BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	
NITROGEN OXIDES EMISSIONS FROM	)	R08-19
VARIOUS SOURCE CATEGORIES:	)	(Rulemaking – Air)
AMENDMENTS TO 35 ILL. ADM. CODE	)	
PARTS 211 AND 217	)	

NOTICE

TO: John Therriault
Assistant Clerk
Illinois Pollution Control Board
James R. Thompson Center
100 West Randolph St., Suite 11-500
Chicago, IL 60601

SEE ATTACHED SERVICE LIST

PLEASE TAKE NOTICE that I have today filed with the Office of the Clerk of the Illinois Pollution Control Board TESTIMONY OF ROBERT KALEEL, TESTIMONY OF MICHAEL KOERBER, TESTIMONY OF JAMES E. STAUDT, Ph.D., MOTION TO CORRECT TRANSCRIPTS, and DRAFT ATTAINMENT DEMONSTRATION FOR THE 1997 8-HOUR OZONE NATIONAL AMBIENT AIR QUALITY STANDARD FOR THE CHICAGO NONATTAINMENT AREA, AQPSTR 08-07, AND RELATED DOCUMENTS, a copy of which is herewith served upon you.

ILLINOIS ENVIRONMENTAL
PROTECTION AGENCY

By: ______________
Gina Roccaforte
Assistant Counsel
Division of Legal Counsel

DATED: January 20, 2009

1021 North Grand Avenue East
P. O. Box 19276
Springfield, IL 62794-9276
217/782-5544

THIS FILING IS SUBMITTED ON RECYCLED PAPER

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TESTIMONY OF ROBERT KALEEL

My name is Robert Kaleel. I am the Manager of the Air Quality Planning Section in the Bureau of Air at the Illinois Environmental Protection Agency (Illinois EPA). I have previously testified in this rulemaking. My testimony today is intended to update the Board on recent developments affecting or related to this proposal.

The Illinois EPA has continued to work with potentially affected industries to address some of the concerns and issues raised at the previous hearing. The Illinois EPA anticipates filing a motion to amend its proposal prior to the public hearing scheduled on February 3, 2009, to address concerns raised at the previous hearing or to reflect agreements between the Illinois EPA and stakeholders. I will highlight some of the expected amendments to the proposal.

In response to several comments that the proposed implementation date of May 1, 2010 would not allow enough time for industries to reasonably comply with the requirements of the rule, the Illinois EPA is recommending three changes. First, the Illinois EPA recommends that the compliance date in Sections 217.152, 217.155, 217.164, 217.184, 217.204, 217.224, 217.244, and 217.344 of Part 217 be extended until January 1, 2012, to allow industries enough time to plan and implement the measures needed to comply. Second, recognizing the unique role of petroleum refineries in the region's economy, the Illinois EPA is recommending that the compliance date for refineries coincide with already planned maintenance turnarounds to avoid unplanned shut-downs and potential disruptions to the region's fuel supply. Third, in response to concerns about the availability of continuous emissions monitoring system (CEMS) equipment, the Illinois EPA recommends extending the compliance date for CEMS for a period of three years after the effective date of this rule. For refineries with potentially later compliance dates, CEMS would be required by the compliance date for the emissions limitations contained in the rule. For other industries with compliance dates prior to the CEMS compliance date, the Illinois EPA recommends that compliance be determined through the testing and reporting requirements under Sections 217.156 and 217.157 of Part 217.

The Illinois EPA continues to discuss other issues raised by stakeholders in this rulemaking, and will continue to do so. Illinois EPA is working with US Steel regarding its concerns about emission limits for its reheat furnaces and boilers. We are also working with ArcelorMittal USA regarding concerns about the emission limits for its reheat furnace. We are discussing with Saint-Gobain Containers, Inc., the appropriate regulatory language to address its comment provided to the Board prior to the last hearing. It is our understanding that Saint-Gobain Containers, Inc., will either comply with the requirements of this proposal by the compliance date recommended by Illinois EPA, or agree to more stringent requirements to be implemented by 2014. We hope to agree on the revised regulatory provisions prior to the third hearing to allow Saint-Gobain Containers, Inc., the flexibility to comply with the more stringent requirement at the later date. The Illinois EPA is also working with Midwest Generation and ConocoPhillips to try to resolve some of the concerns raised during this rulemaking. Again it is hoped that these issues will be resolved prior to the next hearing.

I would also like to update the Board on some recent developments that have been mentioned during this rulemaking. On December 16, 2008, the Illinois EPA held a public hearing to take comments on its draft attainment demonstration for Chicago for the 1997 8-hour ozone standard, and its draft maintenance plan. The maintenance plan is intended to provide continued attainment of the ozone standard after the area has been redesignated to attainment. Per the Board's request, the Illinois EPA is filing the associated documents, in conjunction with this testimony, as part of this rulemaking. Since the primary technical support for the attainment demonstration was prepared by the Lake Michigan Air Directors Consortium (LADCO), the Illinois EPA requested that LADCO's Executive Director, Mr. Michael Koerber, provide testimony and appear at hearing to discuss the key findings contained in the LADCO technical support document. The Illinois EPA continues to maintain, however, that modeling did not play a role in the development of this NOx RACT proposal.

On December 23, 2008, the United States Court of Appeals for the District of Columbia issued its decision regarding the Clean Air Interstate Rule (CAIR). *North Carolina v. EPA,* No. 05-1244, 2008 WL 5335481 (D.C. Cir. Dec. 23, 2008). The Court's decision to remand the rule back to United States Environmental Protection Agency (USEPA) means that the CAIR rule remains in effect while USEPA works to correct deficiencies identified by the Court. As of January 1, 2009, the requirements of the NOx SIP Call have been replaced by the CAIR. Since the Board has already adopted, and USEPA has approved, regulations that comply with CAIR for electric generating units (EGUs) in Illinois, the Illinois EPA is developing revisions to the Illinois CAIR rule to sunset the provisions of the NOx SIP Call. These revisions will be submitted to the Board in the near future. Illinois must also correct its CAIR rule to ensure that non-EGUs affected by the NOx SIP Call meet the emissions budget contained in the NOx SIP Call even though Illinois did not opt to include non-EGUs in the CAIR trading program. The Illinois EPA is also developing a regulatory proposal to resolve this deficiency and hopes to submit this proposal to the Board in the near future.

On December 22, 2008, the USEPA designated areas throughout the United States, including areas in Illinois, as nonattainment for the 24-hour $PM_{2.5}$ air quality standard established in 2006. Areas in Illinois that have been designated as nonattainment include both Chicago and the Metro-East, the same areas designated previously as nonattainment for the annual $PM_{2.5}$ standard. Illinois must develop an attainment plan and adopt control measures needed to attain the 24-hour $PM_{2.5}$ standard within three years of the effective date of U.S. EPA's decision, and Illinois must attain the standards within five years of the effective date.

On December 16, 2008, the Illinois EPA held a public meeting in Chicago to present, and take comments on, its recommendation for establishing nonattainment area boundaries for the 2008 8-hour ozone standard. A similar meeting is planned for the Metro-East area on January 22, 2009. The Illinois EPA's initial proposal is for Illinois to recommend to USEPA to establish nonattainment boundaries for the 2008 standard that generally match the boundaries already established for the 1997 ozone standard. Illinois must provide recommendations to USEPA no later than March 12, 2009. USEPA is expected to finalize the nonattainment designations in 2010, initiating a new cycle of planning and regulatory development. Obviously such planning has not occurred yet for either the 2008 ozone standard or the 2006 $PM_{2.5}$ standard, so it is not possible to identify emissions reduction measures needed to attain these standards. As the Illinois EPA has presented testimony, however, NOx emission reductions will improve both ozone and $PM_{2.5}$ air quality since NOx is a precursor to both pollutants. The reductions provided by the subject NOx RACT proposal will help to meet the new standards and should help to address any future requirements to implement RACT for the new standards.

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TESTIMONY OF MICHAEL KOERBER

My name is Michael Koerber. I am the Executive Director for the Lake Michigan Air Directors Consortium (LADCO). I have a Bachelor of Science degree in Environmental Engineering from the University of Illinois at Chicago, and a Master of Science degree in Meteorology from the Pennsylvania State University. I have worked at LADCO for over 19 years, and have been in my present position since 1997. Previously, I worked as the Regional Meteorologist at USEPA, Region V. In that capacity, I was responsible for reviewing, overseeing, and conducting air quality studies for new source permits, state implementation plans, and other purposes.

As Executive Director for LADCO, I am responsible for overseeing and managing the day-to-day operations of the organization. The main purposes of LADCO are to provide technical assessments for and assistance to our member states (Illinois, Indiana, Michigan, Ohio, and Wisconsin) on problems of air quality, and to provide a forum for our member states to discuss air quality issues. LADCO is committed to an open and public process, as exemplified by our long-standing actions to share data and information, conduct regular public meetings, and welcome participation by outside parties (e.g., industry and citizen groups) on our committees.

During my career at LADCO, I have managed the identification and evaluation of emissions control strategies to address 1-hour ozone nonattainment in the Lake Michigan region as part of the Lake Michigan Ozone Study (LMOS), ozone transport problems in the eastern half of the U.S. as part of the Ozone Transport Assessment Group (OTAG), visibility impairment in Class I areas across the country as part of the Regional Planning Organization (RPO) process, and 8-hour ozone nonattainment, $PM_{2.5}$ nonattainment, and visibility impairment throughout the upper Midwest as part of the latest round of state air quality planning.

The purpose of my testimony is to summarize the results of technical analyses performed by LADCO and its contractors to support the development of State Implementation Plans (SIPs) for ozone, $PM_{2.5}$, and regional haze in the States of Illinois, Indiana, Michigan, Ohio, and Wisconsin. The analyses include preparation of regional emissions inventories and meteorological modeling for two base years (2002 and 2005), evaluation and application of regional chemical transport models, and analysis of ambient monitoring data. The results of these analyses are summarized in LADCO's report, "Regional Air Quality Analyses for Ozone, $PM_{2.5}$, and Regional Haze: Final Technical Support Document", April 25, 2008. This document is included in the Illinois Environmental Protection Agency's attainment demonstration for ozone, and which, I believe, has already been submitted to the Illinois Pollution Control Board in this rulemaking.

As described in the report, the first step in the technical analyses was to review ambient monitoring data to provide a conceptual understanding of the air quality problems. Key findings of the data review are as follows.

<u>Ozone</u>

Based on monitoring data for the period 2005-2007, there were about 20 sites in violation of the 1997 8-hour ozone standard of 85 parts per billion (ppb) in the upper Midwest, including eight sites in the Lake Michigan area. Based on the preliminary monitoring data for the period 2006-2008, there is only one site in the Lake Michigan area in violation of the 1997 8-hour ozone standard (i.e., Holland, Michigan). Historical ozone data show a steady downward trend over the past 15 years, especially since 2001-2003, due likely to federal and state emission control programs.

Ozone concentrations are strongly influenced by meteorological conditions, with more high ozone days and higher ozone levels during summers with above normal temperatures.

Inter- and intra-regional transport of ozone and ozone precursors affects many portions of the five LADCO states, and is the principal cause of nonattainment in some areas far from population or industrial centers. As I discuss below, the source region with the largest contribution on high ozone days in Holland, Michigan is northeastern Illinois.

$\underline{PM_{2.5}}$

Based on monitoring data for the period 2005-2007, there were 30 sites in violation of the current (1997 version) annual $PM_{2.5}$ standard of 15 $\mu g/m^3$ in the upper Midwest, including five sites in the Chicago area. Nonattainment sites are characterized by an elevated regional background (about 12 – 14 $\mu g/m^3$) and a significant local (urban) increment (about 2 – 3 $\mu g/m^3$). Historical $PM_{2.5}$ data show a slight downward trend since deployment of the $PM_{2.5}$ monitoring network in 1999.

$PM_{2.5}$ concentrations are also influenced by meteorology, but the relationship is more complex and less well understood compared to ozone.

On an annual average basis, $PM_{2.5}$ chemical composition consists mostly of sulfate, nitrate, and organic carbon in similar proportions.

The second step in the technical analyses was to apply air quality models to support the regional planning efforts. The modeling was conducted in accordance with USEPA's air quality modeling guidance. Two base years were used in the modeling: 2002 and 2005. Basecase modeling was conducted to evaluate model performance (i.e., assess the model's ability to reproduce observed concentrations). This exercise was intended to build confidence in the model prior to its use in examining control strategies.

Future-year strategy modeling was conducted to determine whether existing ("on the books") controls would be sufficient to provide for attainment of the standards for ozone and $PM_{2.5}$ and if not, then what additional emission reductions would be necessary for attainment.

The third step in the technical analyses was to provide an attainment demonstration based on the primary (guideline) modeling and supplemental analyses (i.e., other modeling, examination of historical trends in emissions and monitored data, and special data analyses). Such a "weight of evidence" approach for the attainment demonstration is recommended by USEPA's modeling guidance. It should be noted that among the other modeling analyses considered for inclusion in our weight of evidence demonstration was modeling conducted by a contractor for the Five States Stakeholders, which includes the Midwest Ozone Group (a consortium of Midwest utilities). Because this analysis relied on several assumptions that were counter to USEPA's modeling guidance (and, as such, would not be acceptable to USEPA as part of a valid modeled attainment demonstration), we were unable to include this other modeling in our weight of evidence demonstration.

Based on the modeling and supplemental analyses, the LADCO report provides the following conclusions.

> First, existing controls are expected to produce significant improvement in ozone and $PM_{2.5}$ concentrations.
>
> Second, the choice of the base year affects the future-year model projections. A key difference between the base years of 2002 and 2005 is meteorology. Both are technically valid, although 2002 was more ozone conducive than 2005. The choice of base year as the basis for the SIP is a policy decision (i.e., how much safeguard to incorporate).

Third, modeling suggests that most sites are expected to meet the 1997 8-hour ozone standard by the applicable attainment date, except for sites in western Michigan. The highest ozone concentration site in western Michigan is Holland, Michigan. It is relevant to note that USEPA is required to address ozone nonattainment problems in western Michigan, pursuant to the Energy Policy Act of 2005. On January 21, 2009, USEPA is expected to release a report entitled "Western Michigan Ozone Study." The report is expected to conclude that the 1997 8-hour ozone standard will be met at most, but not all, sites in western Michigan by the applicable attainment date (i.e., by 2009) – the one site projected to remain in nonattainment is Holland. Shoreline areas in western Michigan, such as Holland, are affected by inter-regional transport and intra-regional transport, especially from Illinois (e.g., modeling estimates that 1/4 of the high ozone concentrations in Holland are from northeastern Illinois emissions).

Fourth, modeling suggests that most sites are expected to meet the current annual $PM_{2.5}$ standard by the applicable attainment date, except for sites in Detroit, Cleveland, and Granite City. The regional modeling for $PM_{2.5}$ does not include air quality benefits expected from $PM_{2.5}$ controls from local industries. States are conducting local-scale analyses and will use these results, in conjunction with the regional-scale modeling, to support their attainment demonstrations for $PM_{2.5}$.

These findings of residual nonattainment for ozone and $PM_{2.5}$ are supported by monitoring data for the period 2005 – 2007, which show significant nonattainment in the region (e.g., peak ozone design values on the order of 90 – 93 ppb, and peak $PM_{2.5}$ design values on the order of 16 - 17 $\mu g/m^3$). Because existing controls will not provide sufficient emission reductions in the next couple of years, additional emission reductions are necessary to provide for attainment at all sites.

Attainment at most sites by the applicable attainment date is dependent on actual future year meteorology (e.g., if the weather conditions are similar to [or less severe than] 2005, then attainment is likely) and actual future year emissions (e.g., if the emission reductions associated with the existing controls are achieved, then attainment is likely). If either of these conditions is not met (e.g., if the weather conditions are similar to 2002), then attainment may be less likely.

Modeling suggests that the new (2006 version) $PM_{2.5}$ 24-hour standard and the new (2008 version) ozone standard will not be met at several sites in the Lake Michigan region, even by 2018, with existing controls.

January 16, 2009

Western Michigan Ozone Study: Draft Final Report (excerpt)

Two figures from the Draft Final Report are presented here to provide information on the contribution from various source regions to high ozone concentrations in Holland, Michigan (site with highest monitored ozone levels in western Michigan).

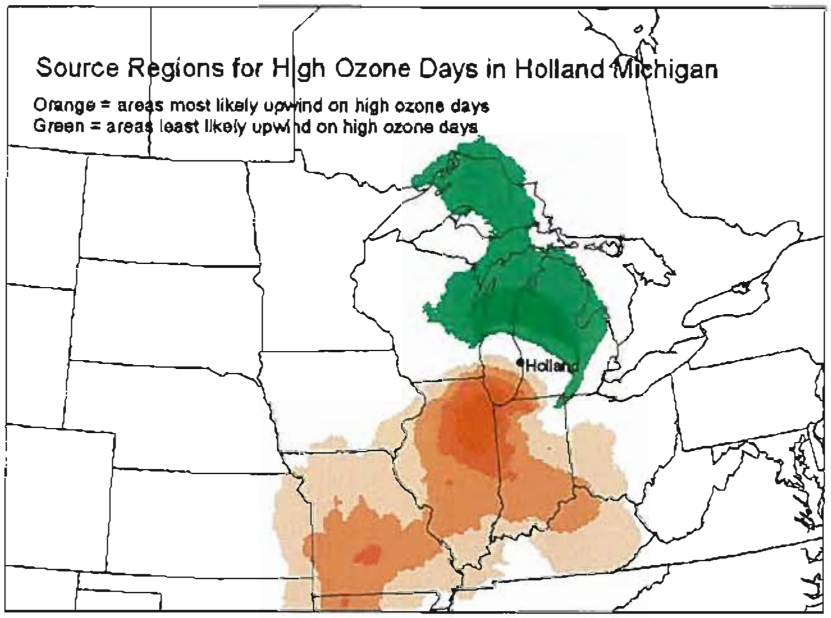

Figure 12. Monitor-based back trajectory plot for high ozone days in Holland, Michigan
Note: darker shading represents higher frequency (e.g., air is most likely to have passed through areas with dark orange shading

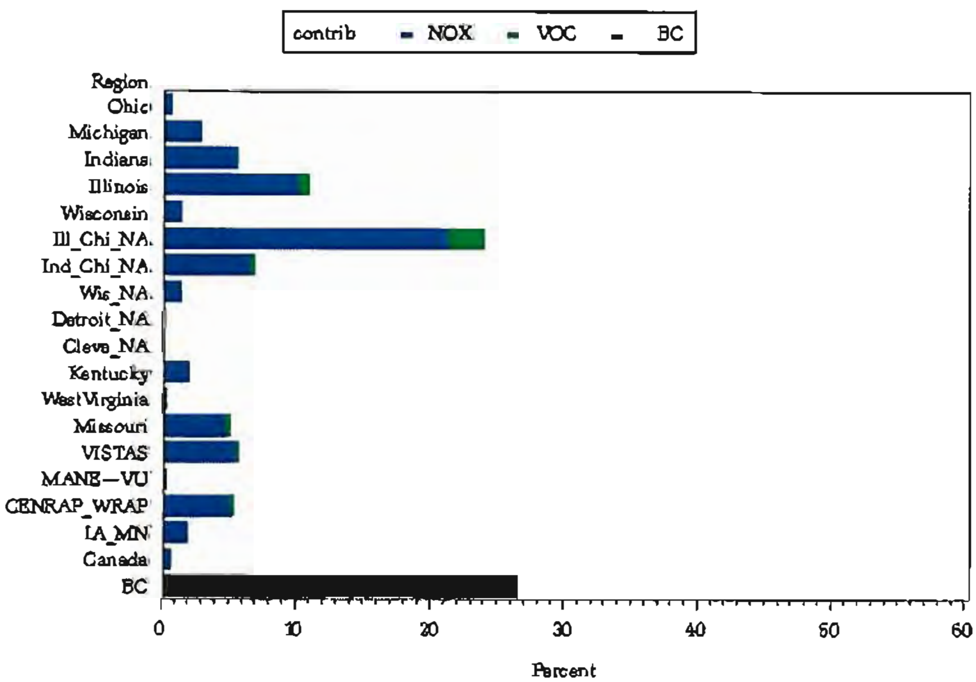

Figure 15. Model-based ozone source apportionment results for Holland, Michigan
Note: BC represents the contribution from the boundary conditions

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TESTIMONY OF JAMES E. STAUDT, Ph.D.

I, James E. Staudt, have been retained by the Illinois Environmental Protection Agency ("Illinois EPA") as an expert in this nitrogen oxides ("NOx") rulemaking addressing various source categories and Reasonably Available Control Technology ("RACT"). I have previously testified regarding this rulemaking in both pre-filed testimony and in person on October 14, 2008. I have also examined the testimony of witnesses for industries affected by the proposed rule during the hearing on December 9 and 10, 2008. In response to this testimony by industry, I have prepared the following rebuttal testimony.

Summary of Testimony

It is my opinion that ConocoPhillips and United States Steel ("US Steel") were not convincing in their arguments to increase the emissions rates proposed in the rule. In support of their argument for higher emission limits, ConocoPhillips cited costs estimated from Ultra Low NOx Burner ("ULNB") projects associated with ConocoPhillips' Consent Decree that are far above the costs (about 15 to 20 times) reported for similar technology by numerous independent, publicly available studies. However, to date, none of the supporting information for these cost estimates has been made available for examination and ConocoPhillips could not provide many important details on these estimates when asked at the December 9 hearing. With regard to US Steel, information it provided was found to have errors and contradictions and was missing key pieces of information, as I will describe in more detail in the following testimony. Using more consistent information, even using US Steel's presumed NOx emission rates for various fuels, it appears that the currently proposed NOx emission rate for Boilers 11 and 12 is a reasonable one. With regard to the reheat furnaces, US Steel has not, to date, provided adequate back-up information – such as the proposal from the burner supplier – that is necessary to evaluate the information they did provide. This information was requested at the hearing, but has not yet been provided (Transcript of December 10, 2008, hearing, ("12/10/08 TR") p. 31, lines 11-20). For these reasons I do not believe either ConocoPhillips or US Steel provided convincing information in support of their arguments for higher NOx emission rates.

Comments on ConocoPhillips Testimony

ConocoPhillips' argument largely relies on Mr. Dunn's assertion that the costs of NOx controls that could meet the proposed limits are well above the cost range targeted by the rule. Mr. Dunn stated that as a result of the proposed emission rates ConocoPhillips is "looking at least at low NOx burners probably with FGR, flue gas recirculation, or ultra low NOx burners" (Transcript of December 9, 2008, hearing ("12/9/08 TR"), p. 144, lines 5-7). Mr. Dunn testified that the proposed emission rates are well above what is achievable with ULNB (12/9/08 TR, p. 146, lines 2-13; p. 148, lines 2-21). Mr. Dunn also testified that the proposed rule does not require ULNB (12/9/08 TR, p. 143, lines 9-13). Moreover, according to the technical support document ("TSD"), emissions limits are consistent with those achievable with low NOx burners, and as noted above, Mr. Dunn cited low NOx burners as a possibility. So, facility owners have more options than just ultra low NOx burners. Mr. Dunn also admitted that ULNB could be used on a large unit to allow smaller units to average in with little or no effort (12/9/08 TR, p. 148, line 22 through p. 149, line 5). So, this is not a question of whether or not the emissions rates proposed in the rule are achievable. It is a question of whether the costs for necessary controls are within the range of RACT.

According to the TSD, which references numerous independent studies, both LNB and ULNB are well within the cost effectiveness range targeted by this rule, about $3000/ton of NOx removed. ULNB are reported in the TSD to cost in the range of about $1000/ton of NOx removed (TSD pages 43, 64, 65). In his pre-filed testimony, Mr. Dunn used a cost estimate of burners installed pursuant to a Consent Decree to argue that ULNB are more expensive – in the range of $15,000 to $20,000/ton of NOx removed (Pre-filed Testimony of David Dunn, p. 7-12). However, Mr. Dunn could not explain why the cost effectiveness estimate ConocoPhillips developed for ULNB retrofits was so much higher than what is widely reported in literature from LADCO, USEPA, and others, and as documented in the TSD (12/9/08 TR, p. 153, lines 15-20).

It is important to point out that a dollar per ton of NOx removed estimate entails many assumptions that can greatly skew the estimate in one direction or another. There are assumptions regarding what should be included in the capital cost, the amortization of that cost to a yearly capital charge, what is assumed as the initial versus the final emissions levels, how and if overhead should be accounted for, insurance costs, taxes, assumptions for allowance for spare parts, maintenance, the cost of other routine maintenance that may be performed at the same time as the project, etc. Many of these are outlined in USEPA's Air Pollution Control Cost Manual (http://www.epa.gov/ttn/catc/products.html#cccinfo). As a result, by adjusting the assumptions, it is possible to arrive at a wide range of dollar per ton of NOx removed cost estimates for any given project. Because of this, examination of the assumptions is important for interpreting such a cost estimate.

Due to the large difference in the cost estimates between those presented by Mr. Dunn and those that have been widely published in numerous independent studies as presented in the TSD, there must be something unique about the specific project or the assumptions ConocoPhillips used to craft the dollar per ton cost effectiveness estimate the company presented in Mr. Dunn's pre-filed testimony. The Illinois EPA attempted to learn what would account for this difference during hearing, such as inclusion of other "routine maintenance" items or what assumptions were used to craft this estimate of dollar per ton. When asked about assumptions of the cost effectiveness estimate, Mr. Dunn admitted that the cost estimate included significant indirect costs. Furthermore, he could not describe many of the key underlying assumptions used to craft the dollar per ton estimate (12/9/08 TR, p. 159, lines 2-20; p. 161, lines 8-11). The underlying cost analysis has not been provided to the Board to date. In addition, due to claims that the "detailed" cost estimate is privileged, it is not clear whether the Illinois EPA can allow me, as an Illinois EPA contactor, to examine and comment on it (12/9/08 TR, p. 151, lines 4-10; p. 154, lines 18-20).

Considering that ConocoPhillips' cost estimates are so inconsistent with numerous independent estimates that have been widely published, and that the company will not subject the data to public scrutiny, it is my opinion that the company's cost information should not be considered. The Illinois EPA has relied on independent and publicly verifiable estimates, as documented in the TSD, and this information demonstrates that the proposed emissions limits are achievable with available technology at a cost that is within the range of RACT.

Comments on US Steel Testimony

US Steel appears to have reached its conclusion regarding its approach to reducing NOx emissions from boilers 11 and 12 without a thorough evaluation of the technologies that are available. Moreover, there are errors and inconsistencies in the data presented. In justifying its conclusions, US Steel made several assertions without any supporting data or calculations. Upon examination I found these assertions to be erroneous. In the following paragraphs I will examine these assertions as well as errors or inconsistencies in calculations that were presented.

Assertions by US Steel Found to be Erroneous

US Steel's consultant, Mr. Stapper, ruled out low NOx burners and selective non-catalytic reduction ("SNCR") as viable NOx control options, although he made no effort to contact suppliers of these technologies to determine the suitability of these technologies (12/10/08 TR, p. 39, line 16 through p. 40, line 3; p. 48, line 19 through p. 49, line 17). Despite having no information from burner suppliers, Mr. Stapper testified that there were no low NOx burners that would apply to the multi-fuel application of Boilers 11 and 12 (12/10/08 TR, p. 19-20, 39). Moreover, he testified that burners would cause dangerous conditions that could result in furnace explosions (12/10/08 TR, p. 20, lines 14-17). These assertions, as will be demonstrated, are incorrect.

While there are challenges to cofiring low BTU fuels such as Blast Furnace Gas with Natural Gas or other higher BTU fuels, this can and has been done. Mr. Stapper relied solely on his own experience without consulting any burner suppliers or boiler manufacturers. Mr. Stapper made it clear that it is URS's normal practice not to contact technology suppliers for information (12/10/08 TR, p. 49, lines 8-17). As a result, it is uncertain whether Mr. Stapper is using the most up-to-date technical information. On the other hand, in developing the rule the Illinois EPA relied on independent sources of information available to the public.

In light of Mr. Stapper's testimony, which seemed to suggest that low NOx burners were both unsuitable and, in fact, dangerous to apply to Boilers 11 and 12 at the Granite City Works, I have since contacted burner suppliers to evaluate Mr. Stapper's assertions. In contrast to Mr. Stapper's testimony, Bloom Engineering, North American Burner, Coen and Hamworthy Peabody, all reputable burner suppliers, have stated that they supply burners that are capable of safely reducing the NOx from US Steel's boilers for the fuel conditions that US Steel projected. As for specific emissions rates, they could not confirm emission rates without a more careful examination of the boiler. However, some of them provided ranges based upon the burners that they offer. Information from these companies is provided in Exhibit 1 and as attachments to this testimony. These companies have experience in supplying such burners on other steel mill and mixed fuel applications. In fact, multi-fuel burners are not as rare as Mr. Stapper asserted in his testimony and are commonly used in the steel industry as well as in the refining industry. Refinery coking processes can also produce low BTU gases that are fired at the refinery. According to the Handbook of Petroleum Processing,[1] edited by D. S. J. Jones and Peter R. Pujado, Exxon Mobil's Flexicoke process produces a low BTU gas with a lower heating value of 127 Btu/SCF that is similar to the heating value of Blast Furnace Gas. This gas is fired at the refinery once sulfur bearing compounds are cleaned from the gas.

Mr. Stapper further testified that installing a circular low NOx burner on the tangentially fired (also referred to as "corner fired") Boiler number 11 would require complete reconstruction

[1] http://books.google.com/books?id=D6pb1Yn0vYoC&dq=Handbook+of+Petroleum+Processing&printsec=frontcover&source=bl&ots=XW2zZa1Qct&sig=nKh8rkyzFJmKLTX0_WZ7cmGB8_s&hl=en&sa=X&oi=book_result&resnum=8&ct=result#PPA453,M1

of the boiler (12/10/08 TR, p. 19). Mr. Stapper also testified that "Low NOx burners are generally circular burners designed for wall-fired applications" (12/10/08 TR, p. 19, lines 14-16). Mr. Stapper neglected to mention, however, that low NOx burners are available for corner fired burners, and he would not have made this oversight had he contacted burner suppliers or even conducted a simple Google search for "Tangential Low NOx Burners" (see http://www.coen.com/i_html/pdf/TFireLowNoxOilRef.pdf, which was the first item to come up on such a search). Coen, as well as other companies, sell low NOx burners or burner modifications for tangentially fired boilers that fire gas. These are burners that are installed in the existing corner burner area and do not require reconstruction of the boiler. In response to my request for information, the Coen Company stated that they could supply low NOx burners for this application (Boilers 11 and 12).

Mr. Stapper also testified that there would be risks of furnace explosions with the use of Low NOx burners (12/10/08 TR, p. 20, lines 11-17) and stated that "There are no low NOx burners that could safely be installed on boiler 12 to burn blast furnace gas and Coke oven gas" (12/10/08 TR, p. 39, lines 13-15). He did not provide any data or calculations to support this assertion and did not contact any burner suppliers to check on this. (12/10/08 TR, p. 39, lines 16-20) There is always a risk of a boiler explosion, regardless of the burner type or fuel. Because a boiler explosion is such a catastrophic event, under the National Fire Protection Association (NFPA) codes, all boilers must be equipped with instrumentation and controls to avoid such events, which is why these events are, thankfully, so rare. In contrast to Mr. Stapper's assertion that such burners are dangerous, which he did not support with any information from technology suppliers or with any engineering calculations, four reputable burner suppliers have stated that they can supply low NOx burners for this application.

Mr. Stapper further testified to the issues of concern regarding the use of SNCR (12/10/08 TR, p. 44, line 1 through p. 46, line 17). However, I had already testified that each of these concerns had been addressed in application of SNCR on hundreds of facilities that are in commercial operation. Although it is understandable for companies to raise concerns, the suppliers of this technology have shown in the hundreds of industrial installations that the technology is available and works in multi-fuel industrial boiler applications, as well as a wide array of other applications, which is supported by the TSD and supporting documents in the original submittal. Mr. Stapper admitted that he did not contact a single supplier of SNCR technology for technical input, and that URS has never supplied an SNCR system (12/10/08 TR, p. 47, line 20 through p. 48, line 4). As a result, his testimony regarding SNCR, like his testimony regarding low NOx burners, amounts only to his assertions without adequate supporting data.

In Mr. Stapper's hearing testimony, he discussed the John Zink Rapid Mix Burner (12/10/08 TR, p. 51, line 6 through p. 53, line 17). He testified that the Rapid Mix Burner achieves 0.01 lb/MMBtu and that it "works only in a very narrow niche of industrial boiler applications" (12/10/08 TR, p. 52, line 8-10). However, as he stated, this technology is not required by the rule (12/10/08 TR, p. 54, line 11-12). Moreover, the Illinois EPA's proposed limits for boilers are ***eight times*** the emission rate that Mr. Stapper testified the Rapid Mix Burner is capable of. Therefore, the Rapid Mix Burner, or other ultra low NOx burners from other manufacturers, may be used to comply with the proposed rule where the owner deems this the appropriate technology. However, because the proposed limits are far in excess of what ultra low NOx burners are capable of, facility owners have many more options at their disposal than the Rapid Mix Burner to achieve the proposed emission rates.

Errors or Inconsistencies in US Steel Calculations or Assumptions

In addition to making several assertions without any supporting information, US Steel provided information regarding emissions estimates that, upon examination, were found to be incorrect or inconsistent. I will examine a few of these here.

US Steel did not provide back up for the assumptions that underlie its recommended emission rates for Boilers 11 and 12 that are shown in Exhibit A to Mr. Siebenberger's pre-filed testimony. US Steel did not provide any test data or other supporting information. Calculations were not shown to explain the large difference between the presumed emission rate for coke oven gas (COG) versus that of natural gas (NG). Supporting information for Exhibit A was requested, but to date has not yet been provided. (12/10/08 TR, p. 28, line 22 - p. 29 line 7)

The principal reason coke oven gas has higher NOx emissions than natural gas is the hydrogen cyanide ("HCN") present in the gas (Pre-filed Testimony of Larry Siebenberger, p. 5), shown on the gas analysis provided by US Steel to the Illinois EPA as 0.185% (mole weighted) without the COG scrubber and 0.013% (mole weighted) with the COG scrubber.[2] However, even if it is conservatively assumed that 100% of the nitrogen in the HCN of the COG is oxidized to form NOx, it would not explain the increased NOx URS assumed for scrubbed COG over NG. URS assumed in Exhibit A to Mr. Siebenberger's pre-filed testimony that with the COG scrubber in service, NG produces emissions of 0.084 lb/MMBtu and COG produces 0.144 lb/MMBtu, a difference of 0.06 lb/MMBtu. No basis for these emission estimates, such as test

[2] Fuel analysis provided by US Steel to the Illinois EPA shows that, on a mole weight basis, COG has 52% hydrogen, 26% methane, 5% CO, 2% ethylene and most of the rest are incombustibles (nitrogen, water, CO_2). Pure hydrogen would potentially increase the flame temperature and the NOx relative to natural gas. But for COG, which contains significant amounts of moisture and non-combustibles, and only 52% hydrogen, we would not expect an increase in thermal or prompt NOx generation over natural gas, likely even a decrease. This is supported by data generated by Waibel and others on NOx generation from gas mixtures. ADVANCED BURNER TECHNOLOGY FOR STRINGENT NOx REGULATIONS, R . T. WAIBEL , PHD ., D. N. PRICE AND P. S . TISH, M.L. HALPRIN, PRESENTED AT THE AMERICAN PETROLEUM INSTITUTE MIDYEAR REFINING MEETING JOINT MEETING OF THE SUBCOMMITTEE ON HEAT TRANSFER EQUIPMENT, ORLANDO, FL, MAY 8 , 1990, *www.johnzink.com/elibrary/DownloadFile.aspx?fileguid=8e219961-ec78-410f-bb6754dd871d2d47*

data, was provided by US Steel. Based upon data shown by Waibel and others for NOx from various gas mixtures,[3] excluding the effect of fuel bound nitrogen, one would expect a similar NOx level from COG as natural gas. So, the 0.06 lb/MMBtu difference in NOx estimated by URS must be predominantly NOx from fuel bound nitrogen. However, based on US Steel's COG fuel analysis, I estimate that if all of the nitrogen in the HCN in the cleaned COG oxidized to NOx, this would increase NOx by only about 0.03 lb/MMBtu – half that estimated by URS for US Steel (see Table 1, attached). Furthermore, in actual practice, significantly less than 100% of the fuel bound nitrogen actually gets converted to NOx, particularly if low NOx burners or other combustion controls are used. So, the difference in the emission rate should be less than the 0.03 lb/MMBtu contributed by 100% HCN oxidation. Additionally, URS's estimate in Exhibit A of Mr. Siebenberger's pre-filed testimony shows a difference between NG and COG without the scrubber to be 0.252 lb/MMBtu (0.336-0.084 lb/MMBtu), roughly 59% of what is theoretically predicted for 100% conversion of fuel bound nitrogen to NOx (0.252/0.422 - see Table 1 for estimate of fuel bound NOx from unscrubbed COG). It appears that URS has overestimated the emissions level of scrubbed COG. Therefore, URS may have made a mistake in its calculations for NOx from the various gases, which it has not yet provided for the Illinois EPA or the Board to review.

Mr. Siebenberger also testified that there is an error in Exhibit A of his pre-filed testimony. Exhibit A of his pre-filed testimony does not have the correct mix of gases for conditions where the blast furnace is out of service (12/10/08 TR, p. 28, line 17-21). Instead of firing 60% COG and 40% NG when the Blast Furnace is not in service as stated on page 2 of Exhibit A, the boilers would fire 60% NG and 40% COG. Since this error overestimates the

[3] *Id.*

amount of COG that would be fired and underestimates the amount to NG that would be fired under this condition, the impact of this estimate would be to overestimate the NOx emission rate for Boilers 11 and 12.

I attempted to reproduce the Controlled case and Base Case results shown in Exhibit A of Mr. Siebenberger's pre-filed testimony using the assumptions that are shown in that exhibit and his testimony. I arrived at different results for both tons of NOx emitted and the emission rate. The Controlled case calculations were performed two ways: one assuming 60% COG and 40% NG during the Furnace Down period (see Table 2, attached), and one assuming 40% COG and 60% NG during the Furnace Down period (see Table 3, attached). Neither case produced results that corresponded with the annual NOx emissions rate or total NOx shown in Exhibit A. I was able to reproduce the "Base Case" calculations for emissions (see Table 4, attached), so it appears that I am using the same approach as used by US Steel in Exhibit A. Therefore, while the Illinois EPA is not stating that it agrees with the assumptions of US Steel's analysis, the assumptions that US Steel uses do not appear to produce the results shown in Exhibit A for the controlled case.

The rate that US Steel requests of 0.113 lb/MMBtu that was developed from these assumptions does correspond with the estimated Ozone Season emission rate using the original assumptions stated in Mr. Siebenberger's pre-filed testimony. However, this higher NOx emission rate for the Ozone Season is an anomaly of the assumption to shut down the COG scrubber during the Ozone Season and the fact that he overstated the amount of COG fired when BFG was unavailable. In light of the importance of keeping NOx emissions low during the Ozone Season, it would certainly make more sense to have the COG scrubber serviced at other times. The annual total NOx emissions and the rate that I calculated in attempting to reproduced

Exhibit A of Mr. Siebenberger's pre-filed testimony, however, do not correspond with what is shown in Exhibit A. So, the analysis as well as the assumptions associated with the Controlled emission levels of Mr. Siebenberger's Exhibit A appear to be incorrect.

Regarding the "Baseline" emissions levels shown in Exhibit A, these are incorrect because the assumptions are incorrect. As Mr. Siebenberger stated on page 4 of his pre-filed testimony, Boilers 1-10 will be shut down as part of the Cogen project improvement. This will cause more COG to be burned in Boilers 11 and 12. So, the historical baseline NOx emissions for Boilers 11 and 12 are not as great as assumed in the Baseline calculation for Exhibit A. More importantly, US Steel did not take into account in their Baseline calculation the fact that the COG desulfurization system would be in operation. US Steel should certainly have assumed the reduced COG NOx level for the COG resulting from the desulfurization system, because this is definitely going to be the case regardless of the proposed NOx RACT rule. Since US Steel assumed in its Baseline the higher NOx levels for COG without desulfurization at all times, its estimate of the Baseline is grossly overstated and the reduction in emissions shown on Exhibit A is therefore grossly overstated.

Moreover, the COG usage will likely be less for the boilers than assumed in Exhibit A due to limitations on availability of COG. According to a January 8, 2009, e-mail sent from Mr. Siebenberger to Mr. Kaleel, the available COG is 3,830,400 million Btu/yr. US Steel did not provide information on how much COG is fired in the reheat furnaces, except that its emission rate for the reheat furnaces was based on the "maximum combusted blend of desulfurized coke oven gas and non-desulfurized coke oven gas." The reheat furnaces have the heat input capacity to accept 100% of the COG. If US Steel opted to use all of the available COG in the reheat furnaces, then none of it would be available to boilers 11 and 12. If it is assumed that the reheat furnace burners obtained only 40% of their heat input from COG, and using the heat inputs for the furnaces shown in Exhibit B of Mr. Siebenberger's pre-filed testimony, only 963,740 million Btu of COG will be available to the boilers per year (see Table 5, attached). This leaves a shortfall in availability of COG between 400,000 and 500,000 million Btu per year versus what appears to have been assumed by US Steel in developing Exhibit A of Mr. Siebenberger's pre-filed testimony. This is a significant overestimate of the amount of COG that is actually available, which results in a significant overestimate of the amount of NOx generated from this fuel. It is likely that the "excess" COG would have to be replaced with natural gas, which would further reduce emissions, since natural gas has a lower NOx content than COG. As a result, US Steel has overstated the controlled NOx emission rate.

I re-estimated the rate using US Steel's assumptions, but corrected per Mr. Siebenberger's testimony and corrected to account for the actual availability of COG and 40% COG firing in the reheat furnaces (making COG firing in the boilers less than 40%). The results are shown in Table 6, attached. As shown, using US Steel's estimates for emissions rates, which as discussed earlier are probably high for COG, I arrive at an annual rate of 0.091 lb/MMBtu – which is less than the rate recommended by US Steel. Correcting the COG NOx rate for the maximum amount of fuel NOx results in an annual rate of 0.084 lb/MMBtu – very close to the Illinois EPA's proposed rate (see Table 7, attached). It is possible that all of the COG could be used in the reheat furnaces, leaving none for the boilers, since the available COG has roughly 53% of the heat input available for the reheat furnaces. As shown in Table 8, attached, if all of the COG is fired in the reheat furnaces, leaving none for Boilers 11 and 12, the annual emission rate is 0.075 lb/MMBtu, which is less than the proposed rule.

I am not stating that any one of the emissions rates offered by URS for US Steel for Boilers 11 or 12 are "correct." In fact, I believe that they are conservatively high, especially since US Steel has not contacted any technology suppliers or even examined low NOx burners, which would reduce NOx further while keeping costs within the range of RACT. But, the data that US Steel provided in its fuel analysis and testimony show inconsistencies, and no back up calculations or test data were provided. I have shown, by reproducing US Steel's calculations, that US Steel apparently made several errors in assumptions and in calculations. Therefore, US Steel's emission estimates for Boilers 11 and 12 should be regarded with caution, and the Board should not consider them until such time as more reliable information is available from US Steel.

US Steel claims that its approach for NOx control on Boilers 11 and 12 was the result of an optimization study. This study was requested for examination at hearing (12/10/08 TR, p. 41, lines 12-23). To date, this has not yet been produced for the Illinois EPA or Board to examine.

US Steel's emission rates for the reheat furnace were also provided without any supporting backup. The Illinois EPA requested this additional information at the hearings. On page 7 of his pre-filed testimony, Mr. Siebenberger stated that the limit was "based on the burner manufacturer's warranty and the maximum combusted blend of desulfurized coke oven gas and non-desulfurized coke oven gas (during desulfurized maintenance outage) with natural gas." Exhibit A states that these are developed by Bloom Manufacturing and Mr. Siebenberger testified that he believed that they were guaranteed values. (12/10/08 TR, p. 34, lines 20-23) The Illinois EPA has asked to see the technical proposal from Bloom and URS's supporting calculations. Once we receive that information, it will enable us to examine the emissions rate requested by US Steel for the reheat furnaces and also examine how much COG will actually be available for use in Boilers 11 and 12.

To summarize, I am not convinced that US Steel or its consultant, URS, have made a complete and diligent effort to explore all options for reducing NOx at the Granite City Works. Numerous errors were identified in their analysis that would have been avoided had they or their consultant contacted technology suppliers or performed a diligent evaluation of independent information. Further, Mr. Stapper made numerous assertions, without supporting data, which in some cases appear to have been intended to shock the Board rather than to inform them (especially the testimony regarding furnace explosions). There also appear to be calculation errors in their estimates of emissions, and there are errors in assumptions. Calculations were found to be inconsistent or inaccurate, and no back up was provided in support of estimates of NOx emission rates. It appears that US Steel expects the Board to take these estimates on faith.

As the Illinois EPA has repeatedly stated, it does not consider RACT any particular technology, but an emission rate that is achievable at a reasonable cost. The emissions rates that the Illinois EPA has proposed for gas-fired facilities are achievable at a reasonable cost using technologies such as low NOx burners or other combustion controls. This is supported by numerous independent studies that are publicly available and have been cited in the TSD.

Exhibit 1. Responses from Burner Suppliers

COEN

Hello Mr. Staudt,

I'm not sure how the Blast Furnace Gas is currently injected with existing burners, but Coen has experience supplying low NOx burner designs firing Natural Gas, Coke Oven Gas and Blast Furnace Gas. We use a "Low Btu Gas Scroll," which is an integral part of the burner, to fire the Blast Furnace Gas. In this case, the Natural Gas and Coke Oven Gas are each fired through their own set of gas injectors, but the Blast Furnace Gas, since it is injected directly into the burner through a scroll, acts like FGR (flue gas recirculation) to reduce the flame temperature and corresponding NOx emissions.

Your Coke Oven Gas analysis reveals a relatively low HCN level. In other words, the NOx contribution from this fuel bound nitrogen is refreshingly small. We would need a host of details regarding the boilers, firing rates, number of burners per boiler, burner spacing, etc., but assuming ambient combustion air, I would guess our burners would be in the range of 0.03 to 0.05 lb/MMBtu NOx when firing all three fuels at once (normal operation).

However, when the Blast Furnace Gas is down, you would have to run with some FGR to meet the same level of NOx emissions that you would have under normal operation.

If you have any questions, please call. If you can provide more details, we can take a closer look at each application.

Best regards,
Scott Krahn
Application Engineer
Industrial Retrofits Group
Coen Company, Inc.
1510 Tanforan Avenue,
Woodland, CA 95776
USA
Tel: 1 (530) 668-2100
Fax: 1 (530) 668-2171
Direct: 1 (530) 668-2119
http://www.coen.com

Hamworthy Peabody Combustion

Jim,

We have significant experience with low BTU, multi-fuel applications and have supplied both new and retrofit burners and ancillary equipment to steel mills throughout North America. I will forward our experience list with our response.

Please expand on your definition of "low NOx" as that means different things to different people. What levels are you striving for on each firing scenario?

Regards,

Scott Ingram
Regional Sales Manager
Hamworthy Peabody Combustion - Global Solutions, Local Delivery
Hamworthy Peabody Combustion Inc, 70 Shelton Technology Center, Shelton, CT 06484
Direct: (952) 476-5972 Fax: (952) 473-2639 Mobile: (320) 260-5807 Email:
singram@hamworthy-peabody.com
www.hamworthy-peabody.com
Offices: UK (Poole HQ, Birmingham, Glasgow), USA (Houston TX, Norwich NY, Shelton CT)
, Australia, Brazil, Canada, China, Dubai, France, Germany, India, Italy, Japan, S.Korea, Mexico, Netherlands, Poland, Spain

North American Manufacturing

In addition to the e-mail below, North American sent a letter that is provided as an attachment to this testimony

Jim,

Good to hear from you again.

We do have Ultra- Low NOx technology in the Magna Flame LE series.. I've copied in several NA key people so they have visibility of your request. The lean- premix technology is described in the attached bulletins. The concept is applicable to any gaseous fuel.

There's a few other application questions that we would need answered (available pressures, BOF and COG analysis, etc) to set expectations.. If you are around next week, I'll call to discuss.

Bill Tracey
+ 610-996-8005
billtracey@namfg.com

From: Jim Staudt [mailto:staudt@andovertechnology.com]
Sent: Friday, December 19, 2008 12:06 PM
To: Bill Tracey
Subject: NOx reduction at steel mill boilers
Bill,

I am looking to reduce NOx from two 225 MMBtu boilers at a steel mill that fires some natural gas, some coke oven gas, and some blast furnace gas. I was wondering if you had a low NOx burner that could handle these different fuels.

Normal Operation
35% Blast Furnace Gas
25% natural gas
40% Coke oven Gas

When Blast Furnace is down
40% natural gas
60% coke oven gas

Note that coke oven gas will be desulfurized. So, it will usually have most or all of HCN removed.

Also, one boiler is wall fired with two burners and the other is corner fired.

I'm trying to determine:
Ballpark, what kind of NOx levels you might be able to achieve (with/without FGR)
What your experience has been (experience list, if possible)

Thanks in advance for your help.

Best Regards,

Jim Staudt, Ph.D., CFA
office: 978-683-9599
mobile: 978-884-5510
staudt@AndoverTechnology.com

Bloom Engineering

From: Binni, Mike [mailto:mbinni@bloomeng.com]
Sent: Monday, December 22, 2008 5:06 PM
To: staudt@andovertechnology.com
Subject: Basic Idea of Predicted NOx emissions on BFG/NG/COG mixed fuel

Dear Jim:

In General with the limited information you have provide us. Under operating condition of 25% natural gas, 35% Blast Furnace Gas, and 45% COG using a Bloom 1030 Series burner on boiler we predict emissions of approximately 0.114Lbs/MM at nominal capacity of the burner. This is not a guarantee. This prediction would have to be confirmed based on information you would need to provide us. Such information would include Fuel analysis of each fuel, Air to Fuel Ratio Control System, Boiler Dimensions including burner wall dimensions among other information.

I have attached 1030 Series Burner sheets. This only shows a single fuel design. Multiply fuel design would will cause the burner to get bigger in size.

If you have any questions, please give me a call.

Very truly yours,
Bloom Engineering Company, Inc.
Michael J. Binni, P.E.
Product Manager of Dryer, Incinerator and Boiler Applications

Table 1. Calculation of fuel NOx from scrubbed and unscrubbed COG

		mole %		Mole % times MW		wt %							
	MW	unscrubbed	scrubbed	unscrubbed	scrubbed	unscrubbed	scrubbed						
H2S	34	0.603	0.037	0.20502	0.01258	1.783%	0.112%						
CO2	44	1.421	0.709	0.62524	0.31196	5.437%	2.776%						
CO2	28	4.975	4.950	1.393	1.386	12.114%	12.333%	as N		fuel bound N, lb/MMBtu		NO2, lb/MMBtu*	
CS	60	0.005	0.002	0.003	0.0012	0.026%	0.011%	unscrubbed	scrubbed	unscrubbed	scrubbed	unscrubbed	scrubbed
HCN	27	0.185	0.013	0.04995	0.00351	0.434%	0.031%	0.225%	0.016%	0.128	0.009	0.422	0.030
SO2	64	0.000	0.000	0	0	0.000%	0.000%					* assuming 100% conversion of	
CS2	76	0.010	0.010	0.0076	0.0076	0.066%	0.068%					fuel bound nitrogen to NOx	
Merc	48	0.000	0.000	0	0	0.000%	0.000%			HHV			
NH3	17	0.000	0.000	0	0	0.000%	0.000%			with scrubber			
CH4	16	26.295	26.163	4.2072	4.18608	36.588%	37.248%			Btu/scf	Btu/lbmole	Btu/lb	
Ethylene	28	2.132	2.121	0.59696	0.59388	5.191%	5.284%			524	199,120	17,718	
Ethane	30	0.622	0.619	0.1866	0.1857	1.623%	1.652%			without scrubber			
Propane	44	0.177	0.176	0.07788	0.07744	0.677%	0.689%			Btu/scf	Btu/lbmole	Btu/lb	
Isobutane	58	0.089	0.088	0.05162	0.05104	0.449%	0.454%			531	201,780	17,548	
n Butane	58	0.089	0.088	0.05162	0.05104	0.449%	0.454%						
Isocentane	72	0.089	0.088	0.06408	0.06336	0.557%	0.564%						
n Pentane	72	0.089	0.088	0.06408	0.06336	0.557%	0.564%						
Benzene	78	0.523	0.519	0.40794	0.40482	3.548%	3.602%						
Heavies	86	0.042	0.042	0.03612	0.03612	0.314%	0.321%						
H2S	2	52.145	51.885	1.0429	1.0377	9.070%	9.234%						
Nitrogen	28	4.962	4.938	1.38936	1.38264	12.082%	12.303%						
O2	32	0.283	0.281	0.09056	0.08992	0.788%	0.800%						
H2O	18	5.268	7.180	0.94824	1.2924	8.246%	11.500%						
Total		100.00	100.00	11.499	11.238								
	Note: Mole % and HHV data provided by US Steel to IL EPA												

Table 2. Calculation of Siebenberger Exhibit A

Boiler Analysis										
Calculation of Siebenberger Exhibit A Information										
Boiler heat input		450	million BTU/hr							
Annual	Ozone Season									
15	15	days BF rebuild				COG Scrubber Downtime		35	days per year	
55	23	days BF down (15% of time)								
2	2	days maintenance								
72	40	days total BF outage								
365	153	Total Days in Period								
293	113	Total Days Operating in Period								
Normal Operation										
Annual						Ozone Season				
Capacity Factor	days	Heat In (MMBtu)				Capacity Factor	days	Heat In (MMBtu)		
100%	293	3,164,400				100%	113	1,220,400		
	Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons			Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons
NG	25%	0.084	791,100	33.2		NG	25%	0.084	305,100	12.8
COG	40%	0.144	1,265,760	91.1		COG	40%	0.144	488,160	35.1
BFG	35%	0.0288	1,107,540	15.9		BFG	35%	0.0288	427,140	6.2
Total	100%		3,164,400	140.3		Total	100%		1,220,400	54.1
	Blended NOx Rate	0.08868					Blended NOx	0.08868		
Blast Furnace Downtime (no BFG available)										
Annual						Ozone Season				
Capacity Factor	days	Heat In (MMBtu)				Capacity Factor	days	Heat In (MMBtu)		
40%	72	311,040				40%	40	172,800		
	Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons			Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons
NG	40%	0.084	124,416	5.2		NG	40%	0.084	69,120	2.9
COG	60%	0.144	186,624	13.4		COG	60%	0.144	103,680	7.5
BFG	0%	0.0288	0	0.0		BFG	0%	0.0288	0	0.0
Total	100%		311,040	18.7		Total	100%		172,800	10.4
	Blended NOx Rate	0.12					Blended NOx	0.12		
COG Scrubber Maintenance										
Annual						Ozone Season				
35.00	days					35.00	days			
	COG Rate	0.34	lb/MMBtu				COG Rate	0.34	lb/MMBtu	
	Delta in COG Rate	0.19	lb/MMBtu				Delta in COG	0.19	lb/MMBtu	
	Heat In	151,200	million Btu				Heat In	151,200	million Btu	
	NOx delta	14.5	tons				NOx delta	14.5	tons	
Total for Period										
Annual						Ozone Season				
	Total NOx	173.5	tons				Total NOx	79.0	tons	
	Total Heat In	3,475,440	million Btu				Total Heat In	1,393,200	million Btu	
	NOx Rate	0.100	lb/MMBtu				NOx Rate	0.119	lb/MMBtu	
	Total NG In	915,516	million Btu				Total NG In	374,220	million Btu	
	Total COG In	1,452,384	million Btu				Total COG In	591,840	million Btu	
	Total BFG In	1,107,540	million Btu				Total BFG In	427,140	million Btu	

Table 3 Siebenberger Exhibit A with Corrected Gas for Blast Furnace Downtime

Boiler Analysis										
Calculation of Siebenberger Exhibit A Information - with corrected gas for blast furnace downtime										
Boiler heat input		450	million BTU/hr							
Annual	Ozone Season									
15	15	days BF rebuild				COG Scrubber Downtime		35	days per year	
55	23	days BF down (15% of time)								
2	2	days maintenance								
72	40	days total BF outage								
365	153	Total Days in Period								
293	113	Total Days Operating in Period								
Normal Operation										
Annual						Ozone Season				
Capacity Factor	days	Heat In (MMBtu)				Capacity Factor	days	Heat In (MMBtu)		
100%	293	3,164,400				100%	113	1,220,400		
	Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons			Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons
NG	25%	0.084	791,100	33.2		NG	25%	0.084	305,100	12.8
COG	40%	0.144	1,265,760	91.1		COG	40%	0.144	488,160	35.1
BFG	35%	0.0288	1,107,540	15.9		BFG	35%	0.0288	427,140	6.2
Total	100%		3,164,400	140.3		Total	100%		1,220,400	54.1
	Blended NOx Rate	0.08868					Blended NOx	0.08868		
Blast Furnace Downtime (no BFG available)										
Annual						Ozone Season				
Capacity Factor	days	Heat In (MMBtu)				Capacity Factor	days	Heat In (MMBtu)		
40%	72	311,040				40%	40	172,800		
	Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons			Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons
NG	60%	0.084	186,624	7.8		NG	60%	0.084	103,680	4.4
COG	40%	0.144	124,416	9.0		COG	40%	0.144	69,120	5.0
BFG	0%	0.0288	0	0.0		BFG	0%	0.0288	0	0.0
Total	100%		311,040	16.8		Total	100%		172,800	9.3
	Blended NOx Rate	0.108					Blended NOx	0.108		
COG Scrubber Maintenance										
Annual						Ozone Season				
35.00	days					35.00	days			
	COG Rate	0.34	lb/MMBtu				COG Rate	0.34	lb/MMBtu	
	Delta in COG Rate	0.19	lb/MMBtu				Delta in COG	0.19	lb/MMBtu	
	Heat In	151,200	million Btu				Heat In	151,200	million Btu	
	NOx delta	14.5	tons				NOx delta	14.5	tons	
Total for Period										
Annual						Ozone Season				
	Total NOx	171.6	tons				Total NOx	78.0	tons	
	Total Heat In	3,475,440	million Btu				Total Heat In	1,393,200	million Btu	
	NOx Rate	0.099	lb/MMBtu				NOx Rate	0.112	lb/MMBtu	
	Total NG In	977,724	million Btu				Total NG In	408,780	million Btu	
	Total COG In	1,390,176	million Btu				Total COG In	557,280	million Btu	
	Total BFG In	1,107,540	million Btu				Total BFG In	427,140	million Btu	

Table 4. Calculation of Siebenberger Exhibit A Baseline

Boiler Analysis										
Calculation of Siebenberger Exhibit A Information - Baseline										
Boiler heat input		450	million BTU/hr							
Annual	**Ozone Season**									
15	15	days BF rebuild				COG Scrubber Downtime		35	days per year	
55	23	days BF down (15% of time)								
2	2	days maintenance								
72	40	days total BF outage								
365	153	Total Days in Period								
293	113	Total Days Operating in Period								
Normal Operation										
Annual						**Ozone Season**				
Capacity Factor	**days**	**Heat In (MMBtu)**				**Capacity Factor**	**days**	**Heat In (MMBtu)**		
100%	293	3,164,400				100%	113	1,220,400		
	Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons			Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons
NG	25%	0.3	791,100	118.7		NG	25%	0.3	305,100	45.8
COG	40%	0.729	1,265,760	461.4		COG	40%	0.729	488,160	177.9
BFG	35%	0.066	1,107,540	36.5		BFG	35%	0.066	427,140	14.1
Total	100%		3,164,400	616.6		Total	100%		1,220,400	237.8
	Blended NOx Rate	0.3897					Blended NOx	0.3897		
Blast Furnace Downtime (no BFG available)										
Annual						**Ozone Season**				
Capacity Factor	**days**	**Heat In (MMBtu)**				**Capacity Factor**	**days**	**Heat In (MMBtu)**		
40%	72	311,040				40%	40	172,800		
	Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons			Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons
NG	40%	0.3	124,416	18.7		NG	40%	0.3	69,120	10.4
COG	60%	0.729	186,624	68.0		COG	60%	0.729	103,680	37.8
BFG	0%	0.066	0	0.0		BFG	0%	0.066	0	0.0
Total	100%		311,040	86.7		Total	100%		172,800	48.2
	Blended NOx Rate	0.5574					Blended NOx	0.5574		
COG Scrubber Maintenance										
Annual						**Ozone Season**				
35.00	days					35.00	days			
	COG Rate	0.73	lb/MMBtu				COG Rate	0.73	lb/MMBtu	
	Delta in COG Rate	0.00	lb/MMBtu				Delta in COG	0.00	lb/MMBtu	
	Heat In	151,200	million Btu				Heat In	151,200	million Btu	
	NOx delta	0.0	tons				NOx delta	0.0	tons	
Total for Period										
Annual						**Ozone Season**				
	Total NOx	**703.3**	**tons**				**Total NOx**	**286.0**	**tons**	
	Total Heat In	**3,475,440**	**million Btu**				**Total Heat In**	**1,393,200**	**million Btu**	
	NOx Rate	**0.405**	**lb/MMBtu**				**NOx Rate**	**0.411**	**lb/MMBtu**	
	Total NG In	**915,516**	**million Btu**				**Total NG In**	**374,220**	**million Btu**	
	Total COG In	**1,452,384**	**million Btu**				**Total COG In**	**591,840**	**million Btu**	
	Total BFG In	**1,107,540**	**million Btu**				**Total BFG In**	**427,140**	**million Btu**	

Table 5. Estimation of Available COG for boilers				
Reheat Furnace Heat In (Exhibit B)				
1	*1,654,304*	*million BTU/yr*	From Siebenberger Exhibit B	
2	*1,654,304*	*million BTU/yr*		
3	*1,654,304*	*million BTU/yr*		
4	*2,206,238*	*million BTU/yr*		
Total Annual HI	7,169,150	million BTU/yr		
40% heat input for COG	2,867,660	million BTU/yr		
Total available COG	3,830,400	million Btu/yr	from Siebenberger e-mail	
Balance available to	962,740	million Btu/yr		
Total Boiler COG heat in (based on Exhibit A)				
60% when BF down	1,452,384	million Btu/yr		
40% when BF down	1,390,176	million Btu/yr		
Shortfall				
60% when BF down	**489,644**	million Btu/yr		
40% when BF down	**427,436**	million Btu/yr		

Table 6. Siebenberger Exhibit A Corrected for Available COG with 40% firing of COG in reheat furnaces

Boiler Analysis

Calculation of Siebenberger Exhibit A Information - accounting for available COG with 40% COG firing in Reheat Furnace

Boiler heat input		450	million BTU/hr		
Annual	Ozone Season				
15	15	days BF rebuild	COG Scrubber Downtime	35	days per year
55	23	days BF down (15% of time)			
2	2	days maintenance			
72	40	days total BF outage			
365	153	Total Days in Period			
293	113	Total Days Operating in Period			

Normal Operation

Annual					Ozone Season				
Capacity Factor	days	Heat In (MMBtu)			Capacity Factor	days	Heat In (MMBtu)		
100%	293	3,164,400			100%	113	1,220,400		
	Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons		Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons
NG	37%	0.084	1,180,321	49.6	NG	37%	0.084	455,209	19.1
COG	28%	0.144	876,539	63.1	COG	28%	0.144	338,051	24.3
BFG	35%	0.0288	1,107,540	15.9	BFG	35%	0.0288	427,140	6.2
Total	100%		3,164,400	128.6	Total	100%		1,220,400	49.6
	Blended NOx Rate	0.0813				Blended NOx	0.0813		

Blast Furnace Downtime (no BFG available)

Annual					Ozone Season				
Capacity Factor	days	Heat In (MMBtu)			Capacity Factor	days	Heat In (MMBtu)		
40%	72	311,040			40%	40	172,800		
	Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons		Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons
NG	72%	0.084	224,882	9.4	NG	72%	0.084	124,934	5.2
COG	28%	0.144	86,158	6.2	COG	28%	0.144	47,866	3.4
BFG	0%	0.0288	0	0.0	BFG	0%	0.0288	0	0.0
Total	100%		311,040	15.6	Total	100%		172,800	8.7
	Blended NOx Rate	0.10062				Blended NOx	0.10062		

COG Scrubber Maintenance

Annual				Ozone Season			
35.00	days			35.00	days		
	COG Rate	0.34	lb/MMBtu		COG Rate	0.34	lb/MMBtu
	Delta in COG Rate	0.19	lb/MMBtu		Delta in COG	0.19	lb/MMBtu
	Heat In	151,200	million Btu		Heat In	151,200	million Btu
	NOx delta	14.5	tons		NOx delta	14.5	tons

Total for Period

Annual			Ozone Season		
Total NOx	158.8	tons	Total NOx	72.8	tons
Total Heat In	3,475,440	million Btu	Total Heat In	1,393,200	million Btu
NOx Rate	0.091	lb/MMBtu	NOx Rate	0.105	lb/MMBtu
Total NG In	1,405,203	million Btu	Total NG In	580,144	million Btu
Total COG In	962,697	million Btu	Total COG In	385,916	million Btu
Total BFG In	1,107,540	million Btu	Total BFG In	427,140	million Btu

* * * Replacement for Authorized Fax Filing for Clarity and Color * * *

Table 7. Siebenberger Exhibit A with COG fired in reheat furnaces at 40% and scrubbed COG NOx corrected for available fuel bound nitrogen.

Boiler Analysis										
Calculation of Siebenberger Exhibit A information - accounting for available COG with 40% COG firing in Reheat Furnace and reduced fuel NOx from COG										
Boiler heat input		450	million BTU/hr							
Annual	Ozone Season									
15	15	days BF rebuild				COG Scrubber Downtime		35	days per year	
55	23	days BF down (15% of time)								
2	2	days maintenance								
72	40	days total BF outage								
365	153	Total Days in Period								
293	113	Total Days Operating in Period								
Normal Operation										
		Annual						**Ozone Season**		
Capacity Factor	**days**	**Heat In (MMBtu)**				**Capacity Factor**	**days**	**Heat In (MMBtu)**		
100%	293	3,164,400				100%	113	1,220,400		
	Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons			Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons
NG	37%	0.084	1,180,321	49.6		NG	37%	0.084	455,209	19.1
COG	28%	0.114	876,539	50.0		COG	28%	0.114	338,051	19.3
BFG	35%	0.0288	1,107,540	15.9		BFG	35%	0.0288	427,140	6.2
Total	100%		3,164,400	115.5		Total	100%		1,220,400	44.5
	Blended NOx Rate	0.07299					Blended NOx	0.07299		
Blast Furnace Downtime (no BFG available)										
		Annual						**Ozone Season**		
Capacity Factor	**days**	**Heat In (MMBtu)**				**Capacity Factor**	**days**	**Heat In (MMBtu)**		
40%	72	311,040				40%	40	172,800		
	Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons			Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons
NG	72%	0.084	224,882	9.4		NG	72%	0.084	124,934	5.2
COG	28%	0.114	86,158	4.9		COG	28%	0.114	47,866	2.7
BFG	0%	0.0288	0	0.0		BFG	0%	0.0288	0	0.0
Total	100%		311,040	14.4		Total	100%		172,800	8.0
	Blended NOx Rate	0.09231					Blended NOx	0.09231		
COG Scrubber Maintenance										
		Annual						**Ozone Season**		
35.00	days					35.00	days			
	COG Rate	0.34	lb/MMBtu				COG Rate	0.34	lb/MMBtu	
	Delta in COG Rate	0.22	lb/MMBtu				Delta in COG I	0.22	lb/MMBtu	
	Heat In	151,200	million Btu				Heat In	151,200	million Btu	
	NOx delta	16.8	tons				NOx delta	16.8	tons	
Total for Period										
		Annual						**Ozone Season**		
	Total NOx	**146.6**	**tons**				**Total NOx**	**69.3**	**tons**	
	Total Heat In	**3,475,440**	**million Btu**				**Total Heat In**	**1,393,200**	**million Btu**	
	NOx Rate	**0.084**	**lb/MMBtu**				**NOx Rate**	**0.099**	**lb/MMBtu**	
	Total NG In	**1,405,205**	**million Btu**				**Total NG In**	**580,144**	**million Btu**	
	Total COG In	**962,697**	**million Btu**				**Total COG In**	**385,916**	**million Btu**	
	Total BFG In	**1,107,540**	**million Btu**				**Total BFG In**	**427,140**	**million Btu**	

Table 8. Siebenberger Exhibit A with all COG fired in reheat furnaces – none in boilers

Boiler Analysis										
Calculation of Siebenberger Exhibit A Information - all COG fired in Reheat Furnace										
Boiler heat input		450	million BTU/hr							
Annual	**Ozone Season**									
15	15	days BF rebuild				COG Scrubber Downtime		35	days per year	
55	23	days BF down (15% of time)								
2	2	days maintenance								
72	40	days total BF outage								
365	153	Total Days in Period								
293	113	Total Days Operating in Period								
Normal Operation										
Annual						**Ozone Season**				
Capacity Factor	**days**	**Heat In (MMBtu)**				**Capacity Factor**	**days**	**Heat In (MMBtu)**		
100%	293	3,164,400				100%	113	1,220,400		
	Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons			Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons
NG	65%	0.084	2,056,860	86.4		NG	65%	0.084	793,260	33.3
COG	0%	0.144	0	0.0		COG	0%	0.144	0	0.0
BFG	35%	0.0288	1,107,540	15.9		BFG	35%	0.0288	427,140	6.2
Total	100%		3,164,400	102.3		Total	100%		1,220,400	39.5
	Blended NOx Rate	0.06468					Blended NOx	0.06468		
Blast Furnace Downtime (no BFG available)										
Annual						**Ozone Season**				
Capacity Factor	**days**	**Heat In (MMBtu)**				**Capacity Factor**	**days**	**Heat In (MMBtu)**		
40%	72	311,040				40%	40	172,800		
	Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons			Fuel Mix	NOx Rate (lb/MMBtu)	Heat In (MMBTU)	NOx Tons
NG	100%	0.084	311,040	13.1		NG	100%	0.084	172,800	7.3
COG	0%	0.144	0	0.0		COG	0%	0.144	0	0.0
BFG	0%	0.0288	0	0.0		BFG	0%	0.0288	0	0.0
Total	100%		311,040	13.1		Total	100%		172,800	7.3
	Blended NOx Rate	0.084					Blended NOx	0.084		
COG Scrubber/Maintenance										
Annual						**Ozone Season**				
35.00	days					35.00	days			
	COG Rate	0.34	lb/MMBtu				COG Rate	0.34	lb/MMBtu	
	Delta in COG Rate	0.19	lb/MMBtu				Delta in COG I	0.19	lb/MMBtu	
	Heat In	151,200	million Btu				Heat In	151,200	million Btu	
	NOx delta	14.5	tons				NOx delta	14.5	tons	
Total for Period										
Annual						**Ozone Season**				
	Total NOx	**129.9**	**tons**				**Total NOx**	**61.2**	**tons**	
	Total Heat In	**3,475,440**	**million Btu**				**Total Heat In**	**1,393,200**	**million Btu**	
	NOx Rate	**0.075**	**lb/MMBtu**				**NOx Rate**	**0.088**	**lb/MMBtu**	
	Total NG In	**2,367,900**	**million Btu**				**Total NG In**	**966,060**	**million Btu**	
	Total COG In	**0**	**million Btu**				**Total COG In**	**0**	**million Btu**	
	Total BFG In	**1,107,540**	**million Btu**				**Total BFG In**	**427,140**	**million Btu**	

Other Attachments

Letter from Bill Tracey of North American Burner
Product Bulletins

- Bloom Engineering
- North American Burner

Waibel paper -Advanced Burner Technology for Stringent NOx Regulations
Coen Case Study – tangential low NOx burner
Link to Handbook for Petroleum Processing:
http://books.google.com/books?id=D6pb1Yn0vYoC&dq=Handbook+of+Petroleum+Processing&printsec=frontcover&source=bl&ots=XW2zZa1Qct&sig=nKh8rkyzFJmKLTX0_WZ7cmGB8_s&hl=en&sa=X&oi=book_result&resnum=8&ct=result#PPA453,M1

Bloomengineering
GLOBAL ENERGY AND ENVIRONMENTAL SOLUTIONS

1030 SERIES LARGE CAPACITY GAS, AMBIENT OR PREHEATED AIR BURNER

CAPABILITIES

- Short, compact, clear and bushy flame
- Suitable for rich gases
- 10% to 300% excess air through burner with rich gaseous fuels
- Additional excess air may be introduced down-stream of burner's port
- Operates with moderate air and fuel pressures
- Standard design suitable for furnace pressure of -1" WC to +5" WC
- Special designs available for other furnace conditions

FEATURES

- Rugged fabricated construction
- Flame stabilization with all refractory or refractory faced fabricated plate and tube baffle
- Baffle shields burner internals from flame convection and chamber radiation
- Designed for cold air or preheated air to 600°F (315°C) with external insulation of the burner
- Suitable for high chamber operating temperature

APPLICATIONS

- Air Heaters
- Thermal Oxidizers
- Dryers
- Kilns
- Boilers
- Others

CONTROL

- Metered flow
- Linked values
- Fuel modulation only

FLAME MONITORING

- U.V. Detector

BURNER IGNITION

- Pilot only

FUEL CAPABILITIES

- Natural Gas
- LPG
- Mixed Gases

OPTIONS

- Burner block/tile can be supplied
- Low Btu gas designs
- Designs are available for windbox installations

CAUTION: The improper use of combustion equipment can result in a condition hazardous to people and property. Users are urged to comply with National Safety Standards and/or Insurance Underwriters recommendations

1030 SERIES LARGE CAPACITY GAS, AMBIENT OR PREHEATED AIR BURNER

AIR FLOW AND FLAME DIMENSIONS

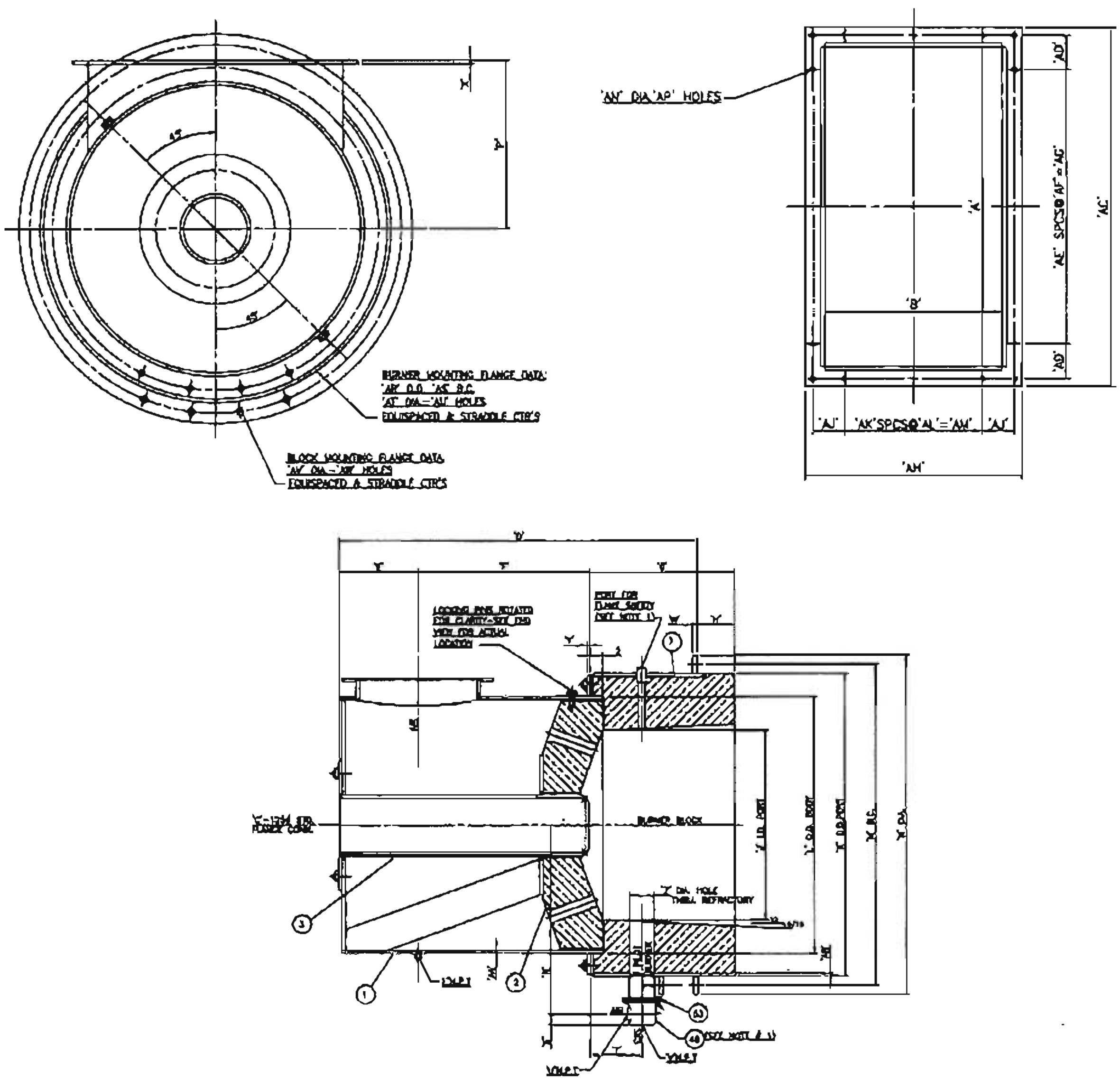
Catalog No. 1030-	Air Flow 1000 SCFH at 100°F Nm³/hr x 1000 @ 38° C				Flame Length[2]		Flame Diameter[2]		Pilot[3] Part No.
	4" WC	10 mBar	8" WC	20 mBar	ft	mm	ft	mm	
020A	235	6.35	333	9.00	10	3048	4.0	1219	2300-010
020B	300	8.00	425[1]	11.50	11	3353	4.0	1219	2300-010
025A	375	10.10	531	14.35	13	3962	4.5	1372	2300-010
025B	469	12.70	664[1]	18.00	16	4877	5.0	1524	2300-010
031A	563	15.20	797	21.50	18	5486	5.5	1676	2300-030
031B	705	19.00	997[1]	27.00	20	6096	6.0	1829	2300-030
037A	845	22.80	1195	32.30	22	6706	6.5	1981	2300-030
037B	1030	27.80	1460[1]	39.50	24	7315	7.0	2134	2300-030
046A	1268	34.30	1793	48.50	27	8230	7.5	2286	2300-030
046B	1550	42.00	2190[1]	59.00	32	9754	8.0	2438	2300-030
057A	1878	50.75	2655	72.00	33	10058	8.5	2591	2300-030
057B	2347	63.40	3320[1]	90.00	36	10973	9.0	2743	2300-030
070A	2817	76.00	3983	107.5	40	12192	10.0	3048	2300-030
070B	3521	95.00	4979[1]	134.5	44	13411	10.5	3200	2300-030

[1]Do not exceed this maximum air capacity rating.
[2]Flame dimensions are for 10% excess air.
Flame size decreases with increasing excess air.
Contact Bloom for information at other conditions.
[3]2300-010 Air = 4,000 scfh (108 Nm³/hr) @ 8" wc (20 mBar)
Gas = 560 scfh (13.5 Nm³/hr) @ 8" wc (20 mBar)
2300-030 Air = 12,000 scfh (325 Nm³/hr) @ 10" wc (25 mBar)
Gas = 1,500 scfh (40 Nm³/hr) @ 14" wc (35 mBar)

CAUTION: The improper use of combustion equipment can result in a condition hazardous to people and property. Users are urged to comply with National Safety Standards and/or Insurance Underwriters recommendations

1030 SERIES LARGE CAPACITY GAS, AMBIENT OR PREHEATED AIR BURNER

GENERAL DIMENSIONS – 020-031



NOTE: GENERAL DIMENSION INFORMATION. SEE BLOOM REPRESENTATIVE FOR CERTIFIED DIMENSIONS FOR CONSTRUCTION.

CAUTION: The improper use of combustion equipment can result in a condition hazardous to people and property. Users are urged to comply with National Safety Standards and/or Insurance Underwriters recommendations

1030 SERIES LARGE CAPACITY GAS, AMBIENT OR PREHEATED AIR BURNER

GENERAL DIMENSIONS – 020-031

Catalog No. 1030-	A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S	T	U	V	W	X	Y	Z
020	22	14	8	37.50	9.00	18.5	16	6	20.5	36.5	28	39.0	42.0	17	25.00	1.75	6.5	1	½	.75	.25	.5	3
	559	356	203	953	229	470	406	152	521	927	711	991	1067	432	635	44	165	25	13	19	6	13	76
025	30	16	8	46.00	10.00	22.0	20	6	25.5	44.5	36	47.0	50.0	21	27.50	2.25	6.5	3	½	.75	.25	.5	4
	762	406	203	1168	254	559	508	152	648	1130	914	1194	1270	533	699	57	165	76	13	19	6	13	102
031	36	20	8	58.25	12.75	27.5	24	6	31.0	49.5	42	52.5	55.5	24	31.38	2.25	6.5	3	1 ¼	.75	.25	.5	4
	914	508	203	1480	324	699	610	152	787	1257	1067	1334	1410	610	797	57	165	76	32	19	6	13	102

Inches in black and mm in blue

Catalog No. 1030-	AA	AB	AC	AD	AE	AF	AG	AH	AJ	AK	AL	AM	AN	AP	AR	AS	AT	AU	AV	AW	Nom. Cap Rich Fuels mmbtu/hr
020	.25	.38	26.5	4.13	4	4.13	16.5	18.5	4.13	2	4.25	8.50	.56	20	36	32	.88	16	1.13	18	32
	6	10	673	105	102	105	419	470	105	51	108	216	14	508	914	813	22	406	29	457	
025	.25	.38	34.5	4.38	6	4.00	24.0	20.5	3.75	3	3.75	11.25	.56	26	44	40	.88	20	1.13	28	50
	6	10	876	111	152	102	610	521	95	76	95	286	14	660	1118	1016	22	508	29	711	
031	.25	.38	40.5	3.88	8	3.88	31.0	24.5	3.38	4	3.88	15.50	.56	32	48	46	.88	28	1.13	28	75
	6	10	1029	99	203	99	787	622	86	102	99	394	14	813	1219	1168	22	711	29	711	

Inches in black and mm in blue

PARTS LIST

Part Number	Description
01	Body
02	Baffle
03	Gas Nozzle Assembly
07	Port Block
48	Ignition Burner Assembly
53	Gasket

Part number must be preceded by catalog number.
Example:
To order Part 07 – Port Block
Specify –
1030-031 - 07
(catalog number) (part number)

NOTE: GENERAL DIMENSION INFORMATION. SEE BLOOM REPRESENTATIVE FOR CERTIFIED DIMENSIONS FOR CONSTRUCTION.

CAUTION: The improper use of combustion equipment can result in a condition hazardous to people and property. Users are urged to comply with National Safety Standards and/or Insurance Underwriters recommendations

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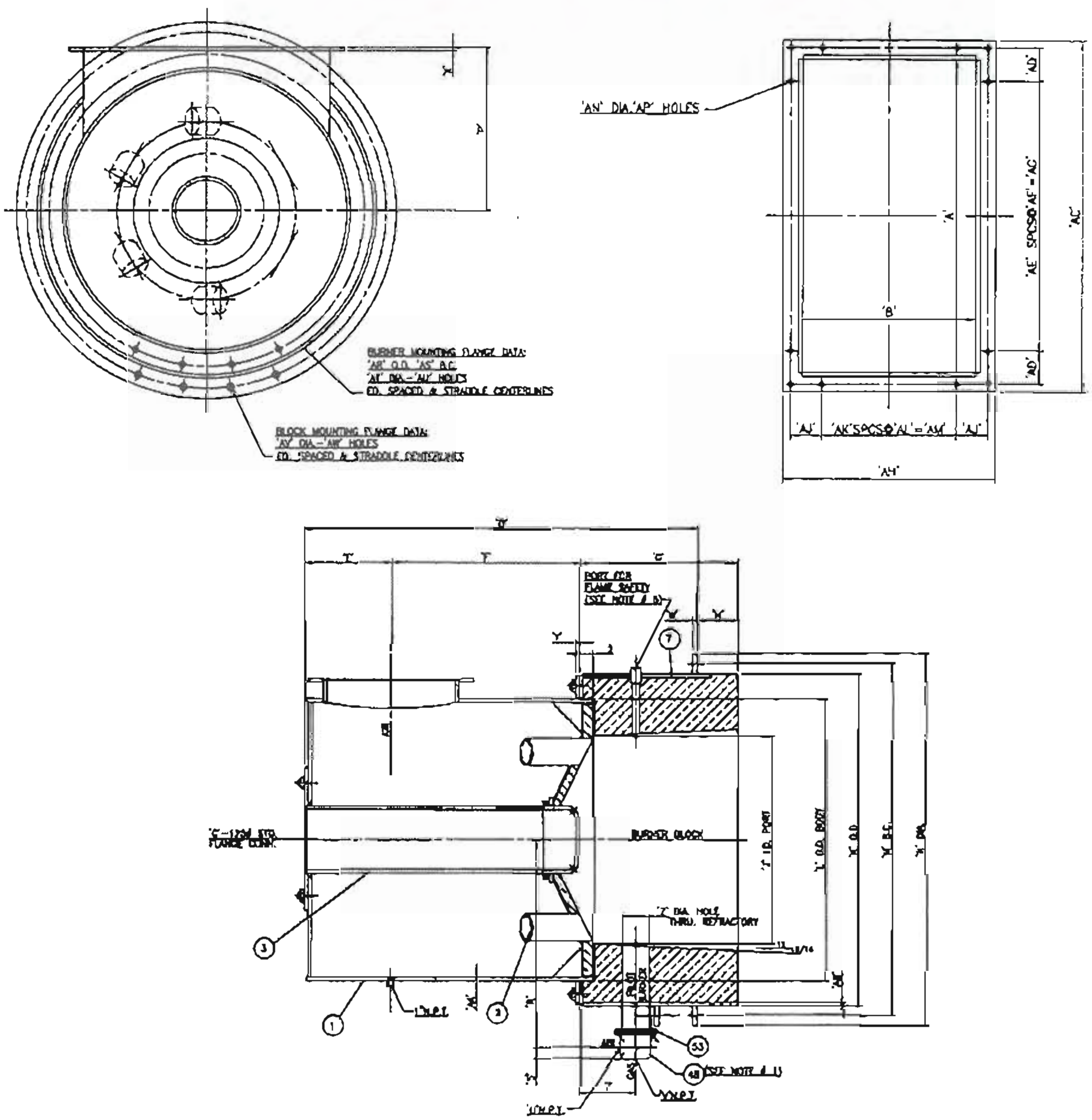
Bloomengineering
GLOBAL ENERGY AND ENVIRONMENTAL SOLUTIONS

1030 SERIES LARGE CAPACITY GAS, AMBIENT OR PREHEATED AIR BURNER

GENERAL DIMENSIONS – 037-070



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1030 SERIES LARGE CAPACITY GAS, AMBIENT OR PREHEATED AIR BURNER

GENERAL DIMENSIONS – 037-070

Catalog No. 1030-	A	B	C	D	E	F	G	H	J	K	L	M	N	P	R	S	T	U	V	W	X	Y	Z
037	44	24	10	70.25	14.75	33	28.5	6	37.5	59	52	62	65	29	34.63	2.25	6.5	3	1 ¼	.75	.25	.50	4
	1118	610	254	1784	375	838	724	152	953	1499	1321	1575	1651	737	880	57	165	76	32	19	6	13	102
046	54	30	10	85.75	17.75	40	34	6	46	71	64	74	77	35	41.88	2.25	6.5	3	1 ¼	.75	.38	.75	4
	1372	762	254	2178	451	1016	864	152	1168	1803	1626	1880	1956	889	1064	57	165	76	32	19	10	19	102
057	70	35	12	104.25	20.25	48	42	6	57	87.5	80	90.5	93.5	43	50.38	2.25	6.5	3	1 ¼	.75	.38	.75	4
	1778	889	305	2648	514	1219	1067	152	1448	2223	2032	2299	2375	1092	1280	57	165	76	32	19	10	19	102
070	88	42	16	128.75	25.75	60	51	6	70	105.5	98	108.5	111.5	52	59.38	2.25	6.5	3	1 ¼	.75	.38	.75	4
	2235	1067	406	3270	654	1524	1295	152	1778	2680	2489	2756	2832	1321	1508	57	165	76	32	19	10	19	102

Inches in black and mm in blue

Catalog No. 1030-	AA	AB	AC	AD	AE	AF	AG	AH	AJ	AK	AL	AM	AN	AP	AR	AS	AT	AU	AV	AW	Nom. Cap Rich Fuels mmbtu/hr
037	.25	.38	48.5	4	10	3.88	38.75	28.5	4	5	3.75	18.75	.56	38	58.75	56	.88	32	1.13	36	110
	6	10	1232	102	254	99	984	724	102	127	95	476	14	965	1492	1422	22	813	29	914	
046	.38	.38	58.5	2.38	13	4	52	34.5	2.38	7	4	28	.56	48	71	68	.88	40	1.13	44	165
	10	10	1486	60	330	102	1321	876	60	178	102	711	14	1219	1803	1727	22	1016	29	1118	
057	.38	.38	74.5	4.38	16	4	64	39.5	2.88	8	4	32	.56	56	86.75	84	.88	48	1.13	48	250
	10	10	1892	111	406	102	1626	1003	73	203	102	813	14	1422	2203	2134	22	1219	29	1219	
070	.38	.38	92.5	4.13	20	4.13	82.5	46.5	4.38	9	4	36	.56	66	105	102	.88	52	1.13	60	375
	10	10	2350	105	568	105	2096	1181	111	229	102	914	14	1676	2667	2591	22	1321	29	1524	

Inches in black and mm in blue

PARTS LIST

Part No.	Description
01	Body
02	Baffle
03	Gas Nozzle Assembly
07	Port Block
48	Ignition Burner Assembly
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Part number must be preceded by catalog number.
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Specify –
1030-037 - 07
(catalog number) (part number)

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North American
Manufacturing Company, Ltd.
4455 East 71st Street Cleveland, OH 44105-5600 USA
Tel 216.271.6000 Fax 216.641.7852 email: sales@namfg.com

Andover Technologies

January 12, 2009

Attn: Jim Staudt

Subject: Low NOx Burners for Boiler Retrofits

Jim,

Thanks again for the opportunity to talk to you the other day regarding Low NOx Burner Technology and its application on industrial processes.

A large part of North American's core business over the last 20 years has been the development and commercialization of a variety of Low NOx technologies. There are many choices that range in sophistication, from external flue gas recirculation, to gas staging (flameless oxidation), to the North American Magna Flame LE platform that uses lean premix technology and fuel staging. The optimum choice is somewhat process dependent as well as a function of the level of NOx reduction that is needed. Most of our business is the retrofit market and has included steel reheat furnaces, aluminum melting furnaces, industrial boilers and process heaters.

Based upon our discussions to date, we understand that the particular case of interest at the moment is a pair of field erected industrial boilers that need to operate on blast furnace gas, coke oven gas and natural gas. We don't know all of the application details at this time, but we are very confident that a significant NOx reduction can be made with Low NOx burner technology. Our first reaction is that the Magna Flame LE platform would be the most applicable and we've included a few photos of reference jobs as well as a copy of our catalog literature.

We appreciate that discussions are in the early stages, but if a project does develop, North American would be delighted to pursue any opportunity with you or the end-user.

As always, if you need any additional information, do not hesitate to call

William E Tracey
Global Sales Group
billtracey@namfg.com
1-610-996-8005

North American
Manufacturing Company, Ltd.
4455 East 71st Street Cleveland, OH 44105-5600 USA
Tel 216.271.6000 Fax 216.641.7852 email: sales@namfg.com

Magna Flame LE Applications

Installed At:
Steam generator in an oil field Long Beach, California, USA.

Burner:
50 MMBtu/hr. capacity LE burner operating on gaseous waste fuel (550-1000 Btu/scf)

Performance:
The boiler produces a maximum of 58,500 lb. of steam per hour at 1700 psi, using waste fuel which has no commercial value.

Emissions:
NOx emissions measured by the SCAQMD at <7 ppm_{vd} corrected to 3% O_2 dry at 100% capacity without the use of FGR.

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Magna Flame LE Applications

Installed At:
D-type water tube boiler at a refinery
Arroyo Grande, California, USA.

Burners:
127 MMBtu/hr LE operating over a 5:1 turndown.

116.5 MMBtu/hr LE operating over a 7:1 turndown

Performance:
NOx emissions measured between 25 to 29 ppm_{vd} on each system.
CO emissions measured at 0 ppm_{vd} on each system.
(all corrected to 3% O_2 dry)

Additionally, the North American supplied PLC based controller allows for accurate metering of the system, realized in improved operational efficiency.

North American
Manufacturing Company, Ltd.

Ultra Low NOx MAGNA-FLAME™ LE BURNER

Bulletin 4211

July 2006

- **9 to 210 million Btu/hr**
- **For processes up to 2000 F such as boilers, process heaters, and other applications requiring low excess air (10-15%)**
- **Ultra Low NOx with or without the use of Flue Gas Recirculation depending on emissions required**
- **Natural gas, propane, LPG, and other industrial fuel gases**

The Magna-Flame LE Burner, available in sizes ranging from 9 to 210 million Btu/hr, produces a luminous flame with moderate tile velocity.

The 4211 LE was developed to meet increasingly more stringent low NOx emission requirements globally. It can easily meet the requirements of 15-20 ppm_v NOx without the need for flue gas recirculation or any other external thermal diluent. Additionally, FGR can be added to the 4211 to achieve even lower NOx emissions when needed. It has achieved 8.3 ppm_v (0.01 lb/million Btu/hr) in the field in a water tube boiler.

Operation

The LE is designed to operate at up to 15"wc combustion air pressure, split into two separate air connections for the primary air and the radial air. It is designed to operate with 8 psig natural gas fuel pressure, which is fed through three separate connections; primary, secondary, and radial. The radial gas is designed for start-up and stabilization of the primary (lean) core. The primary gas is fed to the mixers, which typically operate at 60-70% XSA. The secondary gas is fed into the reaction chamber and mixes with the lean premix flame at the outlet of the reaction chamber. Final air/fuel ratio in the heater is typically 10-15% XSA (2-3% O_2 in the stack).

Stoichiometric turndown is about 4:1 with higher turndowns obtained by progressively increasing the excess air rate (thermal turndown). The minimum primary air pressure required for continuous operation is 0.75"wc.

Excess Air Version

A standard excess air version of the burner is also available. See Bulletin 4213 for information regarding this burner.

Control

Control of the LE is done via the PLC based controller with full metering of the combustion air (or vitiated air stream when FGR is used) and the three fuel flows; primary, secondary, and radial. Typical control systems also utilize an oxygen sensor in the exhaust stream. When FGR is used an oxygen sensor may also be located in the air stream to measure vitiation.

Combustion air is measured with a North American Model 8631 Venturi Air Meter or other means of air measurement and can also be controlled from either an inlet damper or VFD when appropriate. A separate radial air blower is normally required when a VFD is used on the primary air blower.

The critical element of primary air/fuel ratio control is done through the PLC based controller which then adjusts the secondary gas valve as needed to maintain the overall excess oxygen recorded by the O_2 sensor (O_2 trim).

As input needs vary, the primary air/fuel ratio is maintained by cross-limiting the air and primary gas valves in order to prevent any excursions outside desired operating parameters.

The radial gas is typically controlled via a bypass solenoid which allows for a two position 'hi/lo' setting, with the high radial gas flow set for the ignition and low fire rate and the low radial gas set at the design firing rate of the unit. The high fire radial gas flow is set at a flow rate that will not be detected by the main UV and should be restrained from exceeding that rate. For the tightest (lowest) emission requirements, fully modulated radial gas control may be required.

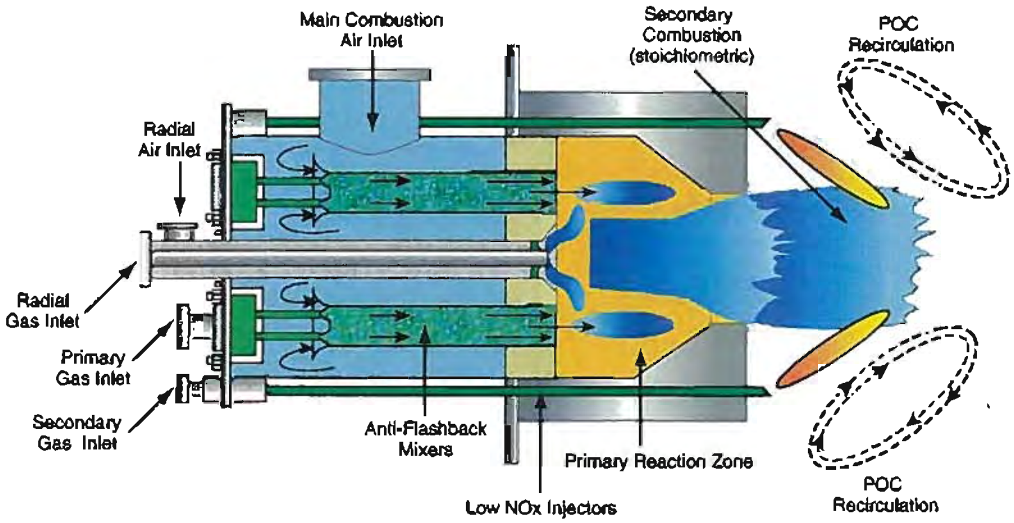


Figure 1. The Magna-Flame LE is a staged fuel burner design with lean burn primary combustion zone. The balance of the fuel is injected downstream.

Pilot and Flame Supervision

There is no 1400 F bypass required as dual flame supervisory detectors (UV) provide full compliance with NFPA86 specifications. The pilot UV initially provides assurance that the pilot, and radial gas flames have been adequately established. The main UV then assures that the primary fuel flame has been established so that the secondary fuel valve can then be opened. Contact North American Mfg. Co. Ltd. for the specific requirements for flame supervision.

A loss of the main UV signal will cause the secondary gas valve to close and re-establishes the 'pilot' UV in order to continue operation of the unit on primary and radial gas only. Loss of the pilot UV would result in the unit shutting down completely, and requiring a re-start of the safety sequence (see NFPA for specific requirements). If the main UV is only going to shut down the secondary gas, approved shutoff valves are required on the secondary gas piping and the controller needs to be designed accordingly.

Construction

The 4211 LE burner is sturdily constructed of steel and stainless steel where necessary to withstand the operating environment. The primary mixer tubes are constructed of a silicon carbide/mullite material that is then cast into a dense refractory which ensures that the metal parts are sufficiently protected from flame radiation. Options are available for corrosion resistant stainless steels as necessary to handle fuel gases with significant levels of sulfur.

The LE reaction chamber (or tile) is constructed of a 3000 F dense castable in addition to four stainless steel secondary injectors which protrude just past the hot face of the refractory. The reaction chamber for an LE is typically greater in length than the refractory wall of most furnaces; consequently a significant portion of it will extend back from the burner wall. While this requires extra room for the burner footprint outside the furnace it allows for a smaller overall combustion chamber (where the flame is contained).

Table 1

Burner designation	Input at 10% XSA (million Btu/hr)	Air flow at 10"wc (scfh)	Pilot designation	Flame length (ft)	Flame diameter (ft)
4211-10	9.0	99 300	4020-4-LP	8	3
4211-12	11.4	125 000	4020-4-LP	9½	3
4211-15	14.2	156 300	4020-5-LP	10	3
4211-18	17.0	187 500	4020-5-LP	12	3½
4211-21	19.6	215 300	4020-5-LP	12½	3½
4211-27	24.5	269 000	4020-6-LP/5	13½	3½
4211-33	29.4	322 900	4020-6-LP/5	14	4
4211-38	34.2	376 700	4020-6-LP/5	15	4
4211-49	44.4	488 500	4020-6-LP/5	16½	4
4211-62	55.5	610 600	4020-6-LP/5	18	5
4211-74	66.6	732 700	4020-7-LP/6	20	5
4211-86	77.7	854 900	4020-7-LP/6	21½	6
4211-96	88.8	977 029	4020-7-LP/6	22	6
4211-106	99.9	1 099 157	4020-7-LP/6	23	6
4211-116	111.0	1 221 286	4020-7-LP/6	24	7
4211-140	125.6	1 382 000	4020-7-LP/6	26	7
4211-163	146.5	1 612 000	4020-7-LP/6	28	7
4211-182	167.5	1 842 286	4020-7-LP/6	30	8
4211-200	188.4	2 072 571	4020-7-LP/6	33	8
4211-230	209.4	2 302 857	4020-7-LP/6	36	8

Variants

The 4231 GLE burner is a pre-packaged LE designed to fire steam generaters at 62.5 million Btu/hr. It is supplied with a pre-piped 4020 pilot, ignition cable, NEMA 4 ignition transformer; three pre-piped, pre-wired, and pre-set pressure switches for purge, low combustion air, and low fire; and a junction box for wiring to the necessary control hardware, simplifying installation and field start-up.

The 4213 LEx burner is designed to operate at excess rates between 60-80% at an input ranging from 7 to 175 million Btu/hr. It is intended for lower temperature applications where secondary air is normally employed to achieve process temperatures between 300-1800 F. It is similar to an LE burner but does not use secondary injectors and normally requires an extended reaction chamber to protect the flame from the low or ambient temperature secondary process stream.

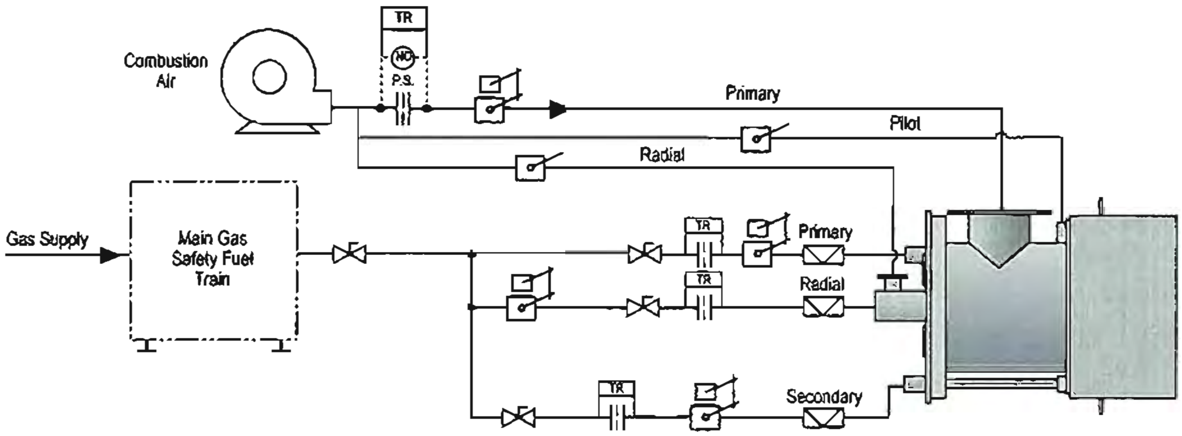


Figure 2. Typical Piping Schematic for MAGNA-FLAME™ LE Cold Air System.
A mass flow ratio control system with two selectable setpoints is required. Setpoint switches when secondary gas valve opens.

The graph at right shows actual test results of a burner fired with 10% excess air. Other variables such as higher excess air, preheated air temperatures, firing rate, and furnace design can effect NOx emission levels.

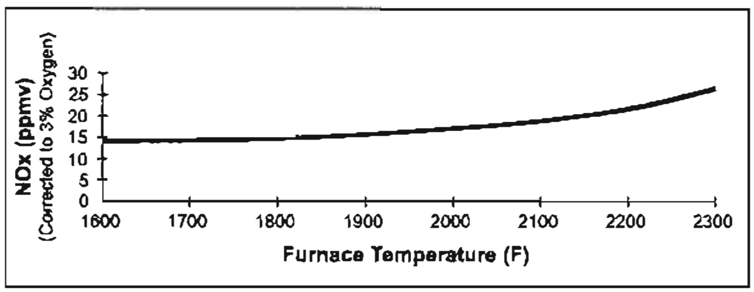
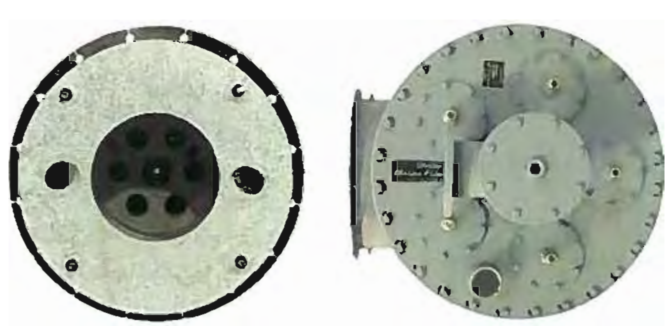
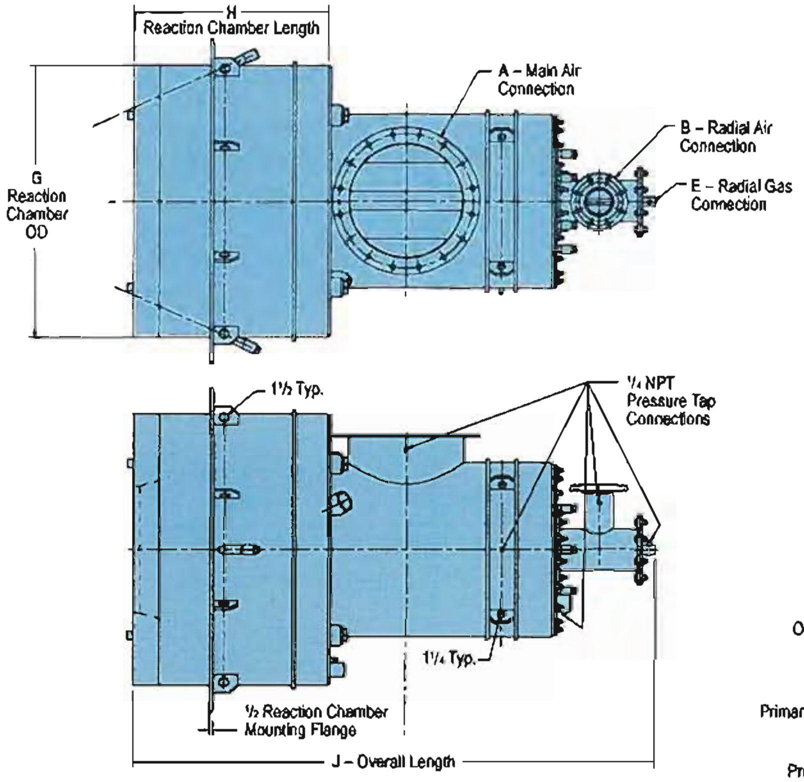


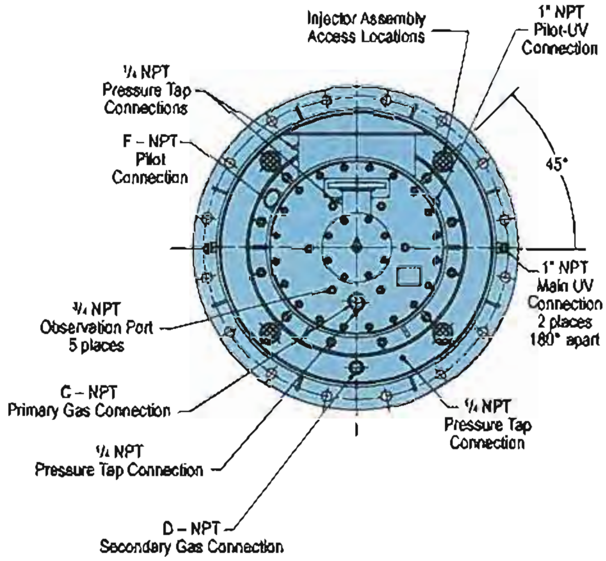
Figure 3. NOx Emissions vs. Furnace Temperature.

Packaged boiler at a southern U.S. chemical plant equipped with 4211-72 burner firing at 70 million Btu/hr, achieving less than 0.01 lb/million Btu NOx and 0.015 lb/million Btu CO.



DIMENSIONS
in inches





DIMENSIONS SHOWN ARE SUBJECT TO CHANGE. PLEASE OBTAIN CERTIFIED PRINTS FROM NORTH AMERICAN MFG. CO., LTD. IF SPACE LIMITATIONS OR OTHER CONSIDERATIONS MAKE EXACT DIMENSION(S) CRITICAL.

Burner designation	dimensions in inches									Approx. weight
	A	B	C	D	E	F	G	H	J	
4211-10	10	2½	1½	1	½	2	28	26	60	2450
4211-12	12	2½	1½	1	½	2	36	34½	76	2770
4211-15	12	3	1½	1	½	2½	36	34½	76	2770
4211-18	14	3	1½	1	½	2½	37	34½	82	2770
4211-21	14	4	2	1	½	2½	38	34½	82	2770
4211-27	16	4	2	1	½	2½	43	34½	82	3500
4211-33	18	4	2	1½	½	2½	43	34½	82	3750
4211-38	20	4	2½	1½	¾	2½	43	34½	82	4000
4211-49	22	4	3	2	1	2½	57	36½	104	5500
4211-62	24	4	3	2	1	2½	57	36½	104	6400
4211-74	26	6	3	2½	1	2½	57	36½	110	7000
4211-86	28	6	4	2½	1½	3	68	36½	110	7000
4211-96	30	6	4	2½	2	3	68	36½	110	7000
4211-106	30	6	4	3	2	3	76	36½	110	8500
4211-116	32	6	6	3	2	3	76	36½	110	8500
4211-140	34	6	6	3	2	3	82	42½	140	12000
4211-163	36	6	6	4	2½	3	88	42½	140	13000
4211-182	40	8	6	4	2½	3	92	42½	140	14000
4211-200	42	8	6	4	2½	3	98	42½	170	16000
4211-230	44	8	6	4	2½	3	104	42½	170	20000

WARNING: Situations dangerous to personnel and property can develop from incorrect operation of combustion equipment. North American urges compliance with National Safety Standards and Insurance Underwriters recommendations, and care in operation.

North American Mfg. Co., Ltd., 4455 East 71st Street, Cleveland, OH 44105-5600 USA, Tel: +1.216.271.6000, Fax: +1.216.641.7852
email: sales@namfg.com • www.namfg.com

Printed in USA

North American
Manufacturing Company

System Overview
Ultra Low NOx MAGNA-FLAME™ LEx

Bulletin 4213

April 2002

- **Ultra low NOx and CO without FGR**
- **Dual-fuel capability**
- **High intensity flame allows significant reductions in firing chamber size**
- **5 to 400 million Btu/hr**
- **Single UV monitoring**

Applications:

- air heaters
- process heaters
- dryers & calciners
- incinerators
- aggregate dryers
- soil remediation

Magna-Flame LEx systems greatly reduce the typical pollutants (NOx, CO) from gas combustion. Utilizing lean premix technology the patented burner produces NOx emissions of less than 10 ppm in many applications. The companion burner reaction chamber completes over 80 percent of the combustion producing very compact flame geometry. This compact flame allows significant reductions in furnace size and overall installed cost.

Operation

The burner incorporates internal mixing elements that premix the fuel and air prior to combustion in the reaction chamber. By completing over 80 percent of the combustion in the burner reaction chamber, the low NOx characteristics of the burner are protected from process influences.

The burner is designed to operate at 10"wc main air pressure and 8 psig gas pressure. The burner and control system are designed to hold to a preset ratio over a 4:1 turndown. Thermal turndowns of 10:1 or greater are also possible in most applications.

Control

A characterizable mass flow ratio control device is recommended. This gives the operator the tools to tailor the burner ratio through the turndown for optimum emissions performance.

Pilot and Flame Supervision

The 4020-HP nozzle mix pilot is recommended for use on the burner. Refer to Bulletin 4020 for specific information on the operation of this pilot.

For flame supervision the pilot must be the interrupted type. A single UV scanner monitors both the main flame and the pilot.

Burner Construction

The burner is of rugged construction suitable for industrial applications. The front face of the burner is constructed of high temperature refractory. The anti-flashback mixers are made of high grade alloy components.

Other Fuels

The LEx burner can fire many gaseous fuels with similar low emission performance. The LEx reaction chamber makes it extremely effective for low Btu gases. Light fuel oils may be used as a back up fuel. Consult your North American Sales and Application Engineer for your specific needs.

NOx and CO Emissions Comparison*

Example at 1200 F Temp.

	Typical Cold Air Burner	Magna-Flame LEx System
NOx	82	9
CO	20	5

Emissions ppm_v at 3% O_2

*Application dependent

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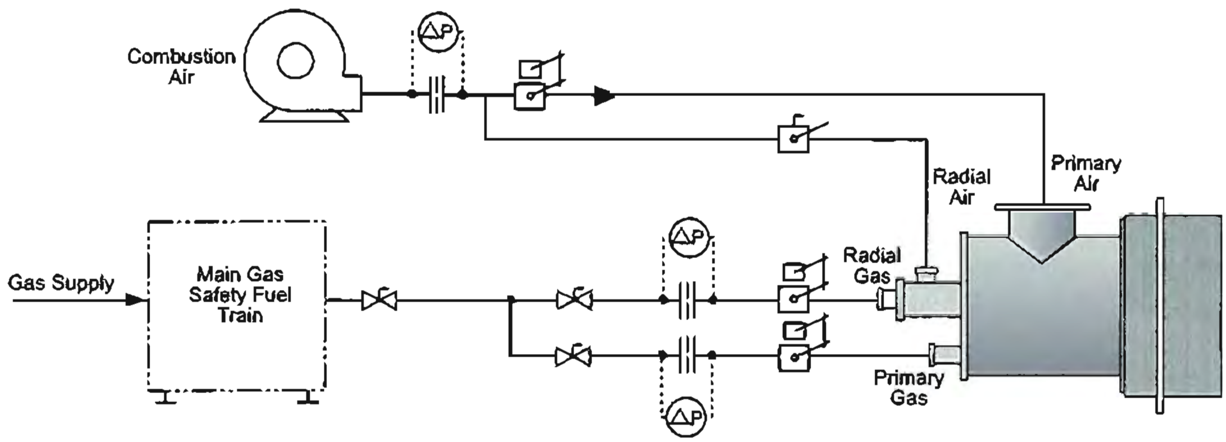
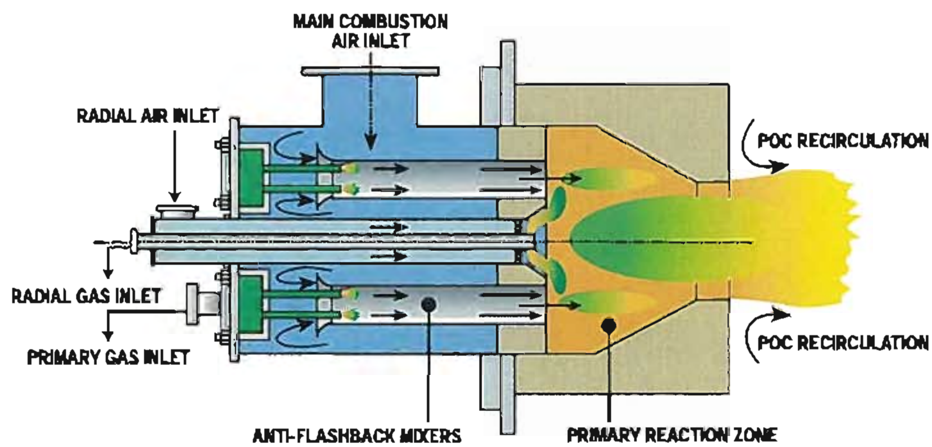
Flow Control Concept

Figure 1. Typical Control Concept for Single Burner MAGNA-FLAME™ LEx Combustion System.
A characterizable mass flow ratio control device is recommended for tailoring burner ratio through turndown.



Simplified Burner Design — No Moving Parts — No FGR

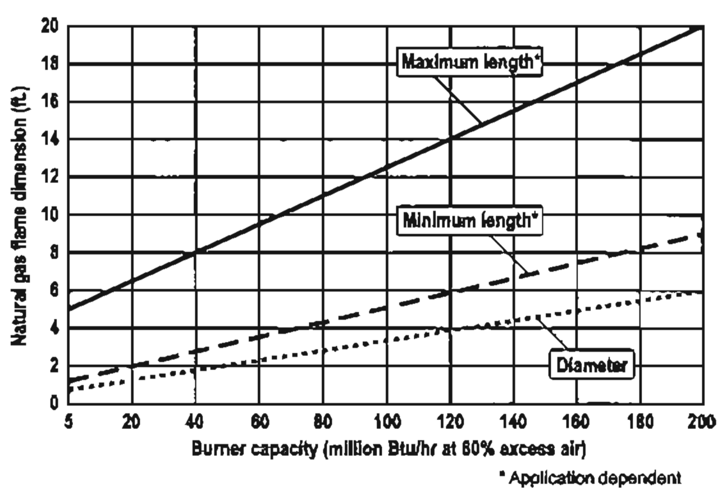
Figure 2. The Magna-Flame LEx uses patented premix technology to establish a lean premix and then combusts the mixture in a controlled reaction zone without the use of FGR, complex staging devices or moving parts. The fuel and air are introduced separately into the burner where they are intimately mixed within anti-flashback mixers. This mixture is then directed into the reaction region where lean combustion takes place.



Gas Burner Flames

Figure 3. Gas Flame Dimensions vs. Burner Capacity (Btu/hr)

The LEx flame exits the reaction chamber 80 percent combusted resulting in shorter, more compact flame geometry. In most applications the firing chamber size can be significantly reduced.



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COEN CASE HISTORY

Clean combustion. Powerful results.

COEN COMPANY, INC. 1510 TANFORAN AVE. WOODLAND, CA 95776 USA (530) 668-2100 WWW.COEN.COM

LOW NOx BURNER MODIFICATION FOR TANGENTIAL-FIRED BOILERS

SITUATION

Coen Company teamed with a major oil refinery to define and implement the most economical approach to reduce NOx emissions on three, 550,000 lb/hr, tangentially-fired boilers. Burner modifications supplied by Coen were an integral part of the selected strategy, which involved the application of increased rates of induced flue gas recirculation (IFGR) to achieve target NOx emission when burning refinery gas and natural gas. The primary objectives of the Coen burner modifications were to augment the NOx reductions from IFGR and, most importantly, to provide stable combustion when operating with high rates of IFGR. The projected rates of IFGR (up to 30%) would pose high risk of combustion instabilities and unacceptable fuel efficiency, if applied with the existing burner design. Coen proposed a design that would minimize modifications to the plant by adapting to the existing windbox geometry, backup fuel oil firing system, and ignition equipment.

Boiler Design:	Tangentially-fired, four corners
No. Of Burners:	3 elevations, 12 burners total
Windbox Temp.:	500 F
IFGR Rate:	30% at low load; 18% at high load
Equipment:	Custom engineered tilting burners with ultra-stable flame stabilizers and low NOx gas injectors
Guarantee:	0.085 lb/MBtu NOx Flame Stability

SOLUTION

Coen modeling and combustion testing supported the decision to proceed with the IFGR approach. To help ensure that performance requirements would be met and to demonstrate satisfactory operation to the customer, a 1/4-scale model of one low NOx corner burner element was tested at Coen's Combustion Test Facility under simulated field conditions. The tests demonstrated the NOx characteristics of the proposed burner modification and excellent flame stability and lightoff characteristics over the required burner turndown range.

Coen also evaluated the impact of increased IFGR rates on superheater heat absorption and temperature control. Utilizing a mathematical model of furnace heat transfer that was developed by Coen and validated with actual plant data, the analysis indicated that the superheater would accommodate the projected IFGR rates and that superheat temperature control could be maintained via existing means (e.g., burner tilts). A complementary CFD study of the combustion air ductwork and windboxes indicated that no modifications were necessary to achieve uniform air flow to the burners.

Coen Retrofit Ultra-Stable Low NOx Gas Burner

Coen's burner equipment design kept the retrofit cost to a minimum by replacing only critical gas firing components with custom-engineered components, while most of the burner system remained intact. The Coen-supplied equipment included low NOx gas injectors, new flame stabilizers, and replacement of associated windbox air nozzles ("buckets"). These components were designed to adapt to existing windbox compartments and burner tilt mechanisms. Special nozzle pivot pin socket assemblies, included in Coen's scope of supply, simplified installation of the new air nozzles and avoided costly asbestos abatement that would likely have been required with a standard socket replacement. In designing the replacement windbox air nozzles, Coen took care to ensure that the existing oil firing equipment could be re-used with minor modifications.

The project had a very short execution time and was subject to rigorous quality assurance testing during fabrication. It was also imperative that the Coen equipment attain design performance immediately after the installation outage.

RESULTS

With the first of three boilers retrofitted in Summer 2004, the Coen burner modifications were confirmed to provide stable flames, good flame shape and reliable lightoffs over the boiler load range and with the maximum rates of IFGR in the windbox. Startup of the remaining two boilers and optimization of the IFGR system is expected to continue into 2005.

Coen Burner Components Installed In Shop Windbox Mock-up to Ensure Proper Field Fit-up and Demonstrate Installation Procedures to Customer

CUSTOMER NEEDS

- Stable Flames and Complete Combustion When Using High Rates of Induced Flue Gas Recirculation (IFGR) for NOx Control.
- Minimum Retrofit Cost and Low Risk
- Short Project Execution Time
- Compatibility With Existing Windbox Structures and No.2 Oil Backup System
- Rigorous Quality Control For Fabricated Equipment

OPERATIONS

- Preserve Boiler Turndown
- Maintain High Combustion Efficiency
- Reliable Burner Light offs With High Rates of IFGR
- Maintain Superheat Steam Temperature Control

AIR QUALITY

- NOx Emissions $\leq$0.085 lb/MBtu
- High Combustion Efficiency
- Low CO emissions

For combustion upgrades and emission reduction at the lowest cost, contact:
Robert Carr - Manager, Utility Combustion Systems
Roberto Santos – Manager, Industrial Combustion Systems

COEN

Apr-07

ADVANCED BURNER TECHNOLOGY FOR STRINGENT NOx REGULATIONS

R.T. WAIBEL, PHD.
JOHN ZINK COMPANY
TULSA, OK

D.N. PRICE AND P.S. TISH
UNOCAL CORPORATION
LOS ANGELES REFINERY
WILMINGTON, CA

M.L. HALPRIN
FOSTER WHEELER USA CORPORATION
FIRED HEATER DIVISION
LIVINGSTON, NJ

PRESENTED AT THE
AMERICAN PETROLEUM INSTITUTE MIDYEAR REFINING MEETING JOINT MEETING OF THE SUBCOMMITTEE ON HEAT TRANSFER EQUIPMENT

ORLANDO, FL
MAY 8, 1990

JOHN ZINK®
A KOCH INDUSTRIES COMPANY

INTRODUCTION

In 1984 the South Coast Air Quality Management District (SCAQMD), which oversees the Los Angeles air basin in Southern California, enacted Rule 1109 limiting the NOx emissions from furnaces and boilers in petroleum refineries and chemical plants. This rule provided that furnaces over 40 million Btu/hr (42.2 GJ/hr) were limited to 0.14 lb. of NOx per million Btu of heat input (0.06 g/MJ). The limit was given as a plant wide average for existing furnaces. In order to comply, the plant owners retrofitted some of their furnaces with low NOx burners capable of producing less than 0.06 to 0.08 lb. of NOx per million Btu in order to produce the offsets needed to reduce the overall average emissions. In the Fall of 1988 Rule 1109 was revised and this limit was reduced from 0.14 to 0.03 lb. per million Btu (HHV) (0.013 g/MJ), which is a reduction of more than 75%. Rule 1146 was also enacted, limiting the emissions from furnaces and boilers with less than 40 MM Btu/hr (42.2 GJ/hr) heat input to 40 PPMV, dry basis, corrected to 3% 02 (80 mg/NM 3).

Both of these new limits, which are about 50 and 80 mg/Nm3, respectively, have presented significant challenges to burner designers as well as furnace operators. This paper discusses the development of burners by John Zink which meet this challenge and the results of a successful application of these burners by Unocal.

NOx emissions are influenced by the furnace operating temperature, excess air and factors that determine the flame temperature, such as fuel composition and air preheat temperature. One of the major difficulties facing burner designers, refineries and chemical plants is the nature of the fuels utilized. Typically, waste gases from several processes make up the greater portion of their fuel gas supply. They may be burned as is or they may be blended together with natural gas and distributed via a plant wide fuel gas system. These waste gases contain large volumes of hydrogen, ethane, propane and butane and, at times, significant quantities of ethylene, propylene and butylene. These components can produce higher flame temperatures than a typical natural gas. Table 1 provides a comparison of calculated flame temperatures for each of these gases.

Table 1

Adiabatic Flame Temperatures Calculated For Various Gas Species

Gas Species	Temperature, °F
CH_4	3308
C_2H_6	3342
C_3H_8	3345
C_4H_{10}	3345
C_4H_8	3423
C_3H_6	3446
C_2H_4	3512
H_2	3650

LOW NOx BURNER TECHNOLOGY

Early low NOx burner technology relied on low excess air operation to reduce NOx emissions. Although low excess air operation is still used today, it is not sufficiently effective to meet the latest regulations. Staged air combustion was also one of the early techniques used to reduce NOx. This technique, however, has limitations in flame quality, flame length and it limits the ability to operate with low excess air. Flue gas recirculation has also been shown to be an effective method for reducing NOx, although past applications have proven to be costly to implement. The staged fuel technique, developed and patented by John Zink Company, has proven to be one of the most effective techniques for reducing NOx. Staged fuel burners produce the lowest NOx emissions, while allowing low excess air operation with stiff, compact flames.

The latest staged fuel burners can meet the requirements of Rule 1146 for most applications. Meeting the new NOx emission limit of 0.03 lb/MM Btu (Rule 1109) has proven more difficult, but it is also achievable. By itself the John Zink Low NOx Staged Fuel burner can meet or approach the emission level required for many refinery applications. By combining fuel staging with flue gas recirculation it has been demonstrated that the required level can be reliably achieved for nearly all furnaces and boilers.

The key factor in meeting the emission levels mandated by these rules is the John Zink Staged Fuel burner, shown in Figure 1. Fuel staging reduces NOx by burning a portion of the fuel gas with the combustion air in a lean primary combustion zone. NOx in this region is low because flame temperatures are depressed by the high excess air levels. The remaining fuel is then injected into the tail end of the primary flame zone to form a secondary combustion zone. The NOx emissions from this region are also low because the fuel is burned with an "air" stream containing reduced oxygen content due to the inert products of combustion from the primary flame. By adding recirculated flue gas to the combustion air the overall emissions from both the primary and secondary combustion zones can be further reduced. NOx is limited in the primary combustion zone because the inert flue gas further reduces the oxygen concentration and also reduces the adiabatic flame temperature. The NOx in the secondary combustion zone is reduced for the same reasons.

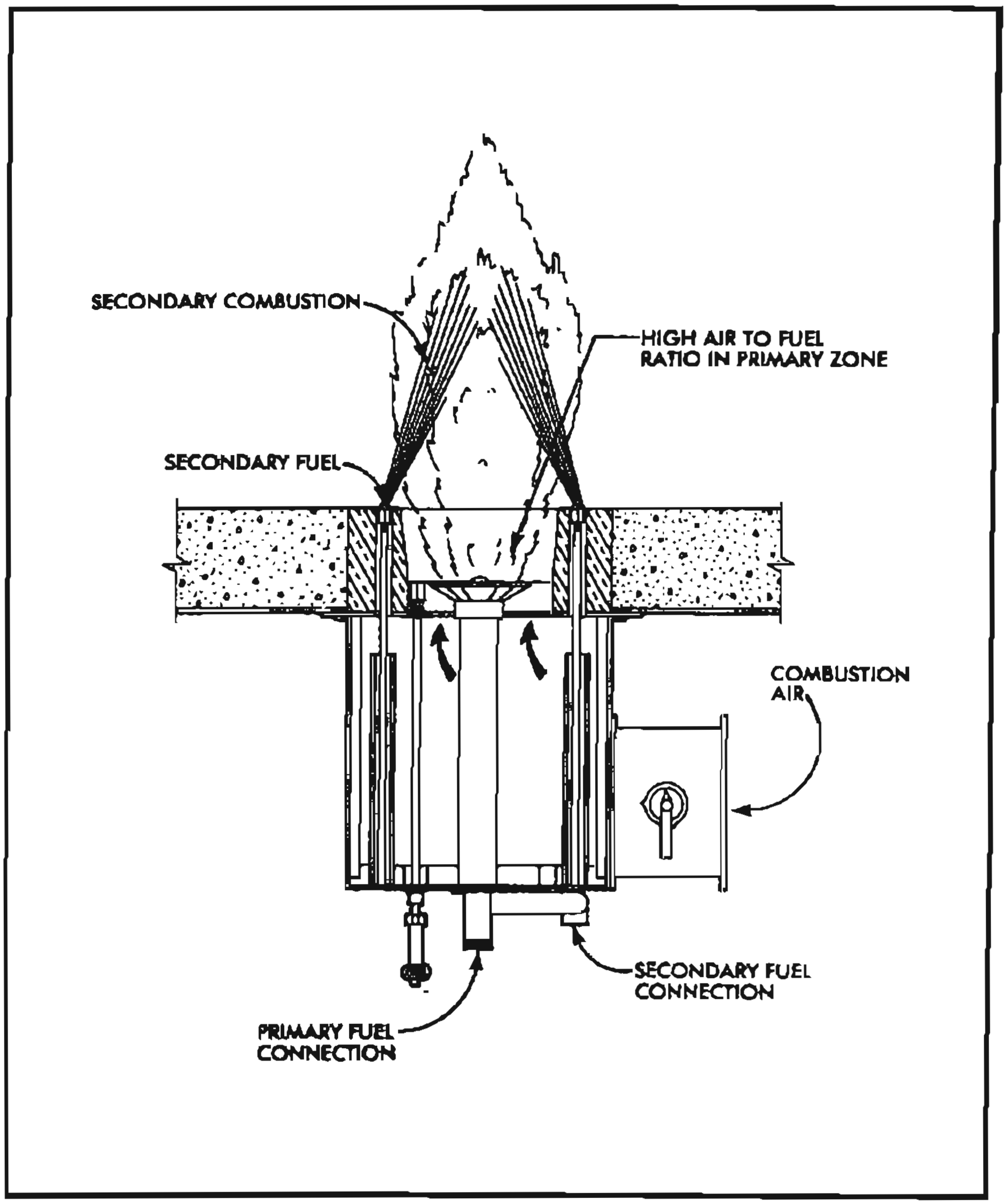

Figure 1 JOHN ZINK STAGED FUEL LoNox™ BURNER

JOHN ZINK TEST FACILITY

The John Zink International Research Center has 9 furnaces of various sizes and configurations for burner research and development. Full scale burners from less than 1 million Btu/hr (0.3 MW) to more than 250 million Btu/hr (75 MW) can be tested. In order to develop a suitable burner system, Furnace No. 8 was fitted with a flue gas recirculation system as shown in Figure 2. No. 8 test furnace is a vertical cylindrical furnace with a combustion chamber 8 ft. (2.44 m) in diameter and 20 ft. (6.1 m) tall. The furnace wall is a double shell with water in the annulus to absorb part of the heat input to the furnace. A portion of the interior surface is insulated to control the heat absorption rate. The furnace exit temperature during all tests was about 1600°F (870 °C), which is typical of many refinery process heaters. A 12 inch (305 mm) recirculation duct was installed at the furnace outlet to extract a portion of the flue gases. This duct was routed to a shell and tube heat exchanger where the flue gases were cooled to about 500 °F (260 °C). A hot fan was used to draw the flue gases through the heat exchanger and inject them into the combustion air stream. The flue gas recirculation flow rate was measured with a venturi flow meter.

The tests reported here were conducted with burners designed for a nominal heat input of 7 to 10 million Btu/hr (7.4 to 10.55 GJ/hr). The development work involved tests over the entire operating range of each burner. The NOx emission results included in this paper are those collected with the burners operating at their nominal firing rate. Both ambient and preheated air were tested. A variety of fuel gases were utilized during the testing. Some of the fuel blends that have been tested are:

Natural Gas
Hydrogen / Natural Gas
Hydrogen / Propane / Natural Gas
Hydrogen / Propylene / Natural Gas
Hydrogen / Butane / Propane / Natural Gas

Flue gas recirculation rates were varied from 0 to 35%. The excess oxygen level was varied from 0.2% to 4% 02. Data collected included fuel composition, fuel flow rate, fuel pressure, air temperature, FGR flow rate, FGR temperature, burner draft loss, furnace pressure, furnace temperature, and flue gas temperature, NOx, CO, and 02. The NOx concentrations reported here are given as PPM by volume, dry basis, and are corrected to 3% excess oxygen.

* * * Replacement for Authorized Fax Filing for Clarity and Color * * *

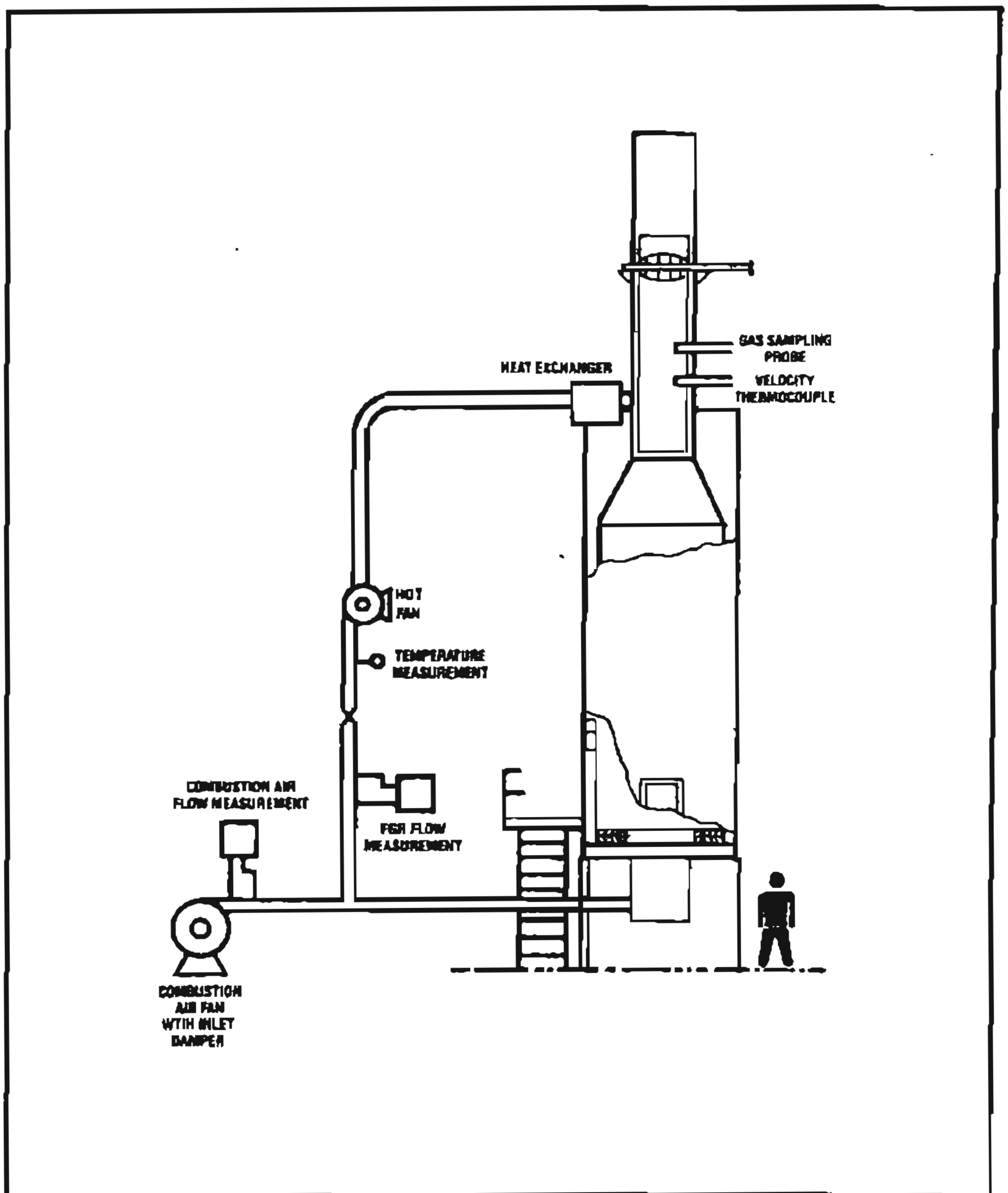

Figure 2 FLUE GAS RECIRCULATION TEST SETUP

BURNER DEVELOPMENT

The bulk of the early development work involved optimizing the fuel staging method to achieve minimum NOx and stable operation with flue gas recirculation at all firing rates from maximum to minimum. This work involved determining the optimum ratio of primary to secondary fuel, primary and secondary fuel injection pattern, number and location of primary and secondary fuel injectors and air velocity and flow pattern. After determining the optimum design configuration while firing natural gas, the burner was tested with a variety of other fuels and further optimization was done. The resultant staged fuel burner designed for flue gas recirculation has been designated as the John Zink SFR burner.

In addition to the development of the John Zink SFR burner, work was done to develop a staged fuel burner that recirculates products of combustion within the burner itself without an external fan. This natural draft staged fuel burner with self recirculated flue gas, designated as the John Zink NDR burner, uses the momentum of the fuel and combustion air to recirculate combustion products from the furnace and does not require flue gas recirculation fans or duct work. The performance of this burner can be enhanced with the utilization of a small amount of inert gas or compressed air.

DEVELOPMENT TEST RESULTS

Figures 3 through 5 show the results from the SFR burner development tests done at the John Zink International Research Center. Figure 3 shows some of the data collected for natural gas firing. The lower curve shows the variation of NOx with flue gas recirculation for ambient combustion air. The data shows that the NOx level was about 27 PPM without FGR, which is well below the 40 PPM limit of Rule 1146 and very near the limit of 25 PPM (0.03 lb. of NOx per million Btu) mandated by Rule 1109. By introducing flue gas recirculation this low NOx level was further reduced. With 15% FGR the level was less than half. The upper curve shows the behavior with 500 °F combustion air. Without FGR the NOx was nearly double that seen with ambient air. However, with less than 5% FGR, the Rule 1146 level is met and with 15% FGR the NOx level was below the 0.031b per million Btu level mandated by Rule 1109.

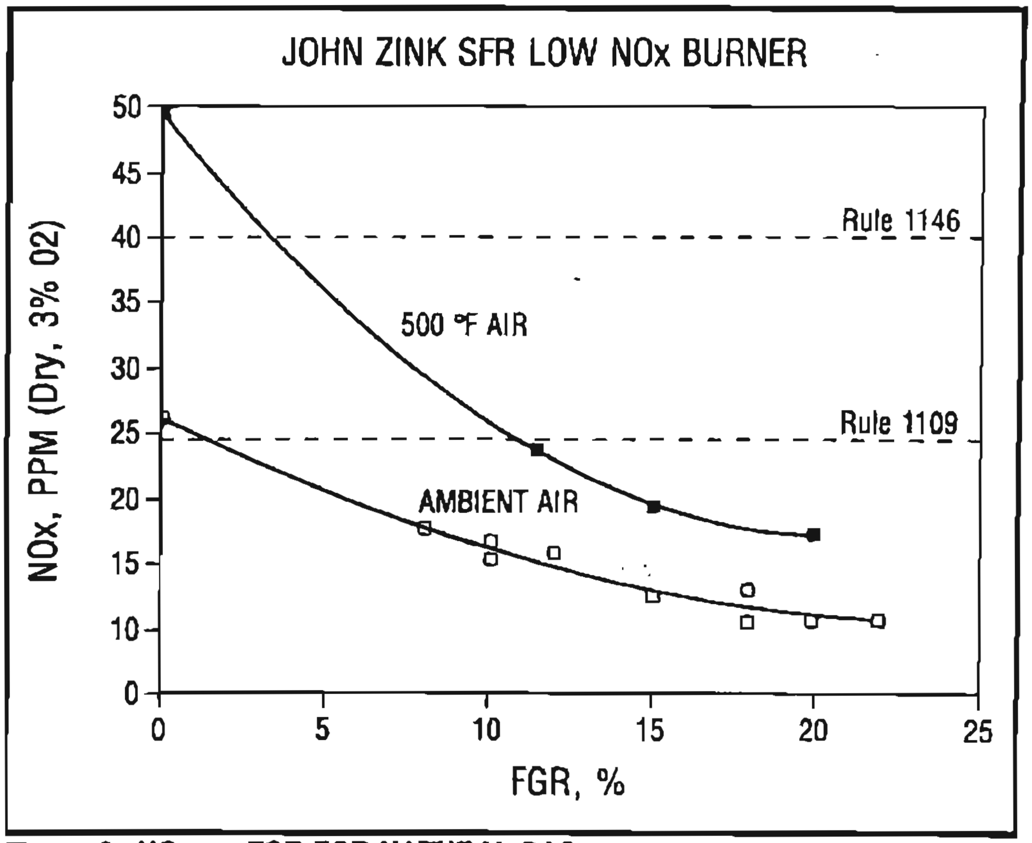

Figure 3 NOx vs. FGR FOR NATURAL GAS

Figure 4 compares the natural gas data with data for a fuel gas mixture of 30% propane, 40% hydrogen and 30% natural gas for ambient combustion air and 500 °F combustion air. Once again the NOx for the fuel gas mixture is higher than that for natural gas. With ambient air the Rule 1146 level of 40 PPM was met without FGR. For the preheated air case FGR was required to meet both rules. With 500°F combustion air, meeting the Rule 1109 level required the addition of nearly 20% flue gas recirculation. The data show FGR levels up to 35%. This high FGR rate is possible because the hydrogen in the fuel aids in stabilizing the flame.

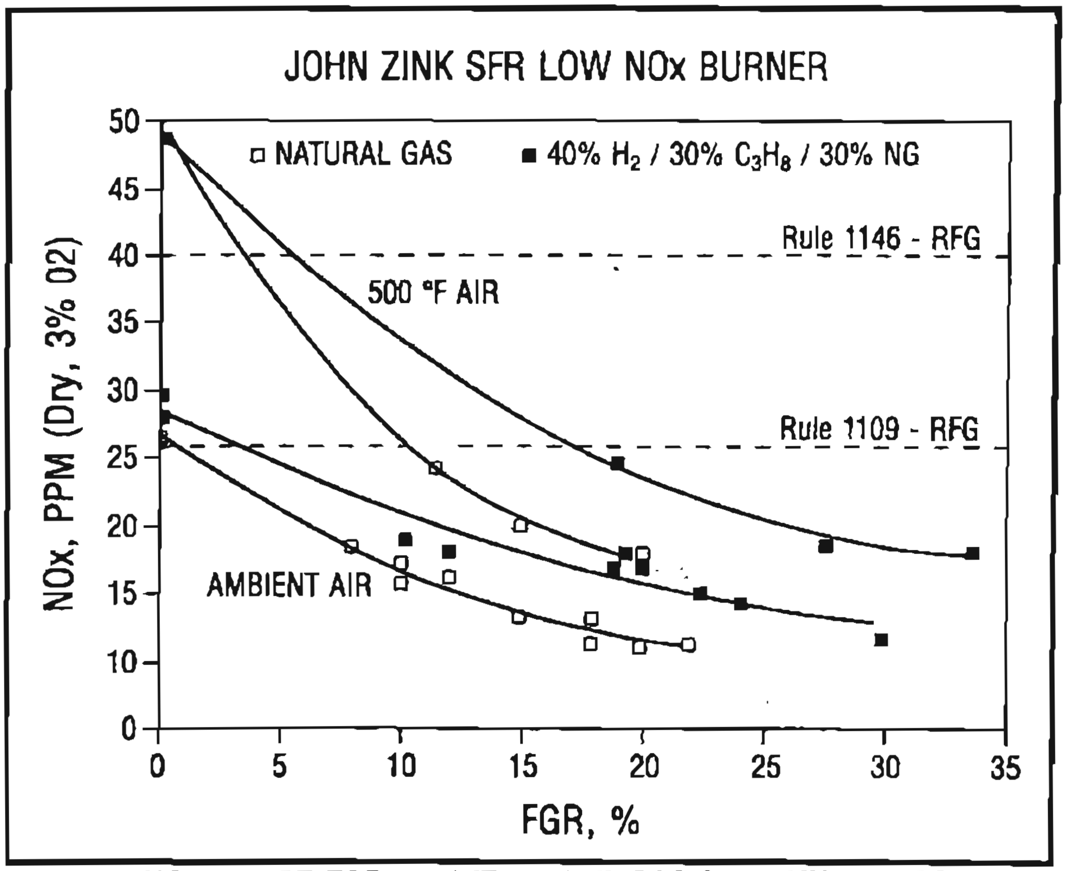

Figure 4 NOx vs. FGR FOR REFINERY FUEL GAS CONTAINING PROPANE

Figure 5 shows the same comparison for a mixture of 30% propylene, 40% hydrogen and 30% natural gas with ambient combustion air. This figure shows that the base NOx without FGR, 35 PPM, is higher for this composition than for the other fuels. This is the case because this mixture has a higher adiabatic flame temperature than the other fuels. As with the other fuel compositions, however, this level drops with the addition of FGR. In this case the NOx level is down to 18 PPM with 20% FGR.

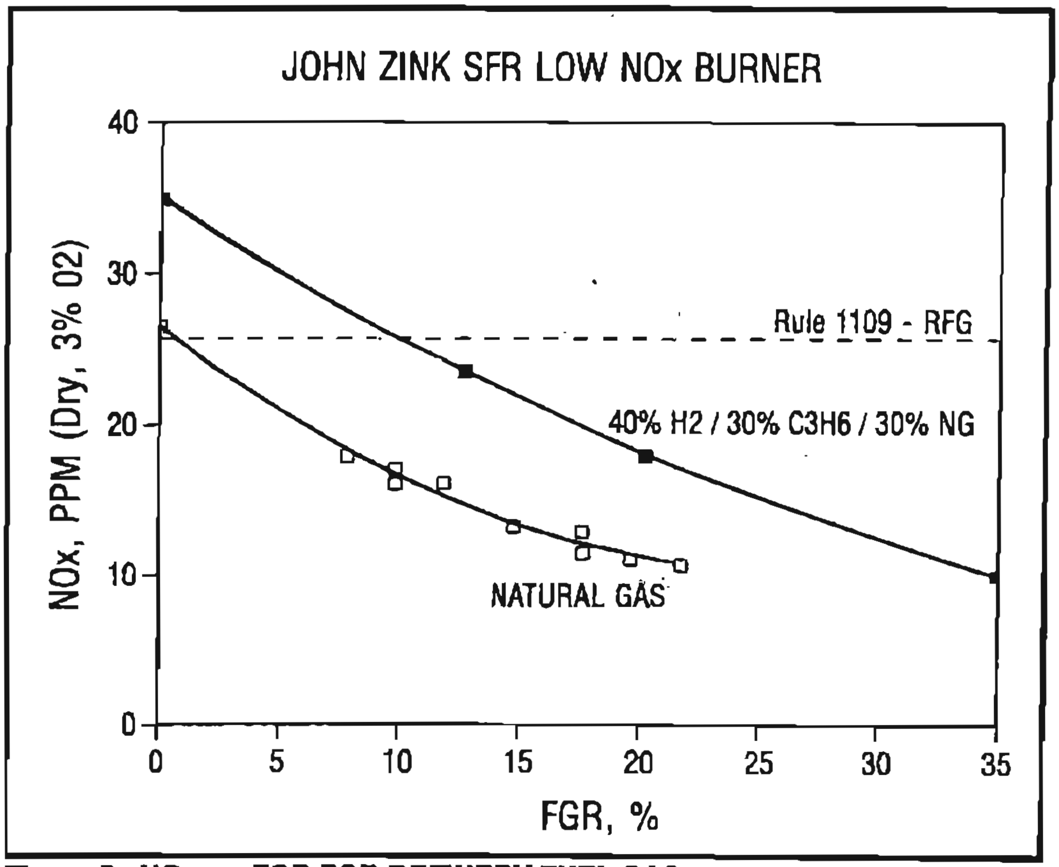

Figure 5 NOx vs. FGR FOR REFINERY FUEL GAS

Figure 6 shows results from the John Zink NDR (self-recirculating) burner using a mixture of 30% propane, 40°.6 hydrogen and 30% natural gas. With this burner, the rate of flue gas recirculation can be increased by injecting a small amount of inert gas or compressed air into the burner. As shown, a small quantity of steam can significantly reduce the NOx level, even with a difficult fuel. In this case, the NOx level was reduced by nearly two-thirds, from 26 PPM to about 9 PPM with approximately 0.22 lb. of steam per lb. of fuel.

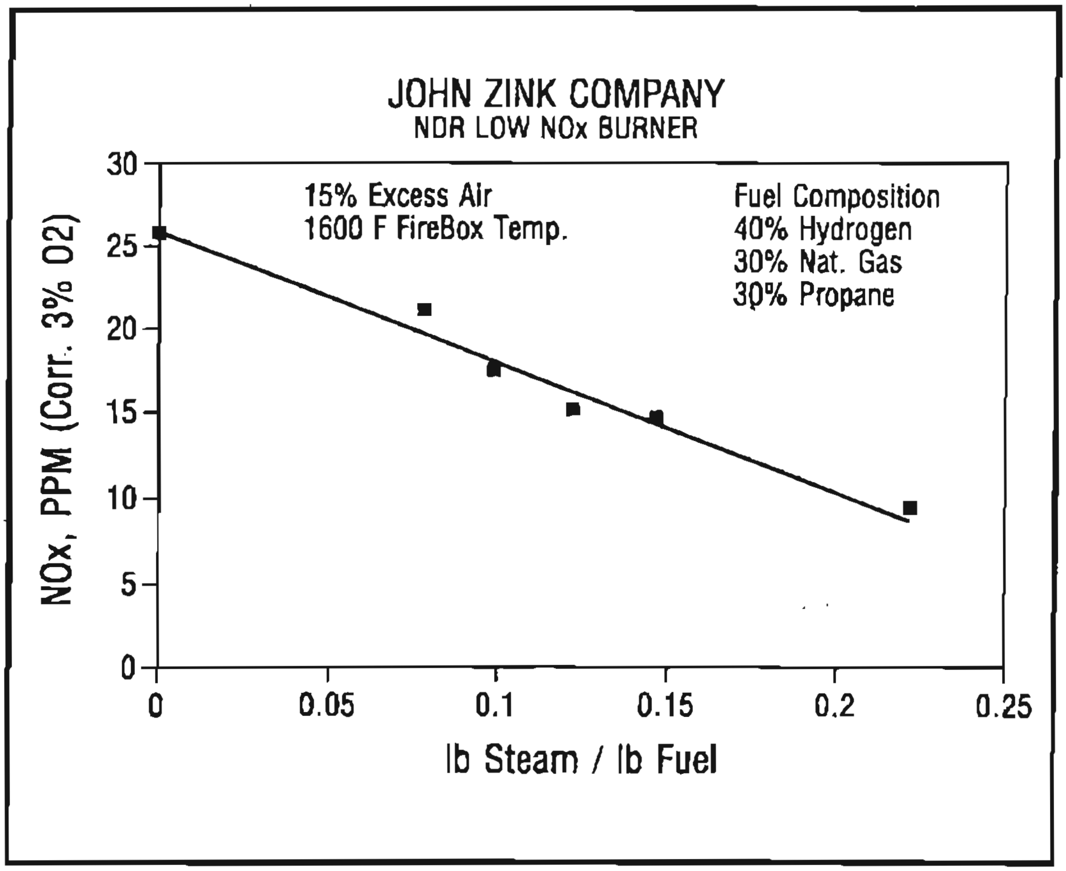

Figure 6 NDR LOW NOx PERFORMANCE

FIELD TEST RESULTS

Three John Zink PSFR-16M LoNox burners were installed in August 1989 at Unocal's Los Angeles Refinery in Wilmington, California. The installation was to verify the John Zink development test results in an operating environment. Flue gas recirculation was not utilized for this test.

The heater is a vertical cylindrical furnace built in 1969. The heater superheats 400 psig saturated steam from a refinery header from 448°F to 750°F and delivers it to a steam turbine. Typical steam flow rate is 80-90 M lbs/hr with a design capacity of 100 M lbs/hr. The radiant section is 7 ft.-2 in. diameter and 25 ft. tall. The nominal bridge wall temperature is 1650°F and the available draft at the floor is 0.35 in. w.c.

An SCAQMD permit was submitted and approved to test this heater under Rule 441, Research Operation. The heater maximum gross input is limited to 25 MM Btu/hr, while the capacity of each burner is 9.5 MM Btu/hr. The refinery fuel gas has a heat content of 1300-1500 Btu/scf (HHV).

Three John Zink HEVR-20 burners were removed and the floor and fuel gas piping were modified to accept the new John Zink PSFR burners. The three PSFR burners were initially configured exactly the same as one used in the test furnace. Minor modification of the secondary burner tips was needed to optimize the NOx and CO emissions to acceptable levels. This was necessary because the three burners were installed on a very tight burner circle. Emissions data are tabulated for the HEVR and PSFR burners in Table 2, and plotted for the PSFR burners in Figures 7 and 8. With the optimized secondary fuel tips, CO emissions from the PSFR burners were 0 ppm in most cases. When the 02 was reduced to 2%, the CO emissions were still less than 50 ppm.

Table 2

Unocal Los Angeles Refinery
Heater Emissions Tests
John Zink HEVR-20 vs. PSFR-16M Burners
Fuel Firing Rate Approximately 20 MM Btu/hr (HHV)

		NOx		CO
Burners	O_2%	PPM	#/MM Btu	PPM
HEVR-20	2.4-2.8	100-130	0.12-0.15	10-21
PSRF-16M	2.0	29	0.033	41
	3.5	32	0.040	0
	4.2	34	0.044	0
	4.6	35	0.046	0
	5.3	35	0.048	0
	5.9	35	0.050	0

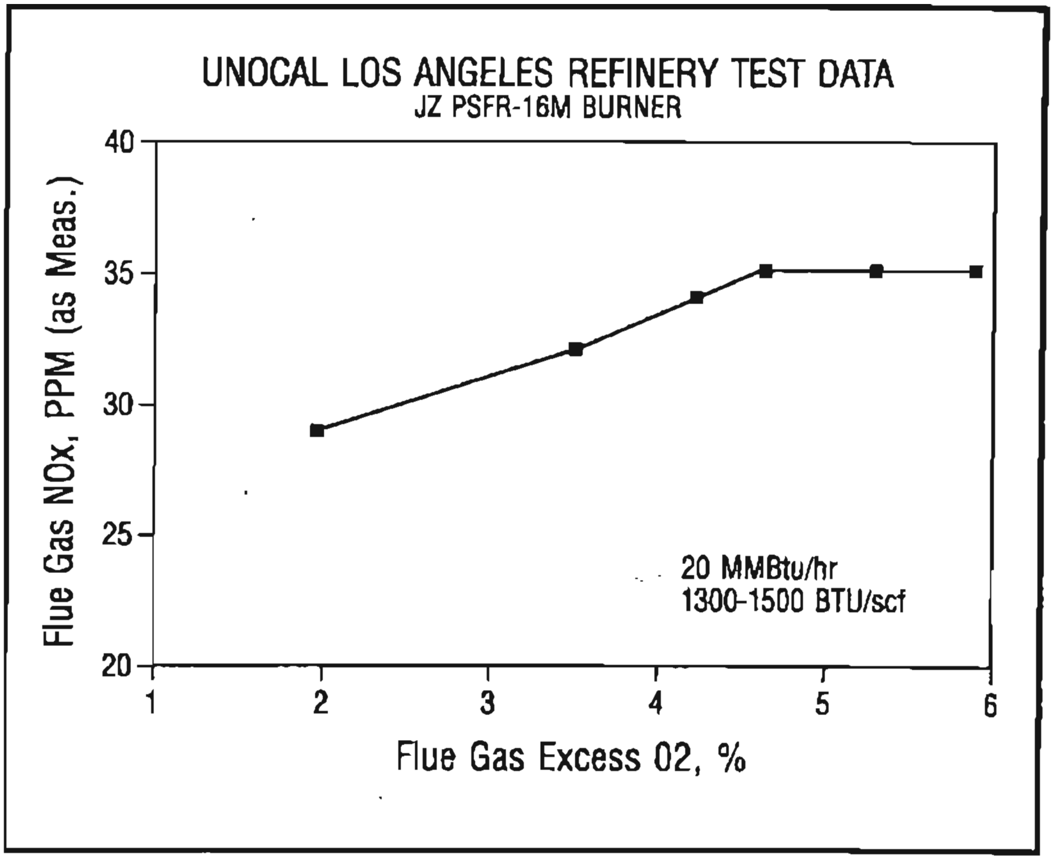

Figure 7 FIELD TEST DATA IN PPM OF NOx vs. EXCESS O_2 IN STACK

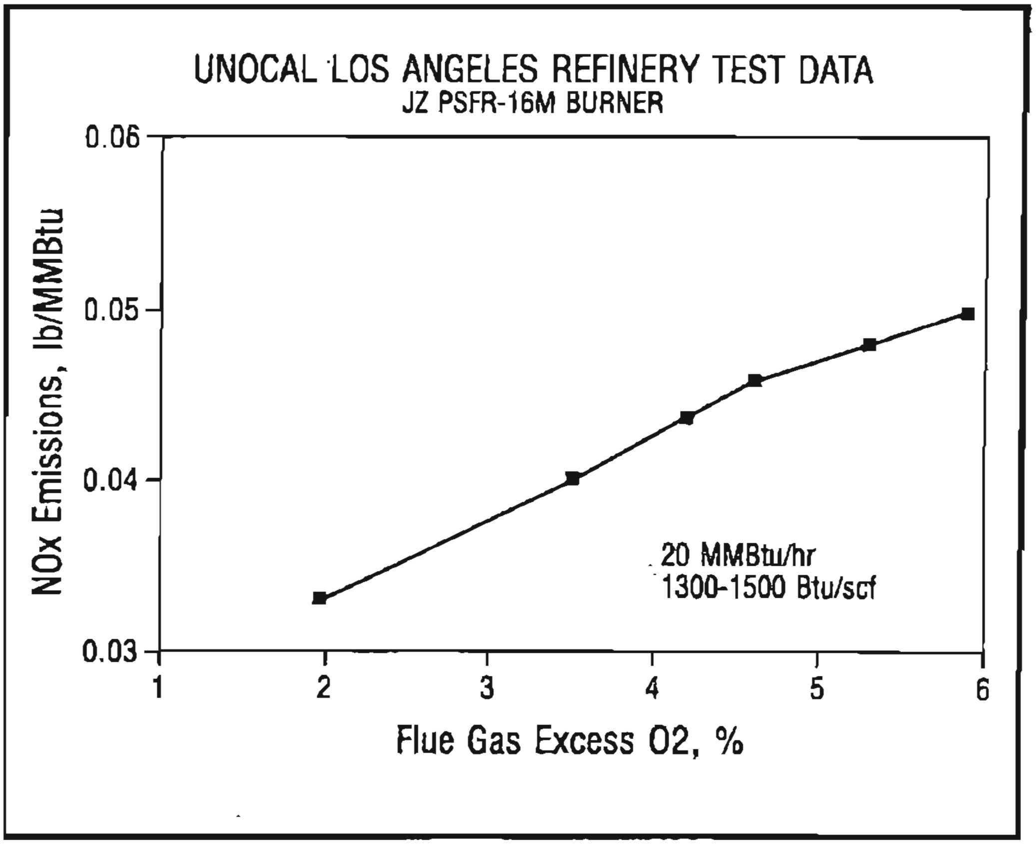

Figure 8 FIELD TEST DATA IN LBS OF NOx PER MMBtu vs. EXCESS O_2

DISCUSSION AND CONCLUSIONS

Table 3 shows a comparison of the measured base NOx emissions (without FGR) and calculated adiabatic flame temperature for several fuel compositions. As would be expected, the table shows that the NOx emissions increase as the adiabatic flame temperature increases. The emissions also appear to be very sensitive to flame temperature, since they increase by 33%, from 27 to 35 PPM, with only a 130 °F increase in adiabatic flame temperature.

Table 3

Flame Temperature and NOx for Various Fuel Gases without Flue Gas Recirculation

	Flame Temp. °F	NOx, (3% O_2) PPM
Natural Gas	3385	27
40% H_2 / 30% C_3H_8 / 30% Nat. Gas	3450	28
50% H_2 / 50% Nat. Gas	3465	28
40% H_2 / 30% C_3H_6 / 30% Nat. Gas	3515	35

Another interesting finding is that, except for the propylene fuel mixture, a higher rate of flue gas recirculation was required to achieve a given percentage reduction in NOx for the refinery fuel gas mixtures compared to the natural gas fuel. This is shown by the lower slope of the NOx versus FGR curves for the mixed fuel gases. The variation in response to FGR between the different fuel compositions is also great enough to require that data must be collected for a wide variety of fuel compositions in order to allow accurate prediction of emissions.

The test furnace at Unocal has been in nearly continuous service since it was first started up in August 1989. Any downtime cannot be attributed to the burners. With a three-burner arrangement and their maximum capacity, one burner can be removed from service at a time with slightly reduced steam outlet temperature. No flame impingement problems or hot spots have been observed.

After about three months service the tips were removed for inspection and cleaning. Heavy fouling was found in the primary tips but emission readings prior to removal showed acceptable results.

In the field test, the PSFR burners meet the Rule 1146 requirements over the range of operation tested. To date, the actual refinery fuel gas composition is less severe in terms of NOx emissions than the fuel gas compositions that were used during the development tests, and each burner has been fired at about 70% of maximum firing rate.

In summary, John Zink development data and the Unocal field test data, show that it is possible to meet the SCAQMD Rule 1146 NOx emission limit of 40 PPM utilizing the SFR burner without FGR when using ambient air. The John Zink development data shows that the Rule 1109 NOx emission limit of 0.03 Ib/MM Btu can be easily met using either the SFR burner with forced draft flue gas recirculation or with the self-recirculating NDR and a small quantity of inert gas, such as steam.

JOHN ZINK COMPANY

A Division of KOCH

KOCH ENGINEERING COMPANY INC

International Headquarters
4401 South Peoria Avenue P.O. Box 702220
Tulsa, Oklahoma 74170 (918) 7471371
Other offices are located in major cities around the world.

Technical Paper 4600

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	
NITROGEN OXIDES EMISSIONS FROM	)	R08-19
VARIOUS SOURCE CATEGORIES:	)	(Rulemaking – Air)
AMENDMENTS TO 35 ILL. ADM. CODE	)	
PARTS 211 AND 217	)	

MOTION TO CORRECT TRANSCRIPTS

NOW COMES the Illinois Environmental Protection Agency ("Illinois EPA"), by its attorneys, and pursuant to 35 Ill. Adm. Code § 101.604, requests that the Illinois Pollution Control Board ("Board") order the correction of the transcripts of the hearing held in this matter on December 9 and 10, 2008, as follows:

Transcript for December 9, 2008

Page	Line	Correction
5	3	Change "Arselor Natel" to "ArcellorMittal"
13	17	Change "TOx" to "NOx"
15	17	Change "SCR's" to "SCRs"
16	6	Change "SCR's" to "SCRs"
29	2	Change "controlled" to "control"
33	4	Change "or" to "for"
37	7	Change "MOD" to "MOG"
39	15	Change "state" to "date"
48	11	Change "non-EGU's" to "non-EGUs"
50	3	Change "proposed" to "that the proposed"
50	4	Change "rules" to "rule is"
51	13	Change "EGU's" to "EGUs"
52	9	Change "Agency's" to "Agency is"

Page	Line	Correction
52	10	Change "strength in" to "strengthened"
53	6	Change "in" to "with"
60	6	Change "non-EGU's" to "non-EGUs"
60	7	Change "EGU's" to "EGUs"
61	6	Change "it binding" to "a finding"
61	12	Change "findings" to "finding"
61	13	Change "block" to "clock"
61	14	Change "block" to "clock"
61	15	Change "block" to "clock"
67	4	Change "Mr. Vetterhoffer" to "Ms. Vetterhoffer"
67	9	Change "obtain acts" to "attain NAAQS"
67	11	Change "for successful" to "for a successful"
81	3	Change "EGU's" to "EGUs"
82	1	Change "non-EGU's" to "non-EGUs"
82	8	Change "non-EGU's" to "non-EGUs"
82	11	Change "non-EGU's" to "non-EGUs"
82	12	Change "non-EGU's" to "non-EGUs"
82	18	Change "non-EGU's" to "non-EGUs"
83	8	Change "non-EGU's" to "non-EGUs"
83	10	Change "non-EGU's" to "non-EGUs"
83	12	Change "non-EGU's" to "non-EGUs"
83	22	Change "non-EGU's" to "non-EGUs"
85	4	Change "EGU's" to "EGUs"

Page	Line	Correction
85	6	Change "non-EGU's" to "non-EGUs"
85	24	Change "non-EGU's" to "non-EGUs"
86	9	Change "non-EGU's" to "non-EGUs"
96	18	Change "strength in" to "strengthened"
108	11	Change "EGU's" to "EGUs"
112	8	Change "EGU's" to "EGUs"
112	11	Change "non-EGU's" to "non-EGUs"
112	14	Change "limitation" to "implementation"
117	10	Change "SCR's and SNCR's" to "SCRs and SNCRs"
127	11	Change "NCR" to "SNCR"
128	8	Change "SCR's" to "SCRs"
128	11	Change "SCR's" to "SCRs"
133	7	Change "EGU's" to "EGUs"
133	8	Change "EGU's" to "EGUs"
142	22	Change "to" to "due to"
144	8	Change "RACT" to "BACT"
144	16	Change "SCR's" to SCR as"
144	22	Change "RACT/BACT" to "RACT/BACT/LAER"
144	24	Change "specifically" to "typically"
145	6	Change "such" to "such a"
145	11	Change "MMBtu's" to "MMBtu"
161	8	Change "boiler process heater" to "boiler or process heater"
166	7	Change "SCR's" to SCRs"

Page	Line	Correction
166	16	Change "per pounds" to "in pounds"

Transcript for December 10, 2008

Page	Line	Correction
4	4	Change "wil" to "will"
5	8	Change "controlled" to "control"
5	23	Change "Siebenberg" to "Siebenberger"
6	11	Change "Siebenberg" to "Siebenberger"
6	14	Change "Greater" to "Granite"
7	13	Change "combustion" to "combust"
7	17	Change "through" to "flue"
7	22	Change "inflation" to "installation"
10	12	Change "controlled" to "control"
10	21	Change "boilers on 11 and 12" to "boilers 11 and 12"
11	23	Change "questions on my" to "questions on"
12	15	Change "promotion" to "combustion"
12	26	Change "results in" to "resulting"
12	17	Change "unsulphurized" to "undesulphurized"
15	14	Change "emission case" to "emission rate"
19	9	Insert "burners" after "NOx"
21	20	Change "production" to "reduction"
30	3	Insert "burner" after "NOx"
30	13	Change "source" to "worst"

Page	Line	Correction
36	20	Change "boiler 1" to "boiler 11"
36	23	Change "Strapper" to "Stapper"
37	5	Change "boilers" to "further"
37	15	Change "Ulstom" to "Alstom"
38	3	Change "Ulstom" to "Alstom"
40	24	Change "draft emission" to "RACT emission limits"
42	3	Change "if" to "is that"
42	7	Change "controlled" to "control"
42	8	Change "flammability" to "flame stability"
43	6	Change "NGCR" to "SNCR"
43	9	Change "NGCR" to "SNCR"
43	13	Change "NGCR" to "SNCR"
43	20	Change "NGCR available" to "SNCR a viable"
44	9	Change "uria" to "urea"
49	22	Change "Strapper" to "Stapper"
54	10	Change "Strapper" to "Stapper"
54	11	Change "Strapper" to "Stapper"
57	17	Change "exempts" to "accepts"
58	5	Change "EK" to "DK"
58	8	Change "IER" to "IERG"
58	12	Change "Wanningers'" to "Wanninger's"
59	5	Change "10.15" to "0.15"
60	11	Change "noncatalyte" to "noncatalytic"

Page	Line	Correction
62	5	Change "HIS Sarah" to "IHS-CERA"
62	11	Change "Webco" to "WEPCO"
63	21	Change "combine" to "combined"
63	23	Change "vacature" to vacatur"
65	1	Change "burn" to "burden"
65	13	Change "I H I C" to "IHI-CERA"
65	14	Delete "ERA"
68	23	Change "extrapolaiton" to "extrapolation"
69	24	Change "projection costs," to "projection, costs"
70	20	Insert "Ms. Roccaforte:" before "I'm sure"
70	24	Change "Mr. Roccaforte" to "Ms. Roccaforte"
73	22	Change "Generations" to "Generation's"
75	24	Change "plan to start the update" to "planned startup date"

WHEREFORE, for the reasons set forth above, the Illinois EPA respectfully requests that the Board order the correction of the hearing transcripts as set forth above.

Respectfully submitted,
ILLINOIS ENVIRONMENTAL
PROTECTION AGENCY

By: ____________________
Gina Roccaforte
Assistant Counsel
Division of Legal Counsel

DATED: January 20, 2009

1021 North Grand Avenue East
P. O. Box 19276
Springfield, IL 62794-9276
217/782-5544

THIS FILING IS SUBMITTED ON RECYCLED PAPER

STATE OF ILLINOIS)
) **SS**
COUNTY OF SANGAMON)
)

CERTIFICATE OF SERVICE

I, the undersigned, an attorney, state that I have served electronically the attached TESTIMONY OF ROBERT KALEEL, TESTIMONY OF MICHAEL KOERBER, TESTIMONY OF JAMES E. STAUDT, Ph.D., MOTION TO CORRECT TRANSCRIPTS, and DRAFT ATTAINMENT DEMONSTRATION FOR THE 1997 8-HOUR OZONE NATIONAL AMBIENT AIR QUALITY STANDARD FOR THE CHICAGO NONATTAINMENT AREA, AQPSTR 08-07, AND RELATED DOCUMENTS, upon the following person:

John Therriault
Assistant Clerk
Illinois Pollution Control Board
James R. Thompson Center
100 West Randolph St., Suite 11-500
Chicago, IL 60601

and electronically to the following persons:

SEE ATTACHED SERVICE LIST

ILLINOIS ENVIRONMENTAL
PROTECTION AGENCY,

Gina Roccaforte
Assistant Counsel
Division of Legal Counsel

Dated: January 20, 2009

1021 North Grand Avenue East
Springfield, Illinois 62794-9276
(217) 782-5544

SERVICE LIST 08-19

Timothy J. Fox
Hearing Officer
Illinois Pollution Control Board
100 W. Randolph St., Suite 11-500
Chicago, IL 60601
foxt@ipcb.state.il.us

Matthew Dunn
Chief
Environmental Bureau North
Office of the Attorney General
69 W. Washington St., Suite 1800
Chicago, IL 60602
mdunn@atg.state.il.us

Virginia Yang
Deputy Legal Counsel
Illinois Department of Natural Resources
One Natural Resources Way
Springfield, IL 62702-1271
virginia.yang@illinois.gov

Kathleen C. Bassi
Stephen J. Bonebrake
Schiff Hardin LLP
6600 Sears Tower
233 S. Wacker Drive
Chicago, IL 60606-6473
kbassi@schiffhardin.com
sbonebrake@schiffhardin.com

Katherine D. Hodge
Monica T. Rios
Hodge Dwyer Zeman
3150 Roland Ave.
P.O. Box 5776
Springfield, IL 62705-5776
khodge@hdzlaw.com
mrios@hdzlaw.com

Alec M. Davis
General Counsel
Illinois Environmental Regulatory Group
215 E. Adams St.
Springfield, IL 62701
adavis@ierg.org

Christina L. Archer
Associate General Counsel
ArcelorMittal USA
1 South Dearborn Street, 19th Floor
Chicago, IL 60603
christina.archer@arcelormittal.com