DEVELOPMENT OF FIRESIDE CORROSION MODELS FOR ADVANCED COMBUSTION SYSTEMS

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ABSTRACT

A comprehensive fireside corrosion project was undertaken to better understand the corrosion mechanisms operating on the lower furnace walls and superheaters in modern coal-fired utility boilers. Eight U.S. coals commonly burned in boilers have been selected to represent a wide range of coal chemistry. These coals will be burned in a pilot-scale combustion facility to closely simulate the actual conditions of staged combustion in utility boilers. During the combustion testing, gas and deposit samples will be collected and analyzed via in-furnace probing during each of the eight coal burns in the combustion facility at selected waterwall and superheater/reheater locations. Such efforts will allow better characterization of the realistic combustion conditions present in the boilers. Once the conditions are defined, a series of long-term laboratory corrosion tests, each for 1000 hours, will follow. These fireside corrosion tests will involve exposure of different alloys and weld overlays in a wide range of compositions to the laboratory conditions that simulate the environments measured in the combustion facility. As a result of the laboratory testing, a fireside corrosion database will be generated and used for the subsequent corrosion modeling. It is anticipated that results from the modeling work will produce two predictive equations, one for the corrosion rate of waterwalls in the lower furnace and the other for the superheaters/reheaters in the upper furnace. These equations may be used to estimate the service lives of boiler tubes as a function of several key variables, such as the sulfur, chlorine, alkali, alkaline, ash, and pyrite contents in coal, as well as the metal temperatures. Applications of these predictive equations are expected to be applicable to both the conventional and advanced combustion systems and not coal specific.

INTRODUCTION

The recent development of high-efficiency and low-emission coal-fired utility boilers has led to the demand for higher steam temperature and pressure conditions. The design strategies of these boilers often involve implementation of staged combustion that produces corrosive combustion products in the lower furnace and the requirements for use of high-strength corrosion-resistant superheater/reheater tubing alloys in the upper furnace. Examples include recent development of the ultra supercritical (USC) and oxy-coal combustion systems that will push the steam outlet temperatures up to 760^{o}C (1400^{o}F) and steam pressures up to 35 MPa (5000 psi).[1] While higher efficiencies and lower emissions can be realized from these advanced combustion systems, accelerated fireside corrosion is also expected to occur on the boiler tubes. For instance, low-NO_X combustion produces H_2S in the flue gas and FeS in the deposit due to incomplete combustion of the sulfur-bearing species in coal. Both of these sulfides are known to increase fireside corrosion on the waterwalls via sulfidation, although the corrosion mechanisms are distinctly different.[2,3] Utility boilers retrofitted with low-NO_X burners and NOx ports in recent years have indeed experienced accelerated tube wastage in the lower furnace. Consequently, coatings and weld overlays are often applied on the lower furnace walls to impede the corrosion wastage. In the upper furnace, higher steam temperatures and pressures inevitably raise the metal temperatures of superheaters and reheaters, thus potentially increasing the tendency for coal ash corrosion attack.

While the boiler operating conditions are important variables, the coal chemistry also plays a vital role in fireside corrosion. Some impurity constituents of coals are well known to cause accelerated corrosion. For example, high sulfur and chlorine contents in coal have long been recognized as a major reason for boiler tube corrosion on both the waterwall and superheater/reheater surfaces. The effects of other coal constituents on corrosion, such as the alkali and alkaline metal concentrations as well as the total ash content, are also important but less understood. Indeed, operating experiences indicate that the corrosivity of coal is not just determined by individual impurities. Rather, it is the result of a complex, synergistic effect from all these impurity constituents interacting each others. There were attempts in the past to link coal corrosivity to its impurities based on empirical correlation and indexing. However, the results proved to be unreliable and often coal-specific due to oversimplification of the interactions and/or significant variations in coal chemistry from seam to seam and mine to mine.

Therefore, it is the objective of this multi-year project to develop comprehensive corrosion models that can be used to reliably predict the corrosion rates of boiler tubes under staged combustion conditions in the lower furnace and coal ash corrosion conditions in the upper furnace. To accomplish this goal, B&W has selected eight U.S. coals to represent a wide range of coal compositions commonly burned in modern utility boilers. These coals will be combusted in a pilot-scale combustion facility to closely simulate the actual staged combustion conditions encountered in utility boilers. During the combustion testing, in-situ gas and deposit samples will be obtained and analyzed for each coal at lower furnace walls and superheaters. Such efforts will allow better definition of the realistic combustion environments and corrosive products present adjacent to the boiler tubes. Once the conditions are determined, a series of long-term laboratory corrosion tests, 1000 hours each, will be performed. These corrosion tests will expose different alloys and coatings in a wide range of compositions to the laboratory conditions simulating the actual boiler environments. As a result of the laboratory tests, a fireside corrosion database will be generated and used for the subsequent corrosion modeling. It is anticipated that the modeling efforts will lead to two predictive equations, one for the lower furnace walls and the other for superheaters/reheaters, that can be used to estimate the corrosion rates of boiler tubes as a function of key variables, such as the sulfur, chlorine, alkali, alkaline, ash, and FeS_2 contents in coal, as well as the metal and gas temperatures. Application of these predictive equations is expected to be versatile for both conventional and advanced combustion systems and not coal specific.

EXPERIMENTAL PROCEDURES

Eight US coals commonly burned in utility boilers have been successfully selected from Task 1as a major deliverable to this project. In addition, preparation of the combustion facility has begun for Tasks 2 and 3. The coal selection processes and justifications as well as facility site preparation are discussed in this paper. The status of remaining tasks, which are either in early or planning stage, will not be presented in detail here.

Coal Selection, Procurement, and Handling

Several coal databases were explored in the selection processes to help narrow the coal choices to eight groups. These databases included the Penn State Coal Database, USGS Coal Quality Database, Keystone Coal Industry Manual, and coal analyses from the Argonne Premium Coal Sample (APCS) Program. Based on these databases, a number of coals have been identified as prime candidates for the project. For high sulfur bituminous coals, multiple choices are available. For example, the Ohio #5 coal seam has a sulfur content, on a dry basis, as high as 9 wt.%. Specifically, the Empire mine (hvAb) contains a sulfur content of approximately 4%, the East Fairfield County mine (hvAb) of 5%, and the Holmes County (hvBb) mine of 6%. In Kentucky, the Camp #1 mine (hvBb) of Kentucky #9 seam has a sulfur concentration of 4%, Paradise mine (hvBb) of the Kentucky #11 seam at 5%, and Homestead mine (hvCb) of the Kentucky #11 seam at 6%.

Since chlorine is also an important coal impurity on fireside corrosion, various chlorine-bearing coals have been considered along with their sulfur contents. In Illinois, the Will Scarlett mine (hvAb) of Top Dekoven seam has a chlorine content of 0.27% and sulfur of 4.69% on a dry basis. Similarly, the Eagle #2 mine (hvAb) of Illinois #5 seam has 0.27% chlorine and 4.72% sulfur. Furthermore, the Orient #3 mine (hvBb) of Illinois #6 seam has a combination of lower sulfur content of 1.35% but higher chlorine of 0.45%. This Illinois coal was considered an ideal candidate for this study to highlight the effect of chlorine on fireside corrosion.

For additional selection of medium-sulfur bituminous coals, the Hillsville mine (hvBb) of Middle Kittanning seam, which consists of 2.77 % sulfur and 0.16 % chlorine, and the O’Donnell #1 mine (hvAb) of Pittsburgh seam, which consists of 3.07 % sulfur and 0.06 % chlorine, were considered. The Stinson #3 mine (hvAb) of Elkhorn #3 seam containing 0.98% sulfur and 0.33% chlorine was also a good choice for this coal group.

In addition to individual impurities, the base/acid ratio (BAR) was also used as a starting parameter to identify bituminous coals that have a relatively high calcium and magnesium content in the ash. Several coals were identified as candidates for this group. For example, the Stahlman mine (3500 Pit) (hvAb) of Clarion seam, with a BAR of 3.58, and the Bokoshe #10 mine (hvAb) of Upper Hartshorne seam, with a BAR of 7.0, were among the candidates of coals with a high alkaline earth metal content. There are bituminous coals, such as the Michigan #5 mine (hvCb) in Iowa, which contain an even higher BAR ratio at 12-78. Such a high BAR is attributed to an unusually high calcium concentration, i.e., 20-30%, in the ash. Typically, these coals also have a high sulfur contents, ranging from 9 to 10%, with pyretic sulfur being the main constituent at approximately 7%.

For sub-bituminous coals, the Spring Creek mine (subB) in Montana has a sulfur content of 0.5% and chlorine content of 0.07%. Similarly, the Black Thunder mine in Wyoming has a relatively low sulfur content at 0.43% and a very low chlorine content. Both of these sub-bituminous mines are from Powder River Basin (PRB). On the other hand, North Dakota lignite of the Beulah mine was considered a unique candidate for its high ash content at 9% and extremely high moisture content at approximately 30% as-received. This coal has a sulfur concentration of typically less than 1%.

Due to its unique characteristics and popularity, a Powder River Basin (PRB) coal, i.e., Wyoming coal from the Black Thunder mine, was included in the test matrix as one of the final eight. In general, the PRB coal is considered non-corrosive. However, this coal exhibits a very high (Ca+Mg)/S ratio, which has been linked to potential causes for high fireside corrosion found in some utility boilers, especially those blending PRB with a high chlorine-bearing coal. Therefore, this coal is of interest to this study.

In summary, to select eight coals that are representative of a wide range of compositions important to fireside corrosion, the following properties of coal were considered, i.e., the sulfur content and its forms, chlorine content, BAR (the base/acid ratio calculated from elemental ash analysis), and ash content. Concentrating mainly on steam coals for the ultimate fireside corrosion modeling and reducing the large number of U.S. coals to eight, it was decided to exclude the low and medium volatile bituminous coals from this study.

Preparation of Pilot-Scale Combustion Facility

The combustion testing facility consists of a variable swirl burner, as shown in Figure 1 that is capable of producing a stabilized pulverized coal flame. This movable block-type swirl generator is controlled by a metal push rod that changes the angle of the upper-swirl vanes when compared to the lower-swirl vanes. The angle of the swirl plate has been measured with respect to the linear position on the push rod to produce a repeatable swirl plate angle, as shown in Figure 2. The swirl produced by the burner was CFD-modeled, with results summarized in the next section.

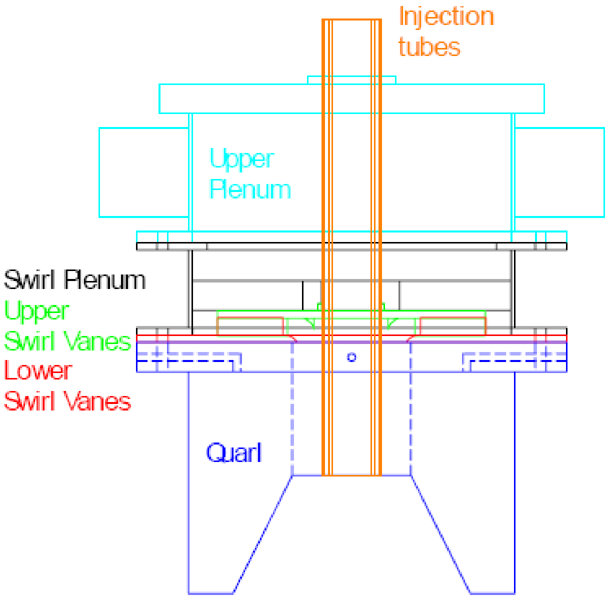


Figure 1 - Components of the Variable Swirl Burner.

The orifice used for the primary air has also been calibrated, with results shown in Figure 3. The calibrated flow rates are compared to the calculated chocked flow values, and they are in good agreement at a C_D (discharge coefficient of orifice) of 0.967. The lowest flow rate was also used to calibrate the secondary air flow and produced a C_D of 0.93.

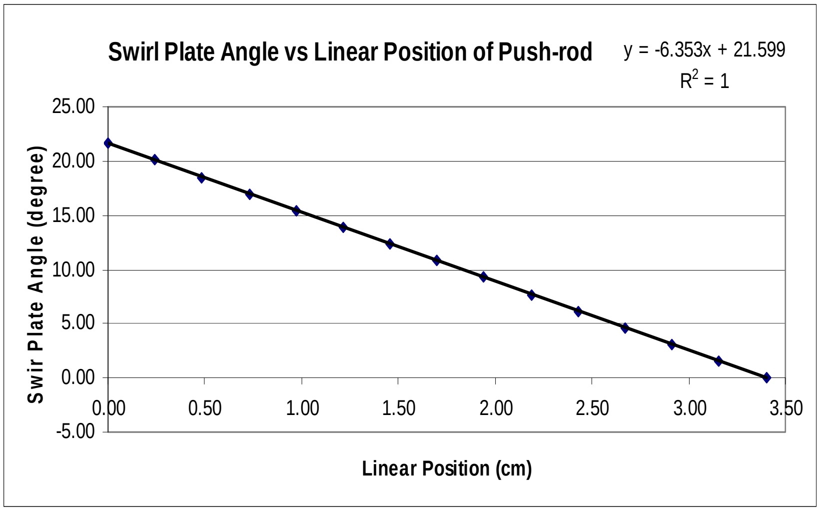


Figure 2 – Variation of Burner Swirl Plate Angle with Linear Position of the Push Rod.

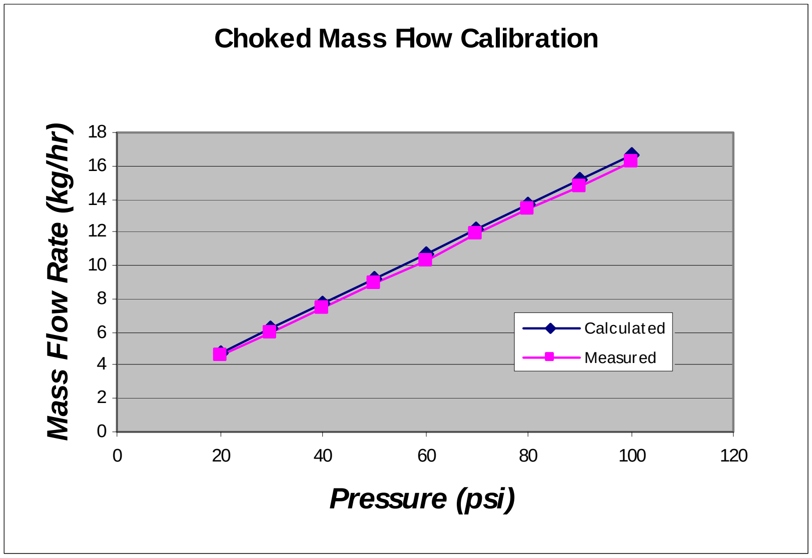


Figure 3 - Measured and Calculated Mass Flow Rates as a Function of Upstream Pressure for 1.8 mm Primary Air Flow Orifice.

The combustion facility was originally equipped with a coal delivery system that consisted of an Acrison variable speed SCR-DC motor controller, a Baldor DC electric motor, and an Acrison 105x-f volumetric feeder. An acceptable coal flow rate was achievable by partially filling the fluted region of the ½" auger in the existing feeder wrapped with steel wires to achieve the volume flow rate. A plot of fuel flow rate versus controller load is shown in Figure 4, which exhibits a linear relationship between the mass flow and voltage control position. However, the original feed system had a small coal hopper and consequently, the coal must be loaded manually and frequently.

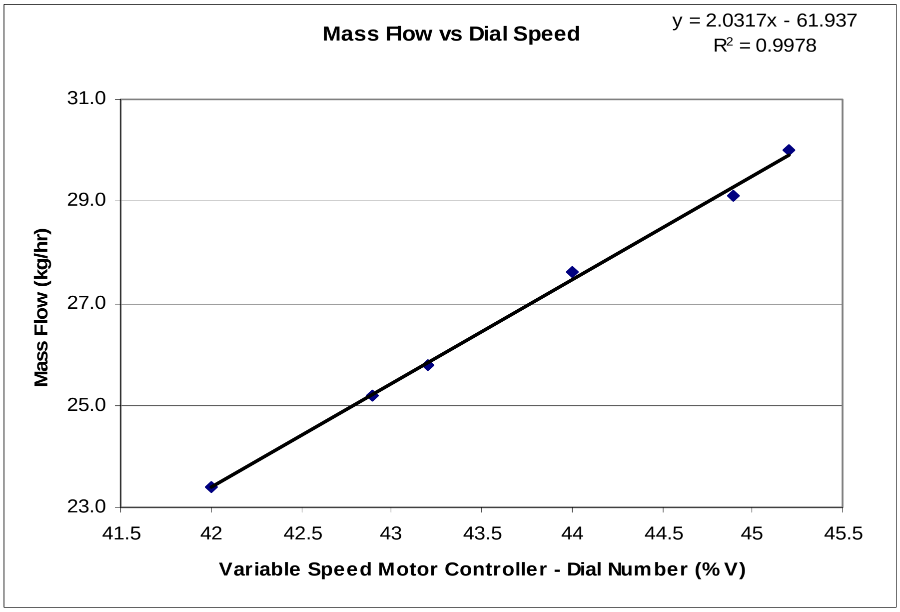


Figure 4 - Mass Flow Rate as a Function of Motor Speed Controller Position.

In preparation of the combustion tests planned for this study, a new coal feed system was installed. This system consists of a bulk bag unloader and loss-in-weight feeder, as shown in Figure 5. The system also includes a platform to hold a bulk bag in place and pneumatic massage paddles to help discharge the coal from the bag. The bulk bag is approximately 49”x38”x38” in dimension and can hold up to 1000 lb of pulverized coal at a time. After discharge, the coal is fed through an agitator hopper that fills the feeder hopper on demand. A pneumatic line was installed to convey the pulverized coal from the feeder to the burner. This integrated system allows the coal feed rate to be controlled within 5% of the set point for an extended period of time.

As part of the site preparation effort, approximately 15 short test runs have been performed to date. Several test burns exceeded 4 hours of operation at a time. From these test burns, the capability of the test facility to produce staged combustion, i.e., fuel rich near the burner zone and air rich at the furnace exit, has been successfully demonstrated. Data generated from these tests were also used to calibrate online instruments and help identify necessary modifications to improve the facility functionality.

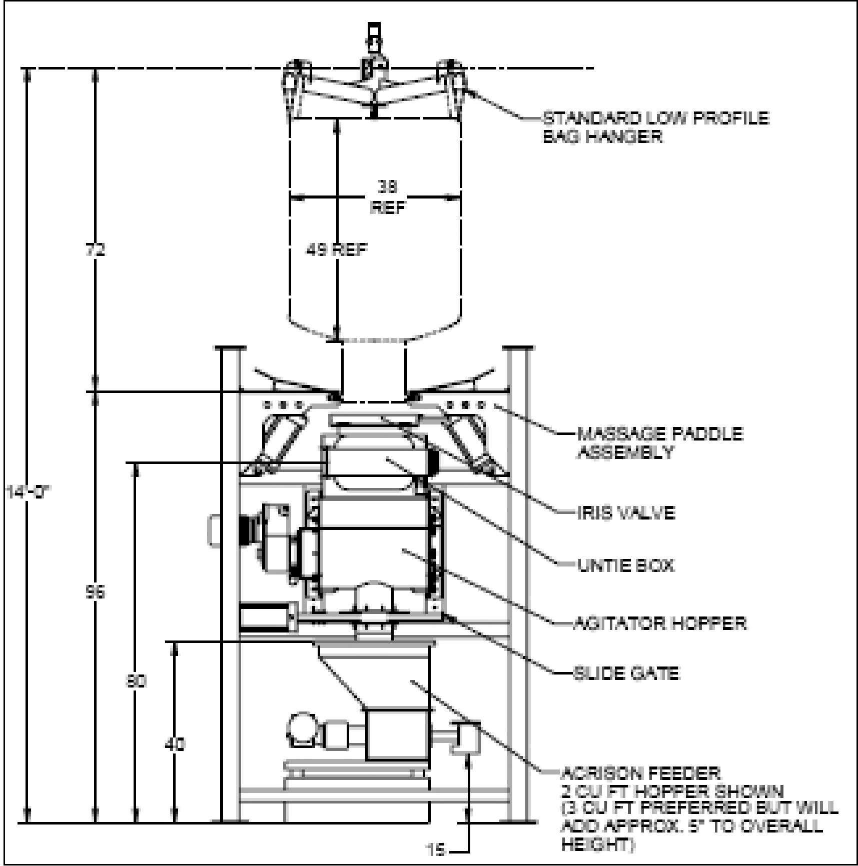


Figure 5 - Schematic of the Bulk Bag Unloader and Feeder.

Laboratory Fireside Corrosion Testing

The corrosion rates of selected boiler-tube alloys and weld overlays will be evaluated by exposing them to laboratory corrosion conditions. These conditions are to be determined through in-furnace gas sampling and analysis while burning each of the eight coals in the pilot-scale combustion facility. Mixed gases and ash deposits will be employed in the laboratory to closely simulate the actual combustion conditions measured near the furnace walls and superheaters/reheaters. Each laboratory test will last for 1,000 hours.

Corrosion Model Development

The development of two fireside corrosion models will be attempted, one for the lower furnace walls in coal-fired utility boilers burning coal staged and the other for the superheaters/reheaters in the upper furnace. Because the corrosion mechanisms operating on the furnace walls and superheaters/reheaters are distinctly different, they must be modeled separately. In the lower furnace, sulfidation dominates the corrosion mechanism due primarily to the staged combustion of coals. Stage combustion allows the formation of reduced sulfur species in the flue gas and deposit layer. These species react with the boiler tubes to form rapidly growing metal sulfides, such as FeS and NiS. Consequently, the formation of sulfides leads to accelerated metal loss on the furnace walls. In addition, coals containing a high level of chlorine can induce chlorination, also known as active corrosion, that further accelerates the wastage rate of boiler tubes.

On the other hand, coal ash corrosion on superheaters and reheaters involves the condensation of a thin layer of inorganic salt beneath the bulk of the ash deposit. The inner layer, often referred to as the “white layer” when seen under an optical microscope, consists primarily of sulfates, such as $(Na,K)_2SO_4$ and $Fe_2(SO_4)_3$. The presence of multiple sulfate compounds can reduce the liquidus temperatures of the white layer below the tube OD temperatures, thus allowing “hot corrosion” to take place. Hot corrosion is a special class of high-temperature corrosion that involves the presence of molten salts.[4] Once molten, the salts can attack the metals by means of dissolution and breakdown of the otherwise protective oxide scales formed on the boiler tubes. The addition of chlorides to the white layer from burning high-chlorine coals may further facilitate the alkali and chloride condensations as well as reduce the liquidus temperatures.

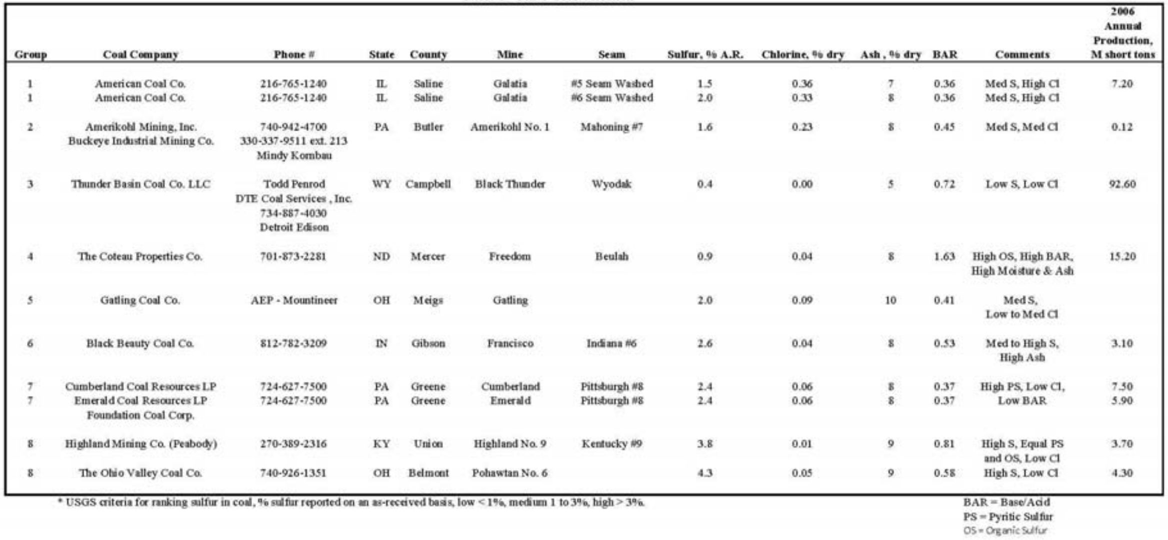
Based on the current understanding of fireside corrosion, corrosion modeling must take into account the thermodynamics and kinetics simultaneously involved in the corrosion mechanisms. In the literature, the compositions of combustion gases in boilers have often been estimated by performing simple equilibrium calculations. This approach assumes equilibrium is maintained at all times. However, such an assumption can result in misleading information, as the reaction kinetics is severely impeded by the rapid decrease of combustion temperatures from the burner zone to surfaces of the boiler tubes. Therefore, the in-furnace gas and deposit sampling in the pilot-scale combustion facility, along with corrosion data generated from long-term laboratory simulations, would assure better corrosion models to be developed from this study.

RESULTS AND DISCUSSION

The final selection of eight U.S. coals commonly burned in modern utility boilers has been completed. Special considerations were given to the various coal properties and impurity concentrations mentioned above. As expected, it was extremely challenging to narrow the coal sources to only eight mines that would cover all of the coal properties importance to fireside corrosion. However, the selected eight coals are believed to represent a wide range of coal properties relevant to the fireside corrosion of interest.

Listed in Table 1 are the coal groups that have been selected for this study. The coals of interest are listed by the group numbers. For some of the groups, there are multiple coal options listed due to uncertainty of availability of the preferred coals. The alternate coals will be pursued if the primary choices become difficult to obtain due to the relatively small quantity needed. It should be mentioned that all of the coals listed in Table 1 are of high usage in the utility industry. Coal usage was another consideration taken into account for the selection processes.

Table 1 - Final Coal Selection



Group	Coal Company	Phone #	State	County	Mine	Seam	Sulfur, % A.R.	Chlorine, % dry	Ash , % dry	BAR	Comments	2006 Annual Production, M short tons
1	American Coal Co.	216-765-1240	IL	Saline	Galatia	#5 Seam Washed	1.5	0.36	7	0.36	Med S, High Cl	7.20
1	American Coal Co.	216-765-1240	IL	Saline	Galatia	#6 Seam Washed	2.0	0.33	8	0.36	Med S, High Cl	
2	Amerikohl Mining, Inc. Buckeye Industrial Mining Co.	740-942-4700 330-337-9511 ext. 213 Mindy Kornbau	PA	Butler	Amerikohl No. 1	Mahoning #7	1.6	0.23	8	0.45	Med S, Med Cl	0.12
3	Thunder Basin Coal Co. LLC	Todd Penrod DTE Coal Services , Inc. 734-887-4030 Detroit Edison	WY	Campbell	Black Thunder	Wyodak	0.4	0.00	5	0.72	Low S, Low Cl	92.60
4	The Coteau Properties Co.	701-873-2281	ND	Mercer	Freedom	Beulah	0.9	0.04	8	1.63	High OS, High BAR, High Moisture & Ash	15.20
5	Gatling Coal Co.	AEP - Mountineer	OH	Meigs	Gatling		2.0	0.09	10	0.41	Med S, Low to Med Cl	
6	Black Beauty Coal Co.	812-782-3209	IN	Gibson	Francisco	Indiana #6	2.6	0.04	8	0.53	Med to High S, High Ash	3.10
7	Cumberland Coal Resources LP	724-627-7500	PA	Greene	Cumberland	Pittsburgh #8	2.4	0.06	8	0.37	High PS, Low Cl, Low BAR	7.50
7	Emerald Coal Resources LP Foundation Coal Corp.	724-627-7500	PA	Greene	Emerald	Pittsburgh #8	2.4	0.06	8	0.37		5.90
8	Highland Mining Co. (Peabody)	270-389-2316	KY	Union	Highland No. 9	Kentucky #9	3.8	0.01	9	0.81	High S, Equal PS and OS, Low Cl	3.70
8	The Ohio Valley Coal Co.	740-926-1351	OH	Belmont	Pohawtan No. 6		4.3	0.05	9	0.58	High S, Low Cl	4.30

* USGS criteria for ranking sulfur in coal, % sulfur reported on an as-received basis, low < 1%, medium 1 to 3%, high > 3%.

BAR = Base/Acid
PS = Pyritic Sulfur
OS = Organic Sulfur

In general, the coal groups listed in Table 1 are presented in the order of high to low chlorine, starting with Group 1, on a percent dry basis. Furthermore, starting with Group 3, the sulfur content, on an as-received percent basis, increases with the group number. An exception is the Group 6 coal that has a slightly higher sulfur content than those in Group 7. It should be pointed out that the properties of actual coals received from the mines would vary somewhat from the typical values listed in Table 1 due to variation in the mine.

Some specific properties of each coal group and rationale for the selection are given below. The ranking of each coal is classified per ASTM D388, Standard Classification of Coals by Rank.

Coal Group 1 - In general, Illinois coals are highly enriched with trace elemental chlorine. The Galatia Mine located in SE Illinois produces both washed Illinois #5 and #6 seams. The ASTM coal rank is hvBb. For the sulfur content, it is considered a medium sulfur coal. The sulfur forms for these coals are a close balance of pyritic and organic, with the sulfate sulfur being very low to negligible. The main reason for selecting this coal is its relatively high chlorine content (0.33 %, on a dry basis) and medium sulfur content.

Coal Group 2 - B&W has previously tested the Mahoning No. 7A Stoker coal in its CEDF (the Clean Environment Development Facility) in Alliance, OH, for a separate project. The coal is mined in southwest Pennsylvania and ranked as hvAb with a medium sulfur content. This coal was mainly selected for its high chlorine percentage (0.23 %, dry basis), representing the second highest chlorine content in the study.

Coal Group 3 - Currently, Powder River Basin (PRB) coal is the most used coal for utility electricity production in the U.S. For this reason, Wyoming is the number one coal producing state. Part of the Wyodak PRB seam for the Black Thunder mine is located in NE Wyoming. The coal rank is sub-bituminous (subB). Since PRB is a compliance coal, it is characterized as having low sulfur (< 1.0 %, as-received basis) and chlorine (< 0.01 %, dry basis) contents. Therefore, it was selected for this study. The majority of the sulfur in this coal is in the form of organic, and the BAR of 0.72 for this coal is considered moderately high. Sub-bituminous coals typically have lower calorific values than bituminous coals.

Coal Group 4 - The Beulah lignite seam is located in Mercer County in west central North Dakota. The coal rank is lignite, which is characterized as having high moisture, ash, BAR, and low calorific value. The sulfur content can vary from low to medium and almost exclusively in the form of organic. The Beulah lignite was selected mainly for these reasons.

Coal Group 5 - The Gatling Mine is located in Meigs County in southeast Ohio. This mine is a source of coal for the AEP Mountaineer Plant located in New Haven, WV. The ASTM coal rank is hvBb. In general, the high volatile eastern bituminous coals are characterized as having a low chlorine content with a varying sulfur content ranging from low to high. Specifically, the chlorine percentage of this coal is relatively low (0.09 %, dry basis), and the sulfur content (2.0 %, as-received basis) is considered medium. For these reasons this coal was selected for the study.

Coal Group 6 - The Indiana #6 seam mined at the Francisco Mine is located in southwest Indiana. The coal rank is hvCb. The chlorine percentage in this coal (0.04%, % dry) is low. Even though the sulfur content of this coal is considered medium, its sulfur percentage (2.6 %, as-received basis) is greater than that of the Group 5 coal (2.0 %, as-received basis). Since sulfur in coal is one of the key contributors to corrosion, a number of coals having varying sulfur contents were selected for this study, and the Francisco coal is considered one of the candidates of interest.

Coal Group 7 - The Pittsburgh #8 seam is located in Greene County in southwest Pennsylvania. The coal rank is hvAb. The sulfur content of this coal is ranked medium, and the chlorine percentage (0.06 %, dry basis) is considered low. The pyritic to organic sulfur ratio can vary significantly in this coal, but the sulfate sulfur is very low (i.e. ~0.02 %, dry basis). This is another of the medium-sulfur coals selected for this study.

Coal Group 8 - The Kentucky #9 seam is located in Union County of southwest Kentucky. The coal rank is hvBb. The sulfur content of this coal is ranked high, and the chlorine percentage (0.01 %, dry basis) is considered very low. Minimum fusion temperatures of the coal ash typically occur at a base-to-acid ratio of 0.7 to 0.8. A ratio in the range of 0.5 to 1.2 is generally an indication of high slagging potential.[1] The BAR for this coal is 0.81, on the fringe of minimum fusion temperatures occurs. Compared to the bituminous coals selected for this study, the Kentucky #9 coal also has a relatively high BAR.

A further representation of the selected U.S. coal groups in terms of their chlorine and sulfur contents is shown in Figure 6. The numbers reference to the coal groups listed in Table 1. The ranges of chlorine and sulfur in these test coals vary from 0.01% to 0.36 % on the dry basis and 0.43 to 4.25 % on the as-received basis, respectively.

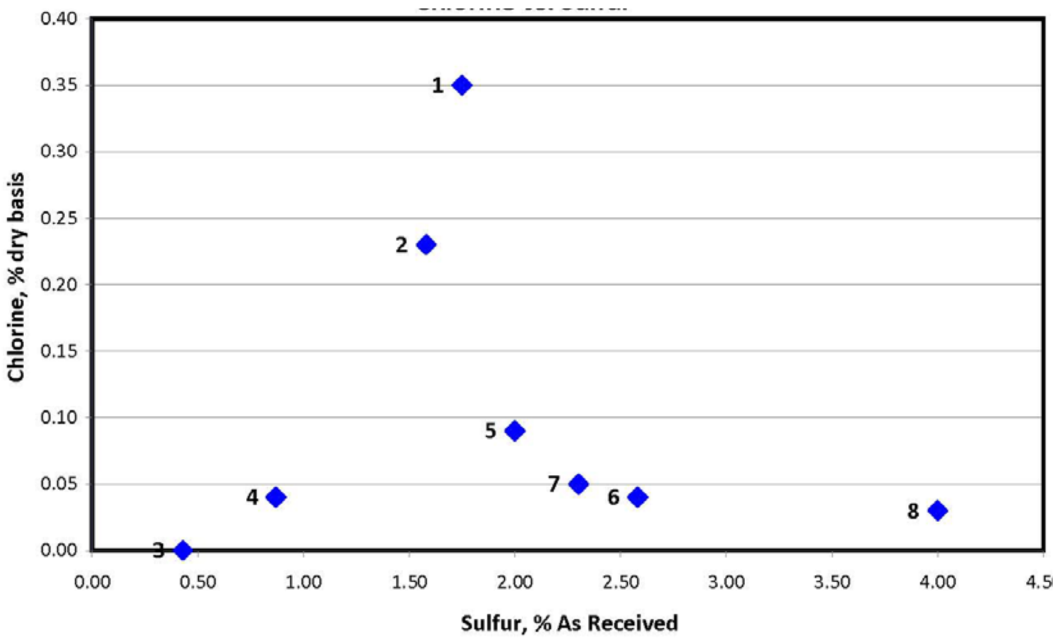


Figure 6 – Final Coal Selection by Comparing Chlorine and Sulfur Contents.

Among the selected eight coal groups, six are eastern high volatile bituminous coals. The other two consist of a sub-bituminous coal from Wyoming and a lignite coal from North Dakota. Figure 7 shows the geographical locations of the selected coal groups. Again, the numbers refer to the coal groups listed in Table 1.

Figure 7 - Final Selection of Coal Groups by Geographical Location.

For site preparation, a CFD parametric study was performed to determine the burner settings of two swirler blocks required for a well mixed primary combustion zone and optimized swirl in the furnace. The maximum adjustment angle between the swirler blocks is 21.5°. Nine different cases were set-up by gradually varying the angle between the swirler blocks to control the tangential and axial flow split, which helped characterize its effect on swirl number of the flow. The secondary airflow entered through the plenum section above the swirl device at the location of the porous media to get a uniform flow, which was then distributed through the flow channels formed between the swirler blocks below. The flow continued into the diverging quarl section before entering into the furnace that was modeled separately.

For the CFD analysis, the entire computational domain was approximated using a volumetric mesh for the burner, as shown in Figure 8. Based on the expected operating conditions of the combustion facility, a mass flow of 0.044 kg/s at 350°C was used for the secondary airflow through the plenum inlet. The turbulence kinetic energy was calculated using a turbulence intensity of 4%. A mass flow of 0.00038 kg/s was applied for the primary airflow through the fuel core pipe with a length scale of 0.002 m used to calculate the turbulence dissipation rate. An outflow boundary condition was used to define the model outlet that is located beyond the burner outlet. Figure 9 shows the airflow path through the burner that houses the movable block type swirl device.

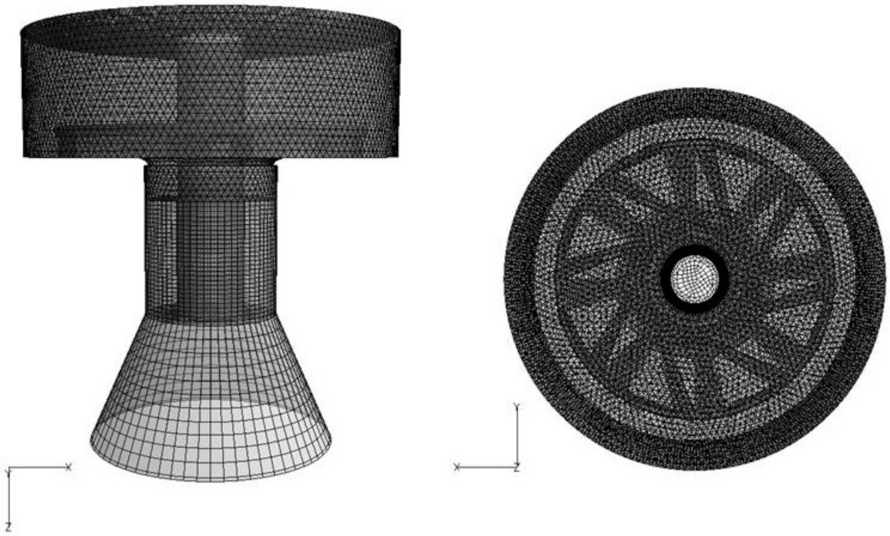


Figure 8 - Mesh Generated for the Burner Geometry

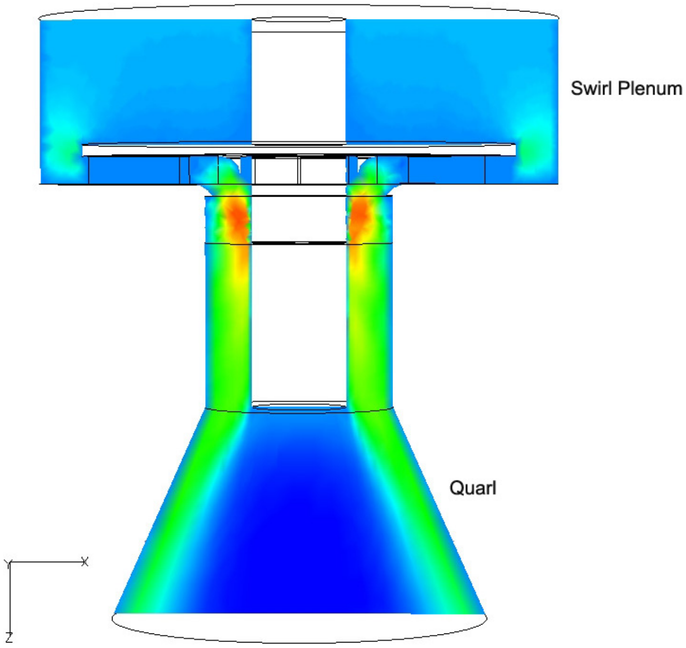


Figure 9 - Contour Plot of Z-Velocity Showing the Air Flow Path for the Burner Geometry

Based on the expected operating conditions, the CFD numerical modeling was able to create steady-state simulations of the flow. The flow distribution at two different sections of the burner for a high swirl number case of 0.833 is shown in Figure 10. As the angle between the blocks was varied, increasing the tangential component of airflow increased the swirl number. A plot of the swirl number as a function of the swirler block setting determined from the simulations of the nine cases is shown in Figure 11. These results are in good agreement with the swirl numbers obtained by Leuckel who conducted experiments on similar movable block-type swirl generators at the International Flame Research Foundation (IFRF) in Holland.[5]

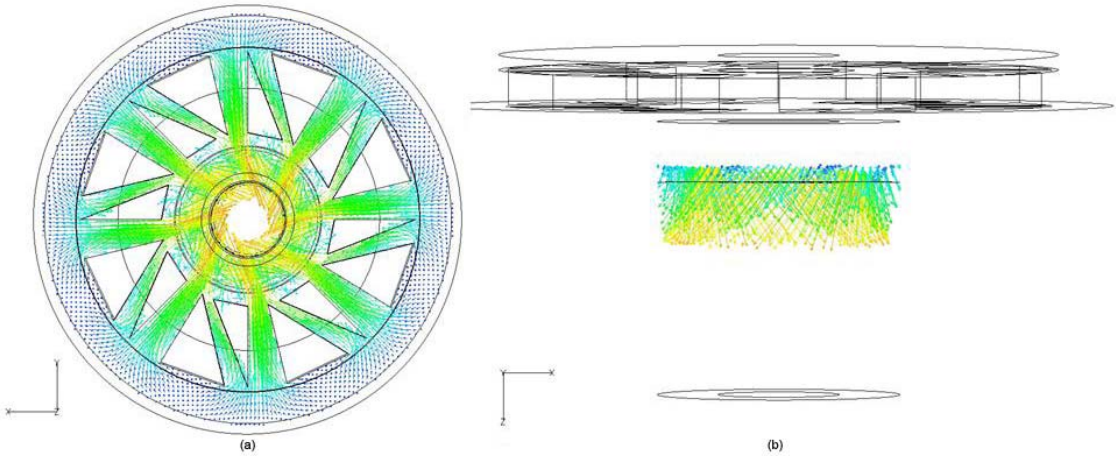


Figure 10 - Plot of Velocity Vectors at a Swirl Number of 0.833 Showing the Flow Pattern of (a) Plane Cut Through the Swirler Block and (b) Side View of Location Below the Swirler Block Entering the Quarl.

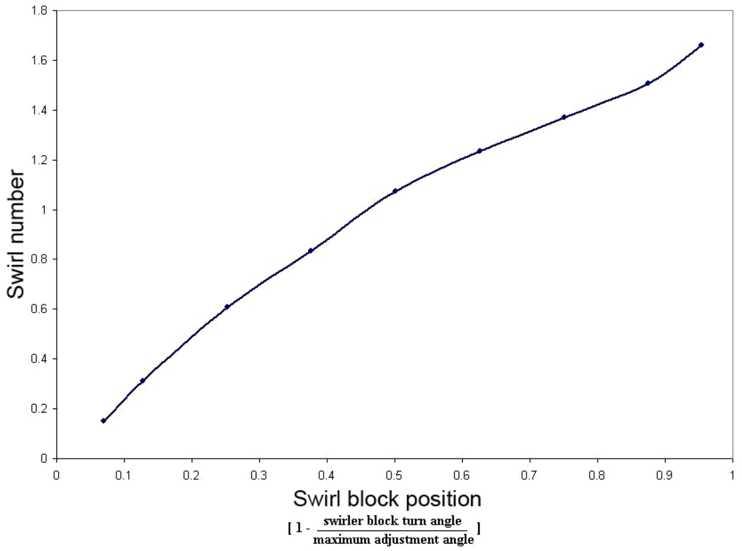


Figure 11 - Variation of Swirl Number of the Gas Flow with Swirler Block Setting

From the results of individual burner model simulations, velocity profile of the burner was then mapped to the inlet of the furnace model. The inlet of the furnace model started at the beginning of the quarl. A coal flow rate of 0.0063 kg/s was used for a fuel rich near-burner stoichiometry of 0.85.

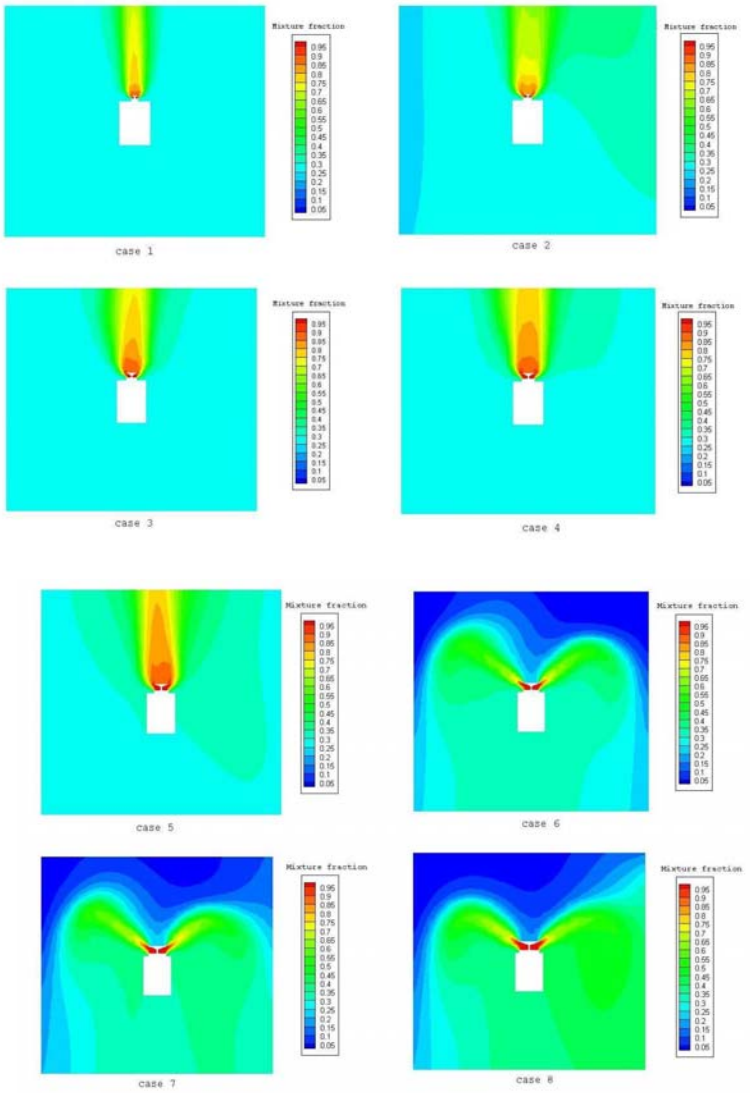
As a second objective of the CFD work, the NOx port design has also been investigated. Based on the operating conditions of the combustion facility, a mass flow of 0.044 kg/s was used for the secondary airflow through the plenum inlet. The turbulence kinetic energy was calculated using a turbulence intensity of 4%. The mass flow of 0.01344 kg/s was used for the secondary air through the NOx port at 86000 Pa and 293K. The mass flow of 0.00038 kg/s was applied for the primary airflow through the coal pipe, with a length scale of 0.002m used to calculate the turbulence dissipation rate. An outflow boundary condition defined the model outlet. Coal properties of the Illinois #6 Galatia coal were used for the modeling and a coal flow rate of 0.0063 kg/s was maintained.

Eight different cases were set-up by varying the diameter of the NOx port while keeping the rest of the geometry constant, as shown in Table 2. The results of these simulations are summarized in Figure 12 in the form of contour plots of mixture fraction near the NOx port region. The distribution of the secondary air comes through the plenum and NOx port inlets. It can be seen from Figure 12 that, for the smaller diameter NOx ports, the velocity is very high, thus causing the air flow to behave like a jet and negatively impacting on the intended staged combustion conditions.

Table 2 – NOx Port Design Cases Investigated by CFD Modeling

	NOx Port OD		Spindle OD		Spindle Height
	m	in	m	in	m
case 1	0.01905	0.75	0.00635	0.25	0.00423
case 2	0.02540	1.00	0.00635	0.25	0.00595
case 3	0.03175	1.25	0.00635	0.25	0.00762
case 4	0.03810	1.50	0.00635	0.25	0.00926
case 5	0.04445	1.75	0.00635	0.25	0.01089
case 6	0.05080	2.00	0.00635	0.25	0.01250
case 7	0.05715	2.25	0.00635	0.25	0.01411
case 8	0.06350	2.50	0.00635	0.25	0.01572

An additional set of eight cases were set-up to extend the diameter of the spindle head and to better match the diameter of the water jacket around the NOx port. These cases would help direct the air flow exiting the NOx port downward, thus maintaining a lower stoichiometry in the burner zone. Table 3 lists the geometries used.



case 1 case 2 case 3 case 4 case 5 case 6 case 7 case 8

Figure 12 - Contour Plots of Mixture Fraction near NOx Port for Table-5 Cases

Table 3
Additional NOx Port Design Cases Investigated by CFD Modeling

	NOx Port OD		Spindle OD		Spindle Height
	m	inches	m	inches	m
case 1	0.01905	0.75	0.02705	1.06	0.00423
case 2	0.02540	1.00	0.03340	1.31	0.00595
case 3	0.03175	1.25	0.03975	1.56	0.00762
case 4	0.03810	1.50	0.0461	1.81	0.00926
case 5	0.04445	1.75	0.05245	2.06	0.01089
case 6	**0.05080**	**2.00**	**0.05880**	**2.31**	**0.01250**
case 7	0.05715	2.25	0.06515	2.56	0.01411
case 8	0.06350	2.50	0.07150	2.81	0.01572
Outer jacket thickness = 8 mm					

Figure 13 shows that the air flow through the NOx port is now directed towards the bottom half of the furnace, thus producing better staged combustion conditions in the furnace. Based on these CFD results, the geometry of Case 6 was considered for the optimal NOx port design due to enhanced air flow structure and less recirculation near the walls.

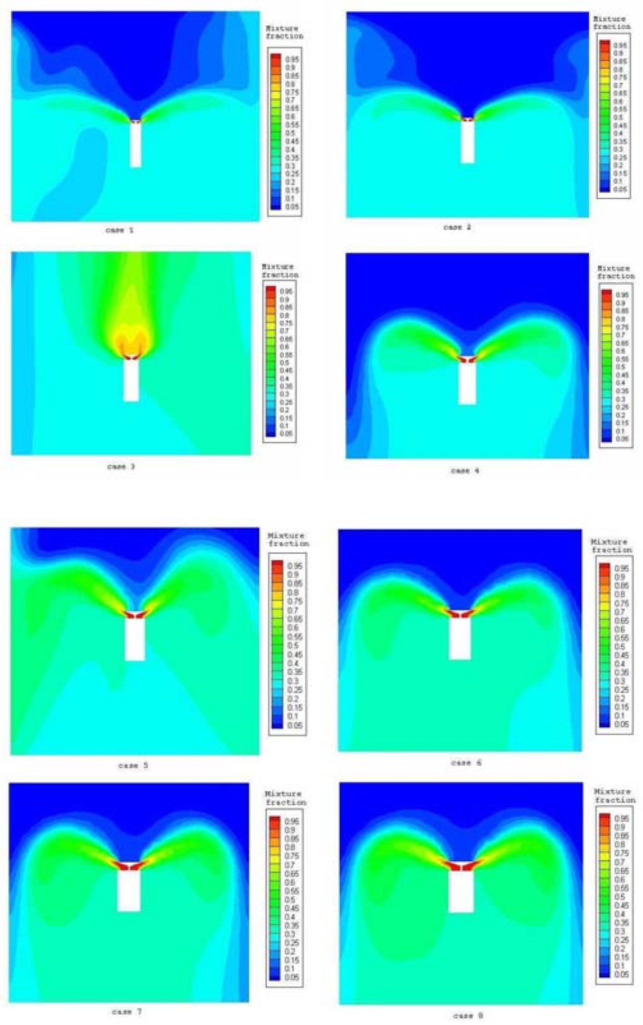


Figure 13 - Additional Contour Plots of Mixture Fraction near NOx Port for Table-6 Cases with Larger Port Diameters

SUMMARY

Eight U.S. coals commonly burned in boilers have been selected to represent a wide range of coal chemistry for the fireside corrosion modeling study. These coals will be burned in a pilot-scale combustion facility to closely simulate the actual conditions of staged combustion in utility boilers. During the combustion testing, gas and deposit samples will be collected and analyzed via in-furnace probing during each of the eight coal burns in the combustion facility at the waterwall and superheater/reheater locations. Once the conditions are defined, a series of long-term laboratory corrosion tests, each for

1000 hours, will follow. These fireside corrosion tests will involve exposure of different alloys and weld overlays in a wide range of compositions to the laboratory conditions that simulate the environments measured in the combustion facility. As a result of the laboratory testing, a fireside corrosion database will be generated and used for the subsequent corrosion modeling.

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