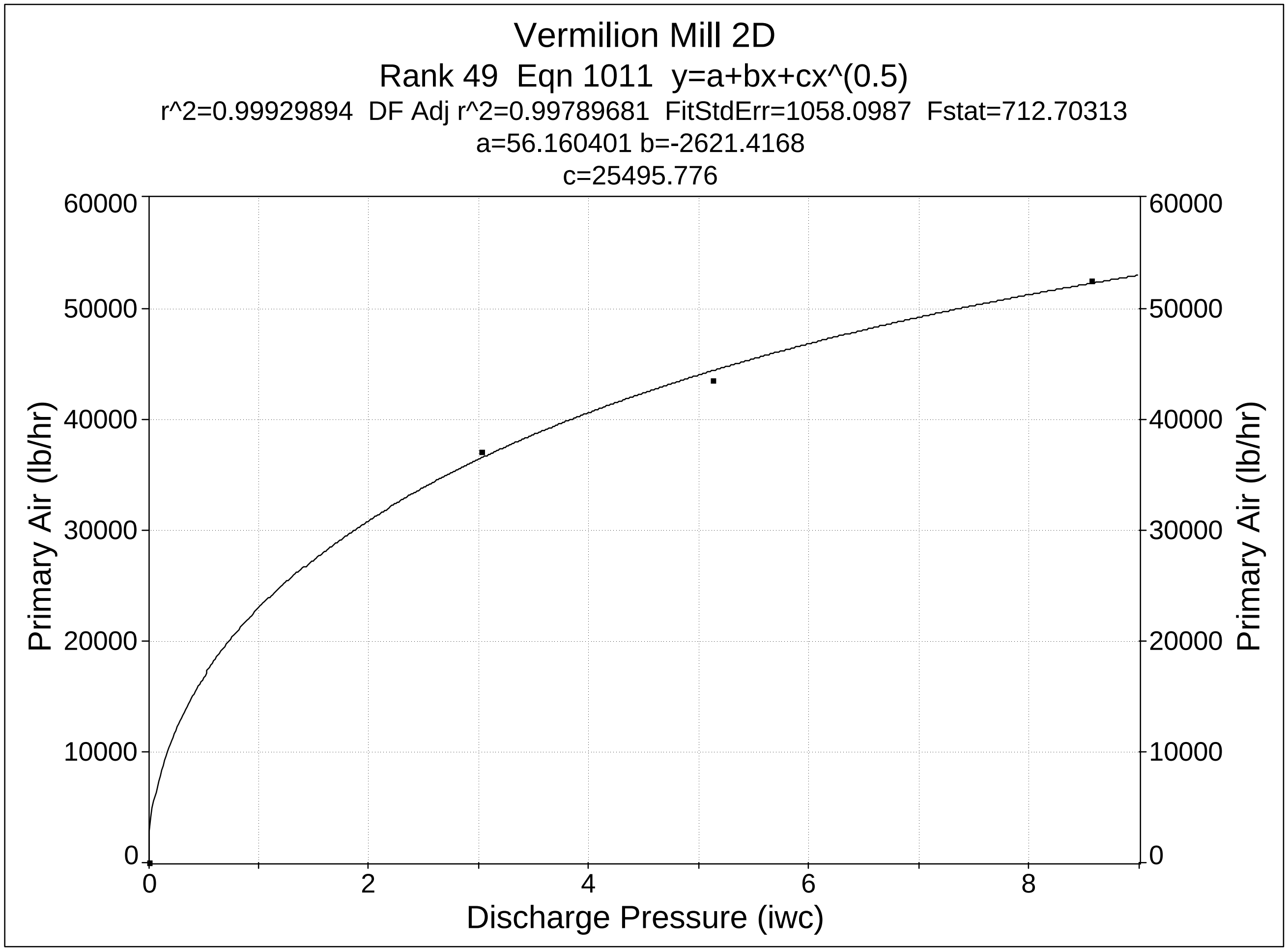
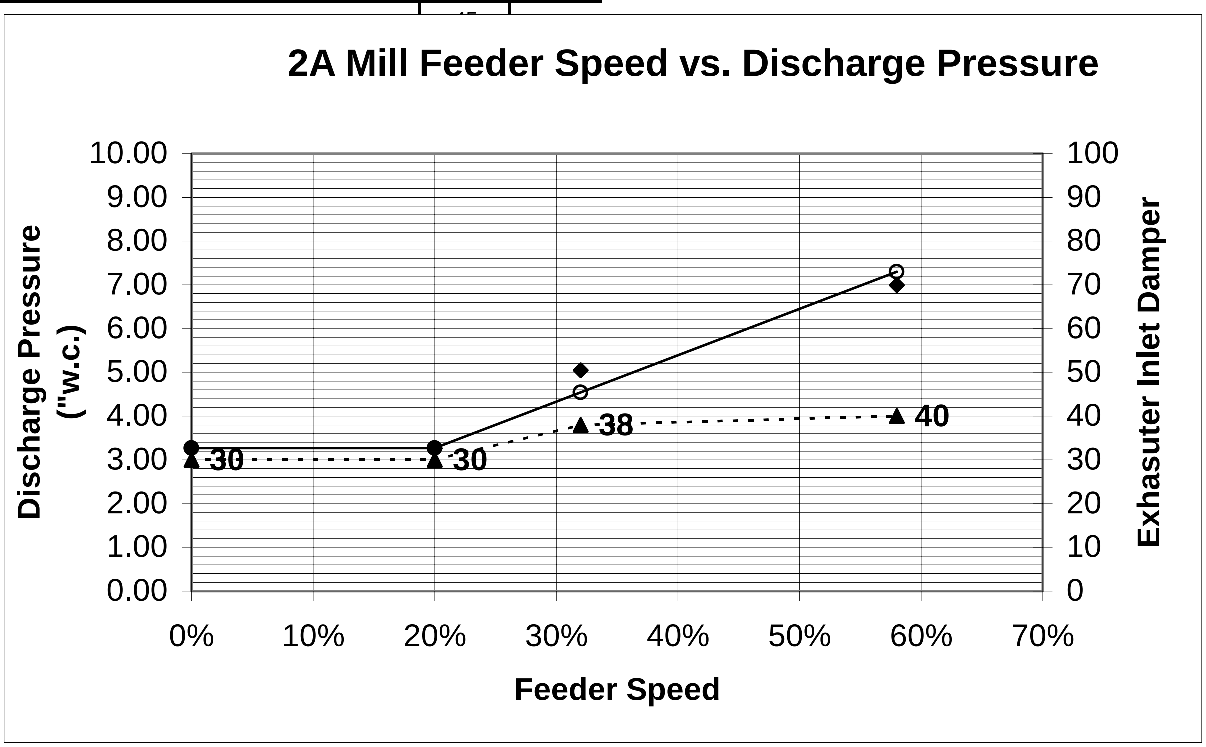


Figure A-1.4. Relationship between primary air mass flow rate and discharge pressure for Vermilion Mill 2D (Section 4.4.1)

Time:	x	10:52	12:35	13:39	15:08	16:00	17:25	18:00		
Date:	x	01-May	01-May	01-May	01-May	01-May	01-May	01-May		
Pulverizer:	x	2A	2A	2A	2A	2A	2A	2A		
Unit Load:	Mw	71	72	72	73	79	79	88		
Feeder Speed Demand:	%	20	20	20	20	32	32	58		
Feeder Speed Feedback:	%	35.3	35.3	33.45	35.3	45.3	45.3	65.66		
Exhauster Damper:	%	40	40	30	30	38	38	40		
Mill Motor Current:	Amps	53.8	54.15	54.14	54.14	60.02	59.55	73.89		
Feeder Speed (Panel):	Rpm	4.70	4.70	4.70	4.70	5.50	5.50	7.10		
Feeder Speed (stopwatch):	Rpm	4.19	4.19	4.19	4.19	5.60	5.6	6.77		
Mill Temperature:	°F	153.6	150.3	147.0	148.1	143.9	145.2	132.1		
Suction Pressure:	"H2O	-0.38	-1.26	-0.23	-0.30	-0.26	-0.25	-0.31		
Hot Air Damper:	%	24.4	18.29	30.04	27.15	35.92	35.27	31.75		
Discharge Pressure:	"H2O	5.74	5.52	3.28	3.25	4.97	5.12	6.99		
Temp. Air Dmpr Opening:	inches	4"	1-1/2"	3/4"	3/4"	3/4"	3/4"	3/4"		
Meas. Burner Line Airflow:	Lbs./Hr.		48,252	38,401		44,243		48,535		
Meas. Coal Flow:	Lbs./Hr.		na	13,105		16,815		27,526		
Air to Fuel Ratio:	# air/# Fuel		na	***2.93***		***2.63***		***1.76***		
Coal flow per RPM:	Lb.Hr./Rpm		na	2788.2		3057.2		3876.9		
Coal per % Feeder Speed:	Lb.Hr./%		na	655.235		525.461		474.588		
Minimum Pipe Velocity	Fpm		***4,375.7***	***3,378.4***		***3,868.0***		***4,415.0***		
Maximum Pipe Velocity	Fpm		5,110.8	4,109.8		4,682.4		4,998.5		
Average Pipe Velocity	Fpm		***4,698.0***	***3,718.4***		***4,265.7***		***4,599.1***		
Average Pipe Velocity	Fps		***78.3***	***62.0***		***71.1***		***76.7***		

A Mill Curve

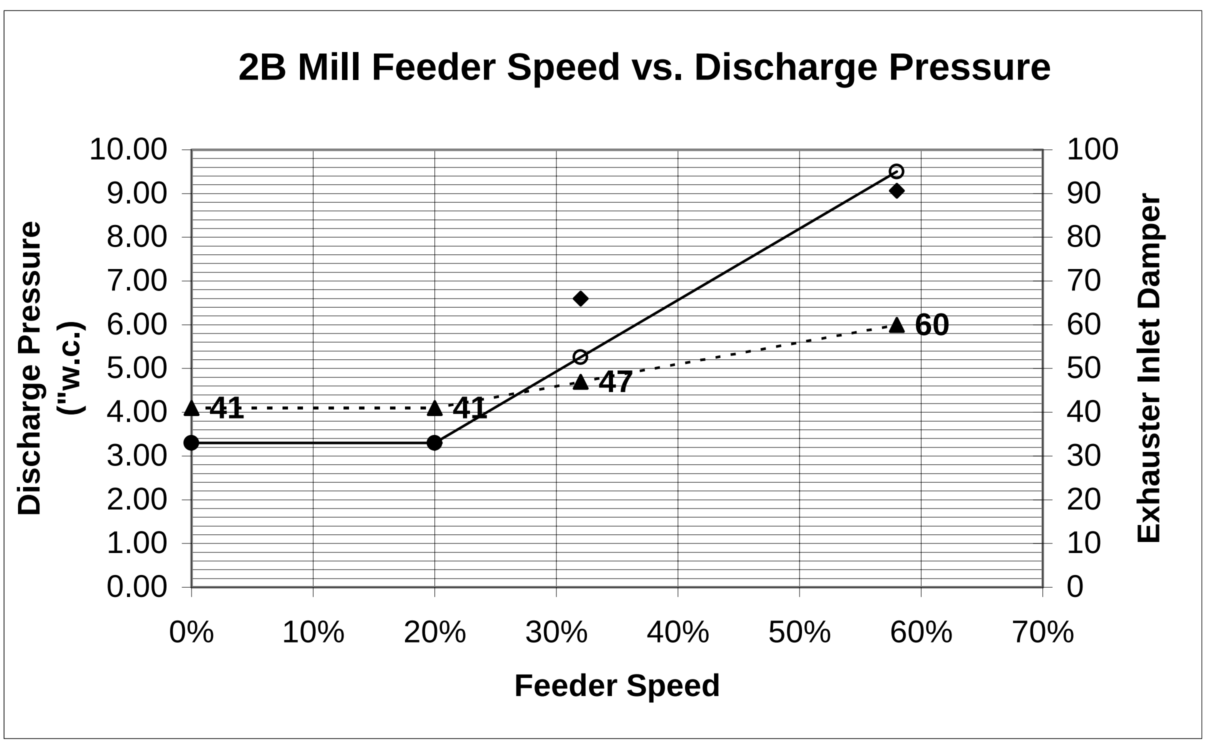
Feeder Speed	Test Points	Damper	Curve
0%	3.27	30	3.27
20%	3.27	30	3.27
32%	5.05	38	4.54
58%	6.99	40	7.3



Time:	x	9:22	10:12	10:35	11:47	13:10	14:32	15:00	16:16	
Date:	x	02-May	02-May	02-May	02-May	02-May	02-May	02-May	02-May	
Pulverizer:	x	2B	2B	2B	2B	2B	2B	2B	2B	
Unit Load:	Mw	75	75	75	75	75	75	75	75	
Feeder Speed Demand:	%	20	20	20	20	32	32	58	58	
Feeder Speed Feedback:	%	35.26	35.23	35.26	35.26	44.81	44.81	65.52	65.49	
Exhauster Damper:	%	50	50	41	41	47	47	60	60	
Mill Motor Current:	Amps	51.69	50.9	50.79	50.96	54.69	55	63.57	64.04	
Feeder Speed (Panel):	Rpm	4.70	4.70	4.70	4.70	5.40	5.40	7.00	7.00	
Feeder Speed (stopwatch):	Rpm	4.24	4.24	4.24	4.24	5.52	5.52	6.64	6.64	
Mill Temperature:	°F	147.7	148.2	150.6	149.5	149.8	152.0	135.2	136.8	
Suction Pressure:	"H2O	-1.60	-1.89	-0.48	-0.47	-0.59	-0.78	-0.61	-0.55	
Hot Air Damper:	%	54.83	50.9	66.76	65.86	75.28	75.34	99.62	99.62	
Discharge Pressure:	"H2O	3.77	4.33	3.01	3.6	6.6	6.58	8.96	9.16	
Temp. Air Dmpr Opening:	inches	~2-1/2"	~2-1/2"	3/4"	3/4"	3/4"	3/4"	3/4"	3/4"	
Meas. Burner Line Airflow:	Lbs./Hr.	46,273		38,866		47,933		56,048		
Meas. Coal Flow:	Lbs./Hr.	na		14,201		17,615		25,144		
Air to Fuel Ratio:	# air/# Fuel	na		***2.74***		***2.72***		***2.23***		
Coal flow per RPM:	Lb.Hr./Rpm	na		3021.5		3262.0		3592.0		
Coal per % Feeder Speed:	Lb.Hr./%	na		710.054		550.467		433.52		
Minimum Pipe Velocity	Fpm	***4,336.8***		***3,690.6***		***4,571.1***		***5,112.4***		
Maximum Pipe Velocity	Fpm	4,788.2		3,945.7		4,882.5		5,670.9		
Average Pipe Velocity	Fpm	***4,518.9***		***3,813.8***		***4,705.0***		***5,354.0***		
Average Pipe Velocity	Fps	***75.3***		***63.6***		***78.4***		***89.2***		

B Mill Curve

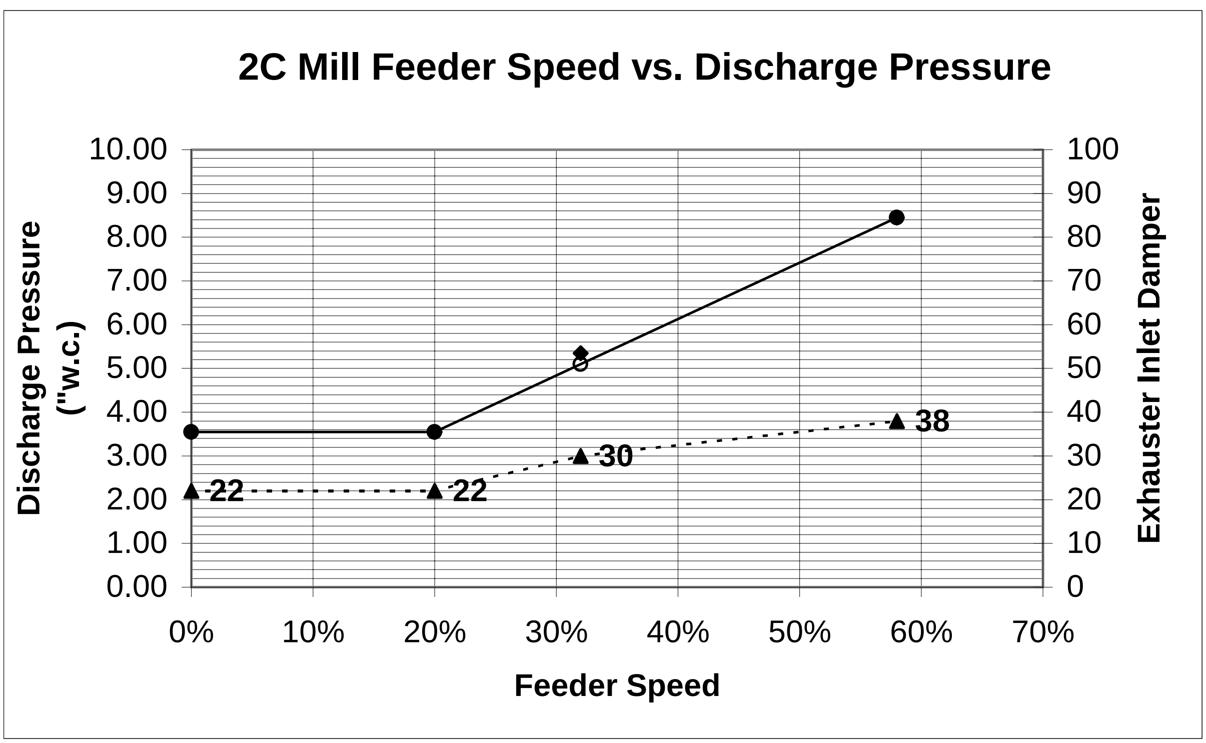
Feeder Speed	Test Points	Damper	Curve
0%	3.30	41	3.30
20%	3.30	41	3.30
32%	6.60	47	5.26
58%	9.06	60	9.50



Time:	x	7:30	8:52	9:15	10:26	11:10	12:09			
Date:	x	03-May	03-May	03-May	03-May	03-May	03-May			
Pulverizer:	x	2C	2C	2C	2C	2C	2C			
Unit Load:	Mw	77	77	77	77	77	77			
Feeder Speed Demand:	%	20	20	32	32	58	58.04			
Feeder Speed Feedback:	%	35.66	35.69	45.38	45.38	66.29	66.34			
Exhauster Damper:	%	22	22	30	30	38	38			
Mill Motor Current:	Amps	61.16	60.59	67.32	67.81	81.25	81.78			
Feeder Speed (Panel):	Rpm	4.70	4.70	5.40	5.40	7.00	7.00			
Feeder Speed (stopwatch):	Rpm	4.23	4.23	5.38	-	4.54	-			
Mill Temperature:	°F	151.3	149.7	149.7	149.3	144.8	145.8			
Suction Pressure:	"H2O	-0.83	-0.88	-0.86	-0.89	-0.45	-0.31			
Hot Air Damper:	%	38.18	36.28	53.92	52.32	100.63	100.63			
Discharge Pressure:	"H2O	3.49	3.61	5.32	5.38	8.4	8.5			
Temp. Air Dmpr Opening:	inches	2"	2"	7/8"	7/8"	3/4"	3/4"			
Meas. Burner Line Airflow:	Lbs./Hr.	41,506		48,622		55,230				
Meas. Coal Flow:	Lbs./Hr.	15,188		18,025		26,261				
Air to Fuel Ratio:	# air/# Fuel	***2.73***		***2.70***		***2.10***				
Coal flow per RPM:	Lb.Hr./Rpm	3231.6		3338.0		3751.6				
Coal per % Feeder Speed:	Lb.Hr./%	759.417		563.295		452.782				
Minimum Pipe Velocity	Fpm	3,956.6		***4,571.4***		***5,136.5***				
Maximum Pipe Velocity	Fpm	4,257.3		5,034.9		5,543.8				
Average Pipe Velocity	Fpm	***4,041.1***		***4,721.5***		***5,329.7***				
Average Pipe Velocity	Fps	***67.4***		***78.7***		***88.8***				

C Mill Curve

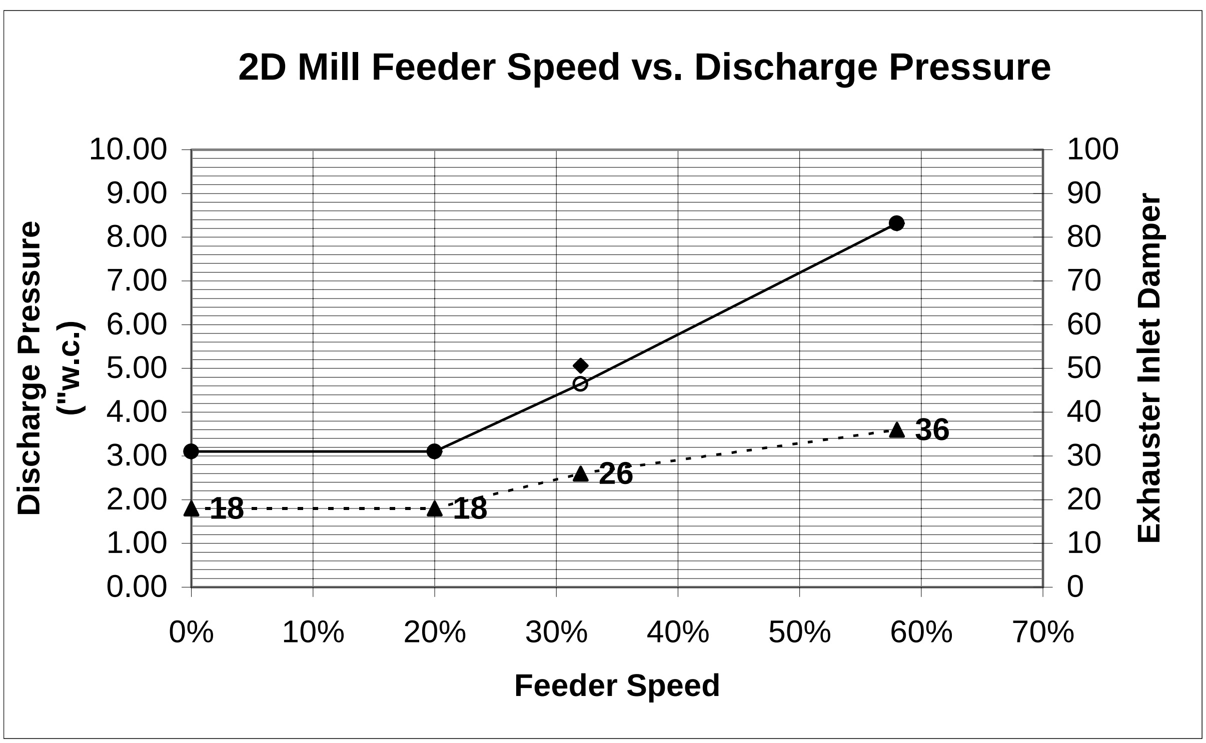
Feeder Speed	Test Points	Damper	Curve
0%	3.55	22	3.55
20%	3.55	22	3.55
32%	5.35	30	5.10
58%	8.45	38	8.45



Time:	x	13:48	15:00	15:32	16:40	17:10	12:09			
Date:	x	03-May	03-May	03-May	03-May	03-May	03-May			
Pulverizer:	x	2D	2D	2D	2D	2D	2D			
Unit Load:	Mw	76	77	77	76	77	77			
Feeder Speed Demand:	%	20	20	31.96	31.96	58	58			
Feeder Speed Feedback:	%	35.91	35.99	45.73	45.69	66.84	66.88			
Exhauster Damper:	%	18	18	26	26	36	36			
Mill Motor Current:	Amps	55.79	56.29	60.17	59.25	71.52	71.22			
Feeder Speed (Panel):	Rpm	4.70	4.70	5.50	5.50	7.10	7.10			
Feeder Speed (stopwatch):	Rpm	4.26	-	5.42	-	7.96	-			
Mill Temperature:	°F	152.2	147.1	151.9	149.0	145.7	148.7			
Suction Pressure:	"H2O	-1.05	-0.64	-1.05	-0.99	-0.56	-0.70			
Hot Air Damper:	%	35.98	51.21	47.15	51.57	100.03	100.05			
Discharge Pressure:	"H2O	3.03	3.17	5.13	4.99	8.57	8.06			
Temp. Air Dmpr Opening:	inches	~2.5"	1 -7/8"	1-1/2'	1-1/2"	3/4"	3/4"			
Meas. Burner Line Airflow:	Lbs./Hr.	37,092		43,531		52,510				
Meas. Coal Flow:	Lbs./Hr.	13,630		16,281		24,401				
Air to Fuel Ratio:	# air/# Fuel	***2.72***		***2.67***		***2.15***				
Coal flow per RPM:	Lb.Hr./Rpm	2899.9		2960.1		3436.8				
Coal per % Feeder Speed:	Lb.Hr./%	681.475		509.40		420.709				
Minimum Pipe Velocity	Fpm	3,305.1		***3,894.3***		***4,606.6***				
Maximum Pipe Velocity	Fpm	3,884.1		4,474.9		5,428.9				
Average Pipe Velocity	Fpm	***3,623.1***		***4,249.4***		***5,090.0***				
Average Pipe Velocity	Fps	***60.4***		***70.8***		***84.8***				

D Mill Curve

Feeder Speed	Test Points	Damper	Curve
0%	3.10	18	3.10
20%	3.10	18	3.10
32%	5.06	26	4.65
58%	8.32	36	8.32



Baseline Test		**Barometric Pressure (" Hg) :**	**29.90"**
Coal Pipe I.D. (inches) :	**11.000**	**Pulverizer :**	**2A**
Coal Pipe Area (Ft²) :	**0.65995**	**Date:**	**02-May-00**
Test Personnel:	**RPS/WEP**	**Test No. :**	**1**

Burner No. :	**A1**	**Right Front**		**Burner No. :**	**A2**	**Right Rear**	
Point	**Port 1**	**Port 2**		**Point**	**Port 1**	**Port 2**	
1	1.85	1.70		1	1.25	1.25	
2	1.80	1.75		2	1.35	1.35	
3	1.75	1.75		3	1.35	1.35	
4	1.75	1.75		4	1.45	1.35	
5	1.65	1.75		5	1.35	1.30	
6	1.65	1.55		6	1.25	1.20	
7	1.60	1.50		7	1.25	1.25	
8	1.55	1.35		8	1.35	1.35	
9	1.55	1.45		9	1.45	1.45	
10	1.10	0.30		10	0.44	0.85	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	1.23496	"w.c.		Sqrt Vh	1.11594	"w.c.	
Temperature	155	°F		Temperature	151.5	°F	
Static	0.3	"w.c.		Static	0.56	"w.c.	
Density	0.0646	Lbs./Ft³		Density	0.0651	Lbs./Ft³	
Velocity	5,110.8	Fpm		Velocity	4,603.6	Fpm	
Airflow	13,081.1	Lbs./Hr.	Burner Line	Airflow	11,857.9	Lbs./Hr.	Burner Line
Grams Recv	0.00	Grams	Air:Fuel	Grams Recv	0.00	Grams	Air:Fuel
Fuel Flow	0.0	Lbs./Hr.	#DIV/0!	Fuel Flow	0.0	Lbs./Hr.	#DIV/0!

Burner No. :	**A3**	**Left Rear**		**Burner No. :**	**A4**	**Left Front**	
Point	**Port 1**	**Port 2**		**Point**	**Port 1**	**Port 2**	
1	1.25	1.40		1	1.65	1.45	
2	1.35	1.45		2	1.60	1.55	
3	1.35	1.45		3	1.50	1.55	
4	1.32	1.45		4	1.45	1.50	
5	1.25	1.35		5	1.45	1.45	
6	1.10	1.15		6	1.25	1.35	
7	1.10	1.15		7	1.25	1.40	
8	1.10	1.05		8	1.20	1.45	
3	1.05	1.05		9	1.15	1.40	
10	0.32	0.39		10	0.44	0.38	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	1.06109	"w.c.		Sqrt Vh	1.13608	"w.c.	
Temperature	150.2	°F		Temperature	154.9	°F	
Static	0.00	"w.c.		Static	0.2	"w.c.	
Density	0.0651	Lbs./Ft³		Density	0.0646	Lbs./Ft³	
Velocity	4,375.7	Fpm		Velocity	4,701.8	Fpm	
Airflow	11,279.4	Lbs./Hr.	Burner Line	Airflow	12,033.3	Lbs./Hr.	Burner Line
Grams Recv	0.00	Grams	Air:Fuel	Grams Recv	0.00	Grams	Air:Fuel
	0.0	Lbs./Hr.	#DIV/0!	Fuel Flow	0.0	Lbs./Hr.	#DIV/0!

Total Dirty Airflow	**48,251.7**	**Lbs./Hr.**	**Average Pipe Temperature**	**152.9**	**°F**
Total Fuel Flow	**0.0**	**Lbs./Hr.**	**Average Pipe Velocity**	**4,698.0**	**Fpm**
Measured Air to Fuel Ratio	**#DIV/0!**	**Lb. Air/Lb. Fuel**	**Average Fuel Flow**	**0.0**	**Lbs./Hr.**

Fuel Balance				***Dirty Air Balance***			
A1	**A2**	**A3**	**A4**	**A1**	**A2**	**A3**	**A4**
#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	+8.79%	-2.01%	-6.86%	+0.08%

Baseline Test						**Barometric Pressure (" Hg) :**	**29.90"**
Coal Pipe I.D. (inches) :	**11.000**					**Pulverizer :**	**2A**
Coal Pipe Area (Ft²) :	**0.65995**					**Date:**	**02-May-00**
Test Personnel:	**RPS/WEP**					**Test No. :**	**2**

Burner No. :	**A1**	**Right Front**		**Burner No. :**	**A2**	**Right Rear**	
Point	**Port 1**	**Port 2**		**Point**	**Port 1**	**Port 2**	
1	1.10	1.15		1	0.76	0.81	
2	1.25	1.10		2	0.81	0.89	
3	1.25	1.10		3	0.86	0.93	
4	1.15	1.10		4	0.85	0.91	
5	1.25	1.10		5	0.87	0.86	
6	1.15	1.00		6	0.83	0.83	
7	1.05	0.99		7	0.84	0.84	
8	1.00	0.97		8	0.88	0.85	
9	0.93	0.92		9	0.88	0.87	
10	0.46	0.22		10	0.35	0.51	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	0.99453	"w.c.		Sqrt Vh	0.89673	"w.c.	
Temperature	154.4	°F		Temperature	148.3	°F	
Static	1.1	"w.c.		Static	0.00	"w.c.	
Density	0.0648	Lbs./Ft³		Density	0.0653	Lbs./Ft³	
Velocity	4,109.8	Fpm		Velocity	3,692.2	Fpm	
Airflow	10,549.9	Lbs./Hr.	Burner Line	Airflow	9,547.1	Lbs./Hr.	Burner Line
Grams Recv	326.00	Grams	Air:Fuel	Grams Recv	293.00	Grams	Air:Fuel
Fuel Flow	3,387.9	Lbs./Hr.	3.11	Fuel Flow	3,044.9	Lbs./Hr.	3.14

Burner No. :	**A3**	**Left Rear**		**Burner No. :**	**A4**	**Left Front**	
Point	**Port 1**	**Port 2**		**Point**	**Port 1**	**Port 2**	
1	0.61	0.85		1	0.71	0.89	
2	0.81	0.89		2	0.73	1.05	
3	0.89	0.89		3	0.75	1.05	
4	0.90	0.86		4	0.76	1.05	
5	0.86	0.82		5	0.77	1.05	
6	0.79	0.71		6	0.81	1.05	
7	0.81	0.63		7	0.81	0.99	
8	0.85	0.46		8	0.79	0.96	
3	0.78	0.37		9	0.79	0.83	
10	0.22	0.09		10	0.38	0.23	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	0.82140	"w.c.		Sqrt Vh	0.89699	"w.c.	
Temperature	147	°F		Temperature	148.3	°F	
Static	0.00	"w.c.		Static	0	"w.c.	
Density	0.0654	Lbs./Ft³		Density	0.0653	Lbs./Ft³	
Velocity	3,378.4	Fpm		Velocity	3,693.2	Fpm	
Airflow	8,754.4	Lbs./Hr.	Burner Line	Airflow	9,549.9	Lbs./Hr.	Burner Line
Grams Recv	317.50	Grams	Air:Fuel	Grams Recv	324.50	Grams	Air:Fuel
Fuel Flow	3,299.6	Lbs./Hr.	2.65	Fuel Flow	3,372.3	Lbs./Hr.	2.83

Total Dirty Airflow	**38,401.4**	**Lbs./Hr.**	**Average Pipe Temperature**	**149.5**	**°F**
Total Fuel Flow	**13,104.7**	**Lbs./Hr.**	**Average Pipe Velocity**	**3,718.4**	**Fpm**
Measured Air to Fuel Ratio	**2.93**	**Lb. Air/Lb. Fuel**	**Average Fuel Flow**	**3,276.2**	**Lbs./Hr.**

Fuel Balance				***Dirty Air Balance***			
A1	**A2**	**A3**	**A4**	**A1**	**A2**	**A3**	**A4**
+3.41%	-7.06%	+0.71%	+2.93%	+10.53%	-0.71%	-9.14%	-0.68%

Baseline Test				Barometric Pressure (" Hg) :	29.90"
Coal Pipe I.D. (inches) :	11.000			Pulverizer :	2A
Coal Pipe Area (Ft²) :	0.65995			Date:	02-May-00
Test Personnel:	RPS/WEP			Test No. :	3

Burner No. :	A1	Right Front		Burner No. :	A2	Right Rear	
Point	Port 1	Port 2		Point	Port 1	Port 2	
1	1.55	1.35		1	1.00	1.15	
2	1.45	1.45		2	1.10	1.25	
3	1.55	1.50		3	1.15	1.25	
4	1.45	1.50		4	1.15	1.20	
5	1.45	1.45		5	1.25	1.20	
6	1.40	1.35		6	1.20	1.10	
7	1.35	1.35		7	1.15	1.05	
8	1.35	1.35		8	1.15	1.10	
9	1.20	1.25		9	1.10	1.10	
10	0.69	0.38		10	0.43	0.51	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	1.13877	"w.c.		Sqrt Vh	1.03205	"w.c.	
Temperature	147.5	°F		Temperature	147	°F	
Static	0.57	"w.c.		Static	0.35	"w.c.	
Density	0.0655	Lbs./Ft³		Density	0.0655	Lbs./Ft³	
Velocity	4,682.4	Fpm		Velocity	4,242.9	Fpm	
Airflow	12,140.5	Lbs./Hr.	Burner Line	Airflow	11,004.3	Lbs./Hr.	Burner Line
Grams Recv	416.00	Grams	Air:Fuel	Grams Recv	393.50	Grams	Air:Fuel
Fuel Flow	4,323.2	Lbs./Hr.	2.81	Fuel Flow	4,089.4	Lbs./Hr.	2.69

Burner No. :	A3	Left Rear		Burner No. :	A4	Left Front	
Point	Port 1	Port 2		Point	Port 1	Port 2	
1	1.05	1.05		1	1.35	1.25	
2	1.20	1.05		2	1.25	1.25	
3	1.25	1.05		3	1.25	1.35	
4	1.15	1.05		4	1.30	1.35	
5	1.10	1.05		5	1.25	1.25	
6	0.99	0.95		6	1.15	1.15	
7	0.88	0.94		7	1.15	1.10	
8	0.86	0.97		8	1.15	1.15	
3	0.81	0.90		9	1.15	1.05	
10	0.14	0.10		10	0.22	0.21	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	0.94057	"w.c.		Sqrt Vh	1.03846	"w.c.	
Temperature	147	°F		Temperature	147	°F	
Static	0.10	"w.c.		Static	0.3	"w.c.	
Density	0.0655	Lbs./Ft³		Density	0.0655	Lbs./Ft³	
Velocity	3,868.0	Fpm		Velocity	4,269.5	Fpm	
Airflow	10,025.8	Lbs./Hr.	Burner Line	Airflow	11,071.9	Lbs./Hr.	Burner Line
Grams Recv	378.50	Grams	Air:Fuel	Grams Recv	430.00	Grams	Air:Fuel
Fuel Flow	3,933.5	Lbs./Hr.	2.55	Fuel Flow	4,468.7	Lbs./Hr.	2.48

Total Dirty Airflow	44,242.6	Lbs./Hr.	Average Pipe Temperature	147.125	°F
Total Fuel Flow	16,814.7	Lbs./Hr.	Average Pipe Velocity	4,265.7	Fpm
Measured Air to Fuel Ratio	2.63	Lb. Air/Lb. Fuel	Average Fuel Flow	4,203.7	Lbs./Hr.

Fuel Balance				*Dirty Air Balance*			
A1	A2	A3	A4	A1	A2	A3	A4
+2.84%	-2.72%	-6.43%	+6.30%	+9.77%	-0.53%	-9.32%	+0.09%

Baseline Test				Barometric Pressure (" Hg) :	29.90"
Coal Pipe I.D. (inches) :	11.000			Pulverizer :	2A
Coal Pipe Area (Ft²) :	0.65995			Date:	02-May-00
Test Personnel:	RPS/WEP			Test No. :	4

Burner No. :	A1	Right Front		Burner No. :	A2	Right Rear	
Point	Port 1	Port 2		Point	Port 1	Port 2	
1	1.65	1.95		1	1.00	1.45	
2	1.65	1.80		2	1.35	1.45	
3	1.65	1.90		3	1.45	1.45	
4	1.55	1.85		4	1.45	1.45	
5	1.65	1.75		5	1.45	1.35	
6	1.50	1.65		6	1.40	1.25	
7	1.55	1.60		7	1.40	1.20	
8	1.60	1.60		8	1.45	1.25	
9	1.50	1.50		9	1.35	1.05	
10	0.35	0.59		10	0.49	0.56	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	1.22704	"w.c.		Sqrt Vh	1.11450	"w.c.	
Temperature	137	°F		Temperature	138.8	°F	
Static	1.05	"w.c.		Static	0.85	"w.c.	
Density	0.0667	Lbs./Ft³		Density	0.0665	Lbs./Ft³	
Velocity	4,998.5	Fpm		Velocity	4,548.0	Fpm	
Airflow	13,203.8	Lbs./Hr.	Burner Line	Airflow	11,971.8	Lbs./Hr.	Burner Line
Grams Recv	811.00	Grams	Air:Fuel	Grams Recv	635.50	Grams	Air:Fuel
Fuel Flow	8,428.2	Lbs./Hr.	1.57	Fuel Flow	6,604.3	Lbs./Hr.	1.81

Burner No. :	A3	Left Rear		Burner No. :	A4	Left Front	
Point	Port 1	Port 2		Point	Port 1	Port 2	
1	1.50	1.45		1	1.85	0.92	
2	1.35	1.65		2	1.80	1.25	
3	1.20	1.55		3	1.65	1.45	
4	1.25	1.40		4	1.65	1.40	
5	1.05	1.45		5	1.45	1.35	
6	1.05	1.30		6	1.20	1.35	
7	1.05	1.25		7	1.20	1.15	
8	1.10	1.20		8	1.20	1.15	
3	1.05	1.25		9	1.05	1.05	
10	0.09	1.05		10	0.21	0.32	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	1.08326	"w.c.		Sqrt Vh	1.08839	"w.c.	
Temperature	136.7	°F		Temperature	136.9	°F	
Static	0.45	"w.c.		Static	0.75	"w.c.	
Density	0.0666	Lbs./Ft³		Density	0.0667	Lbs./Ft³	
Velocity	4,415.0	Fpm		Velocity	4,435.0	Fpm	
Airflow	11,651.0	Lbs./Hr.	Burner Line	Airflow	11,708.5	Lbs./Hr.	Burner Line
Grams Recv	578.50	Grams	Air:Fuel	Grams Recv	623.70	Grams	Air:Fuel
Fuel Flow	6,011.9	Lbs./Hr.	1.94	Fuel Flow	6,481.7	Lbs./Hr.	1.81

Total Dirty Airflow	48,535.2	Lbs./Hr.	Average Pipe Temperature	137.35	°F
Total Fuel Flow	27,526.1	Lbs./Hr.	Average Pipe Velocity	4,599.1	Fpm
Measured Air to Fuel Ratio	1.76	Lb. Air/Lb. Fuel	Average Fuel Flow	6,881.5	Lbs./Hr.

Fuel Balance				*Dirty Air Balance*			
A1	A2	A3	A4	A1	A2	A3	A4
+22.48%	-4.03%	-12.64%	-5.81%	+8.68%	-1.11%	-4.00%	-3.57%

Baseline Test		Barometric Pressure (" Hg) :	29.90"
Coal Pipe I.D. (inches) :	11.000	Pulverizer :	2B
Coal Pipe Area (Ft²) :	0.65995	Date:	02-May-00
Test Personnel:	RPS/WEP	Test No. :	1

Burner No. :	B1	Right Front		Burner No. :	B2	Right Rear	
Point	Port 1	Port 2		Point	Port 1	Port 2	
1	1.45	1.35		1	1.10	1.45	
2	1.55	1.40		2	1.25	1.35	
3	1.65	1.45		3	1.25	1.35	
4	1.65	1.40		4	1.25	1.35	
5	1.50	1.45		5	1.25	1.30	
6	1.45	1.40		6	1.20	1.25	
7	1.35	1.40		7	1.20	1.25	
8	1.40	1.40		8	1.25	1.15	
9	1.35	1.40		9	1.20	1.25	
10	0.94	0.26		10	0.45	0.31	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	1.15515	"w.c.		Sqrt Vh	1.07047	"w.c.	
Temperature	157.3	°F		Temperature	155	°F	
Static	0.52	"w.c.		Static	0.70	"w.c.	
Density	0.0644	Lbs./Ft³		Density	0.0647	Lbs./Ft³	
Velocity	4,788.2	Fpm		Velocity	4,427.9	Fpm	
Airflow	12,216.3	Lbs./Hr.	Burner Line	Airflow	11,344.4	Lbs./Hr.	Burner Line
Grams Recv	0.00	Grams	Air:Fuel	Grams Recv	0.00	Grams	Air:Fuel
Fuel Flow	0.0	Lbs./Hr.	#DIV/0!	Fuel Flow	0.0	Lbs./Hr.	#DIV/0!

Burner No. :	B3	Left Rear		Burner No. :	B4	Left Front	
Point	Port 1	Port 2		Point	Port 1	Port 2	
1	1.25	1.45		1	1.60	1.30	
2	1.25	1.45		2	1.60	1.35	
3	1.25	1.45		3	1.55	1.35	
4	1.25	1.40		4	1.45	1.40	
5	1.25	1.40		5	1.45	1.35	
6	1.25	1.10		6	1.25	1.35	
7	1.15	1.15		7	1.25	1.25	
8	1.15	1.15		8	1.10	1.30	
3	1.15	1.05		9	0.87	1.30	
10	0.14	0.20		10	0.21	0.46	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	1.04720	"w.c.		Sqrt Vh	1.09533	"w.c.	
Temperature	156.1	°F		Temperature	152.7	°F	
Static	0.45	"w.c.		Static	0.6	"w.c.	
Density	0.0645	Lbs./Ft³		Density	0.0649	Lbs./Ft³	
Velocity	4,336.8	Fpm		Velocity	4,522.8	Fpm	
Airflow	11,084.4	Lbs./Hr.	Burner Line	Airflow	11,628.1	Lbs./Hr.	Burner Line
Grams Recv	0.00	Grams	Air:Fuel	Grams Recv	0.00	Grams	Air:Fuel
Fuel Flow	0.0	Lbs./Hr.	#DIV/0!	Fuel Flow	0.0	Lbs./Hr.	#DIV/0!

Total Dirty Airflow	46,273.1	Lbs./Hr.	Average Pipe Temperature	155.275	°F
Total Fuel Flow	0.0	Lbs./Hr.	Average Pipe Velocity	4,518.9	Fpm
Measured Air to Fuel Ratio	#DIV/0!	Lb. Air/Lb. Fuel	Average Fuel Flow	0.0	Lbs./Hr.

Fuel Balance				*Dirty Air Balance*			
B1	B2	B3	B4	B1	B2	B3	B4
#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	+5.96%	-2.01%	-4.03%	+0.09%

Baseline Test		**Barometric Pressure (" Hg) :**	**29.90"**
Coal Pipe I.D. (inches) :	**11.000**	**Pulverizer :**	**2B**
Coal Pipe Area (Ft²) :	**0.65995**	**Date:**	**02-May-00**
Test Personnel:	**RPS/WEP**	**Test No. :**	**6**

Burner No. :	B1	Right Front	Burner No. :	B2	Right Rear
Point	Port 1	Port 2	Point	Port 1	Port 2
1	0.89	0.13	1	0.87	1.10
2	0.98	0.99	2	1.00	1.00
3	1.00	1.00	3	0.97	1.00
4	1.00	1.00	4	0.97	0.99
5	1.00	1.00	5	0.99	0.96
6	1.00	0.97	6	0.92	0.88
7	0.98	0.99	7	0.86	0.85
8	0.98	1.00	8	0.79	0.82
9	1.00	1.10	9	0.73	0.71
10	0.66	0.75	10	0.44	0.38

K Factor	0.96			K Factor	0.96		
Sqrt Vh	0.94880	"w.c.		Sqrt Vh	0.92194	"w.c.	
Temperature	160.9	°F		Temperature	153.7	°F	
Static	0.23	"w.c.		Static	0.20	"w.c.	
Density	0.0640	Lbs./Ft³		Density	0.0648	Lbs./Ft³	
Velocity	3,945.7	Fpm		Velocity	3,811.8	Fpm	
Airflow	10,001.2	Lbs./Hr.	Burner Line	Airflow	9,774.6	Lbs./Hr.	Burner Line
Grams Recv	313.00	Grams	Air:Fuel	Grams Recv	299.50	Grams	Air:Fuel
Fuel Flow	3,252.8	Lbs./Hr.	3.07	Fuel Flow	3,112.5	Lbs./Hr.	3.14

Burner No. :	B3	Left Rear	Burner No. :	B4	Left Front
Point	Port 1	Port 2	Point	Port 1	Port 2
1	0.81	0.83	1	0.15	1.10
2	0.91	0.86	2	0.99	1.00
3	0.93	0.90	3	1.00	1.00
4	0.96	0.92	4	1.10	0.99
5	0.95	0.92	5	1.00	0.96
6	0.83	0.86	6	0.86	0.85
7	0.82	0.90	7	0.83	0.85
8	0.81	0.90	8	0.77	0.82
9	0.90	0.89	9	0.72	0.71
10	0.66	0.41	10	0.30	0.38

K Factor	0.96			K Factor	0.96		
Sqrt Vh	0.91822	"w.c.		Sqrt Vh	0.88877	"w.c.	
Temperature	156.9	°F		Temperature	159.3	°F	
Static	0.07	"w.c.		Static	0.37	"w.c.	
Density	0.0644	Lbs./Ft³		Density	0.0642	Lbs./Ft³	
Velocity	3,806.9	Fpm		Velocity	3,690.6	Fpm	
Airflow	9,708.3	Lbs./Hr.	Burner Line	Airflow	9,382.2	Lbs./Hr.	Burner Line
Grams Recv	369.50	Grams	Air:Fuel	Grams Recv	384.50	Grams	Air:Fuel
Fuel Flow	3,840.0	Lbs./Hr.	2.53	Fuel Flow	3,995.8	Lbs./Hr.	2.35

Total Dirty Airflow	38,866.4	Lbs./Hr.	Average Pipe Temperature	157.7	°F
Total Fuel Flow	14,201.1	Lbs./Hr.	Average Pipe Velocity	3,813.8	Fpm
Measured Air to Fuel Ratio	2.74	Lb. Air/Lb. Fuel	Average Fuel Flow	3,550.3	Lbs./Hr.

Fuel Balance				*Dirty Air Balance*			
B1	B2	B3	B4	B1	B2	B3	B4
-8.38%	-12.33%	+8.16%	+12.55%	+3.46%	-0.05%	-0.18%	-3.23%

Baseline Test			Barometric Pressure (" Hg) :	29.90"
Coal Pipe I.D. (inches) :	11.000		Pulverizer :	2B
Coal Pipe Area (Ft²) :	0.65995		Date:	02-May-00
Test Personnel:	RPS/WEP		Test No. :	7

Burner No. :	B1	Right Front		Burner No. :	B2	Right Rear	
Point	Port 1	Port 2		Point	Port 1	Port 2	
1	1.40	1.40		1	1.30	1.00	
2	1.50	1.45		2	1.50	1.35	
3	1.50	1.45		3	1.45	1.40	
4	1.45	1.45		4	1.40	1.30	
5	1.40	1.50		5	1.35	1.30	
6	1.25	1.40		6	1.30	1.20	
7	1.25	1.50		7	1.30	1.30	
8	1.30	1.45		8	1.30	1.30	
9	1.45	1.65		9	1.30	1.30	
10	1.00	1.00		10	0.86	0.78	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	1.17588	"w.c.		Sqrt Vh	1.12134	"w.c.	
Temperature	159.9	°F		Temperature	157.8	°F	
Static	0.82	"w.c.		Static	0.82	"w.c.	
Density	0.0642	Lbs./Ft³		Density	0.0644	Lbs./Ft³	
Velocity	4,882.5	Fpm		Velocity	4,648.2	Fpm	
Airflow	12,413.9	Lbs./Hr.	Burner Line	Airflow	11,858.3	Lbs./Hr.	Burner Line
Grams Recv	424.00	Grams	Air:Fuel	Grams Recv	377.00	Grams	Air:Fuel
Fuel Flow	4,406.3	Lbs./Hr.	2.82	Fuel Flow	3,917.9	Lbs./Hr.	3.03

Burner No. :	B3	Left Rear		Burner No. :	B4	Left Front	
Point	Port 1	Port 2		Point	Port 1	Port 2	
1	1.10	1.40		1	1.50	1.55	
2	1.30	1.55		2	1.60	1.60	
3	1.35	1.50		3	1.55	1.50	
4	1.30	1.50		4	1.55	1.60	
5	1.30	1.40		5	1.50	1.50	
6	1.25	1.30		6	1.30	1.40	
7	1.15	1.15		7	1.15	1.30	
8	1.20	1.15		8	1.10	1.35	
9	1.20	1.00		9	1.00	1.30	
10	0.84	0.62		10	0.65	0.36	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	1.10311	"w.c.		Sqrt Vh	1.13609	"w.c.	
Temperature	157.3	°F		Temperature	160.1	°F	
Static	0.76	"w.c.		Static	0.77	"w.c.	
Density	0.0645	Lbs./Ft³		Density	0.0642	Lbs./Ft³	
Velocity	4,571.1	Fpm		Velocity	4,718.3	Fpm	
Airflow	11,669.4	Lbs./Hr.	Burner Line	Airflow	11,991.1	Lbs./Hr.	Burner Line
Grams Recv	441.50	Grams	Air:Fuel	Grams Recv	452.50	Grams	Air:Fuel
Fuel Flow	4,588.2	Lbs./Hr.	2.54	Fuel Flow	4,702.5	Lbs./Hr.	2.55

Total Dirty Airflow	47,932.7	Lbs./Hr.	Average Pipe Temperature	158.775	°F
Total Fuel Flow	17,614.9	Lbs./Hr.	Average Pipe Velocity	4,705.0	Fpm
Measured Air to Fuel Ratio	2.72	Lb. Air/Lb. Fuel	Average Fuel Flow	4,403.7	Lbs./Hr.

Fuel Balance				*Dirty Air Balance*			
B1	B2	B3	B4	B1	B2	B3	B4
+0.06%	-11.03%	+4.19%	+6.78%	+3.77%	-1.21%	-2.85%	+0.28%

Baseline Test			Barometric Pressure (" Hg) :	29.90"
Coal Pipe I.D. (inches) :	11.000		Pulverizer :	2B
Coal Pipe Area (Ft²) :	0.65995		Date:	02-May-00
Test Personnel:	RPS/WEP		Test No. :	8

Burner No. :	B1	Right Front		Burner No. :	B2	Right Rear	
Point	Port 1	Port 2		Point	Port 1	Port 2	
1	1.50	1.80		1	1.60	2.00	
2	1.70	2.10		2	1.90	1.90	
3	1.75	1.95		3	2.00	1.80	
4	1.75	2.05		4	1.75	1.85	
5	1.80	2.10		5	1.70	1.70	
6	2.00	2.80		6	1.60	1.60	
7	1.90	2.85		7	1.70	1.60	
8	1.95	2.00		8	1.70	1.50	
9	1.90	1.95		9	1.95	1.60	
10	1.30	1.40		10	1.25	0.75	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	1.38235	"w.c.		Sqrt Vh	1.28775	"w.c.	
Temperature	146.1	°F		Temperature	142.7	°F	
Static	1.5	"w.c.		Static	1.50	"w.c.	
Density	0.0658	Lbs./Ft³		Density	0.0662	Lbs./Ft³	
Velocity	5,670.9	Fpm		Velocity	5,268.0	Fpm	
Airflow	14,771.2	Lbs./Hr.	Burner Line	Airflow	13,799.1	Lbs./Hr.	Burner Line
Grams Recv	571.50	Grams	Air:Fuel	Grams Recv	581.00	Grams	Air:Fuel
Fuel Flow	5,939.2	Lbs./Hr.	2.49	Fuel Flow	6,037.9	Lbs./Hr.	2.29

Burner No. :	B3	Left Rear		Burner No. :	B4	Left Front	
Point	Port 1	Port 2		Point	Port 1	Port 2	
1	2.10	1.50		1	1.70	2.20	
2	1.95	1.95		2	1.80	2.10	
3	2.00	1.90		3	1.75	2.10	
4	1.80	1.95		4	1.90	2.10	
5	1.80	1.65		5	1.85	1.95	
6	1.40	1.70		6	1.70	1.85	
7	1.25	1.65		7	1.90	1.90	
8	1.20	1.65		8	1.90	1.70	
9	1.00	1.70		9	1.85	1.40	
10	0.39	1.30		10	0.88	0.60	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	1.24808	"w.c.		Sqrt Vh	1.31465	"w.c.	
Temperature	144.3	°F		Temperature	144.4	°F	
Static	1.50	"w.c.		Static	4.65	"w.c.	
Density	0.0660	Lbs./Ft³		Density	0.0665	Lbs./Ft³	
Velocity	5,112.4	Fpm		Velocity	5,364.9	Fpm	
Airflow	13,356.3	Lbs./Hr.	Burner Line	Airflow	14,121.7	Lbs./Hr.	Burner Line
Grams Recv	620.50	Grams	Air:Fuel	Grams Recv	646.50	Grams	Air:Fuel
Fuel Flow	6,448.4	Lbs./Hr.	2.07	Fuel Flow	6,718.6	Lbs./Hr.	2.10

Total Dirty Airflow	56,048.3	Lbs./Hr.	Average Pipe Temperature	144.375	°F
Total Fuel Flow	25,144.2	Lbs./Hr.	Average Pipe Velocity	5,354.0	Fpm
Measured Air to Fuel Ratio	2.23	Lb. Air/Lb. Fuel	Average Fuel Flow	6,286.0	Lbs./Hr.

Fuel Balance				*Dirty Air Balance*			
B1	B2	B3	B4	B1	B2	B3	B4
-5.52%	-3.95%	+2.58%	+6.88%	+5.92%	-1.61%	-4.51%	+0.20%

Baseline Test								
Coal Pipe I.D. (inches) :	11.000					Barometric Pressure (" Hg) :		29.90"
Coal Pipe Area (Ft^2) :	0.65995					Pulverizer :		2C
Test Personnel:	RPS/WEP					Date:		02-May-00
						Test No. :		9

Burner No. :	B1	Right Front		Burner No. :	B2	Right Rear	
Point	Port 1	Port 2		Point	Port 1	Port 2	
1	1.00	0.87		1	1.20	1.20	
2	1.00	1.00		2	1.20	1.15	
3	1.10	1.00		3	1.10	1.10	
4	1.00	1.00		4	1.05	1.05	
5	1.00	1.00		5	1.00	0.96	
6	0.99	1.00		6	0.84	0.88	
7	0.97	1.10		7	0.77	0.86	
8	0.96	1.10		8	0.72	0.80	
9	0.68	1.15		9	0.72	0.84	
10	0.25	0.70		10	0.60	0.66	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	0.96362	"w.c.		Sqrt Vh	0.96200	"w.c.	
Temperature	152.4	°F		Temperature	152	°F	
Static	0.42	"w.c.		Static	0.30	"w.c.	
Density	0.0649	Lbs./Ft^3		Density	0.0650	Lbs./Ft^3	
Velocity	3,978.9	Fpm		Velocity	3,971.4	Fpm	
Airflow	10,230.2	Lbs./Hr.	Burner Line	Airflow	10,214.8	Lbs./Hr.	Burner Line
Grams Recv	326.50	Grams	Air:Fuel	Grams Recv	419.50	Grams	Air:Fuel
Fuel Flow	3,393.1	Lbs./Hr.	3.02	Fuel Flow	4,359.6	Lbs./Hr.	2.34

Burner No. :	B3	Left Rear		Burner No. :	B4	Left Front	
Point	Port 1	Port 2		Point	Port 1	Port 2	
1	1.20	1.10		1	1.00	1.20	
2	1.10	1.10		2	1.00	1.25	
3	1.10	1.10		3	1.15	1.20	
4	1.00	1.05		4	1.20	1.15	
5	1.00	0.99		5	1.20	1.10	
6	0.88	0.90		6	1.10	0.99	
7	0.76	0.93		7	1.00	0.93	
8	0.78	0.95		8	1.10	0.87	
9	0.69	0.94		9	1.25	0.95	
10	0.50	0.50		10	0.99	0.65	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	0.95772	"w.c.		Sqrt Vh	1.02885	"w.c.	
Temperature	153	°F		Temperature	155.1	°F	
Static	0.38	"w.c.		Static	0.46	"w.c.	
Density	0.0649	Lbs./Ft^3		Density	0.0647	Lbs./Ft^3	
Velocity	3,956.6	Fpm		Velocity	4,257.3	Fpm	
Airflow	10,162.0	Lbs./Hr.	Burner Line	Airflow	10,899.2	Lbs./Hr.	Burner Line
Grams Recv	404.50	Grams	Air:Fuel	Grams Recv	311.00	Grams	Air:Fuel
Fuel Flow	4,203.7	Lbs./Hr.	2.42	Fuel Flow	3,232.0	Lbs./Hr.	3.37

Total Dirty Airflow	41,506.1	Lbs./Hr.	Average Pipe Temperature	153.125	°F
Total Fuel Flow	15,188.3	Lbs./Hr.	Average Pipe Velocity	4,041.1	Fpm
Measured Air to Fuel Ratio	2.73	Lb. Air/Lb. Fuel	Average Fuel Flow	3,797.1	Lbs./Hr.

Fuel Balance				*Dirty Air Balance*			
B1	B2	B3	B4	B1	B2	B3	B4
-10.64%	+14.81%	+10.71%	-14.88%	-1.54%	-1.72%	-2.09%	+5.35%

Baseline Test				Barometric Pressure (" Hg) :	29.90"
Coal Pipe I.D. (inches) :	11.000			Pulverizer :	2C
Coal Pipe Area (Ft²) :	0.65995			Date:	02-May-00
Test Personnel:	RPS/WEP			Test No. :	10

Burner No. :	B1	Right Front		Burner No. :	B2	Right Rear	
Point	Port 1	Port 2		Point	Port 1	Port 2	
1	1.20	1.50		1	1.60	1.15	
2	1.30	1.20		2	1.45	1.20	
3	1.35	1.35		3	1.50	1.20	
4	1.40	1.35		4	1.50	1.30	
5	1.35	1.30		5	1.30	1.30	
6	1.30	1.30		6	1.20	1.25	
7	1.35	1.25		7	1.20	1.20	
8	1.45	1.20		8	1.25	1.20	
9	1.50	1.30		9	1.25	1.30	
10	1.10	0.94		10	0.57	1.00	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	1.13850	"w.c.		Sqrt Vh	1.11167	"w.c.	
Temperature	152.6	°F		Temperature	148	°F	
Static	0.98	"w.c.		Static	0.82	"w.c.	
Density	0.0650	Lbs./Ft³		Density	0.0655	Lbs./Ft³	
Velocity	4,698.5	Fpm		Velocity	4,571.4	Fpm	
Airflow	12,093.0	Lbs./Hr.	Burner Line	Airflow	11,850.3	Lbs./Hr.	Burner Line
Grams Recv	383.00	Grams	Air:Fuel	Grams Recv	435.50	Grams	Air:Fuel
Fuel Flow	3,980.3	Lbs./Hr.	3.04	Fuel Flow	4,525.8	Lbs./Hr.	2.62

Burner No. :	B3	Left Rear		Burner No. :	B4	Left Front	
Point	Port 1	Port 2		Point	Port 1	Port 2	
1	1.45	1.45		1	1.65	1.50	
2	1.50	1.40		2	1.60	1.55	
3	1.45	1.45		3	1.65	1.50	
4	1.40	1.35		4	1.60	1.55	
5	1.35	1.35		5	1.60	1.55	
6	1.15	1.20		6	1.50	1.30	
7	1.05	1.20		7	1.55	1.25	
8	0.96	1.30		8	1.60	1.25	
9	0.84	1.30		9	1.60	1.25	
10	0.75	0.92		10	1.75	0.97	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	1.10917	"w.c.		Sqrt Vh	1.21757	"w.c.	
Temperature	153.7	°F		Temperature	155.1	°F	
Static	1.00	"w.c.		Static	1	"w.c.	
Density	0.0649	Lbs./Ft³		Density	0.0647	Lbs./Ft³	
Velocity	4,581.4	Fpm		Velocity	5,034.9	Fpm	
Airflow	11,771.2	Lbs./Hr.	Burner Line	Airflow	12,906.9	Lbs./Hr.	Burner Line
Grams Recv	534.00	Grams	Air:Fuel	Grams Recv	382.00	Grams	Air:Fuel
Fuel Flow	5,549.5	Lbs./Hr.	2.12	Fuel Flow	3,969.9	Lbs./Hr.	3.25

Total Dirty Airflow	48,621.5	Lbs./Hr.	Average Pipe Temperature	152.35	°F
Total Fuel Flow	18,025.4	Lbs./Hr.	Average Pipe Velocity	4,721.5	Fpm
Measured Air to Fuel Ratio	2.70	Lb. Air/Lb. Fuel	Average Fuel Flow	4,506.4	Lbs./Hr.

Fuel Balance				*Dirty Air Balance*			
B1	B2	B3	B4	B1	B2	B3	B4
-11.67%	+0.43%	+23.15%	-11.91%	-0.49%	-3.18%	-2.97%	+6.64%

Baseline Test

Coal Pipe I.D. (inches) :	11.000
Coal Pipe Area (Ft^2) :	0.65995
Test Personnel:	RPS/WEP
Barometric Pressure (" Hg) :	29.90"
Pulverizer :	2C
Date:	02-May-00
Test No. :	11

Burner No. : B1 Right Front

Point	Port 1	Port 2
1	1.30	1.75
2	1.40	1.75
3	1.55	1.90
4	1.65	1.90
5	1.70	1.90
6	1.90	1.70
7	1.85	1.60
8	1.90	1.80
9	2.10	1.95
10	1.20	1.60

K Factor	0.96	
Sqrt Vh	1.30855	"w.c.
Temperature	149.5	°F
Static	1.65	"w.c.
Density	0.0654	Lbs./Ft^3
Velocity	5,382.2	Fpm
Airflow	13,946.1	Lbs./Hr.
Grams Recv	632.00	Grams
Fuel Flow	6,567.9	Lbs./Hr.

Burner Line Air:Fuel 2.12

Burner No. : B2 Right Rear

Point	Port 1	Port 2
1	2.00	1.60
2	1.90	1.55
3	1.80	1.55
4	1.75	1.60
5	1.70	1.55
6	1.60	1.55
7	1.55	1.55
8	1.60	1.55
9	1.70	1.70
10	1.40	1.50

K Factor	0.96	
Sqrt Vh	1.27756	"w.c.
Temperature	149.3	°F
Static	1.25	"w.c.
Density	0.0654	Lbs./Ft^3
Velocity	5,256.4	Fpm
Airflow	13,611.4	Lbs./Hr.
Grams Recv	647.00	Grams
Fuel Flow	6,723.8	Lbs./Hr.

Burner Line Air:Fuel 2.02

Burner No. : B3 Left Rear

Point	Port 1	Port 2
1	1.95	2.10
2	1.70	2.00
3	1.75	1.90
4	1.60	1.80
5	1.60	1.75
6	1.50	1.40
7	1.60	1.25
8	1.70	1.30
9	1.70	1.25
10	1.20	0.60

K Factor	0.96	
Sqrt Vh	1.24930	"w.c.
Temperature	149.1	°F
Static	1.70	"w.c.
Density	0.0655	Lbs./Ft^3
Velocity	5,136.5	Fpm
Airflow	13,319.8	Lbs./Hr.
Grams Recv	722.50	Grams
Fuel Flow	7,508.4	Lbs./Hr.

Burner Line Air:Fuel 1.77

Burner No. : B4 Left Front

Point	Port 1	Port 2
1	1.40	1.80
2	1.60	2.00
3	1.65	2.00
4	1.80	2.00
5	1.85	1.95
6	1.80	1.90
7	1.85	1.80
8	2.00	2.05
9	2.10	2.00
10	1.20	1.70

K Factor	0.96	
Sqrt Vh	1.34728	"w.c.
Temperature	150.4	°F
Static	1.9	"w.c.
Density	0.0654	Lbs./Ft^3
Velocity	5,543.8	Fpm
Airflow	14,352.7	Lbs./Hr.
Grams Recv	525.50	Grams
Fuel Flow	5,461.2	Lbs./Hr.

Burner Line Air:Fuel 2.63

Total Dirty Airflow	55,229.9	Lbs./Hr.
Total Fuel Flow	26,261.3	Lbs./Hr.
Measured Air to Fuel Ratio	2.10	Lb. Air/Lb. Fuel
Average Pipe Temperature	149.575	°F
Average Pipe Velocity	5,329.7	Fpm
Average Fuel Flow	6,565.3	Lbs./Hr.

Fuel Balance

B1	B2	B3	B4
+0.04%	+2.41%	+14.36%	-16.82%

Dirty Air Balance

B1	B2	B3	B4
+0.98%	-1.38%	-3.63%	+4.02%

Baseline Test					Barometric Pressure (" Hg) :	29.90"
Coal Pipe I.D. (inches) :	11.000				Pulverizer :	2D
Coal Pipe Area (Ft²) :	0.65995				Date:	02-May-00
Test Personnel:	RPS/WEP				Test No. :	12

Burner No. :	B1	Right Front		Burner No. :	B2	Right Rear	
Point	Port 1	Port 2		Point	Port 1	Port 2	
1	1.20	0.83		1	0.75	1.00	
2	1.10	0.87		2	0.66	0.98	
3	1.05	0.91		3	0.69	0.91	
4	0.96	0.85		4	0.64	0.81	
5	0.87	0.84		5	0.60	0.72	
6	0.76	0.74		6	0.55	0.59	
7	0.74	0.78		7	0.55	0.54	
8	0.71	0.86		8	0.55	0.65	
9	0.64	0.91		9	0.52	0.53	
10	0.33	0.58		10	0.43	0.40	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	0.90265	"w.c.		Sqrt Vh	0.80237	"w.c.	
Temperature	158.2	°F		Temperature	150.7	°F	
Static	0.43	"w.c.		Static	1.25	"w.c.	
Density	0.0643	Lbs./Ft³		Density	0.0652	Lbs./Ft³	
Velocity	3,744.7	Fpm		Velocity	3,305.1	Fpm	
Airflow	9,537.9	Lbs./Hr.	Burner Line	Airflow	8,538.8	Lbs./Hr.	Burner Line
Grams Recv	357.00	Grams	Air:Fuel	Grams Recv	378.00	Grams	Air:Fuel
Fuel Flow	3,710.1	Lbs./Hr.	2.57	Fuel Flow	3,928.3	Lbs./Hr.	2.17

Burner No. :	B3	Left Rear		Burner No. :	B4	Left Front	
Point	Port 1	Port 2		Point	Port 1	Port 2	
1	0.75	0.74		1	0.87	0.96	
2	0.75	0.83		2	1.00	0.96	
3	0.80	0.84		3	1.00	0.95	
4	0.77	0.84		4	0.98	0.93	
5	0.76	0.77		5	0.92	0.88	
6	0.67	0.66		6	0.73	0.88	
7	0.71	0.65		7	0.73	0.89	
8	0.75	0.68		8	0.72	0.92	
9	0.79	0.71		9	0.74	0.97	
10	0.80	0.56		10	0.62	0.97	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	0.86011	"w.c.		Sqrt Vh	0.93670	"w.c.	
Temperature	154.8	°F		Temperature	158	°F	
Static	0.42	"w.c.		Static	0.67	"w.c.	
Density	0.0647	Lbs./Ft³		Density	0.0644	Lbs./Ft³	
Velocity	3,558.4	Fpm		Velocity	3,884.1	Fpm	
Airflow	9,113.4	Lbs./Hr.	Burner Line	Airflow	9,902.2	Lbs./Hr.	Burner Line
Grams Recv	280.00	Grams	Air:Fuel	Grams Recv	296.50	Grams	Air:Fuel
Fuel Flow	2,909.8	Lbs./Hr.	3.13	Fuel Flow	3,081.3	Lbs./Hr.	3.21

Total Dirty Airflow	37,092.4 Lbs./Hr.		Average Pipe Temperature	155.425 °F
Total Fuel Flow	13,629.5 Lbs./Hr.		Average Pipe Velocity	3,623.1 Fpm
Measured Air to Fuel Ratio	2.72 Lb. Air/Lb. Fuel		Average Fuel Flow	3,407.4 Lbs./Hr.

Fuel Balance				*Dirty Air Balance*			
B1	B2	B3	B4	B1	B2	B3	B4
+8.88%	+15.29%	-14.60%	-9.57%	+3.36%	-8.78%	-1.79%	+7.21%

Baseline Test			Barometric Pressure (" Hg) :	29.90"
Coal Pipe I.D. (inches) :	11.000		Pulverizer :	2D
Coal Pipe Area (Ft²) :	0.65995		Date:	02-May-00
Test Personnel:	RPS/WEP		Test No. :	13

Burner No. :	B1	Right Front		Burner No. :	B2	Right Rear	
Point	Port 1	Port 2		Point	Port 1	Port 2	
1	1.00	1.70		1	1.25	1.05	
2	1.05	1.50		2	1.05	1.00	
3	1.05	1.45		3	1.00	1.00	
4	1.10	1.30		4	0.95	0.93	
5	1.10	1.20		5	0.92	0.93	
6	1.10	1.00		6	0.80	0.81	
7	1.10	1.10		7	0.80	0.84	
8	1.15	1.00		8	0.80	0.86	
9	1.30	0.95		9	0.87	0.83	
10	0.93	0.72		10	0.50	0.67	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	1.06310	"w.c.		Sqrt Vh	0.94133	"w.c.	
Temperature	156.1	°F		Temperature	155.8	°F	
Static	1	"w.c.		Static	1.10	"w.c.	
Density	0.0646	Lbs./Ft³		Density	0.0647	Lbs./Ft³	
Velocity	4,399.7	Fpm		Velocity	3,894.3	Fpm	
Airflow	11,260.3	Lbs./Hr.	Burner Line	Airflow	9,974.2	Lbs./Hr.	Burner Line
Grams Recv	436.00	Grams	Air:Fuel	Grams Recv	402.00	Grams	Air:Fuel
Fuel Flow	4,531.0	Lbs./Hr.	2.49	Fuel Flow	4,177.7	Lbs./Hr.	2.39

Burner No. :	B3	Left Rear		Burner No. :	B4	Left Front	
Point	Port 1	Port 2		Point	Port 1	Port 2	
1	1.00	1.00		1	1.15	1.30	
2	1.15	1.10		2	1.30	1.40	
3	1.20	1.10		3	1.20	1.40	
4	1.20	1.10		4	1.20	1.30	
5	1.10	1.05		5	1.10	1.25	
6	0.95	0.98		6	1.25	0.99	
7	1.00	1.00		7	1.30	0.98	
8	1.00	1.05		8	1.30	0.94	
9	1.10	1.05		9	1.45	0.99	
10	0.95	0.92		10	1.05	0.65	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	1.02399	"w.c.		Sqrt Vh	1.08000	"w.c.	
Temperature	153.3	°F		Temperature	158	°F	
Static	0.95	"w.c.		Static	1.3	"w.c.	
Density	0.0649	Lbs./Ft³		Density	0.0645	Lbs./Ft³	
Velocity	4,228.5	Fpm		Velocity	4,474.9	Fpm	
Airflow	10,870.2	Lbs./Hr.	Burner Line	Airflow	11,425.9	Lbs./Hr.	Burner Line
Grams Recv	385.60	Grams	Air:Fuel	Grams Recv	343.00	Grams	Air:Fuel
Fuel Flow	4,007.3	Lbs./Hr.	2.71	Fuel Flow	3,564.6	Lbs./Hr.	3.21

Total Dirty Airflow	43,530.6	Lbs./Hr.	Average Pipe Temperature	155.8	°F
Total Fuel Flow	16,280.6	Lbs./Hr.	Average Pipe Velocity	4,249.4	Fpm
Measured Air to Fuel Ratio	2.67	Lb. Air/Lb. Fuel	Average Fuel Flow	4,070.1	Lbs./Hr.

Fuel Balance				*Dirty Air Balance*			
B1	B2	B3	B4	B1	B2	B3	B4
+11.32%	+2.64%	-1.54%	-12.42%	+3.54%	-8.35%	-0.49%	+5.31%

Baseline Test		**0**	**29.90"**
Coal Pipe I.D. (inches) :	**11.000**	**Pulverizer :**	**2D**
Coal Pipe Area (Ft²) :	**0.65995**	**Date:**	**02-May-00**
Test Personnel:	**RPS/WEP**	**Test No. :**	**14**

Burner No. :	B1	Right Front		Burner No. :	B2	Right Rear	
Point	**Port 1**	**Port 2**		**Point**	**Port 1**	**Port 2**	
1	1.50	1.35		1	1.00	1.50	
2	1.60	1.60		2	1.15	1.45	
3	1.55	1.70		3	1.30	1.40	
4	1.65	1.70		4	1.35	1.35	
5	1.65	1.70		5	1.40	1.45	
6	1.60	1.65		6	1.35	1.25	
7	1.60	1.70		7	1.25	1.10	
8	1.60	1.70		8	1.30	1.20	
9	1.75	1.75		9	1.35	1.10	
10	1.60	1.30		10	1.05	0.87	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	1.26899	"w.c.		Sqrt Vh	1.11932	"w.c.	
Temperature	153.1	°F		Temperature	150.7	°F	
Static	2.1	"w.c.		Static	1.97	"w.c.	
Density	0.0651	Lbs./Ft³		Density	0.0654	Lbs./Ft³	
Velocity	5,232.0	Fpm		Velocity	4,606.6	Fpm	
Airflow	13,492.1	Lbs./Hr.	Burner Line	Airflow	11,922.3	Lbs./Hr.	Burner Line
Grams Recv	631.00	Grams	Air:Fuel	Grams Recv	585.50	Grams	Air:Fuel
Fuel Flow	6,557.5	Lbs./Hr.	2.06	Fuel Flow	6,084.7	Lbs./Hr.	1.96

Burner No. :	B3	Left Rear		Burner No. :	B4	Left Front	
Point	**Port 1**	**Port 2**		**Point**	**Port 1**	**Port 2**	
1	1.80	1.20		1	2.00	2.10	
2	1.90	1.30		2	1.95	2.00	
3	1.80	1.30		3	1.85	2.00	
4	1.70	1.50		4	1.85	1.95	
5	1.60	1.55		5	1.70	1.85	
6	1.50	1.35		6	1.75	1.30	
7	1.40	1.45		7	1.75	1.30	
8	1.60	1.50		8	1.85	1.45	
9	1.70	1.60		9	1.80	1.60	
10	1.35	1.50		10	1.50	1.25	
K Factor	0.96			K Factor	0.96		
Sqrt Vh	1.23475	"w.c.		Sqrt Vh	1.31543	"w.c.	
Temperature	152.9	°F		Temperature	155.1	°F	
Static	1.70	"w.c.		Static	2.6	"w.c.	
Density	0.0651	Lbs./Ft³		Density	0.0650	Lbs./Ft³	
Velocity	5,092.5	Fpm		Velocity	5,428.9	Fpm	
Airflow	13,123.8	Lbs./Hr.	Burner Line	Airflow	13,971.7	Lbs./Hr.	Burner Line
Grams Recv	577.00	Grams	Air:Fuel	Grams Recv	554.50	Grams	Air:Fuel
Fuel Flow	5,996.4	Lbs./Hr.	2.19	Fuel Flow	5,762.5	Lbs./Hr.	2.42

Total Dirty Airflow	**52,509.9**	**Lbs./Hr.**	**Average Pipe Temperature**	**152.95**	**°F**
Total Fuel Flow	**24,401.1**	**Lbs./Hr.**	**Average Pipe Velocity**	**5,090.0**	**Fpm**
Measured Air to Fuel Ratio	**2.15**	**Lb. Air/Lb. Fuel**	**Average Fuel Flow**	**6,100.3**	**Lbs./Hr.**

Fuel Balance				*Dirty Air Balance*			
B1	**B2**	**B3**	**B4**	**B1**	**B2**	**B3**	**B4**
+7.50%	-0.26%	-1.70%	-5.54%	+2.79%	-9.50%	+0.05%	+6.66%

B

March 2000 Estimates of Unit Air Flow Rates and Lower Furnace Stoichiometry

Test Matrix for Evaluating Vermilion 2 OFA System for Improved NOx Reduction

Day	Task start/end Time	Test	Condition	Load (% MCR)	Mills In Serv	Excess Oxygen	Burner Sec Air	DCS Data	Coal Sample	Coal Flow	Primary Air	Total Air Flow	OFA Air Flow
2/28/2000	0800 - 1700		Baseline Mill Test	100	4	Normal	As Found	x	x	x	x	DCS	DCS
2/29/2000	8:00 - 9:00	1	Baseline Emissions	100	4	Normal	As Found	x	---	---	---	DCS	DCS
2/29/2000	12:00 - 14:00	2	Reduced Mill Air	100	4	Normal	Air Bias	x	---	---	---	DCS	DCS
2/29/2000	14:00 - 15:30	3	Air Bias	100	4	Normal	Air Bias	x	x	---	---	DCS	DCS
2/29/2000	15:45 - 16:30	4	Increased Bias	100	4	Normal	Air Bias	x	---	---	---	DCS	DCS
2/29/2000	16:45 - 17:30	5	Increased Bias	100	4	Normal	Air Bias	x	---	---	---	DCS	DCS
3/1/2000	08:00 - 11:30		Full Load	100	4	Normal	As Found	x	---	---	---	DCS	DCS
3/1/2000	12:00 - 14:00	6	Baseline	70	4	Normal	As Found	x	x	---	---	DCS	DCS
3/1/2000	15:00 - 16:00	7	Air Bias	70	4	Normal	Air Bias	x	---	---	---	DCS	DCS
3/2/2000	09:00 - 10:30	8	Baseline	70	3	Normal	As Found	x	x	---	---	DCS	DCS
3/2/2000	12:00 - 13:00	9	Air Bias	70	3	Normal	Air Bias	x	---	---	---	DCS	DCS
3/2/2000			Teardown/Travel										

Day	Task start/end Time	Test	Condition	Load (% MCR)	Mills In Serv	Excess Oxygen	Burner Sec Air	Boiler O2	Economizer Outlet			LOI	Station CEMS
									NO	CO	O2		
2/28/2000	0800 - 1700		Baseline	100	4	Normal	As Found	---	---	---	---	---	---
2/29/2000	8:00 - 9:00	1	Baseline Emissions	100	4	Normal	As Found	---	x	x	x	x	---
2/29/2000	12:00 - 14:00	2	Reduced Mill Air	100	4	Normal	Air Bias	---	x	x	x	x	---
2/29/2000	14:00 - 15:30	3	Air Bias	100	4	Normal	Air Bias	---	x	x	x	x	---
2/29/2000	15:45 - 16:30	4	Increased Bias	100	4	Normal	Air Bias	---	x	x	x	x	---
2/29/2000	16:45 - 17:30	5	Increased Bias	100	4	Normal	Air Bias	---	x	x	x	x	---
3/1/2000	08:00 - 11:30		Full Load	100	4	Normal	As Found	x	---	---	---	---	---
3/1/2000	12:00 - 14:00	6	Baseline	70	4	Normal	As Found	---	x	x	x	x	---
3/1/2000	15:00 - 16:00	7	Air Bias	70	4	Normal	Air Bias	---	x	x	x	x	---
3/2/2000	09:00 - 10:30	8	Baseline	70	3	Normal	As Found	---	x	x	x	x	---
3/2/2000	12:00 - 13:00	9	Air Bias	70	3	Normal	Air Bias	---	x	x	x	x	---
3/2/2000			Teardown/Travel										

Utility: Dynegy
Plant: Vermilion
Unit: 2
Date: 2/28/00
Test: As Found Full Load Baseline Test

Data Source	Furnace		
DCS Shift Area 1	Gross Load	103.0	gMW
DCS Shift Area 1	Net Load	98.3	nMW
DCS Shift Area 1	Main Steam	755	klb/hr
Calculated	Gross Heat Rate	10,411	Btu/kWhr
Calculated	Net Heat Rate	10,909	Btu/kWhr
DCS Shift Area 1	Furance Draft	-0.3	iwc
DCS Shift Area 1	Windbox Pressure	2.3	iwc
Calculated	Stoich A/F	8.09	

Fuel

		Feed Rate		Coal/Air Temp	
Coal Overview Screen 29	Mill 2D	23,187	lb/hr	150	F
Coal Overview Screen 29	Mill 2C	25,011	lb/hr	146	F
Coal Overview Screen 29	Mill 2B	27,230	lb/hr	150	F
Coal Overview Screen 29	Mill 2A	25,063	lb/hr	150	F
Calculated	**Total Fuel wet basis**	100,490	lb/hr		
Estimate	estimated coal moisture loss in mill	7.49%			

	Sum	Relative Percent	Std Dev
Pipe D	21,451	23.07%	25.72%
Pipe C	23,138	24.89%	11.76%
Pipe B	25,191	27.10%	5.28%
Pipe A	23,186	24.94%	8.97%
	92,966	100.00%	

Fuel Flow Coal Pipe Measurements (lb/hr)

LF	LR	RF	RR
6,745	6,059	3,565	5,082
6,183	5,191	6,537	5,227
5,976	6,048	6,620	6,547
6,163	5,040	5,872	6,111
25,067	22,338	22,594	22,967

Air

	Ambient Temp	65	F
	Bar Press	29.90	in Hg
	Rel Hum	60.00%	
Calculated	Total Air Flow	907,306	klb/hr

Dirty Air Coal Pipe Measurements

	Sum	Std Dev	LF	LR	RF	RR
Pipe D	63,276	4.67%	16,147	16,173	16,243	14,713
Pipe C	67,574	2.17%	17,165	16,769	17,210	16,430
Pipe B	66,563	3.19%	16,821	16,372	17,292	16,078
Pipe A	70,006	5.40%	17,941	16,609	18,618	16,838
	267,419		68,074	65,923	69,363	64,059

	Economizer Outlet O2	
Mainscreen 2100	A Side	3.22%
		1.83%
Mainscreen 2100	B Side	2.09%
	Average	2.38%

Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry	Burner Level Stoich		Volumetric Flowrate * (CFH)	Nozzle Velocities (ft/s)
Upper SOFA		1.15	9.54%	90%	8.58%	144,436	1.12			3,603,235	217
Lower SOFA		1.15	9.54%	100%	9.54%	160,484	0.94			4,003,594	241
	OFA Corner Subtotal	2.31				304,920				7,377,686	222
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	21%	1.13%	19,084	0.74			476,090	51
D Mill	Burner Level 4 SA	0.32	2.64%	46%	1.22%	20,457	0.72	0.73	Note 1	510,338	111
	Level 4 PA	0.57				63,276				974,226	119
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	20%	3.97%	66,823	0.90			1,667,039	48
C Mill	Burner Level 3	0.32	2.64%	46%	1.22%	20,457	0.69	0.80	Note 2	510,338	111
	Level 3 PA	0.57				67,574				1,036,411	126
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	24%	4.76%	80,188	0.82			2,000,447	58
B Mill	Burner Level 2	0.32	2.64%	46%	1.22%	20,457	0.63	0.74	Note 2	510,338	111
	Level 2 PA	0.57				66,563				1,003,967	122
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	21%	4.17%	70,164	0.88			1,750,391	51
A Mill	Burner Level 1	0.32	2.64%	39%	1.03%	17,344	0.53	0.70	Note 1	432,678	94
	Level 1PA	0.57				70,006				1,069,120	130
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	22%	1.19%	19,993	-			498,761	53
	Windbox Corner Subtotal	9.78				602,386				14,575,031	103
	TOTAL SA ONLY (no SOFA)					334,967				8,104,694	
	TOTAL SA + SOFA	12.09	100.00%		38.02%	907,306				21,952,717	

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air
Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air
* at 530°F for SA

Control Room Total Airflow Indication

Location	Data Source	Percent	Mass Flow
Primary Air Mill 2D	Dirty Air Measurement	23.7%	63,276 lb/hr
Primary Air Mill 2C	Dirty Air Measurement	25.3%	67,574 lb/hr
Primary Air Mill 2B	Dirty Air Measurement	24.9%	66,563 lb/hr
Primary Air Mill 2A	Dirty Air Measurement	26.2%	70,006 lb/hr
Total Hot Combustion Air	Calculated by Difference		867,193 lb/hr
Total Sec Air + OFA	Calculated by Difference		639,887 lb/hr
Total Comb Air to Boiler	Calculated	-	907,306 lb/hr

Assumes 15% tramp air inleakage on mills

Airflow Distribution Summary

Location	Data Source	Mass Flow	Air/Fuel Ratio
Measured PA @ Mill 2D	Assumed Equal Distribution	63,276 lb/hr	2.73
Measured PA @ Mill 2C	Assumed Equal Distribution	67,574 lb/hr	2.70
Measured PA @ Mill 2B	Assumed Equal Distribution	66,563 lb/hr	2.44
Measured PA @ Mill 2A	Assumed Equal Distribution	70,006 lb/hr	2.79
Total Primary Air	Sum	267,419 lb/hr	29.5%
Secondary Air	By Difference	334,967 lb/hr	36.9%
Overfire Air	Calculated	304,920 lb/hr	33.6%
Total Air to Boiler	Sum	907,306 lb/hr	100.0%

UTILITY:	Dynegy	
PLANT:	Vermilion 2	BLEND PERCENTAGE
FUEL 1:	Eastern Bituminous	100%
FUEL 2:		0%
FUEL 3:		0%
TYPE:	Bituminous	100%
ANALYSIS DATE:	Commercial Testing Composite Analysis February 28 - March 2, 2000	

Proximate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	14.98%	-	-
ASH:	11.04%	12.99%	-
VOLATILE:	30.94%	36.39%	41.82%
FIXED CARBON:	43.04%	50.63%	58.18%
	100.00%	100.00%	100.00%
BTU/LB:	10,671	12,551	

Ultimate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	14.98%	-	-
CARBON:	60.00%	70.57%	81.10%
HYDROGEN:	4.02%	4.73%	5.43%
NITROGEN:	1.24%	1.45%	1.67%
CHLORINE:	0.00%	0.00%	0.00%
SULFUR:	2.01%	2.36%	2.71%
ASH:	11.04%	12.99%	-
OXYGEN (by diff):	6.72%	7.90%	9.08%
	100.00%	100.00%	100.00%

OPERATING CONDITIONS

GROSS HEAT RATE (Btu/kWh):	10,411	Calculated from coal pipe tests assuming 50% moisture retention
HEAT INPUT (Btu/hr):	1.07E+09	
LOAD (MWg):	103	
EXCESS OXYGEN (%,dry):	2.25%	
(%,wet):	2.04%	
HUMIDITY RATIO:	0.0055	Based on 50% relative humidity (60F ambient)
STOICH A/F:	8.09	
THEORETICAL A/F:	9.03	
MOLECULAR WEIGHT (lb/lbmole):	29.61	
AIR FLOW (lb/hr):	907,306	
FUEL FLOW (lb/hr):	100,490	
(tph):	50.2	

Combustion Mass Balance Stack Calculations	Wet Basis	Dry Basis	Mass Flow (lb/hr)	Molar Basis (lbmole/hr)	Mass/Heat Input (lb/10^6 Btu)
O2 (%):	2.04%	2.25%	21,975	687	20.49
CO2 (%):	14.92%	16.46%	220,982	5,022	206.08
H2O (%):	9.34%	-	56,593	3,144	52.78
N2 (%):	73.49%	81.06%	692,713	24,740	645.99
SO_2 (PPM @ 99% CONV):	1,854	2,045	3,994	62	3.72
SO_3 (PPM @ 1% CONV):	20	22	53	1	0.05
HCl (ppmv):	0	0	0	0	0.00
Measured NO (ppmv):	250	273	387	8	0.36
		100.00%	996,696	33,664	929.46

ASH (gr/scf):	5.97
ASH (lb/hr):	11,094
FLUE GAS (lb/hr):	996,702
FLUE GAS (lb/lbmole):	29.61
FLUE GAS (lb/lbfuel):	9.92
FLUE GAS DENSITY @ 300 F (lb/ft^3):	0.0534

Utility: Dynegy
Plant: Vermilion
Unit: 2
Date: 2/28/00
Test: As Found Full Load Baseline Test

Data Source	**Furnace**		
DCS Shift Area 1	Gross Load	103.0	gMW
DCS Shift Area 1	Net Load	98.3	nMW
DCS Shift Area 1	Main Steam	755	klb/hr
Calculated	Gross Heat Rate	10,411	Btu/kWhr
Calculated	Net Heat Rate	10,909	Btu/kWhr
DCS Shift Area 1	Furance Draft	-0.3	iwc
DCS Shift Area 1	Windbox Pressure	2.3	iwc
Calculated	Stoich A/F	8.09	

Fuel

		Feed Rate		Coal/Air Temp	
Coal Overview Screen 29	Mill 2D	23,187	lb/hr	150	F
Coal Overview Screen 29	Mill 2C	25,011	lb/hr	146	F
Coal Overview Screen 29	Mill 2B	27,230	lb/hr	150	F
Coal Overview Screen 29	Mill 2A	25,063	lb/hr	150	F
Calculated	**Total Fuel wet basis**	100,490	lb/hr		
Estimate	estimated coal moisture loss in mill	7.49%			

	Sum	Relative Percent	Std Dev
Pipe D	21,451	23.07%	25.72%
Pipe C	23,138	24.89%	11.76%
Pipe B	25,191	27.10%	5.28%
Pipe A	23,186	24.94%	8.97%
	92,966	100.00%	

Fuel Flow Coal Pipe Measurements (lb/hr)

LF	LR	RF	RR
6,745	6,059	3,565	5,082
6,183	5,191	6,537	5,227
5,976	6,048	6,620	6,547
6,163	5,040	5,872	6,111
25,067	22,338	22,594	22,967

Air

	Ambient Temp	65	F
	Bar Press	29.90	in Hg
	Rel Hum	60.00%	
Calculated	Total Air Flow	907,306	klb/hr

Dirty Air Coal Pipe Measurements

	Sum	Std Dev	LF	LR	RF	RR
Pipe D	63,276	4.67%	16,147	16,173	16,243	14,713
Pipe C	67,574	2.17%	17,165	16,769	17,210	16,430
Pipe B	66,563	3.19%	16,821	16,372	17,292	16,078
Pipe A	70,006	5.40%	17,941	16,609	18,618	16,838
	267,419		68,074	65,923	69,363	64,059

	Economizer Outlet O2	
Mainscreen 2100	A Side	3.22%
		1.83%
Mainscreen 2100	B Side	2.09%
	Average	2.38%

Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry	Burner Level Stoich		Volumetric Flowrate * (CFH)	Nozzle Velocities (ft/s)
Upper SOFA		1.15	9.54%	90%	8.58%	126,215	1.12			3,148,694	190
Lower SOFA		1.15	9.54%	100%	9.54%	140,239	0.96			3,498,549	211
	OFA Corner Subtotal	2.31				266,455				6,447,006	194
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	37%	2.00%	29,383	0.79			733,009	78
D Mill	Burner Level 4 SA	0.32	2.64%	24%	0.63%	9,327	0.75	0.82	Note 1	232,675	51
	Level 4 PA	0.57				63,276				974,226	119
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	36%	7.15%	105,109	0.96			2,622,142	76
C Mill	Burner Level 3	0.32	2.64%	26%	0.69%	10,104	0.69	0.93	Note 2	252,064	55
	Level 3 PA	0.57				67,574				1,036,411	126
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	40%	7.94%	116,787	0.84			2,913,491	84
B Mill	Burner Level 2	0.32	2.64%	26%	0.69%	10,104	0.57	0.76	Note 2	252,064	55
	Level 2 PA	0.57				66,563				1,003,967	122
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	22%	4.37%	64,233	0.80			1,602,420	46
A Mill	Burner Level 1	0.32	2.64%	24%	0.63%	9,327	0.49	0.64	Note 1	232,675	51
	Level 1PA	0.57				70,006				1,069,120	130
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	24%	1.30%	19,059	-			475,465	51
	Windbox Corner Subtotal	9.78				640,851				15,505,711	110
	TOTAL SA ONLY (no SOFA)					373,432				9,035,374	
	TOTAL SA + SOFA	12.09	100.00%		43.51%	907,306				21,952,717	

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air

Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

* at 530°F for SA

Control Room Total Airflow Indication

Location	Data Source	Percent	Mass Flow
Primary Air Mill 2D	Dirty Air Measurement	23.7%	63,276 lb/hr
Primary Air Mill 2C	Dirty Air Measurement	25.3%	67,574 lb/hr
Primary Air Mill 2B	Dirty Air Measurement	24.9%	66,563 lb/hr
Primary Air Mill 2A	Dirty Air Measurement	26.2%	70,006 lb/hr
Total Hot Combustion Air	Calculated by Difference		867,193 lb/hr
Total Sec Air + OFA	Calculated by Difference		639,887 lb/hr
Total Comb Air to Boiler	Calculated	-	907,306 lb/hr

Assumes 15% tramp air inleakage on mills

Airflow Distribution Summary

Location	Data Source	Mass Flow	Air/Fuel Ratio
Measured PA @ Mill 2D	Assumed Equal Distribution	63,276 lb/hr	2.73
Measured PA @ Mill 2C	Assumed Equal Distribution	67,574 lb/hr	2.70
Measured PA @ Mill 2B	Assumed Equal Distribution	66,563 lb/hr	2.44
Measured PA @ Mill 2A	Assumed Equal Distribution	70,006 lb/hr	2.79
Total Primary Air	Sum	267,419 lb/hr	29.5%
Secondary Air	By Difference	373,432 lb/hr	41.2%
Overfire Air	Calculated	266,455 lb/hr	29.4%
Total Air to Boiler	Sum	907,306 lb/hr	100.0%

UTILITY:	Dynegy	
PLANT:	Vermilion 2	BLEND PERCENTAGE
FUEL 1:	Eastern Bituminous	100%
FUEL 2:		0%
FUEL 3:		0%
TYPE:	Bituminous	100%
ANALYSIS DATE:	Commercial Testing Composite Analysis February 28 - March 2, 2000	

Proximate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	14.98%	-	-
ASH:	11.04%	12.99%	-
VOLATILE:	30.94%	36.39%	41.82%
FIXED CARBON:	43.04%	50.63%	58.18%
	100.00%	100.00%	100.00%
BTU/LB:	10,671	12,551	

Ultimate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	14.98%	-	-
CARBON:	60.00%	70.57%	81.10%
HYDROGEN:	4.02%	4.73%	5.43%
NITROGEN:	1.24%	1.45%	1.67%
CHLORINE:	0.00%	0.00%	0.00%
SULFUR:	2.01%	2.36%	2.71%
ASH:	11.04%	12.99%	-
OXYGEN (by diff):	6.72%	7.90%	9.08%
	100.00%	100.00%	100.00%

OPERATING CONDITIONS

GROSS HEAT RATE (Btu/kWh):	10,411	Calculated from coal pipe tests assuming 50% moisture retention
HEAT INPUT (Btu/hr):	1.07E+09	
LOAD (MWg):	103	
EXCESS OXYGEN (%,dry):	2.25%	
(%,wet):	2.04%	
HUMIDITY RATIO:	0.0055	Based on 50% relative humidity (60F ambient)
STOICH A/F:	8.09	
THEORETICAL A/F:	9.03	
MOLECULAR WEIGHT (lb/lbmole):	29.61	
AIR FLOW (lb/hr):	907,306	
FUEL FLOW (lb/hr):	100,490	
(tph):	50.2	

Combustion Mass Balance Stack Calculations	Wet Basis	Dry Basis	Mass Flow (lb/hr)	Molar Basis (lbmole/hr)	Mass/Heat Input (lb/10^6 Btu)
O2 (%):	2.04%	2.25%	21,975	687	20.49
CO2 (%):	14.92%	16.46%	220,982	5,022	206.08
H2O (%):	9.34%	-	56,593	3,144	52.78
N2 (%):	73.49%	81.06%	692,713	24,740	645.99
SO_2 (PPM @ 99% CONV):	1,854	2,045	3,994	62	3.72
SO_3 (PPM @ 1% CONV):	20	22	53	1	0.05
HCl (ppmv):	0	0	0	0	0.00
Measured NO (ppmv):	250	273	387	8	0.36
		100.00%	996,696	33,664	929.46

ASH (gr/scf):	5.97
ASH (lb/hr):	11,094
FLUE GAS (lb/hr):	996,702
FLUE GAS (lb/lbmole):	29.61
FLUE GAS (lb/lbfuel):	9.92
FLUE GAS DENSITY @ 300 F (lb/ft^3):	0.0534

Utility: Dynegy
Plant: Vermilion
Unit: 2
Date: 2/28/00
Test: As Found Full Load Baseline Test

Data Source	**Furnace**		
DCS Shift Area 1	Gross Load	103.0	gMW
DCS Shift Area 1	Net Load	98.3	nMW
DCS Shift Area 1	Main Steam	755	klb/hr
Calculated	Gross Heat Rate	10,411	Btu/kWhr
Calculated	Net Heat Rate	10,909	Btu/kWhr
DCS Shift Area 1	Furance Draft	-0.3	iwc
DCS Shift Area 1	Windbox Pressure	2.3	iwc
Calculated	Stoich A/F	8.09	

Fuel

		Feed Rate		**Coal/Air Temp**	
Coal Overview Screen 29	Mill 2D	23,187	lb/hr	150	F
Coal Overview Screen 29	Mill 2C	25,011	lb/hr	146	F
Coal Overview Screen 29	Mill 2B	27,230	lb/hr	150	F
Coal Overview Screen 29	Mill 2A	25,063	lb/hr	150	F
Calculated	**Total Fuel wet basis**	100,490	lb/hr		
Estimate	estimated coal moisture loss in mill	7.49%			

	Sum	Relative Percent	Std Dev
Pipe D	21,451	23.07%	25.72%
Pipe C	23,138	24.89%	11.76%
Pipe B	25,191	27.10%	5.28%
Pipe A	23,186	24.94%	8.97%
	92,966	100.00%	

Fuel Flow Coal Pipe Measurements (lb/hr)

LF	LR	RF	RR
6,745	6,059	3,565	5,082
6,183	5,191	6,537	5,227
5,976	6,048	6,620	6,547
6,163	5,040	5,872	6,111
25,067	22,338	22,594	22,967

Air

	Ambient Temp	65	F
	Bar Press	29.90	in Hg
	Rel Hum	60.00%	
Calculated	Total Air Flow	907,306	klb/hr

Dirty Air Coal Pipe Measurements

	Sum	Std Dev	LF	LR	RF	RR
Pipe D	63,276	4.67%	16,147	16,173	16,243	14,713
Pipe C	67,574	2.17%	17,165	16,769	17,210	16,430
Pipe B	66,563	3.19%	16,821	16,372	17,292	16,078
Pipe A	70,006	5.40%	17,941	16,609	18,618	16,838
	267,419		68,074	65,923	69,363	64,059

	Economizer Outlet O2	
Mainscreen 2100	A Side	3.22%
		1.83%
Mainscreen 2100	B Side	2.09%
	Average	2.38%

Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry	Burner Level Stoich		Volumetric Flowrate * (CFH)	Nozzle Velocities (ft/s)
Upper SOFA		1.15	9.54%	90%	8.58%	141,623	1.12			3,533,073	213
Lower SOFA		1.15	9.54%	100%	9.54%	157,359	0.94			3,925,637	236
	OFA Corner Subtotal	2.31				298,982				7,234,028	218
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	25%	1.35%	22,277	0.75			555,738	59
D Mill	Burner Level 4 SA	0.32	2.64%	20%	0.53%	8,721	0.72	0.72	Note 1	217,565	47
	Level 4 PA	0.57				63,276				974,226	119
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	25%	4.96%	81,903	0.92			2,043,223	59
C Mill	Burner Level 3	0.32	2.64%	23%	0.61%	10,029	0.69	0.82	Note 2	250,200	54
	Level 3 PA	0.57				67,574				1,036,411	126
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	29%	5.76%	95,007	0.84			2,370,139	69
B Mill	Burner Level 2	0.32	2.64%	21%	0.55%	9,157	0.61	0.75	Note 2	228,444	50
	Level 2 PA	0.57				66,563				1,003,967	122
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	25%	4.96%	81,903	0.91			2,043,223	59
A Mill	Burner Level 1	0.32	2.64%	18%	0.48%	7,849	0.50	0.71	Note 1	195,809	43
	Level 1PA	0.57				70,006				1,069,120	130
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	27%	1.46%	24,059	-			600,197	64
	Windbox Corner Subtotal	9.78				608,323				14,718,688	104
	TOTAL SA ONLY (no SOFA)					340,904				8,248,352	
	TOTAL SA + SOFA	12.09	100.00%		38.78%	907,306				21,952,717	

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air

Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

* at 530°F for SA

Control Room Total Airflow Indication

Location	Data Source	Percent	Mass Flow
Primary Air Mill 2D	Dirty Air Measurement	23.7%	63,276 lb/hr
Primary Air Mill 2C	Dirty Air Measurement	25.3%	67,574 lb/hr
Primary Air Mill 2B	Dirty Air Measurement	24.9%	66,563 lb/hr
Primary Air Mill 2A	Dirty Air Measurement	26.2%	70,006 lb/hr
Total Hot Combustion Air	Calculated by Difference		867,193 lb/hr
Total Sec Air + OFA	Calculated by Difference		639,887 lb/hr
Total Comb Air to Boiler	Calculated	-	907,306 lb/hr

Assumes 15% tramp air inleakage on mills

.

Airflow Distribution Summary

Location	Data Source	Mass Flow	Air/Fuel Ratio
Measured PA @ Mill 2D	Assumed Equal Distribution	63,276 lb/hr	2.73
Measured PA @ Mill 2C	Assumed Equal Distribution	67,574 lb/hr	2.70
Measured PA @ Mill 2B	Assumed Equal Distribution	66,563 lb/hr	2.44
Measured PA @ Mill 2A	Assumed Equal Distribution	70,006 lb/hr	2.79
Total Primary Air	Sum	267,419 lb/hr	29.5%
Secondary Air	By Difference	340,904 lb/hr	37.6%
Overfire Air	Calculated	298,982 lb/hr	33.0%
Total Air to Boiler	Sum	907,306 lb/hr	100.0%

UTILITY: Dynegy
PLANT: Vermilion 2

		BLEND PERCENTAGE
FUEL 1:	Eastern Bituminous	100%
FUEL 2:		0%
FUEL 3:		0%
TYPE:	Bituminous	100%

ANALYSIS DATE: Commercial Testing Composite Analysis
February 28 - March 2, 2000

Proximate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	14.98%	-	-
ASH:	11.04%	12.99%	-
VOLATILE:	30.94%	36.39%	41.82%
FIXED CARBON:	43.04%	50.63%	58.18%
	100.00%	100.00%	100.00%
BTU/LB:	10,671	12,551	

Ultimate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	14.98%	-	-
CARBON:	60.00%	70.57%	81.10%
HYDROGEN:	4.02%	4.73%	5.43%
NITROGEN:	1.24%	1.45%	1.67%
CHLORINE:	0.00%	0.00%	0.00%
SULFUR:	2.01%	2.36%	2.71%
ASH:	11.04%	12.99%	-
OXYGEN (by diff):	6.72%	7.90%	9.08%
	100.00%	100.00%	100.00%

OPERATING CONDITIONS

GROSS HEAT RATE (Btu/kWh):	10,411	Calculated from coal pipe tests assuming 50% moisture retention
HEAT INPUT (Btu/hr):	1.07E+09	
LOAD (MWg):	103	
EXCESS OXYGEN (%,dry):	2.25%	
(%,wet):	2.04%	
HUMIDITY RATIO:	0.0055	Based on 50% relative humidity (60F ambient)
STOICH A/F:	8.09	
THEORETICAL A/F:	9.03	
MOLECULAR WEIGHT (lb/lbmole):	29.61	
AIR FLOW (lb/hr):	907,306	
FUEL FLOW (lb/hr):	100,490	
(tph):	50.2	

Combustion Mass Balance Stack Calculations	Wet Basis	Dry Basis	Mass Flow (lb/hr)	Molar Basis (lbmole/hr)	Mass/Heat Input (lb/10^6 Btu)
O2 (%):	2.04%	2.25%	21,975	687	20.49
CO2 (%):	14.92%	16.46%	220,982	5,022	206.08
H2O (%):	9.34%	-	56,593	3,144	52.78
N2 (%):	73.49%	81.06%	692,713	24,740	645.99
SO_2 (PPM @ 99% CONV):	1,854	2,045	3,994	62	3.72
SO_3 (PPM @ 1% CONV):	20	22	53	1	0.05
HCl (ppmv):	0	0	0	0	0.00
Measured NO (ppmv):	250	273	387	8	0.36
		100.00%	996,696	33,664	929.46

ASH (gr/scf):	5.97
ASH (lb/hr):	11,094
FLUE GAS (lb/hr):	996,702
FLUE GAS (lb/lbmole):	29.61
FLUE GAS (lb/lbfuel):	9.92
FLUE GAS DENSITY @ 300 F (lb/ft^3):	0.0534

Utility: Dynegy
Plant: Vermilion
Unit: 2
Date: 2/28/00
Test: As Found Full Load Baseline Test

Data Source	**Furnace**		
DCS Shift Area 1	Gross Load	103.0	gMW
DCS Shift Area 1	Net Load	98.3	nMW
DCS Shift Area 1	Main Steam	755	klb/hr
Calculated	Gross Heat Rate	10,411	Btu/kWhr
Calculated	Net Heat Rate	10,909	Btu/kWhr
DCS Shift Area 1	Furance Draft	-0.3	iwc
DCS Shift Area 1	Windbox Pressure	2.3	iwc
Calculated	Stoich A/F	8.09	

Fuel

		Feed Rate		Coal/Air Temp	
Coal Overview Screen 29	Mill 2D	23,187	lb/hr	150	F
Coal Overview Screen 29	Mill 2C	25,011	lb/hr	146	F
Coal Overview Screen 29	Mill 2B	27,230	lb/hr	150	F
Coal Overview Screen 29	Mill 2A	25,063	lb/hr	150	F
Calculated	**Total Fuel wet basis**	100,490	lb/hr		
Estimate	estimated coal moisture loss in mill	7.49%			

	Sum	Relative Percent	Std Dev
Pipe D	21,451	23.07%	25.72%
Pipe C	23,138	24.89%	11.76%
Pipe B	25,191	27.10%	5.28%
Pipe A	23,186	24.94%	8.97%
	92,966	100.00%	

Fuel Flow Coal Pipe Measurements (lb/hr)

LF	LR	RF	RR
6,745	6,059	3,565	5,082
6,183	5,191	6,537	5,227
5,976	6,048	6,620	6,547
6,163	5,040	5,872	6,111
25,067	22,338	22,594	22,967

Air

	Ambient Temp	65	F
	Bar Press	29.90	in Hg
	Rel Hum	60.00%	
Calculated	Total Air Flow	907,306	klb/hr

Dirty Air Coal Pipe Measurements

	Sum	Std Dev	LF	LR	RF	RR
Pipe D	63,276	4.67%	16,147	16,173	16,243	14,713
Pipe C	67,574	2.17%	17,165	16,769	17,210	16,430
Pipe B	66,563	3.19%	16,821	16,372	17,292	16,078
Pipe A	70,006	5.40%	17,941	16,609	18,618	16,838
	267,419		68,074	65,923	69,363	64,059

	Economizer Outlet O2	
Mainscreen 2100	A Side	3.22%
		1.83%
Mainscreen 2100	B Side	2.09%
	Average	2.38%

Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry	Burner Level Stoich		Volumetric Flowrate * (CFH)	Nozzle Velocities (ft/s)
Upper SOFA		1.15	9.54%	90%	8.58%	138,947	1.12			3,466,297	209
Lower SOFA		1.15	9.54%	100%	9.54%	154,385	0.95			3,851,441	232
	OFA Corner Subtotal	2.31				293,332				7,097,302	214
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	44%	2.38%	38,466	0.76			959,612	102
D Mill	Burner Level 4 SA	0.32	2.64%	20%	0.53%	8,556	0.71	0.80	Note 1	213,453	46
	Level 4 PA	0.57				63,276				974,226	119
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	25%	4.96%	80,355	0.91			2,004,605	58
C Mill	Burner Level 3	0.32	2.64%	23%	0.61%	9,840	0.68	0.80	Note 2	245,471	53
	Level 3 PA	0.57				67,574				1,036,411	126
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	28%	5.56%	89,997	0.82			2,245,158	65
B Mill	Burner Level 2	0.32	2.64%	20%	0.53%	8,556	0.61	0.73	Note 2	213,453	46
	Level 2 PA	0.57				66,563				1,003,967	122
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	25%	4.96%	80,355	0.89			2,004,605	58
A Mill	Burner Level 1	0.32	2.64%	18%	0.48%	7,701	0.50	0.69	Note 1	192,108	42
	Level 1PA	0.57				70,006				1,069,120	130
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	26%	1.40%	22,730	-			567,043	60
	Windbox Corner Subtotal	9.78				613,974				14,855,414	105
	TOTAL SA ONLY (no SOFA)					346,555				8,385,078	
	TOTAL SA + SOFA	12.09	100.00%		39.52%	907,306				21,952,717	

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air

Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

* at 530°F for SA

Control Room Total Airflow Indication

Location	Data Source	Percent	Mass Flow
Primary Air Mill 2D	Dirty Air Measurement	23.7%	63,276 lb/hr
Primary Air Mill 2C	Dirty Air Measurement	25.3%	67,574 lb/hr
Primary Air Mill 2B	Dirty Air Measurement	24.9%	66,563 lb/hr
Primary Air Mill 2A	Dirty Air Measurement	26.2%	70,006 lb/hr
Total Hot Combustion Air	Calculated by Difference		867,193 lb/hr
Total Sec Air + OFA	Calculated by Difference		639,887 lb/hr
Total Comb Air to Boiler	Calculated	-	907,306 lb/hr

Assumes 15% tramp air inleakage on mills

.

Airflow Distribution Summary

Location	Data Source	Mass Flow	Air/Fuel Ratio
Measured PA @ Mill 2D	Assumed Equal Distribution	63,276 lb/hr	2.73
Measured PA @ Mill 2C	Assumed Equal Distribution	67,574 lb/hr	2.70
Measured PA @ Mill 2B	Assumed Equal Distribution	66,563 lb/hr	2.44
Measured PA @ Mill 2A	Assumed Equal Distribution	70,006 lb/hr	2.79
Total Primary Air	Sum	267,419 lb/hr	29.5%
Secondary Air	By Difference	346,555 lb/hr	38.2%
Overfire Air	Calculated	293,332 lb/hr	32.3%
Total Air to Boiler	Sum	907,306 lb/hr	100.0%

UTILITY: Dynegy
PLANT: Vermilion 2
FUEL 1: Eastern Bituminous
FUEL 2:
FUEL 3:
TYPE: Bituminous
ANALYSIS DATE: Commercial Testing Composite Analysis
February 28 - March 2, 2000

	BLEND PERCENTAGE
FUEL 1	100%
FUEL 2	0%
FUEL 3	0%
TYPE	100%

Proximate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	14.98%	-	-
ASH:	11.04%	12.99%	-
VOLATILE:	30.94%	36.39%	41.82%
FIXED CARBON:	43.04%	50.63%	58.18%
	100.00%	100.00%	100.00%
BTU/LB:	10,671	12,551	

Ultimate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	14.98%	-	-
CARBON:	60.00%	70.57%	81.10%
HYDROGEN:	4.02%	4.73%	5.43%
NITROGEN:	1.24%	1.45%	1.67%
CHLORINE:	0.00%	0.00%	0.00%
SULFUR:	2.01%	2.36%	2.71%
ASH:	11.04%	12.99%	-
OXYGEN (by diff):	6.72%	7.90%	9.08%
	100.00%	100.00%	100.00%

OPERATING CONDITIONS

GROSS HEAT RATE (Btu/kWh):	10,411	Calculated from coal pipe tests assuming 50% moisture retention
HEAT INPUT (Btu/hr):	1.07E+09	
LOAD (MWg):	103	
EXCESS OXYGEN (%,dry):	2.25%	
(%,wet):	2.04%	
HUMIDITY RATIO:	0.0055	Based on 50% relative humidity (60F ambient)
STOICH A/F:	8.09	
THEORETICAL A/F:	9.03	
MOLECULAR WEIGHT (lb/lbmole):	29.61	
AIR FLOW (lb/hr):	907,306	
FUEL FLOW (lb/hr):	100,490	
(tph):	50.2	

Combustion Mass Balance Stack Calculations	Wet Basis	Dry Basis	Mass Flow (lb/hr)	Molar Basis (lbmole/hr)	Mass/Heat Input ($lb/10^6$ Btu)
O2 (%):	2.04%	2.25%	21,975	687	20.49
CO2 (%):	14.92%	16.46%	220,982	5,022	206.08
H2O (%):	9.34%	-	56,593	3,144	52.78
N2 (%):	73.49%	81.06%	692,713	24,740	645.99
SO_2 (PPM @ 99% CONV):	1,854	2,045	3,994	62	3.72
SO_3 (PPM @ 1% CONV):	20	22	53	1	0.05
HCl (ppmv):	0	0	0	0	0.00
Measured NO (ppmv):	250	273	387	8	0.36
		100.00%	996,696	33,664	929.46

ASH (gr/scf):	5.97
ASH (lb/hr):	11,094
FLUE GAS (lb/hr):	996,702
FLUE GAS (lb/lbmole):	29.61
FLUE GAS (lb/lbfuel):	9.92
FLUE GAS DENSITY @ 300 F (lb/ft^3):	0.0534

Utility: Dynegy
Plant: Vermilion
Unit: 2
Date: 2/28/00
Test: As Found Full Load Baseline Test

Data Source	**Furnace**				
DCS Shift Area 1	Gross Load	70.0	gMW		
DCS Shift Area 1	Net Load	67.0	nMW		
DCS Shift Area 1	Main Steam	519	klb/hr		
Calculated	Gross Heat Rate	10,411	Btu/kWhr		
Calculated	Net Heat Rate	10,877	Btu/kWhr		
DCS Shift Area 1	Furance Draft	-0.3	iwc		
DCS Shift Area 1	Windbox Pressure	2.3	iwc		
Calculated	Stoich A/F	8.09			
	Fuel				
		Feed Rate		**Coal/Air Temp**	
Coal Overview Screen 29	Mill 2D	17,074	lb/hr	150	F
Coal Overview Screen 29	Mill 2C	17,074	lb/hr	151	F
Coal Overview Screen 29	Mill 2B	17,074	lb/hr	151	F
Coal Overview Screen 29	Mill 2A	17,074	lb/hr	153	F
Calculated	**Total Fuel wet basis**	68,294	lb/hr		
Estimate	estimated coal moisture loss in mill	NA			

	Estimated	Relative Percent	Std Dev
Pipe D	17,074	25.00%	
Pipe C	17,074	25.00%	
Pipe B	17,074	25.00%	
Pipe A	17,074	25.00%	
	68,294	100.00%	

Fuel Flow Coal Pipe Measurements (lb/hr)

LF	LR	RF	RR
0	0	0	0

	Air		
	Ambient Temp	65	F
	Bar Press	29.90	in Hg
	Rel Hum	60.00%	
Calculated	Total Air Flow	698,631	klb/hr

Dirty Air Coal Pipe Measurements (Assumed Constant over Load Based on Single Mill Measurement)

	Sum	Std Dev	LF	LR	RF	RR
Pipe D	63,276	4.67%	16,147	16,173	16,243	14,713
Pipe C	67,574	2.17%	17,165	16,769	17,210	16,430
Pipe B	66,563	3.19%	16,821	16,372	17,292	16,078
Pipe A	70,006	5.40%	17,941	16,609	18,618	16,838
	267,419		68,074	65,923	69,363	64,059

	Economizer Outlet O2	
Mainscreen 2100	A Side	4.90%
		3.52%
Mainscreen 2100	B Side	3.98%
	Average	4.13%

Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry	Burner Level Stoich		Volumetric Flowrate * (CFH)	Nozzle Velocities (ft/s)
Upper SOFA		1.15	9.54%	90%	8.58%	96,590	1.27			2,409,640	145
Lower SOFA		1.15	9.54%	100%	9.54%	107,323	1.09			2,677,377	161
	OFA Corner Subtotal	2.31				203,913				4,933,779	149
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	21%	1.13%	12,762	0.90			318,382	34
D Mill	Burner Level 4 SA	0.32	2.64%	44%	1.16%	13,086	0.87	0.82	Note 1	326,446	71
	Level 4 PA	0.57				63,276				974,226	119
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	22%	4.37%	49,156	1.13			1,226,303	35
C Mill	Burner Level 3	0.32	2.64%	41%	1.08%	12,193	0.86	0.95	Note 2	304,189	66
	Level 3 PA	0.57				67,574				1,036,411	126
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	24%	4.76%	53,625	1.00			1,337,785	39
B Mill	Burner Level 2	0.32	2.64%	44%	1.16%	13,086	0.81	0.94	Note 2	326,446	71
	Level 2 PA	0.57				66,563				1,003,967	122
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	21%	4.17%	46,922	1.04			1,170,562	34
A Mill	Burner Level 1	0.32	2.64%	42%	1.11%	12,491	0.70	0.87	Note 1	311,608	68
	Level 1PA	0.57				70,006				1,069,120	130
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	23%	1.24%	13,978	-			348,704	37
	Windbox Corner Subtotal	9.78				494,718				11,969,951	85
	TOTAL SA ONLY (no SOFA)					227,299				5,499,615	
	TOTAL SA + SOFA	12.09	100.00%		38.31%	698,631				16,903,730	

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air
Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air
* at 530°F for SA

Control Room Total Airflow Indication

Location	Data Source	Percent	Mass Flow
Primary Air Mill 2D	Dirty Air Measurement	23.7%	63,276 lb/hr
Primary Air Mill 2C	Dirty Air Measurement	25.3%	67,574 lb/hr
Primary Air Mill 2B	Dirty Air Measurement	24.9%	66,563 lb/hr
Primary Air Mill 2A	Dirty Air Measurement	26.2%	70,006 lb/hr
Total Hot Combustion Air	Calculated by Difference		658,518 lb/hr
Total Sec Air + OFA	Calculated by Difference		431,212 lb/hr
Total Comb Air to Boiler	Calculated	-	698,631 lb/hr

Assumes 15% tramp air inleakage on mills

Airflow Distribution Summary

Location	Data Source	Mass Flow	Air/Fuel Ratio
Measured PA @ Mill 2D	Assumed Equal Distribution	63,276 lb/hr	3.71
Measured PA @ Mill 2C	Assumed Equal Distribution	67,574 lb/hr	3.96
Measured PA @ Mill 2B	Assumed Equal Distribution	66,563 lb/hr	3.90
Measured PA @ Mill 2A	Assumed Equal Distribution	70,006 lb/hr	4.10
Total Primary Air	Sum	267,419 lb/hr	38.3%
Secondary Air	By Difference	227,299 lb/hr	32.5%
Overfire Air	Calculated	203,913 lb/hr	29.2%
Total Air to Boiler	Sum	698,631 lb/hr	100.0%

UTILITY: Dynegy
PLANT: Vermilion 2
FUEL 1: Eastern Bituminous
FUEL 2:
FUEL 3:
TYPE: Bituminous
ANALYSIS DATE: Commercial Testing Composite Analysis
February 28 - March 2, 2000

BLEND PERCENTAGE
100%
0%
0%
100%

Proximate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	14.98%	-	-
ASH:	11.04%	12.99%	-
VOLATILE:	30.94%	36.39%	41.82%
FIXED CARBON:	43.04%	50.63%	58.18%
	100.00%	100.00%	100.00%
BTU/LB:	10,671	12,551	

Ultimate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	14.98%	-	-
CARBON:	60.00%	70.57%	81.10%
HYDROGEN:	4.02%	4.73%	5.43%
NITROGEN:	1.24%	1.45%	1.67%
CHLORINE:	0.00%	0.00%	0.00%
SULFUR:	2.01%	2.36%	2.71%
ASH:	11.04%	12.99%	-
OXYGEN (by diff):	6.72%	7.90%	9.08%
	100.00%	100.00%	100.00%

OPERATING CONDITIONS

GROSS HEAT RATE (Btu/kWh):	10,411	Calculated from coal pipe tests assuming 50% moisture retention
HEAT INPUT (Btu/hr):	7.29E+08	
LOAD (MWg):	70	
EXCESS OXYGEN (%,dry):	4.50%	
(%,wet):	4.12%	
HUMIDITY RATIO:	0.0055	Based on 50% relative humidity (60F ambient)
STOICH A/F:	8.09	
THEORETICAL A/F:	10.23	
MOLECULAR WEIGHT (lb/lbmole):	29.51	
AIR FLOW (lb/hr):	698,631	
FUEL FLOW (lb/hr):	68,294	
(tph):	34.1	

Combustion Mass Balance Stack Calculations	Wet Basis	Dry Basis	Mass Flow (lb/hr)	Molar Basis (lbmole/hr)	Mass/Heat Input (lb/10^6 Btu)
O2 (%):	4.12%	4.50%	33,941	1,061	46.57
CO2 (%):	13.27%	14.48%	150,188	3,413	206.08
H2O (%):	8.40%	-	38,915	2,162	53.40
N2 (%):	74.02%	80.81%	533,303	19,047	731.79
SO_2 (PPM @ 99% CONV):	1,648	1,799	2,714	42	3.72
SO_3 (PPM @ 1% CONV):	18	19	36	0	0.05
HCl (ppmv):	0	0	0	0	0.00
Measured NO (ppmv):	250	271	296	6	0.41
		100.00%	759,393	25,732	1042.02

ASH (gr/scf):	5.32
ASH (lb/hr):	7,540
FLUE GAS (lb/hr):	759,386
FLUE GAS (lb/lbmole):	29.51
FLUE GAS (lb/lbfuel):	11.12
FLUE GAS DENSITY @ 300 F (lb/ft^3):	0.0532

Utility: Dynegy
Plant: Vermilion
Unit: 2
Date: 2/28/00
Test: As Found Full Load Baseline Test

Data Source	Furnace		
DCS Shift Area 1	Gross Load	70.0	gMW
DCS Shift Area 1	Net Load	67.0	nMW
DCS Shift Area 1	Main Steam	519	klb/hr
Calculated	Gross Heat Rate	10,411	Btu/kWhr
Calculated	Net Heat Rate	10,877	Btu/kWhr
DCS Shift Area 1	Furance Draft	-0.3	iwc
DCS Shift Area 1	Windbox Pressure	2.3	iwc
Calculated	Stoich A/F	8.09	

Fuel

Data Source		Feed Rate		Coal/Air Temp	
Coal Overview Screen 29	Mill 2D	17,074	lb/hr	150	F
Coal Overview Screen 29	Mill 2C	17,074	lb/hr	151	F
Coal Overview Screen 29	Mill 2B	17,074	lb/hr	151	F
Coal Overview Screen 29	Mill 2A	17,074	lb/hr	153	F
Calculated	**Total Fuel wet basis**	68,294	lb/hr		
Estimate	estimated coal moisture loss in mill	NA			

	Estimated	Relative Percent	Std Dev
Pipe D	17,074	25.00%	
Pipe C	17,074	25.00%	
Pipe B	17,074	25.00%	
Pipe A	17,074	25.00%	
	68,294	100.00%	

Fuel Flow Coal Pipe Measurements (lb/hr)

LF	LR	RF	RR
0	0	0	0

Air

Data Source			
	Ambient Temp	65	F
	Bar Press	29.90	in Hg
	Rel Hum	60.00%	
Calculated	Total Air Flow	709,145	klb/hr

Dirty Air Coal Pipe Measurements (Assumed Constant over Load Based on Single Mill Measurement)

	Sum	Std Dev	LF	LR	RF	RR
Pipe D	63,276	4.67%	16,147	16,173	16,243	14,713
Pipe C	67,574	2.17%	17,165	16,769	17,210	16,430
Pipe B	66,563	3.19%	16,821	16,372	17,292	16,078
Pipe A	70,006	5.40%	17,941	16,609	18,618	16,838
	267,419		68,074	65,923	69,363	64,059

Data Source	Economizer Outlet O2	
Mainscreen 2100	A Side	5.04%
		3.79%
Mainscreen 2100	B Side	4.24%
	Average	4.36%

Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry	Burner Level Stoich		Volumetric Flowrate * (CFH)	Nozzle Velocities (ft/s)
Upper SOFA		1.15	9.54%	90%	8.58%	121,483	1.28			3,030,633	183
Lower SOFA		1.15	9.54%	100%	9.54%	134,981	1.06			3,367,370	203
	OFA Corner Subtotal	2.31				256,464				6,205,274	187
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	76%	4.10%	58,091	0.82			1,449,186	154
D Mill	Burner Level 4 SA	0.32	2.64%	10%	0.26%	3,740	0.71	1.02	Note 1	93,313	20
	Level 4 PA	0.57				63,276				974,226	119
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	11%	2.18%	30,912	0.94			771,168	22
C Mill	Burner Level 3	0.32	2.64%	13%	0.34%	4,863	0.72	0.78	Note 2	121,306	26
	Level 3 PA	0.57				67,574				1,036,411	126
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	14%	2.78%	39,343	0.81			981,487	28
B Mill	Burner Level 2	0.32	2.64%	12%	0.32%	4,489	0.67	0.77	Note 2	111,975	24
	Level 2 PA	0.57				66,563				1,003,967	122
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	11%	2.18%	30,912	0.82			771,168	22
A Mill	Burner Level 1	0.32	2.64%	10%	0.26%	3,740	0.60	0.71	Note 1	93,313	20
	Level 1PA	0.57				70,006				1,069,120	130
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	12%	0.65%	9,172	-			228,819	24
	Windbox Corner Subtotal	9.78				452,681				10,952,850	78
	TOTAL SA ONLY (no SOFA)					185,262				4,482,513	
	TOTAL SA + SOFA	12.09	100.00%		31.21%	709,145				17,158,123	

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air

Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

* at 530°F for SA

Control Room Total Airflow Indication

Location	Data Source	Percent	Mass Flow
Primary Air Mill 2D	Dirty Air Measurement	23.7%	63,276 lb/hr
Primary Air Mill 2C	Dirty Air Measurement	25.3%	67,574 lb/hr
Primary Air Mill 2B	Dirty Air Measurement	24.9%	66,563 lb/hr
Primary Air Mill 2A	Dirty Air Measurement	26.2%	70,006 lb/hr
Total Hot Combustion Air	Calculated by Difference		669,032 lb/hr
Total Sec Air + OFA	Calculated by Difference		441,726 lb/hr
Total Comb Air to Boiler	Calculated	-	709,145 lb/hr

Assumes 15% tramp air inleakage on mills

Airflow Distribution Summary

Location	Data Source	Mass Flow	Air/Fuel Ratio
Measured PA @ Mill 2D	Assumed Equal Distribution	63,276 lb/hr	3.71
Measured PA @ Mill 2C	Assumed Equal Distribution	67,574 lb/hr	3.96
Measured PA @ Mill 2B	Assumed Equal Distribution	66,563 lb/hr	3.90
Measured PA @ Mill 2A	Assumed Equal Distribution	70,006 lb/hr	4.10
Total Primary Air	Sum	267,419 lb/hr	37.7%
Secondary Air	By Difference	185,262 lb/hr	26.1%
Overfire Air	Calculated	256,464 lb/hr	36.2%
Total Air to Boiler	Sum	709,145 lb/hr	100.0%

UTILITY: Dynegy
PLANT: Vermilion 2 — BLEND PERCENTAGE
FUEL 1: Eastern Bituminous — 100%
FUEL 2: — 0%
FUEL 3: — 0%
TYPE: Bituminous — 100%
ANALYSIS DATE: Commercial Testing Composite Analysis
February 28 - March 2, 2000

Proximate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	14.98%	-	-
ASH:	11.04%	12.99%	-
VOLATILE:	30.94%	36.39%	41.82%
FIXED CARBON:	43.04%	50.63%	58.18%
	100.00%	100.00%	100.00%
BTU/LB:	10,671	12,551	

Ultimate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	14.98%	-	-
CARBON:	60.00%	70.57%	81.10%
HYDROGEN:	4.02%	4.73%	5.43%
NITROGEN:	1.24%	1.45%	1.67%
CHLORINE:	0.00%	0.00%	0.00%
SULFUR:	2.01%	2.36%	2.71%
ASH:	11.04%	12.99%	-
OXYGEN (by diff):	6.72%	7.90%	9.08%
	100.00%	100.00%	100.00%

OPERATING CONDITIONS

GROSS HEAT RATE (Btu/kWh):	10,411	Calculated from coal pipe tests assuming 50% moisture retention
HEAT INPUT (Btu/hr):	7.29E+08	
LOAD (MWg):	70	
EXCESS OXYGEN (%,dry):	4.75%	
(%,wet):	4.36%	
HUMIDITY RATIO:	0.0055	Based on 50% relative humidity (60F ambient)
STOICH A/F:	8.09	
THEORETICAL A/F:	10.38	
MOLECULAR WEIGHT (lb/lbmole):	29.50	
AIR FLOW (lb/hr):	709,145	
FUEL FLOW (lb/hr):	68,294	
(tph):	34.1	

Combustion Mass Balance Stack Calculations	Wet Basis	Dry Basis	Mass Flow (lb/hr)	Molar Basis (lbmole/hr)	Mass/Heat Input (lb/10^6 Btu)
O2 (%):	4.36%	4.75%	36,377	1,137	49.92
CO2 (%):	13.08%	14.26%	150,188	3,413	206.08
H2O (%):	8.30%	-	38,973	2,165	53.48
N2 (%):	74.08%	80.78%	541,319	19,333	742.78
SO_2 (PPM @ 99% CONV):	1,625	1,772	2,714	42	3.72
SO_3 (PPM @ 1% CONV):	17	19	36	0	0.05
HCl (ppmv):	0	0	0	0	0.00
Measured NO (ppmv):	250	271	300	7	0.41
		100.00%	769,908	26,098	1056.45

ASH (gr/scf):	5.25
ASH (lb/hr):	7,540
FLUE GAS (lb/hr):	769,900
FLUE GAS (lb/lbmole):	29.50
FLUE GAS (lb/lbfuel):	11.27
FLUE GAS DENSITY @ 300 F (lb/ft^3):	0.0532

Utility: Dynegy
Plant: Vermilion
Unit: 2
Date: 2/28/00
Test: As Found Full Load Baseline Test

Data Source	**Furnace**		
DCS Shift Area 1	Gross Load	70.0	gMW
DCS Shift Area 1	Net Load	67.0	nMW
DCS Shift Area 1	Main Steam	519	klb/hr
Calculated	Gross Heat Rate	10,411	Btu/kWhr
Calculated	Net Heat Rate	10,877	Btu/kWhr
DCS Shift Area 1	Furance Draft	-0.3	iwc
DCS Shift Area 1	Windbox Pressure	2.3	iwc
Calculated	Stoich A/F	8.09	

Fuel

		Feed Rate		Coal/Air Temp	
Coal Overview Screen 29	Mill 2D	22,765	lb/hr	150	F
Coal Overview Screen 29	Mill 2C	22,765	lb/hr	151	F
Coal Overview Screen 29	Mill 2B	22,765	lb/hr	151	F
Coal Overview Screen 29	Mill 2A	0	lb/hr	153	F
Calculated	**Total Fuel wet basis**	68,294	lb/hr		
Estimate	estimated coal moisture loss in mill	NA			

	Estimated	Relative Percent	Std Dev
Pipe D	22,765	33.33%	
Pipe C	22,765	33.33%	
Pipe B	22,765	33.33%	
Pipe A	0	0.00%	
	68,295	100.00%	

Fuel Flow Coal Pipe Measurements (lb/hr)

LF	LR	RF	RR
0	0	0	0

Air

	Ambient Temp	65	F
	Bar Press	29.90	in Hg
	Rel Hum	60.00%	
Calculated	Total Air Flow	697,804	klb/hr

Dirty Air Coal Pipe Measurements (Assumed Constant over Load Based on Single Mill Measurement)

	Sum	Std Dev	LF	LR	RF	RR
Pipe D	63,276	4.67%	16,147	16,173	16,243	14,713
Pipe C	67,574	2.17%	17,165	16,769	17,210	16,430
Pipe B	66,563	3.19%	16,821	16,372	17,292	16,078
Pipe A	70,006	5.40%	17,941	16,609	18,618	16,838
	267,419		68,074	65,923	69,363	64,059

	Economizer Outlet O2	
Mainscreen 2100	A Side	4.44%
		3.60%
Mainscreen 2100	B Side	4.26%
	Average	4.10%

Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry	Burner Level Stoich		Volumetric Flowrate * (CFH)	Nozzle Velocities (ft/s)
Upper SOFA		1.15	9.54%	90%	8.58%	89,959	1.26			2,244,207	135
Lower SOFA		1.15	9.54%	100%	9.54%	99,954	1.10			2,493,563	150
	OFA Corner Subtotal	2.31				189,914				4,595,053	138
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	30%	1.62%	16,980	0.92			423,605	45
D Mill	Burner Level 4 SA	0.32	2.64%	41%	1.08%	11,356	0.89	0.62	Note 1	283,305	62
	Level 4 PA	0.57				63,276				974,226	119
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	21%	4.17%	43,701	1.30			1,090,198	32
C Mill	Burner Level 3	0.32	2.64%	41%	1.08%	11,356	1.01	0.69	Note 2	283,305	62
	Level 3 PA	0.57				67,574				1,036,411	126
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	25%	4.96%	52,025	1.60			1,297,855	38
B Mill	Burner Level 2	0.32	2.64%	43%	1.14%	11,910	1.31	0.81	Note 2	297,125	65
	Level 2 PA	0.57				66,563				1,003,967	122
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	43%	8.54%	89,482	#DIV/0!			2,232,310	65
A Mill	Burner Level 1	0.32	2.64%	3%	0.08%	831	#DIV/0!	#DIV/0!	Note 1	20,730	5
	Level 1PA	0.57				70,006				1,069,120	130
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	5%	0.27%	2,830	-			70,601	8
	Windbox Corner Subtotal	9.78				507,890				12,288,658	87
	TOTAL SA ONLY (no SOFA)					240,471				5,818,322	
	TOTAL SA + SOFA	12.09	100.00%		41.06%	697,804				16,883,711	

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air
Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air
* at 530°F for SA

Control Room Total Airflow Indication

Location	Data Source	Percent	Mass Flow
Primary Air Mill 2D	Dirty Air Measurement	23.7%	63,276 lb/hr
Primary Air Mill 2C	Dirty Air Measurement	25.3%	67,574 lb/hr
Primary Air Mill 2B	Dirty Air Measurement	24.9%	66,563 lb/hr
Primary Air Mill 2A	Dirty Air Measurement	26.2%	70,006 lb/hr
Total Hot Combustion Air	Calculated by Difference		657,691 lb/hr
Total Sec Air + OFA	Calculated by Difference		430,385 lb/hr
Total Comb Air to Boiler	Calculated	-	697,804 lb/hr

Assumes 15% tramp air inleakage on mills

.

Airflow Distribution Summary

Location	Data Source	Mass Flow	Air/Fuel Ratio
Measured PA @ Mill 2D	Assumed Equal Distribution	63,276 lb/hr	2.78
Measured PA @ Mill 2C	Assumed Equal Distribution	67,574 lb/hr	2.97
Measured PA @ Mill 2B	Assumed Equal Distribution	66,563 lb/hr	2.92
Measured PA @ Mill 2A	Assumed Equal Distribution	70,006 lb/hr	#DIV/0!
Total Primary Air	Sum	267,419 lb/hr	38.3%
Secondary Air	By Difference	240,471 lb/hr	34.5%
Overfire Air	Calculated	189,914 lb/hr	27.2%
Total Air to Boiler	Sum	697,804 lb/hr	100.0%

UTILITY:	Dynegy	
PLANT:	Vermilion 2	BLEND PERCENTAGE
FUEL 1:	Eastern Bituminous	100%
FUEL 2:		0%
FUEL 3:		0%
TYPE:	Bituminous	100%
ANALYSIS DATE:	Commercial Testing Composite Analysis February 28 - March 2, 2000	

Proximate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	14.98%	-	-
ASH:	11.04%	12.99%	-
VOLATILE:	30.94%	36.39%	41.82%
FIXED CARBON:	43.04%	50.63%	58.18%
	100.00%	100.00%	100.00%
BTU/LB:	10,671	12,551	

Ultimate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	14.98%	-	-
CARBON:	60.00%	70.57%	81.10%
HYDROGEN:	4.02%	4.73%	5.43%
NITROGEN:	1.24%	1.45%	1.67%
CHLORINE:	0.00%	0.00%	0.00%
SULFUR:	2.01%	2.36%	2.71%
ASH:	11.04%	12.99%	-
OXYGEN (by diff):	6.72%	7.90%	9.08%
	100.00%	100.00%	100.00%

OPERATING CONDITIONS

GROSS HEAT RATE (Btu/kWh):	10,411	Calculated from coal pipe tests assuming 50% moisture retention
HEAT INPUT (Btu/hr):	7.29E+08	
LOAD (MWg):	70	
EXCESS OXYGEN (%,dry):	4.48%	
(%,wet):	4.10%	
HUMIDITY RATIO:	0.0055	Based on 50% relative humidity (60F ambient)
STOICH A/F:	8.09	
THEORETICAL A/F:	10.22	
MOLECULAR WEIGHT (lb/lbmole):	29.51	
AIR FLOW (lb/hr):	697,804	
FUEL FLOW (lb/hr):	68,294	
(tph):	34.1	

Combustion Mass Balance Stack Calculations	Wet Basis	Dry Basis	Mass Flow (lb/hr)	Molar Basis (lbmole/hr)	Mass/Heat Input ($lb/10^6$ Btu)
O2 (%):	4.10%	4.48%	33,749	1,055	46.31
CO2 (%):	13.28%	14.50%	150,188	3,413	206.08
H2O (%):	8.41%	-	38,910	2,162	53.39
N2 (%):	74.01%	80.81%	532,673	19,024	730.92
SO_2 (PPM @ 99% CONV):	1,650	1,801	2,714	42	3.72
SO_3 (PPM @ 1% CONV):	18	19	36	0	0.05
HCl (ppmv):	0	0	0	0	0.00
Measured NO (ppmv):	250	271	296	6	0.41
		100.00%	758,565	25,703	1040.88

ASH (gr/scf):	5.33
ASH (lb/hr):	7,540
FLUE GAS (lb/hr):	758,558
FLUE GAS (lb/lbmole):	29.51
FLUE GAS (lb/lbfuel):	11.11
FLUE GAS DENSITY @ 300 F (lb/ft^3):	0.0532

Utility: Dynegy
Plant: Vermilion
Unit: 2
Date: 2/28/00
Test: As Found Full Load Baseline Test

Data Source	Furnace		
DCS Shift Area 1	Gross Load	70.0	gMW
DCS Shift Area 1	Net Load	67.0	nMW
DCS Shift Area 1	Main Steam	519	klb/hr
Calculated	Gross Heat Rate	10,411	Btu/kWhr
Calculated	Net Heat Rate	10,877	Btu/kWhr
DCS Shift Area 1	Furance Draft	-0.3	iwc
DCS Shift Area 1	Windbox Pressure	2.3	iwc
Calculated	Stoich A/F	8.09	

Fuel

Data Source		Feed Rate		Coal/Air Temp	
Coal Overview Screen 29	Mill 2D	22,765	lb/hr	150	F
Coal Overview Screen 29	Mill 2C	22,765	lb/hr	151	F
Coal Overview Screen 29	Mill 2B	22,765	lb/hr	151	F
Coal Overview Screen 29	Mill 2A	0	lb/hr	153	F
Calculated	**Total Fuel wet basis**	68,294	lb/hr		
Estimate	estimated coal moisture loss in mill	NA			

	Estimated	Relative Percent	Std Dev
Pipe D	22,765	33.33%	
Pipe C	22,765	33.33%	
Pipe B	22,765	33.33%	
Pipe A	0	0.00%	
	68,295	100.00%	

Fuel Flow Coal Pipe Measurements (lb/hr)

LF	LR	RF	RR
0	0	0	0

Air

Data Source			
	Ambient Temp	65	F
	Bar Press	29.90	in Hg
	Rel Hum	60.00%	
Calculated	Total Air Flow	693,697	klb/hr

Dirty Air Coal Pipe Measurements (Assumed Constant over Load Based on Single Mill Measurement)

	Sum	Std Dev	LF	LR	RF	RR
Pipe D	63,276	4.67%	16,147	16,173	16,243	14,713
Pipe C	67,574	2.17%	17,165	16,769	17,210	16,430
Pipe B	66,563	3.19%	16,821	16,372	17,292	16,078
Pipe A	70,006	5.40%	17,941	16,609	18,618	16,838
	267,419		68,074	65,923	69,363	64,059

Economizer Outlet O2

Mainscreen 2100	A Side	4.33%
		3.41%
Mainscreen 2100	B Side	4.28%
	Average	4.01%

Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry	Burner Level Stoich		Volumetric Flowrate * (CFH)	Nozzle Velocities (ft/s)
Upper SOFA		1.15	9.54%	90%	8.58%	104,856	1.26			2,615,846	158
Lower SOFA		1.15	9.54%	100%	9.54%	116,507	1.07			2,906,496	175
	OFA Corner Subtotal	2.31				221,363				5,355,991	161
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	89%	4.81%	58,717	0.86			1,464,804	156
D Mill	Burner Level 4 SA	0.32	2.64%	11%	0.29%	3,551	0.75	0.80	Note 1	88,596	19
	Level 4 PA	0.57				63,276				974,226	119
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	18%	3.57%	43,661	1.11			1,089,201	32
C Mill	Burner Level 3	0.32	2.64%	14%	0.37%	4,520	0.82	0.64	Note 2	112,758	25
	Level 3 PA	0.57				67,574				1,036,411	126
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	20%	3.97%	48,512	1.26			1,210,223	35
B Mill	Burner Level 2	0.32	2.64%	12%	0.32%	3,874	0.99	0.62	Note 2	96,650	21
	Level 2 PA	0.57				66,563				1,003,967	122
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	16%	3.18%	38,809	#DIV/0!			968,178	28
A Mill	Burner Level 1	0.32	2.64%	4%	0.11%	1,291	#DIV/0!	#DIV/0!	Note 1	32,217	7
	Level 1PA	0.57				70,006				1,069,120	130
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	3%	0.16%	1,979	-			49,375	5
	Windbox Corner Subtotal	9.78				472,334				11,428,347	81
	TOTAL SA ONLY (no SOFA)					204,915				4,958,011	
	TOTAL SA + SOFA	12.09	100.00%		34.89%	693,697				16,784,338	

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air
Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air
* at 530°F for SA

Control Room Total Airflow Indication

Location	Data Source	Percent	Mass Flow
Primary Air Mill 2D	Dirty Air Measurement	23.7%	63,276 lb/hr
Primary Air Mill 2C	Dirty Air Measurement	25.3%	67,574 lb/hr
Primary Air Mill 2B	Dirty Air Measurement	24.9%	66,563 lb/hr
Primary Air Mill 2A	Dirty Air Measurement	26.2%	70,006 lb/hr
Total Hot Combustion Air	Calculated by Difference		653,584 lb/hr
Total Sec Air + OFA	Calculated by Difference		426,278 lb/hr
Total Comb Air to Boiler	Calculated	-	693,697 lb/hr

Assumes 15% tramp air inleakage on mills

.

Airflow Distribution Summary

Location	Data Source	Mass Flow	Air/Fuel Ratio
Measured PA @ Mill 2D	Assumed Equal Distribution	63,276 lb/hr	2.78
Measured PA @ Mill 2C	Assumed Equal Distribution	67,574 lb/hr	2.97
Measured PA @ Mill 2B	Assumed Equal Distribution	66,563 lb/hr	2.92
Measured PA @ Mill 2A	Assumed Equal Distribution	70,006 lb/hr	#DIV/0!
Total Primary Air	Sum	267,419 lb/hr	38.5%
Secondary Air	By Difference	204,915 lb/hr	29.5%
Overfire Air	Calculated	221,363 lb/hr	31.9%
Total Air to Boiler	Sum	693,697 lb/hr	100.0%

UTILITY: Dynegy
PLANT: Vermilion 2 — BLEND PERCENTAGE
FUEL 1: Eastern Bituminous — 100%
FUEL 2: — 0%
FUEL 3: — 0%
TYPE: Bituminous — 100%
ANALYSIS DATE: Commercial Testing Composite Analysis
February 28 - March 2, 2000

Proximate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	14.98%	-	-
ASH:	11.04%	12.99%	-
VOLATILE:	30.94%	36.39%	41.82%
FIXED CARBON:	43.04%	50.63%	58.18%
	100.00%	100.00%	100.00%
BTU/LB:	10,671	12,551	

Ultimate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	14.98%	-	-
CARBON:	60.00%	70.57%	81.10%
HYDROGEN:	4.02%	4.73%	5.43%
NITROGEN:	1.24%	1.45%	1.67%
CHLORINE:	0.00%	0.00%	0.00%
SULFUR:	2.01%	2.36%	2.71%
ASH:	11.04%	12.99%	-
OXYGEN (by diff):	6.72%	7.90%	9.08%
	100.00%	100.00%	100.00%

OPERATING CONDITIONS

GROSS HEAT RATE (Btu/kWh):	10,411	Calculated from coal pipe tests assuming 50% moisture retention
HEAT INPUT (Btu/hr):	7.29E+08	
LOAD (MWg):	70	
EXCESS OXYGEN (%,dry):	4.38%	
(%,wet):	4.01%	
HUMIDITY RATIO:	0.0055	Based on 50% relative humidity (60F ambient)
STOICH A/F:	8.09	
THEORETICAL A/F:	10.16	
MOLECULAR WEIGHT (lb/lbmole):	29.52	
AIR FLOW (lb/hr):	693,697	
FUEL FLOW (lb/hr):	68,294	
(tph):	34.1	

Combustion Mass Balance Stack Calculations	Wet Basis	Dry Basis	Mass Flow (lb/hr)	Molar Basis (lbmole/hr)	Mass/Heat Input (lb/10^6 Btu)
O2 (%):	4.01%	4.38%	32,797	1,025	45.00
CO2 (%):	13.35%	14.59%	150,187	3,413	206.08
H2O (%):	8.45%	-	38,887	2,160	53.36
N2 (%):	73.99%	80.82%	529,541	18,912	726.62
SO_2 (PPM @ 99% CONV):	1,659	1,812	2,714	42	3.72
SO_3 (PPM @ 1% CONV):	18	19	36	0	0.05
HCl (ppmv):	0	0	0	0	0.00
Measured NO (ppmv):	250	271	294	6	0.40
		100.00%	754,458	25,560	1035.25

ASH (gr/scf):	5.36
ASH (lb/hr):	7,540
FLUE GAS (lb/hr):	754,451
FLUE GAS (lb/lbmole):	29.52
FLUE GAS (lb/lbfuel):	11.05
FLUE GAS DENSITY @ 300 F (lb/ft^3):	0.0532

C
May 2000 Unit Air Flow Rates and Lower Furnace Stoichiometry

Test Matrix for Evaluating Vermilion 2 Gas Co-Firing for Incremental Additional NOx Reduction

Day	Task start/end Time	Condition	Load (% MCR)	Mills In Serv	Gas % # Levels	Excess Oxygen	Burner Sec Air	DCS Data	Coal Sample	Total Air Flow	OFA Air Flow
5/23/2000	0800 - 1030	Baseline	100	4	0/0	2%	Air Bias	x	x	DCS	DCS
5/23/2000	1130 - 1330	Gas Co-Firing 3	100	4	7.5%/3	2%	Air Bias	x	---	DCS	DCS
5/23/2000	1400 - 1600	Gas Co-Firing Bottom	100	4	7.5%/1	2%	Air Bias	x	---	DCS	DCS
5/23/2000	1630 - 1830	Gas Co-Firing Top	100	4	7.5%/1	2%	Air Bias	x	---	DCS	DCS
5/24/2000	0800 - 1130	Percent Gas Addition	100	4	7.5%/Opt	2%	Air Bias	x	x	DCS	DCS
5/24/2000	1230 - 1500	Percent Gas Addition	100	4	5.0%/Opt	2%	Air Bias	x	---	DCS	DCS
5/24/2000	1530 - 1800	Percent Gas Addition	100	4	2.5%/Opt	2%	Air Bias	x	---	DCS	DCS
5/25/2000	0600 - 0800	Low Load Baseline	70	4	0/0	2%	Air Bias	x	x	DCS	DCS
5/25/2000	0830 - 1030	Gas Co-Firing	70	4	Opt	2%	Air Bias	x	x	DCS	DCS
5/25/2000	1130 - 1330	Int Load Baseline	85	4	0/0	2%	Air Bias	x	x	DCS	DCS
5/25/2000	1400 - 1600	Gas Co-Firing	85	4	Opt	2%	Air Bias	x	x	DCS	DCS
5/26/2000	0600 - 0800	Low Load Baseline	70	3	0/0	2%	Air Bias	x	x	DCS	DCS
5/26/2000	0830 - 1030	Gas Co-Firing	70	3	Opt	2%	Air Bias	x	x	DCS	DCS

Day	Task start/end Time	Condition	Load (% MCR)	Mills In Serv	Gas % # Levels	Excess Oxygen	Burner Sec Air	Economizer Outlet			LOI	Station CEMS
								NO	CO	O2		
5/23/2000	0800 - 1030	Baseline	100	4	0/0	2%	Air Bias	x	x	x	x	---
5/23/2000	1130 - 1330	Gas Co-Firing 3	100	4	7.5%/3	2%	Air Bias	x	x	x	x	---
5/23/2000	1400 - 1600	Gas Co-Firing Bottom	100	4	7.5%/1	2%	Air Bias	x	x	x	x	---
5/23/2000	1630 - 1830	Gas Co-Firing Top	100	4	7.5%/1	2%	Air Bias	x	x	x	x	---
5/24/2000	0800 - 1130	Percent Gas Addition	100	4	7.5%/Opt	2%	Air Bias	x	x	x	x	---
5/24/2000	1230 - 1500	Percent Gas Addition	100	4	5.0%/Opt	2%	Air Bias	x	x	x	x	---
5/24/2000	1530 - 1800	Percent Gas Addition	100	4	2.5%/Opt	2%	Air Bias	x	x	x	x	---
5/25/2000	0600 - 0800	Low Load Baseline	70	4	0/0	2%	Air Bias	x	x	x	x	---
5/25/2000	0830 - 1030	Gas Co-Firing	70	4	Opt	2%	Air Bias	x	x	x	x	---
5/25/2000	1130 - 1330	Int Load Baseline	85	4	0/0	2%	Air Bias	x	x	x	x	---
5/25/2000	1400 - 1600	Gas Co-Firing	85	4	Opt	2%	Air Bias	x	x	x	x	---
5/26/2000	0600 - 0800	Low Load Baseline	70	3	0/0	2%	Air Bias	x	x	x	x	---
5/26/2000	0830 - 1030	Gas Co-Firing	70	3	Opt	2%	Air Bias	x	x	x	x	---

Utility: Dynegy
Plant: Vermilion
Unit: 2
Date: 5/23/2000
Test: Full Load Baseline

Data Source	**Furnace**		
DCS Shift Area 1	Gross Load	108.0	gMW
DCS Shift Area 1	Net Load	101.0	nMW
DCS Shift Area 1	Main Steam	804	klb/hr
Calculated	Gross Heat Rate	10,411	Btu/kWhr
Calculated	Net Heat Rate	11,133	Btu/kWhr
DCS Shift Area 1	Furance Draft	-0.3	iwc
DCS Shift Area 1	Windbox Pressure	2.0	iwc
Calculated	Stoich A/F	8.15	

	Fuel	**Feed Rate** (lb/hr)	**Exh Press** (iwc)	**Coal/Air Temp** (F)	**Pri Air** (lb/hr)	Dirty Air Coal Pipe Measurements Sum	Std Dev	LF	LR	RF	RR
Coal Overview Screen 29	Mill 2D	26,342	-1.32	151	50,000	0	#DIV/0!				
Coal Overview Screen 29	Mill 2C	26,342	-1.06	140	50,000	0	#DIV/0!				
Coal Overview Screen 29	Mill 2B	26,342	-0.24	131	50,000	0	#DIV/0!				
Coal Overview Screen 29	Mill 2A	26,342	-0.16	143	50,000	0	#DIV/0!				
Calculated	**Total Fuel wet basis**	105,369			200,000	0		0	0	0	0

	Natural Gas Co-Firing	**SCFM**	**Mass (lb/hr)**
	Level D/C	0	0
	Level C/B	0	0
	Level B/A	0	0
Gas Overview Screen	Total	0	0
Gas Overview Screen	Levels Fired	3	
Gas Overview Screen	Pressure	150	psig
	Density @ Standard Conditions	0.0447	lbm/ft3

	Air		
	Ambient Temp	83	F
	Bar Press	29.90	in Hg
	Rel Hum	50.00%	
Calculated	Total Air Flow	923,390	klb/hr
	Economizer Outlet O2		
Mainscreen 2100	A Side	3.22%	
		1.83%	
Mainscreen 2100	B Side	2.09%	
	Average	2.38%	

Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry (Coal + Gas)	Coal Burner Level Stoich		Volumetric Flowrate * (CFH)	Nozzle Velocities (ft/s)
Upper SOFA		1.15	9.54%	77%	7.37%	90,534	1.07			2,258,552	136
Lower SOFA		1.15	9.54%	99%	9.42%	115,761	0.97			2,887,876	174
	OFA Corner Subtotal	2.31				206,295				4,991,400	150
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	54%	2.93%	36,003	0.83			898,155	96
D Mill	Burner Level 4 SA	0.32	2.64%	45%	1.19%	14,614	0.79	0.77	Note 1	364,581	79
	Level 4 PA	0.57				50,000				769,823	94
Gas Spud	Gas Fuel Addition						1.03				
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	53%	10.57%	129,927	1.03			3,241,282	94
C Mill	Burner Level 3	0.32	2.64%	43%	1.15%	14,095	0.76	0.90	Note 2	351,618	76
	Level 3 PA	0.57				50,000				766,871	94
Gas Spud	Gas Fuel Addition						0.98				
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	53%	10.55%	129,683	0.98			3,235,195	94
B Mill	Burner Level 2	0.32	2.64%	43%	1.14%	13,957	0.68	0.90	Note 2	348,175	76
	Level 2 PA	0.57				50,000				754,148	92
Gas Spud	Gas Fuel Addition						1.07				
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	53%	10.60%	130,293	1.07			3,250,412	94
A Mill	Burner Level 1	0.32	2.64%	43%	1.13%	13,884	0.46	0.76	Note 1	346,352	75
	Level 1PA	0.57				50,000				763,592	93
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	52%	2.82%	34,642	-			864,215	92
	Windbox Corner Subtotal	9.78				717,096				17,350,493	123
	TOTAL SA ONLY (no SOFA)					517,096				12,511,393	
	TOTAL SA + SOFA	12.09	100.00%		58.86%	923,390				22,341,893	

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air

Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

* at 530°F for SA

Control Room Total Airflow Indication

Location	Data Source	Percent	Mass Flow
Primary Air Mill 2D	Dirty Air Measurement	25.0%	50,000 lb/hr
Primary Air Mill 2C	Dirty Air Measurement	25.0%	50,000 lb/hr
Primary Air Mill 2B	Dirty Air Measurement	25.0%	50,000 lb/hr
Primary Air Mill 2A	Dirty Air Measurement	25.0%	50,000 lb/hr
Total Hot Combustion Air	Calculated by Difference		893,390 lb/hr
Total Sec Air + OFA	Calculated by Difference		723,390 lb/hr
Total Comb Air to Boiler	Calculated	-	923,390 lb/hr

Assumes 15% tramp air inleakage on mills

.

Airflow Distribution Summary

Location	Data Source	Mass Flow	Air/Fuel Ratio
Measured PA @ Mill 2D	Assumed Equal Distribution	50,000 lb/hr	1.90
Measured PA @ Mill 2C	Assumed Equal Distribution	50,000 lb/hr	1.90
Measured PA @ Mill 2B	Assumed Equal Distribution	50,000 lb/hr	1.90
Measured PA @ Mill 2A	Assumed Equal Distribution	50,000 lb/hr	1.90
Total Primary Air	Sum	200,000 lb/hr	21.7%
Secondary Air	By Difference	517,096 lb/hr	56.0%
Overfire Air	Calculated	206,295 lb/hr	22.3%
Total Air to Boiler	Sum	923,390 lb/hr	100.0%

UTILITY:	Dynegy	BLEND	
PLANT:	Vermilion 2	WEIGHT PERCENT	
FUEL 1:	Eastern Bituminous	100.0%	
FUEL 2:	Natural Gas	0.0%	
FUEL 3:		0%	
TYPE:	Bituminous Coal with Nat Gas Cc	100%	
ANALYSIS DATE:	Commercial Testing Coal Composite Analysis		May 23 - 25, 2000
	Natural Gas Sample April 26		

Proximate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	16.69%	-	-
ASH:	10.27%	12.33%	-
VOLATILE:	30.88%	37.07%	42.28%
FIXED CARBON:	42.13%	50.57%	57.68%
	99.97%	99.96%	99.96%
BTU/LB:	10,747	12,900	

Ultimate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	16.69%	-	-
CARBON:	59.90%	71.90%	82.01%
HYDROGEN:	3.95%	4.74%	5.41%
NITROGEN:	1.28%	1.54%	1.75%
CHLORINE:	0.00%	0.00%	0.00%
SULFUR:	1.38%	1.66%	1.89%
ASH:	10.27%	12.33%	-
OXYGEN (by diff):	6.53%	7.84%	8.94%
	100.00%	100.00%	100.00%

OPERATING CONDITIONS

GROSS HEAT RATE (Btu/kWh):	10,411	Calculated
TOTAL HEAT INPUT (Btu/hr):	1.05E+09	
COAL HEAT INPUT (Btu/hr):	1.05E+09	100.00%
GAS HEAT INPUT (Btu/hr):	0.00E+00	0.00%
LOAD (MWg):	101	
EXCESS OXYGEN (%,dry):	2.21%	
(%,wet):	1.97%	
HUMIDITY RATIO:	0.0160	Based on 60% Relative Humidity (86F)
STOICH A/F:	8.11	
THEORETICAL A/F:	9.04	
MOLECULAR WEIGHT (lb/lbmole):	29.39	
AIR FLOW (lb/hr):	884,842	
COAL FUEL FLOW (lb/hr):	97,842	
(tph):	48.9	
GAS FUEL FLOW (lb/hr):	0	
(ft3/min):	0	
GAS DENSITY (lbm/ft3):	0.0447	

Combustion Mass Balance Stack Calculations	Wet Basis	Dry Basis	Mass Flow (lb/hr)	Molar Basis (lbmole/hr)	Mass/Heat Input (lb/10^6 Btu)
O2 (%):	1.97%	2.21%	20,815	650	19.80
CO2 (%):	14.74%	16.57%	214,578	4,877	204.07
H2O (%):	11.05%	-	65,817	3,656	62.59
N2 (%):	72.10%	81.06%	667,994	23,857	635.27
SO_2 (PPM @ 99% CONV):	1,261	1,417	2,670	42	2.54
SO_3 (PPM @ 1% CONV):	13	15	35	0	0.03
HCl (ppmv):	0	0	0	0	0.00
Measured NO (ppmv):	197	219	300	7	0.29
		100.00%	972,208	33,089	924.58

ASH (gr/scf):	5.54
ASH (lb/hr):	10,048
FLUE GAS (lb/hr):	972,636
FLUE GAS (lb/lbmole):	29.39
FLUE GAS (lb/lbfuel):	9.94
FLUE GAS DENSITY @ 300 F (lb/ft^3):	0.0530

Utility: Dynegy
Plant: Vermilion
Unit: 2
Date: 5/23/2000
Test: Gas Cofiring - Upper Level
Test 2

Data Source	Furnace					
DCS Shift Area 1	Gross Load	104.0	gMW			
DCS Shift Area 1	Net Load	98.9	nMW			
DCS Shift Area 1	Main Steam	758	klb/hr			
Calculated	Gross Heat Rate	10,432	Btu/kWhr			
Calculated	Net Heat Rate	10,970	Btu/kWhr			
DCS Shift Area 1	Furance Draft	-0.3	iwc			
DCS Shift Area 1	Windbox Pressure	4.0	iwc			
Calculated	Stoich A/F	8.37				
	Fuel	**Feed Rate** (lb/hr)	**Disch Press** (iwc)	**Coal/Air Temp** (F)	**Pri Air** (lb/hr)	
Coal Overview Screen 29	Mill 2D	23,734	4.22	139	41,165	
Coal Overview Screen 29	Mill 2C	23,734	5.69	144	48,999	
Coal Overview Screen 29	Mill 2B	23,734	9.24	128	55,360	
Coal Overview Screen 29	Mill 2A	23,734	6.04	133	47,460	
Calculated	**Total Fuel wet basis**	94,936			192,984	

	Natural Gas Co-Firing	SCFM	Mass (lb/hr)
	Level D/C	1,030	2,762
	Level C/B		0
	Level B/A		0
Gas Overview Screen	Total	1,030	2,762
Gas Overview Screen	Levels Fired	1	LR/RF Corners Only
Gas Overview Screen	Burner Gas Header Pressure	11.1	psig
	Density @ Standard Conditions	0.0447	lbm/ft3

	Air		
	Ambient Temp	86	F
	Bar Press	29.90	in Hg
	Rel Hum	60.00%	
Calculated	Total Air Flow	879,893	klb/hr
	Economizer Outlet O2		
Mainscreen 2100	A Side	OOS	
		1.45%	
Mainscreen 2100	B Side	1.25%	
	Average	1.35%	

Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry (Coal + Gas)	Coal Burner Level Stoich	
Upper SOFA		1.15	9.54%	77%	7.37%	111,522	1.08		
Lower SOFA		1.15	9.54%	99%	9.42%	142,596	0.94		
	OFA Corner Subtotal	2.31				254,118			
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	99%	5.34%	80,840	0.77		
D Mill	Burner Level 4 SA	0.32	2.64%	22%	0.58%	8,779	0.67	0.89	Note 1
	Level 4 PA	0.57				41,165			
Gas Spud	Gas Fuel Addition						0.87		
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	31%	6.18%	93,506	0.90		
C Mill	Burner Level 3	0.32	2.64%	23%	0.61%	9,223	0.67	0.79	Note 2
	Level 3 PA	0.57				48,999			
Gas Spud	Gas Fuel Addition						0.86		
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	34%	6.78%	102,690	0.86		
B Mill	Burner Level 2	0.32	2.64%	23%	0.59%	9,001	0.61	0.82	Note 2
	Level 2 PA	0.57				55,360			
Gas Spud	Gas Fuel Addition						0.89		
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	31%	6.18%	93,506	0.89		
A Mill	Burner Level 1	0.32	2.64%	21%	0.54%	8,223	0.42	0.65	Note 1
	Level 1PA	0.57				47,460			
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	33%	1.78%	27,022	-		
	Windbox Corner Subtotal	9.78				625,776			
	TOTAL SA ONLY (no SOFA)					432,792			
	TOTAL SA + SOFA	12.09	100.00%		45.37%	879,893			

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air
Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

Control Room Total Airflow Indication

Location	Data Source	Percent	Mass Flow
Primary Air Mill 2D	Dirty Air Measurement	21.3%	41,165 lb/hr
Primary Air Mill 2C	Dirty Air Measurement	25.4%	48,999 lb/hr
Primary Air Mill 2B	Dirty Air Measurement	28.7%	55,360 lb/hr
Primary Air Mill 2A	Dirty Air Measurement	24.6%	47,460 lb/hr
Total Hot Combustion Air	Calculated by Difference		850,946 lb/hr
Total Sec Air + OFA	Calculated by Difference		686,909 lb/hr
Total Comb Air to Boiler	Calculated	-	879,893 lb/hr

Assumes 15% tramp air inleakage on mills

Airflow Distribution Summary

Location	Data Source	Mass Flow	Air/Fuel Ratio
Measured PA @ Mill 2D	Assumed Equal Distribution	41,165 lb/hr	1.73
Measured PA @ Mill 2C	Assumed Equal Distribution	48,999 lb/hr	2.06
Measured PA @ Mill 2B	Assumed Equal Distribution	55,360 lb/hr	2.33
Measured PA @ Mill 2A	Assumed Equal Distribution	47,460 lb/hr	2.00
Total Primary Air	Sum	192,984 lb/hr	21.9%
Secondary Air	By Difference	432,792 lb/hr	49.2%
Overfire Air	Calculated	254,118 lb/hr	28.9%
Total Air to Boiler	Sum	879,893 lb/hr	100.0%

UTILITY:	Dynegy		BLEND
PLANT:	Vermilion 2		WEIGHT PERCENT
FUEL 1:	Eastern Bituminous		97.2%
FUEL 2:	Natural Gas		2.8%
FUEL 3:			0%
TYPE:	Bituminous Coal with Nat Gas Cc		100%
ANALYSIS DATE:	Commercial Testing Coal Composite Analysis		May 23 - 25, 2000
	Natural Gas Sample April 26		

Proximate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	16.22%	-	-
ASH:	9.98%	11.91%	-
VOLATILE:	32.83%	39.19%	44.49%
FIXED CARBON:	40.94%	48.86%	55.47%
	99.97%	99.97%	99.96%
BTU/LB:	11,105	13,254	

Ultimate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	16.22%	-	-
CARBON:	60.29%	71.96%	81.69%
HYDROGEN:	4.53%	5.41%	6.14%
NITROGEN:	1.29%	1.55%	1.75%
CHLORINE:	0.00%	0.00%	0.00%
SULFUR:	1.34%	1.60%	1.82%
ASH:	9.98%	11.91%	-
OXYGEN (by diff):	6.35%	7.57%	8.60%
	100.00%	100.00%	100.00%

OPERATING CONDITIONS

GROSS HEAT RATE (Btu/kWh):	10,432	Calculated
TOTAL HEAT INPUT (Btu/hr):	1.08E+09	
COAL HEAT INPUT (Btu/hr):	1.02E+09	94.04%
GAS HEAT INPUT (Btu/hr):	6.46E+07	5.96%
LOAD (MWg):	104	
EXCESS OXYGEN (%,dry):	1.53%	
(%,wet):	1.35%	
HUMIDITY RATIO:	0.0160	Based on 60% Relative Humidity (86F)
STOICH A/F:	8.37	
THEORETICAL A/F:	9.01	
MOLECULAR WEIGHT (lb/lbmole):	29.31	
AIR FLOW (lb/hr):	879,893	
COAL FUEL FLOW (lb/hr):	94,936	
(tph):	47.5	
GAS FUEL FLOW (lb/hr):	2,762	
(ft3/min):	1,030	
GAS DENSITY (lbm/ft3):	0.0447	

Combustion Mass Balance Stack Calculations	Wet Basis	Dry Basis	Mass Flow (lb/hr)	Molar Basis (lbmole/hr)	Mass/Heat Input (lb/10^6 Btu)
O2 (%):	1.35%	1.53%	14,219	444	13.49
CO2 (%):	14.84%	16.83%	215,101	4,889	204.04
H2O (%):	11.83%	-	70,131	3,896	66.52
N2 (%):	71.84%	81.48%	662,563	23,663	628.48
SO_2 (PPM @ 99% CONV):	1,226	1,390	2,584	40	2.45
SO_3 (PPM @ 1% CONV):	13	15	34	0	0.03
HCl (ppmv):	0	0	0	0	0.00
Measured NO (ppmv):	194	216	293	6	0.28
		100.00%	964,926	32,939	915.29

ASH (gr/scf):	5.26
ASH (lb/hr):	9,474
FLUE GAS (lb/hr):	965,355
FLUE GAS (lb/lbmole):	29.31
FLUE GAS (lb/lbfuel):	10.17
FLUE GAS DENSITY @ 300 F (lb/ft^3):	0.0528

Utility: Dynegy
Plant: Vermilion
Unit: 2
Date: 5/23/2000
Test: Gas Cofiring - Upper Level
Test 3

Data Source	Furnace		
DCS Shift Area 1	Gross Load	104.8	gMW
DCS Shift Area 1	Net Load	99.6	nMW
DCS Shift Area 1	Main Steam	760	klb/hr
Calculated	Gross Heat Rate	10,408	Btu/kWhr
Calculated	Net Heat Rate	10,951	Btu/kWhr
DCS Shift Area 1	Furance Draft	-0.3	iwc
DCS Shift Area 1	Windbox Pressure	4.0	iwc
Calculated	Stoich A/F	8.49	

Data Source	Fuel	Feed Rate (lb/hr)	Disch Press (iwc)	Coal/Air Temp (F)	Pri Air (lb/hr)
Coal Overview Screen 29	Mill 2D	23,177	4.19	140	41,082
Coal Overview Screen 29	Mill 2C	23,177	5.62	144	48,805
Coal Overview Screen 29	Mill 2B	23,177	8.52	128	54,131
Coal Overview Screen 29	Mill 2A	23,177	5.74	132	46,691
Calculated	**Total Fuel wet basis**	92,708			190,709

Data Source	Natural Gas Co-Firing	SCFM	Mass (lb/hr)
	Level D/C		0
	Level C/B		0
	Level B/A	1,505	4,036
Gas Overview Screen	Total	1,505	4,036
Gas Overview Screen	Levels Fired	1	Three Corners Only
Gas Overview Screen	Burner Gas Header Pressure	11.1	psig
	Density @ Standard Conditions	0.0447	lbm/ft3

Data Source	Air		
	Ambient Temp	86	F
	Bar Press	29.90	in Hg
	Rel Hum	60.00%	
Calculated	Total Air Flow	892,646	klb/hr
	Economizer Outlet O2		
Mainscreen 2100	A Side	OOS	
		1.74%	
Mainscreen 2100	B Side	1.29%	
	Average	1.52%	

Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry (Coal + Gas)	Coal Burner Level Stoich	
Upper SOFA		1.15	9.54%	77%	7.37%	113,961	1.09		
Lower SOFA		1.15	9.54%	99%	9.42%	145,716	0.95		
	OFA Corner Subtotal	2.31				259,677			
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	99%	5.34%	82,609	0.77		
D Mill	Burner Level 4 SA	0.32	2.64%	22%	0.58%	8,971	0.67	0.92	Note 1
	Level 4 PA	0.57				41,082			
Gas Spud	Gas Fuel Addition						0.87		
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	31%	6.18%	95,552	0.87		
C Mill	Burner Level 3	0.32	2.64%	23%	0.61%	9,425	0.65	0.81	Note 2
	Level 3 PA	0.57				48,805			
Gas Spud	Gas Fuel Addition						0.81		
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	34%	6.78%	104,937	0.81		
B Mill	Burner Level 2	0.32	2.64%	23%	0.59%	9,198	0.56	0.83	Note 2
	Level 2 PA	0.57				54,131			
Gas Spud	Gas Fuel Addition						0.77		
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	31%	6.18%	95,552	0.91		
A Mill	Burner Level 1	0.32	2.64%	21%	0.54%	8,403	0.42	0.66	Note 1
	Level 1PA	0.57				46,691			
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	33%	1.78%	27,614	-		
	Windbox Corner Subtotal	9.78				632,969			
	TOTAL SA ONLY (no SOFA)					442,260			
	TOTAL SA + SOFA	12.09	100.00%		45.37%	892,646			

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air

Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

Control Room Total Airflow Indication

Location	Data Source	Percent	Mass Flow
Primary Air Mill 2D	Dirty Air Measurement	21.5%	41,082 lb/hr
Primary Air Mill 2C	Dirty Air Measurement	25.6%	48,805 lb/hr
Primary Air Mill 2B	Dirty Air Measurement	28.4%	54,131 lb/hr
Primary Air Mill 2A	Dirty Air Measurement	24.5%	46,691 lb/hr
Total Hot Combustion Air	Calculated by Difference		864,040 lb/hr
Total Sec Air + OFA	Calculated by Difference		701,937 lb/hr
Total Comb Air to Boiler	Calculated	-	892,646 lb/hr

Assumes 15% tramp air inleakage on mills

.

Airflow Distribution Summary

Location	Data Source	Mass Flow	Air/Fuel Ratio
Measured PA @ Mill 2D	Assumed Equal Distribution	41,082 lb/hr	1.77
Measured PA @ Mill 2C	Assumed Equal Distribution	48,805 lb/hr	2.11
Measured PA @ Mill 2B	Assumed Equal Distribution	54,131 lb/hr	2.34
Measured PA @ Mill 2A	Assumed Equal Distribution	46,691 lb/hr	2.01
Total Primary Air	Sum	190,709 lb/hr	21.4%
Secondary Air	By Difference	442,260 lb/hr	49.5%
Overfire Air	Calculated	259,677 lb/hr	29.1%
Total Air to Boiler	Sum	892,646 lb/hr	100.0%

UTILITY:	Dynegy	BLEND	
PLANT:	Vermilion 2	WEIGHT PERCENT	
FUEL 1:	Eastern Bituminous	95.8%	
FUEL 2:	Natural Gas	4.2%	
FUEL 3:		0%	
TYPE:	Bituminous Coal with Nat Gas Cc	100%	
ANALYSIS DATE:	Commercial Testing Coal Composite Analysis		May 23 - 25, 2000
	Natural Gas Sample April 26		

Proximate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	15.99%	-	-
ASH:	9.84%	11.72%	-
VOLATILE:	33.76%	40.19%	45.53%
FIXED CARBON:	40.37%	48.06%	54.44%
	99.97%	99.97%	99.96%
BTU/LB:	11,275	13,421	

Ultimate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	15.99%	-	-
CARBON:	60.48%	71.99%	81.54%
HYDROGEN:	4.81%	5.72%	6.48%
NITROGEN:	1.30%	1.55%	1.76%
CHLORINE:	0.00%	0.00%	0.00%
SULFUR:	1.32%	1.57%	1.78%
ASH:	9.84%	11.72%	-
OXYGEN (by diff):	6.26%	7.45%	8.44%
	100.00%	100.00%	100.00%

OPERATING CONDITIONS

GROSS HEAT RATE (Btu/kWh):	10,408	Calculated
TOTAL HEAT INPUT (Btu/hr):	1.09E+09	
COAL HEAT INPUT (Btu/hr):	9.96E+08	91.34%
GAS HEAT INPUT (Btu/hr):	9.44E+07	8.66%
LOAD (MWg):	104.8	
EXCESS OXYGEN (%,dry):	1.73%	
(%,wet):	1.52%	
HUMIDITY RATIO:	0.0160	Based on 60% Relative Humidity (86F)
STOICH A/F:	8.49	
THEORETICAL A/F:	9.23	
MOLECULAR WEIGHT (lb/lbmole):	29.25	
AIR FLOW (lb/hr):	892,646	
COAL FUEL FLOW (lb/hr):	92,708	
(tph):	46.4	
GAS FUEL FLOW (lb/hr):	4,036	
(ft3/min):	1,505	
GAS DENSITY (lbm/ft3):	0.0447	

Combustion Mass Balance Stack Calculations	Wet Basis	Dry Basis	Mass Flow (lb/hr)	Molar Basis (lbmole/hr)	Mass/Heat Input (lb/10^6 Btu)
O2 (%):	1.52%	1.73%	16,266	508	15.56
CO2 (%):	14.53%	16.51%	213,415	4,850	204.18
H2O (%):	11.97%	-	71,889	3,994	68.78
N2 (%):	71.84%	81.61%	671,384	23,978	642.32
SO_2 (PPM @ 99% CONV):	1,180	1,340	2,520	39	2.41
SO_3 (PPM @ 1% CONV):	13	14	34	0	0.03
HCl (ppmv):	0	0	0	0	0.00
Measured NO (ppmv):	195	218	299	7	0.29
		100.00%	975,806	33,377	933.56

ASH (gr/scf):	5.01
ASH (lb/hr):	9,124
FLUE GAS (lb/hr):	976,230
FLUE GAS (lb/lbmole):	29.25
FLUE GAS (lb/lbfuel):	10.53
FLUE GAS DENSITY @ 300 F (lb/ft^3):	0.0527

Utility: Dynegy
Plant: Vermilion
Unit: 2
Date: 5/23/2000
Test: Gas Cofiring - Upper Level
Test 4

Data Source	Furnace					
DCS Shift Area 1	Gross Load	106.4	gMW			
DCS Shift Area 1	Net Load	101.0	nMW			
DCS Shift Area 1	Main Steam	774	klb/hr			
Calculated	Gross Heat Rate	10,414	Btu/kWhr			
Calculated	Net Heat Rate	10,971	Btu/kWhr			
DCS Shift Area 1	Furance Draft	-0.3	iwc			
DCS Shift Area 1	Windbox Pressure	2.9	iwc			
Calculated	Stoich A/F	10.04				
	Fuel	**Feed Rate** (lb/hr)		**Disch Press** (iwc)	**Coal/Air Temp** (F)	**Pri Air** (lb/hr)
Coal Overview Screen 29	Mill 2D	16,202		3.30	145	37,899
Coal Overview Screen 29	Mill 2C	16,202		5.95	150	49,705
Coal Overview Screen 29	Mill 2B	16,202		6.18	131	49,529
Coal Overview Screen 29	Mill 2A	16,202		6.13	144	47,686
Calculated	**Total Fuel wet basis**	64,808				184,819

Data Source	Natural Gas Co-Firing	SCFM	Mass (lb/hr)
	Level D/C	6,559	17,591
	Level C/B		0
	Level B/A		0
Gas Overview Screen	Total	6,559	17,591
Gas Overview Screen	Levels Fired	1	4 corners at D/C level
Gas Overview Screen	Pressure	46	psig
	Density @ Standard Conditions	0.0447	lbm/ft3

Data Source	Air		
	Ambient Temp	86	F
	Bar Press	29.90	in Hg
	Rel Hum	60.00%	
Calculated	Total Air Flow	877,597	klb/hr
	Economizer Outlet O2		
Mainscreen 2100	A Side	OOS	
		1.10%	
Mainscreen 2100	B Side	1.08%	
	Average	1.09%	

Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry (Coal + Gas)	Coal Burner Level Stoich	
Upper SOFA		1.15	9.54%	90%	8.56%	116,034	1.06		
Lower SOFA		1.15	9.54%	99%	9.42%	127,667	0.92		
	OFA Corner Subtotal	2.31				243,701			
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	4%	0.24%	3,253	0.77		
D Mill	Burner Level 4 SA	0.32	2.64%	21%	0.56%	7,561	0.76	0.38	Note 1
	Level 4 PA	0.57				37,899			
Gas Spud	Gas Fuel Addition						0.94		
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	10%	1.99%	26,909	1.28		
C Mill	Burner Level 3	0.32	2.64%	23%	0.62%	8,357	1.14	0.94	Note 2
	Level 3 PA	0.57				49,705			
Gas Spud	Gas Fuel Addition						1.54		
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	60%	11.97%	162,201	1.54		
B Mill	Burner Level 2	0.32	2.64%	21%	0.57%	7,661	1.04	1.32	Note 2
	Level 2 PA	0.57				49,529			
Gas Spud	Gas Fuel Addition						1.73		
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	57%	11.25%	152,484	1.73		
A Mill	Burner Level 1	0.32	2.64%	21%	0.55%	7,462	0.79	1.26	Note 1
	Level 1PA	0.57				47,686			
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	100%	5.40%	73,190	-		
	Windbox Corner Subtotal	9.78				633,896			
	TOTAL SA ONLY (no SOFA)					449,077			
	TOTAL SA + SOFA	12.09	100.00%		51.11%	877,597			

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air

Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

Control Room Total Airflow Indication

Location	Data Source	Percent	Mass Flow
Primary Air Mill 2D	Dirty Air Measurement	20.5%	37,899 lb/hr
Primary Air Mill 2C	Dirty Air Measurement	26.9%	49,705 lb/hr
Primary Air Mill 2B	Dirty Air Measurement	26.8%	49,529 lb/hr
Primary Air Mill 2A	Dirty Air Measurement	25.8%	47,686 lb/hr
Total Hot Combustion Air	Calculated by Difference		849,874 lb/hr
Total Sec Air + OFA	Calculated by Difference		692,778 lb/hr
Total Comb Air to Boiler	Calculated	-	877,597 lb/hr

Assumes 15% tramp air inleakage on mills

.

Airflow Distribution Summary

Location	Data Source	Mass Flow	Air/Fuel Ratio
Measured PA @ Mill 2D	Assumed Equal Distribution	37,899 lb/hr	2.34
Measured PA @ Mill 2C	Assumed Equal Distribution	49,705 lb/hr	3.07
Measured PA @ Mill 2B	Assumed Equal Distribution	49,529 lb/hr	3.06
Measured PA @ Mill 2A	Assumed Equal Distribution	47,686 lb/hr	2.94
Total Primary Air	Sum	184,819 lb/hr	21.1%
Secondary Air	By Difference	449,077 lb/hr	51.2%
Overfire Air	Calculated	243,701 lb/hr	27.8%
Total Air to Boiler	Sum	877,597 lb/hr	100.0%

UTILITY:	Dynegy	BLEND	
PLANT:	Vermilion 2	WEIGHT PERCENT	
FUEL 1:	Eastern Bituminous	78.7%	
FUEL 2:	Natural Gas	21.3%	
FUEL 3:		0%	
TYPE:	Bituminous Coal with Nat Gas Cc	100%	
ANALYSIS DATE:	Commercial Testing Coal Composite Analysis		May 23 - 25, 2000
	Natural Gas Sample April 26		

Proximate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	13.13%	-	-
ASH:	8.08%	9.30%	-
VOLATILE:	45.64%	52.53%	57.92%
FIXED CARBON:	33.14%	38.14%	42.05%
	99.98%	99.97%	99.97%
BTU/LB:	13,447	15,479	

Ultimate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	13.13%	-	-
CARBON:	62.85%	72.34%	79.76%
HYDROGEN:	8.34%	9.60%	10.58%
NITROGEN:	1.39%	1.60%	1.77%
CHLORINE:	0.00%	0.00%	0.00%
SULFUR:	1.09%	1.25%	1.38%
ASH:	8.08%	9.30%	-
OXYGEN (by diff):	5.14%	5.91%	6.52%
	100.00%	100.00%	100.00%

OPERATING CONDITIONS

GROSS HEAT RATE (Btu/kWh):	10,414	Calculated
TOTAL HEAT INPUT (Btu/hr):	1.11E+09	
COAL HEAT INPUT (Btu/hr):	6.96E+08	62.86%
GAS HEAT INPUT (Btu/hr):	4.12E+08	37.14%
LOAD (MWg):	106	
EXCESS OXYGEN (%,dry):	1.28%	
(%,wet):	1.09%	
HUMIDITY RATIO:	0.0160	Based on 60% Relative Humidity (86 F)
STOICH A/F:	10.04	
THEORETICAL A/F:	10.65	
MOLECULAR WEIGHT (lb/lbmole):	28.71	
AIR FLOW (lb/hr):	877,597	
COAL FUEL FLOW (lb/hr):	64,808	
(tph):	32.4	
GAS FUEL FLOW (lb/hr):	17,591	
(ft3/min):	6,559	
GAS DENSITY (lbm/ft3):	0.0447	

Combustion Mass Balance Stack Calculations	Wet Basis	Dry Basis	Mass Flow (lb/hr)	Molar Basis (lbmole/hr)	Mass/Heat Input (lb/10^6 Btu)
O2 (%):	1.09%	1.28%	11,423	357	13.11
CO2 (%):	12.98%	15.19%	186,421	4,237	213.91
H2O (%):	14.57%	-	85,624	4,757	98.25
N2 (%):	71.26%	83.41%	651,340	23,262	747.40
SO_2 (PPM @ 99% CONV):	832	974	1,739	27	1.99
SO_3 (PPM @ 1% CONV):	9	10	23	0	0.03
HCl (ppmv):	0	0	0	0	0.00
Measured NO (ppmv):	181	207	272	6	0.31
		100.00%	936,842	32,646	1075.01

ASH (gr/scf):	3.00
ASH (lb/hr):	5,235
FLUE GAS (lb/hr):	937,170
FLUE GAS (lb/lbmole):	28.71
FLUE GAS (lb/lbfuel):	14.46
FLUE GAS DENSITY @ 300 F (lb/ft^3):	0.0518

Utility: Dynegy
Plant: Vermilion
Unit: 2
Date: 5/23/2000
Test: Gas Cofiring - Upper Level
Test 5

Data Source	Furnace		
DCS Shift Area 1	Gross Load	105.9	gMW
DCS Shift Area 1	Net Load	100.0	nMW
DCS Shift Area 1	Main Steam	766	klb/hr
Calculated	Gross Heat Rate	10,411	Btu/kWhr
Calculated	Net Heat Rate	11,026	Btu/kWhr
DCS Shift Area 1	Furance Draft	-0.3	iwc
DCS Shift Area 1	Windbox Pressure	2.9	iwc
Calculated	Stoich A/F	9.84	

	Fuel	Feed Rate (lb/hr)	Disch Press (iwc)	Coal/Air Temp (F)	Pri Air (lb/hr)
Coal Overview Screen 29	Mill 2D		-0.16	133	
Coal Overview Screen 29	Mill 2C	22,562	8.46	150	55,632
Coal Overview Screen 29	Mill 2B	22,562	9.39	130	55,607
Coal Overview Screen 29	Mill 2A	22,562	8.68	145	53,315
Calculated	**Total Fuel wet basis**	67,686			164,554

	Natural Gas Co-Firing	SCFM	Mass (lb/hr)
	Level D/C	5,979	16,036
	Level C/B		0
	Level B/A		0
Gas Overview Screen	Total	5,979	16,036
Gas Overview Screen	Levels Fired	1	Four corners D/C level
Gas Overview Screen	Pressure	46	psig
	Density @ Standard Conditions	0.0447	lbm/ft3

	Air		
	Ambient Temp	86	F
	Bar Press	29.90	in Hg
	Rel Hum	60.00%	
Calculated	Total Air Flow	870,066	klb/hr
	Economizer Outlet O2		
Mainscreen 2100	A Side	OOS	
		1.10%	
Mainscreen 2100	B Side	0.87%	
	Average	0.99%	

Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry (Coal + Gas)	Coal Burner Level Stoich	
Upper SOFA		1.15	9.54%	96%	9.14%	124,297	1.06		
Lower SOFA		1.15	9.54%	99%	9.42%	128,023	0.91		
	OFA Corner Subtotal	2.31				252,320			
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	5%	0.25%	3,466	0.75		
D Mill	Burner Level 4 SA	0.32	2.64%	6%	0.15%	1,995	0.75		Note 1
	Level 4 PA	0.57				0			
Gas Spud	Gas Fuel Addition						0.74		
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	10%	1.93%	26,234	0.92		
C Mill	Burner Level 3	0.32	2.64%	24%	0.62%	8,480	0.88	0.72	Note 2
	Level 3 PA	0.57				55,632			
Gas Spud	Gas Fuel Addition						1.18		
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	62%	12.30%	167,151	1.18		
B Mill	Burner Level 2	0.32	2.64%	22%	0.59%	7,981	0.80	1.02	Note 2
	Level 2 PA	0.57				55,607			
Gas Spud	Gas Fuel Addition						1.31		
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	58%	11.58%	157,407	1.31		
A Mill	Burner Level 1	0.32	2.64%	20%	0.52%	7,083	0.60	0.96	Note 1
	Level 1PA	0.57				53,315			
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	100%	5.40%	73,394	-		
	Windbox Corner Subtotal	9.78				617,746			
	TOTAL SA ONLY (no SOFA)					453,192			
	TOTAL SA + SOFA	12.09	100.00%		51.91%	870,066			

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air
Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

Control Room Total Airflow Indication

Location	Data Source	Percent	Mass Flow	
Primary Air Mill 2D	Dirty Air Measurement	0.0%	0 lb/hr	
Primary Air Mill 2C	Dirty Air Measurement	33.8%	55,632 lb/hr	
Primary Air Mill 2B	Dirty Air Measurement	33.8%	55,607 lb/hr	
Primary Air Mill 2A	Dirty Air Measurement	32.4%	53,315 lb/hr	
Total Hot Combustion Air	Calculated by Difference		845,383 lb/hr	**Assumes 15% tramp air inleakage on mills**
Total Sec Air + OFA	Calculated by Difference		705,512 lb/hr	
Total Comb Air to Boiler	Calculated	-	870,066 lb/hr	

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Airflow Distribution Summary

Location	Data Source	Mass Flow	Air/Fuel Ratio	
Measured PA @ Mill 2D	Assumed Equal Distribution	0 lb/hr		
Measured PA @ Mill 2C	Assumed Equal Distribution	55,632 lb/hr	2.47	
Measured PA @ Mill 2B	Assumed Equal Distribution	55,607 lb/hr	2.46	
Measured PA @ Mill 2A	Assumed Equal Distribution	53,315 lb/hr	2.36	
Total Primary Air	115% x Sum	189,237 lb/hr	21.7%	**Assumes 15% tramp air inleakage on mills**
Secondary Air	By Difference	428,509 lb/hr	49.3%	
Overfire Air	Calculated	252,320 lb/hr	29.0%	
Total Air to Boiler	Sum	870,066 lb/hr	100.0%	

UTILITY:	Dynegy		BLEND
PLANT:	Vermilion 2		WEIGHT PERCENT
FUEL 1:	Eastern Bituminous		80.8%
FUEL 2:	Natural Gas		19.2%
FUEL 3:			0%
TYPE:	Bituminous Coal with Nat Gas Cc		100%
ANALYSIS DATE:	Commercial Testing Coal Composite Analysis		May 23- 25, 2000
	Natural Gas Sample April 26		

Proximate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	13.49%	-	-
ASH:	8.30%	9.60%	-
VOLATILE:	44.12%	51.00%	56.42%
FIXED CARBON:	34.06%	39.37%	43.55%
	99.98%	99.97%	99.97%
BTU/LB:	13,169	15,224	

Ultimate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	13.49%	-	-
CARBON:	62.54%	72.30%	79.97%
HYDROGEN:	7.89%	9.12%	10.08%
NITROGEN:	1.38%	1.59%	1.76%
CHLORINE:	0.00%	0.00%	0.00%
SULFUR:	1.12%	1.29%	1.43%
ASH:	8.30%	9.60%	-
OXYGEN (by diff):	5.28%	6.10%	6.75%
	100.00%	100.00%	100.00%

OPERATING CONDITIONS

GROSS HEAT RATE (Btu/kWh):	10,411	Calculated
TOTAL HEAT INPUT (Btu/hr):	1.10E+09	
COAL HEAT INPUT (Btu/hr):	7.27E+08	65.98%
GAS HEAT INPUT (Btu/hr):	3.75E+08	34.02%
LOAD (MWg):	106	
EXCESS OXYGEN (%,dry):	1.18%	
(%,wet):	1.01%	
HUMIDITY RATIO:	0.0160	Based on 60% Relative Humidity (86 F)
STOICH A/F:	9.84	
THEORETICAL A/F:	10.39	
MOLECULAR WEIGHT (lb/lbmole):	28.77	
AIR FLOW (lb/hr):	870,066	
COAL FUEL FLOW (lb/hr):	67,686	
(tph):	33.8	
GAS FUEL FLOW (lb/hr):	16,036	
(ft3/min):	5,979	
GAS DENSITY (lbm/ft3):	0.0447	

Combustion Mass Balance Stack Calculations	Wet Basis	Dry Basis	Mass Flow (lb/hr)	Molar Basis (lbmole/hr)	Mass/Heat Input (lb/10^6 Btu)
O2 (%):	1.01%	1.18%	10,478	327	11.75
CO2 (%):	13.24%	15.46%	188,765	4,290	211.77
H2O (%):	14.36%	-	83,750	4,653	93.96
N2 (%):	71.28%	83.24%	646,705	23,097	725.51
SO_2 (PPM @ 99% CONV):	877	1,024	1,818	28	2.04
SO_3 (PPM @ 1% CONV):	9	11	24	0	0.03
HCl (ppmv):	0	0	0	0	0.00
Measured NO (ppmv):	159	181	236	5	0.27
		100.00%	931,776	32,401	1045.32

ASH (gr/scf):	3.23
ASH (lb/hr):	5,620
FLUE GAS (lb/hr):	932,131
FLUE GAS (lb/lbmole):	28.77
FLUE GAS (lb/lbfuel):	13.77
FLUE GAS DENSITY @ 300 F (lb/ft^3):	0.0519

Utility: Dynegy
Plant: Vermilion
Unit: 2
Date: 5/24/2000
Test: Gas Cofiring - Upper Level
Test 6

Data Source	Furnace					
DCS Shift Area 1	Gross Load	105.8	gMW			
DCS Shift Area 1	Net Load	100.5	nMW			
DCS Shift Area 1	Main Steam	765	klb/hr			
Calculated	Gross Heat Rate	10,411	Btu/kWhr			
Calculated	Net Heat Rate	10,960	Btu/kWhr			
DCS Shift Area 1	Furance Draft	-0.3	iwc			
DCS Shift Area 1	Windbox Pressure	2.9	iwc			
Calculated	Stoich A/F	9.81				
	Fuel	**Feed Rate** (lb/hr)	**Disch Press** (iwc)	**Coal/Air Temp** (F)	**Pri Air** (lb/hr)	
Coal Overview Screen 29	Mill 2D		-0.13	122		
Coal Overview Screen 29	Mill 2C	22,709	8.34	150	55,378	
Coal Overview Screen 29	Mill 2B	22,709	9.41	130	55,640	
Coal Overview Screen 29	Mill 2A	22,709	8.70	145	53,354	
Calculated	**Total Fuel wet basis**	68,126			164,372	

	Natural Gas Co-Firing	SCFM	Mass (lb/hr)
	Level D/C	5,887	15,789
	Level C/B		0
	Level B/A		0
Gas Overview Screen	Total	5,887	15,789
Gas Overview Screen	Levels Fired	1	
Gas Overview Screen	Pressure	46	psig
	Density @ Standard Conditions	0.0447	lbm/ft3

	Air		
	Ambient Temp	86	F
	Bar Press	29.90	in Hg
	Rel Hum	60.00%	
Calculated	Total Air Flow	870,238	klb/hr
	Economizer Outlet O2		
Mainscreen 2100	A Side	OOS	
		1.23%	
Mainscreen 2100	B Side	0.83%	
	Average	1.03%	

Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry (Coal + Gas)	Coal Burner Level Stoich	
Upper SOFA		1.15	9.54%	96%	9.14%	124,359	1.06		
Lower SOFA		1.15	9.54%	99%	9.42%	128,087	0.91		
	OFA Corner Subtotal	2.31				252,446			
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	5%	0.25%	3,468	0.75		
D Mill	Burner Level 4 SA	0.32	2.64%	6%	0.15%	1,996	0.75		Note 1
	Level 4 PA	0.57				0			
Gas Spud	Gas Fuel Addition						0.74		
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	10%	1.93%	26,248	0.92		
C Mill	Burner Level 3	0.32	2.64%	24%	0.62%	8,484	0.88	0.72	Note 2
	Level 3 PA	0.57				55,378			
Gas Spud	Gas Fuel Addition						1.17		
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	62%	12.30%	167,235	1.17		
B Mill	Burner Level 2	0.32	2.64%	22%	0.59%	7,985	0.80	1.01	Note 2
	Level 2 PA	0.57				55,640			
Gas Spud	Gas Fuel Addition						1.31		
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	58%	11.58%	157,486	1.31		
A Mill	Burner Level 1	0.32	2.64%	20%	0.52%	7,087	0.60	0.95	Note 1
	Level 1PA	0.57				53,354			
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	100%	5.40%	73,431	-		
	Windbox Corner Subtotal	9.78				617,792			
	TOTAL SA ONLY (no SOFA)					453,419			
	TOTAL SA + SOFA	12.09	100.00%		51.91%	870,238			

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air
Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

Control Room Total Airflow Indication

Location	Data Source	Percent	Mass Flow	
Primary Air Mill 2D	Dirty Air Measurement	0.0%	0 lb/hr	
Primary Air Mill 2C	Dirty Air Measurement	33.7%	55,378 lb/hr	
Primary Air Mill 2B	Dirty Air Measurement	33.9%	55,640 lb/hr	
Primary Air Mill 2A	Dirty Air Measurement	32.5%	53,354 lb/hr	
Total Hot Combustion Air	Calculated by Difference		845,582 lb/hr	**Assumes 15% tramp air inleakage on mills**
Total Sec Air + OFA	Calculated by Difference		705,865 lb/hr	
Total Comb Air to Boiler	Calculated	-	870,238 lb/hr	

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Airflow Distribution Summary

Location	Data Source	Mass Flow	Air/Fuel Ratio	
Measured PA @ Mill 2D	Assumed Equal Distribution	0 lb/hr		
Measured PA @ Mill 2C	Assumed Equal Distribution	55,378 lb/hr	2.44	
Measured PA @ Mill 2B	Assumed Equal Distribution	55,640 lb/hr	2.45	
Measured PA @ Mill 2A	Assumed Equal Distribution	53,354 lb/hr	2.35	
Total Primary Air	115% x Sum	189,028 lb/hr	21.7%	**Assumes 15% tramp air inleakage on mills**
Secondary Air	By Difference	428,764 lb/hr	49.3%	
Overfire Air	Calculated	252,446 lb/hr	29.0%	
Total Air to Boiler	Sum	870,238 lb/hr	100.0%	

UTILITY: Dynegy
PLANT: Vermilion 2
FUEL 1: Eastern Bituminous
FUEL 2: Natural Gas
FUEL 3:
TYPE: Bituminous Coal with Nat Gas Cc
ANALYSIS DATE: Commercial Testing Coal Composite Analysis May 23 - 25, 2000
Natural Gas Sample April 26

BLEND WEIGHT PERCENT
81.2%
18.8%
0%
100%

Proximate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	13.55%	-	-
ASH:	8.34%	9.64%	-
VOLATILE:	43.89%	50.76%	56.18%
FIXED CARBON:	34.20%	39.56%	43.79%
	99.98%	99.97%	99.97%
BTU/LB:	13,127	15,184	

Ultimate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	13.55%	-	-
CARBON:	62.50%	72.29%	80.01%
HYDROGEN:	7.82%	9.04%	10.01%
NITROGEN:	1.38%	1.59%	1.76%
CHLORINE:	0.00%	0.00%	0.00%
SULFUR:	1.12%	1.30%	1.43%
ASH:	8.34%	9.64%	-
OXYGEN (by diff):	5.30%	6.13%	6.79%
	100.00%	100.00%	100.00%

OPERATING CONDITIONS

GROSS HEAT RATE (Btu/kWh):	10,411	Calculated
TOTAL HEAT INPUT (Btu/hr):	1.10E+09	
COAL HEAT INPUT (Btu/hr):	7.32E+08	66.47%
GAS HEAT INPUT (Btu/hr):	3.69E+08	33.53%
LOAD (MWg):	105.8	
EXCESS OXYGEN (%,dry):	1.20%	
(%,wet):	1.03%	
HUMIDITY RATIO:	0.0160	Based on 60% Relative Humidity (86 F)
STOICH A/F:	9.81	
THEORETICAL A/F:	10.37	
MOLECULAR WEIGHT (lb/lbmole):	28.78	
AIR FLOW (lb/hr):	870,238	
COAL FUEL FLOW (lb/hr):	68,126	
(tph):	34.1	
GAS FUEL FLOW (lb/hr):	15,789	
(ft3/min):	5,887	
GAS DENSITY (lbm/ft3):	0.0447	

Combustion Mass Balance Stack Calculations	Wet Basis	Dry Basis	Mass Flow (lb/hr)	Molar Basis (lbmole/hr)	Mass/Heat Input (lb/10^6 Btu)
O2 (%):	1.03%	1.20%	10,664	333	11.93
CO2 (%):	13.26%	15.48%	189,109	4,298	211.47
H2O (%):	14.31%	-	83,468	4,637	93.34
N2 (%):	71.30%	83.20%	646,986	23,107	723.48
SO_2 (PPM @ 99% CONV):	883	1,030	1,831	29	2.05
SO_3 (PPM @ 1% CONV):	9	11	24	0	0.03
HCl (ppmv):	0	0	0	0	0.00
Measured NO (ppmv):	168	192	250	5	0.28
		100.00%	932,333	32,409	1042.57

ASH (gr/scf):	3.27
ASH (lb/hr):	5,680
FLUE GAS (lb/hr):	932,684
FLUE GAS (lb/lbmole):	28.78
FLUE GAS (lb/lbfuel):	13.69
FLUE GAS DENSITY @ 300 F (lb/ft^3):	0.0519

Utility: Dynegy
Plant: Vermilion
Unit: 2
Date: 5/24/2000
Test: Gas Cofiring - Upper Level
Test 7

Data Source	Furnace					
DCS Shift Area 1	Gross Load	105.8	gMW			
DCS Shift Area 1	Net Load	99.4	nMW			
DCS Shift Area 1	Main Steam	776	klb/hr			
Calculated	Gross Heat Rate	9,474	Btu/kWhr			
Calculated	Net Heat Rate	10,084	Btu/kWhr			
DCS Shift Area 1	Furance Draft	-0.3	iwc			
DCS Shift Area 1	Windbox Pressure	3.3	iwc			
Calculated	Stoich A/F	8.92				
	Fuel	**Feed Rate (lb/hr)**		**Disch Press (iwc)**	**Coal/Air Temp (F)**	**Pri Air (lb/hr)**
Coal Overview Screen 29	Mill 2D			-0.16	112	
Coal Overview Screen 29	Mill 2C	28,113		9.00	150	56,745
Coal Overview Screen 29	Mill 2B	28,113		11.11	133	58,256
Coal Overview Screen 29	Mill 2A	28,113		10.77	136	57,135
Calculated	**Total Fuel wet basis**	84,338				172,137

	Natural Gas Co-Firing	SCFM	Mass (lb/hr)
	Level D/C	3,110	8,341
	Level C/B		0
	Level B/A		0
Gas Overview Screen	Total	3,110	8,341
Gas Overview Screen	Levels Fired	1	
Gas Overview Screen	Pressure	46	psig
	Density @ Standard Conditions	0.0447	lbm/ft3

	Air		
	Ambient Temp	86	F
	Bar Press	29.90	in Hg
	Rel Hum	60.00%	
Calculated	Total Air Flow	890,798	klb/hr
	Economizer Outlet O2		
Mainscreen 2100	A Side	OOS	
		1.57%	
Mainscreen 2100	B Side	1.17%	
	Average	1.37%	

Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry (Coal + Gas)	Coal Burner Level Stoich	
Upper SOFA		1.15	9.54%	96%	9.14%	137,555	1.08		
Lower SOFA		1.15	9.54%	99%	9.42%	141,678	0.91		
	OFA Corner Subtotal	2.31				279,233			
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	5%	0.25%	3,836	0.74		
D Mill	Burner Level 4 SA	0.32	2.64%	6%	0.16%	2,429	0.73		Note 1
	Level 4 PA	0.57				0			
Gas Spud	Gas Fuel Addition						0.73		
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	7%	1.38%	20,738	0.80		
C Mill	Burner Level 3	0.32	2.64%	24%	0.62%	9,385	0.78	0.62	Note 2
	Level 3 PA	0.57				56,745			
Gas Spud	Gas Fuel Addition						1.03		
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	53%	10.59%	159,265	1.03		
B Mill	Burner Level 2	0.32	2.64%	22%	0.59%	8,833	0.72	0.88	Note 2
	Level 2 PA	0.57				58,256			
Gas Spud	Gas Fuel Addition						1.16		
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	49%	9.71%	145,993	1.16		
A Mill	Burner Level 1	0.32	2.64%	19%	0.51%	7,729	0.58	0.87	Note 1
	Level 1PA	0.57				57,135			
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	100%	5.40%	81,222	-		
	Windbox Corner Subtotal	9.78				611,566			
	TOTAL SA ONLY (no SOFA)					439,429			
	TOTAL SA + SOFA	12.09	100.00%		47.78%	890,798			

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air
Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

Control Room Total Airflow Indication

Location	Data Source	Percent	Mass Flow
Primary Air Mill 2D	Dirty Air Measurement	0.0%	0 lb/hr
Primary Air Mill 2C	Dirty Air Measurement	33.0%	56,745 lb/hr
Primary Air Mill 2B	Dirty Air Measurement	33.8%	58,256 lb/hr
Primary Air Mill 2A	Dirty Air Measurement	33.2%	57,135 lb/hr
Total Hot Combustion Air	Calculated by Difference		864,978 lb/hr
Total Sec Air + OFA	Calculated by Difference		718,662 lb/hr
Total Comb Air to Boiler	Calculated	-	890,798 lb/hr

Assumes 15% tramp air inleakage on mills

.

Airflow Distribution Summary

Location	Data Source	Mass Flow	Air/Fuel Ratio
Measured PA @ Mill 2D	Assumed Equal Distribution	0 lb/hr	
Measured PA @ Mill 2C	Assumed Equal Distribution	56,745 lb/hr	2.02
Measured PA @ Mill 2B	Assumed Equal Distribution	58,256 lb/hr	2.07
Measured PA @ Mill 2A	Assumed Equal Distribution	57,135 lb/hr	2.03
Total Primary Air	115% x Sum	197,957 lb/hr	22.2%
Secondary Air	By Difference	413,609 lb/hr	46.4%
Overfire Air	Calculated	279,233 lb/hr	31.3%
Total Air to Boiler	Sum	890,798 lb/hr	100.0%

Assumes 15% tramp air inleakage on mills

UTILITY:	Dynegy	BLEND	
PLANT:	Vermilion 2	WEIGHT PERCENT	
FUEL 1:	Eastern Bituminous	91.0%	
FUEL 2:	Natural Gas	9.0%	
FUEL 3:		0%	
TYPE:	Bituminous Coal with Nat Gas Cc	100%	
ANALYSIS DATE:	Commercial Testing Coal Composite Analysis		May 23 - 25, 2000
	Natural Gas Sample April 26		

Proximate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	15.19%	-	-
ASH:	9.35%	11.02%	-
VOLATILE:	37.10%	43.74%	49.16%
FIXED CARBON:	38.34%	45.20%	50.80%
	99.97%	99.97%	99.96%
BTU/LB:	11,885	14,014	

Ultimate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	15.19%	-	-
CARBON:	61.14%	72.09%	81.02%
HYDROGEN:	5.80%	6.84%	7.68%
NITROGEN:	1.33%	1.56%	1.76%
CHLORINE:	0.00%	0.00%	0.00%
SULFUR:	1.26%	1.48%	1.66%
ASH:	9.35%	11.02%	-
OXYGEN (by diff):	5.94%	7.01%	7.87%
	100.00%	100.00%	100.00%

OPERATING CONDITIONS

GROSS HEAT RATE (Btu/kWh):	10,411	Calculated
TOTAL HEAT INPUT (Btu/hr):	1.10E+09	
COAL HEAT INPUT (Btu/hr):	9.06E+08	82.29%
GAS HEAT INPUT (Btu/hr):	1.95E+08	17.71%
LOAD (MWg):	105.8	
EXCESS OXYGEN (%,dry):	1.56%	
(%,wet):	1.36%	
HUMIDITY RATIO:	0.0160	Based on 60% Relative Humidity (86 F)
STOICH A/F:	8.92	
THEORETICAL A/F:	9.61	
MOLECULAR WEIGHT (lb/lbmole):	29.08	
AIR FLOW (lb/hr):	890,798	
COAL FUEL FLOW (lb/hr):	84,338	
(tph):	42.2	
GAS FUEL FLOW (lb/hr):	8,341	
(ft3/min):	3,110	
GAS DENSITY (lbm/ft3):	0.0447	

Combustion Mass Balance Stack Calculations	Wet Basis	Dry Basis	Mass Flow (lb/hr)	Molar Basis (lbmole/hr)	Mass/Heat Input (lb/10^6 Btu)
O2 (%):	1.36%	1.56%	14,479	452	14.44
CO2 (%):	14.07%	16.13%	205,869	4,679	205.38
H2O (%):	12.80%	-	76,620	4,257	76.44
N2 (%):	71.65%	82.16%	667,285	23,832	665.70
SO_2 (PPM @ 99% CONV):	1,073	1,230	2,283	36	2.28
SO_3 (PPM @ 1% CONV):	11	13	30	0	0.03
HCl (ppmv):	0	0	0	0	0.00
Measured NO (ppmv):	184	208	282	6	0.28
		100.00%	966,848	33,262	964.56

ASH (gr/scf):	4.37
ASH (lb/hr):	7,882
FLUE GAS (lb/hr):	967,255
FLUE GAS (lb/lbmole):	29.08
FLUE GAS (lb/lbfuel):	11.47
FLUE GAS DENSITY @ 300 F (lb/ft^3):	0.0524

Utility: Dynegy
Plant: Vermilion
Unit: 2
Date: 5/25/2000
Test: Low Load Gas Cofiring - Upper Level
Test 8

Data Source	Furnace					
DCS Shift Area 1	Gross Load	69.1	gMW			
DCS Shift Area 1	Net Load	65.1	nMW			
DCS Shift Area 1	Main Steam	505	klb/hr			
Calculated	Gross Heat Rate	10,410	Btu/kWhr			
Calculated	Net Heat Rate	11,050	Btu/kWhr			
DCS Shift Area 1	Furance Draft	-0.3	iwc			
DCS Shift Area 1	Windbox Pressure	2.7	iwc			
Calculated	Stoich A/F	9.30				

	Fuel	Feed Rate (lb/hr)	Disch Press (iwc)	Coal/Air Temp (F)	Pri Air (lb/hr)
Coal Overview Screen 29	Mill 2D			106	
Coal Overview Screen 29	Mill 2C	16,481	5.27	150	47,811
Coal Overview Screen 29	Mill 2B	16,481	4.13	136	44,303
Coal Overview Screen 29	Mill 2A	16,481	5.15	144	45,094
Calculated	**Total Fuel wet basis**	49,444			137,208

	Natural Gas Co-Firing	SCFM	Mass (lb/hr)
	Level D/C	2,996	8,035
	Level C/B		0
	Level B/A		0
Gas Overview Screen	Total	2,996	8,035
Gas Overview Screen	Levels Fired	1	
Gas Overview Screen	Pressure	46 psig	
	Density @ Standard Conditions	0.0447 lbm/ft3	

	Air		
	Ambient Temp	75	F
	Bar Press	29.90	in Hg
	Rel Hum	60.00%	
Calculated	Total Air Flow	645,587	klb/hr
	Economizer Outlet O2		
Mainscreen 2100	A Side	OOS	
		3.46%	
Mainscreen 2100	B Side	3.13%	
	Average	3.30%	

Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry (Coal + Gas)	Coal Burner Level Stoich	
Upper SOFA		1.15	9.54%	96%	9.11%	142,123	1.21		
Lower SOFA		1.15	9.54%	98%	9.39%	146,475	0.94		
	OFA Corner Subtotal	2.31				288,598			
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	1%	0.05%	842	0.67		
D Mill	Burner Level 4 SA	0.32	2.64%	3%	0.07%	1,103	0.67		Note 1
	Level 4 PA	0.57				0			
Gas Spud	Gas Fuel Addition						0.66		
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	2%	0.34%	5,343	0.77		
C Mill	Burner Level 3	0.32	2.64%	8%	0.21%	3,226	0.76	0.64	Note 2
	Level 3 PA	0.57				47,811			
Gas Spud	Gas Fuel Addition						0.97		
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	29%	5.78%	90,138	0.97		
B Mill	Burner Level 2	0.32	2.64%	9%	0.24%	3,772	0.68	0.89	Note 2
	Level 2 PA	0.57				44,303			
Gas Spud	Gas Fuel Addition						1.05		
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	28%	5.61%	87,505	1.05		
A Mill	Burner Level 1	0.32	2.64%	9%	0.23%	3,587	0.48	0.76	Note 1
	Level 1PA	0.57				45,094			
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	29%	1.56%	24,264	-		
	Windbox Corner Subtotal	9.78				356,988			
	TOTAL SA ONLY (no SOFA)					219,781			
	TOTAL SA + SOFA	12.09	100.00%		32.58%	645,587			

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air
Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

Control Room Total Airflow Indication

Location	Data Source	Percent	Mass Flow	
Primary Air Mill 2D	Curve Fit of Dirty Air Meas	0.0%	0 lb/hr	
Primary Air Mill 2C	Curve Fit of Dirty Air Meas	34.8%	47,811 lb/hr	
Primary Air Mill 2B	Curve Fit of Dirty Air Meas	32.3%	44,303 lb/hr	
Primary Air Mill 2A	Curve Fit of Dirty Air Meas	32.9%	45,094 lb/hr	
Total Hot Combustion Air	Calculated by Difference		625,006 lb/hr	**Assumes 15% tramp air inleakage on mills**
Total Sec Air + OFA	Calculated by Difference		508,379 lb/hr	
Total Comb Air to Boiler	Calculated	-	645,587 lb/hr	

Airflow Distribution Summary

Location	Data Source	Mass Flow	Air/Fuel Ratio	
Measured PA @ Mill 2D	Assumed Equal Distribution	0 lb/hr		
Measured PA @ Mill 2C	Assumed Equal Distribution	47,811 lb/hr	2.90	
Measured PA @ Mill 2B	Assumed Equal Distribution	44,303 lb/hr	2.69	
Measured PA @ Mill 2A	Assumed Equal Distribution	45,094 lb/hr	2.74	
Total Primary Air	115% x Sum	157,789 lb/hr	24.4%	**Assumes 15% tramp air inleakage on mills**
Secondary Air	By Difference	199,199 lb/hr	30.9%	
Overfire Air	Calculated	288,598 lb/hr	44.7%	
Total Air to Boiler	Sum	645,587 lb/hr	100.0%	

UTILITY:	Dynegy	BLEND	
PLANT:	Vermilion 2	WEIGHT PERCENT	
FUEL 1:	Eastern Bituminous	86.0%	
FUEL 2:	Natural Gas	14.0%	
FUEL 3:		0%	
TYPE:	Bituminous Coal with Nat Gas Cc	100%	
ANALYSIS DATE:	Commercial Testing Coal Composite Analysis		May 23 - 25, 2000
	Natural Gas Sample April 26		

Proximate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	14.36%	-	-
ASH:	8.83%	10.32%	-
VOLATILE:	40.54%	47.34%	52.78%
FIXED CARBON:	36.24%	42.32%	47.18%
	99.97%	99.97%	99.97%
BTU/LB:	12,515	14,613	

Ultimate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	14.36%	-	-
CARBON:	61.83%	72.19%	80.50%
HYDROGEN:	6.82%	7.97%	8.88%
NITROGEN:	1.35%	1.58%	1.76%
CHLORINE:	0.00%	0.00%	0.00%
SULFUR:	1.19%	1.39%	1.55%
ASH:	8.83%	10.32%	-
OXYGEN (by diff):	5.62%	6.56%	7.31%
	100.00%	100.00%	100.00%

OPERATING CONDITIONS

GROSS HEAT RATE (Btu/kWh):	10,410	Calculated
TOTAL HEAT INPUT (Btu/hr):	7.19E+08	
COAL HEAT INPUT (Btu/hr):	5.31E+08	73.87%
GAS HEAT INPUT (Btu/hr):	1.88E+08	26.13%
LOAD (MWg):	69	
EXCESS OXYGEN (%,dry):	3.76%	
(%,wet):	3.34%	
HUMIDITY RATIO:	0.0080	Based on 50% Relative Humidity (70 F)
STOICH A/F:	9.30	
THEORETICAL A/F:	11.23	
MOLECULAR WEIGHT (lb/lbmole):	29.01	
AIR FLOW (lb/hr):	645,587	
COAL FUEL FLOW (lb/hr):	49,444	
(tph):	24.7	
GAS FUEL FLOW (lb/hr):	8,035	
(ft3/min):	2,996	
GAS DENSITY (lbm/ft3):	0.0447	

Combustion Mass Balance Stack Calculations	Wet Basis	Dry Basis	Mass Flow (lb/hr)	Molar Basis (lbmole/hr)	Mass/Heat Input (lb/10^6 Btu)
O2 (%):	3.34%	3.76%	25,411	794	41.06
CO2 (%):	12.30%	13.87%	128,868	2,929	208.26
H2O (%):	11.29%	-	48,375	2,688	78.18
N2 (%):	72.97%	82.26%	486,412	17,372	786.06
SO_2 (PPM @ 99% CONV):	877	988	1,336	21	2.16
SO_3 (PPM @ 1% CONV):	9	11	18	0	0.03
HCl (ppmv):	0	0	0	0	0.00
Measured NO (ppmv):	146	162	160	3	0.26
		100.00%	690,580	23,807	1116.01

ASH (gr/scf):	3.39
ASH (lb/hr):	4,368
FLUE GAS (lb/hr):	690,663
FLUE GAS (lb/lbmole):	29.01
FLUE GAS (lb/lbfuel):	13.97
FLUE GAS DENSITY @ 300 F (lb/ft^3):	0.0523

Utility: Dynegy
Plant: Vermilion
Unit: 2
Date: 5/25/2000
Test: Low Load Gas Cofiring - Upper Level
Test 9

Data Source	Furnace		
DCS Shift Area 1	Gross Load	68.9	gMW
DCS Shift Area 1	Net Load	64.9	nMW
DCS Shift Area 1	Main Steam	504	klb/hr
Calculated	Gross Heat Rate	10,410	Btu/kWhr
Calculated	Net Heat Rate	11,052	Btu/kWhr
DCS Shift Area 1	Furance Draft	-0.3	iwc
DCS Shift Area 1	Windbox Pressure	2.5	iwc
Calculated	Stoich A/F	8.82	

Data Source	Fuel	Feed Rate (lb/hr)	Disch Press (iwc)	Coal/Air Temp (F)	Pri Air (lb/hr)
Coal Overview Screen 29	Mill 2D			97	
Coal Overview Screen 29	Mill 2C	18,445	5.77	151	49,218
Coal Overview Screen 29	Mill 2B	18,445	4.39	135	45,058
Coal Overview Screen 29	Mill 2A	18,445	5.64	144	46,428
Calculated	**Total Fuel wet basis**	55,334			140,704

Data Source	Natural Gas Co-Firing	SCFM	Mass (lb/hr)
	Level D/C	1,954	5,241
	Level C/B		0
	Level B/A		0
Gas Overview Screen	Total	1,954	5,241
Gas Overview Screen	Levels Fired	1	
Gas Overview Screen	Pressure	46	psig
	Density @ Standard Conditions	0.0447	lbm/ft3

Data Source	Air		
	Ambient Temp	75	F
	Bar Press	29.90	in Hg
	Rel Hum	60.00%	
Calculated	Total Air Flow	646,364	klb/hr
	Economizer Outlet O2		
Mainscreen 2100	A Side	OOS	
		3.52%	
Mainscreen 2100	B Side	3.14%	
	Average	3.33%	

Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry (Coal + Gas)	Coal Burner Level Stoich	
Upper SOFA		1.15	9.54%	96%	9.11%	141,363	1.21		
Lower SOFA		1.15	9.54%	98%	9.39%	145,692	0.94		
	OFA Corner Subtotal	2.31				287,055			
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	1%	0.05%	838	0.67		
D Mill	Burner Level 4 SA	0.32	2.64%	3%	0.07%	1,097	0.67		Note 1
	Level 4 PA	0.57				0			
Gas Spud	Gas Fuel Addition						0.67		
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	2%	0.34%	5,315	0.73		
C Mill	Burner Level 3	0.32	2.64%	8%	0.21%	3,209	0.72	0.61	Note 2
	Level 3 PA	0.57				49,218			
Gas Spud	Gas Fuel Addition						0.92		
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	29%	5.78%	89,656	0.92		
B Mill	Burner Level 2	0.32	2.64%	9%	0.24%	3,752	0.65	0.84	Note 2
	Level 2 PA	0.57				45,058			
Gas Spud	Gas Fuel Addition						0.99		
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	28%	5.61%	87,037	0.99		
A Mill	Burner Level 1	0.32	2.64%	9%	0.23%	3,568	0.46	0.72	Note 1
	Level 1PA	0.57				46,428			
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	29%	1.56%	24,134	-		
	Windbox Corner Subtotal	9.78				359,309			
	TOTAL SA ONLY (no SOFA)					218,605			
	TOTAL SA + SOFA	12.09	100.00%		32.58%	646,364			

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air
Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

Control Room Total Airflow Indication

Location	Data Source	Percent	Mass Flow	
Primary Air Mill 2D	Curve Fit of Dirty Air Meas	0.0%	0 lb/hr	
Primary Air Mill 2C	Curve Fit of Dirty Air Meas	35.0%	49,218 lb/hr	
Primary Air Mill 2B	Curve Fit of Dirty Air Meas	32.0%	45,058 lb/hr	
Primary Air Mill 2A	Curve Fit of Dirty Air Meas	33.0%	46,428 lb/hr	
Total Hot Combustion Air	Calculated by Difference		625,259 lb/hr	**Assumes 15% tramp air inleakage on mills**
Total Sec Air + OFA	Calculated by Difference		505,660 lb/hr	
Total Comb Air to Boiler	Calculated	-	646,364 lb/hr	

Airflow Distribution Summary

Location	Data Source	Mass Flow	Air/Fuel Ratio	
Measured PA @ Mill 2D	Assumed Equal Distribution	0 lb/hr		
Measured PA @ Mill 2C	Assumed Equal Distribution	49,218 lb/hr	2.67	
Measured PA @ Mill 2B	Assumed Equal Distribution	45,058 lb/hr	2.44	
Measured PA @ Mill 2A	Assumed Equal Distribution	46,428 lb/hr	2.52	
Total Primary Air	115% x Sum	161,810 lb/hr	25.0%	**Assumes 15% tramp air inleakage on mills**
Secondary Air	By Difference	197,500 lb/hr	30.6%	
Overfire Air	Calculated	287,055 lb/hr	44.4%	
Total Air to Boiler	Sum	646,364 lb/hr	100.0%	

UTILITY: Dynegy
PLANT: Vermilion 2
FUEL 1: Eastern Bituminous
FUEL 2: Natural Gas
FUEL 3:
TYPE: Bituminous Coal with Nat Gas Cc
ANALYSIS DATE: Commercial Testing Coal Composite Analysis May 23 - 25, 2000
Natural Gas Sample April 26

BLEND WEIGHT PERCENT
91.3%
8.7%
0%
100%

Proximate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	15.25%	-	-
ASH:	9.38%	11.07%	-
VOLATILE:	36.86%	43.49%	48.90%
FIXED CARBON:	38.49%	45.41%	51.06%
	99.97%	99.97%	99.96%
BTU/LB:	11,841	13,971	

Ultimate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	15.25%	-	-
CARBON:	61.09%	72.08%	81.06%
HYDROGEN:	5.73%	6.76%	7.60%
NITROGEN:	1.32%	1.56%	1.76%
CHLORINE:	0.00%	0.00%	0.00%
SULFUR:	1.26%	1.49%	1.67%
ASH:	9.38%	11.07%	-
OXYGEN (by diff):	5.97%	7.04%	7.91%
	100.00%	100.00%	100.00%

OPERATING CONDITIONS

GROSS HEAT RATE (Btu/kWh):	10,410	Calculated
TOTAL HEAT INPUT (Btu/hr):	7.17E+08	
COAL HEAT INPUT (Btu/hr):	5.95E+08	82.91%
GAS HEAT INPUT (Btu/hr):	1.23E+08	17.09%
LOAD (MWg):	68.9	
EXCESS OXYGEN (%,dry):	3.76%	
(%,wet):	3.36%	
HUMIDITY RATIO:	0.0080	Based on 50% Relative Humidity (70 F)
STOICH A/F:	8.82	
THEORETICAL A/F:	10.67	
MOLECULAR WEIGHT (lb/lbmole):	29.17	
AIR FLOW (lb/hr):	646,364	
COAL FUEL FLOW (lb/hr):	55,334	
(tph):	27.7	
GAS FUEL FLOW (lb/hr):	5,241	
(ft3/min):	1,954	
GAS DENSITY (lbm/ft3):	0.0447	

Combustion Mass Balance Stack Calculations	Wet Basis	Dry Basis	Mass Flow (lb/hr)	Molar Basis (lbmole/hr)	Mass/Heat Input ($lb/10^6$ Btu)
O2 (%):	3.36%	3.76%	25,688	803	39.21
CO2 (%):	12.82%	14.34%	134,694	3,061	205.57
H2O (%):	10.59%	-	45,510	2,528	69.46
N2 (%):	73.12%	81.77%	488,844	17,459	746.08
SO_2 (PPM @ 99% CONV):	982	1,098	1,501	23	2.29
SO_3 (PPM @ 1% CONV):	10	12	20	0	0.03
HCl (ppmv):	0	0	0	0	0.00
Measured NO (ppmv):	143	158	157	3	0.24
		100.00%	696,414	23,878	1062.87

ASH (gr/scf):	4.00
ASH (lb/hr):	5,191
FLUE GAS (lb/hr):	696,507
FLUE GAS (lb/lbmole):	29.17
FLUE GAS (lb/lbfuel):	12.59
FLUE GAS DENSITY @ 300 F (lb/ft^3):	0.0526

Utility: Dynegy
Plant: Vermilion
Unit: 2
Date: 5/25/2000
Test: Low Load Gas Cofiring - Upper Level
Test 10

Data Source	Furnace				
DCS Shift Area 1	Gross Load	68.6 gMW			
DCS Shift Area 1	Net Load	64.6 nMW			
DCS Shift Area 1	Main Steam	498 klb/hr			
Calculated	Gross Heat Rate	10,411 Btu/kWhr			
Calculated	Net Heat Rate	11,056 Btu/kWhr			
DCS Shift Area 1	Furance Draft	-0.3 iwc			
DCS Shift Area 1	Windbox Pressure	2.6 iwc			
Calculated	Stoich A/F	8.47			
	Fuel	**Feed Rate** (lb/hr)	**Disch Press** (iwc)	**Coal/Air Temp** (F)	**Pri Air** (lb/hr)
Coal Overview Screen 29	Mill 2D			93	
Coal Overview Screen 29	Mill 2C	19,991	6.30	149	50,622
Coal Overview Screen 29	Mill 2B	19,991	4.50	138	45,367
Coal Overview Screen 29	Mill 2A	19,991	5.92	144	47,155
Calculated	**Total Fuel wet basis**	59,974			143,145

	Natural Gas Co-Firing	SCFM	Mass (lb/hr)
	Level D/C	1,110	2,977
	Level C/B		0
	Level B/A		0
Gas Overview Screen	Total	1,110	2,977
Gas Overview Screen	Levels Fired	1	
Gas Overview Screen	Pressure	46 psig	
	Density @ Standard Conditions	0.0447 lbm/ft3	

	Air	
	Ambient Temp	75 F
	Bar Press	29.90 in Hg
	Rel Hum	60.00%
Calculated	Total Air Flow	652,711 klb/hr
	Economizer Outlet O2	
Mainscreen 2100	A Side	OOS
		3.76%
Mainscreen 2100	B Side	3.35%
	Average	3.56%

Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry (Coal + Gas)	Coal Burner Level Stoich	
Upper SOFA		1.15	9.54%	96%	9.11%	142,455	1.22		
Lower SOFA		1.15	9.54%	98%	9.39%	146,817	0.96		
	OFA Corner Subtotal	2.31				289,272			
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	1%	0.05%	844	0.68		
D Mill	Burner Level 4 SA	0.32	2.64%	3%	0.07%	1,105	0.68		Note 1
	Level 4 PA	0.57				0			
Gas Spud	Gas Fuel Addition						0.68		
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	2%	0.34%	5,356	0.71		
C Mill	Burner Level 3	0.32	2.64%	8%	0.21%	3,234	0.70	0.60	Note 2
	Level 3 PA	0.57				50,622			
Gas Spud	Gas Fuel Addition						0.89		
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	29%	5.78%	90,348	0.89		
B Mill	Burner Level 2	0.32	2.64%	9%	0.24%	3,781	0.63	0.82	Note 2
	Level 2 PA	0.57				45,367			
Gas Spud	Gas Fuel Addition						0.96		
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	28%	5.61%	87,709	0.96		
A Mill	Burner Level 1	0.32	2.64%	9%	0.23%	3,595	0.44	0.70	Note 1
	Level 1PA	0.57				47,155			
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	29%	1.56%	24,321	-		
	Windbox Corner Subtotal	9.78				363,439			
	TOTAL SA ONLY (no SOFA)					220,294			
	TOTAL SA + SOFA	12.09	100.00%		32.58%	652,711			

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air

Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

Control Room Total Airflow Indication

Location	Data Source	Percent	Mass Flow	
Primary Air Mill 2D	Curve Fit of Dirty Air Meas	0.0%	0 lb/hr	
Primary Air Mill 2C	Curve Fit of Dirty Air Meas	35.4%	50,622 lb/hr	
Primary Air Mill 2B	Curve Fit of Dirty Air Meas	31.7%	45,367 lb/hr	
Primary Air Mill 2A	Curve Fit of Dirty Air Meas	32.9%	47,155 lb/hr	
Total Hot Combustion Air	Calculated by Difference		631,240 lb/hr	**Assumes 15% tramp air inleakage on mills**
Total Sec Air + OFA	Calculated by Difference		509,566 lb/hr	
Total Comb Air to Boiler	Calculated	-	652,711 lb/hr	

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Airflow Distribution Summary

Location	Data Source	Mass Flow	Air/Fuel Ratio	
Measured PA @ Mill 2D	Assumed Equal Distribution	0 lb/hr		
Measured PA @ Mill 2C	Assumed Equal Distribution	50,622 lb/hr	2.53	
Measured PA @ Mill 2B	Assumed Equal Distribution	45,367 lb/hr	2.27	
Measured PA @ Mill 2A	Assumed Equal Distribution	47,155 lb/hr	2.36	
Total Primary Air	115% x Sum	164,617 lb/hr	25.2%	**Assumes 15% tramp air inleakage on mills**
Secondary Air	By Difference	198,822 lb/hr	30.5%	
Overfire Air	Calculated	289,272 lb/hr	44.3%	
Total Air to Boiler	Sum	652,711 lb/hr	100.0%	

UTILITY:	Dynegy	BLEND	
PLANT:	Vermilion 2	WEIGHT PERCENT	
FUEL 1:	Eastern Bituminous	95.3%	
FUEL 2:	Natural Gas	4.7%	
FUEL 3:		0%	
TYPE:	Bituminous Coal with Nat Gas Cc	100%	
ANALYSIS DATE:	Commercial Testing Coal Composite Analysis		May 23 - 25, 2000
	Natural Gas Sample April 26		

Proximate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	15.90%	-	-
ASH:	9.78%	11.63%	-
VOLATILE:	34.15%	40.61%	45.95%
FIXED CARBON:	40.14%	47.73%	54.01%
	99.97%	99.97%	99.96%
BTU/LB:	11,345	13,490	

Ultimate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	15.90%	-	-
CARBON:	60.55%	72.00%	81.48%
HYDROGEN:	4.92%	5.85%	6.62%
NITROGEN:	1.30%	1.55%	1.76%
CHLORINE:	0.00%	0.00%	0.00%
SULFUR:	1.31%	1.56%	1.77%
ASH:	9.78%	11.63%	-
OXYGEN (by diff):	6.22%	7.40%	8.37%
	100.00%	100.00%	100.00%

OPERATING CONDITIONS

GROSS HEAT RATE (Btu/kWh):	10,411	Calculated
TOTAL HEAT INPUT (Btu/hr):	7.14E+08	
COAL HEAT INPUT (Btu/hr):	6.45E+08	90.25%
GAS HEAT INPUT (Btu/hr):	6.96E+07	9.75%
LOAD (MWg):	68.6	
EXCESS OXYGEN (%,dry):	3.95%	
(%,wet):	3.56%	
HUMIDITY RATIO:	0.0080	Based on 50% Relative Humidity (70 F)
STOICH A/F:	8.47	
THEORETICAL A/F:	10.37	
MOLECULAR WEIGHT (lb/lbmole):	29.29	
AIR FLOW (lb/hr):	652,711	
COAL FUEL FLOW (lb/hr):	59,974	
(tph):	30.0	
GAS FUEL FLOW (lb/hr):	2,977	
(ft3/min):	1,110	
GAS DENSITY (lbm/ft3):	0.0447	

Combustion Mass Balance Stack Calculations	Wet Basis	Dry Basis	Mass Flow (lb/hr)	Molar Basis (lbmole/hr)	Mass/Heat Input (lb/10^6 Btu)
O2 (%):	3.56%	3.95%	27,471	858	40.37
CO2 (%):	13.11%	14.55%	139,155	3,163	204.51
H2O (%):	9.93%	-	43,146	2,397	63.41
N2 (%):	73.28%	81.36%	495,133	17,683	727.69
SO_2 (PPM @ 99% CONV):	1,056	1,173	1,632	25	2.40
SO_3 (PPM @ 1% CONV):	11	12	22	0	0.03
HCl (ppmv):	0	0	0	0	0.00
Measured NO (ppmv):	147	162	163	4	0.24
		100.00%	706,721	24,131	1038.66

ASH (gr/scf):	4.45
ASH (lb/hr):	5,868
FLUE GAS (lb/hr):	706,818
FLUE GAS (lb/lbmole):	29.29
FLUE GAS (lb/lbfuel):	11.79
FLUE GAS DENSITY @ 300 F (lb/ft^3):	0.0528

		Utility:	Dynegy			
		Plant:	Vermilion			
		Unit:	2			
		Date:	5/25/2000			
		Test:	Low Load Gas Cofiring - Upper Level			
			Test 11			
Data Source	**Furnace**					
DCS Shift Area 1		Gross Load	69.1 gMW			
DCS Shift Area 1		Net Load	65.1 nMW			
DCS Shift Area 1		Main Steam	498 klb/hr			
Calculated		Gross Heat Rate	10,411 Btu/kWhr			
Calculated		Net Heat Rate	11,051 Btu/kWhr			
DCS Shift Area 1		Furance Draft	-0.3 iwc			
DCS Shift Area 1		Windbox Pressure	2.6 iwc			
Calculated		Stoich A/F	8.05			
	Fuel		**Feed Rate** (lb/hr)	**Disch Press** (iwc)	**Coal/Air Temp** (F)	**Pri Air** (lb/hr)
Coal Overview Screen 29		Mill 2D			88	
Coal Overview Screen 29		Mill 2C	22,313	7.35	150	53,183
Coal Overview Screen 29		Mill 2B	22,313	5.86	136	48,806
Coal Overview Screen 29		Mill 2A	22,313	7.20	143	50,211
Calculated		**Total Fuel wet basis**	66,940			152,201

	Natural Gas Co-Firing	**SCFM**	**Mass (lb/hr)**	
	Level D/C		0	
	Level C/B		0	
	Level B/A		0	
Gas Overview Screen	Total	0	0	
Gas Overview Screen	Levels Fired	0		
Gas Overview Screen	Pressure	46	psig	
	Density @ Standard Conditions	0.0447	lbm/ft3	

	Air	
	Ambient Temp	75 F
	Bar Press	29.90 in Hg
	Rel Hum	60.00%
Calculated	Total Air Flow	655,896 klb/hr
	Economizer Outlet O2	
Mainscreen 2100	A Side	OOS
		3.62%
Mainscreen 2100	B Side	3.34%
	Average	3.48%

Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry (Coal + Gas)	Coal Burner Level Stoich	
Upper SOFA		1.15	9.54%	96%	9.11%	140,814	1.22		
Lower SOFA		1.15	9.54%	98%	9.39%	145,126	0.96		
	OFA Corner Subtotal	2.31				285,940			
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	1%	0.05%	835	0.69		
D Mill	Burner Level 4 SA	0.32	2.64%	3%	0.07%	1,093	0.68		Note 1
	Level 4 PA	0.57				0			
Gas Spud	Gas Fuel Addition						0.68		
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	2%	0.34%	5,294	0.68		
C Mill	Burner Level 3	0.32	2.64%	8%	0.21%	3,196	0.67	0.58	Note 2
	Level 3 PA	0.57				53,183			
Gas Spud	Gas Fuel Addition						0.85		
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	29%	5.78%	89,307	0.85		
B Mill	Burner Level 2	0.32	2.64%	9%	0.24%	3,738	0.60	0.78	Note 2
	Level 2 PA	0.57				48,806			
Gas Spud	Gas Fuel Addition						0.92		
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	28%	5.61%	86,699	0.92		
A Mill	Burner Level 1	0.32	2.64%	9%	0.23%	3,554	0.43	0.67	Note 1
	Level 1PA	0.57				50,211			
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	29%	1.56%	24,040	-		
	Windbox Corner Subtotal	9.78				369,956			
	TOTAL SA ONLY (no SOFA)					217,756			
	TOTAL SA + SOFA	12.09	100.00%		32.58%	655,896			

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air
Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

Control Room Total Airflow Indication

Location	Data Source	Percent	Mass Flow
Primary Air Mill 2D	Curve Fit of Dirty Air Meas	0.0%	0 lb/hr
Primary Air Mill 2C	Curve Fit of Dirty Air Meas	34.9%	53,183 lb/hr
Primary Air Mill 2B	Curve Fit of Dirty Air Meas	32.1%	48,806 lb/hr
Primary Air Mill 2A	Curve Fit of Dirty Air Meas	33.0%	50,211 lb/hr
Total Hot Combustion Air	Calculated by Difference		633,066 lb/hr
Total Sec Air + OFA	Calculated by Difference		503,695 lb/hr
Total Comb Air to Boiler	Calculated	-	655,896 lb/hr

Assumes 15% tramp air inleakage on mills

.

Airflow Distribution Summary

Location	Data Source	Mass Flow	Air/Fuel Ratio
Measured PA @ Mill 2D	Assumed Equal Distribution	0 lb/hr	
Measured PA @ Mill 2C	Assumed Equal Distribution	53,183 lb/hr	2.38
Measured PA @ Mill 2B	Assumed Equal Distribution	48,806 lb/hr	2.19
Measured PA @ Mill 2A	Assumed Equal Distribution	50,211 lb/hr	2.25
Total Primary Air	115% x Sum	175,031 lb/hr	26.7%
Secondary Air	By Difference	194,926 lb/hr	29.7%
Overfire Air	Calculated	285,940 lb/hr	43.6%
Total Air to Boiler	Sum	655,896 lb/hr	100.0%

Assumes 15% tramp air inleakage on mills

UTILITY:	Dynegy	BLEND	
PLANT:	Vermilion 2	WEIGHT PERCENT	
FUEL 1:	Eastern Bituminous	100.0%	
FUEL 2:	Natural Gas	0.0%	
FUEL 3:		0%	
TYPE:	Bituminous Coal with Nat Gas Cc	100%	
ANALYSIS DATE:	Commercial Testing Coal Composite Analysis		May 23 - 25, 2000
	Natural Gas Sample April 26		

Proximate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	16.69%	-	-
ASH:	10.27%	12.33%	-
VOLATILE:	30.88%	37.07%	42.28%
FIXED CARBON:	42.13%	50.57%	57.68%
	99.97%	99.96%	99.96%
BTU/LB:	10,747	12,900	

Ultimate Analysis	As Received	Dry	Dry Ash-Free
MOISTURE:	16.69%	-	-
CARBON:	59.90%	71.90%	82.01%
HYDROGEN:	3.95%	4.74%	5.41%
NITROGEN:	1.28%	1.54%	1.75%
CHLORINE:	0.00%	0.00%	0.00%
SULFUR:	1.38%	1.66%	1.89%
ASH:	10.27%	12.33%	-
OXYGEN (by diff):	6.53%	7.84%	8.94%
	100.00%	100.00%	100.00%

OPERATING CONDITIONS

GROSS HEAT RATE (Btu/kWh):	10,411	Calculated
TOTAL HEAT INPUT (Btu/hr):	7.19E+08	
COAL HEAT INPUT (Btu/hr):	7.19E+08	100.00%
GAS HEAT INPUT (Btu/hr):	0.00E+00	0.00%
LOAD (MWg):	69.1	
EXCESS OXYGEN (%,dry):	3.83%	
(%,wet):	3.48%	
HUMIDITY RATIO:	0.0080	Based on 50% Relative Humidity (70 F)
STOICH A/F:	8.05	
THEORETICAL A/F:	9.80	
MOLECULAR WEIGHT (lb/lbmole):	29.46	
AIR FLOW (lb/hr):	655,896	
COAL FUEL FLOW (lb/hr):	66,940	
(tph):	33.5	
GAS FUEL FLOW (lb/hr):	0	
(ft3/min):	0	
GAS DENSITY (lbm/ft3):	0.0447	

Combustion Mass Balance Stack Calculations	Wet Basis	Dry Basis	Mass Flow (lb/hr)	Molar Basis (lbmole/hr)	Mass/Heat Input (lb/10^6 Btu)
O2 (%):	3.48%	3.83%	27,030	845	37.57
CO2 (%):	13.74%	15.14%	146,930	3,339	204.24
H2O (%):	9.24%	-	40,417	2,245	56.18
N2 (%):	73.41%	80.88%	499,457	17,838	694.27
SO_2 (PPM @ 99% CONV):	1,175	1,295	1,828	29	2.54
SO_3 (PPM @ 1% CONV):	13	14	24	0	0.03
HCl (ppmv):	0	0	0	0	0.00
Measured NO (ppmv):	159	173	177	4	0.25
		100.00%	715,864	24,300	995.08

ASH (gr/scf):	5.15
ASH (lb/hr):	6,875
FLUE GAS (lb/hr):	715,961
FLUE GAS (lb/lbmole):	29.46
FLUE GAS (lb/lbfuel):	10.70
FLUE GAS DENSITY @ 300 F (lb/ft^3):	0.0531

D
Numerical Model Boundary Inputs

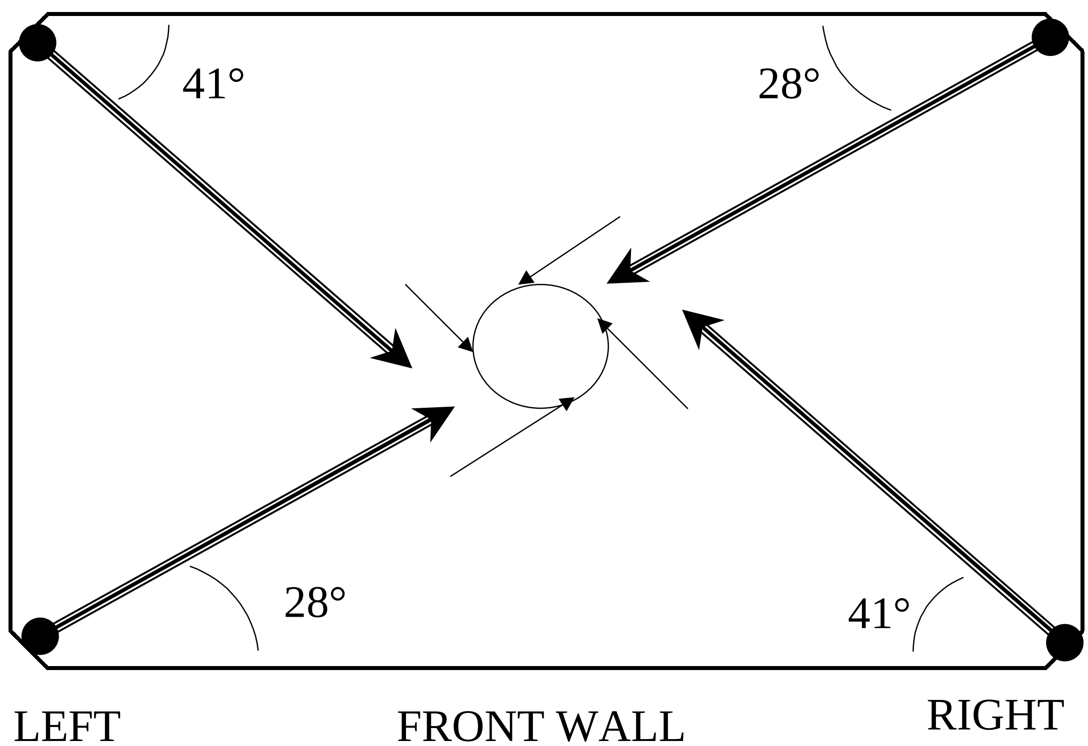

Figure D-1
Firing Configuration for Numerical Model Flow Inputs

CASE 1 - BASELINE - NOx reburn model disabled

Calculation of Secondary/OFA Airflow Distribution

(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry	Burner Level Stoich		Volumetric Flowrate * (CFH)	Nozzle Velocities (ft/s)
Upper SOFA		1.15	9.54%	100%	9.54%	129,599	1.12			3,233,108	195
Lower SOFA		1.15	9.54%	90%	8.58%	116,639	0.96			2,909,797	175
	OFA Corner Subtotal	2.31				246,238				6,142,905	185
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	35%	1.88%	25,502	0.81			636,202	68
D Mill	Burner Level 4 SA	0.32	2.64%	53%	1.40%	19,034	0.78	0.82	Note 1	474,838	103
	Level 4 PA	0.57				63,276				970,640	118
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	34%	6.71%	91,198	0.98			2,275,111	66
C Mill	Burner Level 3	0.32	2.64%	47%	1.25%	16,942	0.74	0.87	Note 2	422,651	92
	Level 3 PA	0.57				67,574				1,036,570	126
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	34%	6.68%	90,726	0.89			2,263,331	65
B Mill	Burner Level 2	0.32	2.64%	49%	1.29%	17,535	0.67	0.80	Note 2	437,434	95
	Level 2 PA	0.57				66,563				1,021,062	125
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	34%	6.67%	90,658	0.99			2,261,649	65
A Mill	Burner Level 1	0.32	2.64%	43%	1.13%	15,290	0.54	0.77	Note 1	381,439	83
	Level 1PA	0.57				70,006				1,073,876	131
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	33%	1.77%	24,034	-			599,586	64
	Windbox Corner Subtotal	9.78				658,338				13,854,388	
	TOTAL SA ONLY (no SOFA)					390,919				9,752,240	
	TOTAL SA + SOFA	12.09	100.00%		46.88%	904,576				15,895,146	

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air

Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

530°F for SA and 149°F for PA

CASE 2 - MAX. STAGING - NOx Reburn Disabled
Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

SOFA adj	100.00%
Burner Flow Adj	100.00%
SA Flow Adj	100.00%

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry	Burner Level Stoich		Volumetric Flowrate * (CFH)	Nozzle Velocities (ft/s)
Upper SOFA		1.15	9.54%	75%	7.15%	175,141	1.10			4,369,248	263
Lower SOFA		1.15	9.54%	75%	7.15%	175,141	0.87			4,369,248	263
	OFA Corner Subtotal	2.31				**350,283**				8,738,496	
Cofiring Port	Cofiring PA	0.57	**No Fuel**			0	0.65	[redacted]		0	0
Cofiring Port	Cofiring SA	0.00	0.00%	0%	0.00%	0				0	[redacted]
DD Aux Air	ated to Control WB Press	0.65	5.40%	25%	1.35%	33,059	0.65			824,718	88
D Mill	Burner Level D SA	0.32	2.64%	15%	0.40%	9,707				242,151	53
	Level D PA	0.57	**FUEL INPUT**			43,790	0.61	0.68	Note 1	674,205	82
D/C Middle Air	ated to Control WB Press	2.40	19.85%	15%	2.98%	72,926	0.70			1,819,292	53
C Mill	Burner Level C SA	0.32	2.64%	15%	0.40%	9,707				242,151	53
	Level C PA	0.57	**FUEL INPUT**			47,281	0.58	0.66	Note 2	725,170	88
C/B Middle Air	ated to Control WB Press	2.40	19.85%	15%	2.98%	72,926	0.72			1,819,292	53
B Mill	Burner Level B SA	0.32	2.64%	15%	0.40%	9,707				242,151	53
	Level B PA	0.57	**FUEL INPUT**			51,350	0.55	0.63	Note 2	774,509	94
B/A Middle Air	ated to Control WB Press	2.40	19.85%	15%	2.98%	72,926	0.83			1,819,292	53
A Mill	Burner Level A SA	0.32	2.64%	15%	0.40%	9,707				242,151	53
	Level A PA	0.57	**FUEL INPUT**			47,382	0.46	0.64	Note 1	723,606	88
AA Aux Air	ated to Control WB Press	0.65	5.40%	25%	1.35%	33,059	-			824,718	88
	Corner Subtotal No SOFA	9.78				**513,525**				19,711,901	
	TOTAL SA ONLY	12.09				674,006				16,814,411	
	TOTAL PA + SA + SOFA		100.00%		27.52%	**863,808**				20,900,266	

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air

CURRENT CASE SEC AIR **674,006**

Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

* at 530°F for SA

CASE 3 - BASELINE
Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

SOFA adj	100.00%
Burner Flow Adj	100.00%
SA Flow Adj	100.00%

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry	Burner Level Stoich		Volumetric Flowrate * (CFH)	Nozzle Velocities (ft/s)
Upper SOFA		1.15	9.54%	76%	7.25%	96,651	1.10			2,411,153	145
Lower SOFA		1.15	9.54%	99%	9.44%	125,901	0.97			3,140,845	189
	OFA Corner Subtotal	2.31				**222,552**				5,551,998	
Cofiring Port	Cofiring PA	0.57	**No Fuel**			0	0.81	[redacted]		0	0
Cofiring Port	Cofiring SA	0.00	0.00%	0%	0.00%	0				0	[redacted]
DD Aux Air	ated to Control WB Press	0.65	5.40%	35%	1.89%	25,205	0.81			628,781	67
D Mill	Burner Level D SA	0.32	2.64%	58%	1.53%	20,440				509,905	111
	Level D PA	0.57	**FUEL INPUT**			59,904	0.78	0.83	Note 1	918,769	112
D/C Middle Air	ated to Control WB Press	2.40	19.85%	34%	6.75%	90,020	0.88			2,245,721	65
C Mill	Burner Level C SA	0.32	2.64%	47%	1.24%	16,563				413,199	90
	Level C PA	0.57	**FUEL INPUT**			63,937	0.73	0.87	Note 2	980,621	120
C/B Middle Air	ated to Control WB Press	2.40	19.85%	34%	6.75%	90,020	0.89			2,245,721	65
B Mill	Burner Level B SA	0.32	2.64%	49%	1.29%	17,268				430,782	94
	Level B PA	0.57	**FUEL INPUT**			62,603	0.67	0.80	Note 2	960,165	117
B/A Middle Air	ated to Control WB Press	2.40	19.85%	34%	6.75%	90,020	0.99			2,245,721	65
A Mill	Burner Level A SA	0.32	2.64%	43%	1.14%	15,153				378,033	82
	Level A PA	0.57	**FUEL INPUT**			66,361	0.54	0.76	Note 1	1,017,806	124
AA Aux Air	ated to Control WB Press	0.65	5.40%	33%	1.78%	23,764	-			592,850	63
	Corner Subtotal No SOFA	9.78				**641,256**				19,120,071	
	TOTAL SA ONLY	12.09				611,004				15,242,710	
	TOTAL PA + SA + SOFA		100.00%		45.82%	**863,808**				20,900,266	

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air

CURRENT CASE SEC AIR **611,004**

Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

* at 530°F for SA

CASE 4 - OPTIMIZED PA/F RATIOS LFS=0.81

Calculation of Secondary/OFA Airflow Distribution

(Based on flow area and damper position)

SOFA adj 100.00%
Burner Flow Adj 100.00%
SA Flow Adj 100.00%

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry	Burner Level Stoich		Volumetric Flowrate * (CFH)	Nozzle Velocities (ft/s)
Upper SOFA		1.15	9.54%	76%	7.25%	110,992	1.10			2,768,918	167
Lower SOFA		1.15	9.54%	80%	7.63%	116,834	0.95			2,914,651	176
	OFA Corner Subtotal	2.31				**227,826**				5,683,569	
Cofiring Port	Cofiring PA	0.57	**No Fuel**			0	0.81			0	0
Cofiring Port	Cofiring SA	0.00	0.00%	0%	0.00%	0				0	
DD Aux Air	ated to Control WB Press	0.65	5.40%	35%	1.89%	28,945	0.81			722,078	77
D Mill	Burner Level D SA	0.32	2.64%	58%	1.53%	23,472				585,564	127
	Level D PA	0.57	**FUEL INPUT**			47,385	0.77	0.77	Note 1	726,760	89
D/C Middle Air	ated to Control WB Press	2.40	19.85%	34%	6.75%	103,377	0.91			2,578,939	75
C Mill	Burner Level C SA	0.32	2.64%	47%	1.24%	19,021				474,509	103
	Level C PA	0.57	**FUEL INPUT**			47,541	0.73	0.86	Note 2	729,152	89
C/B Middle Air	ated to Control WB Press	2.40	19.85%	34%	6.75%	103,377	0.93			2,578,939	75
B Mill	Burner Level B SA	0.32	2.64%	49%	1.29%	19,830				494,700	108
	Level B PA	0.57	**FUEL INPUT**			47,591	0.67	0.87	Note 2	729,921	89
B/A Middle Air	ated to Control WB Press	2.40	19.85%	34%	6.75%	103,377	0.99			2,578,939	75
A Mill	Burner Level A SA	0.32	2.64%	43%	1.14%	17,402				434,125	94
	Level A PA	0.57	**FUEL INPUT**			47,376	0.47	0.73	Note 1	726,618	89
AA Aux Air	ated to Control WB Press	0.65	5.40%	33%	1.78%	27,291	-			680,817	72
	Corner Subtotal No SOFA	9.78				**635,982**				19,724,630	
	TOTAL SA ONLY	12.09				673,916				16,812,179	
	TOTAL PA + SA + SOFA		100.00%		44.00%	**863,808**				20,900,266	

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air

CURRENT CASE SEC AIR **673,916**

Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

* at 530°F for SA

CASE 5 - OPTIMIZED PA/F RATIOS - LFS=0.87

Calculation of Secondary/OFA Airflow Distribution

(Based on flow area and damper position)

SOFA adj	100.00%
Burner Flow Adj	100.00%
SA Flow Adj	100.00%

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry	Burner Level Stoich		Volumetric Flowrate * (CFH)	Nozzle Velocities (ft/s)
Upper SOFA		1.15	9.54%	76%	7.25%	90,677	1.10			2,262,109	136
Lower SOFA		1.15	9.54%	76%	7.25%	90,677	0.98			2,262,109	136
	OFA Corner Subtotal	2.31				**181,353**				4,524,218	
Cofiring Port	Cofiring PA	0.57	**No Fuel**			0	0.87	[redacted]		0	0
Cofiring Port	Cofiring SA	0.00	0.00%	0%	0.00%	0				0	[redacted]
DD Aux Air	ated to Control WB Press	0.65	5.40%	47%	2.54%	31,754	0.87			792,168	84
D Mill	Burner Level D SA	0.32	2.64%	47%	1.24%	15,539				387,657	84
	Level D PA	0.57	**FUEL INPUT**			43,790	0.83	0.81	Note 1	674,205	82
D/C Middle Air	ated to Control WB Press	2.40	19.85%	46%	9.13%	114,263	0.97			2,850,515	82
C Mill	Burner Level C SA	0.32	2.64%	50%	1.32%	16,531				412,401	90
	Level C PA	0.57	**FUEL INPUT**			47,281	0.79	0.93	Note 2	725,170	88
C/B Middle Air	ated to Control WB Press	2.40	19.85%	50%	9.93%	124,199	1.01			3,098,386	90
B Mill	Burner Level B SA	0.32	2.64%	50%	1.32%	16,531				412,401	90
	Level B PA	0.57	**FUEL INPUT**			51,350	0.70	0.90	Note 2	774,509	94
B/A Middle Air	ated to Control WB Press	2.40	19.85%	50%	9.93%	124,199	1.12			3,098,386	90
A Mill	Burner Level A SA	0.32	2.64%	50%	1.32%	16,531				412,401	90
	Level A PA	0.57	**FUEL INPUT**			47,382	0.49	0.81	Note 1	723,606	88
AA Aux Air	ated to Control WB Press	0.65	5.40%	49%	2.65%	33,105	-			825,878	88
	Corner Subtotal No SOFA	9.78				**682,455**				19,711,901	
	TOTAL SA ONLY	12.09				674,006				16,814,411	
	TOTAL PA + SA + SOFA		100.00%		53.87%	**863,808**				20,900,266	

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air

CURRENT CASE SEC AIR **674,006**

Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

* at 530°F for SA

CASE 6 -SEPARATED SOFA - NOx Reburn Disabled

Calculation of Secondary/OFA Airflow Distribution

(Based on flow area and damper position)

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry	Burner Level Stoich		Volumetric Flowrate * (CFH)	Nozzle Velocities (ft/s)
Upper SOFA		1.15	9.54%	100%	9.54%	129,599	1.12			3,233,108	195
Lower SOFA		1.15	9.54%	90%	8.58%	116,639	0.96			2,909,797	175
	OFA Corner Subtotal	2.31				246,238				6,142,905	185
DD Aux Air	Modulated to Control WB Press	0.65	5.40%	35%	1.88%	25,502	0.81			636,202	68
D Mill	Burner Level 4 SA	0.32	2.64%	53%	1.40%	19,034	0.78	0.82	Note 1	474,838	103
	Level 4 PA	0.57				63,276				970,640	118
D/C Middle Air	Modulated to Control WB Press	2.40	19.85%	34%	6.71%	91,198	0.98			2,275,111	66
C Mill	Burner Level 3	0.32	2.64%	47%	1.25%	16,942	0.74	0.87	Note 2	422,651	92
	Level 3 PA	0.57				67,574				1,036,570	126
C/B Middle Air	Modulated to Control WB Press	2.40	19.85%	34%	6.68%	90,726	0.89			2,263,331	65
B Mill	Burner Level 2	0.32	2.64%	49%	1.29%	17,535	0.67	0.80	Note 2	437,434	95
	Level 2 PA	0.57				66,563				1,021,062	125
B/A Middle Air	Modulated to Control WB Press	2.40	19.85%	34%	6.67%	90,658	0.99			2,261,649	65
A Mill	Burner Level 1	0.32	2.64%	43%	1.13%	15,290	0.54	0.77	Note 1	381,439	83
	Level 1PA	0.57				70,006				1,073,876	131
AA Aux Air	Modulated to Control WB Press	0.65	5.40%	33%	1.77%	24,034	-			599,586	64
	Windbox Corner Subtotal	9.78				658,338				13,854,388	
	TOTAL SA ONLY (no SOFA)					390,919				9,752,240	
	TOTAL SA + SOFA	12.09	100.00%		46.88%	904,576				15,895,146	

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air

Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

530°F for SA and 149°F for PA

CASE 7 - SEPARATED SOFA LFS=0.88

Calculation of Secondary/OFA Airflow Distribution

(Based on flow area and damper position)

SOFA adj	100.00%
Burner Flow Adj	100.00%
SA Flow Adj	100.00%

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry	Burner Level Stoich		Volumetric Flowrate * (CFH)	Nozzle Velocities (ft/s)
Upper SOFA		1.15	9.54%	75%	7.15%	74,416	1.10			1,856,455	112
Lower SOFA		1.15	9.54%	95%	9.06%	94,260	1.00			2,351,510	142
	OFA Corner Subtotal	2.31				**168,676**				4,207,965	
Cofiring Port	Cofiring PA	0.57	**No Fuel**			0	0.88	[redacted]		0	0
Cofiring Port	Cofiring SA	0.00	0.00%	66%	0.00%	0				0	[redacted]
DD Aux Air	ated to Control WB Press	0.65	5.40%	60%	3.24%	33,711	0.88			840,997	89
D Mill	Burner Level D SA	0.32	2.64%	60%	1.59%	16,497				411,552	89
	Level D PA	0.57	**FUEL INPUT**			47,385	0.84	0.81	Note 1	726,760	89
D/C Middle Air	ated to Control WB Press	2.40	19.85%	60%	11.91%	123,943	1.01			3,092,005	89
C Mill	Burner Level C SA	0.32	2.64%	60%	1.59%	16,497				411,552	89
	Level C PA	0.57	**FUEL INPUT**			47,541	0.80	0.95	Note 2	729,152	89
C/B Middle Air	ated to Control WB Press	2.40	19.85%	60%	11.91%	123,943	1.04			3,092,005	89
B Mill	Burner Level B SA	0.32	2.64%	60%	1.59%	16,497				411,552	89
	Level B PA	0.57	**FUEL INPUT**			47,591	0.72	0.95	Note 2	729,921	89
B/A Middle Air	ated to Control WB Press	2.40	19.85%	60%	11.91%	123,943	1.12			3,092,005	89
A Mill	Burner Level A SA	0.32	2.64%	60%	1.59%	16,497				411,552	89
	Level A PA	0.57	**FUEL INPUT**			47,376	0.50	0.81	Note 1	726,618	89
AA Aux Air	ated to Control WB Press	0.65	5.40%	60%	3.24%	33,711	-			840,997	89
	Corner Subtotal No SOFA	9.78				**695,132**				19,724,630	
	TOTAL SA ONLY	12.09				673,916				16,812,179	
	TOTAL PA + SA + SOFA		100.00%		64.77%	**863,808**				20,900,266	

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air

Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

* at 530°F for SA

CURRENT CASE SEC AIR **673,916**

CASE 8 - SEPARATED SOFA LFS=0.81
Calculation of Secondary/OFA Airflow Distribution
(Based on flow area and damper position)

SOFA adj	100.00%
Burner Flow Adj	100.00%
SA Flow Adj	100.00%

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry	Burner Level Stoich		Volumetric Flowrate * (CFH)	Nozzle Velocities (ft/s)
Upper SOFA		1.15	9.54%	76%	7.25%	110,992	1.10			2,768,918	167
Lower SOFA		1.15	9.54%	80%	7.63%	116,834	0.95			2,914,651	176
	OFA Corner Subtotal	2.31				**227,826**				5,683,569	
Cofiring Port	Cofiring PA	0.57	**No Fuel**			0	0.81			0	0
Cofiring Port	Cofiring SA	0.00	0.00%	66%	0.00%	0				0	
DD Aux Air	ated to Control WB Press	0.65	5.40%	35%	1.89%	28,945	0.81			722,078	77
D Mill	Burner Level D SA	0.32	2.64%	58%	1.53%	23,472				585,564	127
	Level D PA	0.57	**FUEL INPUT**			47,385	0.77	0.77	Note 1	726,760	89
D/C Middle Air	ated to Control WB Press	2.40	19.85%	34%	6.75%	103,377	0.91			2,578,939	75
C Mill	Burner Level C SA	0.32	2.64%	47%	1.24%	19,021				474,509	103
	Level C PA	0.57	**FUEL INPUT**			47,541	0.73	0.86	Note 2	729,152	89
C/B Middle Air	ated to Control WB Press	2.40	19.85%	34%	6.75%	103,377	0.93			2,578,939	75
B Mill	Burner Level B SA	0.32	2.64%	49%	1.29%	19,830				494,700	108
	Level B PA	0.57	**FUEL INPUT**			47,591	0.67	0.87	Note 2	729,921	89
B/A Middle Air	ated to Control WB Press	2.40	19.85%	34%	6.75%	103,377	0.99			2,578,939	75
A Mill	Burner Level A SA	0.32	2.64%	43%	1.14%	17,402				434,125	94
	Level A PA	0.57	**FUEL INPUT**			47,376	0.47	0.73	Note 1	726,618	89
AA Aux Air	ated to Control WB Press	0.65	5.40%	33%	1.78%	27,291	-			680,817	72
	Corner Subtotal No SOFA	9.78				**635,982**				19,724,630	
	TOTAL SA ONLY	12.09				673,916				16,812,179	
	TOTAL PA + SA + SOFA		100.00%		44.00%	**863,808**				20,900,266	

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air

CURRENT CASE SEC AIR **673,916**

Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

* at 530°F for SA

CASE 9 - GAS COFIRING

Calculation of Secondary/OFA Airflow Distribution

(Based on flow area and damper position)

SOFA adj	100.00%
Burner Flow Adj	100.00%
SA Flow Adj	100.00%

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cumulative Stoichiometry	Burner Level Stoich		Volumetric Flowrate * (CFH)	Nozzle Velocities (ft/s)
Upper SOFA		1.15	9.54%	100%	9.54%	160,197	1.09			3,996,440	241
Lower SOFA		1.15	9.54%	100%	9.54%	160,197	0.91			3,996,440	241
	OFA Corner Subtotal	2.31				320,395				7,752,108	
DD Aux Air	ated to Control WB Press	0.65	5.40%	6%	0.30%	5,040	0.73			125,725	13
D Mill	Burner Level 4 SA	0.32	2.64%	6%	0.15%	2,466	0.73			61,525	13
	Level 4 PA	0.57				0				0	0
D/C Middle Air	ated to Control WB Press	2.40	19.85%	6%	1.10%	18,529	0.80	0.24	Note 1	462,239	13
C Mill	Burner Level 3 SA	0.32	2.64%	26%	0.68%	11,345	0.74	0.36	Note 2	283,014	62
	Level 3 PA	0.57				55,082				844,814	103
C/B Middle Air	ated to Control WB Press	2.40	19.85%	52%	10.37%	174,171	1.11			4,345,046	126
B Mill	Burner Level 2 SA	0.32	2.64%	22%	0.59%	9,865	0.77	0.93	Note 2	246,099	53
	Level 2 PA	0.57				56,866				857,705	105
B/A Middle Air	ated to Control WB Press	2.40	19.85%	50%	9.93%	166,760	1.27			4,160,150	120
A Mill	Burner Level 1 SA	0.32	2.64%	22%	0.59%	9,865	0.61	0.94	Note 1	246,099	53
	Level 1PA	0.57				55,440				846,670	103
AA Aux Air	ated to Control WB Press	0.65	5.40%	100%	5.40%	90,714	-			2,263,045	241
	Windbox Corner Subtotal	9.78				656,142				15,875,678	
	TOTAL SA ONLY (no SOFA)					488,754				11,825,649	
	TOTAL PA + SA + SOFA	12.09	100.00%		48.17%	**976,536**				23,627,786	

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air

Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

* at 530°F for SA

CURRENT CASE SEC AIR **809,149**

CASE 10 - PC Reburn

Calculation of Secondary/OFA Airflow Distribution

(Based on flow area and damper position)

SOFA adj	100.00%
Burner Flow Adj	100.00%
SA Flow Adj	100.00%

Location	Comment	Nozzle Area (ft2)	Windbox Flow Area (%)	Damper Position (%)	Flow Factor	Total Elevation Air Flow (lb/hr)	Cummulative Stoichiometry	Burner Level Stoich		Volumetric Flowrate * (CFH)	Nozzle Velocities (ft/s)
Upper SOFA		1.15	9.29%	100%	9.29%	110,254	1.10			2,750,494	166
Lower SOFA		1.15	9.29%	100%	9.29%	110,254	0.96			2,750,494	166
	OFA Corner Subtotal	2.31				**220,507**				5,500,989	
Cofiring Port	Cofiring PA	0.57	**FUEL INPUT**			59,622	0.82	0.42		914,452	111
Cofiring Port	Cofiring SA	0.32	2.57%	66%	1.70%	20,164				503,042	109
								0.37			
DD Aux Air	ated to Control WB Press	0.65	5.26%	10%	0.53%	6,243	0.95			155,751	17
D Mill	Burner Level D SA	0.32	2.57%	10%	0.26%	3,055				76,219	17
	Level D PA	0.57	**NO FUEL**			0	0.94	[redacted]	Note 1	0	0
D/C Middle Air	ated to Control WB Press	2.40	19.34%	40%	7.74%	91,816	0.94			2,290,532	66
C Mill	Burner Level C SA	0.32	2.57%	71%	1.83%	21,692				541,151	118
	Level C PA	0.57	**FUEL INPUT**			63,920	0.78	0.90	Note 2	980,372	120
C/B Middle Air	ated to Control WB Press	2.40	19.34%	40%	7.74%	91,816	0.96			2,290,532	66
B Mill	Burner Level B SA	0.32	2.57%	69%	1.78%	21,081				525,908	114
	Level B PA	0.57	**FUEL INPUT**			62,909	0.72	0.83	Note 2	964,866	118
B/A Middle Air	ated to Control WB Press	2.40	19.34%	30%	5.80%	68,862	1.02			1,717,899	50
A Mill	Burner Level A SA	0.32	2.57%	62%	1.60%	18,942				472,555	103
	Level A PA	0.57	**FUEL INPUT**			66,352	0.67	0.84	Note 1	1,017,673	124
AA Aux Air	ated to Control WB Press	0.65	5.26%	75%	3.95%	46,825	-			1,168,132	124
	Corner Subtotal No SOFA	9.78				**643,301**				18,617,029	
	TOTAL SA ONLY	12.41				611,004				14,739,667	
	TOTAL PA + SA + SOFA		100.00%		51.49%	**863,808**				20,900,266	

CURRENT CASE SEC AIR **611,004**

Note 1: Stoichiometry based on 1/2 of B/A or D/C Middle air, and all of AA or BB Aux Air

Note 2: Stoichiometry based on 1/2 of adjacent auxiliary air

* at 530°F for SA

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