

REINHOLD ENVIRONMENTAL Ltd.



## **2015 NO<sub>x</sub>-Combustion Round Table & Expo Presentations**

February 23 & 24, 2015, in Richmond, VA / Hosted by Dominion

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# **Enhanced Gas Cofiring Commercial & Environmental Benefits**

Presented by: Cal Lockert/Breen Energy

March, 2014





# What Drives Economic Plant Viability?





- MATS
- Acid Rain
- SO<sub>2</sub>
- NO<sub>x</sub>
- PM<sub>2.5</sub>
- Hg/HAPS



Env Cost

Oper  
Cost



Economy

- Fuel
  - Natural Gas
  - CAPP Coal
  - ILB Coal
  - PRB Coal
- Heat Rate
- Unit Turn Down

Env Cost

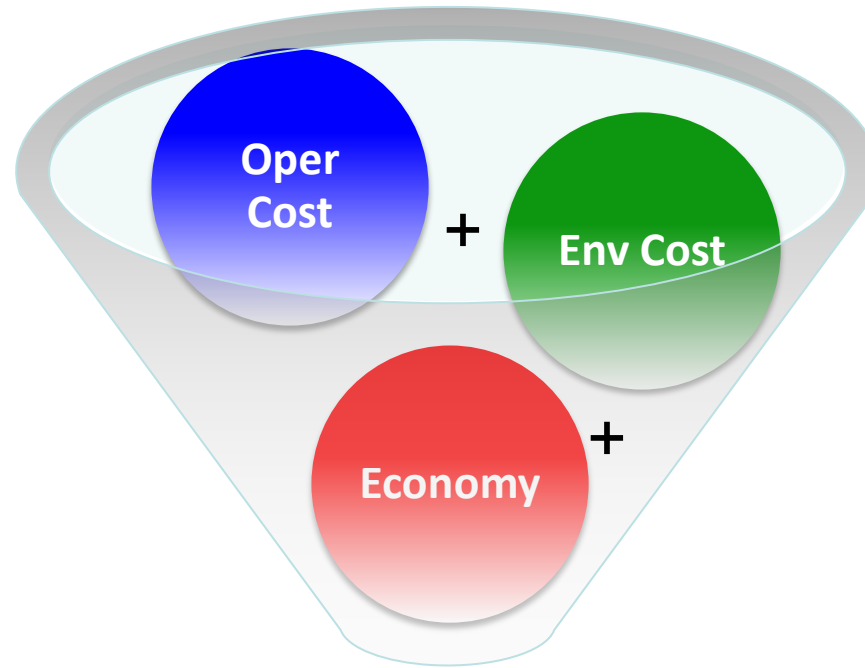
Oper Cost

**Economy**



- Demand
- Wind
- Solar

# A Different Look



**Unit Viability**



***This was all written before the release of the EPA's Clean Power Plan in June 2014.***

**Now plants must also consider this:**

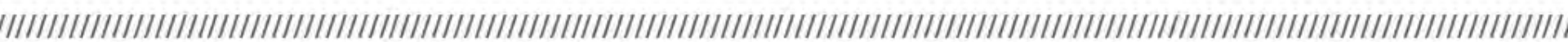
Technical Support Document (TSD) for  
Carbon Pollution Guidelines for Existing Power Plants:  
Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources:  
Electric Utility Generating Units

Docket ID No. EPA-HQ-OAR-2013-0602

**GHG Abatement Measures**

U.S. Environmental Protection Agency  
Office of Air and Radiation

June 10, 2014



1. Reducing the carbon intensity of generation at individual affected EGUs through **heat rate improvements**;
2. Reducing emissions from the most carbon-intensive affected EGUs in the amount that results from **substituting generation at those EGUs with generation from less carbon intensive affected EGUs** (including NGCC units under construction);
3. Reducing emissions from affected EGUs in the amount that results from **substituting generation at those EGUs with expanded low- or zero-carbon generation**; and,
4. Reducing emissions from affected EGUs in the amount that results from the use of **demand-side energy efficiency** that reduces the amount of generation required.

# Section Details

ENVIRONMENTAL, OPERATING & ECONOMY IMPACTS



# Commercial Considerations



# Current Coal Prices

Coal commodity regions	Week ended			
	1/30/2015	2/6/2015	2/13/2015	2/20/2015
Central Appalachia 12,500 Btu, 1.2 SO <sub>2</sub>	\$53.06	\$53.06	\$53.06	\$53.06
Northern Appalachia 13,000 Btu, <3.0 SO <sub>2</sub>	\$63.15	\$63.15	\$63.15	\$61.15
Illinois Basin 11,800 Btu, 5.0 SO <sub>2</sub>	\$45.32	\$45.32	\$42.32	\$40.32
Powder River Basin 8,800 Btu, 0.8 SO <sub>2</sub>	\$11.55	\$11.55	\$11.55	\$11.55
Uinta Basin 11,700 Btu, 0.8 SO <sub>2</sub>	\$38.13	\$38.13	\$38.13	\$38.13

Source: U.S. Energy Information Administration, [Coal News & Markets](#)

$$CApp_{Avg} = \$2.12$$

$$Napp_{Avg} = \$2.41$$

$$ILB_{Avg} = \$1.84$$

$$PRB_{Avg} = \$0.65$$

**Avg. Delivered  
Forecast for 2015  
= \$2.34/mmBTU**

**Henry Hub Natural Gas Spot Price (Dollars per Million Btu)**

Week Of	Mon	Tue	Wed	Thu	Fri
2015 Jan-19 to Jan-23		2.94	2.94	2.95	2.96
2015 Jan-26 to Jan-30	2.92	2.96	2.89	2.88	2.88
2015 Feb- 2 to Feb- 6	2.88	2.67	2.73	2.66	2.66
2015 Feb- 9 to Feb-13	2.62	2.67	2.86	2.86	2.75
2015 Feb-16 to Feb-20	2.75	2.75			

Average Henry Hub Pricing for last 4 weeks = \$2.81

Allowing \$0.40/mmBTU for Delivery = \$3.21/mmBTU

## Heat Rates

- **Small Coal Plant** 10.00 mmBTU/MW hr
- **Combined Cycle Gas Plant** 6.75 mmBTU/MW hr

## Fuel Prices

- **Avg. Coal (delivered)** \$2.34/mmBTU
- **Gas (delivered)** \$3.21/mmBTU

## Cost/MW hr

- **CAPP = \$2.34 x 10 = \$23.40/MW hr**
- **Gas = \$3.21 x 6.75 = \$21.67/MW hr**

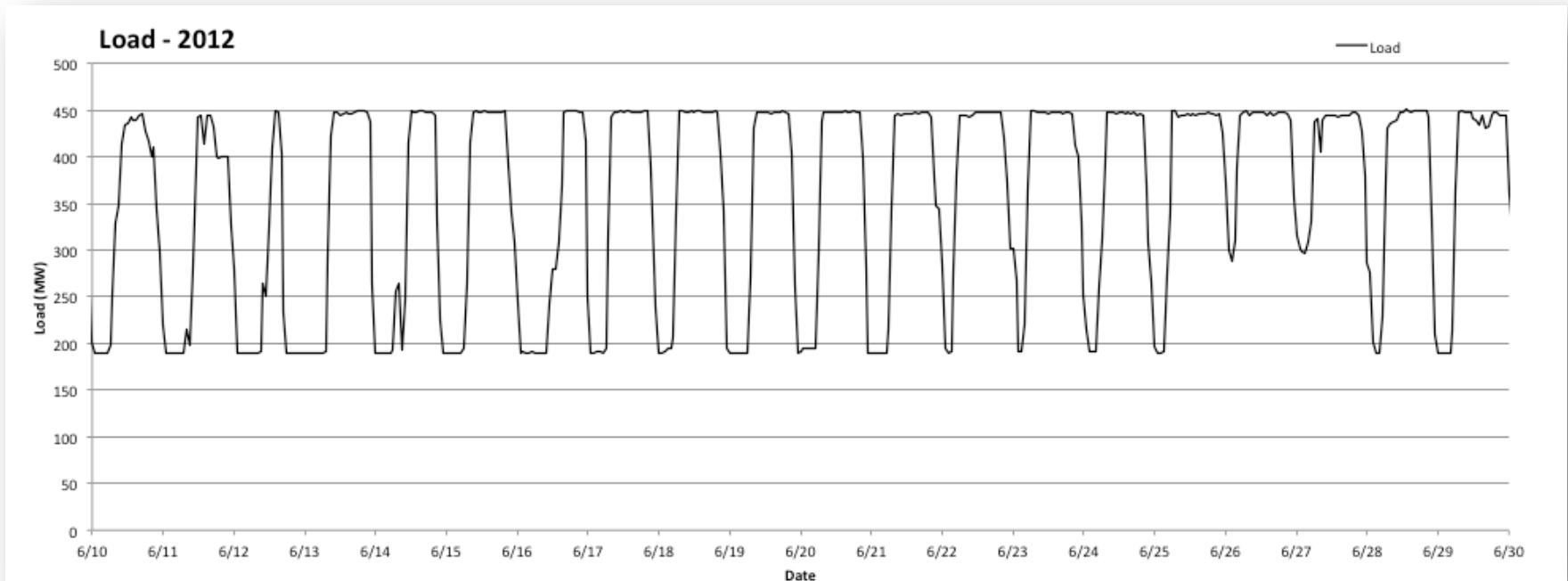


# Economy Considerations

## LOAD CYCLING



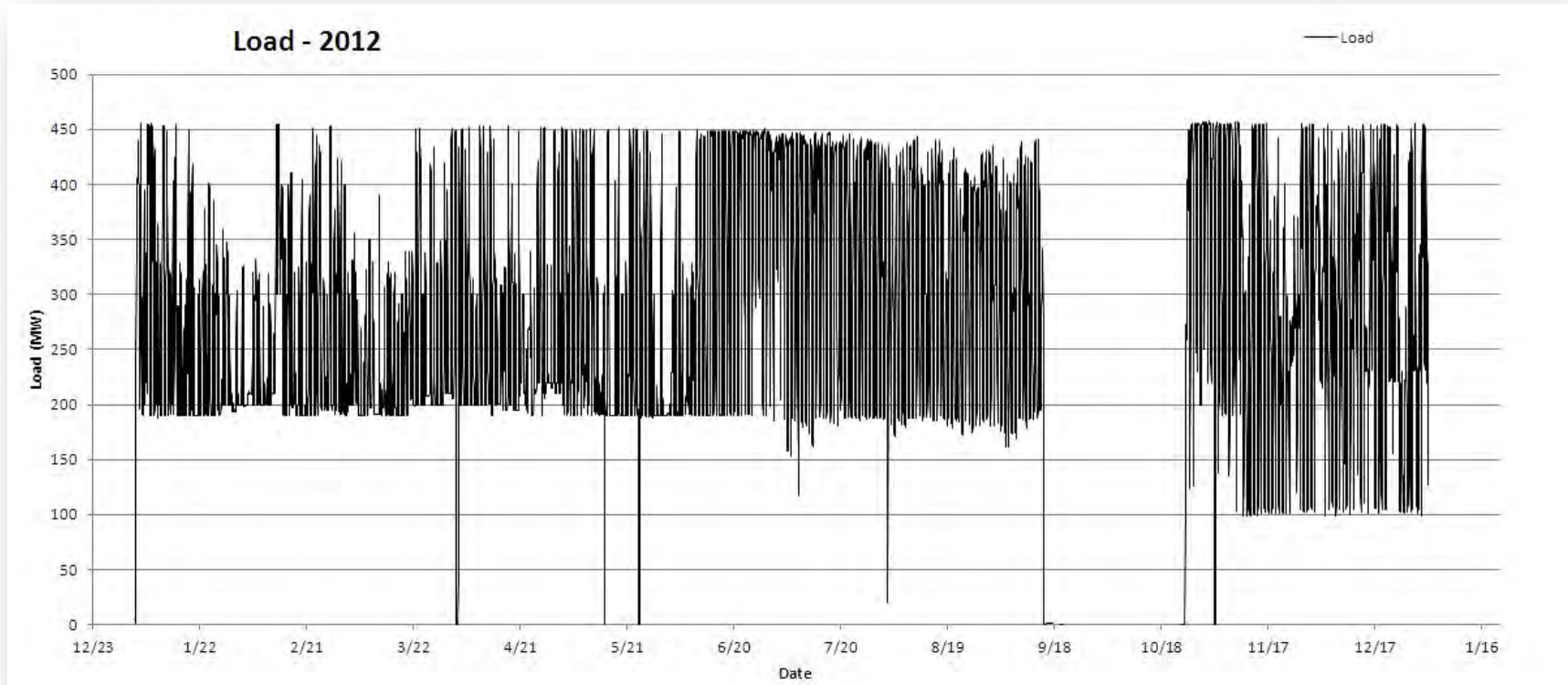
# Typical Load Cycling Curve



In the presence of solar and wind supply, coal plants are being forced to cycle more dramatically than in the past. All emissions are affected by load transition and unstable firing conditions.

- **Wind in the Southwest presents problems due to variability and timing of useful wind patterns**
- **PV in Southern Ca/FL and NC has become a major problem:**
  - Residential PV is creating phase imbalances that require non-billable utility generation to stabilize,
  - Timing of Solar residential generation does not coincide with residential vs. industrial demand
- **Coal and CC generation must be able to follow demand on a much more rapid and close coupled basis**

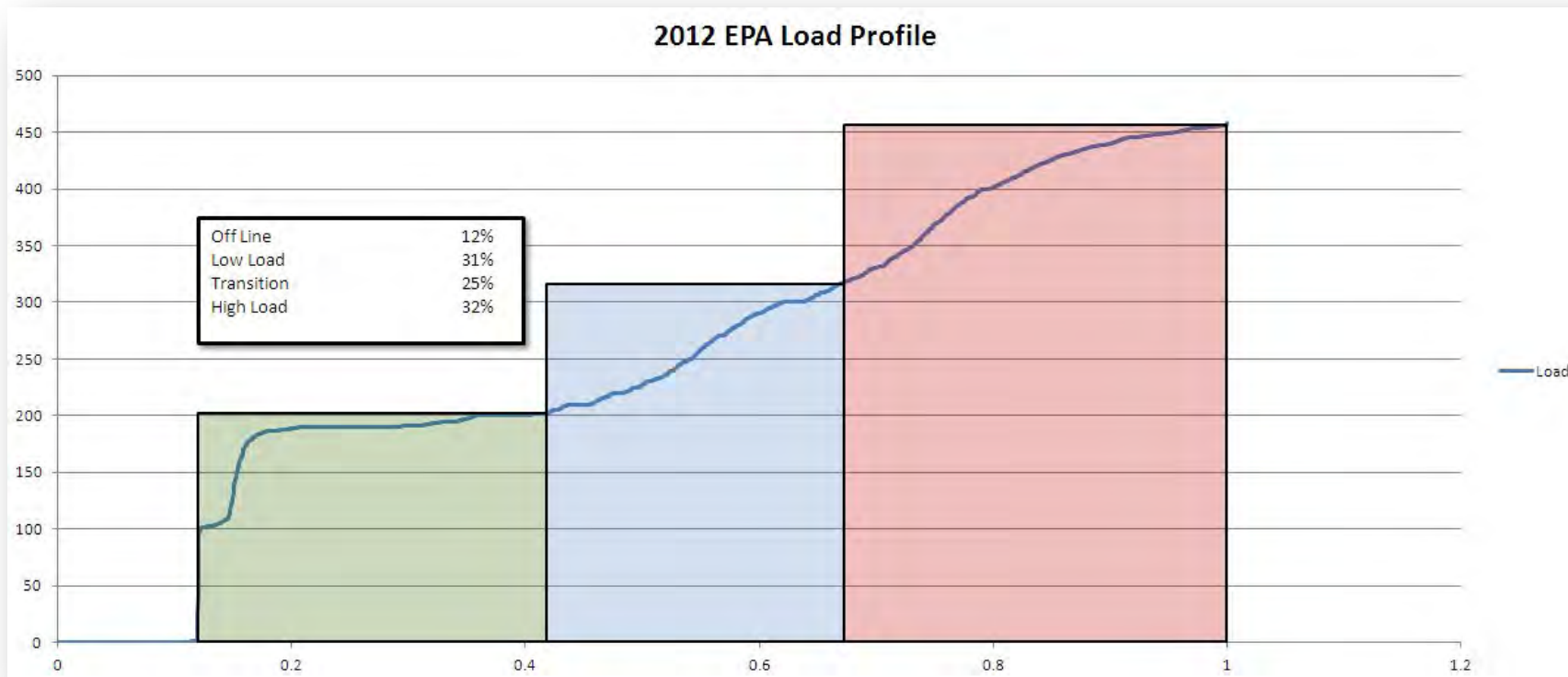
# Minimum Load Considerations



Source: EPA Acid Rain Database

Cycling has a major effect on total system dispatch effectiveness. Allowing the coal plant to achieve a much lower minimum load can have dramatic system wide cost and emissions implications.

# Load Profile



**31% of 8,760 hours = 2,716 annual hours at low load**

- **$2,716 \times 200\text{MW} = 543,200 \text{ MWH}$**
- **$543,200\text{MWH} \times 10 \text{ mmBTU/MWH} = 5,432,000 \text{ mmBTU}$**
- **$5,432,000 \text{ mmBTU} \times \$2.34/\text{mmBTU} = \$12,710,880$**
  
- **$2,716 \text{ Hr} \times 100\text{MW} (50\% \text{ Coal/Gas})$**
- **$2,716 \times 50\text{MW} \times 10 \text{ mmBTU/MWH} = 1,358,000 \text{ mmBTU Each, Gas and Coal}$**
- **$1,358,000 \text{ mmBTU}_{\text{Coal}} \times \$2.34 = \$3,177,720$**
- **$1,358,000 \text{ mmBTU}_{\text{Gas}} \times \$3.21 = \$4,359,180$**
- **$\text{Total Fuel Low Load CoFire} = \$7,536,900$**

**Fuel Savings from Low Load CoFire Operation = \$5,353,980**



**Reduction to 100MW Floor = \$5,353,980 in coal savings**

- ***Replacement Power from NGCC***
- ***2,716 x 100MW = 271,600 MWH***
- ***271,600 x 6.75 mmBTU/MWH = 1,833,300 mmBTU Gas***
- ***1,833,300 mmBTU x \$3.21 = \$5,884,893 in CC Gas Cost***

**Worst-case Fuel Savings(Loss) = -(\$531,003)/yr.**

**Best-case Fuel Savings = \$5,353,980/yr.**

## CO<sub>2</sub> Emission Factors by Fuel Type per Unit Volume, Mass, and Energy

<i>Fossil Fuel</i>	<i>Emission Factor</i>	<i>Emission Factor</i>	<i>Carbon Factor</i>	<i>Heat Content (HHV)</i>	<i>Carbon Content Coefficient</i>
<b>Coal</b>	(lb CO <sub>2</sub> /short ton)	(lb CO <sub>2</sub> /MMBtu)	(kg C/ short ton)	(MMBtu/ short ton)	(kg C/ MMBtu)
Anthracite Coal	5,675.29	226.16	709.04	25.09	28.26
Bituminous Coal	5,086.36	203.99	635.47	24.93	25.49
Sub-bituminous Coal	3,656.14	211.91	456.78	17.25	26.48
Lignite	2,991.33	210.47	373.72	14.21	26.30
Unspecified (industrial coking)	5,444.58	205.11	680.22	26.54	25.63
Unspecified (industrial other)	4,744.80	205.99	592.79	23.03	25.74
Unspecified (electric utility)	4,289.96	207.91	535.97	20.63	25.98
Unspecified (residential/commercial)	4,779.26	208.39	597.10	22.93	26.04
<b>Natural Gas</b>	(lb CO <sub>2</sub> /ft <sup>3</sup> )		(kg C/ft <sup>3</sup> )	(Btu/ft <sup>3</sup> )	
Natural Gas	0.120	116.39	0.0149	1,027	14.47

CO<sub>2</sub> Release:

Gas = 0.058 Ton/mmBTU

Coal = 0.102 – 0.106 Ton/mmBTU

**31% of 8,760 hours = 2,716 annual hours at low load**

- **$2,716 \times 200\text{MW} = 543,200 \text{ MWH}$**
- **$543,200\text{MWH} \times 10 \text{ mmBTU/MWH} = 5,432,000 \text{ mmBTU}$**
- **$5,432,000 \text{ mmBTU} \times 0.103 \text{ Ton/mmBTU} = 559,496 \text{ Tons CO}_2$**

**Reduction to 100MW Floor @ 50% Coal/Gas**

- **$2,716 \times 50\text{MW}_{\text{Gas/Coal}} = 135,800 \text{ MWH}$**
- **$135,800 \times 10 \text{ mmBTU/MWH} = 1,358,000 \text{ mmBTU Gas \& Coal}$**
- **$1,358,000 \text{ mmBTU} \times 0.058 = 78,764 \text{ Tons CO}_2 \text{ from Gas}$**
- **$1,358,000 \text{ mmBTU} \times 0.103 = 139,874 \text{ Tons CO}_2 \text{ from Coal}$** 
  - **$\text{Total Tons CO}_2 \text{ from Low Load CoFire} = 218,638 \text{ Tons}$**

**Total Low Load CO2 Reduction = 340,858 Tons CO2**



If the 100 MW of reduced load is needed by can be moved to NGCC:

- $2,716 \text{ Hr} \times 100 \text{ MW} = 271,600 \text{ MWH}$
- $271,600 \text{ MWH} \times 6.75 \text{ mmBTU/MWH} = 1,833,300 \text{ mmBTU}$
- $1,833,300 \text{ mmBTU} \times 0.058 = 103,331 \text{ Tons CO}_2 \text{ from CC}$

Low Load CO2 Reduction:

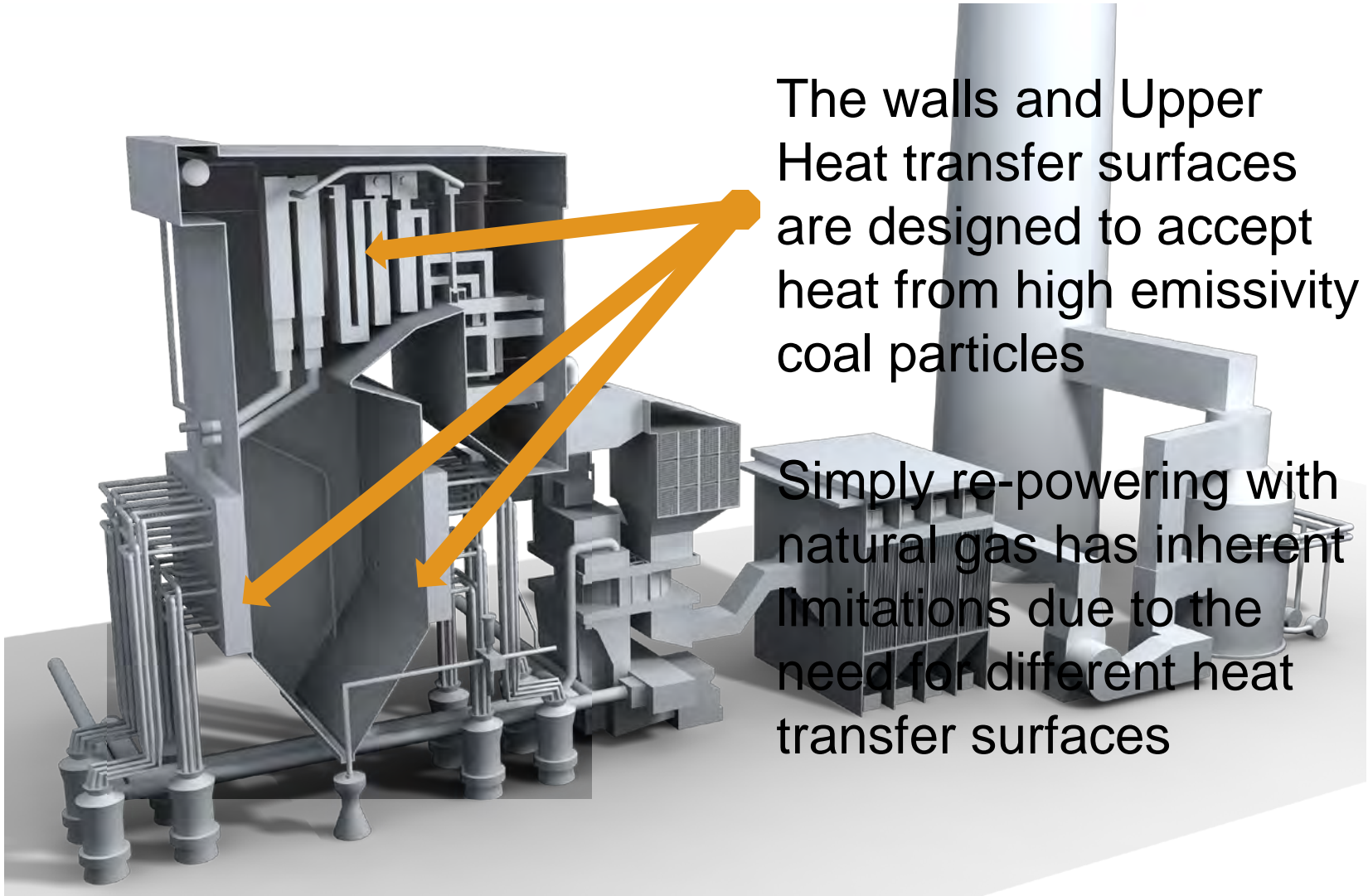
Best-case = ***340,858 Tons***

Worst-case =  $(340,858 - 103,331) =$  ***237,527 Tons***

# Enhanced Gas CoFiring

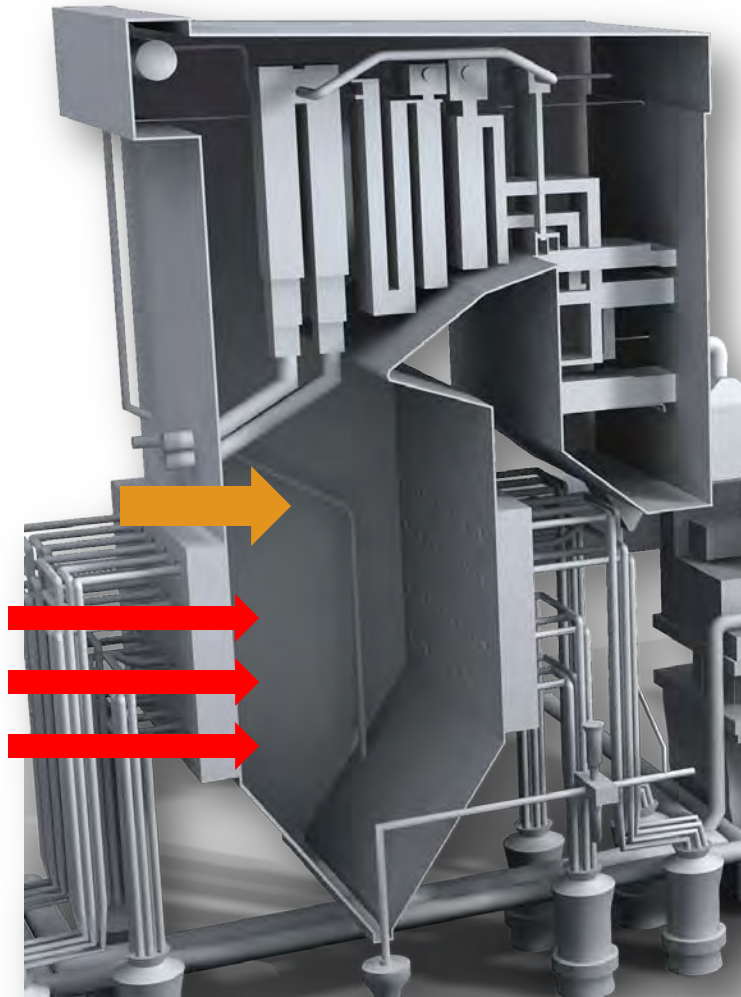
THE BEST OF BOTH WORLDS





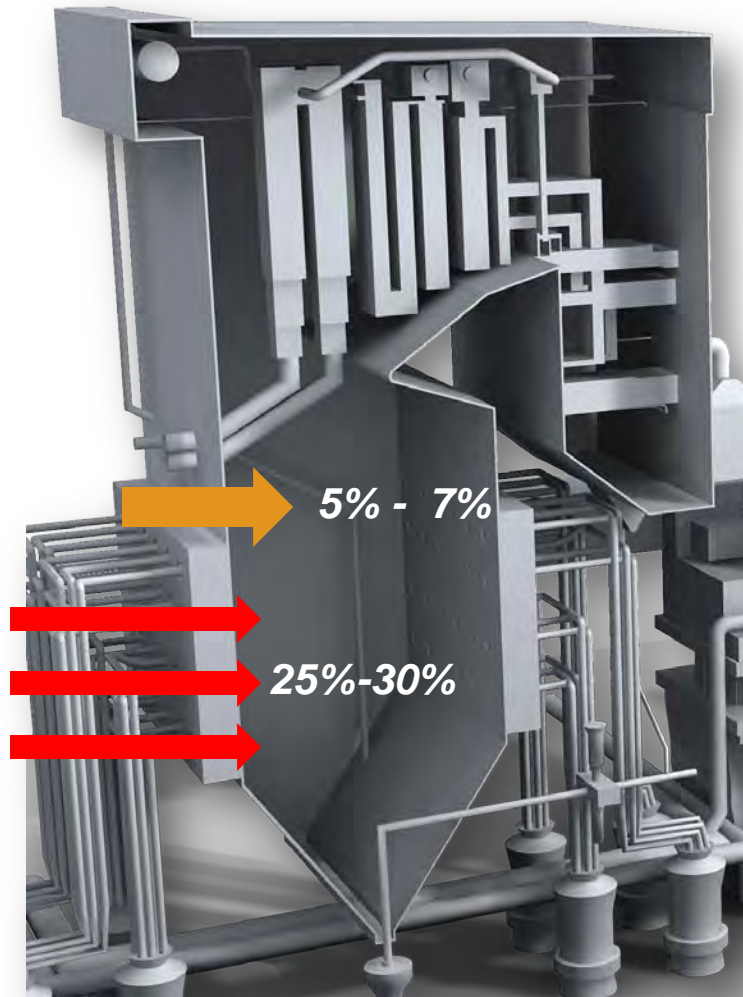
The walls and Upper Heat transfer surfaces are designed to accept heat from high emissivity coal particles

Simply re-powering with natural gas has inherent limitations due to the need for different heat transfer surfaces



Gas CoFiring marries natural gas and coal at each burner, injected through a modified igniter.

It also adds a portion of the total heat input as gas in the upper furnace. This is known as Fuel Lean Gas Reburn.



The Goal is to get up to 35% of the total heat input converted from coal to gas.

With 25% - 30% of that coming at the igniter location and 5% - 10% coming at the FLGR location.

# Dual Orifice CoFire Igniter





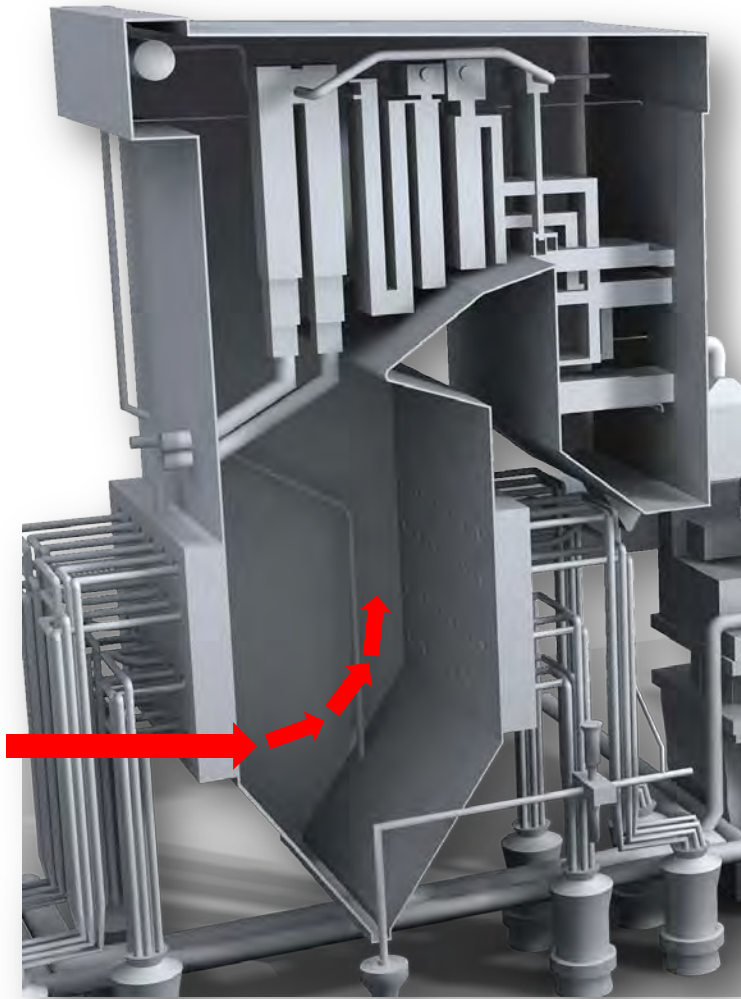
## A typical NFPA Class 1 Igniter:

- **10% of the Heat Input of the associated burner,**
- **Single, fixed size fuel spud,**
- **Single, fixed flow air supply**

## Providing Higher Gas Volume:

- **Requires higher gas inlet pressure,**
- **Increases gas igniter flame velocity and penetration**

# 25% Heat Input Igniter



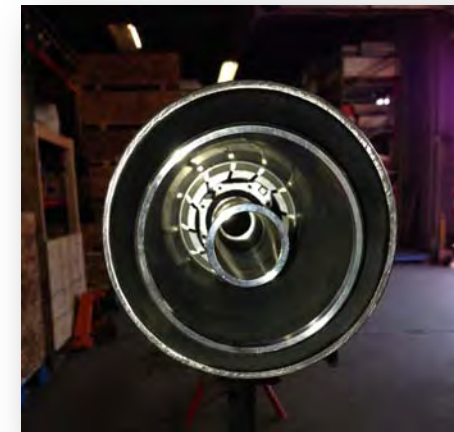
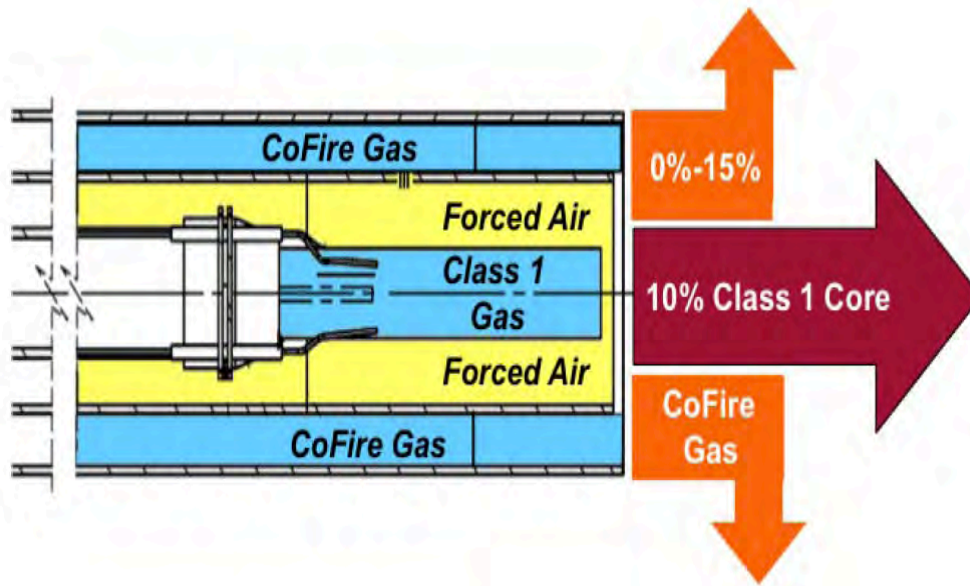
Providing 25% of the Heat to the boiler through a Class 1 igniter will extend the ignition flame into the center of the furnace.

This will have the effect of driving Furnace Exit temperatures UP, but keeping wall steam generation LOW.

Resizing the igniter for 25% standard throughput will make it unstable at low throughputs

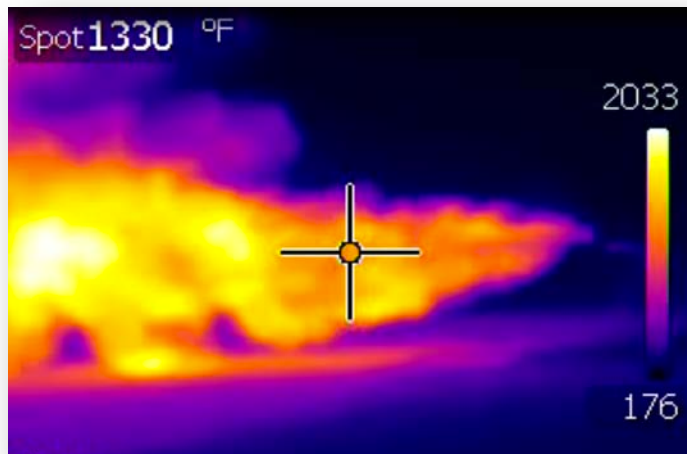
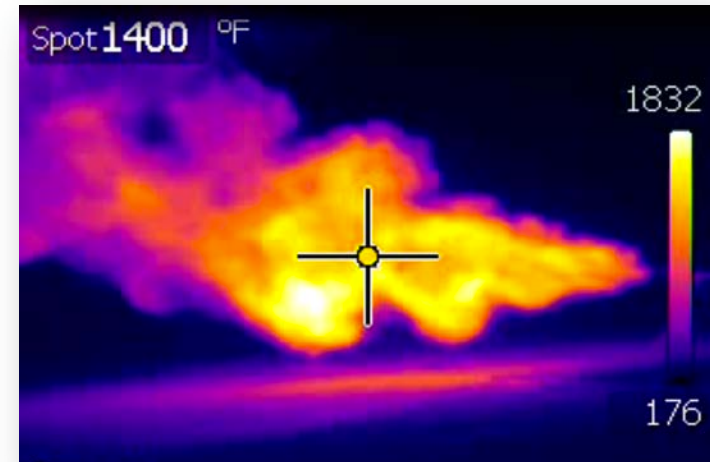
# Dual Orifice Design

Maximizes Gas flow while maintaining heat proximity to the furnace walls



Cofire gas comes from a higher area secondary annulus

# IR Images



- 1) Upper Left is Core only with 20 mmBTU. Max flame temp = 1644, notice the flame size
- 2) Upper Right is Cofire with 35 mmBTU-combined heat release. Max flame temp = 1832.
- 3) Lower Left is Cofire with 65 mmBTU-combined heat release. Max flame temp = 2033.



## System Requires:

- 80 CFM Forced Combustion Air/Igniter
  - Isolation Valve between Core and CoFire sides
  - Pressure Control on the Core side
- 
- Additionally we remotely monitored:
- Gas Pressure
  - Air Pressure
  - Core Flame Stability

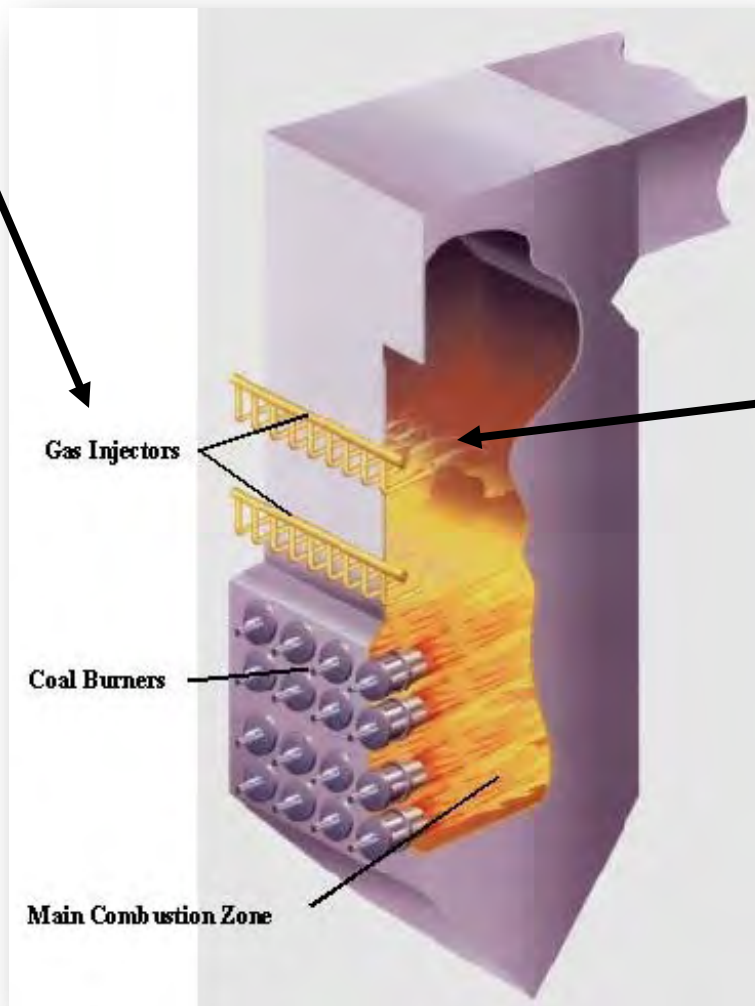
# Fuel Lean Gas Reburn

COAL DISPLACEMENT WITH NO<sub>x</sub> REDUCTION



# Fuel Lean Gas Reburn (FLGR)

- **Injects 3% to 10% of Fuel into Upper Furnace**

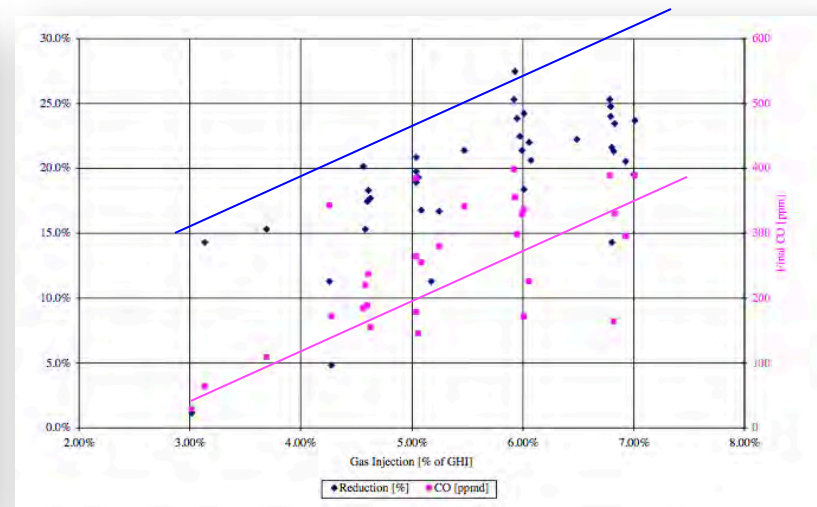
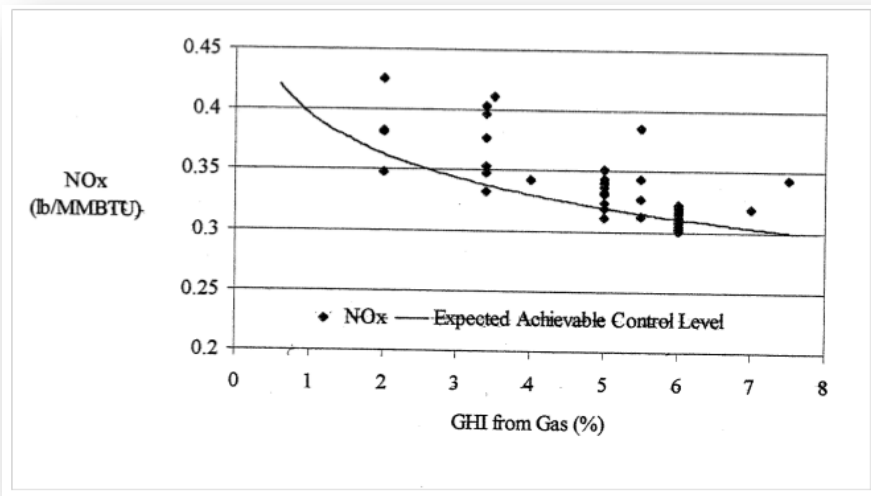


- Locally Fuel-rich Pockets with-in Fuel-lean Upper Furnace

- 3 - 5% NO<sub>x</sub> Reduction for each 1% Fuel

- **Natural Gas is injected via a series of injectors that are designed to create Micro-Swirls in identified higher NO<sub>x</sub> zones,**
- **Essentially:**
  - $\text{CH}_4 + \text{NO}_x = \text{N}_2 + \text{H}_2\text{O} + \text{CO}$
- **The N<sub>2</sub> and H<sub>2</sub>O parts are simple, the CO combines with flue gas Oxygen to become CO<sub>2</sub> through the backpass.**
- **The limiting factor on the amount of Natural Gas used, and the resulting NO<sub>x</sub> reduction, is the mixing and residence time required to complete the CO:CO<sub>2</sub> reaction**

# Historical Data On NOx Removal



13 System were deployed between 1998 – 2001.

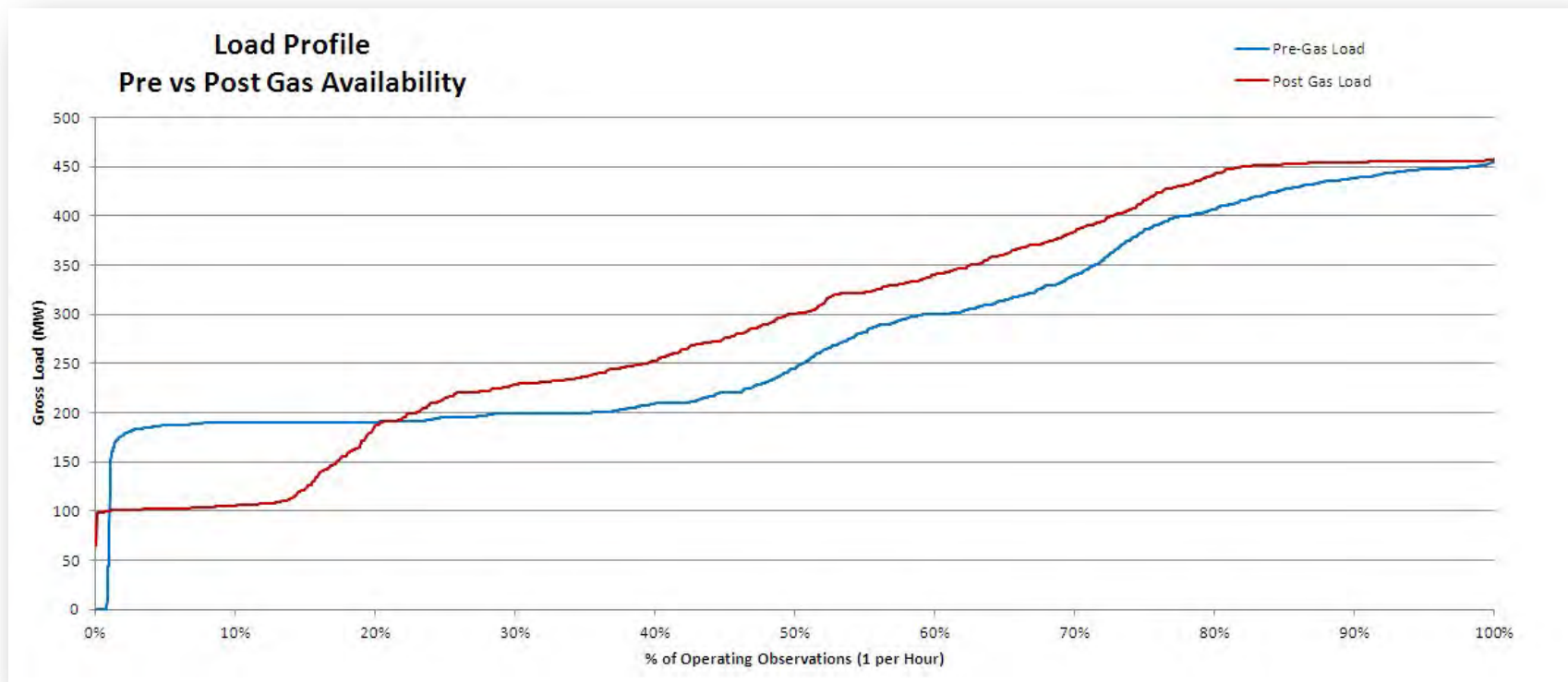
On average a 5% - 7% Gas Heat Input realized a 25% - 30% reduction in NOx prior to the current SCR location

# Furnace CoFiring Impact

RESULTS, STRATEGY AND TACTICS



# Pre/Post Outage Load Profile

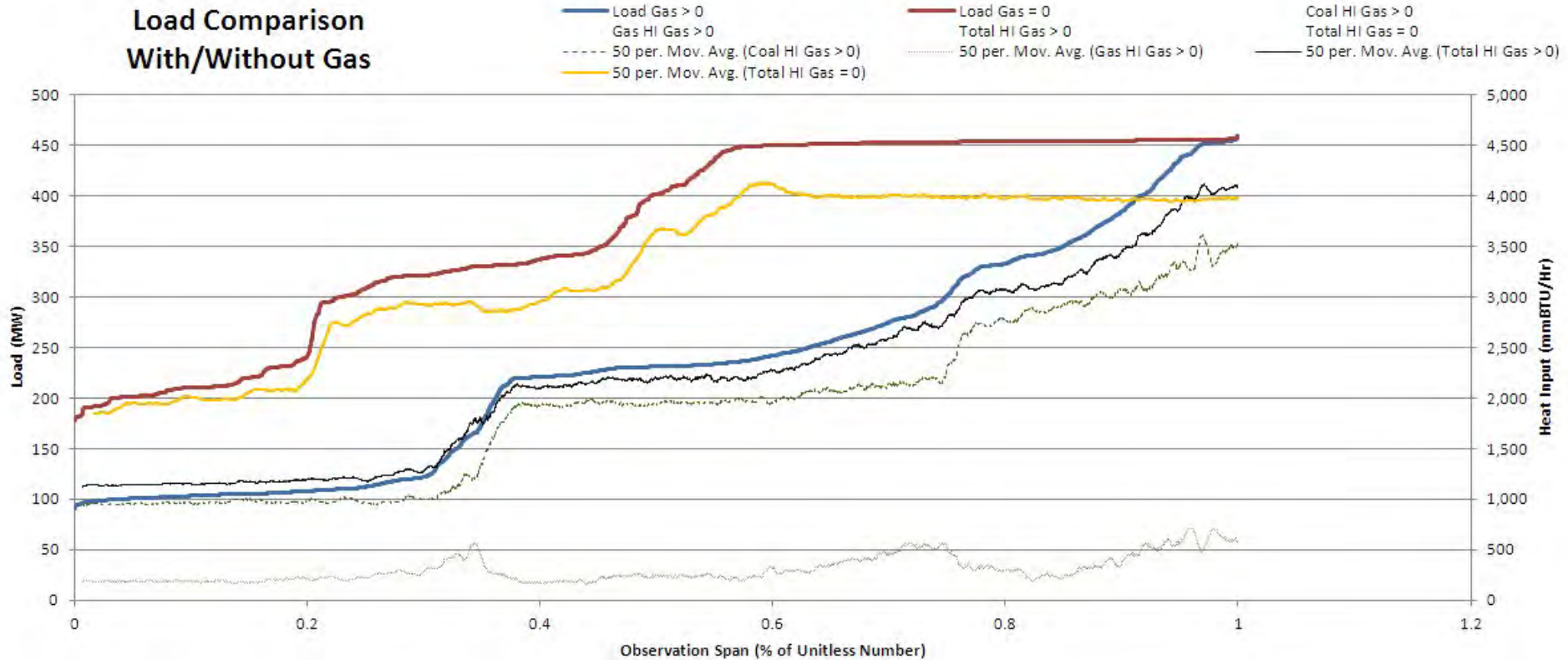


Reduction in Minimum Operating floor was derived from avoidance of SCR MOT issues (due to reduction in SCR Inlet SO<sub>3</sub>) and ability to run safely on 1 mill instead of two

# Pre/Post Outage Fuel Use



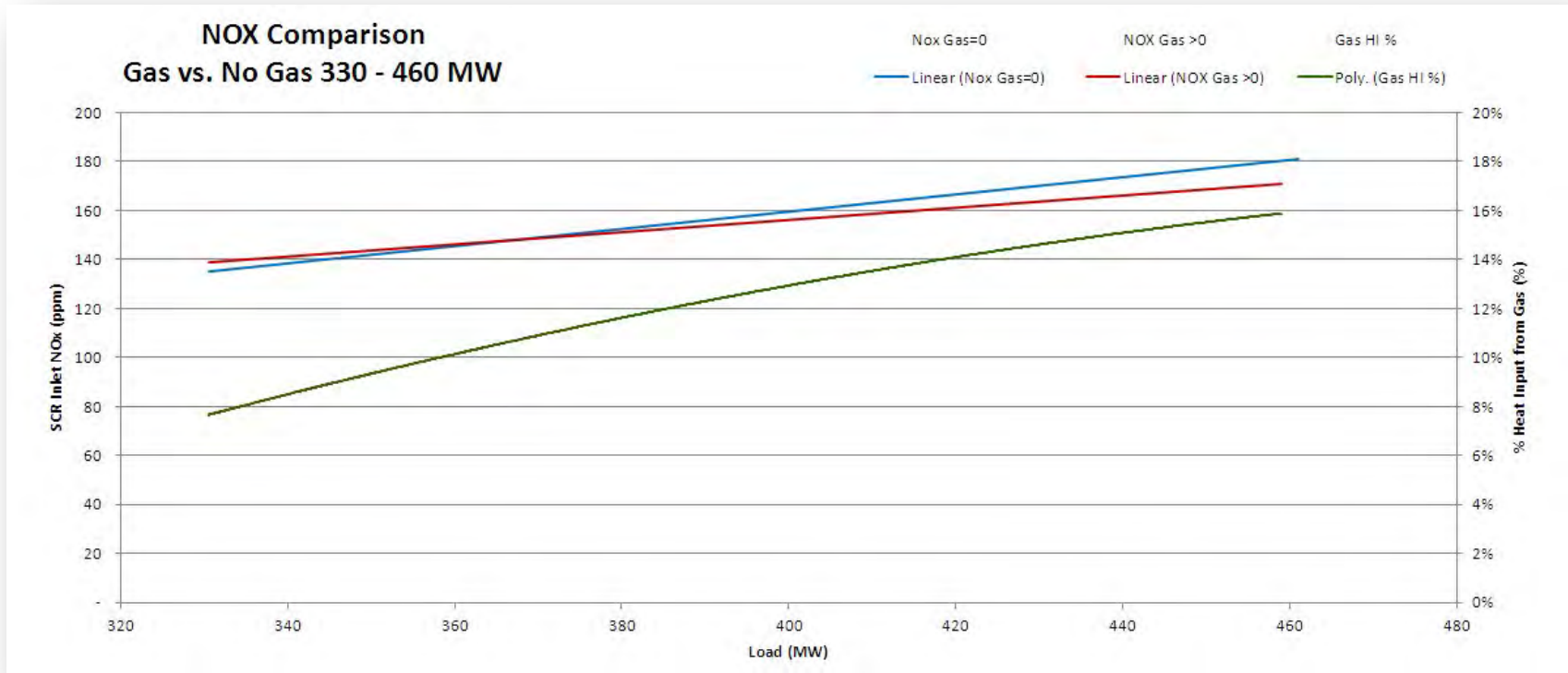
## Load Comparison With/Without Gas



# Environmental Impacts

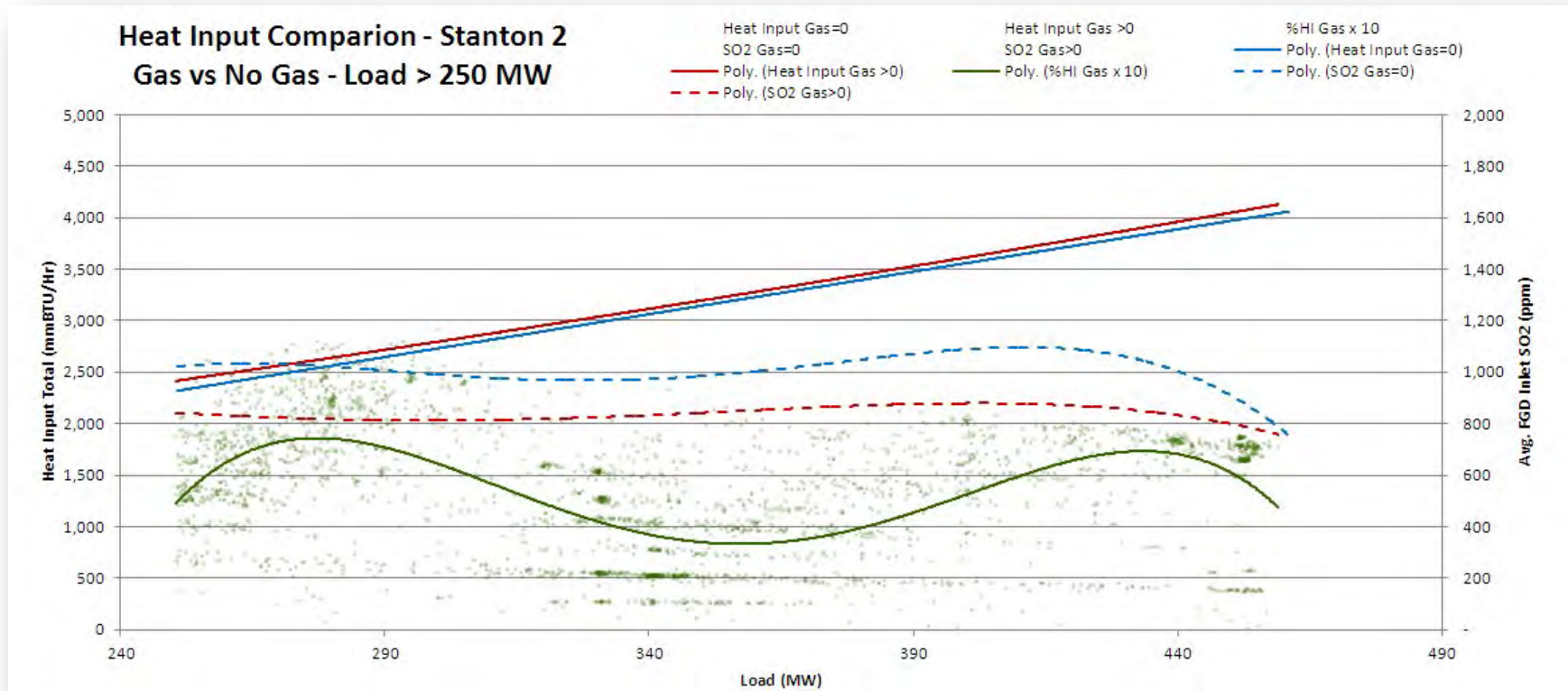


# Gas vs NOx 330-460 MW



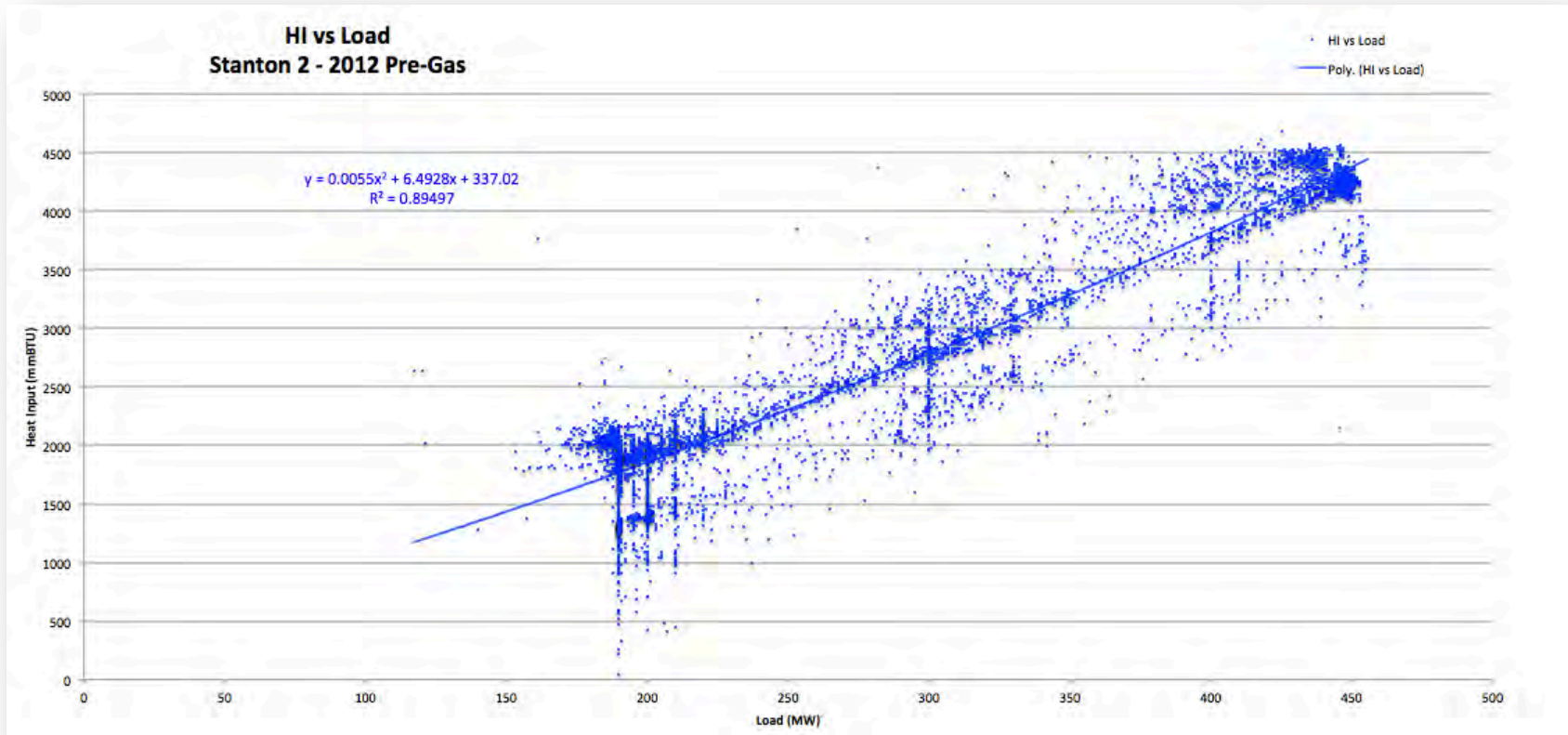
At Full Load a 16% NG Heat Input  
resulted in a 4.6% reduction in SCR  
Inlet NOx

# SO<sub>2</sub>/Heat Rate vs. Gas – High Load

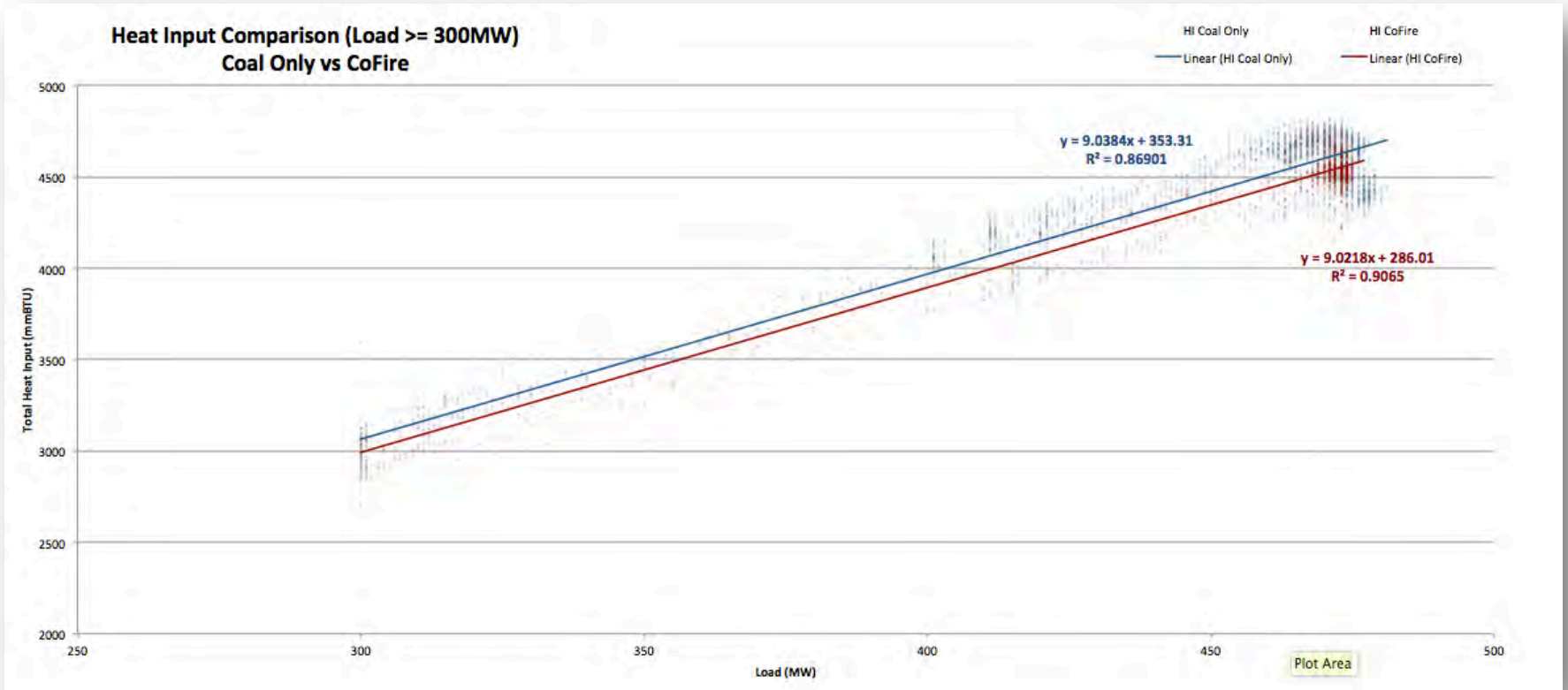


In general, the drop in SO<sub>2</sub> followed the Displacement of Coal with Natural Gas on a percentage basis.

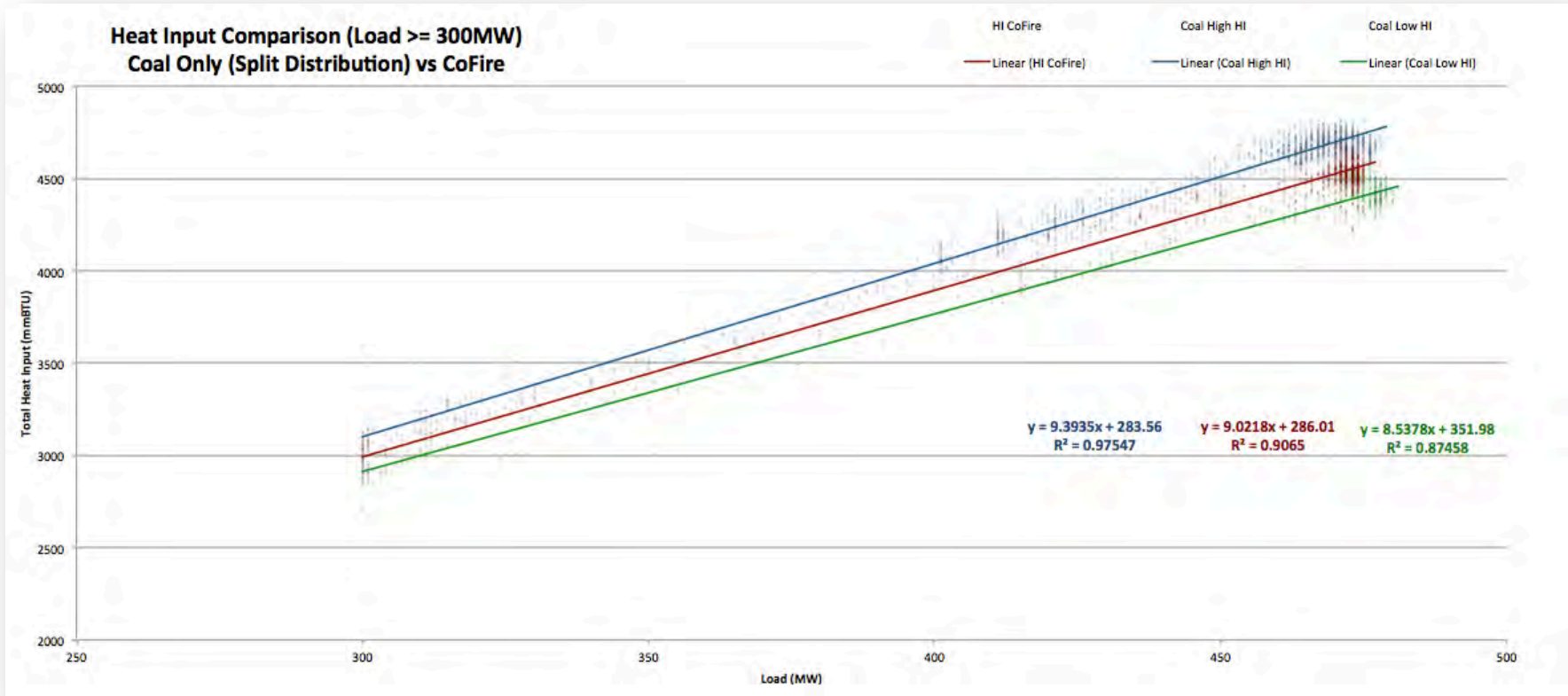
# Pre-Gas Heat Rate



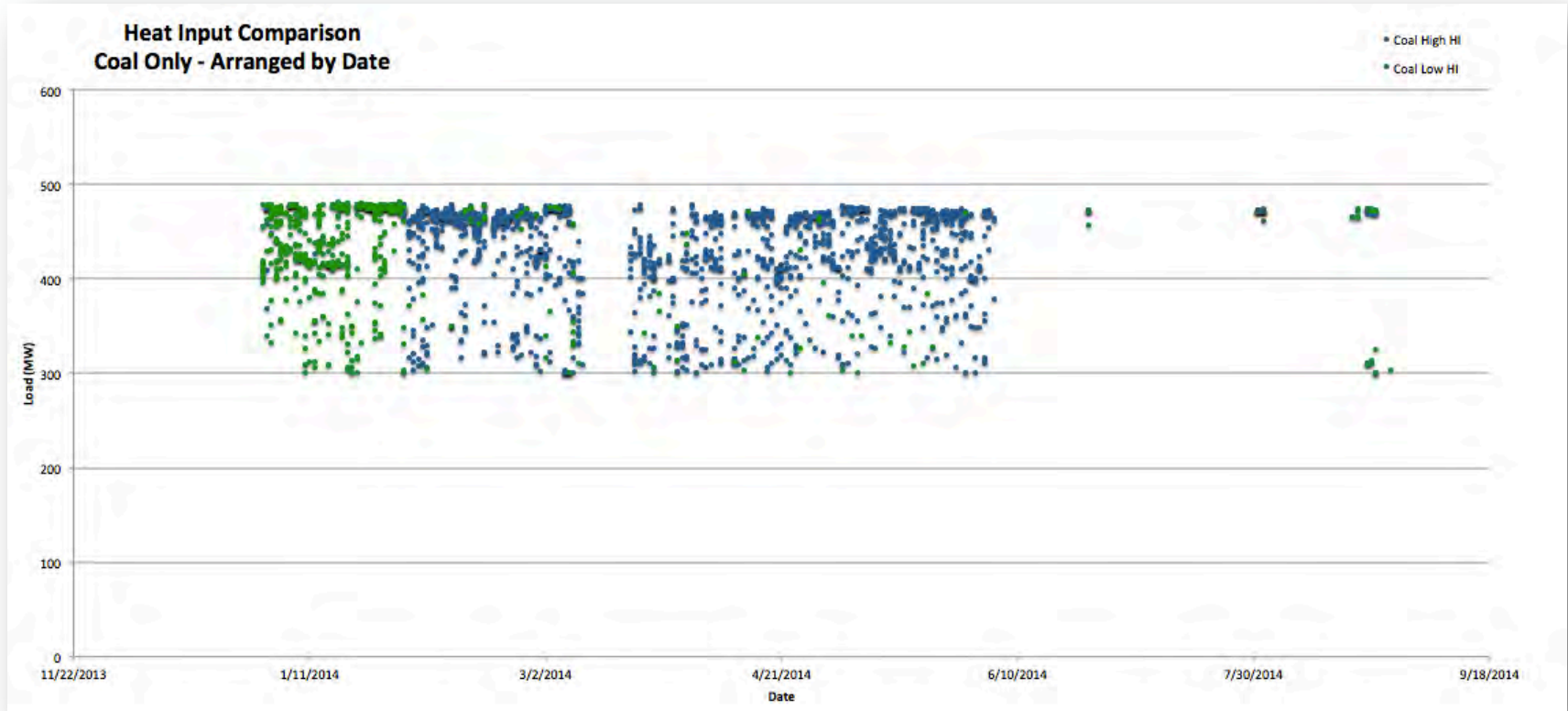
# 2014 9 Mo. Heat Rate Comparison



# Dual Scatter Analysis

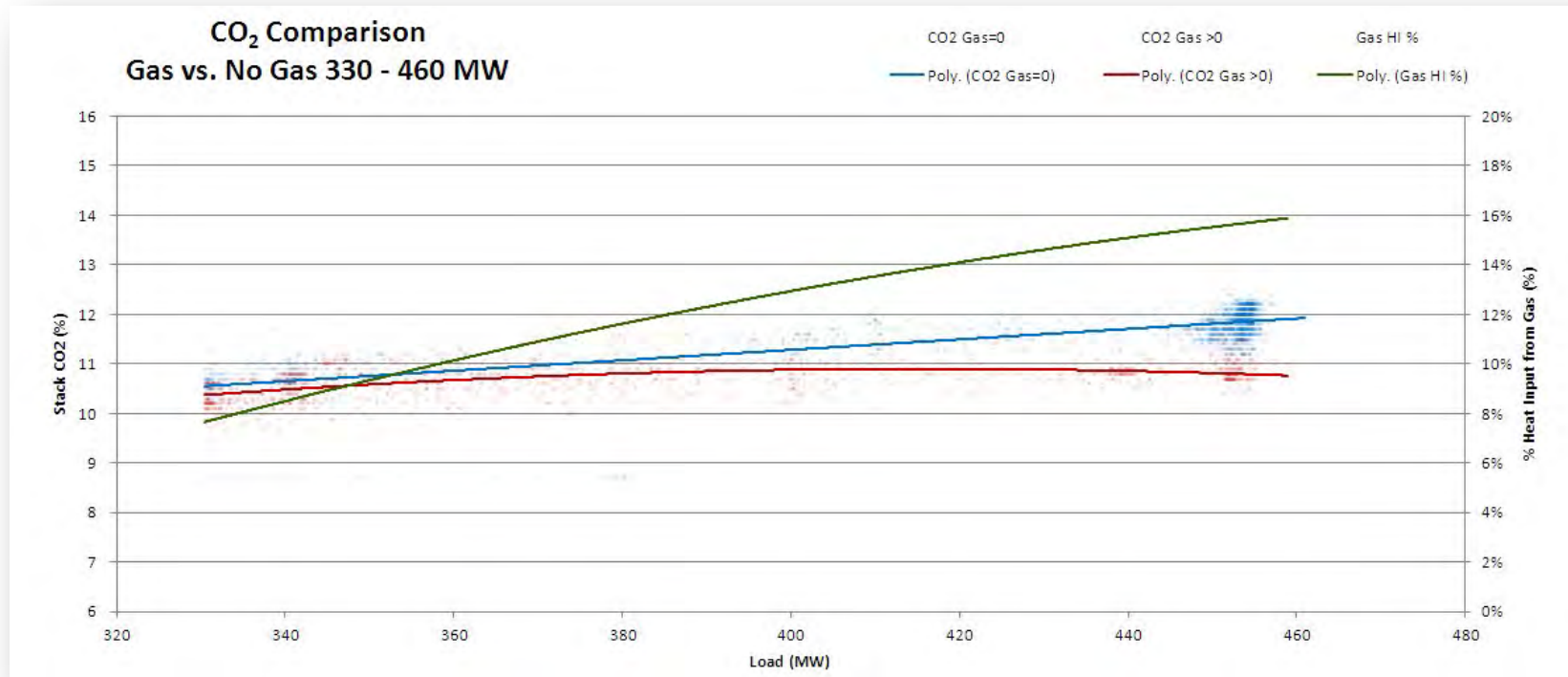


# Scatter Analysis



Low Heat Rate Scatter is generated in Dry Months.  
Typical Heat Rate is improved with Gas CoFiring

# Gas vs. CO<sub>2</sub> 330 – 460 MW



Load	CO <sub>2</sub> Gas = 0	CO <sub>2</sub> Gas > 0	% Redux
340	10.65	10.48	1.65%
400	11.29	10.88	3.65%
460	11.92	10.75	9.81%

At full load, 16% NG Heat Input gas a 9.8% reduction in CO<sub>2</sub>

# Gas Replacement Commercial Benefits



- **From Industry Publications:**
- **Cost of SO<sub>2</sub> O&M = \$135.90/Ton removed**
- **Cost of NO<sub>x</sub> O&M = \$407.70/Ton removed**
- **Cost of CCR Disposal = \$20.00/Ton avoided**
  
- **Cost of Hg? = \$10,000/Lb.**
- **Cost of SO<sub>3</sub> Removal**

## SO<sub>2</sub>

- **Original = 5,432,000 mmBTU x 4 Lb/mmBTU = 10,864 Tons SO<sub>2</sub>**
- **Cofire = 1,358,000 mmBTU<sub>Coal</sub> x 4 Lb/mmBTU = 2,716 Tons SO<sub>2</sub>**
- **Reduction = 10,864 – 2,716 = 8,148 Tons SO<sub>2</sub>**
- **\$135.90/ton x 8,148 Tons = \$1,107,313 Saved**

## NO<sub>x</sub>

- **Original = 5,432,000mmBTU x .3 Lb/mmBTU = 815 Tons NO<sub>x</sub>**
- **CoFire = 2,716,000 mmBTU x .255 Lb/mmBTU = 346 Tons Nox**
- **Reduction = 469 Tons**
- **\$407.70/Ton x 469 Tons = \$191,200 Saved**
- **This could be offset by NO<sub>x</sub> Reduction cost at NGCC**

## Particulate

- *Original = 5,432,000 mmBTU/25mmBTU Per ton coal*
- *Original = 217,280 Tons Coal x 10% = 21,728 Tons Ash*
- *100 MW CoFire = 25% coal use = 5,432 Tons Ash*
- *16,296 Tons Ash Avoided @ \$20/Ton = \$325,920*

## Combined Low Load Environmental Savings

*\$1,107,313 +*

*\$191,200 +*

*\$325,920 =*

**\$1,624,433**

## Baseline:

- 465 MW x 10mmBTU/MWH x 2800 Hr = 13,000,000 mmBTU
- SO<sub>2</sub> = 26,000 Tons
- NO<sub>x</sub> = 1,950 Tons
- Particulate = 52000 Tons

<i>SO<sub>2</sub> Reduction = 20% = 5,200 Tons =</i>	<i>\$706,680</i>
<i>NO<sub>x</sub> Reduction = 30% = 585 Tons =</i>	<i>\$238,505</i>
<i>Particulate Reduction = 20% = 10,400 Tons =</i>	<i>\$208,000</i>
	<b>=====</b>
<b>Total High Load Environmental Benefit =</b>	<b>\$1,153,185</b>

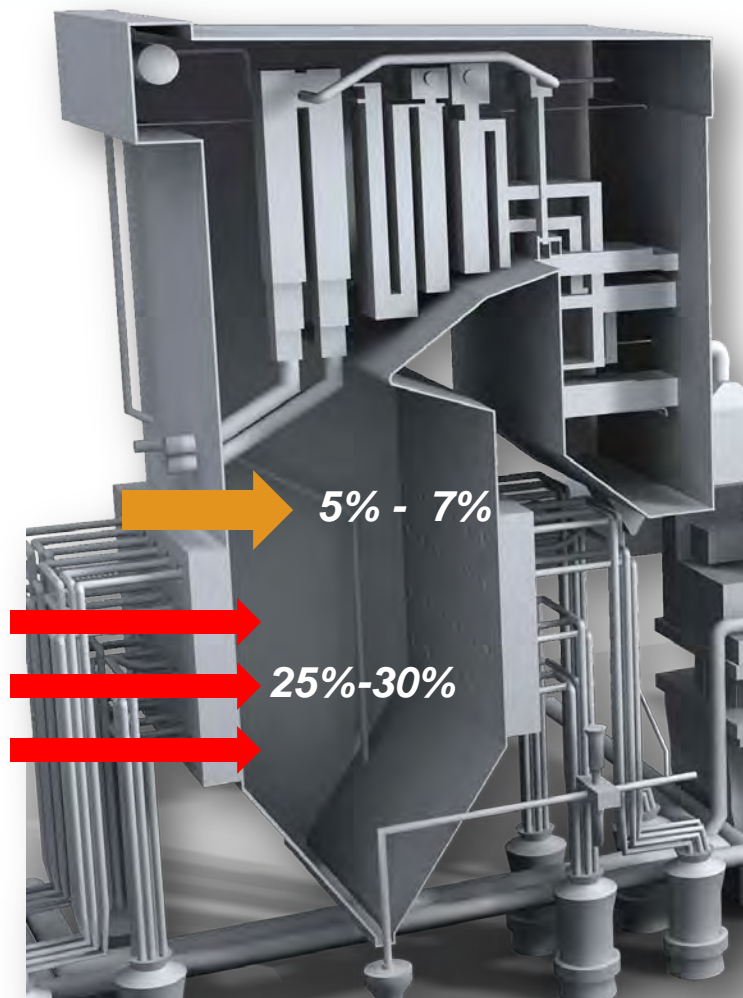
**Plus a CO<sub>2</sub> reduction of 117,000 Tons (8.7%)**



- **Original = 13,000,000 mmBTU x \$2.34 = \$30,420,000**
- *20% Cofire*
  - *\$24,336,000 in Coal Cost*
  - *\$8,346,000 in Gas Cost*
  - *\$32,682,000 in Total Cost*
- *A total fuel cost penalty of \$2,262,000*
- *When Offset by the Environmental Savings of \$1,153,185*
- **Total Cost Penalty = \$1,108,815 per year**

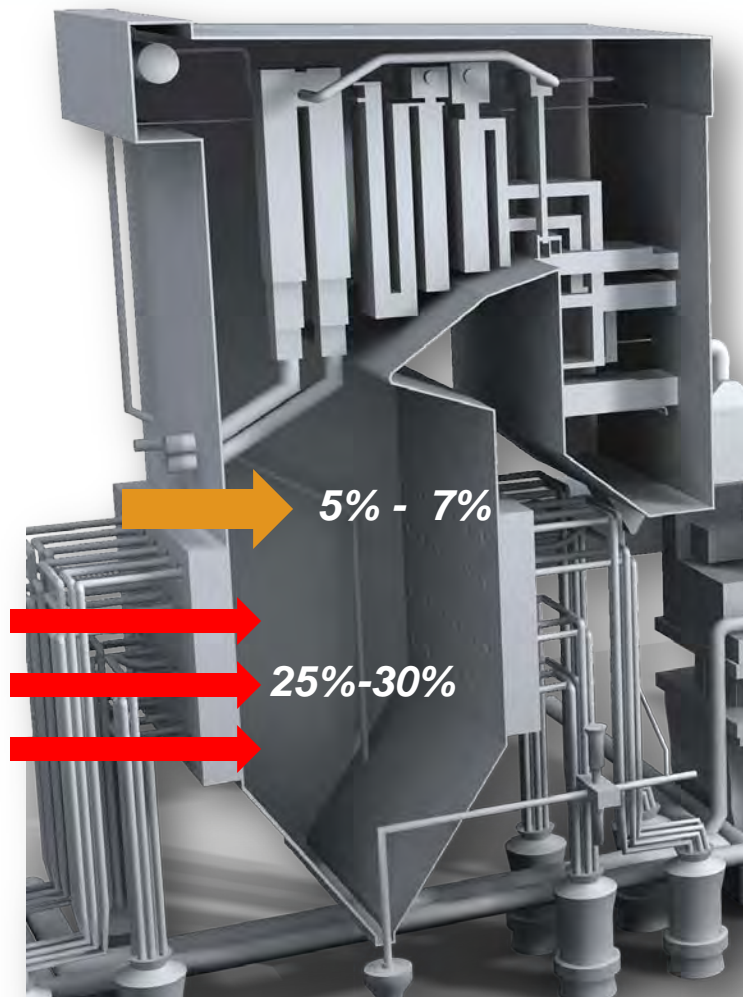
# Summary





Coordinated use of Natural gas at the burner and upper furnace areas provides a significant environmental benefit at moderate to little cost

Advanced use of Enhance Gas Cofiring can provide up to 70% of the environmental improvements needed by non-controlled EGUs at less than 10% of the cost

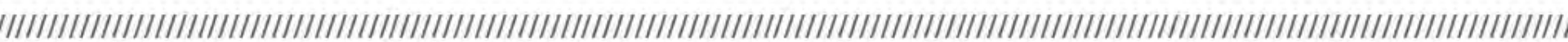


Employment of Enhance Gas Cofiring on both controlled and uncontrolled units provides Fuel Flexibility options that can:

1. Maintain dispatch viability for smaller, bubble, units
2. Allow blending of lower cost coals to enhance commercial viability,
3. Allow a current “Coal Fired” EGU to remain coal permitted as a hedge against changes in fuel pricing.

- **This analysis does NOT include:**
- **Maintenance impacts of reduced start/stop**
- **Savings in Mercury removal cost**
- **Savings in improved mill performance**
- **The ability to move from Bituminous to PRB fuel with Natural Gas Dilution**

**Many, many thanks to the Staff at Orlando Utilities Stanton Energy Center**



**Questions?**

